

Report of the Committee on Regulations Parts II and III, Federal Power Act

The most significant cases during 1990 under parts II and III involved (1) movement toward market-based pricing, both by traditional utilities and by non-traditional generators and (2) merger and acquisition activity, both friendly and hostile. Issues of transmission access were at the forefront in these cases.

I. MARKET-BASED PRICING

A. Traditional Utilities

In its first “paper hearing” under the Federal Power Act, the Federal Energy Regulatory Commission (FERC or Commission) approved, with conditions, a proposal by Public Service Company of Indiana (PSI) to sell firm power at market-based prices under a new rate schedule.¹ In return for permission to engage in such pricing, PSI agreed to provide long-term firm transmission service (as well as nonfirm transmission service) to all utilities, including qualifying facilities (QFs) and independent power producers (IPPs), and to construct additional facilities if needed. The new rate schedule would be available if the following four conditions are met:

1. The purchaser must be an eligible customer, defined as any electric utility, rural electric cooperative, or municipality, power authority or agency, except PSI's current full requirements customers
2. The sale must be for him a minimum period of five years
3. The sale must be negotiated at arm's length
4. The purchaser must provide written certification that the negotiated price does not exceed the purchaser's alternative cost of power

PSI's transmission tariff will: (1) be available to any eligible utility (including QFs and IPPs, but excluding ultimate customers) for firm and nonfirm transmission service; (2) give firm transmission priority over all nonfirm service; (3) provide for expansion of PSI's transmission system at the purchaser's expense; (4) allow transmission rights to be reassigned or resold; (5) provide for reciprocal transmission service; and (6) define rates for transmission (\$1.05/kw/month for firm service based on embedded costs—nonfirm based on PSI's losses plus one mill/kwh plus up to one-third of net savings).

1. Open Season

A 60-day open season will be in effect to accommodate all initial transmission requests including sales by PSI. If transmission is over-subscribed there will be a lottery to allocate capacity, and all initial subscribers will share

1. Opinion No. 349, Public Serv. Co. of Ind., 51 F.E.R.C. ¶ 61,367, *modified on reh'g*, 52 F.E.R.C. ¶ 61,260, *modified further*, 53 F.E.R.C. ¶ 61,131 (1990), *review pending sub nom.* Northern Ind. Pub. Serv. Co. v. F.E.R.C., No. 90-1528 (D.C. Cir. Nov. 9, 1990).

the costs of any needed expansion in capacity.²

2. Ongoing "No-Fault" Risk

The Commission rejected the staff's "no-fault" proposal. The proposal would have required that, if PSI could not meet a request for long-term firm transmission, all sales under agreements entered into after the date of the transmission request would be subject to retroactive refund. Instead, the FERC adopted a proposal by PSI to submit disputes over whether the denials of transmission are reasonable to "baseball arbitration." In addition, a complaint can be filed under section 206 of the Federal Power Act, with the refund obligation to commence sixty days after the date a complaint is filed at the Commission rather than after the date of a hearing order (as proposed by PSI).³ A suspension and refund ordered by the Commission would apply only to those transactions using the limited transmission corridors needed for the unfulfilled transmission request.

3. Nonfirm Transmission Pricing

The Commission rejected proposals to limit the price of nonfirm transmission service. Rather, it accepted PSI's proposal including a limit equal to the 100% load factor firm transmission rate.⁴

4. PSI as an Eligible Utility

PSI is required to be included as an eligible utility for its own sales so as "to serve itself under the same terms of the transmission tariff to which other eligible utilities are subject" in order to "clarify that PSI cannot use its transmission ownership to exercise an unfair competitive advantage."⁵ The Commission denied a request that PSI be required to provide back-up services because "[b]ack-up power is an ancillary service" and "is not imbued with the same natural monopoly qualities as transmission and would not be required to be provided by any other provider of generation services under similar circumstances."⁶

5. Construction and Cost of Additional Transmission Facilities

The FERC rejected PSI's position that a transmission customer should pay the full cost of a facility upgrade, stating: "[W]e believe that appropriate cost sharing can best be determined at the time the facilities will be added."⁷ The Commission required PSI to "file a substitute requirement that transmission customers proffer sufficient security that will not expose PSI to financial risk for non-performance by the requester."⁸

2. *Public Serv.*, 51 F.E.R.C. ¶ 61,367, at 62,192-93.

3. *Id.* at 62,195-97.

4. *Id.* at 62, 199.

5. *Id.* at 62,201.

6. *Id.*

7. *Id.* at 62,203.

8. *Id.*

6. Market Power

The opinion contains an extensive discussion of market power.⁹ It concludes:

PSI is unlikely to possess market power due to generation asset ownership because:

- (1) PSI is not a dominant firm in ECAR. It has a small share of the total excess generation capacity in ECAR.
- (2) PSI's customers will have access to several alternative suppliers. Those alternative suppliers include: (a) existing utilities within ECAR, (b) existing utilities outside of ECAR, and, most importantly, (c) new units built in response to increased demand or to any attempt by PSI to exercise market power.
- (3) All of the eligible customers under PSI's FS-1 tariff are sophisticated buyers of bulk power, able to recognize and take advantage of their alternatives in the market for generation. PSI's FS-1 offering will add to those alternatives and thereby improve its potential customers' supply options.
- (4) PSI's transmission tariff will significantly increase the range of alternatives available to its customers. The transmission tariff is essential to the mitigation of PSI's market power in FS-1 sales.¹⁰

7. Use of Non-Traditional Pricing

The Commission's opinion concludes with an extended discussion and rationale for non-traditional pricing.¹¹ It represents a generic discussion and rationale that is repeated in orders approving market-based pricing by non-traditional entities (which are discussed in the next section of this report).

In a partial dissent, Commissioner Trabandt disagreed with the imposition by the majority of "extra transmission conditions and penalties" and disavowed what he described as "some of its sweeping statements and unsupported conclusions this order endorses."¹² His view is that the majority "almost went 'the whole nine yards' toward deregulation."¹³

The Commission investigated market power in a case involving an Interconnection Agreement (IA) entered into by Pacific Gas and Electric Company (PG&E) and Sacramento Municipal Utility District (SMUD) and required it to be modified as a condition to approval of market-based rates.¹⁴ The Commission reached a different conclusion on the issue of PG&E's market power from that reached in two earlier cases involving similar agreements between PG&E and Turlock Irrigation District and PG&E and Modesto Irrigation District. In those agreements, the FERC approved market-based flexible pricing.¹⁵

9. *Id.* at 62,204-09.

10. *Id.* at 62,209.

11. *Id.* at 62,220-27.

12. *Id.* at 62,229.

13. *Id.* at 62,231.

14. Pacific Gas & Elec. Co., 53 F.E.R.C. ¶ 61,145 (1990).

15. See Pacific Gas & Elec. Co., 42 F.E.R.C. ¶ 61,406, *order on rehearing*, 43 F.E.R.C. ¶ 61,403 (1988); Pacific Gas & Elec. Co., 44 F.E.R.C. ¶ 61,010, *order on rehearing*, 45 F.E.R.C. ¶ 61,061 (1988), *order on compliance*, 46 F.E.R.C. ¶ 61,390 (1989).

In the case involving SMUD, the FERC concluded, as to generation, that "PG&E is not likely to be able to exercise market power over SMUD in the provision of CPS [Coordination Power Services] power services for the next six years" and therefore accepted flexible pricing for only a six-year period rather than the twenty-year term of the agreement. In addition, PG&E was given the right to submit a section 205 filing at the expiration of the period to seek to continue market-based rates.¹⁶

The Commission found, however, that PG&E has market power over transmission which was not mitigated by the filing.¹⁷ It concluded that the proposed transmission should be modified in several ways in order to "have sufficiently mitigated . . . market power in transmission to warrant approval of the market-based aspects of the IA."¹⁸ Under the IA, PG&E would have been able to flexibly price CPS power unless SMUD could demonstrate that it experienced a resource deficiency due to PG&E's failure to provide Reserved Transmission Service (RTS) at cost-based rates. The FERC required the IA to be modified to permit pricing flexibility only so long as RTS is provided, regardless of whether SMUD incurs a resource deficiency.¹⁹ The IA permitted SMUD to use RTS for exports only if the power to be exported was from a resource owned or purchased by SMUD to meet its own planned needs and was surplus for only a limited period of time. The FERC required this restriction to be eliminated "because it may allow PG&E to exercise both monopoly and monopsony power."²⁰ The FERC also required removal of the IA provision which prohibited SMUD from reassigning RTS once it was under contract. The order found that the prohibition "enhance[d] PG&E's market power in both the CPS power services market and in the CTS transmission service market."²¹

B. Non-Traditional Generators

The FERC issued a number of orders involving non-traditional generators in which it both approved and rejected market-based pricing. The key to whether such pricing is permitted is whether or not the Commission finds that the seller lacks market power over the buyer or, if not, whether the seller has taken steps to adequately mitigate that power.

