SUBMITTED COMMITTEE REPORTS

As a general policy, the Federal Energy Bar Association does not take positions in published Committee Reports on substantive issues that are the subject of pending litigation.

REPORT OF THE ELECTRIC COMMITTEE

I. STRUCTURAL CHANGES IN THE INDUSTRY

A. Mergers

1. Merger Policy

In 1998, the Federal Energy Regulatory Commission (FERC or Commission) continued in its commitment to expedite approval of those mergers that pose no significant threat to competition, and to promote alternatives to the hearing process where possible. The FERC set only two proposed mergers for hearing during the year,[1] one of which included an optional divestiture alternative,[2] and allowed four others to go forward without additional inquiry.[3] In addition, the FERC continued its efforts to define rules for streamlining the approval process, and to clarify what measures are required to adequately mitigate market power and otherwise protect ratepayers from potentially harmful merger effects.

As expected, during 1998, the FERC issued a Notice of Proposed Rulemaking (NOPR) clarifying the Commission's merger policies and filing requirements.[4] The Commission noted that the rapidly evolving nature of the industry had increased the need for clearer guidance on what information is required in a section 203 application, and for greater certainty about the ultimate outcome of a merger application.[5] To that end, the NOPR proposes to codify existing merger policy as outlined in the 1996 Policy Statement and in subsequent cases, including codification of the Commission's existing horizontal market power analysis and adoption of a vertical market power analysis. The NOPR also proposes to revise the Commission's filing requirements, including the elimination of outdated requirements, and to provide a streamlined process for those mergers that do not raise competitive concerns.[6] Finally, the NOPR asks for industry comment on its proposed computer simulation model for analyzing a merger's anticompetitive effects, and for comment on how to approach mergers that fail the Commission's competitive screen analysis.[7]

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1. *American Elec. Power Co. & Central & Southwest Corp.*, 85 F.E.R.C. ¶ 61,201 (1998); *Allegheny Energy, Inc. & DQE, Inc.*, 84 F.E.R.C. ¶ 61,223 (1998).

2. 84 F.E.R.C. ¶ 61,223, at 62,073 (giving the applicants 10 days in which to inform the Commission whether they would agree to divest the 570 megawatt (MW) Cheswick unit, or would proceed to hearing). The Commission also indicated it would set the ratepayer protection issues for hearing if the parties failed to reach a settlement. *Id.* at 62,074.

3. *Louisville Gas & Elec. Co.*, 82 F.E.R.C. ¶ 61,308 (1998); *WPS Resources Corp. & Upper Peninsula Energy Corp.*, 83 F.E.R.C. ¶ 61,196 (1998); *Wisconsin Energy Corp., Inc. & ESELCO., Inc.*, 83 F.E.R.C. ¶ 61,069 (1998); *MidAmerican Energy Co.*, 85 F.E.R.C. ¶ 61,354 (1998). In addition, the Commission gave final approval for the Pacific Enterprises-Enova merger following the imposition of satisfactory conditions by the California Commission on Pacific's subsidiary, Southern California Gas. *San Diego Gas & Elec. Co. & Enova Energy, Inc.*, 83 F.E.R.C. ¶ 61,199 (1998).

4. Notice of Proposed Rulemaking, *Revised Filing Requirements Under Part 33 of the Commission's Regulations*, F.E.R.C. STAT. & REGS. ¶ 32,528 (April 16, 1998) [hereinafter Merger NOPR].

5. *Id.* at 33,361.

6. Merger NOPR, *supra* note 4, at 33,361-62.

7. *Id.* at 33,362, 33,383.

The NOPR generated a number of requests for more definitive Commission action in curbing what some perceive as a trend toward an increasingly limited pool of suppliers. Public power advocates reiterated their request for a two-year moratorium on mergers beyond a certain threshold size, and called for closer scrutiny over the retail impacts of proposed mergers.[8] Large industrial customers and consumer representatives joined with public power representatives in asking the FERC to take a closer look at the retail impacts of proposed mergers.[9] Industrial customers also asked the FERC to take a stronger stance on mandatory participation in a functioning Independent System Operator (ISO), rather than relying on applicants' promises to join an independent transmission entity at some point in the future.[10] With respect to the FERC's initial merger analysis and investigation, the Federal Trade Commission suggested that the FERC expand its initial review beyond applicants' market share data, to include review of applicants' internal documents and reports, and review of third-party data.[11] The Commission has yet to issue a final rule in this proceeding.

2. Effects on Horizontal Competition

In 1998, the Commission continued to allow mergers that resulted in little to no increase in generation market power to go forward with relatively limited scrutiny. The FERC summarily approved the acquisition of MidAmerican Energy by CalEnergy just three months after the application was filed, noting that virtually all of the applicants' existing generation served different, noncontiguous markets.[12] Consistent with the guidance provided in the Merger Policy Statement, the Commission did not require applicants to submit a delivered price test analysis for the majority of the applicants' generation, due to the lack of a common geographic market.[13] In addition, the Commission approved two other mergers without hearing based on one of the applicants' status as a net purchaser of energy.[14] In both cases, the Commission noted that the acquisition of a utility with no available generating capacity should not have a significant effect on generation market share.

Even where the applicants' competitive screen analysis exceeded the Policy

8. *Some Urge FERC to 'Plow New Ground' on Mergers; IOUs Push for Status Quo*, ELECTRIC UTIL. WK., Aug. 31, 1998, at 5; *see also* Comments of the American Public Power Association and the Transmission Access Policy Study Group, FERC Docket No. RM98-4-000 at 23-28 (filed Aug. 24, 1998).

9. *Some Urge FERC to 'Plow New Ground' on Mergers*, ELECTRIC UTIL. WK., Aug. 31, 1998, at 5.

10. *Id. See also* Comments of Industrial Customers, FERC Docket No. RM98-4-000, at 4-5 (filed Aug. 14, 1998).

11. Comments of the Staff of the Bureau of Economics of the Federal Trade Commission, FERC Docket RM98-4-000, at 2-3 (visited May 11, 1999) <http://www.ftc.gov/be/v980022.htm>.

12. 85 F.E.R.C. ¶ 61,354.

13. *Id.* at 62,368. The only overlap in generation involved a plant to be built as a joint venture between applicants. Applicants submitted a limited screen analysis as to that market, which did not exceed the Commission's thresholds. *Id.*; *see also Enron Corp.*, 78 F.E.R.C. ¶ 61,179 (1997) (in which the Commission determined the small amount of generating capacity affected by the merger in any relevant market warranted summary approval, with no need for a detailed screen analysis).

14. 83 F.E.R.C. ¶ 61,069, at 61,358 (approving merger between parents of Wisconsin Electric Power Co. and Edison Sault Electric Co.); 83 F.E.R.C. ¶ 61,196, at 61,837 (approving indirect merger of Wisconsin Public Service and Upper Peninsula Power).

Statement's thresholds, the FERC demonstrated substantial willingness to summarily approve a merger if adequately mitigated. In both the Louisville Gas and Electric Company (LG&E) - Kentucky Utilities Company (KU) merger and Allegheny-DQE merger, the FERC showed considerable confidence in the viability of structural approaches to remedying anticompetitive merger effects. The FERC approved the LG&E-KU merger less than six months after it was filed, despite initial Herfindahl-Hirschman Indices (HHIs) that exceeded the competitive screen thresholds.[15] The FERC relied heavily on the applicants' planned participation in the Midwest ISO and noted its intention to ensure continued participation through its post-merger conditioning authority.[16] Likewise, the Commission was willing to approve the Allegheny-DQE merger without further inquiry into its competitive effects *if* DQE agreed to divest its Cheswick generating unit.[17] The Commission agreed with applicants that an adequate relinquishment of control of Cheswick would mitigate the merged company's market power, but found that applicants' proposed short-term sale of capacity from that unit did not constitute an effective relinquishment of control.[18] Thus, the Commission directed DQE to divest the 570 MW unit, or proceed to hearing.

By contrast, the FERC did not go out of its way to develop alternative mitigation measures in the American Electric Power (AEP) – Central and Southwest Corporation (CSW) merger after it found that the merger failed the competitive screen analysis.[19] Instead, the Commission noted that the AEP merger raised concerns with respect to all three factors identified in the Merger Policy Statement as warranting a hearing: 1) the applicant's competitive screen analysis exceeded the HHI thresholds in several markets; 2) the input assumptions and data used for the analysis were subject to substantial question; and 3) external factors suggested that the screen analysis did not accurately reflect the merger's effects.[20] In addition to setting the merger's effect on wholesale competition for hearing, the FERC agreed to examine the merger's effect on retail competition in Missouri—the first case in which it had accepted any responsibility for examining a merger's retail impact.[21]

15. 82 F.E.R.C. ¶ 61,308.

16. *Id.* at 62,221-23.

17. 84 F.E.R.C. ¶ 61,223, at 62,073. DQE has since refused to go ahead with the merger based on the Pennsylvania PUC's disallowance of $1 billion of Allegheny's projected stranded costs, and not as a result of FERC's divestiture requirement. *Pennsylvania Stranded Cost Ruling Sours DQE, Inc. on Merger, But Allegheny Vows to Fight*, ELECTRIC UTIL. WK., Aug. 3, 1998, at 1; *DQE Formally Terminates Merger Deal; Allegheny Files Suit in Federal Court*, ELECTRIC UTIL. WK., Oct. 12, 1998, at 1.

18. 84 F.E.R.C. ¶ 61,223, at 62,071.

19. 85 F.E.R.C. ¶ 61,201. *See also Western Resources, Inc. & Kansas City Power & Light Co.*, 86 F.E.R.C. ¶ 61,312 (1999) (setting merger for hearing on market power and customer protection).

20. 85 F.E.R.C. ¶ 61,201, at 61,818-19. The only external factors identified by the Commission were the increased incentive to use transmission to prevent competitors from gaining access to markets, and AEP's increased ability to raise its competitors' costs through its proposed acquisition of gas transportation facilities. *Id.* at 61,189.

21. *Id.* at 61,819. Because Missouri lacked the authority to review the merger, FERC granted its request to review the merger's effect on retail customers in that state.

3. Effect on Vertical Competition

In the Merger NOPR, the Commission set out separate filing requirements and a separate screen analysis for vertical combinations.[22] The Commission's proposal follows the approach taken in the recent vertical merger cases the FERC has considered,[23] and was based on the framework between the Department of Justice (DOJ) and the Federal Trade Commission (FTC). The NOPR proposes abbreviated filing requirements for mergers unlikely to affect competition in the downstream electric market, and provides examples of situations in which such an effect is unlikely.[24] For other vertical combinations, the FERC proposed a four-step analysis requiring: (1) a definition of relevant products traded by merging firms; (2) a definition of relevant downstream and upstream geographic markets; (3) an evaluation of competitive conditions using HHI statistics; and (4) an evaluation of potential adverse effects.

The Commission did not rule on any new vertical combinations in 1998, but denied rehearing and gave final approval for the Sempra Energy merger.[25] In that order, the FERC rejected arguments that it had improperly relied on conditions imposed by other agencies in conditionally approving the merger. Specifically, the FERC had given its approval contingent on the California Commission's imposition of adequate restrictions and standards of conduct on Southern California Gas, a subsidiary of one of the merging companies, and a state jurisdictional entity.[26] The FERC also rejected claims that the conditions imposed would not adequately mitigate the merged company's market power. The FERC noted that the planned divestiture of gas-fired generation from San Diego Gas & Electric (SDG&E), required by the DOJ, provided additional protection against potential harm to SDG&E's competitors by reducing the merged company's incentive to increase its competitors' costs for delivered gas.[27]

4. Effect on Rates

Consistent with the Merger Policy Statement and the NOPR's proposed requirements,[28] the Commission's 1998 merger orders required applicants to set forth in detail the specific ratepayer protections to be afforded each wholesale customer.[29] While applicants have the burden of proof with respect to the adequacy of ratepayer protection mechanisms,[30] the Commission noted in the *Ameren* rehearing order that opponents of the merger have the burden of going forward with evidence that the proposed mechanisms are inadequate.[31] Moreo-

22. Merger NOPR, *supra* note 4, at 33;375-82.

23. *See, e.g., San Diego Gas & Elec. Co. and Enova Energy, Inc.*, 79 F.E.R.C. ¶ 61,372 (1997).

24. Examples provided include a merger involving: (1) an input supplier that sells a product that is used to produce only a *de minimis* amount in the relevant downstream market; or (2) an input supplier that does not sell into the relevant downstream market. Merger NOPR, *supra* note 4, at 33,375-76.

25. 83 F.E.R.C. ¶ 61,199.

26. *Id.* at 61,868-70.

27. 83 F.E.R.C. ¶ 61,199 at 61,866-68.

28. Merger NOPR, *supra* note 4, at 33,382.

29. *See, e.g.,* 85 F.E.R.C. ¶ 61,201, at 61,821.

