

REPORT OF THE COMMITTEE ON ELECTRIC UTILITY REGULATION

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I. DEREGULATION INITIATIVES

A. Federal

1. Federal Energy Regulatory Commission

The Federal Energy Regulatory Commission (FERC) proceedings on open access transmission in the electric utility industry culminated in Order Nos. 888 and 889, issued April 24, 1996.¹ The two rules require all "public utilities" to: (i) file open access transmission tariffs offering both network and point-to-point transmission service; (ii) participate in an Open Access

1. *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Final Rule, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), F.E.R.C. Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 78 F.E.R.C. ¶ 61,220 (1997); *Open Access Same-Time Information System and Standards of Conduct*, Final Rule, Order No. 889, 61 Fed. Reg. 21,737 (May 10, 1996), F.E.R.C. Stats. & Regs. ¶ 31,037 (1996), *order on reh'g*, Order No. 888-A, 78 F.E.R.C. ¶ 61,221 (1997). This report covers calendar year 1996 and, therefore, does not discuss Order Nos. 888-A and 889-A, which were issued on March 4, 1997.

Same-Time Information System (OASIS); and (iii) “functionally unbundle,” *i.e.*, unbundle generation and transmission rates, separate power marketing from transmission operations, and adhere to a Code of Conduct.

a. Order No. 888—The Open Access Rule

(1) Purpose and Background

In the Energy Policy Act of 1992 (EPAct),² Congress granted the FERC the authority to order “transmitting utilities” to provide transmission service to eligible customers, *i.e.*, other electric utilities, including entities not subject to the FERC’s general Federal Power Act jurisdiction, such as municipalities and rural electric cooperatives.³ Under sections 210, 211, and 212 of the Federal Power Act (FPA),⁴ which were amended by EPAct, an electric utility denied wholesale transmission service by a transmitting utility can seek an order compelling the utility to provide the service.

Despite the broad authority under EPAct, the FERC found the complaint procedures under sections 210 - 212 slow and cumbersome. Following its investigation of discrimination in the electric transmission industry, the FERC concluded that an industry-wide remedy was warranted in order to combat undue discrimination by public utilities in the provision of transmission service. Thus, invoking its general authority under sections 205 and 206 of the FPA,⁵ the FERC launched its “GigaNOPR,” the proposed open access rules, in April 1995.⁶ After considering comments filed by all segments of the electric industry, the FERC adopted the open access rules in Order No. 888. Under those rules, each public utility must provide transmission service to its customers on a basis comparable to that which it provides transmission service for itself on behalf of its own customers. The open access transmission tariff implements comparability.

(2) Open Access Tariff

Order No. 888 requires every “public utility” to file an open access transmission tariff that conforms to the FERC’s *pro-forma* transmission tariff. The tariff (or a request for waiver of the tariff filing requirement) must be filed with the FERC no later than July 9, 1996 (sixty days after the issuance of Order No. 888), or sixty days prior to the time a utility becomes subject to the FERC’s general FPA jurisdiction.

2. Pub. L. No. 102-486, Title VII, § 721 - 722, 106 Stat. 2915-16 (1992).

3. See 16 U.S.C. § 824(f) (1994) (municipalities exempt from Part II of the FPA); *Salt River Project Agricultural Improvement and Power Dist. v. FPC*, 391 F.2d 470 (D.C. Cir.), *cert. denied*, 393 U.S. 857 (1968) (rural electric cooperatives financed by federal Rural Utilities Service not subject to the FERC’s jurisdiction).

4. 16 U.S.C. §§ 824i, 824j, 824k (1994).

5. 16 U.S.C. §§ 824d, 824e (1994).

6. See *Promoting Wholesale Competition Through Open-Access Non-Discriminatory Transmission Service by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, 60 Fed. Reg. 17,662 (Apr. 7, 1995), F.E.R.C. Stats. & Regs. ¶ 32,514 (1995).

Service under the open access tariff must be made available to "eligible customers." These include: (i) any wholesale electric utility (including the transmission provider itself and power marketers); (ii) foreign entities that meet the reciprocity requirement; and (iii) retail customers taking unbundled transmission service under a state retail access program or under a voluntary offer of unbundled retail transmission service by the transmission provider. Service is not available to brokers (who do not take title to power), nor to parties to a "sham transaction."⁷

Public utilities must use the open access tariff for new wholesale transactions, new coordination contracts, and economy energy deals after December 31, 1996. Existing firm service customers (wholesale requirements and transmission-only customers with a contract term of one year or more) have the right to continue to take transmission service from the transmission provider when the contract expires, rolls over, or is renewed.

Order No. 888 requires that the open access tariffs conform to the non-rate terms and conditions of the FERC's *pro-forma* tariff.⁸ The FERC will allow deviations from the *pro-forma*'s terms and conditions to reflect regional practices, but these deviations are limited primarily to scheduling deadlines.⁹ With very limited exceptions, the FERC has rejected all other deviations, including proposed changes to the forms of service agreements for firm and non-firm point-to-point service attached to the tariff.¹⁰

Order No. 888 largely adopted the terms and conditions proposed in the GigaNOPR, but consolidated the GigaNOPR's separate network and point-to-point tariffs into a single *pro-forma* tariff. Under the *pro-forma* tariff, the transmission provider must offer both network and firm and non-firm point-to-point transmission service. Network service allows the network customer to "integrate, economically dispatch, and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers."

Redispatch and curtailments of network service must be done on a non-discriminatory basis, and the transmission provider and network customer must share curtailments in proportion to their load ratio shares.

7. "Sham transactions" are defined and prohibited by section 212(h) of the FPA. 16 U.S.C. § 824k(h) (1994).

8. See *infra*, § III(A)(2)(c), for a discussion of utilities' conformance to the *pro-forma* terms and conditions.

9. See, e.g., *Allegheny Power System, Inc.*, 77 F.E.R.C. ¶ 61,266 (1996); *Atlantic City Electric Co.*, 77 F.E.R.C. ¶ 61,144 (1996). After July 9, 1996, public utilities may also seek to amend their open access tariffs with terms and conditions superior to the *pro-forma*'s provisions.

10. *Allegheny Power*, mimeo, at 14. Order No. 888 also requires public utilities to attach to their tariffs (1) their own methodology for assessing available transmission capability (ATC), (2) their system impact study methodology, (3) a form of network service agreement, and (4) a form of network operating agreement. However, the FERC directed that the ATC assessment methodology must contain some level of detail; mere reference to the criteria and practices established by the North American Electric Reliability Council (NERC) without a description of how those criteria and practices will be used was insufficient. *Atlantic City*, mimeo, at 7. In addition, the FERC requires that "at least basic information with respect to the [network service and network operating] agreements be outlined" in the attachments. *Id.* at 9.

Load shedding procedures are to be established between the customer and transmission provider.

Point-to-point transmission service is used to deliver power from designated receipt point(s) to designated delivery point(s), including the transmission provider's third-party (*i.e.*, off-system) sales. Long-term firm point-to-point (*i.e.*, firm point-to-point of a term of one year or longer) has an equal reservation priority with native load and network customers. Reservation priority for long-term firm is on a first-come, first-served basis. Requests for short-term service are subject to being bumped by requests for longer-term service, with certain limitations. Reservation priority for non-firm point-to-point service is based on duration and price.

As to curtailment priorities, firm point-to-point is on the same level as native load and network customers. Non-firm point-to-point service, however, is subordinate to firm service. Curtailments of non-firm point-to-point service will be made on the basis of the duration of the service.

To accommodate requests for service when the transmission system is constrained, the transmission provider is obligated to expand or upgrade its system, provided that the customer agrees to pay for any such expansion or upgrade. Alternatively, the transmission provider must redispatch its resources if more economical (subject to the customer paying for any redispatch costs).

A customer may assign, on a permanent or temporary basis, its transmission capacity rights to another "eligible customer," *i.e.*, an entity that meets the eligibility and reliability criteria of the tariff. The price for assignment of transmission rights is capped at the higher of the assigning customer's original rate, the maximum tariff rate, or the assigning customer's opportunity cost.