In *Doswell Ltd. Partnership*,²² the FERC approved agreements providing for avoided cost pricing between Doswell, an IPP, and Virginia Electric and Power Company. Doswell had been assigned the agreements by a cogenerator that had originally contracted with Virginia Power. The Commission observed:

To determine that the proposed rates are just and reasonable, the Commission must find that they fall within a "zone of reasonableness," where the rates are

16. *Pacific*, 53 F.E.R.C. ¶ 61,145, at 61,502-03.

17. *Id.* at 61,503.

18. *Id.*

19. *Id.* at 61,504.

20. *Id.*

21. *Id.* at 61,505.

22. 50 F.E.R.C. ¶ 61,251 (1990).

lower than what would be excessive to consumers and higher than what would be confiscatory to investors. The Commission has allowed pricing flexibility in recent cases, and has concluded that noncost based rates fall within a zone of reasonableness in circumstances where the seller can show that it lacks market power or has mitigated its market power, and there is a pricing cap based either on the seller's costs, or on the purchaser's avoided cost.²³

The Commission noted that the rates were initially established in a QF solicitation process but stated that "we cannot accept a QF avoided cost rate as just and reasonable for a non-QF . . . without examining whether market prices were at work to establish the price and non-price terms agreed to by the parties."²⁴ In finding an absence of market power, the FERC considered several factors as significant: neither Doswell nor its QF predecessor was affiliated with or involved in a joint venture with Virginia Power or any entity affiliated with it; neither Doswell nor the QF was a dominant firm in any relevant generation market; and neither Doswell nor the QF controlled facilities that allowed it to erect barriers to potential competitors.

The fact that a contract containing market-based pricing was the result of an all-source, open solicitation was a critical factor in *Commonwealth Atlantic Ltd. Partnership*,²⁵ where the Commission approved a sale to Virginia Electric and Power Company by what the Commission found to be an "affiliated power producer." The Commission rejected Commonwealth's description of itself as an IPP, observing that Commonwealth is indirectly owned in equal shares by Long Lake Energy Company and the Mission Group. Because the Mission Group is a wholly owned subsidiary of SCEcorp, the parent of Southern California Edison Company, the Commission stated "Commonwealth may be termed an affiliated power producer" and "[a]ccordingly, before we can approve Commonwealth's proposed market-based rates, we must satisfy ourselves that there is no evidence of self dealing."²⁶ The Commission identified a potential problem of reciprocal dealing, noting:

Virginia Power states that its affiliate, Dominion, is a part-owner of three QFs that sell power to Southern California Edison, an affiliate of Mission. This sale of QF power by an affiliate of Virginia Power to an affiliate of Mission, which is a parent of Commonwealth, raises the potential for reciprocal dealing in that it is possible that Virginia Power could have agreed to pay more for power to Commonwealth (and, indirectly, to its parents, including Mission, an affiliate of Southern California Edison) in return for Southern California Edison paying more for power from the QFs in which Dominion, Virginia Power's affiliate, has an interest. However, there are several factors which indicate that reciprocal dealing has not occurred in this instance.²⁷

The Commission's conclusion that there had been no reciprocal self dealing was based on three factors. First, the rate Edison pays QFs is the standard offer rate approved by the California Public Utility Commission, and "[s]ince the Dominion QFs receive a rate for power that is no different from the rate paid to similar QFs not affiliated with Dominion, Virginia Power has no incen-

23. *Id.* at 61, 756 (footnotes omitted).

24. *Id.* at 61,757.

25. 51 F.E.R.C. ¶ 61,368 (1990).

26. *Id.* at 62,245.

27. *Id.*

tive to pay a higher rate to Commonwealth."²⁸ Second, the Commission observed that because Commonwealth and/or its parents tendered bids in subsequent Virginia Power solicitations, its actions are not evidence suggesting reciprocal dealing.²⁹ Finally, the Commission stated that "neither Commonwealth nor any of its owners or affiliates has undertaken any joint ventures with Virginia Power or its affiliates."³⁰

The Commission observed that "Commonwealth's submittal is the first case to come before the Commission requesting market-based pricing from a winner in a formal bidding process."³¹ A significant factor is that it was also the first case approving market-based pricing in which there was no avoided cost cap.

The second case in which an avoided cost cap was not considered necessary was *Enron Power Enterprise Corp.*³² where the FERC approved a twenty-year sale by an IPP to New England Power Company of 58% of the output of a large gas-fired turbine baseload unit Enron Power would build.

In concluding that Enron Power's market pricing would result in rates that "are within the legally mandated zone of reasonableness," the FERC found:

First, Enron Power clearly lacks market power in the relevant generation and transmission markets. . . .

Second, the Commission will have the opportunity to reassess its findings if changes to the rate are proposed. . . .

A *third* check against exorbitant rates is the lack of evidence of favoritism because of self-dealing or reciprocal dealing between Enron Power and its affiliates and NEPCO and its affiliates.³³

The Commission then concluded:

Based on the evidence presented herein concerning the solicitation process from which the Enron Power rate was negotiated, our findings as to Enron Power's lack of market power over NEPCO, our conclusion that there is no evidence of self dealing or reciprocal dealing, the fact that NEPCO had a number of meaningful supply alternatives produced by the bids, and the fact that the rate formulae cannot be changed without our review and approval, we conclude that Enron Power's rate will be within the zone of reasonableness. . . . At one end of the zone, the rate will not be excessive to the buyer and its customers because it was constrained by the market process resulting from the all-source competitive solicitation and is reflected in fixed rate formulae which cannot be changed without our approval. At the other end of the zone, the rate will not be confiscatory to Enron Power because Enron Power was free to bid or not to bid in the NEPCO solicitation, and it is reasonable to conclude that Enron Power would not have filed this rate unless it believed the rate was not confiscatory.³⁴

The *Enron* decision is significant in the progression of the FERC's orders because the solicitation was not supervised by any state or local agency.

28. *Id.* at 62,245-46.

29. *Id.* at 62,246.

30. *Id.*

31. *Id.* at 62,243.

32. 52 F.E.R.C. ¶ 61,193 (1990).

33. *Id.* at 61,711-12 (emphasis added).

34. *Id.* at 61,712.

NEPCO sells only at wholesale and is therefore regulated exclusively by the FERC.

The FERC also approved a sale by an IPP, Dartmouth Power Associates, to an unaffiliated utility, Commonwealth Electric Company, at a negotiated market-based rate that was not the direct result of a bidding procedure.³⁵ The negotiations took place while Commonwealth was conducting request for proposals (RFP) proceedings for purchases of capacity from QFs. According to Dartmouth, the negotiated rates are less than the avoided costs revealed in the RFP process.³⁶

In accepting the rate, the FERC made the following findings: (1) Dartmouth was not a dominant supplier for the original 50 MW increment negotiated with Commonwealth Electric; (2) Commonwealth Electric had many supply alternatives for the 17.6 MW increment subsequently negotiated with Dartmouth; (3) Dartmouth and its affiliates do not own transmission, cannot erect barriers to entry, and there is no evidence of affiliate abuse; and (4) the rates are just and reasonable.³⁷ With respect to the fourth finding, the FERC stated that the adjustments under the formula rate in the contract "will be pursuant to the approved formulae, which our review has shown were determined through negotiations in which Dartmouth lacked market power."³⁸ Any changes to the formulae would require further filings with the Commission which would be reviewed de novo in light of the circumstances existing at the time.

In *National Electric Associates Ltd. Partnership*³⁹ and *Chicago Energy Exchange of Chicago, Inc.*,⁴⁰ the FERC approved the avoided cost capped rates proposed by, and granted waivers from traditional utility-type filing requirements for, two power marketer entities. The Commission also granted requests to waive the bulk of the traditional utility-type filing requirements in *Doswell Ltd. Partnership*⁴¹ and *Commonwealth Atlantic Ltd. Partnership*.⁴²

In an IPP case involving industrial facilities, the FERC approved an initial rate schedule, and granted regulatory waivers and pre-approvals to permit Ford Motor Company and Rouge Steel to sell incidental power from a jointly-owned powerhouse to Detroit Edison at rates equal to those Detroit Edison charges the companies.⁴³

In *Entergy Services, Inc.*,⁴⁴ the FERC approved a power coordination, interchange, and transmission agreement for service from Arkansas Power & Light to an IPP subsidiary, Entergy Services. The affiliate, which is to be created by spinning off AP&L's interest in two generating units, would then

35. Dartmouth Power Assocs. Ltd. Partnership, 53 F.E.R.C. ¶ 61,117 (1990).

36. *Id.* at 61,357.

37. *Id.* at 61,359-60.