30. Merger NOPR, *supra* note 4, at 33,382.

31. *Union Elec. Co. & Central Ill. Publ. Serv. Co.*, 82 F.E.R.C. ¶ 61,093, at 61,356 (1998).

ver, the Commission expressly held in that case that applicants need not show that a customer with access to energy from third party suppliers will always get a lower price in the market than it would have obtained absent the merger.[32]

5. Effect on Regulation

In the Merger Policy Statement and subsequent NOPR, the Commission indicated that it would continue to protect against the potential shift in federal authority from the FERC to the Security Exchange Commission (SEC) in mergers involving a registered holding company, by requiring applicants to abide by the FERC's decisions with respect to intrasystem transactions.[33] If applicants make such a commitment, the Commission will not set the issue for hearing.[34] In addition, the Commission will not address the loss of state authority resulting from a merger unless the state does not have adequate authority to address the issue itself.[35] In the NOPR, the Commission proposed to require an affirmative statement as to whether each affected state has the requisite authority.[36]

The Commission's 1998 merger orders do not provide significant additional insight into this element of the FERC's merger review. In some cases, the surviving holding company remained an exempt entity under the Public Utility Holding Company Act (PUHCA), with no resulting shift in its federal authority.[37] In all other cases, the applicants committed to abide by the FERC's decisions with respect to intrastate transactions, as required.[38] With respect to the effect of the merger on state regulations, the FERC found no reason to believe that the affected states were without authority to address the issue in their own state proceedings. Where the issue was disputed, the Commission was unwilling to credit customers' vague assertions of impaired regulation if the state commission had not raised any such concern.[39] Moreover, the FERC declined to require merging companies to commit to abide by state regulatory decisions with respect to intrasystem transactions, given the states' ability to impose appropriate conditions in their own proceedings.[40]

6. Post-Merger Compliance

In conditionally approving the *First Energy* merger in 1997, the FERC expressed its expectation that the merged company would join an ISO in order to

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32. *Id.* at 61,356-57.

33. Merger NOPR, *supra* note 4, at 33,382-83.

34. *Id.*

35. Merger NOPR, *supra* note 4.

36. *Id.* at 33,383.

37. 85 F.E.R.C. ¶ 61,354, at 62,369; 83 F.E.R.C. ¶ 61,069, at 61,359; 83 F.E.R.C. ¶ 61,196, at 61,841; 82 F.E.R.C. ¶ 61,308, at 62,224.

38. 84 F.E.R.C. ¶ 61,223, at 62,074; 85 F.E.R.C. ¶ 61,201, at 61,821 (in which applicants committed to abide by FERC's rulings with respect to intrasystem transactions with the exception of certain existing coal contracts). Even in those mergers involving an exempt holding company, the applicants often made the required commitment to abide by FERC's decisions with respect to intrasystem transactions "to the extent necessary." *See, e.g.*, 85 F.E.R.C. 61,354, at 62,369-70.

39. 82 F.E.R.C. ¶ 61,308, at 62,224; 83 F.E.R.C. ¶ 61,196, at 61,841.

40. 85 F.E.R.C. ¶ 61,201, at 61,821.

help alleviate any uncertainty as to the effectiveness of the other required mitigation measures.[41] In denying rehearing of the 1997 Order, the FERC rejected arguments that it impermissibly relied on post-merger remedies to reduce acknowledged increases in market power. Instead, the FERC described its expectation of ISO participation as an additional step that would remove any "lingering uncertainty surrounding the competitive effects of the proposed merger," which in no way demonstrated that the pre-merger mitigation measures were inadequate. As the FERC further explained, it requires only reasonable, not absolute, assurance that a proposed mitigation measure will be effective to remedy the anticompetitive effects of the merger.[42]

The FERC noted, however, that in the year since the merger order was issued, First Energy had not joined an ISO and was not currently in negotiations to join an approved or functioning ISO. While the FERC repeatedly stressed that it will use its conditioning authority under the Federal Power Act (FPA), section 203(b), to address any concerns associated with First Energy's timely participation in an ISO, the FERC's post-merger review has thus far been limited to a request for more detailed information as to the status of its ISO discussions.[43]

B. *Disaggregation*

As state restructuring plans proceed and as other competitive pressures build, the number of asset sales and announced disaggregation plans continued to increase. In the eighteen month period prior to November, 1998, over 35,000 MW of generating capacity had changed hands, at a cost of $16.5 billion.[44] Despite its lack of jurisdiction over the underlying transfer of generation,[45] the FERC was often called on to review the transaction as part of its authority over transmission facilities, as well as the contracts, books, and records associated with the generating units. Because most such divestitures involved sales to an entity with little uncommitted capacity in the relevant market, the FERC has generally found such sales to be consistent with the public interest.

41. *Ohio Edison Co.*, 81 F.E.R.C. ¶ 61,110, 61,408 (1997). Applicants voluntarily offered: (1) to allow every municipal electric system identified as a destination market to use the Ohio-Edison-Centerior interface as if it were part of the merged company's native load (i.e. to receive the same reservation and curtailment priority on that interface); (2) to treat the aggregate coincident load of all municipal systems as part of First Energy's native load; and (3) to make First Energy's own resources available to Municipal Systems during periods of curtailment caused by an internal condition on the system at First Energy's cost of supply, and to curtail their own transactions on a proportional basis. The Commission imposed a number of additional requirements, including: (1) giving Municipal Systems equal priority for scheduling on the Ohio-Edison-Centerior interface; (2) joint planning of transmission expansion; (3) a hold harmless provision for the redispatch costs not charged to Municipal Systems; and (4) a cap on the amount paid to First Energy for replacement energy required due to an internal constraint. *Id.* at 61,405-07.

42. *Ohio Edison Co.*, 85 F.E.R.C. ¶ 61,203, 61,845 (1998) (Order Denying Rehearing rejecting argument that merger should have been conditioned on participation in fully-functioning ISO, rather than on post-merger expectation of participation).

43. *Id.* at 61,849-50.

44. *RDI Says 35,000 MW Have Changed Hands in 18 Months; Value Tops $1.6 Billion*, ELECTRIC UTIL. WK., Nov. 23, 1998, at 7-8.

45. In a request for a declaratory order filed in Docket No. EL99-40-000, the American Public Power Association asked the FERC to reconsider its historical position on the scope of its section 203 authority, and review transfers of generation.

Utilities in the Northeast have been particularly active in divesting generation, as those states have often ordered divestiture of generation outright, or as a condition for recovering stranded costs.[46] A number of Northeast utilities have completed arrangements for the sale of all their marketable generating capacity,[47] including Boston Edison's sale of 2000 MW of generation to Sithe Energies and its planned sale of the 690 MW Pilgrim unit to Entergy.[48] Although the divestiture plan of Connecticut Light & Power (CL&P) expressly allows its parent, Northeast Utilities, to participate in the auction of the CL&P units,[49] successful bids to date have generally come from other investor-owned utilities (IOUs) (and their affiliates) or from indpendent power producers (IPPs) in the region, without significant existing generating capacity.

So far, the FERC has not been troubled by the acquisition of large blocks of capacity by one, or a few, purchasers. In *New England Power Company*, the Commission approved NEPCO's sale of all its non-nuclear capacity to USGen New England.[50] The Commission noted that market concentration was likely to decrease because NEPCO was retaining its nuclear capacity, while USGen and its affiliates owned only a small amount of uncommitted capacity in the NEPOOL and NYPP regions. Likewise, the FERC found no adverse effect on competition in the sale of Boston Edison's fossil generation to Sithe Energies, based on Boston Edison's retention of nuclear capacity and the *de minimis* level of uncommitted capacity owned by Sithe or a Sithe affiliate in the region.[51]

In *Central Maine Power Company*, the Commission did not require a competitive screen analysis to determine that the transfer of 1185 MW to FPL Energy Maine (FPL)would not increase generation market power.[52] The FERC noted that FPL and its affiliates owned only a limited amount of capacity in the NEPOOL region, virtually all of which was subject to long-term capacity sales.[53]

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46. *NU to Auction 3,482 MW Held by CP&L; UI Proposes to Form Holding Company*, ELECTRIC UTIL. WK., Oct. 5, 1998, at 4-5 (discussing United Illuminating's divestiture plan in Connecticut); *As Bangor Hydro Moves on Asset Sale, Officials Mull Market Concentration*, ELECTRIC UTIL. WK., Feb. 16, 1998, at 3; *Southern to Buy 1,264 MW of Capacity from Commonwealth Energy and EUA*, ELECTRIC UTIL. WK., June 1, 1998, at 3 (discussing Commonwealth Edison's planned sale of Massachusetts generation to Southern Energy).

47. *Id.*

48. *Entergy to Buy Boston Edison's 690 MW Pilgrim Nuclear Plant for $121 Million*, ELECTRIC UTIL. WK., Nov. 23, 1998, at 1, 8-9. On April 7, 1999, the FERC conditionally approved the transfer of Pilgrim to Entergy, subject to the outcome of a hearing ordered April 5, 1999, and subject to refund from the date of transfer. *Boston Edison Co. & Entergy Nuclear Generation Co.*, 87 F.E.R.C. ¶ 61,053 (1999).

49. *NU to Auction 3,482 MW*, ELECTRIC UTIL. WK., Oct. 5, 1998, at 4-5 (discussing Northeast Utilities' plan for divestiture of Connecticut Light & Power generation).

50. *New England Power Co.*, 82 F.E.R.C. ¶ 61,179 (1998). The transfer of NEPCO's 4,000 MW of capacity gave USGen NE approximately 22% of NEPOOL's installed capacity. *FERC Okays NEES Sale of Nearly 4,000 MW to USGen; State Approvals Still Needed*, ELECTRIC UTIL. WK., Mar. 2, 1998, at 1.

51. *Boston Edison Co.*, 82 F.E.R.C. ¶ 61,311, 62,736 (1998). *See also Cambridge Elec. Light Co.*, 85 F.E.R.C. ¶ 61,217 (1998) (approving sale of non-nuclear generation by Commonwealth Energy subsidiaries to Southern Energy affiliates).

52. *Central Me. Power Co.*, 85 F.E.R.C. ¶ 61,272, 62,092-93 (1998). FPL Energy Maine had agreed to purchase the CMP capacity for $846 million, or 4.1 times its estimated book value. *As Bangor Hydro Moves on Asset Sale, Officials Mull Market Concentration*, ELECTRIC UTIL. WK., Feb. 16, 1998, at 3; *Utility Plant Sales Plans in U.S. Total 81,300 MW*, ELECTRIC UTIL. WK., Aug. 24, 1998, at 15.

53. In that order, the FERC also rejected a request to require applicants to undertake the same kind of

However, the Central Maine Power (CMP) divestiture hit a potential snag in October 1998, when the FERC issued an order clarifying the relative access rights and construction obligations of NEPOOL transmission customers.[54] FPL claimed that the FERC's order decreased the value of existing generation in NEPOOL. It subsequently filed suit in the Southern District of New York asking to be relieved of its obligation to purchase the CMP units.[55] The suit has since been dismissed.[56]

While the bulk of divested generating units have been either fossil-fuel or hydroelectric, the first agreements for the transfer of nuclear capacity occurred in 1998. In addition to Boston Edison's announced sale of the Pilgrim nuclear unit to Entergy, AmerGen agreed to purchase GPU's Three Mile Island nuclear unit.[57] The sale was part of GPU's long-term plan to divest all its generation in order to concentrate on transmission and distribution, announced last year.[58] In September of 1998, Duquesne Light & Power also announced plans to sell off its full complement of generating capacity, including its nuclear units.[59]

A number of utilities in the West and Midwest also announced plans to divest all, or substantially all, of their generation units. In some cases, the plan appeared to be a voluntary response to the changing competitive market.[60] In others, the divestiture plan was tied to a request for stranded cost recovery[61] or merger approval.[62] Other utilities announced plans to disaggregate through divestiture of their transmission assets to form an independent, for-profit transmission company.[63] These "Transco" or "ITC" proposals have yet to be fully considered or reviewed by the FERC.[64]

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transmission capacity studies as are required for new units on NEPOOL's system. The FERC noted that existing units cannot be treated the same as new units for purposes of determining available NEPOOL transmission capacity. 85 F.E.R.C. ¶ 61,272, at 62,094.

54. *New England Power Pool*, 85 F.E.R.C. ¶ 61,141 (1998).

55. *CMP Stock Slumps 11.7%, After FPL Group Files Suit to Cancel Power Plant Deal*, ELECTRIC UTIL. WK., Nov. 23, 1998, at 1-2.

56. The district court dismissed FPL's suit in March 1999, finding no reason to absolve FPL of its obligation to purchase the units. *FPL Group's Suit to Break Pact to Acquire CMP Plants Quickly Dismissed by U.S. Judge*, ELECTRIC UTIL. WK., Mar. 15, 1999, at 1, 12.

57. *GPU's Sale of Three-Mile Island Unit Seen Breaking Ice on Nuclear Deals*, ELECTRIC UTIL. WK., July 27, 1998, at 3. AmerGen is a joint venture of PECO Energy and British Energy. *Id.*

58. *GPU Begins Auction of 26 Plants*, ELECTRIC UTIL. WK., Apr. 20, 1998, at 1-2.

59. *Duquesne Plans to Auction 3,035 MW of Mostly Coal and Nuclear Capacity*, ELECTRIC UTIL. WK., Sept. 7, 1998, at 14-15.

60. *Montana Power to Begin Asset Sale, as State Lawmakers Affirm Restructuring*, ELECTRIC UTIL. WK., Mar. 16, 1998, at 9 (describing Montana Power's plan to sell its 1,500 MW of generating capacity).

61. *TEP to Auction Baseload Assets, But Eyes Opportunities in Distributed Generation*, ELECTRIC UTIL. WK., Sept. 7, 1998, at 7 (discussing Tucson Electric Power's restructuring plan). *See also Unicom to Sell Six Coal-Fired Plants; Sale Represents 98% of Coal Capacity*, ELECTRIC UTIL. WK., July 13, 1998, at 1, 8 (discussing sale of Commonwealth Edison units and possible write down of nuclear assets).