The *pro-forma* tariff requires that disputes between the transmission provider and customer to be submitted to informal negotiations between the parties. If the negotiations are unsuccessful, the dispute may be submitted to arbitration, in accordance with the procedures set forth in the tariff.

(3) Ancillary Services

As explained in the *pro-forma* tariff itself, ancillary services are "needed with transmission service to maintain reliability within and among the control areas affected by the transmission service."¹¹ The transmission provider must provide (or offer to arrange with the local control area operator) and the customer must purchase: (i) scheduling, system control, and dispatch and (ii) reactive supply and voltage control from generation sources. For customers serving load within the transmission provider's control area, the transmission provider must offer to provide (or offer to arrange with the local control area operator) the following services: (i) regulation and frequency response, (ii) energy imbalance, (iii) operating reserve-spinning reserve, and (iv) operating reserve-supplemental reserve.

11. *Pro-forma* Tariff, § 3.

The customer may arrange with third-parties to supply these latter four services or supply them itself.¹²

The transmission provider may elect to offer loss compensation service as well (for both network and point-to-point). The tariff requires only that the transmission provider state the real power loss factor in the tariff; unless the transmission provider agrees to provide loss compensation service, the customer is responsible for transmission losses.

The rates and charges for the ancillary services are to be set forth in the schedules attached to the *pro-forma* tariff; the individual rates and charges are to be established by each utility.

(4) Reciprocity Requirement

Section six of the *pro-forma* tariff sets forth the "reciprocity requirement." A *pro-forma* tariff customer must agree to provide, as a condition of taking transmission service under the tariff, "comparable" transmission service to the transmission provider "on similar terms and conditions" over its transmission facilities and the transmission facilities of its corporate affiliates.¹³

The FERC established a voluntary "safe harbor" procedure for non-public utilities to determine if such utilities satisfy the comparability standard. Under this procedure, a utility may request a "declaratory order" from the FERC finding that the terms and conditions of its open access transmission tariff substantially conform, or are superior, to those of the *pro-forma* tariff. If the FERC determines that the petitioning utility meets its standards, the FERC would deem the utility's tariff to be an acceptable reciprocity tariff and would require public utilities to provide open access service to that non-public utility.¹⁴

Through 1996, the FERC decided only one declaratory order petition.¹⁵ In that case, the FERC required the petitioning utility, the South Carolina Public Service Authority (Santee Cooper), as a condition to receiving the declaratory order, to revise its tariff to conform to the *pro-forma* tariff, but allowed Santee Cooper to make some modifications to reflect its non-jurisdictional status as a state entity. The FERC received other petitions,¹⁶ but had not resolved them in 1996.

As a final safeguard, a non-public utility can seek a waiver of all or part of the reciprocity requirement. In this instance, the FERC will apply

12. If any of the services are provided by another entity, the charges to the customer by the transmission provider are to reflect only a pass-through of the costs charged to the transmission provider by the service provider.

13. A customer that is a member of a power pool or regional transmission group (RTG) also agrees to provide comparable service to the members of the pool or RTG. As to rural electric cooperatives, the FERC clarified that a generation and transmission cooperative's distribution member cooperatives are not considered "affiliates" for purposes of the reciprocity requirement.

14. In addition, a non-public utility that has filed a petition for a declaratory order cannot be denied service while the petition is pending.

15. *South Carolina Pub. Serv. Auth.*, 75 F.E.R.C. ¶ 61,209 (1996).

16. See, e.g., *Southern Illinois Power Coop.*, Docket No. NJ97-1-000 (filed Oct. 8, 1996); *Omaha Pub. Power Dist.*, Docket No. NJ97-2-000 (filed Oct. 17, 1996).

the same criteria it uses to determine whether to grant a request for waiver of all or part of the open access rule.

(5) Contract Reformation

The functional unbundling and open access requirements apply to any bilateral wholesale coordination agreement (*i.e.*, any non-requirements contract) executed after July 9, 1996, the effective date of the open access rules. However, all bilateral economy energy coordination agreements executed before July 9 must be modified to require unbundling of economy energy transactions occurring after December 31, 1996. All non-economy energy bilateral coordination contracts executed before July 9 are permitted to continue in effect, but are subject to section 206 complaints that the rates, terms, and conditions of those pre-existing contracts are unduly discriminatory.

The FERC declined to abrogate existing requirements and transmission contracts generically. Moreover, the functional unbundling of the open access rules applies only to new wholesale services. Thus, the terms and conditions of the *pro-forma* tariff do not apply to service under existing requirements contracts and do not supersede existing transmission agreements that have been accepted by the FERC “unless specifically permitted in the agreement.” Once a customer’s existing bundled service (transmission and generation) contract or transmission-only contract expires and the customer takes new transmission service from its former transmission provider, however, the terms and conditions of the open access tariff apply to the new transmission service.¹⁷

In one case, the FERC allowed a public utility to convert the transmission service it currently provided to five customers under preexisting transmission service agreements to service under its *pro-forma* tariff.¹⁸ The FERC found that the proposed service agreement changes were consistent with the terms of the existing transmission service agreements. As to a sixth customer, however, the FERC rejected the proposed service agreement because the public utility proposed a change in the non-rate terms and conditions of the existing service that was not contemplated within the terms of the existing transmission service agreement. The existing agreement provided that transmission service under the agreement would not be subject to the transmission provider’s open access tariff, and specified the particular circumstances under which the contract could be terminated. The agreement thus did not “specifically permit” the transmission provider to supersede the agreement with its *pro-forma* tariff.

17. A public utility seeking to modify or terminate an existing transmission agreement must separately file to modify or terminate the agreement.

18. *Boston Edison Co.*, 77 F.E.R.C. ¶ 61,116 (1996).

(6) Independent System Operators

The FERC declined to mandate that public utilities establish independent system operators (ISOs) for their transmission systems.¹⁹ The FERC encouraged the development of ISOs, and provided a series of "principles" to guide utilities in the formation of ISOs.²⁰

- The ISO's governance should be structured in a fair and non-discriminatory manner. The ISO should be independent of any individual market participant or class of participants.
- An ISO and its employees should have no financial interest in the economic performance of any power market participant. The ISO should adopt and enforce strict conflict of interest standards.
- An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a non-discriminatory manner. No user or class of users should be favored or disfavored.
- An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role should be well-defined and comply with applicable standards set by the NERC and the regional reliability council.
- An ISO should have control over the operation of interconnected transmission facilities within its region.
- An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.
- The ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open competitive market.
- An ISO's transmission and ancillary services pricing policies should promote the efficient use of, and investment in, generation, transmission, and consumption. An ISO or a regional transmission group (RTG) of which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions.
- An ISO should make transmission system information publicly available on a timely basis via an electronic information network (OASIS) consistent with the FERC's requirements.
- An ISO should develop mechanisms to coordinate with neighboring control areas.

19. An ISO would be subject to the FERC's jurisdiction, which extends to the ownership or operation of facilities used for the transmission or wholesale sale of electric energy in interstate commerce. 16 U.S.C. § 824(e) (1994).

20. These principles apply only to ISOs that would be control area operators, including any ISO established in the restructuring of power pools; they do not apply to independent administrators or coordinators that lack operational control.

- An ISO should establish an alternative dispute resolution process to resolve disputes in the first instance.

(7) Stranded Costs

Order No. 888 affirmed that recovery of legitimate, prudent, and verifiable stranded costs should be allowed. The open access rule mandates direct assignment of stranded costs to a departing wholesale generation customer through either an exit fee or a surcharge on transmission. A public utility seeking recovery of stranded costs must demonstrate that it had a reasonable expectation of continuing to serve the departing customer. A notice provision in a contract creates a rebuttable presumption that the utility had no such reasonable expectation of serving the customer beyond the specified period.