38. *Id.* at 61,360.

39. 50 F.E.R.C. ¶ 61,378 (1990).

40. 51 F.E.R.C. ¶ 61,054 (1990).

41. 50 F.E.R.C. ¶ 61,251, at 61,759 (1990).

42. 51 F.E.R.C. ¶ 61,368, at 62,250-51 (1990).

43. Ford Motor Co., 50 F.E.R.C. ¶ 61,426 (1990).

44. 51 F.E.R.C. ¶ 61,376, *reh'g denied*, 52 F.E.R.C. ¶ 61,317 (1990), *appeal pending*, City of New Orleans v. F.E.R.C., No. 90-1494 (D.C. Cir.).

utilize AP&L's facilities to sell power off-system. The Commission found that the services and rates proposed by the utility to Entergy were identical to those currently offered to other customers and that intervenors' fears of discriminatory conduct were premature. Nonetheless, the Commission warned that when and if Entergy filed non-cost-based rates, the IPP would be required to show that it "both individually and in conjunction with its affiliates, lacks market power."⁴⁵

In several cases where affiliation was involved, the Commission rejected proposals for market-based pricing either as unduly preferential or because of the potential for self dealing. In *Portland General Exchange, Inc.*,⁴⁶ the Commission rejected as unduly preferential the rates to be charged by Portland General Electric Co. (PGE) to its marketing affiliate, Portland General Exchange, Inc. (PGX).

The arrangement involved a sale of surplus power to the marketing affiliate at below fully allocated cost rates, with the marketing affiliate then reselling the power at market prices to two cities in California. The companies' rationale was to protect PGE by not subjecting either its retail ratepayers to the vagaries of the wholesale market or its shareholders to the risk of having to bear losses if the retail customers were sheltered from losses.

The FERC explained that, although it has a policy of allowing sales at below their full costs when necessary to meet competition and to provide benefits to the seller's customers, it has additional concerns when affiliate transactions are involved.

[S]ales to marketing affiliates present a different set of concerns than typical off-system sales made by a utility, because they have the potential for preferential dealing. Affiliates may have the incentive to engage in such preferential transactions because they share common corporate goals—profits for stockholders that own both entities. This common interest creates the incentive to maximize profits to the affiliated marketer by having the selling utility charge the affiliated marketer as low a price as possible. For example, in the instant case where there is a stated price to Cities, the lower the price PGE charges PGX, the greater will be the share of the margins (the difference between the Cities' price and PGE's costs) received by PGX rather than PGE. While PGE would have to credit its share of off-system revenue to native load customers, stockholders would keep PGX's share because PGX has no native load. Thus, a utility such as PGE has the incentive to engage in preferentially low pricing to its affiliate: the lower the price from PGE to PGX, the greater the return that accrues to Portland General stockholders.⁴⁷

Significant to the Commission's decision are (1) the emphasis it placed upon the fact that PGE had not offered the same prices, terms, and conditions for power sales to other customers that it had to PGX⁴⁸ and (2) the Commission's approval of PGX's market based sales to the Cities.⁴⁹ In this regard, the Commission provided PGE two options for getting its sale approved: (1) it could offer to PGX the same prices, terms, and conditions as PGX's sale to

45. *Id.* at 62,285 (footnote omitted).

46. 51 F.E.R.C. ¶ 61,108 (1990).

47. *Id.* at 61,244-45 (footnote omitted).

48. *Id.* at 61,245-46.

49. *Id.* at 61,246-47.

the Cities or (2) it could sell directly to the Cities without going through PGX.⁵⁰ In the subsequent compliance filing, PGE chose the first option.

In *Teco Power Services Corp.*,⁵¹ a similar arrangement to sell at market-based prices was rejected by the Commission because there was an opportunity for preferential pricing when dealings were through affiliates. In that case, TECO Energy, Inc., through affiliates, planned to sell power at market-based rates to Seminole Electric Cooperative and to a TECO operating subsidiary, Tampa Electric, from a TECO generating subsidiary, Power Services. Three transactions were to take place as part of the arrangement:

1. Tampa Electric would sell 145 MW of unit power to Power Services at market-based rates
2. Power Services could resell the 145 MW to Seminole at no markup and would also sell to Seminole at market-based rates capacity and energy from combined cycle combustion turbine units Power Services would construct
3. Power Services would sell capacity and energy from the combustion turbine to Tampa Electric, also at market-based rates

The origin of the transactions was a solicitation by Seminole for 440 MW of back-up power.

It was contended that because the three power sales agreements had a common genesis in Seminole's competitive bidding program, the rates should be reviewed as market-based rates and the sale to Tampa Electric should satisfy the "two-part comparison test" for transactions between affiliates. This test examines: "(1) the rate paid by non-affiliate purchasers for similar services and (2) the rate the purchasing affiliate would pay to other non-affiliated suppliers for similar services."⁵² The Commission rejected the suggestion that the unit power sale and resale (the BB4 agreement) should be considered an isolated transaction. It characterized the BB4 agreement as part of a larger bundled transaction, stating: "Presumably, Seminole evaluated the TECO price proposal for 440 MW as a whole, comparing it to alternative costs such as the other bids . . . and to its own self-construction option."⁵³ The Commission's concern was that the BB4 rate might be priced so low as to be unduly preferential, observing:

Had the 145 MW of BB4 been offered by Tampa Electric for sale to the market independently of the Seminole RFP, there would be a market test of the value of the BB4 power. Had Tampa Electric offered the 145 MW of BB4 to the market, including directly to Seminole, at the time of the Seminole RFP, not only would there be a contemporaneous market test of the value of the BB4 power, but all other bidders including Seminole itself would have been able to propose similar combinations of base-load coal fired capacity along with the combined cycle combustion turbine capacity, or any other alternative. Under those circumstances, the Commission would have greater assurance that market forces would discipline the bids offered to Seminole and that the opportunity for undue preferential pricing would be virtually eliminated.⁵⁴

50. *Id.* at 61,251-52.

51. 52 F.E.R.C. ¶ 61,191 (1990).

52. *Id.* at 61,696.

53. *Id.* at 61,698.

54. *Id.* at 61,699 (footnote omitted).

In addition to finding that the proposed rate to Seminole should have been rejected as unduly preferential, the FERC found an independent basis for rejection in the lack of evidence of the exercise of market power over Seminole because of the sparse response to Seminole's bid request.⁵⁵

The Commission further found that Tampa Electric controlled transmission access within its own service territory and observed that "[t]here is no evidence that Tampa Electric made any offer to provide transmission access to competing suppliers[.], . . . and we therefore cannot conclude that Tampa Electric adequately mitigated its control of transmission in this transaction."⁵⁶

On rehearing, the Commission approved the agreements but did not modify its findings.⁵⁷ Rather, it determined that the rates should be accepted on a cost-of-service basis. The Commission observed:

[W]here cost-based (as opposed to market-based) rates are presented and there is no evidence of undue preference and no complaint of preference, we traditionally have not pursued the matter further. That is the case here. Applicants have provided adequate cost data to justify both the affiliate upstream and the downstream transactions. Because all of the transactions are cost-justified, it would be difficult for TECO Energy to divert profits from Tampa Electric's customers to its shareholders, thereby eliminating the principal reason to sell BB4 power at too low a price. This regulatory control of profits ensures that ratepayers are treated fairly and that the region's generation resources are allocated as efficiently as if the affiliate, Power Services, were removed from the transactions.⁵⁸

A third case in which transactions among affiliates caused the FERC to reject negotiated market-based prices was *Terra Comfort Corp.*⁵⁹ That case involved three agreements for, or related to, the sale of power and energy by two affiliates—Terra Comfort Corp. and Iowa Southern Utilities Co.,—to Iowa Electric Light and Power Company. The arrangements included:

1. A capacity and energy (C&E) agreement—Terra Comfort's sale of 118 MW of unit power for twenty-one years for which purpose Terra Comfort recently purchased six used combustion turbine generators
2. An energy agreement—Iowa Southern to sell up to 118 MW of energy for at least sixteen years, with the restriction that Iowa Electric may never schedule more than 118 MW from Terra Comfort and Iowa Southern together
3. A transmission agreement—services to be provided by Terra Comfort and Iowa Southern to each other, consisting of black start service, emergency voltage and transmission support, emergency energy, dispatch, and transmission

Terra Comfort was a recently-created corporation that had no customers apart from the agreements at issue in the proceeding.

In rejecting the arrangement, the FERC found: "In short, it appears that the Energy Agreement is underpriced, to the detriment of Iowa Southern's ratepayers, and that this underpricing allows the C&E Agreement to be over-

55. *Id.* at 61,699-700.

56. *Id.* at 61,700.

57. TECO Power Servs. Corp., 53 F.E.R.C. ¶ 61,202 (1990).

58. *Id.* at 61,811 n.16.