62. Nevada Power and Sierra Pacific announced a divestiture plan as part of their intended merger, with the promise that some of the proceeds would be reinvested in transmission and distribution. *Nevada Power and Sierra Pacific to Sell a Total of 3,062 MW of Capacity*, ELECTRIC UTIL. WK., July 13, 1998, at 4-5.

63. *See e.g., Entergy Spinning Off Transmission Into Regional For-Profit Corporation*, ELECTRIC UTIL. WK., Apr. 20, 1998, at 1-2; *NSP Mulls Forming Separate Nuclear Generating Company in the Midwest*, ELECTRIC UTIL. WK., May 18, 1998, at 5.

64. Entergy's request for guidance on its proposed Transco structure is pending in FERC Docket No.

By the end of 1998, the California IOUs also had gone well beyond the divestiture requirements imposed by their state legislature or commission. Southern California Edison (SoCal Edison) and Pacific Gas & Electric (PG&E) sold off substantially more than the 50% of generating capacity initially required by the California restructuring plan.[65] Meanwhile, SDG&E, which was required to sell off only its gas-fired generation under the California Commission's *Sempra Energy* merger order, announced plans to sell off all its fossil generation.[66]

With the exception of the nuclear units, many of the units changing hands were sold at a price well above book value. In *Duke Energy Moss Landing*, the FERC made it clear that it would not allow recovery of any premium paid above book value as part of a FERC-approved, cost based rate, given the opportunity and expectation of recovery through sales in the newly competitive market.[67] In that case, the FERC rejected Duke Energy's request for recovery of the premium allegedly paid to acquire the Moss Landing must-run unit, noting that it would no longer apply its traditional criteria for recovery of an acquisition adjustment.[68] The Commission went on to note that Duke could not meet the criteria for recovery of an acquisition adjustment under the traditional standard in any case, as the purported benefits to consumers from the sale of the unit were not quantifiable.[69]

The Commission showed substantial deference to the states in developing their restructuring plans, even where the state plan would result in the loss of FERC jurisdiction. In *Long Island Lighting Company*, the Commission approved New York's proposed transfer of Long Island Lighting Company's (LILCO's) transmission facilities to a newly-created state agency, the Long Island Power Authority (LIPA).[70] Although the transmission facilities would no longer be subject to the FERC's jurisdiction after the transfer, the FERC gave its approval based on LIPA's commitment to file an open access tariff. In response to concerns that the transfer harmed LILCO's ratepayers by delaying the implementation of retail access, the Commission noted that it would not "second-guess a state's proposal that otherwise meets our statutory criteria."[71]

EL99-57 (filed Apr. 5, 1999). In addition, First Energy has requested approval for the transfer of its transmission assets into a separate corporation, in order to facilitate a subsequent transfer to an RTO or to serve as a vehicle for the addition of other parties' transmission assets. FERC Docket No. EC99-53 (application filed Mar. 19, 1999).

65. *PG&E to Sell S.F. Plants to Southern; FPL Wins Bid for Geothermal Units*, ELECTRIC UTIL. WK., Nov. 30, 1998, at 3-4.

66. *SDG&E to Divest its Entire 1,897 MW Portfolio of Fossil-Fired Generation*, ELECTRIC UTIL. WK., Nov. 2, 1998, at 12-13.

67. *Duke Energy Moss Landing*, 83 F.E.R.C. ¶ 61,318, 62,304-05 (1998), *reh'g denied*, 86 F.E.R.C. ¶ 61,187 (1999).

68. *Id.*

69. 83 F.E.R.C. ¶ 61,318, at 62,304, n.40.

70. *Long Island Lighting Co.*, 82 F.E.R.C. ¶ 61,129 (1998).

71. *Id.* at 61,465.

II. MAJOR TRENDS THROUGH THE CASES

A. *Implementing Open Access*

There are currently no submissions received for this section.

B. *Pro-Forma Tariffs*

1. Waiver of Requirements of Order Nos. 888 and 889

In its orders on requests for waiver of the requirements of Order Nos. 888 and 889 (including the reciprocity provision for non-public utilities), the FERC continued to adhere to the waiver standards it adopted in its early cases implementing its open access transmission policies.[72] Thus, a waiver of the Order No. 888 requirements will be granted if the public utility can demonstrate that it "own[s], operate[s], or control[s] only limited and discrete transmission facilities (facilities that do not form an integrated transmission grid), until such time as the public utility receives a request for new transmission service."[73] The FERC will grant a waiver of the Order No. 889 requirements if: (i) the public utility owns, operates or controls only limited and discrete transmission facilities (rather than an integrated transmission grid); or (ii) the utility is a small utility (*i.e.*, disposes of no more than four million megawatt-hours annually) that owns, operates, or controls an integrated transmission grid, unless it is a member of a tight power pool or other circumstances are present which indicate that a waiver would not be justified. A waiver of the Order No. 889 requirements will remain in effect until the FERC takes action in response to a complaint that an entity evaluating its transmission needs could not get information necessary to complete its evaluation or an entity complains that the public utility has used its access to transmission information to benefit unfairly the utility or its affiliates. Finally, the FERC considers requests for waiver of all or part of the reciprocity requirement, by a non-public utility (such as a municipality or a cooperative financed by the Rural Utilities Service), using the same criteria used to determine whether to grant a waiver to a public utility.[74]

However, in one case, the FERC appeared to deviate from those standards

72. *Easton Utils. Comm'n*, 83 F.E.R.C. ¶ 62,334 (1998); *Inland Power & Light Co.*, 84 F.E.R.C. ¶ 61,301 (1998); *M-S-R Public Power Agency*, 86 F.E.R.C. ¶ 61,031 (1999); *Alfalfa Elec. Coop., Inc.*, 86 F.E.R.C. ¶ 61,282 (1999). The FERC addressed in 1998 more than a dozen waiver requests submitted by cooperatives and municipal organizations.

73. 86 F.E.R.C. ¶ 61,282.

74. The FERC also reaffirmed in 1998 the procedures applicable to disputes about whether non-public utilities have complied with the pro-forma tariff's reciprocity provision. The FERC also reaffirmed in 1998 the procedures applicable to disputes about whether non-public utilities have complied with the pro-forma tariff's reciprocity provision. The FERC explained, consistent with previous orders, that

> questions about whether a reciprocity provision has been met by a non-public utility can be resolved either when the non-public utility files a reciprocity tariff or when a public utility providing transmission service to that non-public utility asks the non-public utility to provide a specific transmission service and the non-public utility unjustifiably refuses to provide comparable service.

Jacksonville Elec. Auth., 82 F.E.R.C. ¶ 61,203, 61,799 (1998). *See also Seminole Elec. Coop., Inc.*, 85 F.E.R.C. ¶ 61,036 (1998) (quoting 82 F.E.R.C. ¶ 61,203, at 61,799).

in granting a request by a FERC-jurisdictional cooperative for waiver of the requirement that public utilities that are parties to a power pooling agreement must submit a joint, pool-wide, open access transmission tariff for such agreement.[75] In its order, the FERC reiterated the standards applicable to requests for waiver of the requirements of Order No. 888. However, it granted the waiver request even though the cooperative had integrated transmission grid facilities. The FERC explained that because the cooperative already had a *pro-forma* tariff on file with the FERC for transmission service over those facilities, and because the other parties to the pooling arrangement owned "only limited and scattered transmission facilities," waiver was appropriate.[76] The FERC also highlighted the cooperative's commitment to file a joint pool-wide tariff upon receiving a request for pool-wide transmission service and, indeed, conditioned the waiver upon such commitment.[77]

Finally, in response to the FERC's incorporation of the North American Electric Reliability Council's (NERC's) Transmission Loading Relief (TLR) procedures as a "generic amendment" to the *pro-forma* tariff,[78] several FERC-jurisdictional cooperatives sought assurance that their previously granted waivers also exempted them from the TLR procedures. The FERC held that the NERC filing requirements did not apply to the cooperatives because they had been granted waiver of the requirements of Order Nos. 888 and 889.[79]

2. Non-Rate Terms and Conditions

In early 1998, the FERC addressed requests for rehearing of the FERC's early orders on the non-rate terms and conditions of the *pro-forma* tariffs filed in compliance with Order No. 888.[80] The FERC generally reaffirmed its earlier decisions requiring transmission-owning and transmission-operating public utilities to adhere to the uniform terms of the *pro-forma* tariff (other than for regional practices and those areas in which the *pro-forma* tariff expressly gave discretion to the transmission provider). However, the FERC also reiterated its policy of allowing public utilities to propose modifications to the tariff that are "consistent with or superior to" the *pro-forma* terms and conditions, but do not relitigate the "fundamental" terms and conditions of the *pro-forma* tariff.[81] In short, the compliance filings were not the appropriate forum for proposing changes to the *pro-forma* terms and conditions.

The FERC evaluated a number of other proposed changes to individual open access transmission tariffs in 1998, accepting those changes that were "consistent with or superior to" the *pro-forma* terms and conditions and rejecting

75. *Wolverine Power Supply Cooperatives, Inc.*, 87 F.E.R.C. ¶ 61,047 (1999).

76. *Id.* at 61,203.

77. 87 F.E.R.C. ¶ 61,047, at 61,203.

78. *North American Elec. Reliability Council*, 85 F.E.R.C. ¶ 61,353 (1998), *order on compliance filing*, 86 F.E.R.C. ¶ 61,275 (1999).

79. *Petitioning Distribution Cooperatives.*, 87 F.E.R.C. ¶ 61,081 (1999).

80. *See, e.g., Central Me. Power Co.*, 82 F.E.R.C. ¶ 61,251 (1998); *Carolina Power & Light Co.*, 82 F.E.R.C. ¶ 61,204 (1998).

81. 82 F.E.R.C. ¶ 61,251.

those that were not.[82] For example, the FERC rejected a public utility's attempt to modify the indemnification and *force majeure* provisions of its open access transmission tariff.[83] The FERC found that the proposed changes were not regional practices and had not been demonstrated to be "consistent with, or superior to," the *pro-forma* terms and conditions. The FERC also declined to accept a revision to the definition of "Eligible Customer" which would allow the utility to deny service under a state-mandated retail access program. The FERC stated that the proper forum for addressing the utility's objections to such service would be at the state level.[84]

3. Tariff Implementation

The FERC addressed several complaints in 1998 alleging improper denials of service under the *pro-forma* tariff through means such as improper withholding of transmission capacity in order to favor the merchant functions of the transmission providers' affiliates. For example, power marketer Morgan Stanley Capital Group (Morgan Stanley) alleged that transmission provider Illinois Power Company (Illinois Power), in denying a transmission request submitted by Morgan Stanley, failed to post available transmission capacity accurately, failed to award transmission capacity in a non-discriminatory manner, and allocated transmission in favor of its bulk power marketing arm.[85] The FERC found that Illinois Power had failed to implement its *pro-forma* tariff properly, and ordered Illinois Power to take corrective action.[86]

82. *See, e.g., Tucson Elec. Power Co.*, 82 F.E.R.C. ¶ 61,128 (1998) (accepting revisions to tariff); *Public Serv. Co. of N.M.*, 82 F.E.R.C. ¶ 61,127 (1998), *reh'g denied*, 85 F.E.R.C. ¶ 61,240 (1998) (rejecting revisions to tariff); *PJM Interconnection, L.L.C.*, 82 F.E.R.C. ¶ 61,320 (1998) (accepting revisions to tariff); *FirstEnergy Operating Cos.*, 83 F.E.R.C. ¶ 61,030 (1998) (accepting revisions to tariff); *Duke Energy Corp.*, 83 F.E.R.C. ¶ 61,091 (1998) (rejecting revision to tariff); *Northern States Power Co. (Minn.) & Northern States Power Co. (Wis.)*, 83 F.E.R.C. ¶ 61,098 (1998) (accepting and rejecting revisions to tariff, and rejecting unexplained and unidentified revisions to tariff); *Montana Power Co.*, 83 F.E.R.C. ¶ 61,211 (1998) (accepting and rejecting revisions to tariff); *PJM Interconnection, L.L.C.*, 84 F.E.R.C. ¶ 61,212 (1998) (accepting revisions to tariff); *Northern States Power Co. (Minn.) & Northern States Power Co. (Wis.)*, 84 F.E.R.C. ¶ 61,322 (1998) (rejecting revision to tariff); *Niagara Mohawk Power Corp.*, 86 F.E.R.C. ¶ 61,009 (1999) (rejecting separate scheduling and balancing services tariff).

83. *Rochester Gas & Elec. Corp.*, 82 F.E.R.C. ¶ 61,250 (1998). *See also* 82 F.E.R.C. ¶ 61,251, at 62,007 (rejecting the same proposed modifications in open access transmission tariff compliance filing).

84. 82 F.E.R.C. ¶ 61,250, at 62,001-02.

85. *Morgan Stanley Capital Group v. Illinois Power Co.*, 83 F.E.R.C. ¶ 61,204, 61,909 (1998), *order on clarification*, 83 F.E.R.C. ¶ 61,299 (1998).