The rule endorses a snap-shot “revenues lost” approach, with no true-up, for calculating stranded costs. Under this approach, stranded costs are calculated by subtracting the competitive market value of the power the customer would have purchased from the revenues that the customer would have paid had it stayed on the utility’s generation system.²¹

Public utilities will be allowed to recover stranded costs associated with new wholesale requirements contracts (executed after July 11, 1994, the date on which the FERC issued its initial notice of proposed rulemaking on stranded costs) only if their contracts contain *explicit* stranded cost provisions. Public utilities and transmitting utilities may *not* recover stranded costs under existing wholesale requirements contracts executed on or before July 11, 1994, if recovery is explicitly prohibited under the contract, a settlement agreement, or any power sales or transmission tariff on file at the FERC.

The FERC, rather than the states, will be the primary forum for recovery of wholesale stranded costs attributable to unbundled transmission for *retail-turned-wholesale customers*, including those attributable to municipalization, to avoid forum-shopping and duplicative litigation. The states have the primary responsibility for recovery of stranded costs attributable to retail wheeling, although the FERC will step in if a state does not provide for stranded cost recovery.

(8) Power Pools

“Tight” power pools, *i.e.*, New York Power Pool (NYPP), Pennsylvania-New Jersey-Maryland Interconnection (PJM), New England Power Pool (NEPOOL), and Michigan Electric Coordinated Systems (MECS), were required to file pool-wide open access *pro-forma* tariffs by December 31, 1996. The FERC later clarified that the public utility members of the pools would be required to take service under pool-wide tariffs

21. Stranded costs are capped at the average annual contribution to fixed power supply costs that would have been made by the departing generation customer had it remained a customer. In addition, a customer may, at any time prior to the termination date in its existing wholesale requirements contract, ask the public utility to provide an estimate of the customer’s stranded cost obligation.

sixty days after the December 31 filing deadline. Any bulk power market participant must be allowed to join the pool, regardless of type of entity, affiliation or geographic location. "Loose" pools, *i.e.*, the Mid-Continent Area Power Pool (MAPP), also had to file pool-wide *pro-forma* tariffs by December 31. The FERC also encouraged pools to consider forming ISOs.²² Finally, public utility holding companies regulated under the Public Utility Holding Company Act of 1935 (PUHCA)²³ must file single system-wide tariffs with a single system-wide transmission rate.²⁴

In the open access rule, the FERC expressed its support for the voluntary formation of regional transmission groups (RTGs) and the implementation of regional tariffs. Among other benefits, RTGs should help potential users obtain transmission access and resolve disputes over transmission service. RTGs also are expected to aid in regional planning and foster the efficient operation of transmission systems (both of which increase the competitiveness of the market).

To encourage the development of RTGs, the FERC will allow an RTG to file a regional open access transmission tariff that is consistent with the objectives of the open access rule. (It appears that this tariff need not be identical to the *pro-forma* tariff.) Each RTG member (even if a non-public utility is not otherwise subject to the rule) must offer comparable transmission services to the other RTG members under such a tariff. The FERC also states that it will defer to the planning, dispute resolution, and decision-making processes of an RTG. To date, the FERC has approved the formation of three RTGs—the Western Regional Transmission Association, the Southwest Regional Transmission Association, and the Northwest Regional Transmission Association.

(9) Transmission Rates

The FERC discussed, but did not adopt, possible alternative transmission rate methodologies to its traditional contract path methodology.²⁵ While Order No. 888 did not require flow-based pricing, the FERC did indicate it would welcome innovative proposals for alternatives to its contract path, embedded cost rate methodology if they are well-supported.

For ratemaking purposes, the FERC required public utilities to account for *all* uses of the transmission system and to demonstrate that all

22. The members of both tight and loose pools were required to file individual *pro-forma* tariffs like any other public utility, unless a joint pool-wide tariff was filed instead.

23. 15 U.S.C. § 79a (1994).

24. The holding company filing requirement did not apply to the Central and South West System, which presents "special circumstances" due to the operation of two of its operating companies within the Electric Reliability Council of Texas (ERCOT).

25. "Contract paths" denote a single, continuous, electrical path between parties. Actual power flows rarely follow those contract paths. "Flow-based" pricing, by contrast, accounts for actual power flows, including unscheduled flows. Region-wide flow-based pricing may or may not account for unscheduled flows. Flow-based pricing can sometimes make individual customers responsible for load flow effects caused by a third party's development of its transmission system, over which the customer and its transmission provider may have had no control. Flow-based pricing thus may be more practical on a regional basis, rather than for an individual utility.

customers, including native load customers, bear the cost responsibility associated with their respective uses. Utilities *may* use a single cost allocation method for network and point-to-point transmission service.

While not requiring the use of any particular rate methodology, the FERC stated that it would no longer summarily reject a firm point-to-point transmission rate developed by using the average of the utility's twelve monthly system peaks. The FERC adopted the load ratio allocation method for pricing network service. The FERC reaffirmed the use of a twelve monthly coincident peak (12 CP) allocation method, but would welcome other alternative allocation proposals.

In addition, where a public utility can demonstrate that additional opportunity costs are incurred as a direct result of providing transmission service (*i.e.*, when capacity is constrained), the utility may charge the higher of embedded costs or legitimate and verifiable opportunity costs, but not the sum of the two ("or" pricing, not "and" pricing). The opportunity costs would be capped by incremental expansion costs.

The rate for non-firm point-to-point service is capped at the firm rate if the utility does not adopt opportunity cost pricing. If the utility *does* adopt opportunity cost pricing, the non-firm rate is effectively capped by the availability of firm service and is not subject to a separately stated price cap. Discounts of non-firm prices must be nondiscriminatory.

Recovery of redispatch costs requires the proponent to develop a formal redispatch protocol that is made available to all customers and to make information available to customers to enable them to calculate the redispatch costs. Redispatch costs collected on a direct assignment basis must be credited to fuel costs and purchased power expenses.

Expansion costs may be recovered in any way that is consistent with the FERC's Transmission Pricing Policy Statement,²⁶ including by direct assignment, when demonstrated to be appropriate in a section 205 filing on a fact-specific basis. Recovering expansion costs based upon "and" pricing will not be allowed.

Finally, the FERC will determine whether customers may be entitled to a credit against their rates for customer-owned transmission facilities, and what might the appropriate level of that credit be, in case-specific proceedings.

(10) Waiver

The FERC recognized that the requirements of the open access rules could be particularly burdensome on select public utilities, especially small utilities. Therefore, the FERC stated it would consider granting a waiver of some or all of the requirements of Order Nos. 888 and 889 if a utility can show: (i) that it does not own transmission facilities, (ii) that it has turned control of its facilities over to someone else (such as the control area opera-

26. *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act*, Policy Statement, 59 Fed. Reg. 55,031 (1994), F.E.R.C. STATS. & REGS. ¶ 31,005 (1994).

tor) who complies with the rules as its agent, or (iii) that no one is likely to ask to use its facilities.²⁷

b. Order No. 889–OASIS and Standards of Conduct

(1) OASIS

The FERC's OASIS requirements apply to public utilities and non-public utilities that provide reciprocal open access transmission service, unless a waiver is granted. Order No. 889 (the OASIS rule) requires that such utilities establish, maintain, and operate (either individually or jointly with other utilities) a real-time information network on which available transmission capacity will be posted and on which capacity reservations may be made. Information about a utility's transmission system must be made available to all transmission customers at the same times. The OASIS will make that information available to all customers, thus ensuring that utilities do not use their ownership, operation, or control of transmission to deny access unfairly.

The information that must be posted on the OASIS includes:

- available transmission capacity and total transmission capacity on "posted paths";²⁸
- prices and a summary of the terms and conditions of transmission products;
- discounts to the transmission provider's customers or affiliates and to others;
- description, availability, and price of ancillary and other operational services provided by the transmission provider;
- requests for service and denials of requests for service (with the reason for the denial);
- curtailments and reasons for the curtailments;
- audit data on transmission transactions; and
- transfers of personnel between the marketing and transmission functions.

As to technical aspects, the FERC has adopted "Standards and Communications Protocols" to govern OASIS operation. The FERC also contemplates that the OASIS will be an Internet-based system. Although the FERC originally required the OASIS to be in place and operational by November 1, 1996, the FERC later pushed that date to January 3, 1997.