59. 52 F.E.R.C. ¶ 61,241 (1990).

priced, to the benefit of the applicants' shareholders."⁶⁰ In dealing with the contention that a finding of preferential pricing is inappropriate because Iowa Electric certified that Terra Comfort's proposal was its least cost alternative, the Commission found that "Terra Comfort's competitive posture was directly and substantially affected by Iowa Southern's willingness to provide transmission at preferential rates."⁶¹

In determining that there was a "lack of evidence to support a finding that neither Terra Comfort nor Iowa Southern exercises market power over Iowa Electric," the Commission noted that "the relevant issue . . . is whether Iowa Electric has accessible, viable alternatives to the Terra Comfort purchase."⁶² The Commission found market power because of Iowa Electric's control over transmission which the applicants took no steps to mitigate.⁶³ The finding that Terra Comfort/Iowa Southern exercised market power by reason of their control of transmission was made notwithstanding the fact that Iowa Electric had interconnections with six other utilities.⁶⁴

A recent FERC decision that potentially restricts customers' abilities to challenge rates and terms in their existing power purchase agreements may also affect IPPs. In *Soyland Power Cooperative v. Central Illinois Public Service Co.*,⁶⁵ the FERC summarily dismissed, without hearing, Soyland's claims⁶⁶ that certain rates and charges in power supply and transmission services agreements between Soyland Power Cooperative (Soyland) and Central Illinois Public Service Company (CIPS) were unjust and unreasonable because the rates produced revenue in excess of CIPS' cost of service. In dismissing the case, the FERC relied heavily on statements made in Soyland's concurrence letter to the FERC submitted when the contracts were filed in the mid-1980's. In this letter, Soyland supported the contracts and stated that the rates were just and reasonable at the time the contracts were executed in light of the price of Soyland's other power supply alternatives at that time. The FERC apparently concluded that the concurrence letter indicated that Soyland and CIPS had agreed that the contracts and charges could not be challenged subsequently on traditional cost of service grounds (i.e., if the charges exceeded the seller's cost of service), even though there was no contractual provision to that effect.

The decision is significant in several respects. First, the FERC did not follow recognized standards for summary disposition by dismissing a case in reliance on extrinsic evidence and in which there were issues of material fact in dispute between the parties (e.g., the parties' contractual intent).⁶⁷ Second,

60. *Id.* at 61,838-39.

61. *Id.* at 61,840.

62. *Id.* at 61,840-41.

63. *See id.* at 61,842.

64. *Id.* at 61,841.

65. 51 F.E.R.C. ¶ 61,004 (1990).

66. The Commission did summarily dispose of one issue in Soyland's favor relating to the billing of administrative and general expenses. The parties subsequently reached a settlement under which Soyland received a lump sum refund for past incorrectly billed administrative and general amounts plus significant prospective relief relating to this issue. *Id.* at 61,015.

67. *Id.*

the FERC departed from its standard cost-based "just and reasonable standard" by concluding that Soyland must show that the overall benefits and burden over the term of the agreements were unjust and unreasonable.⁶⁸ The FERC's use of the "benefits-burden" test was peculiar, especially because it specifically rejected this test in the very cases cited in its order.⁶⁹

The FERC may be sending a signal through this case as it has in others⁷⁰ that it intends to uphold the deals struck by parties to power supply agreements ("a deal is a deal"). The decision is significant to emerging IPPs who are now entering into contracts with utilities. They should explicitly specify in their agreements the circumstances under which they may seek changes to rates and charges in the future and what standards should apply.

II. MERGERS AND ACQUISITIONS

Hearings were held and completed in two hotly contested merger proceedings—a proposed acquisition of San Diego Gas and Electric Company (SDG&E) by Southern California Edison Company (Edison) and a proposed acquisition of Public Service Company of New Hampshire by Northeast Utilities Service Co. The cases were both tried on an expedited basis, with initial decisions by administrative law judges issuing in the last quarter of 1990.⁷¹ Both cases are before the Commission on exceptions. In *Southern California Edison*, Administrative Law Judge George Lewnes found that the merger should be denied. Judge Lewnes had presided in the case involving the PacifiCorp/UP&L merger, which he denied.⁷² As directed by the Commission in *Southern California Edison*,⁷³ Judge Lewnes considered whether transmission conditions would mitigate the anticompetitive consequences of the Edison/SDG&E merger, and concluded that they would not. Judge Jerome Nelson in *Northeast Utilities* found that an unconditioned merger would have anti-competitive consequences and ordered conditions which he believed would render the merger consistent with the public interest.

The FERC approved a contested merger in *Central Vermont Public Service Corp.*⁷⁴ The Vermont Department of Public Service argued that the merger may adversely affect competition in the markets for both wholesale and retail power in the state of Vermont. The Commission found that, because the acquisition of Allied will cause such a small increase in Central Vermont's market share, there will be "no substantial impact on competition

68. *Id.* at 61,014.

69. See Opinion No. 300, Southern Co. Servs., 43 F.E.R.C. ¶ 61,003, at 61,014-15 (1988); Pub. Serv. Co. of N.M., 43 F.E.R.C. ¶ 61,469 (1988), *aff'd sub nom.* San Diego Gas & Elec. Co. v. FERC, 904 F.2d 727 (D.C. Cir. 1990).

70. *Id.*; see also Cajun Elec. Power Coop., Inc. v. Gulf States Utils. Co., 50 F.E.R.C. ¶ 61,076 (1990).

71. Southern Cal. Edison Co., 53 F.E.R.C. ¶ 63,014 (1990); Northeast Utils. Serv. Co., 53 F.E.R.C. ¶ 63,020 (1990).

72. Utah Power & Light Co., 43 F.E.R.C. ¶ 63,030, *rev'd in part*, 45 F.E.R.C. ¶ 61,095 (1988), *modified on reh'g*, 47 F.E.R.C. ¶ 61,209 (1989).

73. Southern Cal. Edison Co., 47 F.E.R.C. ¶ 61,196, at 61,675, *modified on reh'g*, 49 F.E.R.C. ¶ 61,091 (1989).

74. 52 F.E.R.C. ¶ 61,278 (1990).

in Vermont.”⁷⁵ In reaching this conclusion, the Commission cited a Herfindahl-Hirschman Index (HHI) increase of thirty-six points (the Department of Justice Merger Guidelines use a less than fifty point increase as the threshold for challenging a merger), while pointing out in a footnote that “this is not intended to suggest that the Commission has adopted the HHI or the Department of Justice Merger Guidelines as its standard for reviewing a merger’s effect on the competitive situation.”⁷⁶ The Commission observed that the merger will increase Central Vermont’s share of the state’s total retail energy sales from only 36.36% to 36.89%. It also seemed to find significant that there are currently twenty-six power suppliers in the state.⁷⁷

A novel question was addressed in *Kansas City Power & Light Co.*,⁷⁸ where the FERC established hearing procedures for a proposed merger application although there was no agreement between the proposed merging companies. Indeed, the case was a hostile takeover attempt by Kansas City Power & Light Company (KCP&L) that was being actively and aggressively fought by the utility proposed to be acquired, Kansas Gas & Electric Company (KG&E).

In setting the merger for hearing, the FERC concluded that there is “no statutory authority or judicial precedent which would require us to distinguish between negotiated mergers, and those opposed by the proposed acquiree’s board of directors.”⁷⁹ It found that “an acquiree’s opposition to a proposed merger *in and of itself* is not enough to cause us to look unfavorably upon an applicant’s request for section 203 approval, and thus we deny KG&E’s motion to reject KCP&L’s filing.”⁸⁰ Subsequently KG&E, the company to be acquired, reached agreement on a merger with another utility and the attempted acquisition was eventually withdrawn.

The FERC ruled in *Missouri Basin Municipal Power Agency v. Midwest Energy Co.*⁸¹ that it does not have jurisdiction over a merger of two holding companies exempt under the Public Utility Holding Company Act.⁸² The Commission rejected an argument that the holding companies’ plan to coordinate the operations of their respective public utility subsidiaries constitutes a merger of the subsidiaries. It stated:

Coordination of operations between and among separate public utilities is common and does not *ipso facto* constitute a merger or consolidation of jurisdictional facilities. However, agreements between Iowa Public Service and Iowa Power will continue to be subject to the Commission’s jurisdiction under sections 205 and 206 of the Federal Power Act to the same extent as before the merger was consummated.⁸³

75. *Id.* at 62,103.

76. *Id.* at 62,103 n.36.

77. *Id.* at 62,103.

78. 53 F.E.R.C. ¶ 61,097 (1990).

79. *Id.* at 61,283.

80. *Id.* (emphasis in original).

81. 53 F.E.R.C. ¶ 61,368 (1990).