86. *Id.* at 61,911-13. *See also San Francisco Bay Area Rapid Transit Dist. v. Pacific Gas & Elec. Co.*, 82 F.E.R.C. ¶ 61,282, *order on compliance filing*, 84 F.E.R.C. ¶ 61,307 (1998) (complaint involving network transmission service); *Enron Power Mktg., Inc. v. Pennsylvania-New Jersey-Maryland Interconnection*, 83 F.E.R.C. ¶ 61,032 (1998) (complaint involving network transmission service to retail customer); *Wisconsin Pub. Power Inc. v. Wisconsin Pub. Serv. Corp.*, 83 F.E.R.C. ¶ 61,198, *order on reh'g*, 84 F.E.R.C. ¶ 61,120 (1998) (complaints involving availability of open access transmission services in Upper Midwest, including designation of network resources); *Utah Assoc. Mun. Power Sys. v. PacifiCorp*, 83 F.E.R.C. ¶ 62,337 (1998), *order denying reh'g and granting clarification*, 87 F.E.R.C. ¶ 61,044 (1999) (complaint involving comparability and separation of functions); *Electric Clearinghouse, Inc. v. PJM Interconnection, L.L.C.*, 84 F.E.R.C. ¶ 61,045 (1998) (complaint involving priority of service requests); *Southwestern Pub. Serv. Co. v. El Paso Elec. Co.*, 84 F.E.R.C. ¶ 61,276 (1998) (complaint involving availability of transmission capacity); *QST Energy Trading Inc. v. Central Ill. Pub. Serv. Co. and Union Elec. Co.*, 85 F.E.R.C. ¶ 61,166 (1998) (complaint in-

In further proceedings on another power marketer's complaint seeking transmission service to supply power to the Mexican state utility, the FERC clarified that the Department of Energy (DOE) has "authority to order the provision of transmission services for others over international, cross-border transmission facilities and to condition Presidential Permits and export authorizations on the provision of non-discriminatory open access transmission service over such facilities."[87] The DOE delegated authority to the FERC in that proceeding. The FERC accordingly directed the utility to provide open access transmission service under its *pro-forma* tariff over its cross-border facilities.[88]

In late 1998, the FERC adopted the North American Electric Reliability Council's TLR procedures as a generic amendment to the *pro-forma* tariff.[89] The FERC directed all transmission-owning public utilities in the Eastern Interconnection to file a notice with the FERC indicating their use of the TLR procedures, and also directed them to file proposals for addressing parallel flows associated with service to native load and redispatch solutions to manage regional transmission congestion.[90] However, the FERC rejected a proposed modification to one utility's *pro-forma* tariff that would have adopted the Mid-Continent Area Power Pool's (MAPP) line loading relief (LLR) procedures. The FERC determined that the MAPP's LLR procedures, unlike the NERC's TLR procedures, apparently called for curtailment priorities that were inconsistent with those set forth in the *pro-forma* tariff.[91]

In other NERC-related matters, the FERC found that the NERC's "tagging" requirement, which requires that certain market-sensitive information be provided to control area operators when each transaction is scheduled, did not, by itself, require a change to the *pro-forma* terms and conditions. Rather, the NERC tagging plan's information requirements were consistent with the information requirements already set forth in the *pro-forma* tariff. The FERC emphasized, however, that transmission providers could not use the information collected under the tagging plan in a manner inconsistent with the *pro-forma* terms and conditions. Thus, the FERC rejected a proposal to revise a utility's *pro-forma* tariff to assign the lowest curtailment priority to transactions for which adequate tagging information had not been provided.[92]

The FERC clarified that pool-wide transmission tariffs of loose power pools must provide services to members and non-members alike on a non-discriminatory basis.[93] The FERC approved pool-wide tariffs allowing the pools

volving availability of transmission capacity). *See also The Washington Water Power Co.*, 83 F.E.R.C. ¶ 61,097 (show cause order regarding violations of Order Nos. 888 and 889 by transmission provider and its power marketing affiliate), *order on responses to show cause order*, 83 F.E.R.C. ¶ 61,282 (1998).

87. *Enron Power Mktg., Inc. v. El Paso Elec. Co.*, 83 F.E.R.C. ¶ 61,213, 61,944-45 (1998).

88. *Id.* at 61,946.

89. 85 F.E.R.C. ¶ 61,353 (1998).

90. *Id.* at 62,362-64.

91. *Northern States Power Co. (Minn.) & Northern States Power Co. (Wis.)*, 83 F.E.R.C. ¶ 61,098, *order on clarification*, 83 F.E.R.C. ¶ 62,338, *reh'g denied*, 84 F.E.R.C. ¶ 61,122 (1998). *See also Mid-Continent Area Power Pool*, 85 F.E.R.C. ¶ 61,352 (1998) (rejecting MAPP LLR procedures as not consistent with or superior to the pro-forma tariff's curtailment priorities).

92. *Coalition Against Private Tariffs*, 83 F.E.R.C. ¶ 61,015, *reh'g denied*, 84 F.E.R.C. ¶ 61,050 (1998).

93. *Southwest Power Pool, Inc.*, 82 F.E.R.C. ¶ 61,267, 62,057, *order on reh'g*, 85 F.E.R.C. ¶ 61,031

to offer only limited transmission services, such as short-term firm and non-firm point-to-point transmission services only, under open access transmission tariffs closely modeled after the *pro-forma* tariff.[94]

The FERC continues to require adherence to the *pro-forma* tariff terms and conditions (as modified in Order No. 888-A) and the Open Access Same-time Information System (OASIS) and standards-of-conduct requirements of Order No. 889 for non-public utilities seeking, under the FERC's "safe harbor" procedures, declaratory orders finding that their open access transmission tariffs satisfy the FERC's comparability (non-discrimination) standards and therefore constitute acceptable "reciprocity tariffs."[95] Such reciprocity tariffs must contain terms and conditions that are "consistent with or superior to" those of the *pro-forma* tariff; the FERC evaluates deviations from the *pro-forma* tariff that are sought by non-public utilities in their reciprocity tariffs under the same standards it uses in evaluating modifications sought by public utilities.[96]

The FERC also issued a series of orders on the standards of conduct submitted by non-public utilities as part of their reciprocity tariff filings. As with the transmission tariffs, the FERC requires such non-public utilities to adhere to the same standards and requirements under Order No. 889 to which public utilities must adhere.[97] In short, the FERC's "NJ" orders indicate that the FERC, in its scrutiny of the standards of conduct submitted by non-public utilities, is generally treating public utilities and non-public utilities comparably when they submit reciprocity tariffs.[98]

(1998); *Western Sys. Power Pool*, 83 F.E.R.C. ¶ 61,099, 61,479 (1998). *See also Western Resources, Inc.*, 85 F.E.R.C. ¶ 61,243 (1998) (accepting amendments to multilateral interchange agreement to allow for third-party use of transmission line).

94. *See, e.g.*, 82 F.E.R.C. ¶ 61,267, at 62,054; 83 F.E.R.C. ¶ 61,099, at 61,478-79.

95. *See, e.g.*, *New York Power Auth.*, 82 F.E.R.C. ¶ 61,078, *reh'g denied*, 83 F.E.R.C. ¶ 61,137 (1998); *Salt River Project Agric. Improvement & Power Dist.*, 83 F.E.R.C. ¶ 61,280 (1998); *Long Island Power Auth.*, 84 F.E.R.C. ¶ 61,280 (1998). *See also United States Dep't of Energy - Bonneville Power Admin.*, 84 F.E.R.C. ¶ 61,068 (order accepting compliance reciprocity tariff subject to certain required modifications), *reh'g denied*, 84 F.E.R.C. ¶ 61,250, *order granting extension of time to file compliance tariff*, 85 F.E.R.C. ¶ 61,070 (1998), *order accepting compliance tariff*, 86 F.E.R.C. ¶ 61,278 (1999). The FERC also continues to waive the fee otherwise applicable to the filing of a request for a declaratory order. *See, e.g.*, 82 F.E.R.C. ¶ 61,078, at 61,290.

96. *See, e.g.*, 82 F.E.R.C. ¶ 61,078, at 61,290 (noting that modifications regarding liability and indemnification also had been sought by public utilities but rejected by the FERC).

97. *See, e.g.*, *Colorado Springs Utils.*, 82 F.E.R.C. ¶ 61,297, *order on compliance filings*, 85 F.E.R.C. ¶ 61,286 (1998), *order on compliance filings*, 87 F.E.R.C. ¶ 61,013 (1999); *Big Rivers Elec. Corp.*, 84 F.E.R.C. ¶ 61,257, *order on compliance filings*, 86 F.E.R.C. ¶ 61,150 (1998); *Long Island Power Auth.*, 87 F.E.R.C. ¶ 61,002 (1999).

98. One exception to this general rule was the FERC's decision to consider only those power sales made by the Southwestern Power Administration (Southwestern) above those made to its federal preference power customers in determining whether Southwestern was a "small utility" for purposes of its partial request for waiver of the Order No. 889 requirements. 84 F.E.R.C. ¶ 61,257, at 62,290. The FERC also considered Southwestern's "federal mandate" to provide power to its federal power preference customers and the "undue burden" that would be caused by requiring a separation of Southwestern's merchant and transmission functions. *Id.* Similarly, the FERC showed "some flexibility" in allowing the Western Area Power Administration's (Western) merchant function employees to play a role in setting Western's transmission rates, given the "host of statutes that make [Western's] operation somewhat different from the typical transmission provider" and the fact that Western's transmission rate staff are limited to data that are on the OASIS, publicly available

Finally, the FERC continues to require the unbundling of wholesale power sales from transmission service, including separately stating the rates for wholesale generation, transmission, and ancillary services under contracts which were executed prior to, but the performance of which commenced after, the issuance of Order No. 888.[99] Similarly, the FERC appears to require strict adherence to the *pro-forma* tariff's requirements that delivery and receipt points for service thereunder be designated with specificity and that the transmission provider, when taking service under its own tariff, obtain any necessary ancillary services under its own open access transmission tariff.[100] Indeed, the FERC's staff began using a "check list" setting forth the more common deficiencies in transmission service agreement filings in order to address the many filings by transmission providers.[101]

III. DEVELOPMENTS IN THE STATES

A. Arizona

Changes in the political climate in Arizona at the end of 1998 resulted in major changes for electric deregulation in the state. In early November 1998, the state's two largest investor-owned utilities, Arizona Public Service Company (APS) and Tucson Electric Company (TEC), reached a settlement with the commission's staff under which deregulation would begin January 1, 1999. Under the agreement, TEC was to swap ownership of certain power plants for transmission facilities owned by APS. The agreement also established rate schedules and billing methods, and provided for a retail discount.

Numerous parties raised concerns about the way the APS/TEC settlement was reached. On November 30, 1998, the Arizona Attorney General's Office, in association with numerous other parties, filed a petition with the state Supreme Court seeking to stay the settlement. The Attorney General stated that the settlement process denied the public its right to a full and fair hearing, and alleged that *ex parte* communications had occurred between commission staff and utility officials. The Supreme Court granted the request.

The November 1998 election replaced Democratic Commissioner Renz Jennings with Republican Tony West, the former State treasurer. On December 31, 1998, the Commission voted 2-1, with Commissioner Jennings in the majority, to approve newly constituted electric deregulation rules. On January 5, 1999, the Commission voted 2-1, with Commissioner West then in the majority,

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or otherwise accessible only pursuant to the standards of conduct. 87 F.E.R.C. ¶ 61,002, at 61,009.

99. *Southwestern Pub. Serv. Co.*, 82 F.E.R.C. ¶ 61,083 (1998); *Idaho Power Co.*, 82 F.E.R.C. ¶ 61,050 (1998).

100. *See, e.g., Minn. Power & Light Co.*, Docket No. ER98-1504-000 (Feb. 12, 1998) (letter order) (unpublished); *West Tex. Utils. Co.*, Docket No. ER98-1234-000 (Feb. 17, 1998) (letter order) (unpublished). *See also Northern States Power Co. (Minn.) & Northern States Power Co. (Wis.)*, 82 F.E.R.C. ¶ 61,125 (1998) (accepting power sales tariff for sales of ancillary services to entities taking transmission service under open access transmission tariffs of other transmission providers, but rejecting seller's proposal to provide ancillary services to entities taking transmission service under seller's own transmission tariff).

101. *See, e.g., Commonwealth Edison Co.*, Docket No. ER98-1900-000 (Apr. 20, 1998) (letter order) (unpublished).

to temporarily stay the electric deregulation rules that had been adopted just six days before. The Commission indicated that it would hold a series of intensive public hearings over the next six months to refine the competition rules.

At the first public meeting on restructuring held April 14, 1999, the Arizona Commission voted in favor of an order to allow retail competition for 20% of consumers initially and all consumers by January 1, 2001.[102] Utilities were required to file their proposals for stranded cost recovery by June 14, 1999. The Commission rejected a solar portfolio standard as too costly, but initiated hearings to consider whether to adopt a renewable resource requirement that would include all renewables.

On May 17, 1999, APS and TEC filed a settlement agreement, claiming that it would reduce electricity prices for consumers and open the door to a competitive electric industry market in Arizona sooner than the January 1, 2001 date required by the Arizona Commission. The Arizona Commission will likely hold public hearings on the matter later this summer.

As of this writing, the Arizona political climate remains unsettled. In response to a lawsuit filed by former Commissioner Jennings, the Arizona Supreme Court voted 3-2, on June 9, 1999, to remove newly-elected Commissioner West from office. Because West held a securities license at the time of his election and the Commission also regulates state securities laws, he was found to have violated Ariz. Rev. Stat. § 40-101, which states: "[a] person in the employ of, or holding an official relation to a corporation or person subject to regulation by the commission . . . shall not be elected . . . to . . .the office of commissioner."[103] Although the court ratified all of the Commission's actions during the time of Commissioner West's term, they immediately removed him from office and replaced him with former Commissioner Jennings. Jennings will serve until the governor appoints a new commissioner, who will serve the remainder of West's original term, until a commissioner is elected in the next general election (November 2000). If Commissioner Jennings remains in office for any substantial time period, he could reconstitute his pre-1999 majority and change the course of deregulation. Even if Jennings does not remain in office, the replacement commissioner could alter the direction taken by the former West majority.