Finally, the fixed costs of the OASIS will be recovered in transmission rates and variable costs will be recovered by usage fees, as determined in individual rate cases.

27. See *infra*, § III(A)(2)(a) for a discussion of the FERC's waiver orders.

28. The transmission provider's open access transmission tariff will specify how to calculate ATC. Generally, the ATC assessment methodology must be based on current industry practices, standards, and criteria. In addition, ATC supporting information and transmission studies must be made available if requested.

(2) Standards of Conduct

In connection with the OASIS requirements, Order No. 889 requires that a public utility and non-public utility providing reciprocal service to adopt standards of conduct. These standards are designed to ensure that the utility's employees engaged in transmission system operations function independently of the utility's employees engaged in wholesale purchases and sales of electric energy in interstate commerce.

Functional separation requires physical separation (*i.e.*, no marketing personnel in the control room), as well as prohibitions on preferential access to information about the transmission system from non-public sources. "Preferential access" means that information is obtained from those with access to information about the public utility's transmission system operations that is not equally available to other customers. Inadvertent disclosures of such information must be posted on the OASIS immediately, deviations from the standards must be reported, and all exercises of "discretion" must be recorded.

(3) Waiver

As with the requirements of Order No. 888, utilities that would be burdened by Order No. 889 may also request a waiver of some or all of the requirements. The same standards for obtaining an Order No. 888 waiver apply to a waiver of the Order No. 889 requirements.²⁹

2. Congress

a. PUHCA Reform

Senator D'Amato's PUHCA repeal bill, S. 1317, which he first introduced in 1995, was endorsed by the Securities and Exchange Commission (SEC) and received broad support within the Senate. However, the bill did not have the unqualified support of the FERC or the National Association of Regulatory Utility Commissioners (NARUC). Upon the completion of hearings by the Senate Committee on Banking, Housing and Urban Affairs, the bill was reported out of committee with several amendments. Contemporaneously, a companion bill, H.R. 3601, was introduced by Rep. Tauzin in the House of Representatives.

Neither bill was voted on prior to the adjournment of the 104th Congress. Senate bill 1317 was never brought to a vote on the Senate floor. House bill 3601 languished in the House Committee on Commerce, in which there is a significant level of support for comprehensive federal energy reform legislation, rather than stand-alone PUHCA repeal.

These proposed bills, which are expected to be re-introduced in the 105th Congress along with more comprehensive federal energy reform proposals, provide for a transition period during which portions of the regulatory responsibility for utility holding companies will be shifted from the SEC to the FERC and the states. A key feature of the bills is expansion of

29. See *infra*, § III(A)(2)(a).

the right of the FERC and state utility regulators to obtain access to holding company books and records in order to guard against transactions and cost allocations that might adversely or unfairly impact utility rates or consumer interests. However, the stringent limitations on business activities currently imposed upon registered holding companies would be ended as a result of PUHCA repeal under this legislation.

The 104th Congress passed a significant exemption from PUHCA for telecommunications activities of registered holding companies, as a part of the Telecommunications Act of 1996.³⁰ This Act, which added a new section 34 to PUHCA,³¹ essentially removed all utility telecommunications activities from SEC jurisdiction under PUHCA. The Federal Communications Commission (FCC) took several actions that demonstrated that the exemption for telecommunications activities will be construed liberally. No action was taken by the SEC, however, to adopt proposed Rule 58 under PUHCA, which would have broadened the range of energy-related activities in which registered holding companies could engage without the need for specific SEC approval.

b. Retail Competition and PURPA

On July 11, two electric restructuring bills, both of which encompassed retail wheeling, were introduced. House bill 3790, introduced by Rep. Schaefer, Chairman of the House Commerce Committee's Subcommittee on Energy and Power, would have required states to implement retail wheeling plans by December 15, 2000. In addition, public power utilities not subject to rate regulation by their state commissions would have been directed to implement retail wheeling plans by that date. The bill provided little guidance on the recovery of stranded costs, but directed state commissions and public power systems to develop terms and conditions to recover investment costs incurred prior to July 11, 1996. Finally, PUHCA and section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA),³² which requires utilities to purchase power from qualifying independent power producers, would be waived for utilities that are subject to retail competition.

The other restructuring bill introduced on July 11, H.R. 3782, was offered by Rep. Markey. While it requires all state commissions and public power systems to consider formally whether either: (i) to implement retail wheeling or (ii) to divest generation, there is no requirement for such implementation. Instead, it offers incentives for doing so, such as the waiver of PURPA's mandatory purchase requirement and of PUHCA for utilities implementing either retail wheeling or divestiture.

A third retail wheeling bill, H.R. 4297, was introduced by Rep. DeLay on September 28. This bill would require the implementation of customer choice by January 1, 1998, with no provision for exit fees or other stranded

30. Pub. L. No. 104-104, 110 Stat. 56, to be codified at 47 U.S.C. §§ 151 *et seq.* (1994).

31. To be codified at 15 U.S.C. § 792-5c (1994).

32. 16 U.S.C. § 824a-3 (1994).

cost recovery mechanisms. Although none of the three retail wheeling bills was passed, all are expected to resurface in some form in the 105th Congress.

B. *The State Laboratories*

1. States with Significant Activity

a. Arizona

The Arizona Corporation Commission (ACC) adopted rules on December 26, 1996, in Docket No. U-0000-94-165 to make all retail load of IOUs available for competitive supply by January 1, 2003. Incentives for non-jurisdictional utilities to enter into intergovernmental agreements with the ACC to participate in the retail competition program or to agree to open up their service territories for competing sellers under the same terms as IOUs were added to rules subsequent to their proposal.

The rules phase-in retail competition for all customers over a four-year period, beginning with competition for at least 20 percent of each utility's peak demand in January 1, 1999, and increasing to 50 percent by January 1, 2001. Residential customers must be included as retail competition is phased-in. The rules also include a mandatory solar portfolio for participating utilities. The ACC will consider stranded cost recovery proposals on a case-by-case basis and conduct an inquiry into spot market development and independent system operator arrangements.

b. California

California remained in the forefront of electric utility industry restructuring in 1996. In late 1995, the California Public Utilities Commission (CPUC) directed the state's three investor-owned utilities (California IOUs) to put a wholesale power exchange (PX) and independent system operator (ISO) in place and begin phasing-in retail direct access, by January 1, 1998.³³ The initiative, known as WEPEX, continued to move forward in 1996.

The California IOUs filed Phase I of their WEPEX proposal with the FERC on April 29, 1996. The companies sought approval of their overall framework for the PX and ISO and asked the FERC to approve the companies' split between the FERC-jurisdictional transmission and CPUC-jurisdictional distribution and generation facilities.

Meanwhile, the California State Legislature was completing work on electric restructuring legislation. By the end of the summer, the Legislature enacted, and Governor Wilson signed, a new law regarding the restructuring.³⁴ Assembly Bill 1890 largely embraced the new industry structure previously approved by the CPUC and provided for recovery by the California IOUs of an estimated \$22 billion in stranded costs by 2003.

33. California Commission Decision D.95-12-063 (Dec. 20, 1995), *modified by* D.96-01-009 (Jan. 10, 1996) 166 P.U.R.4th 1 (1996).

34. Assembly Bill 1890, signed by Gov. Wilson on Sept. 23, 1996.

It also provided for retail rate reductions, to be financed through the issuance of rate reduction bonds. It established a State Oversight Board to oversee the operation of the ISO and PX, increased the ISO's responsibility to maintain system reliability, and contained measures encouraging the state's municipal systems to place their transmission facilities under the ISO's control.

The FERC addressed Phase I of the California IOUs' proposal in three orders.³⁵ The first order concerned the California IOUs' proposed split between transmission, distribution and generation facilities. In their April 1996, application, the California IOUs had stated that their transmission/distribution split was based on the seven factors that the FERC had announced in Order No. 888.