82. 15 U.S.C. §§ 79 to 79z-6 (1988).

83. *Missouri Basin*, 53 F.E.R.C. ¶ 61,368, at 62,299 (footnote omitted).

III. FERC JURISDICTION OVER INTER-AFFILIATE TRANSACTIONS WITHIN REGISTERED HOLDING COMPANY SYSTEMS

The Supreme Court handed the FERC a significant victory in *Arcadia, Ohio v. Ohio Power Co.*⁸⁴ by rejecting the D.C. Circuit's analysis of the relationship between FERC and SEC jurisdiction over public utilities and other affiliates of registered public utility holding companies.⁸⁵ The Court arrived at this result by means of an analysis which differs strikingly from the arguments of all of the parties.

The pivotal statutory provision is section 318 of the Federal Power Act (FPA), which provides in relevant part:

If, with respect to the issue, sale, or guaranty of a security, or assumption of obligation or liability in respect of a security, the method of keeping accounts, the filing of reports, or the acquisition or disposition of any security, capital assets, facilities, or any other subject matter, any person is subject both to a requirement of the Public Holding Company Act of 1935 or of a rule, regulation, or order thereunder and to a requirement of [the Federal Power Act] or of a rule, regulation, or order thereunder, the requirement of the Public Utility Holding Company Act of 1935 shall apply to such person, and such person shall not be subject to the [Federal Power Act] requirement . . . with respect to the same subject matter⁸⁶

The majority of the D.C. Circuit panel in *Ohio Power v. FERC* had relied on this provision, and on section 13(b) of the Public Utility Holding Company Act of 1935 (PUHCA), to conclude that the FERC could not disallow that portion of the price paid by Ohio Power to an affiliated coal supplier (SOCCO) in excess of the market price. Under section 13(b), a subsidiary of a registered holding company cannot sell goods or services to any "associate company," such as another subsidiary of the holding company,

except . . . as the [SEC] by rules and regulations or order shall prescribe as necessary or appropriate in the public interest or for the protection of investors or consumers and to insure that such contracts are performed economically and efficiently for the benefit of such associate companies at cost, fairly and equitably allocated among such companies.⁸⁷

The D.C. Circuit reasoned that this statute delegates to the SEC the regulation of the price paid by a utility such as Ohio Power (or I&M) to an affiliate for fuel or other goods and services. Therefore, under section 318 of the FPA, the FERC has no jurisdiction to disallow a portion of the price paid by Ohio Power to SOCCO in setting Ohio Power's wholesale rates, because that would be a prohibited imposition of a requirement as to a "subject matter" regulated by the SEC.

In the Supreme Court litigation, the parties who challenged the D.C. Circuit's ruling advanced two principal arguments:

1. Section 318 does not bar the FERC from any regulation of a subject matter which is subject to the PUHCA or to an SEC regulation or order. Rather, section 318 only prevents the FERC from imposing a requirement which

84. 111 S. Ct. 415 (1990).

85. *Ohio Power Co. v. F.E.R.C.*, 880 F.2d 1400 (D.C. Cir. 1989).

86. 16 U.S.C. § 825q (1988).

87. 15 U.S.C. § 79m(b) (1988).

actually conflicts with an order of the SEC (or with an express requirement of an SEC regulation or of the PUHCA itself).

2. In scrutinizing the justness and reasonableness of Ohio Power's payments to SOCCO for purposes of setting the utility's wholesale rates, the FERC was not addressing the same "subject matter" as the matter addressed by section 13(b) of the PUHCA, the SEC's regulations under section 13(b), and the SEC's orders concerning SOCCO because the concern of the PUHCA and the SEC is to prevent a holding company from earning excessive profits by creating a subsidiary company to supply goods and services to affiliated public utilities at inflated prices (higher than cost).

In its opinion, the Court side-stepped the arguments of the parties by adopting an analysis of section 318 which restricts its scope to the four subjects specifically enumerated at the outset of the statute. The Court observed that all of the parties had assumed that the statute reads as follows:

"If, with respect to [1] the issue, sale, or guaranty of a security, or assumption of obligation or liability in respect of a security, [2] the method of keeping accounts, [3] the filing of reports, or [4] the acquisition or disposition of any security, capital assets, facilities, or [5] *any other subject matter*"⁸⁸

In fact, the statute should be read in the following way:

"If, with respect to [1] the issue, sale, or guaranty of a security, or assumption of obligation or liability in respect of a security, [2] the method of keeping accounts, [3] the filing of reports, or [4] the acquisition or disposition of any security, capital assets, facilities, or *any other subject matter*"⁸⁹

In other words, the phrase "or any other subject matter" is not a "catch-all" which makes section 318 coextensive with the full range of FERC jurisdiction; instead, it is part of the fourth and final category of subject matters with which section 318 is concerned. Therefore, section 318 limits the jurisdiction of the FERC only when the FERC has issued an order which conflicts with the SEC's jurisdiction over securities, accounting, the filing of reports, or acquisitions or dispositions (such as mergers or reorganizations).

The Court then concluded that section 318 in no ways affects the FERC's regulation of rates charged by Ohio Power for electricity generated by coal purchased from an affiliate. The Court assumed that Ohio Power's acquisition and financing of SOCCO, or its acquisition of coal through the acquisition and financing of SOCCO, might fall within the fourth subject matter specified in section 318: "the acquisition or disposition of any security, capital assets, facilities, or any other subject matter." However, although this "subject matter" is subject to SEC regulation under the PUHCA, the FERC did not address that same subject matter, but instead concerned itself with the sale of electricity by Ohio Power. Even if Ohio Power's sale of electricity is conceived as "disposition" of electricity, and therefore as falling within the fourth category of "subject matters" specified by section 318, the FERC addressed a different subject matter from the subject matter within the purview of the SEC.

The Court remanded the case to the D.C. Circuit to consider the arguments made by Ohio Power which the lower court had not resolved:

88. *Arcadia*, 111 S. Ct. at 419 (quoting 16 U.S.C. § 825q (1988)) (emphasis added).

89. *See id.*

(1) whether the FERC's fuel clause regulations preclude application of a market-price test to inter-affiliate sales of fuel within a registered holding company system and (2) whether the rates as set by the FERC were not just and reasonable, as required by the FPA, because costs that had been approved by the SEC had been "trapped."

IV. PROCEEDINGS UNDER THE REGULATORY FAIRNESS ACT

Several orders were issued by the FERC dealing with the question of whether a request for initiation of a complaint proceeding under section 206 of the FPA, as amended by the Regulatory Fairness Act,⁹⁰ may be included as part of a protest and petition to intervene in a rate increase filing brought under section 205 of the FPA. The Commission's position is that "a complaint cannot be submitted as an integral part of a protest and motion to intervene in an ongoing proceeding; it does not allow interested parties sufficient notice of the complaint because it is not formally docketed and noticed."⁹¹ The complainants/intervenors seeking to combine their complaints with the rate increase filings were asserting that existing rates were too high and that refunds below the level of the existing rates should be ordered.

In a case where a section 205 rate increase was filed after a complaint proceeding had been initiated, the FERC consolidated the two proceedings because of the common questions of law and fact presented, stating that "to investigate identical cost support data in separate proceedings would waste the time and resources of the parties as well as the Commission."⁹²

In *Duke Power Co.*,⁹³ the FERC followed its *Louisiana Power & Light* precedent and dismissed a complaint filed by customers as part of a motion to intervene, but in the same order initiated on its own an investigation pursuant to the Regulatory Fairness Act, and established the earliest refund effective date permitted.⁹⁴

Another case in which the FERC on its own motion initiated an investigation of existing rates concerned a filing by Pacific Gas and Electric Company proposing to modify the transmission rate methodology in an interconnection agreement.⁹⁵

In orders dismissing complaints which were included as part of a protest and petition to intervene, the dismissals were without prejudice to refile as separate complaints.⁹⁶ Following the order in *Virginia Electric and Power Co.*, the Commission acted on separate complaints filed by several customers. The

90. Pub. L. No. 100-473, 102 Stat. 2299 (1988).

91. *Louisiana Power & Light Co.*, 50 F.E.R.C. ¶ 61,040, at 61,062-63 (1990); *see also* *Indiana Mich. Power Co.*, 51 F.E.R.C. ¶ 61,191, at 61,524 (1990); *Virginia Elec. & Power Co.*, 53 F.E.R.C. ¶ 61,047, at 61,167 (1990).

92. *Appalachian Power Co.*, 50 F.E.R.C. ¶ 61,261, at 61,814 (1990).

93. 51 F.E.R.C. ¶ 61,266 (1990).

94. *Id.* at 61,787-88.

95. *Pacific Gas & Elec. Co.*, 52 F.E.R.C. ¶ 61,347, at 62,380, *reh'g denied*, 53 F.E.R.C. ¶ 61,443 (1990).