B. California

California is in a relatively advanced stage in restructuring its electric industry compared to most other states. The California Public Utilities Commission (CPUC) initiated restructuring proceedings in 1994.[104] In late 1995, the CPUC issued guidelines for electricity restructuring in California.[105]

In September 1996, the California legislature enacted electric restructuring

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102. *Matter of Competition in the Provision of Elec. Serv. Throughout the State of Ariz.*, Arizona Corporatioin Commission Docket No. RE-00000C-94-0165, Decision No. 61634 (Apr. 14, 1999).

103. ARIZ. REV. STAT § 40-101 (1999).

104. Docket 94-04-031.

105. *Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation*, Docket 95-12-063 (Dec. 20, 1995).

legislation, generally referred to as Assembly Bill 1890 (AB 1890).[106] The bill directed the establishment of both an Independent System Operator (ISO),[107] given planning and operations functions relating largely to transmission, and a Power Exchange (PX), intended to be a competitive market for power transactions. Each of these agencies was designed to be a state chartered, non-profit entity.

The three largest investor-owned utilities (the IOUs) in California were required to turn over operational control, but not ownership, of their transmission facilities to the ISO. In January 1998, the CPUC approved the transfer of utility transmission lines in the state to the California ISO. The ISO, in its words, "assumed computerized command of the long-distance, high-voltage power lines that deliver electricity throughout California and between neighboring states and Mexico" on March 31, 1998. IOUs are mandated by AB 1890 to sell all their generated power to, and purchase all their generation needs from, the PX during a four-year transistion period that ends March 31, 2002.

The PX began operations the same day as the ISO. In addition, a competing, privately-held power exchange, the Automated Power Exchange (APX), was established in competition with the PX, and had captured some 10% of the market.[108]

AB 1890 also required a competitive transition charge for recovery of stranded costs from 1998 through 2002. A 10% rate reduction was also included, as was large scale retail "choice," and the continuance of energy efficiency programs financed with rate surcharges. Securitization of stranded costs is authorized by the bill. Utilities divesting generation assets are required to agree to operate those units for at least two years after the sale.

On October 30, 1996, the FERC implemented the investor-owned utilities' filings that detailed the ISO and PX operations. [109] Among other things, the FERC ordered that the ISO dissolve an "Oversight Board" that was mandated by AB 1890. This board was to be made up of members appointed by the Governor of California and the California legislature. However, it was dissolved due to a conflict with its own jurisdiction after start-up of the ISO.

In June 1998, a coalition of consumer advocates challenged the AB 1890. The coalition succeeded in placing an initiative (Proposition 9) on the November 1998 California ballot that would have shifted the burden of stranded costs to utility shareholders and would have given consumers a 20% rate reduction. Proposition 9 was defeated in the 1998 general election.

As noted above under the section entitled "Disaggregation,"[110] all three California IOUs have, to date, gone well beyond the requirements imposed by the CPUC to divest generation assets. PG&E and SoCal Edison are in the proc-

106. Stats. 1996, ch. 854, amending various subject matter sections of the California code.

107. On October 30, 1997, the FERC authorized the establishment and operation of the ISO and the PX. *Pacific Gas & Elec. Co.*, 81 F.E.R.C. ¶ 61,122 (1997).

108. *APX Launches New York Power Exchange*, THE ENERGY DAILY, Oct. 28, 1998. The FERC held the APX to be a jurisdictional power company subject to the FERC's annual charges. 82 F.E.R.C. ¶ 61,287, and 84 F.E.R.C. ¶ 61,020, pending on petition for review.

109. *Pacific Gas & Elec.Co.*, 77 F.E.R.C. ¶ 61,077 (1996).

110. *See, supra*, Sect. I.B.

ess of divesting more than the 50% of assets required by the CPUC in December 1995.[111] Rather than simply divesting the natural gas fueled generation, as requried by the CPUC's Sempra merger order, SDG&E has announced the sale of all of its fossil fuel generation as well.[112] Sales above book value have been used to offset transition and stranded costs.

On July 16, 1998, the FERC found that the restructuring of the electric industry under AB 1890, "eliminated any reason for the City of Palm Springs, California request for a wheeling order to facilitate a so-called 'muni-lite' approach to municipalization."[113]

On October 2, 1998, the FERC refused to resolve a contractual dispute between SoCal Edison and the Sacramento Municipal Utility District (SMUD) by rejecting SoCal Edison's petition to rule that SMUD remains bound to the terms of two existing contracts even though California's power market has been restructured.[114]

On October 28, 1998, the Commission issued an order providing market-based rate authority to all entities providing Ancillary Services in the state of California.[115]

On February 25, 1999, the FERC established hearing procedures to determine whether two northern California Duke Energy affiliates—Duke Energy Moss Landing, L.L.C., and Duke Energy Oakland, L.L.C.—are abusing affiliate behavior rules for California generating units that must be run to maintain system reliability.[116] Near the end of 1998, the CPUC adopted rules for enforcing its standards governing transactions between utilities and their unregulated affiliates and penalties for violations.

On February 9, 1999, the FERC approved Amendment No. 13 to the ISO FERC tariff.[117] Significant changes included: (1) withholding the Ancillary Service payments to generators that commit to provide Ancillary Services and then fail to honor that commitment; (2) billing Ancillary Services on the basis of metered load rather than scheduled deliveries; (3) eliminating an inconsistency between congestion charges; (4) allowing generators in the ISO Control Area to submit negative Supplemental Energy bids during overgeneration conditions; and (5) amendments to clarify settlement of Replacement Reserve charges.[118]

On March 31, 1999, a FERC administrative law judge issued an initial deci-

111. PG&E's efforts to transfer its hydroelectric generating assets to it subsidiary have been opposed by groups seeking an auction of those assets. *Special Report: California Restructuring One Year Later*, THE ELECTRIC UTIL. DAILY (Mar. 31, 1999).

112. Approved by CPUC on October 22, 1998.

113. City of Palm Springs, Cal., 84 F.E.R.C. ¶ 61,025 (Jul. 16, 1998), *show cause order*, 84 F.E.R.C. ¶ 61, 225, *denying reh'g of*, 76 F.E.R.C. ¶ 61,127 (1996).

114. 85 F.E.R.C. ¶ 61,023, *aff'd on reh'g*, 85 F.E.R.C. ¶ 61,389 (1999).

115. *AES Redondo Beach, L.L.C.*, 85 F.E.R.C. ¶ 61,123, *aff'g*, *AES Redondo Beach, L.L.C*, 83 F.E.R.C. ¶ 61,358 (1998) and *Long Beach Generation, L.L.C.*, 84 F.E.R.C. ¶ 61,011 (1998).

116. *Duke Energy Moss Landing, L.L.C.*, 86 F.E.R.C. ¶ 61,296 (1999).

117. *California Indep. Sys. Operator Corp.*, 86 F.E.R.C. ¶ 61,122 (1999), filing required by *AES Redondo Beach*, 85 F.E.R.C. ¶ 61,123 (1998).

118. *Id.*

sion involving significant issues of California's restructuring.[119] Among other things, the decision addresses, under the rubric of the "customer credits" issue, how facilities owned by pre-restructuring wholesale municipal customers are to be treated in a restructured environment. The decision also addresses rate methodology, return, rate design, rate level, and loss factors for transmission, as well as refunds to retail customers under certain conditions. Many issues relating to contracts existing at the time of restructuring are unresolved, as are many issues on transmission pricing, including congestion pricing.[120]

On May 3, 1999, the FERC approved a California ISO's plan to issue short-term firm transmission rights (FTR).[121] This decision will allow the ISO to issue FTRs through an auction process. Such contracts will last no longer than one year. They can be transferred to other owners throughout the year, and the ISO will post the new identity of the contract owner.

In May of 1999, in what has been publicly described as a compromise between California legislators and the FERC, a bill, SB96, was introduced into the California legislature, with approval by a key committee, to make both the ISO and the PX regional, rather than simply state-wide organizations through compacts with nearby states.

C. Connecticut

In 1995, the Connecticut Department of Public Utility Control began a comprehensive restructuring investigation, which resulted in recommendations submitted to the Connecticut Legislative Task Force which proposed restructuring legislation.[122] The Department's and the Task Force's recommendations resulted in the enactment of the Electric Restructuring Act in April 1998.[123] Under the Act, supplier choice will be phased in for 35% of customers by January 2000, followed by full supplier choice by July 2000.[124] Prior to the implementation of supplier choice, through December 31, 1999, rates will be frozen at their December 1996 levels.[125]

In an effort to implement the Act, the Department has opened a number of rulemakings and utility-specific restructuring dockets. For example, supplier licensing requirements[126] and codes of conduct[127] were adopted, along with unbundled bill format rules.[128] In early 1999, the Department also adopted proto-

119. *Southern Cal. Edison Co.*, 86 F.E.R.C. ¶ 63,014 (1999) *pending on exceptions.*

120. *Id.*

121. *California Indep. Sys. Operator Corp.*, 87 F.E.R.C. ¶ 61,143 (1999).

122. DPUC Investigation Into the Restructuring of the Electric Industry, Docket No. 94-12-13 (final decision issued July 14, 1995) (visited May 5, 1999) <http://www.state.ct.us/dpuc/>.

123. *An Act Concerning Electric Restructuring*, Public Act No. 98-28 (Apr. 29, 1998) (visited May 5, 1999) <http://www.cga.state.ct.us/ps98/act/pa/pa%2D0028.htm> [hereinafter Connecticut Restructuring Act].

124. Connecticut Restructuring Act, *supra* note 123, § 4.

125. Connecticut Restructuring Act, *supra* note 123, § 3 (b).

126. DPUC Promulgation of Regulations on Licensing Electric Suppliers, Docket No. 98-06-15 (final regulations adopted on Dec. 16, 1998).

127. DPUC Promulgation of Regulations on Codes of Conduct for Electric Distribution Companies, Docket No. 98-06-11 (final regulations adopted on Apr. 14, 1999).

128. DPUC Promulgation of Regulations for a Standard Billing Format for Electric Companies and Elec-

cols relating to metering, billing, and collection services[129] and standard offer service rules.[130] In accordance with the Act, the Department also submitted a number of reports to the legislature in 1998 and 1999, including reports on customer aggregation,[131] supplier licensing,[132] dislocated workers,[133] and exit fees.[134]

A number of restructuring implementation dockets are still open, including the proceedings that address the utilities' divestiture and unbundling proposals, which were filed in October 1998. Connecticut Light and Power Company has proposed divesting its nuclear generation, non-nuclear generation, and power agreements in three separate auctions, with bids on the non-nuclear generation assets due in April 1999.[135] The United Illuminating Company also has announced plans to divest its generation plants and create a holding company.[136] The Department's major 1999 decisions are expected to address stranded costs recovery, securitization, reliability, and the standard offer rates.

D. *Maine*

Maine passed its Restructuring Act in May 1997, which provides for supplier choice by March 2000, generation asset divestiture, standard offer service offered by competitively bid suppliers, capped sales by utility affiliates within the utility's service territory, and competitive metering and billing by 2002.[137] The Act directed the Public Utilities Commission to implement the Act and develop the details, which currently is being done via a series of new rules, utility-specific restructuring proceedings, and studies. The Commission made significant progress in 1998 and 1999, including: (i) the adoption of bill unbundling rules;[138] (ii) the creation of a Consumer Education Advisory Board to create an education program;[139] (iii) the adoption of standard offer regulations with stan-

tric Distribution Companies, Docket No. 98-06-16 (final regulations adopted on Mar. 31, 1999).

129. DPUC Investigation into Billing and Metering Protocols and Appropriate Cost-Sharing Allocations among Electric Distribution Companies and Electric Suppliers, Docket No. 98-06-17 (final protocols adopted on Jan. 13, 1999).

130. DPUC Promulgation of Regulations for Procurement of Generation for Standard Offer and Default Service, Docket No. 98-07-14 (final regulations adopted on Mar. 17, 1999).

131. DPUC Report to the General Assembly on Aggregation, Docket No. 98-06-13 (report issued on Dec. 23, 1998).

132. DPUC Report to the General Assembly on Licensing Electric Suppliers, Docket No. 98-06-14 (report issued on Nov. 4, 1998).

133. DPUC Report to the General Assembly on Dislocated Workers, Docket No. 98-07-02 (report issued on Dec. 30, 1998).

134. DPUC Promulgation of Regulation for Procurement of Generation for Standard Offer and Default Service, Docket No. 98-07-01 (report issued on Nov. 25, 1998).

135. DPUC Review of CL&P Divestiture Plan, Docket No. 98-10-08 (opened on Oct. 7, 1998).

136. DPUC Review of UI Divestiture Plan, Docket No. 98-07-14 (opened on Oct. 7, 1998); DPUC Review of The United Illuminating Company's Corporate Unbundling Plan, Docket No. 98-07-05 (opened on July 1, 1998).

137. An Act to Restructure the State's Electric Industry, LD1804, P.L. 1997, ch. 316, codified as ME. REV. STAT. ANN. tit. 35A §§ 3201-17 (West 1999).