The FERC's second order addressed the California IOUs' PX and ISO proposals. Among other things, the FERC:

- accepted the California IOUs' proposal to establish the ISO and PX as separate entities;
- accepted the California IOUs' proposed organizational structure for the ISO and PX (deferring a ruling on the final structure pending submission of bylaws);
- accepted the State Oversight Board (set forth in AB 1890) for start-up functions;
- rejected a permanent role for the State Oversight Board in the governance or operations of the ISO, or appellate review of ISO Board decisions, as an intrusion on the FERC's exclusive jurisdiction;
- rejected as unduly discriminatory or preferential the AB 1890 requirement that ISO and PX governing board members be California residents;
- authorized the transfer of operational control over the California IOUs' transmission facilities to the ISO, subject to a number of conditions;
- held that, based on its preliminary review of the California IOUs' transmission access charge rate proposal (charges based on the revenue requirement for the service area in which the customer withdraws power from the ISO grid) and the California IOUs' alternative proposal (charges based on a uniform regional charge and a utility-specific local charge), the rate proposal and the alternative were both reasonable methods for recovering transmission costs;
- stated that the California IOUs needed to demonstrate in Phase II that market power in the energy market can be adequately mitigated and that the proposal does not recover embedded and opportunity costs ("and" pricing); and
- stated that the ISO should play a more active role in transmission expansion decisions than the California IOUs had proposed.

35. *Pacific Gas & Elec. Co.*, 77 F.E.R.C. ¶ 61,077 (1996); *Pacific Gas & Elec. Co.*, 77 F.E.R.C. ¶ 61,204 (1996); *Pacific Gas & Elec. Co.*, 77 F.E.R.C. ¶ 61,265 (1996).

The FERC's third order addressed market power issues related to the California IOUs' PX and ISO proposals, as well as the PX bidding and pricing proposals. The third order was based on Southern California Edison's (SCE) and Pacific Gas & Electric's original proposals to divest 50% of their fossil-fired generation (SCE later proposed to divest 100% of its gas-fired generation). The FERC concluded the California IOUs' market power studies were inconsistent with expected actual operations and used analytic techniques that defined inappropriately large geographic markets. As a result, the FERC agreed with the CPUC that the California IOUs had understated their transmission market power. The FERC directed the applicants to propose market power mitigation measures in their Phase II filing. The FERC also provided guidance on PX bidding and pricing for the Phase II filing. The FERC directed the California IOUs to submit their Phase II filing by March 31, 1997.

c. Maine

The Maine PUC submitted its final report and recommended restructuring plan on December 31, 1996, in Docket No. 95-462. The PUC recommended that all customers have retail access on January 1, 2000. Customers will be permitted to aggregate in any manner and to purchase power either directly from a power supplier or from intermediaries such as aggregators, power marketers, or energy service companies. All of the State's IOUs will be required to separate functional generation from transmission and distribution by the year 2000. When retail competition is fully implemented in 2000, the PUC will no longer regulate generating entities, nor review or approve construction of generation facilities.

The PUC pledged to permit utilities a reasonable opportunity to recover nonmitigable stranded costs arising from retail wheeling, but declined to impose exit fees on departing customers. Stranded costs will be collected through regulated rates from all customers using the services of a transmission and distribution (T&D) utility. Before retail competition begins, the PUC will establish the design of stranded cost recovery charges in company-specific proceedings, which is likely to take the form of a flat access charge or similar non-usage-sensitive charge. The PUC declined to impose exit fees on departing customers, since power purchases are rarely customer-specific and levying exit fees on new customers may dissuade businesses from moving to Maine.

Standard offer service will be provided to those who do not or cannot choose a competitive power provider. The T&D utilities will administer a competitive bid process to choose the standard offer service provider, subject to terms and conditions set by the PUC, but may not themselves bid to provide standard offer energy. Rates for this service will be capped so that, on average, the price for power combined with the regulated T&D rates will not exceed the total rate for electricity prior to the introduction of direct access. If, on average, the standard offer service price is higher, the PUC will initiate an investigation into whether retail competition is still in the public interest.

The PUC supported the establishment of an ISO and a voluntary power exchange and stressed the importance of ensuring that participants in a restructured NEPOOL meet NERC reliability standards.

d. Massachusetts

The Massachusetts Department of Public Utilities (DPU) issued its restructuring plan on December 30, 1996, in Docket No. 96-100. The plan, which contains model rules and a legislative proposal, contemplates that all customers will obtain direct retail access by January 1, 1998. The DPU rejected utility claims of a legal entitlement to stranded cost recovery, but concluded that "sound public policy" warranted offering utilities a reasonable opportunity to recover net nonmitigable stranded costs. The DPU plan also addressed legislative changes necessary to accommodate its proposal and outlined the positions that the DPU will take on matters subject to federal jurisdiction. In conjunction with its final plan, the DPU adopted standards of conduct for natural gas and electric distribution companies with affiliates engaged in competitive activities and directed utilities to unbundle generation, transmission, and distribution rates by March 3, 1997.

The DPU considered divestiture of generation to be the best means to address vertical market power, but acknowledged that it lacks the authority to order divestiture. Instead, the DPU will require functional separation and unbundling. Furthermore, the DPU does have the authority to order the creation of a separate marketing affiliate if a company wishes to sell generation to its own distribution companies, and may condition the purchase of generation by the distribution company on the existence of a separate marketing entity. In order to clarify the DPU's authority to order both functional separation and the establishment of separate marketing affiliates, the DPU seeks explicit authorizing legislation.

By separate order issued simultaneously with the final rule, the DPU also adopted a code of conduct for affiliate transactions. The standards of conduct require a distribution company to offer to nonaffiliated suppliers or customers the same products it makes available to its competitive affiliates, at the same prices, terms and time. The standards also address disclosure of proprietary customer information, employee sharing and public relations issues.

The DPU announced that it will "evaluate carefully" any mergers subject to its jurisdiction to ensure that no "excessive degree of concentration in the generation market would result." The DPU also will continue to regulate distribution reliability. Universal service will be maintained through the continuation of low-income discounts equivalent to existing discounts. The DPU believes that monopoly distribution companies will facilitate the transition to competition by providing a ready means of collecting stranded costs and public policy costs, so any changes to distribution service areas will be made later. The DPU plans to rely on performance-based regulation (PBR) when setting distribution company rates, but declined either to set rules for PBR or to require that PBR proposals include price caps.

The DPU supports the establishment of an ISO to operate New England's bulk power system in a manner that at least meets current reliability standards. Regarding transmission, the DPU intends to urge the FERC to adopt a location sensitive pricing method.

e. New Hampshire

The New Hampshire PUC is in the process of implementing HB 1392, enacted in May 1996. It issued a preliminary restructuring plan in September 1996. The restructuring law directs the PUC to implement retail wheeling for all customer classes by January 1998, and requires the PUC to issue a final restructuring plan by the end of February 1997. The PUC's restructuring proposal contemplates the introduction of a power pool, a power exchange, and an ISO. The PUC conducted company-specific adjudicative hearings for setting interim stranded cost recovery charges for affected utilities.

In asserting jurisdiction over the intrastate component of retail transmission service, the PUC acknowledged that that assertion of exclusive jurisdiction is inconsistent with Order No. 888, in which the FERC claimed that when a bundled retail sale is unbundled, "the resulting transmission transaction falls within the federal sphere of regulation." The PUC was unwilling to modify its position on jurisdiction over retail transmission. It may seek a waiver or modification of certain FERC-filed open access transmission tariff provisions that it believes should not apply to New Hampshire utilities. In the meantime, however, utilities are expected to begin developing retail transmission tariffs that are substantially consistent with the FERC's open access policies.

The legislature also directed the PUC to consider the use of PBR for transmission and distribution services. The PUC requested comments regarding the cost categories that should form the basis of a PBR scheme for the distribution level. Finally, the state-wide retail wheeling pilots begun in 1996 are underway at five of the state's six utilities.

Additionally, in the ongoing proceeding examining the proposal of Freedom Energy (Freedom) to serve Public Service Company of New Hampshire's (PSNH) customers, Freedom filed evidence with the PUC of its financial and managerial qualifications to conduct business as a public utility. Freedom now proposes to offer electric service to all of PSNH's customers. Freedom plans to obtain financial backing from Westar Energy, Inc., a wholly owned subsidiary of Western Resources.