96. *Indiana Mich. Power Co.*, 51 F.E.R.C. ¶ 61,191, at 61,524 (1990); *Virginia Elec. & Power Co.*, 53 F.E.R.C. ¶ 61,047, at 61,167 (1990).

Commission determined to initiate the complaint proceedings and consolidated those dockets with the section 205 rate proceeding.⁹⁷

V. COST OF SERVICE AND RATE DESIGN

A. Rate Base

In *Union Electric Co.*,⁹⁸ the FERC refused to waive its accounting regulations to permit Union Electric to account for post-operational costs of Calloway nuclear unit No. 1 incurred between the in-service date of the unit and the date the unit was entered into retail rate base, as if the unit were still under construction.⁹⁹ The accounting in question had been ordered by the Missouri PSC on the basis that the lag between the time the unit went on line and its inclusion in rate base was too great.

The FERC's chief accountant had denied waiver of the regulations but noted that the Commission had approved specific accounting to accommodate ratemaking actions where there was significant assurance that such actions created regulatory assets that the utility would recover in future rates. The Commission was not persuaded to the contrary by Union Electric's argument that its rates could be more readily challenged in a complaint if it was required to adhere to FERC accounting regulations. In explanation, the Commission stated:

Even if Union's use of Account 186 leads to future challenges to Calloway's cost recovery, the goals of consistency, uniformity and comparability require use of Account 186 in the circumstances presented here. For financial information to be useful for regulators, investors, bondholders and consumer groups, it must represent what it purports to represent and not be influenced by motives such as reducing the possibility of challenges to the recovery of the costs in rates. Accordingly, we reject the parties' contention that the possibility of challenges to Union's rates warrants granting the requested waiver.¹⁰⁰

The Commission reversed an administrative law judge's initial decision that had excluded from rate base the entire cost of a nuclear generating unit that had not been placed in service as early as reflected in the rate increase filing.¹⁰¹ Southern California Edison Company (Edison) had filed a two-step rate increase in 1982 using a Period II test year for the time period September 1, 1982, to August 31, 1983. The cost support for the Step 2 rates was based on an estimated in-service date for the SONGS 2 nuclear unit of August 15, 1982. That unit did not become commercially operable until August 8, 1983. Apparently, a key factor in the Commission's decision was the fact that Edison voluntarily delayed collection of the Step 2 rates from November 2, 1982, when it was originally permitted to place those rates into effect at the end of the suspension period, until after the unit went into service at a time

97. *North Carolina Elec. Membership Corp. v. Virginia Elec. & Power Co.*, 53 F.E.R.C. ¶ 61,394 (1990).

98. 52 F.E.R.C. ¶ 61,279 (1990).

99. *Id.* at 62,110.

100. *Id.*

101. Opinion No. 359, *Southern Cal. Edison Co.*, 53 F.E.R.C. ¶ 61,408 (1990), *aff'g in part and rev'g in part* 34 F.E.R.C. ¶ 63,016 (1986).

when the costs of the unit were reflected in Edison's retail rates. The Commission held:

The issue of the appropriate in-service criterion for including a nuclear unit in rate base has never been decided by the Commission. Edison's voluntary actions to delay collection of Step 2 rates until after SONGS 2 began commercial operation adequately protected wholesale ratepayers, and ensured that inclusion of SONGS 2 costs in rate base would be synchronized to the maximum extent possible in both its wholesale and retail rates. It appears that Edison's actions were motivated, at least in part, by a desire to avoid price squeeze. On this record, we find that it would be neither fair nor reasonable to exclude the costs of SONGS 2 from the Step 2 rates. Accordingly, for the locked-in period beginning October 9, 1983, and ending June 8, 1984, Edison's rates shall include the costs of SONGS 2 as estimated by Edison in this proceeding in support of the Step 2 rates.¹⁰²

B. Fuel Clause

The Commission continued to require strict adherence to its policy of not permitting improperly recorded costs to be recovered through fuel adjustment clauses. In *Montaup Electric Co.*,¹⁰³ the FERC held that Public Service Company of New Hampshire had improperly recorded indirect costs of nuclear fuel in Account 518 and had therefore improperly recovered those costs through its fuel clause. The Commission refused to apply the Eighth Circuit's decision in *Minnesota Power & Light Co. v. FERC*¹⁰⁴ to other factual situations and reaffirmed its policy against retroactive waiver of fuel clause regulations as stated in *Central Illinois Public Service Co.*¹⁰⁵

The Commission found in *Kansas City Power and Light Co.*¹⁰⁶ that Kansas City Power had improperly reflected, in Account 151, payments associated with a coal contract termination and had therefore improperly charged such costs through its fuel clause. The Commission explained:

In this case, Kansas City Power improperly included the costs in Account 151 when paid because the costs were not a component of the fuel in inventory, but were, instead, associated with fuel burned in a prior period, i.e., long before Kansas City Power recorded the costs. Account 151 requires that costs booked represent the "cost of fuel on hand." 18 C.F.R. Part 101, Account 151 (1989). The final reclamation, mine closing and related costs at issue here are all costs which may be includable in Account 151 as costs directly assignable to the cost of fuel, but they are properly included in Account 151 and recovered through the fuel clause only when included in the unit cost of fuel, matched with the fuel in inventory (i.e., the cost of fuel on hand), and recorded as coal is delivered. Contrary to these requirements, however, Kansas City Power included the costs in Account 151 long after the fuel to which they related was burned. As a result, Kansas City Power improperly shifted to future ratepayers the fuel costs used to generate electricity in prior periods.

In administering its fuel clause regulation, the Commission is responsible for ensuring that current ratepayers are charged the cost of providing current ser-

102. *Id.* at 62,416 (footnotes omitted).

103. Opinion No. 343, 50 F.E.R.C. ¶ 61,149 (1990).

104. 852 F.2d 1070 (1988).

105. 47 F.E.R.C. ¶ 61,043 (1989).

106. Opinion No. 348, 51 F.E.R.C. ¶ 61,285 (1990).

vice, not the cost of providing service in prior periods. For this reason, in *Florida Power Corporation*, 11 [F.E.R.C.] ¶ 61,083, at [] 61,120 (1980), the Commission determined that fuel costs in the current period do not include estimated future disposal costs for fuel burned in past periods. Likewise, we determine here that Kansas City Power's fuel costs in the current period cannot properly include actual reclamation and related costs associated with fuel burned in past periods. Kansas City Power should have added estimates of these costs to the purchase price of the associated coal as it was received in inventory. Had Kansas City Power estimated these costs and filed the estimates with the Commission, with appropriate cost support, together with a provision to adjust for differences between estimated and actual costs, before collecting them through its fuel clause, as *Kansas Municipal*¹⁰⁷ requires, waiver of the fuel clause regulation would have been appropriate and, if granted, no corrective action would be required here. However, since Kansas City Power did not do so, it did not comply with *Kansas Municipal* or the Commission's fuel clause regulation, and corrective action is required.¹⁰⁸

C. Rate of Return in Formula Rates

In *Northern States Power Company (Minnesota)*,¹⁰⁹ the FERC affirmed a staff action rejecting a formula rate for transmission service because the formula index factor reflects an automatically varying return on equity. The parties had contended that departure from the Commission's prior policy against automatic adjustment clauses was warranted because the adjustment was keyed to the Commission's generic return on equity and because the changes to section 206 of the Federal Power Act made by the Regulatory Fairness Act provided the opportunity for refunds if the rates became too high. In rejecting the appeal, the Commission observed:

Northern States seeks to shift to the Commission a burden which is properly borne by the proponent of a rate change. Instead of Northern States bearing the burden of filing with the Commission for the Commission's review and approval the change it proposes in its transmission service rate and bearing the burden of establishing that an increased rate is just and reasonable, Northern States would have the Commission bear the burden of monitoring automatic rate changes, bear the burden of instituting a section 206 proceeding *sua sponte* to review of challenge those changes *and* bear the burden in such a proceeding of establishing that the changed rates are unjust and unreasonable.¹¹⁰

A letter order issued by the Director of the Division of Electric Power Application Review rejecting a filing by Pacific Gas and Electric Company as deficient¹¹¹ reiterated the Commission's policy against automatically varying returns on equity.¹¹² In *Pacific Gas and Electric*, the return was to be indexed on the basis of the return on equity most recently approved by the California Public Utilities Commission.

107. *Kansas Mun. & Coop. Elec. Sys.*, 16 F.E.R.C. ¶ 61,227, *reh'g denied*, 17 F.E.R.C. ¶ 61,141 (1981).

108. Opinion No. 348, 51 F.E.R.C. ¶ 61,285, at 61,899-900 (footnotes omitted).

109. 51 F.E.R.C. ¶ 61,027 (1990).