138. Bill Unbundling and Illustrated Bills, Docket No. 98-306 (final rule adopted on June 30, 1998).

139. Activities of the Consumer Education Advisory Board are summarized on the Maine Public Utilities Commission (Maine PUC) website (visited May 5, 1999) <http://www.state.me.us/mpuc/er-page.htm>.

dard offer bidding to begin in August 1999;[140] (iv) the adoption of supplier licensing and information disclosure requirements;[141] (v) the issuance of standards for the interaction among utilities and providers;[142] and (vi) the expected adoption of electronic business transaction rules in June 1999.[143] The Commission also has opened a proceeding to adopt competitive metering and billing rules.[144]

The remaining proceedings before the Commission include six studies to be submitted to the legislature. The studies' topics include (1) northern Maine's connection to the New England power grid; (2) market share limitations; (3) renewable portfolio requirements; (4) standard offer service; (5) standard offer rate caps; and (6) market power. The Commission submitted a report on market power to the legislature in December 1998 recommending that the legislature ban affiliate marketing in the parent utility's service territory.[145] The Commission also submitted a report in late November 1998 regarding the northern Maine electricity market,[146] which lead to the introduction of legislation to create a Northern Maine Transmission Corporation to connect the northern Maine utilities to the U.S. transmission grid.[147] The remaining reports are expected to lead to the introduction of additional restructuring legislation in 1999.

In regards to utility-specific restructuring, the Commission will conduct two separate proceedings for each utility. The first proceeding will address stranded costs and divestiture issues and the second will develop rates. The stranded costs/divestiture proceedings are scheduled to end in July 1999, with the ratemaking proceedings to conclude by October 1999. In late 1998, Central Maine Power Company (CMP) and Florida Power & Light Company (FP&L) agreed to a sale of CMP's non-nuclear generation assets.[148] However, FP&L attempted to withdraw from the agreement citing FERC regulatory changes. In March 1999, a U.S. District Court upheld the sale[149] and FP&L agreed to continue with the sale, which was completed in April 1999.

E. Maryland

On April 8, 1999, Governor Glendening signed into law a bill to facilitate the restructuring of the electric utility industry of the state under the oversight of

140. Maine PUC Rules, Chapter 301: Standard Offer Ratemaking, Docket Nos. 98-537 and 98-781.

141. Maine PUC Rules, Chapter 305: Licensing Requirements, Enforcement, and Consumer Protection Provisions, Docket No. 98-608; Chapter 306: Uniform Information Disclosure, Docket No. 98-708.

142. Maine PUC Rules, Chapter 322: Interactions among Utilites and Providers - Metering, Billing and Collections and Enrollment for Electric Service, Docket No. 98-810.

143. Notice of Inquiry Into Electronic Business Transaction Standards for the Exchange of Information in a Restructured Electric Industry, Docket No. 98-522 (Request for Comments issued Mar. 23, 1999).

144. Notice of Inquiry into the Provision of Competitive Meter and Billing Services, Docket No. 98-688.

145. Market Power Study, No. 97-877 (final report issued Dec. 2, 1998).

146. Maine PUC Study of Northern Maine Connections to the New England Grid, Docket No. 97-586 (final draft report issued Nov. 24, 1998).

147. An Act to Establish the Northern Maine Transmission Corporation, L.D. 1456 (introduced Feb. 23, 1999).

148. Corrected Order, *Central Maine Power Company Divestiture of Generation Assets - Request for Approval of Sale of Generation Assets,* No. 98-058.

149. *FPL Energy Maine Inc. v. Central Maine Power Co.*, No. 98-CIV-8162 (S.D.N.Y. Mar. 11, 1999).

the Public Service Commission (PSC).[150] The new law, the Electric Utility Industry Restructuring Act (Restructuring Act), implements customer choice for electric customers in the state and introduces competition in the retail electricity supply and supply services markets.

The Act phases in implementation of customer choice, gradually introducing choice to segments of the state's electric company customers beginning on July 1, 2000. The phase in must be completed on July 1, 2002. The PSC is required to establish a separate schedule implementing choice for customers of municipal electric utilities. Municipalities are allowed, but not required, to introduce choice.

Incumbent utilities are required to provide standard offer service through July 1, 2003 to customers that do not select alternative suppliers, at rates set by the Commission. The PSC is required to establish procedures to award standard offer load to a provider selected through competition, and competitive selection of providers of standard offer service must take effect by July 1, 2003. The Act also requires the Commission to implement a universal service program for low-income customers. Costs for the universal service program, in the amount of $34 million during the transition period, may be recovered from ratepayers.

The Restructuring Act caps the total number of unbundled rates that an electric company may charge to its retail electric customers for four years. The cap is set at the level of authorized rates immediately prior to the implementation of customer choice. The Act also generally requires the Commission to reduce residential customer rates for a four-year period by an amount between 3% and 7.5% of the base rates effective on June 30, 1999.

Utilities are required to functionally or legally separate their regulated operations from their unregulated affiliates. However, the Act precludes the Commission from ordering divestiture of generation assets.

The Act gives electric companies the opportunity to recover all of their prudently incurred transition costs, subject to mitigation. Customers may be assessed a competitive transition charge or other revenue generating mechanism to provide for recovery of these costs. Utilities may apply for a qualified rate order for approval to issue transition bonds for some or all of their transition costs, and may impose an intangible transition charge.

The Act also includes a reciprocity provision that prevents an electricity supplier that also provides distribution service in the neighboring states of Pennsylvania, Delaware, West Virginia, Virginia, or the District of Columbia, from providing retail electricity service in the distribution territory of an unaffiliated electric company unless there is electricity competition in at least a portion of the distribution service area of the electricity supplier or affiliate.

Utility restructuring proceedings had commenced prior to the passage of the new restructuring law. Settlement hearings are scheduled for June 1999, in the stranded cost proceedings of Potomac Electric Power Company and Delmarva Power & Light Company. Several roundtable working group discussions are scheduled to take place at the PSC this summer, addressing supplier authorization, competitive billing, universal service, and customer protection.

150. S.B. 300.

F. Massachusetts

Massachusetts enacted the Electric Restructuring Act in November 1997, which authorized the Department of Telecommunications and Energy (Department) to implement open access in March 1998.[151] The Act also mandated an initial rate reduction of 10%, with a 15% rate reduction to follow. In order to implement the Electric Restructuring Act, the Department developed: (i) terms and conditions for distribution services and competitive suppliers;[152] (ii) standards of conduct for utilities and their affiliates;[153] and (iii) performance-based ratemaking principles.[154] Utility-specific restructuring proceedings, which included issues such as stranded cost recovery, were also initiated for each of the state's six utilities. Under the Electric Restructuring Act, utilities may recover 100% of certain non-mitigated stranded costs, including: (i) their generating plants' depreciated book value; (ii) above-market purchase power agreements; (iii) unamortized generation-related regulatory assets; and (iv) post-shutdown nuclear plant costs. Although the Electric Restructuring Act did not require the utilities to divest their generation assets, each of the six utilities is divesting at least a portion of their generation facilities and purchase power agreements, thus reducing stranded costs.

Although supplier choice has been available in Massachusetts since March 1998, supplier participation has been low, which has been largely attributed to the low shopping credits (the utilities' price of generation that suppliers compete with, i.e. the standard offer service).[155] For 1998, the standard offer rate was 2.8 cents per kWh. Standard offer service will be offered by the utilities through January 2004 at Department-approved rates; however, the standard offer service can be provided by a supplier for the utility. For instance, in 1999, Fitchburg Gas and Electric Light Company's standard offer service is being provided by Constellation Power Source, Inc. at the Department-approved rate of 3.5 cents per kWh. As divestiture continues to occur in each of the utility's service areas, the shopping credit is expected to increase, while the customer's total rate either

151. An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electricity and Other Services, and Promoting Enhanced Consumer Protections Therein, Chapter 164 of the Acts of 1997, codified at MASS. GEN. LAWS ch. 164. (1998) [hereinafter Massachusetts Restructuring Act].

152. Investigation by the Department of Telecommunications and Energy on its own motion to develop Model Terms and Conditions governing the relationship between distribution companies and customers (for the provision of distribution service, standard offer generation service, and default generation service) and governing the relationship between distribution companies and competitive suppliers, D.P.U./D.T.E. 97-65 (final regulations adopted on Dec. 31, 1997).

153. Investigation by the Department of Telecommunications and Energy (formerly known as the Department of Public Utilities) upon its own motion commencing a rulemaking pursuant to 220 C.M.R. §§ 2.00 *et seq.*, establishing standards of conduct governing the relationship between electric distribution companies and their affiliates and between natural gas local distribution companies and their affiliates, D.P.U./D.T.E. 97-96 (final order issued May 29, 1998).

154. Investigation by the Department on its own motion into the theory and implementation of incentive regulation for electric and gas companies under its jurisdiction, D.P.U. 94-158 (order stating Department's policy with regard to performance base rates was issued on Feb. 24, 1995).

155. A listing of utility standard offer rates can be found on the Department's website. *Electric Competition in Massachusetts* (visited May 5, 1999) <http://www.magnet.state.ma.us/dpu/restruct/competition/ standardoffer.htm>.

will stay the same or be reduced to comply with the Act's mandatory rate reductions. For instance, the 1999 shopping credit has increased from the 1998 rate of 2.8 cents to a range of 3.1 to 3.7 cents per kWh. The standard offer rate is expected to rise further to over 5 cents per kWh by 2004. It also is important to note that all customers are not eligible for standard offer service, including new customers (customers who began receiving service from the utility after 1998) and most customers who are switching back to utility-provided generation service (except low income customers and certain municipal aggregation customers).

Currently, the billing and metering services are included in the utilities' total rate, but beginning in January 2000, the Department will begin to investigate competitive metering, billing, and information service options.[156] The Department will consider the following alternatives to the current two billing options: (i) single billing by the utility; and (ii) dual billing by the supplier and the utility for their respective charges only.

G. New Hampshire

Although New Hampshire was one of the first states to introduce a retail access pilot program and pass an Electric Restructuring Act in 1996 calling for full choice by 1998,[157] full supplier choice still has not been implemented in New Hampshire and is expected to be delayed further. Although a number of suppliers participated in the New Hampshire retail choice pilot, most suppliers have since withdrawn despite the fact that in May 1998, the Public Utilities Commission extended the pilot indefinitely and removed the mandatory 10% rate reduction, which was an element of the initial pilot program.[158]

Following the enactment of the Electric Restructuring Act, the Commission issued its restructuring plan and ordered the four utilities and one electric cooperative to file restructuring and stranded costs recovery plans by June 1997.[159] However, the largest utility, Public Service Company of New Hampshire (PSNH) was not able to reach a settlement regarding its stranded cost recovery plan and filed suit in the federal district court challenging the Commission's restructuring plan.[160] In particular, PSNH challenged the Commission's disallowance of 100% stranded cost recovery for PSNH. In June 1998, the district court issued an injunction which prevented the Commission from mandating restructuring, with a trial scheduled to begin in spring 1999. In response to the injunction, the legislature granted the Commission statutory authority to delay restructuring,[161] which the Commission did on July 1, 1998. Although restructuring in PSNH's service territory has been delayed indefinitely, the other utilities have continued, to some degree, to negotiate restructuring agreements with the Com-

156. Massachusetts Restructuring Act, *supra* note 151, § 312.

157. An Act Restructuring the Electric Utility Industry in New Hampshire and Establishing a Legislative Oversight Committee, H.B. 1392, Session Law Ch. 0129 (1996) (codified at 1996 N.H. Laws ch. 129).

158. Retail Competition Pilot Program, No. 22,945, Docket No. DR96-250 (N.H.P.U.C. May 20, 1998).

159. Restructuring New Hampshire's Electric Utility Industry, Final Plan, Docket No. DR96-150 (order issued Feb. 28, 1997).

160. Public Serv. Co. of N.H. v. Patch, 173 F.R.D. 17 (D.N.H. June 12, 1997).

161. An Act Relative to the Implementation of Electric Utility Restructuring, S.B. 341 (enacted June 17, 1998) (codified at 1998 N.H. Laws ch. 191).

mission, including Granite State which has reached a settlement with the Commission. Since appeals in the PSNH proceeding are expected, regardless of the outcome in district court, supplier choice in New Hampshire is expected to be significantly delayed, unless the parties reach a settlement.

For the one utility with an approved restructuring plan in place, Granite State Electric Company, there will be an immediate minimum 10% rate reduction, a sale of the non-nuclear generation assets (which is expected to further increase customer savings), and a standard offer rate ranging from 3.2 cents per kWh in 1998 to 4.2 cents by 2002.[162]

H. New Jersey

On February 10, 1999, Governor Whitman signed into law the Electric Discount and Energy Competition Act (Act).[163] The Act sets forth a schedule for the commencement of electric retail choice in 1999 and requires the New Jersey Board of Public Utilities (Board) to implement certain interim standards, rules, and regulations within ninety days. On February 11, 1999, the Board entered an order establishing negotiation and decision timelines during 1999 for the resolution of the pending litigation concerning each of the electric utilities' rate unbundling, stranded cost, and restructuring filings. With regard to many of the restructuring issues, the Board concluded that the formation of a state-wide competitive market is best served by generic policies. Thus, most restructuring issues to be heard by the Board will be decided on a generic basis, and will not be included in any company-specific negotiations for settlement.[164]

I. New York

Although a number of electric restructuring bills have been introduced over the last several years, the New York legislature has not passed any electric restructuring legislation. However, the Public Service Commission has issued a series of utility-specific orders establishing a timeline for electric restructuring in each of the utilities' service territories. Since the implementation timeline is utility specific, the deadline for full supplier choice differs across the state.[165] For instance, Orange & Rockland Utilities, Inc. will offer supplier choice to all its customers as of May 1, 1999, while Central Hudson Gas & Electric Corporation will open 8% of its load to competition each year with complete choice not scheduled until July 2001. Consolidated Edison Company of New York, Inc. and New York State Electric & Gas Corporation are both phasing in supplier choice, with full choice available by December 31, 1999, and August 1, 1999, respectively. Rochester Gas and Electric Corporation, which is offering a differ-

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162. A summary of Granite State's restructuring can be found on the Internet. *Granite State Electrical Website* (visited Apr. 8, 1999) <http:www.granitestateelectric.com/newswire/setlemnt/index.htm>.