The PUC also adopted, without modification, the uniform standards of conduct proposed by Enron Power Marketing, Inc., a power supplier registered to participate in the retail wheeling pilot program. The PUC found that there is a need for clear standards of conduct to govern the relationships and communications between the monopoly electric utilities and their competitive non-regulated affiliates. The PUC noted that, for the purposes of the pilot program, it allows nonregulated utility retail marketing affiliates to use names that suggest an association with the utility, for exam-

ple, PSNH Energy, Granite State Energy, and UNITIL Resources, which have been accepted for use in the pilot.

f. Pennsylvania

Pennsylvania enacted a comprehensive state restructuring and retail competition law, the Utility Restructuring Act of 1996.³⁶ The legislature found that it is in the public interest to permit retail customers to obtain direct access to competitive generation markets beginning on April 1, 1997, with pilot programs approved for all IOUs providing open access to five percent of peak loads of all retail customer classes. Access is expanded to one-third of each utility's customers in 1999, followed by an additional third in each of the following two years. Generation will be subject to competition, while transmission and distribution will remain regulated. The law provides for the recovery of nonmitigable stranded costs through a non-bypassable competitive transition charge (CTC) over a transition period of up to nine years and allows for the issuance of transition bonds to assist in their recovery. Separate rate caps are imposed for transmission service and energy during the transition, which will range from four and one-half to nine years, respectively. Distribution companies will remain suppliers of last resort. The State PUC may permit, but shall not require, an electric utility to divest itself of generation facilities. IOUs are required to file restructuring plans with the PUC between April 1 and September 30, 1997, which the PUC has nine months to review.

The PUC must assure that adequate generation reserves exist to maintain reliable service. Transmission and distribution systems are to continue to meet established national industry standards for installation, maintenance, and operating safety. While the law does not mandate an industry structure or an ISO, it does encourage all market participants to coordinate their plans and transactions through an ISO or its functional equivalent.

g. Rhode Island

Rhode Island enacted the Utility Restructuring Act of 1996,³⁷ which requires the restructuring of the industry and mandates retail wheeling for all customers by July 1, 1998. The law deregulates generation and requires that retail wheeling be phased in over one year beginning on July 1, 1997, with large customers comprising up to ten percent of a utility's load.

The law provides utilities a reasonable opportunity to recover stranded costs that were prudently incurred and imposes a non-bypassable transition charge of 2.8 cents per kilowatt-hour beginning when retail access begins, through the end of 2000. At that time, it will be replaced by a stranded cost recovery charge determined by the PUC.

Utilities were required to file restructuring plans with the PUC by January 1, 1997. These plans included proposals for transferring the ownership of generation, transmission, and distribution facilities to separate affiliates

36. 96 - H8124, Substitute B.

37. R.I. Gen. Laws § 39-1-1 (1996).

of the distribution utility and unbundling rates. The law supports the establishment of an ISO and a PX, allows end-use customers to directly contract with generators for power, and requires the PUC to use performance-based methods for setting distribution company rates during the two-year period after January 1, 1997. Restructured distribution utilities are prohibited from selling power at retail, and they may not own or operate transmission or generation facilities, although their affiliates may.

h. Texas

After holding extensive hearings in Docket No. 14045 throughout the summer of 1995, the Texas PUC adopted in February 1996, rules governing wholesale transmission services, rates, and access within ERCOT. The rules require ERCOT utilities to provide unbundled wholesale transmission services, including ancillary transmission services, on a nondiscriminatory basis. Regarding rates, the rules establish a transmission pricing formula consisting of 70% regional postage stamp and 30% distance sensitive rates.

The rules also require ERCOT utilities to establish an ISO for managing a statewide electronic information network, ensuring reliability of the power grid, ordering changes in utility operation to allow wholesale power transactions to occur, and providing information on pricing and availability of the transmission system to market participants. In August, the PUC approved a plan to reconstitute ERCOT to enable it to administer the ISO function. The new ERCOT board will now consist of three members elected from each of the following interests: (i) investor-owned utilities, (ii) municipal generation and transmission (G&T) utilities and large river authorities, (iii) cooperative G&Ts and small river authorities, (iv) transmission-dependent utilities, (v) independent power producers, and (vi) power marketers. The ISO commenced operation in the fall and should be fully operational by June 1997.

The PUC set up a series of information-collection dockets that resulted in the adoption by the PUC of three reports to be submitted to the Texas Legislature: (a) *The Scope of Competition in the Electric Industry in Texas*, (b) *An Investigation into Electric Industry Restructuring*, and (c) *An Investigation into Potentially Stranded Investment in the Electric Utility Industry in Texas*. These reports will weigh heavily as the Texas legislature considers an anticipated retail wheeling bill during its biennial session.

The stranded investment report examined costs that electric utilities likely would incur under a retail access environment. The report estimates that total stranded costs could range from a high of \$22 billion to a low of negative \$2.9 billion. In adopting this report, the PUC commissioners added recommendations that customers be allowed to continue electric service with their current utility provider in the event of retail wheeling, and that public schools or other public groups be selected as the first customers to receive the benefits of retail competition.

Finally, in December, the PUC requested comments on distribution unbundling. The PUC seeks to determine which distribution facilities or

functions are legitimately competitive and can be set loose from regulation through unbundling. The PUC sought comment on the following: components of metering and billing, physical separation of personnel function, and identification of distribution functions which are partially competitive.

2. Other States

a. Connecticut

A legislative restructuring task force submitted its report to the governor and legislature in December 1996. The report recommended consensus changes in the regulation of the electric industry and increased competition. The report examined costs and efficiency, taxes, public policy goals, purchased power, streamlining regulation, and customer choice. The task force did not reach consensus on fundamental competition and restructuring issues.

b. Idaho

A special legislative committee on utility deregulation was formed in September to consider restructuring legislation. The Idaho PUC concluded its restructuring investigation in August by noting that deregulation "is not feasible or desirable at this time."

c. Illinois

During Illinois' post-election legislative session, a coalition that included Commonwealth Edison, Central Illinois Public Service Company, Illinois Power, and customer groups introduced a restructuring bill. The legislature did not, however, consider the bill in 1996. The 1996 bill would have phased in retail choice with pilot programs in 1998 and direct access for large customers by 2000. All retail customers would have retail choice by 2005. Stranded cost recovery would be based on a five-year transition with lost revenues as the baseline. The market value of "freed up energy and power and a schedule of mitigation classes would be subtracted from the baseline. The Illinois legislative study committee failed to reach consensus on a final recommendation or on restructuring legislation, but noted, without endorsement, that three proposals were before it: one each by the coalition referenced above, Central Illinois Light Company, and the Citizens Utility Board.

d. Kansas

The retail wheeling task force of the Kansas Legislature has delayed its intended proposal for legislative language on competition and restructuring pending the results of a study of the impact of retail competition in Kansas. The task force did, however, approve an interim report on its activities, which it will submit to the Legislature in January 1997.

e. Maryland

The Maryland PSC continued its investigation in which it found in 1995 that retail wheeling was not in the public interest at the time. The PSC noted then that restructuring was a continuous process. The PSC asked its staff to file recommendations on retail competition by May 1997, and ordered utilities to file by August 1997, information that would be applicable if the PSC instituted retail competition.

f. Michigan

On December 19, 1996, the Michigan PSC staff submitted to the PSC a comprehensive restructuring proposal that would phase in retail wheeling for all utilities. All customers would have retail choice by 2004. The staff proposed that the costs of the transition be limited to five types (regulatory assets, nuclear capital costs, contract capacity costs in power purchase agreements, employee-related restructuring costs, and other costs related to implementing restructuring). The staff further proposed that stranded costs not recovered through securitization be recovered only from customers choosing alternative suppliers through 2007. The staff estimated that the rate reduction bonds would reduce retail rates by approximately nine percent by reducing utilities' existing debt and equity capital. Legislation is necessary for the securitization of transition assets.