110. *Id.* at 61,052 (footnote omitted).

111. *Pacific Gas & Elec. Co.*, No. ER90-268-000 (May 18, 1990).

112. *New England Power Co.*, 31 F.E.R.C. ¶ 61,378 (1985); *Southwestern Elec. Power Co.*, 31 F.E.R.C. ¶ 61,389 (1985).

D. Decommissioning

Several decommissioning issues were presented in *Boston Edison Company*.¹¹³ The Commission reversed a finding by the administrative law judge¹¹⁴ and found that a contract between Boston Edison and municipal purchasers of unit power from the Pilgrim nuclear plant permitted Boston Edison to charge for decommissioning prior to retirement of the plant.¹¹⁵ The Commission's opinion adopted the municipals' position that decommissioning charges should be recovered over the life of the plant, that is, over the period ending with the expiration of the NRC license in 2008, rather than over a shorter period ending in 2000 (as Boston Edison proposed). It rejected the staff's position that the amortization period should be extended to 2012, the date Boston Edison had filed at the NRC for a license extension.¹¹⁶ The Commission ordered use of the staff's external fund analysis methodology to calculate monthly decommissioning charges, and determined that the analysis should reflect a real, net of inflation, growth rate in the fund of 3.75%, rather than Boston Edison's assumption of zero real growth.¹¹⁷

The Commission rejected, without prejudice to the filing of a revised proposal, a plan by Vermont Yankee Nuclear Power Corporation to invest in equity securities those funds collected to decommission the Vernon nuclear unit.¹¹⁸ The Commission stated:

Vermont Yankee concludes that over the long term its proposal offers no less assurance that funds will be available for decommissioning than if it pursued strictly *SERI* [¹¹⁹] investments. Vermont Yankee also concludes that its proposal offers the possibility of higher returns without increasing the likelihood of lower returns, thus benefitting ratepayers.

Despite these professed safeguards, the Commission has serious reservations that Vermont Yankee's proposal meets our criteria of providing an equal or greater assurance of fund availability and being at least as beneficial to consumers as a *SERI* strategy. . . .

The Commission concludes that Vermont Yankee has not met its burden of showing that the alternative investment strategy for non-qualifying funds has an equal or greater assurance of the availability of funds at the time of decommissioning. Moreover, Vermont Yankee has simply made a general showing that long-run investments in common equities may provide a higher return than certain other investments. Vermont Yankee has not shown that the specific investment strategy it has proposed will produce similar results for its decommissioning funds. Therefore, the Commission will reject Vermont Yankee's proposed alternative investment strategy, without prejudice to the filing of a revised proposal.¹²⁰

In *Southern California Edison Company*,¹²¹ the Commission summarily affirmed that portion of an initial decision that rejected a proposal by Edison

113. 52 F.E.R.C. ¶ 61,010 (1990).

114. See *Boston Edison Co.*, 42 F.E.R.C. ¶ 63,033, at 65,221-23 (1988).

115. *Boston*, 52 F.E.R.C. ¶ 61,010 at 61,074-77.

116. *Id.* at 61,077-80.

117. *Id.* at 61,081-86.

118. *Vermont Yankee Nuclear Power Corp.*, 52 F.E.R.C. ¶ 61,141 (1990).

119. See *System Energy Resources, Inc.*, 37 F.E.R.C. ¶ 61,261 (1986).

120. *Vermont Yankee*, 52 F.E.R.C. ¶ 61,141, at 61,583-84.

121. 53 F.E.R.C. ¶ 61,408 (1990).

to increase its charge for decommissioning the SONGS nuclear units by using a site-specific study, which the administrative law judge found had not been adequately supported on the record.¹²²

E. Price Squeeze and Predatory Pricing

The Commission issued opinions in two price squeeze cases involving Southern California Edison Company. In the first decision, it affirmed on rehearing the new price squeeze policy it had adopted two and one-half years ago in its earlier opinion.¹²³ In that opinion, the Commission announced a new policy of eliminating the presumption of anticompetitive effect when price discrimination (based on a comparative rate of return test) was shown. It summarized that new policy:

In order to make a *prima facie* case of price squeeze in the future, parties making price squeeze claims would be required to come forward with evidence that the alleged price squeeze would have either an actual or a potential anticompetitive effect, *i.e.*, that the wholesale/retail rate disparity was long enough and severe enough to result in either an actual or a potential anticompetitive effect.¹²⁴

In elaborating on why it retracted the presumption of anticompetitive effect, the Commission observed, "[I]f it cannot be shown that some real harm (actual or potential) is probable, there is little point in wasting the scarce resources of the Commission and the parties, by litigating the price squeeze issue."¹²⁵ The Commission then described the kinds of evidentiary showing it envisioned, concluding: "In summary, the Commission stresses that broad, formal evidentiary submissions are not required and we also do not intend that price squeeze analysis, if filed, should be so restrictive as to rely solely on measures of market shares to show anticompetitive impacts."¹²⁶

In a subsequent opinion, issued in a case that had been tried prior to announcement of the policy eliminating the rebuttal presumption of anticompetitive effect of prior discrimination, the Commission found that the wholesale rates charged by Edison caused a price squeeze during the first five and one half months of a twenty-three month locked-in period.¹²⁷

The Commission rejected a contention that fuel clause credits in retail rates should be ignored in a comparative rate of return analysis, finding that the day-to-day rates in effect should be used.¹²⁸ The Commission noted that eliminating such credits from the analysis would be inconsistent with its use of the overcollected retail rates in the prior case in determining a higher retail rate of return in the comparative analysis which mitigated the price squeeze relief ordered there.¹²⁹

122. Southern Cal. Edison Co., 34 F.E.R.C. ¶ 63,016, at 65,041-43 (1986).

123. Southern Cal. Edison Co., 50 F.E.R.C. ¶ 61,275 (1990), *aff'g* 40 F.E.R.C. ¶ 61,371 (1987), *appeal pending sub nom.* Anaheim v. FERC, No. 90-1236 (D.C. Cir.).

124. *Id.* at 61,869.

125. *Id.* at 61,872.

126. *Id.*

127. Southern Cal. Edison Co., 51 F.E.R.C. ¶ 61,284 (1990).

128. *Id.* at 61,882.

129. *Id.*

The opinion next rejects the administrative law judge's conclusion that the entire twenty three-month period should have been considered in the comparative rate of return analysis. The opinion states:

If a disparity between wholesale and retail rates during the first 5 1/2 months of the 23-month locked-in period resulted, or had a reasonable probability of resulting in, a wholesale customer losing retail customers to Edison, the mere fact that the disparity between wholesale and retail rates during the remainder of the locked-in period favored the wholesale customer is irrelevant, as the harm to competition would have already occurred. As the courts have said repeatedly, the antitrust laws were enacted for the protection of competition, not competitors. Thus, a comparison of the wholesale and average retail earned rates of return over the entire locked-in period is no substitute for an examination as to whether a disparity between wholesale and retail rates had an anticompetitive effect during the 5 1/2 month period when the discrimination took place.¹³⁰

After taking note of the First Circuit decision in *Town of Concord v. Boston Edison Co.*,¹³¹ the Commission on rehearing affirmed its conclusion.¹³² It found that, because of the narrow question addressed by the court concerning the price squeeze theory of antitrust liability, "[t]he court's decision does not affect the Commission's responsibility to review under the Federal Power Act and remedy, where appropriate, price squeeze." The Commission phrased the issue before the First Circuit as, "'does [section two of the Sherman Act] forbid a governmentally regulated firm with *fully regulated* prices—prices that are regulated at both industry levels—from asking regulators to approve prices that could create a price squeeze?" "¹³³

In its opinion on rehearing the Commission rejected the intervenors' argument to change the sub-periods over which price squeeze damages should be calculated, but using the information in an affidavit they presented, the Commission reduced the size of the five and one half month subperiod originally found appropriate.¹³⁴

In *Central Illinois Light Co.*, the FERC refused a request by the Illinois Municipal Electric Agency (IMEA) to reject a rate allegedly below variable cost as predatory.¹³⁵ The rate in question was offered to the village of Riverton in exchange for a five-year extension of a service agreement allegedly in response to a proposal by IMEA to serve Riverton.

F. Rate Design

The Commission approved an incremental cost rate for wholesale requirements service in *New England Power Co.*¹³⁶ The rate was based on a long-run incremental cost rate design rather than average embedded costs.

130. *Id.* at 61,885 (footnote omitted).

131. *Town of Concord v. Boston Edison Co.*, 915 F.2d 17 (1990), *petition for cert. filed* (U.S. Jan. 22, 1991) (No. 90-1168).

132. *Southern Cal. Edison Co.*, 53 F.E.R.C. ¶ 61,101, *appeal pending*, *Anaheim v. FERC*, No. 90-1369 (D.C. Cir.)