163. Public Utilities – Power and Gas – Electric Dscount and Energy Competition Act, ch. 23, 1999 N.J. SESS. LAW SERV. 23.

164. Additional information is available from the Board at http://www.njin.net/njbpu.

165. A complete overview of each utility's competition timeline can be found at the New York Public Service Commission's website. *Energy Choices: The Facts from the PSC* (visited Apr. 15, 1999) <http://www.dps.state.ny.us/energychoices.htm>.

ent supplier choice plan entitled the Single Retailer Model, will offer choice to all its customers by July 2000. Many of the utilities also are divesting some or all of their generation assets.

Although most of the restructuring principles and rules were established in the utility-specific proceedings and settlements, the Commission has decided to standardize the restructuring rules to the greatest extent possible. In January 1999, the Commission issued uniform retail access business practices for all of the electric and gas utilities and suppliers.[166] The business practices, which become effective on June 1, 1999, address a number of topics including metering and billing, customer switching and enrollment procedures, anti-slamming provisions, and dispute resolution procedures. The Commission also has initiated a proceeding to develop uniform electronic data interchange protocols to govern the exchange of information between suppliers and utilities.[167] In the spirit of uniformity, the Commission also has opened proceedings regarding the role of nuclear power in a competitive market, uniform billing rules, and provider of last resort issues.[168] The one issue that has remained utility-specific is the standard offer rate for generation, which was determined in each of the utility-specific settlements. Although the development of uniform business practices and procedures is a critical component, a number of suppliers believe that the standard offer rates must be revised in order to create a robust competitive supply market in New York.

On a related note, the New York Power Pool member have filed an application with the FERC to restructure the New York wholesale market and create an ISO. The FERC approved the application in June 1998, with the ISO tariffs approved, as amended, in January 1999. The creation of a New York ISO is expected to significantly change the interaction between New York utilities and suppliers. The New York Power Pool members also have petitioned the FERC to transfer their transmission systems to the ISO.

J. Pennsylvania

Pennsylvania is one of the first states in the country to provide consumers with the power to choose their electric generation supplier. In December 1996, Pennsylvania enacted the Electricity Generation Customer Choice and Competition Act[169] (the Act), which became effective January 1, 1997. The Act prescribes a period of approximately two years (to January 1, 1999) for electric utilities and other participants to prepare for this transition. Each of Pennsylvania's electric utilities made a filing with the Pennsylvania Public Utility Commission during 1997 for approval of transition plans containing (i) rate unbundling proposals, (ii) the company's detailed plans to implement the Act, and (iii) a request for stranded cost (Competitive Transition Charge) allowances based on

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166. Uniform Retail Access Business Practices, No. 98-M-1343 (N.Y.P.S.C. Feb. 16, 1999).

167. Electronic Data Interchange Proceeding, No. 98-M-0667 (N.Y.P.S.C. Aug. 28, 1998).

168. For a complete review of such restructuring efforts, see the New York Public Service Commission's Competition website. *Electric Competition Information* (visited May 5, 1999) <http://www.dps.state.ny.us/yourenergy.htm>.

169. 66 PA. CONS. STAT. §§ 2801-2812 (1997).

the company's specific circumstances. These proceedings were completed during 1998. Pilot programs and separate rulemaking proceedings also were initiated in 1997 and have now largely concluded with the start of ElectriChoice on about January 1, 1999. Two of the State's largest electric utilities announced their intention to exit the generation business through sale of their generation assets, and to focus on their regulated transmission and distribution business.[170]

K. Rhode Island

In August 1996, Rhode Island enacted the Electric Utility Restructuring Act, which phased in supplier choice for large commercial and industrial customers on July 1, 1997.[171] Full supplier choice was introduced for all customers on January 1, 1998. The utilities will offer standard offer service through 2009, while they are recovering their stranded costs. In response to the Act, the Public Utility Commission ordered the three utilities to file restructuring plans, which included unbundled rates, performance-based rates, and divestiture plans. Under the Act, the utilities may recover stranded costs related to: (i) regulatory assets; (ii) nuclear obligations; (iii) above market purchase power contracts; and (iv) net unrecovered generation plant costs. The stranded cost recovery/transition charge was initially set at 2.8 cents per kWh and will be reduced as the utilities divest their generation assets. For instance, Narragansett Electric Company's transition charge was reduced from 2.8 cents per kWh to 1.15 cents per kWh in January 1999 in response to Narragansett Electric Company completing its divestiture process in September 1998.

According to the Act, standard offer rates are to based on the 1996 price for electricity adjusted for 80% of the change in the Consumer Price Index (CPI). The Commission is also allowed to consider other factors when setting the standard offer rates, "including but not limited to changes in federal, state, or local taxes or extraordinary fuel costs, provided, however, that adjustments to standard offer for factors other than inflation must be approved by the Commission."[172] The standard offer ratesetting mechanism when combined with the Commission's decision to introduce an immediate rate reduction for customers and a relatively high transition charge has created a low, initial standard offer rate. In 1999, Naragansett Electric Company's standard offer rate for residential customers is a flat 3.5 cents per kWh, which is a 17% rate reduction for customers. Beginning on May 1, 1999, Blackstone Valley Electric Company and Newport Electric Corporation also are offering a flat 3.5 cents per kWh standard offer rate. Due in part to the low standard offer rate, supplier choice has been relatively low.[173]

170. The two utilities are GPU Energy (visited May 11, 1999) <http://www2.gpu.com/home> and Duquesne Light Company (visited May 11, 1999) <http://www.dqe.com/indexdl.html>. Additional information is also available from the Pennsylvania Public Utility Commission at http://puc.paoline.com/ and http://www.electrichoice.com/.

171. Electric Utility Restructuring Act, as codified at Title 39-1-27 (1998).

172. *Id.*

173. The standard offer rates and the methods by which they are calculated are summarized on the Rhode Island Public Utilities Commission website. *Consumer Guide to Choosing an Electric Supplier* (visited Apr. 15, 1999) <www.ripuc.org/electric/conguide.htm>.

L. Texas

The Texas legislature passed a comprehensive electric restructuring bill in May 1999, and, as of this writing, has sent it to Governor George W. Bush for his signature. Governor Bush has already indicated that he will sign the legislation. The bill would open most of the state's retail market to competition beginning January 1, 2002.[174] Only municipal utilities and rural electric cooperatives would be exempt from competition unless voters or members of the public power system approve it in an election.

The bill freezes retail rates until January 1, 2002, at rates existing on September 1, 1999. Beginning January 1, 2002, a "price to beat" provision of the bill would require investor-owned utilities to provide an automatic 6% rate cut to existing residential and small commercial customers. Existing utility suppliers would be precluded from changing their rates for three years, or until they lose 40% of existing customer load to a new supplier. This provision enables customers to shop for a better rate and gives new suppliers the opportunity to beat the rates of incumbent utilities. The bill also establishes a system benefit trust fund financed by a non-bypassable fee set by the Commission to fund reduced rates for eligible low-income customers.

The bill authorizes full recovery of stranded costs. It also authorizes utilities to secure 100% of their regulatory assets and up to 75% of their stranded costs and recover those costs through a transition charge.

Electric utilities are required to separate their generation, retail marketing, and transmission and distribution functions by January 2002. The bill does not require divestiture of generation assets, but precludes entities from controlling more than 20% of the total generating capacity in a region. It also sets forth a code of conduct to protect against anti-competitive affiliate transactions or cross-subsidies. The bill also provides for the establishment of independent system operators.

Interestingly, the Commission is required to maintain a list of customers who notify the Commission of their objection to receiving telephone solicitations. Customers may pay a nominal one-time fee of no more than five dollars, to be set by the Commission, to be included on this list, and the bill restricts telephone solicitations of these customers.

M. Vermont

Since the Vermont Senate passed Senate Bill 62 in the spring of 1997, legislation on electric restructuring in Vermont has failed numerous times. This past year was no exception. Several bills on restructuring were introduced in the 1997-98 legislative session, but no action was taken on any of them.

On December 18, 1998, the governor's Working Group on Vermont's Electricity Future presented a report to the Board supporting the move to a restructured environment as quickly as possible. In the report, the Working Group unveiled a restructuring plan with the goal of completing the process by the first quarter of 2000. The report also suggests that the three major utilities in the state

174. 1999 TEX. SESS. LAW SERV. S.B. No. 7 (West).

(Central Vermont Public Service Corporation, Green Mountain Power Corporation, and Citizens Utilities Company) merge and that purchased power contract costs with Hydro Quebec be paid down with loans backed by ratepayers.

During 1998, the Vermont Public Service Board made a number of pronouncements concerning above-market costs associated with the long-term Vermont Joint Owners purchased power contract with Hydro-Quebec and other purchased power arrangements, including those with independent power producers. In a rate case filed by Green Mountain Power Corporation, the Board found that the Company's decision to permanently "lock-in" the contract in August 1991 was imprudent and that a significant portion of the contract costs were neither prudent nor used and useful under Vermont law.[175] Concerned that rates cases offer only a limited remedy to the problem of above-market costs, the Vermont Board called for a creative process to mitigate and reform Vermont's historic power supply arrangements.[176] In September, 1998, the Board issued an order opening an investigation into the reform of Vermont's electric power supply.[177]

The Board's concern about above-market purchased power costs has spawned a wide-ranging discussion of restructuring proposals. For example, in March of 1999, Central Vermont Public Service Corporation and Green Mountain Power Corporation jointly submitted to the Board an informal restructuring plan which considered the possibility of merging the companies into a single distribution company and selling off their generating assets. The plan also stated that the parties would file a petition to develop rules for retail access. If a resolution of the purchased power cost problem was not submitted by September 1, 1999, Green Mountain and Central Vermont ran the risk that the Board might permanently disallow such costs in pending rate cases, which in turn could plunge the companies into severe financial distress or even bankruptcy.

In 1994, the Vermont Public Service Board initiated a review of electric restructuring by establishing a Restructuring Roundtable, which adopted fourteen restructuring principles and concluded that restructuring could benefit consumers if implemented cautiously. Following the Roundtable's recommendations, the Board opened a docket to investigate further electric restructuring and issued a restructuring plan in December 1996.[178] The Board's plan outlined nine implementation steps: (i) customer choice; (ii) separation of generation and distribution; (iii) equitable recovery of stranded costs; (iv) municipal, cooperative, and small utilities; (v) consumer protections; (vi) energy efficiency programs; (vii) renewable resources; (viii) environmental quality; and (ix) the establishment of a regional Independent System Operator (ISO) and Power Exchange.

Despite the Board's early and comprehensive efforts, the Vermont legisla-

175. *Green Mountain Power Corp.*, Docket No. 5983, (order issued Feb. 27, 1998), at 1 <http://www.state.vt.us/psb/5983gmp.htm>.

176. *Green Mountain Power Corp.*, Docket No. 5983, (order issued June 8, 1998), at 3 <http://www.state.vt.us/psb/5983gmp.htm).

177. *Investigation into the Reform of Vermont's Electric Power Supply*, Docket No. 6140, (order entered Sept. 15, 1998).

178. *Investigation into the Restructuring of the Electric Utility Industry in Vermont, The Power to Choose: A Plan to Provide Customer Choice of Electricity Suppliers, Docket No. 5854*, (visited May 5, 1999) <http://www.state.vt.us.document/5854/final.html.

ture has not responded with the passage of a restructuring bill. Instead, a number of bills have been introduced and a House Special Committee has been established. In 1997, the Committee issued a report stating that restructuring was speculative and recommended performance-based ratemaking, discounted standard offers, and securitization. Similarly, in 1997, the Governor formed a bipartisan Working Group to study restructuring. The Working Group issued a report in December 1998 recommending the immediate implementation of electric restructuring and the merging of the three Vermont utilities.[179] As of Spring 1999, the legislature has not acted on either report.

In response to the legislature's inaction on electric restructuring, the Board has taken a "wait and see" position and delayed any major restructuring activity. As an alternative approach to comprehensive, mandatory electric restructuring, the Board opened a docket in 1999 to investigate reform of Vermont's electric power supply and to review securitization and voluntary restructuring by the utilities.[180] Two utilities, Central Vermont Public Service Corporation and Green Mountain Power Corporation, have filed a joint restructuring proposal.[181]

N. Virginia

On March 25, 1999, Governor Gilmore signed into law Senate Bill 1269, the Virginia Electric Utility Restructuring Act (the Act). The Act establishes a phase-in to retail competition beginning on January 1, 2002 and ending on January 1, 2004 to enable any eligible customer to purchase electric energy from any supplier licensed to do business in the Commonwealth. The Act authorizes the State Corporation Commission (SCC) to establish the timing and phasing of the switchover to competition on a class-by-class basis, with the proviso that residential and small business retail customers must be permitted to select suppliers in proportions at least equal to those of other customer classes.