g. Minnesota

The Minnesota PUC's restructuring investigation study group recommended that greater competition be introduced at the wholesale level by deregulating generation, increasing competitive procurement, and forming a regional ISO. The study group also found that the costs of a mandatory power exchange would exceed the benefits.

h. New Jersey

On January 16, 1997, the New Jersey Board of Public Utilities (BPU) issued an "Energy Master Plan Phase 2." This policy document calls for making New Jersey's wholesale electric market fully competitive by the end of 1997, and initiating retail competition between October 1998 and April 2001. The BPU expects to lower electricity prices for all New Jersey electric customers. The BPU has scheduled public hearings on the plan for February, and established a July 15 deadline for New Jersey utilities to file a rate unbundling plan, a stranded cost petition, and a restructuring plan. In March, the BPU will present its policy recommendations to the governor and legislature. The BPU expects to make its final decisions on restructuring in September 1998 and begin retail competition in the following month.

i. New York

The New York PSC issued an order in May 1996 requiring all jurisdictional utilities to file by October a plan for restructuring their corporations and services to accommodate wholesale and retail competition in electricity

markets by 1998. The order rejected arguments that the PSC was bound by law to allow recovery of prudently incurred stranded costs. New York's trial-level Supreme Court has upheld the PSC's order and the matter is now pending before the Appellate Division.

The New York Power Pool filed, at the FERC, plans for implementing an ISO. The ISO includes a governance board composed of all types of market participants using transmission and includes a New York Reliability Council. The ISO will use locational based marginal pricing, which will reflect embedded costs of the transmission system as well as cost differences associated with constraints on the transmission system.

A bill to allow utilities to securitize stranded costs for assured recovery was proposed by the Governor and passed by the Senate, but not the Assembly, in 1996.

j. Ohio

The Ohio PUC adopted guidelines for "conjunctive electric services" to allow utilities and aggregated groups of customers to negotiate rate, cost of service, rate design, rate eligibility, and billing arrangements. The PUC adopted a two-year pilot program for these customer choice options, which were initially developed in the ongoing competition roundtable discussions.

k. Vermont

The Vermont Public Service Board (PSB) issued its final report to the legislature on December 30, 1996. The report calls for a transition to direct access for all customers by the end of 1998. The PSB proposed a nine-part plan that would provide for: (i) customer choice; (ii) functional separation of Vermont's largest investor-owned utilities; (iii) "equitable treatment" of stranded costs; (iv) standards for municipal, cooperative, and small investor-owned utilities; (v) consumer protection; (vi) energy efficiency programs; (vii) renewable energy portfolio standards; (viii) environmental quality recommendations; and (ix) establishment of a regional independent system operator and power exchange.

l. Virginia

The State Corporation Commission has ordered its staff to continue and expand its restructuring inquiry to include the examination of company-specific data on costs, unbundled rates, and the distribution and transmission functions.

m. Wisconsin

The state PSC has adopted eight minimum standards for an ISO as a necessary step in its 32-step, five-year process leading to retail competition by 2000 or 2001. The PSC has continued its generic proceedings in five restructuring implementation issue areas, including corporate unbundling, affiliate transactions, quality of service, public benefits measures, and reform of the Advance Plan process and competitive bidding processes.

II. MERGERS AND DISAGGREGATION

A. *Policy on Mergers*

In early 1996, in response to the increasingly competitive and changing electric utility industry, the FERC launched a general review of its merger policy.³⁸ In the resulting Policy Statement,³⁹ the FERC clarified the procedures, criteria, and policies governing its review of the increasing number of public utility mergers.

Prior to the Policy Statement, the FERC had traditionally considered six factors in evaluating whether a proposed merger was "consistent with the public interest," the statutory standard:⁴⁰

- the effect of the proposed merger on competition;
- the effect on the merger applicants' costs and rates;
- whether the acquiring utility has coerced the to-be-acquired utility into acceptance of the merger;
- the reasonableness of purchase price;
- the effect on state and federal regulation; and
- the contemplated accounting treatment.⁴¹

Under the new policy, FERC focuses on three factors:

- the effect of the proposed merger on competition;
- the effect on rates; and
- the effect on regulation.

The Commission adopted the Department of Justice-Federal Trade Commission Merger Guidelines⁴² as the basis of its review of a proposed merger's effect on competition. Approval will turn on the correct definition of the product market, the proper description of a geographic market, the increase in concentration that may result from the merger, the likelihood of entry to restrain increased market power, and remedies to mitigate anti-competitive effects.

In its evaluation of mergers, as a first step the FERC will utilize a screen analysis to determine if further review is required. The FERC will measure concentration in the relevant product and geographic markets. The product market consists of the electricity products and substitutes for such products sold by the merging entities (*i.e.*, non-firm energy and short- and long-term capacity, under various conditions, such as peak and non-peak periods). The geographic market consists of: (i) those entities directly connected to the merging utilities and the merging utilities' historic trading partners and (ii) the potential suppliers that can compete to serve those entities identified in (i). To be considered in the geographic market,

38. See *Inquiry Concerning Merger Policy Under the Federal Power Act*, Notice of Inquiry, 61 Fed. Reg. 4596 (Feb. 7, 1996), F.E.R.C. STATS. & REGS. ¶ 35,531 (1996).

39. *Inquiry Concerning the Commission's Policy Under the Federal Power Act*, Policy Statement Order No. 592, 77 FERC ¶ 61,263 (1996) (Policy Statement), *reh'g pending*.

40. 16 U.S.C. § 824b (1994).

41. See *Commonwealth Edison Co.*, 36 F.P.C. (1966), *aff'd sub nom.* Utility Users League v. FPC, 394 F.2d 16 (7th Cir. 1968).

42. U.S. Department of Justice and Federal Trade Commission, *Horizontal Merger Guidelines*, 57 Fed. Reg. 41,552 (1992) (DOJ Guidelines).

such potential suppliers must be able to reach the customers *economically* (i.e., a delivered price within five percent of the merging companies' price) and *physically* (i.e., sufficient available transmission capacity). To measure market concentration, the FERC will rely on single firm market share statistics and a Herfindahl-Hirschman Index (HHI) analysis.

If the analytic screen in this first step indicates that the relevant markets are within the Guidelines' market concentration thresholds, the analysis of the effect of the merger on competition is complete. If, however, the analytic screen in this first step indicates that the proposed merger may significantly increase concentration in any of the relevant markets, then the FERC will require further analysis to determine if the other factors such as ease of entry of potential competitors address the potential for adverse competitive effect or mitigate or counterbalance the potential competitive harm.

Parties may agree to conditions to mitigate market power. The mere filing of an open access tariff will not be sufficient. The Policy Statement identifies several examples of mitigation measures: divestiture of generation; turning control over the transmission grid to an ISO; withdrawal from the grid during congested periods; expanding the grid through upgrades and construction; and price reform, such as regional pricing or "real time" spot pricing. The FERC may institute interim measures while the surviving company pursues long-term measures, such as expansion of transmission.

By utilizing these Guidelines, the FERC will be able to identify early in the merger process those proposed mergers that will not harm competition and should receive rapid approval by avoiding a trial-type hearing on competition.⁴³

Effect on Rates

Rather than weighing the benefits and harms of the merger in lengthy litigation, the FERC will require applicants seeking summary disposition to negotiate with customer hold harmless conditions; rate freezes or moratoria; or open seasons. A hold harmless condition would commit the surviving company to bear the costs of the merger, though it may seek to recoup other cost increases. In contrast, a rate freeze would make no distinctions among the type of costs. An open season would give wholesale customers a specific time to look elsewhere for service, even if contracts would otherwise bind them to the applicants.

Effect on Regulation

The primary emphasis shifts from the effect of the proposed merger on state regulation to its effect on the FERC's jurisdiction if the merger entails the parties forming a holding company. Under *Ohio Power Co. v.*

43. In order to allow intervening parties sufficient time to prepare meaningful, substantive interventions, the FERC will routinely allow intervenors sixty days from the merger application filing to comment on a merger filing.