133. *Id.* at 61,314 (quoting *Concord*, 915 F.2d at 18-19) (emphasis in original).

134. *Id.* at 61,319-20.

135. *Central Ill. Light Co.*, 51 F.E.R.C. ¶ 61,192 (1990).

136. 52 F.E.R.C. ¶ 61,090 (1990), *reh'g denied*, 54 F.E.R.C. ¶ 61,055 (1991).

The rates apparently were developed to recover embedded costs, not incremental costs, but the rate *design* was based on incremental costing principles. The opinion stated: "The Commission believes that requirements customers must face prices that reflect their supplier's incremental costs in order for them to make efficient investment decisions and efficient choices when seeking alternative supply sources."¹³⁷

G. *Transmission Issues*

The city of Hamilton challenged the rates and certain terms and conditions relating to transmission service provided by the Cincinnati Gas & Electric Company (CG&E) in consolidated cases initiated in 1989. In response to a rate filing by CG&E, the Commission commenced its own section 206 investigation of the transmission rates.¹³⁸ In its complaint, Hamilton had alleged, *inter alia*, that certain scheduling restrictions imposed on it by CG&E were unjust and unreasonable. These restrictions, applicable to a run-of-the-river hydroelectric plant owned and operated by Hamilton, required Hamilton to submit advance hourly schedules for the output of the project which could not be changed outside of normal business hours. In other words, CG&E did not accept revisions to the hourly schedules during evenings, weekends, or holidays.

CG&E argued that the issue of the justness and reasonableness of these scheduling restrictions was separate and distinct from the transmission rate issues and therefore should not be consolidated with the Commission's investigation of the transmission rates. The Commission disagreed, stating:

[C]ontrary to Cincinnati's assertion that the scheduling issue is separate and distinct from the transmission rate issues[,] . . . the Commission finds that the issues are interrelated. The output of the City's hydroelectric project is part of the power and energy being transmitted by Cincinnati and for which the rates are being investigated. *The manner by which a customer is permitted to use a service is directly related to the pricing of that service.*¹³⁹

Hence, restrictions on use of service were considered by the Commission to be sufficiently relevant to the pricing of that service to warrant consolidation of the proceedings. How this relevancy would have actually affected the pricing of the service is not known because the parties ultimately settled the cases prior to hearing or further Commission decision.¹⁴⁰

In *Cajun Electric Power Cooperative, Inc. v. Gulf States Utilities Co.*,¹⁴¹ the FERC denied rehearing of its order dismissing a complaint by Cajun against Gulf States for failure to provide transmission service to a member cooperative at new distribution points.¹⁴² The FERC interpreted the applicable service agreement as not requiring Gulf States to render the requested ser-

137. *Id.* at 61,335.

138. *City of Hamilton v. Cincinnati Gas & Elec. Co.*, 47 F.E.R.C. ¶ 61,260 (1989).

139. *Id.* at 61,921 (emphasis added).

140. *Cincinnati Gas & Elec. Co.*, 51 F.E.R.C. ¶ 61,162 (1990).

141. 50 F.E.R.C. ¶ 61,076 (1990).

142. *See Cajun Elec. Power Coop., Inc. v. Gulf States Utils. Co.*, 49 F.E.R.C. ¶ 61,089 (1989).

vice. That service would have allowed the member cooperative to compete with Gulf States for the business of two industrials.

The Commission in 1990 labeled the issue of "opportunity cost" pricing for transmission services as a "policy question" and invited parties to submit briefs on the matter in *Northeast Utilities Service Co.*¹⁴³ In a subsequent order consolidating another filing raising virtually identical issues, the FERC noted that opportunity cost pricing would not be acceptable "if it simply provides a mechanism for the transmitter to collect monopoly rents associated with a constrained resource."¹⁴⁴

In a case involving rates for transmission service by PG&E to SMUD, the FERC required several significant changes.¹⁴⁵ The rate schedule was filed as a result of a memorandum of understanding (MOU) and MOU Supplement that resulted from settlement of litigation between PG&E and SMUD. The MOU Supplement established a basic framework for transmission services, with the specific terms and conditions to be negotiated. Those negotiations failed, and PG&E unilaterally filed a transmission service schedule. The Commission stated: "[W]here the MOU Supplement is silent with respect to a provision or an issue, we believe that the provision unilaterally proposed by PG&E in the TRS should control absent such provision being unjust, unreasonable or unduly discriminatory or preferential."¹⁴⁶

The Commission affirmed the administrative law judge's finding that PG&E's proposal to charge SMUD for simultaneous, bi-directional transmission service of 500 MW both north-to-south and south-to-north was not just and reasonable. What PG&E proposed was to bill SMUD for 800 MW when the resulting load approached zero MW.¹⁴⁷

The Commission denied imposition of an area charge under the subfunctionalized rate system where area facilities were not used. The Commission found that, although "the MOU Supplement appears to leave open the possibility of PG&E proposing an additional charge in excess of the backbone and system interconnection charges for service to the . . . SMUD points of delivery[,] . . . on this record, we find no justification for PG&E to charge SMUD for use of area facilities."¹⁴⁸

The FERC also required PG&E to eliminate the restriction in the rate schedule that would restrict SMUD's purchases and sales of electric power at the Midway substation to transactions with Southern California Edison Company. The determination was based on a finding of contract intent. The Commission stated:

No party appears to dispute that the MOU Supplement was negotiated primarily to accommodate the Edison-SMUD power sale. However, the MOU Supplement does not limit service to the Edison-SMUD agreement. On the contrary, the MOU Supplement expressly provides for service between two points—Mid-

143. 52 F.E.R.C. ¶ 61,143, at 61,588 (1990).

144. *Northeast Utils. Serv. Co.*, 52 F.E.R.C. ¶ 61,214, at 61,763 (1990).

145. *Pacific Gas & Elec. Co.*, 53 F.E.R.C. ¶ 61,146 (1990).

146. *Id.* at 61,515.

147. *See id.* at 61,518-19.

148. *Id.* at 61,524.

way and another point—without limitation as to the supplier. In MOU Supplement section 7.3.1, PG&E agreed to provide firm transmission service between “the Midway Substation, and, if possible, the Rancho Seco Switchyard or other points of interconnection between the PG&E and SMUD systems.” Because the parties expressly agreed in the MOU Supplement to provide transmission service between two points without limitation as to the supplier, we do not believe that removal of the restriction to Edison in the TRS represents an expansion of PG&E’s contractual commitment to provide transmission service.¹⁴⁹

The Commission distinguished on the basis of contract intent two earlier decisions that had limited transmission service:

By eliminating the Edison restriction from the TRS, we are merely enforcing the obligations to which the parties agreed in the MOU Supplement. Consequently, our decision here is consistent with our decision in *Wisconsin Electric Power Company (WEPCO)*.¹⁵⁰ In *WEPCO*, a customer sought a change in service from firm transmission to non-firm transmission (as well as a change in suppliers and a change in delivery point) for no extra charge despite a requirement in the parties’ contract that supplements must be executed for each separate transaction. We held in *WEPCO* that the changes sought by the customer represented separate transactions under the contract that, contrary to the customer’s contentions, must be separately agreed to by the utility. Accordingly, we refused to require the utility to provide service “under different terms and conditions than those to which it has voluntarily agreed.”¹⁵¹ Similarly, here, we will require PG&E to provide the service it has agreed to provide in the MOU Supplement—to provide point-to-point service without limitation as to supply source.

Moreover, since removal of the Edison restriction does not constitute a physical expansion of PG&E’s wheeling commitment, it is a very different situation from that presented in *New York State Electric and Gas Corporation v. FERC (NYSEG)*.¹⁵² In *NYSEG*, the contractual modification sought by the customer would have required the utility to transmit more power than it had agreed to carry. Here, PG&E is not being required to transmit any more power than it has agreed to transmit.¹⁵³

James N. Horwood, *Chairman*
Douglas A. Oglesby, *Vice Chairman*

Arthur Hays Butler
Edward H. Comer
Alan I. Robbins
William D. Degrandis

Zori G. Ferkin
H. Liza Moses
Mary Ann Ralls

149. *Id.* at 61,527 (footnotes omitted).

150. Opinion No. 321, *Wisconsin Elec. Power Co.*, 46 F.E.R.C. ¶ 61,019, at 61,111-13, *reh’g denied*, Opinion No. 321-A, 48 F.E.R.C. ¶ 61,247, at 61,859 (1989), *appeal filed*, No. 89-1636 (D.C. Cir. Oct. 17, 1989).

151. *Id.* at p. 61,113.

152. 638 F.2d 388, 400-01 (2d Cir.), *cert. denied*, 454 U.S. 821 (1980).

153. *Pacific*, 53 F.E.R.C. ¶ 61,146, at 61,527-28.