The Act also requires that, as of January 1, 2001, each incumbent electric utility owning, operating, controlling or having an entitlement to transmission capacity shall join or establish a regional transmission entity, which may be an independent system operator, to which the utility must transfer the management and control of its transmission system. The transfer is subject to the prior approval of the SCC. The Act requires the formulation of rules and regulations to promote non-discriminatory pricing and access policies and the orderly development of competition in the Commonwealth. Although the Act generally deregulates the rates for generation services as of January 1, 2002, it specifically allows the Commission to adjust the rates for retail sales of capacity and energy if the utility's market power is not adequately mitigated by the practices or rules of the regional transmission entity. Such adjustments can be made, however,

179. *The Working Group on Vermont's Electricity Future, Report to Governor Howard Dean M.D.*, (visited May 5, 1999) <http://www.state.vt.us/psd/vef.htm>.

180. *Investigation Into the Reform of Vermont's Electric Power Supply, Docket No. 6140*, (order opening the investigation issued on Sept. 15, 1998), (visited May 5, 1999) <http://www.state.vt.us/psb/6140/Index_6140.htm>.

181. *Investigation into the Reform of Vermont's Electric Power Supply, A Working Plan to Restructure a Significant Portion of Vermont's Electric Utility Industry, Docket No. 6140* (visited May 5, 1999) <http://www.state.vt.us/psb/6140-a/cvgmpwp.pdf>.

only to the extent necessary to protect retail customers from market power, and only until the market power has been mitigated.

The Act establishes a novel stranded cost recovery mechanism. Rather than permit the state's utilities dollar-for-dollar recovery of a predetermined quantity of stranded costs, the Act simply allows the utilities to collect capped rates and wire charges that are intended to give the utility an opportunity to realize earnings as compensation for stranded costs over the six-year period from January 1, 2001 through January 1, 2007. Capped rates, which would be charged by the incumbent utility, are to be established on the basis of the utility's settlement rates in effect on July 1, 1999 (for Virginia Electric and Power Company), or rates established through utility rate cases filed before January 1, 2001, for other utilities. Utilities are also authorized to impose a wire charge that would be paid during the 2001 through 2007 period by customers who choose suppliers other than their incumbent utility, or who are purchasing default service. Basically, the wire charge is to be determined as the difference between the incumbent utilities' capped unbundled rates for generation and the market rate for generation, as determined by the Commission.

Other provisions in the bill (i) authorize the SCC to conduct retail customer choice pilot programs, (ii) exempt municipal power systems from retail competition unless the municipalities operating them (a) elect to permit it or (b) compete for electric customers outside the service territories currently served by such systems, (iii) permit electric cooperatives to furnish default service in their current service territories unless they seek to provide default service in the former service territories of other electric utilities, (iv) eliminate the use of eminent domain in conjunction with generation facilities constructed on and after January 1, 2002, (v) require the SCC to submit annual reports on the potential for future competition in metering, billing and other electric services not made competitive by this bill, and (vi) permit customer-generators who are self-generating with solar, wind or hydroelectric generating systems to employ "net metering" equipment, subject to capacity restrictions and regulations to be developed by the SCC.

IV. STRANDED COSTS

The FERC set for hearing a complaint by Southwestern Electric Cooperative, Inc. (Southwestern) against Soyland Power Cooperative (Soyland) regarding Soyland's implementation of its contract termination formula and its application to Southwestern.[182] Southwestern and Soyland entered into an agreement providing for Southwestern to pay a withdrawal payment to Soyland in return for Southwestern's early release from all requirement contracts with Soyland. The withdrawal payment was calculated based on a complex formula, subject to true-ups, intended to serve as liquidated damages for Southwestern's early cancellation. The FERC set for hearing the formulaic inputs, including certain appropriate amounts which Soyland, in its counterclaim, alleged it failed to include.

The Village of Lakewood, New York (Lakewood) sought a determination from FERC that it would not owe stranded costs to Niagara Mohawk Power

182. *Southwestern Elec. Coop., Inc. v. Soyland Power Coop.*, 86 F.E.R.C. ¶ 61,217 (1999).

Corporation (Niagara Mohawk). Lakewood, a retail customer of Niagara Mohawk, filed its petition as it contemplated becoming a municipal utility whereby it would condemn and acquire Niagara Mohawk's distribution facilities. Lakewood argued, *inter alia*, that Niagara Mohawk had no reasonable expectation to continue service based on the following: (1) Niagara Mohawk's knowledge since 1982 that Lakewood could establish a municipal utility; and (2) an earlier settlement agreement between Niagara Mohawk and the New York Power Authority (NYPA) in which Lakewood could obtain transmission service from Niagara Mohawk for NYPA power. Niagara Mohawk estimated Lakewood's stranded cost obligation at $39 million and argued that it had a reasonable expectation to continue service to Lakewood for the following reasons: (1) under state law, it is required to serve all customers within its territory; (2) state law prohibits duplication of distribution facilities; (3) it has been supplying Lakewood for over eight-five years; and (4) the referenced settlement agreement does not require Niagara Mohawk to wheel power for Lakewood. The FERC set the matter for hearing.[183]

At the request of the New York State Public Service Commission (New York Commission) and Niagara Mohawk, the FERC subsequently held the hearing in abeyance pending settlement procedures by the New York Commission for instances of municipal annexation.[184]

The FERC set for hearing Duke Power Company's (Duke) stranded cost recovery request in future transmission rates from the City of Seneca (Seneca) and the City of Greenwood (Greenwood).[185] The parties subsequently filed a settlement which the FERC accepted.[186]

An initial decision was issued in the stranded cost dispute between the City of Las Cruces, New Mexico (Las Cruces) and El Paso Electric Company (El Paso).[187] The ALJ found that El Paso had met its burden under the reasonable expectation standard of Order No. 888 and was therefore entitled to stranded cost recovery once Las Cruces left El Paso's system. The presiding ALJ found that depending on when Las Cruces departs from the EL Paso system, Las Cruces' stranded cost obligation would be between $30.4 and $5 million.[188]

After the FERC rejected a request by Central Vermont Public Service Corporation (Central Vermont) to add a stranded cost surcharge to its open access transmission tariff for transmission over its system to retail customers of its distribution affiliate Connecticut Valley Electric Company (Connecticut Valley),[189] Central Vermont filed an exit fee amendment to its wholesale contract with Connecticut Valley. The FERC accepted and set for hearing the exit fee.[190]

183. *Village of Lakewood, N.Y.*, 85 F.E.R.C. ¶ 61,008 (1998).

184. *Village of Lakewood, N.Y.*, 85 F.E.R.C. ¶ 61,339 (1998).

185. *Duke Power Co.*, 79 F.E.R.C. ¶ 61,161 (1997).

186. Unpublished Letter Order issued Sept. 17, 1998 in Docket Nos. EL95-31-000, et al.

187. *City of Las Cruces, N.M.*, 83 F.E.R.C. ¶ 63,017 (1998).

188. *Id.*

189. *Central Vt. Pub. Serv. Corp.*, 81 F.E.R.C. ¶ 61,336 (1997). *See also Public Serv. Co. of N.H. v. New Hampshire Elec. Coop., Inc.*, 83 F.E.R.C. ¶ 61,223, 61,994 (1998) (refusing to allow recovery of wholesale stranded costs through a retail transmission surcharge).

190. *Central Vt. Pub. Serv. Corp.*, 82 F.E.R.C. ¶ 61,237 (1998).

The City of Alma (Alma) requested that the FERC set for hearing whether Consumers Energy Company (Consumers) was entitled to $56.1 million in stranded costs. Alma argued that Consumers was not entitled to such stranded costs, since Consumers needed new resources to meet load growth. The FERC set the matter for hearing.[191] During the hearing, settlement judge procedures were adopted and subsequently terminated as settlement negotiations failed.[192] The case is awaiting an initial decision.

The Village of Belmont, City of Juneau, City of Plymouth, City of Reedsburg, City of Sheboygan Falls and City of Wisconsin Rapids, Wisconsin (Wisconsin Municipals) filed a complaint against Wisconsin Power & Light (WP&L) alleging, *inter alia*, that by its anti-competitive behavior, WP&L breached certain wholesale power contracts entered into with the Wisconsin Municipals. Central to the dispute was whether the 120-month notice of termination provision was anti-competitive under Order No. 888. The FERC set the termination provision for hearing and included the issue of the appropriate level of stranded costs in case the hearing should result in a shortened notice of termination provision.[193]

Various other utilities have successfully negotiated stranded cost settlements in the context of amendments providing for early termination of requirements contracts including contract termination charges (CTC).[194] Other utilities have filed amendments to specific tariffs providing CTCs for customers opting to terminate service early. The FERC has approved a number of such amendments without suspension or hearing as being based on the revenues lost approach for specific contracts and not designed to recover extra-contractual costs.[195] The FERC has also approved a number of amendments allowing for early termination with a CTC based on recovery of stranded generation related costs not offset by divestiture.[196]

Other utilities have opted for binding arbitration proceedings. Duquesne Light Company (Duquesne) filed for a stranded cost determination in the event that one of its full requirements customers, the Borough of Pitcairn, Pennsylvania (Pitcairn) opted to terminate its power sales agreement prior to December 31, 2005. Pitcairn argued that Duquesne was not entitled to stranded costs as it had no reasonable expectation of continued service to Pitcairn. The FERC set the matter for hearing.[197] During the course of the hearing, Duquesne, with the parties' support, requested the use of binding arbitration under 18 C.F.R § 385.604. The FERC approved the use of arbitration and subsequently let stand the arbitration award of $400,000, representing Pitcairn's stranded cost obligation to

191. *City of Alma, Mich.*, 80 F.E.R.C. ¶ 61,265 (1997).

192. "Order of Chief Judge Terminating Settlement Judge Procedures", No. SC97-4-000 (issued Sept. 10, 1998).

193. *Village of Belmont, Wis. v. Wisconsin Power & Light Co.*, 83 F.E.R.C. ¶ 61,108 (1998).

194. *See, e.g., American Elec. Power Servs. Corp.*, Nos. ER98-443-000 and ER98-444-000.

195. *See, e.g., New England Power Co.*, 83 F.E.R.C. ¶ 61,174 (1998) (approving a CTC formula for recovering the revenues lost over the existing notice term less the estimated market value of the released capacity and energy thereby avoiding payment of the full demand charges over the remaining term of the agreement).

196. *See, e.g., New England Power Co.*, 83 F.E.R.C. ¶ 61,085 (1998).

197. *Duquesne Light Co.*, 79 F.E.R.C. ¶ 61,116 (1997).

Duquesne.[198]

V. PUBLIC UTILITY HOLDING COMPANY ACT OF 1935 REFORMS

Significant events concerning the Public Utility Holding Company Act of 1935 (PUHCA) over the past year largely involve efforts in Congress to amend or repeal the PUHCA. In addition, the Securities and Exchange Commission's (SEC) ongoing, relatively lax application of the PUHCA in the SEC's consideration of utility company mergers is receiving some attention.

Freestanding bills, addressing both the PUHCA and more comprehensive legislation, were introduced in Congress to amend or appeal the PUHCA. The bills that have not advocated outright repeal of the PUHCA involve several general areas of changes. One area of change is the transfer of the SEC's PUHCA duties to the FERC. In lieu of prohibitions or pre-approval requirements on certain activities by utility holding companies, either registered or exempt, reporting and other information provision requirements form the second stage. The third change involves provisions intended to provide state commissions with additional authority over holding companies doing business in multiple states and/or outside of the United States. For instance, the May 1999 Largent/Markey Bill entitled "Electric Consumers' Power to Choose Act of 1999," would repeal the PUHCA within eighteen months of passage in favor of information requirements, as indicated above. Utilities providing retail service in two or more states that elect to remain "closed" to open access as provided in the bill would be exempted.

Timing of the implementation of new PUHCA legislation would vary under the bills. Likewise, treatment of such matters as "exempt wholesale generators" and "foreign utility companies" varies. In May 6, 1999, testimony before a House Commerce Committee Subcommittee on Energy and Power, the SEC supported conditional repeal of the PUHCA, but suggested that additional authority to exempt holding companies from the PUHCA could be more effective.[199] The FERC, in a statement on the same date, supported repeal of the PUHCA coupled with additional informational requirements.[200]

As of the drafting of this report, the Scottish Power Company/PacifiCorp proposed merger seems to be proceeding through state and federal consideration without significant reference to any SEC or PUHCA concerns. Scottish Power has stated that it will become a registered holding company under the PUHCA if the merger is completed.

Another notable merger of a foreign utility with a United States utility is that of the United Kingdom-base National Grid Group, PLC (National Grid) with New England Electric System (NEES), announced December 14, 1998. NEES would become a wholly-owned subsidiary of National Grid. At the time of this draft, approval of the merger was pending before the SEC, the FERC, the Federal Trade Commission, the NRC, and state regulators in Massachusetts,

198. Notice of Finality of Arbitration Award, in Docket No. ER97-1543-000 (issued Feb. 2, 1999).

199. Statement of SEC Commissioner Isaac C. Hunt, Jr. Among other things, the SEC stated that three new registered holding companies had been formed in 1998.

200. Statement of FERC General Counsel Douglas W. Smith.

Rhode Island, and New Hampshire.

The proposed merger between American Electric Power and Central and Southwest was challenged in a motion to intervene in April 1999 by the American Public Power Association and the National Rural Electric Cooperative Association. The challenge is based on the grounds that the merger would not meet PUHCA standards because the merged companies' electric service areas would not be physically connected or contiguous. In addition, the proposed merger would not contribute to an efficient development of an integrated public utility system which could lead to concentrations of market power.

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