FERC,⁴⁴ the SEC, not the FERC, governs dealings among affiliates of registered holding companies. To avoid a hearing on the effect of the merger on regulation, the holding company must agree to abide by the FERC rules on transactions among affiliates.⁴⁵ Finally, the FERC will rely on state commissions to exercise their authority to protect state interests. If a state commission lacks authority to regulate a proposed merger transaction, the FERC will step in to protect state interests.

Procedural Changes

Procedurally, the FERC will require merger applicants to provide supporting information and analyses on the three factors in their case-in-chief. The FERC provides guidance in the Policy Statement on the kind of evidence that the applicants should submit in order to avoid a lengthy, trial-type hearing on competition issues. The FERC hopes that its new filing requirements will expedite the merger review process, which can drag on for years, by narrowing the issues and focusing its review. The FERC intends to process most merger applications within twelve to fifteen months after completion of the applications. The FERC will codify its new filing requirements in a future rulemaking proceeding.

B. *Electric/Electric Merger Cases*

1. Wisconsin Electric/Northern States

On January 31, 1996, the FERC set for hearing the proposed merger between Wisconsin Electric Power Company and Northern States Power Company to address the effect of the proposed merger on bulk power competition,⁴⁶ directing the applicants to address a number of market power concerns. In an August 29, 1996, Initial Decision,⁴⁷ the presiding Administrative Law Judge (ALJ) found that the merged companies will not have significantly more market power than its pre-merger predecessors to influence energy costs in the region and that neither will have the ability nor the material incentive to manipulate the transfer capability over the constrained regional interface. The ALJ recommended that the FERC approve the proposed merger on the condition that the applicants follow through with their commitments to mitigate market power concerns (*i.e.*, through transmission upgrades, certain prohibitions on affiliate transactions, and the establishment of an ISO).

44. 954 F.2d 779 (1992).

45. Under the FERC's rules, holding companies must seek specific authorization for purchases of electricity from each other. They may not sell non-power goods and services in a manner that harms ratepayers. They may not sell above cost or market (whichever is higher) or purchase below cost or market (whichever reaps more revenue). *See, e.g., Duke/Louis Dreyfus Energy Serv. (New England) L.L.C.*, 75 F.E.R.C. ¶ 61,165 (1996), *order on reh'g*, 75 F.E.R.C. ¶ 61,261 (1996).

46. *Wisconsin Elec. Power Co.*, 74 F.E.R.C. ¶ 61,069 (1996).

47. *Wisconsin Elec. Power Co.*, 76 F.E.R.C. ¶ 63,016 (1996).

2. *Public Service of Colorado/Southwestern Public Service*

Public Service Company of Colorado (PSCo), a combination electric and gas utility, and Southwestern Public Service Company (SPS), an electric utility that provides electric service in New Mexico, Texas, Oklahoma, and Kansas, filed for merger approval on November 9, 1995. Applying the *Commonwealth Edison* factors, the Commission set for hearing the proposed merger's effect on costs and rates, competition, and impairment of the FERC's regulation.⁴⁸

The Commission found applicants' commitment to amortize merger-related costs over the first five years after consummation of the merger inadequate to protect ratepayers because it only covered costs that would be booked through the first two years of post-merger operations. Regarding the effect on competition, the Commission noted that because the non-contiguous merger applicants proposed to build a new transmission line to connect the two utilities, it would be difficult to assess the new line's impact on competition. Thus, the applicants would be required to file a supplemental market power study six months prior to the new line becoming operational and the new line would be subject to appropriate remedies to mitigate market power concerns.

Finally, as to the merger's effect on regulations, the Commission gave the applicants two options: (i) elect to have a hearing on the issue of whether the proposed registered holding company structure will effectively impair regulation by the FERC, or (ii) elect to abide by the FERC's policies with respect to intra-corporate transactions.

A settlement was filed in the PSCo-SPS proceeding before the end of the year.

3. *Baltimore Gas and Electric/Potomac Power*

Baltimore Gas and Electric Company, a combination electric and gas utility, and Potomac Power Company, an electric utility, filed for approval to consolidate their jurisdictional facilities through a proposed merger into Constellation Energy Corporation. In *Baltimore Gas and Electric Co.*,⁴⁹ in a split decision, the Commission set for hearing the issue of the proposed merger's effect on competition.

The Commission's preliminary analysis indicated that even with an open access transmission tariff on file, the merger may result in an increase in generation market power that is sufficient to affect competition adversely. The Commission was concerned that the applicants, by including the systems of the other PJM members in their market power analysis, may have overstated the size of the relevant geographic markets.

Commissioners Santa and Bailey dissented because: (i) intervenors had not specifically alleged adverse competitive effects resulting from the merger; (ii) the majority inappropriately relied on transmission constraints and cumulative transmission rates to dismiss PJM as a relevant geographic

48. *Public Serv. Co. of Colo.*, 75 F.E.R.C. ¶ 61,325 (1996).

49. 76 F.E.R.C. ¶ 61,111 (1996).

market; (iii) the majority's redefinition of relevant markets resulted in a more narrowly-defined group of markets; and (iv) the majority disregarded the lack of a finding of market power problems with the applicants' uncommitted capacity concentration.

4. *Union Electric/Central Illinois Public Service Company*

On December 2, 1995, Union Electric Company (UE), a combination electric and gas utility serving retail electric and natural gas customers in Missouri and Illinois, and Central Illinois Public Service Company (CIPS), a combination electric and gas utility serving retail electric and natural gas customers in Central and Southern Illinois, filed a merger application at the FERC. The Commission found significant issues of fact with respect to the effect of the merger on: (i) costs and rates; (ii) impairment of regulation; and (iii) the competitive situation, specifically, how transmission constraints will affect relevant markets.⁵⁰ The Commission set these issues for hearing and directed the presiding ALJ to issue an initial decision no later than April 30, 1997.

5. *Hostile Takeover Attempts*

Two hostile takeover attempts were launched in 1996, one unsuccessful and the other still pending at year's end. In January 1996, Kansas City Power & Light Company (KCP&L) and UtiliCorp United (UtiliCorp) announced plans to merge. Western Resources, Inc. (Western Resources) subsequently launched a hostile takeover bid and proxy battle for KCP&L. The KCP&L-UtiliCorp deal eventually collapsed, and Western Resources and KCP&L were negotiating merger terms at year's end.

The second hostile takeover was waged by MidAmerican Energy Corporation (MidAmerican) for IES Industries, Inc (IES). IES had committed to merge with Interstate Power Company (Interstate) and Wisconsin Power & Light (WP&L), and the three FERC jurisdictional utilities had filed for merger approval at the FERC.⁵¹ Nonetheless, MidAmerican launched a proxy battle and filed for merger approval at the FERC. MidAmerican's bid failed when IES's shareholders chose to remain with Interstate and WP&L after the deal was sweetened for IES.

C. *Gas/Electric Merger Cases*

Mergers between electric utilities and natural gas companies became a hot item in 1996. For example, on September 20, Enron Corporation (Enron) and Portland General Corporation, the corporate parent of electric utility Portland General Electric Company (PGE), filed a joint application with the FERC for approval under section 203 of the FPA for the merger of PGE and Enron Power Marketing, Inc. (Enron's public utility affiliate). On November 25, Duke Power Company and PanEnergy Corpo-

50. *Union Elec. Co.*, 77 F.E.R.C. ¶ 61,026 (1996).

51. Docket No. EC96-13-000.

ration announced that they would be filing for the FERC merger approval to create Duke Energy Corp., an integrated energy company.⁵²

The Commission determined in its Merger Policy Statement that it would apply its new criteria and procedures, including the competitive screen analysis, to gas-electric mergers. The Commission believes that its new policy is "sufficiently flexible to accommodate the review of these new and innovative business combinations."⁵³

III. MAJOR TRENDS THROUGH CASES

A. *Implementing Open Access*

1. The Power Pools

a. PJM

The Commission rejected a proposal by nine of the ten members of the Pennsylvania-New Jersey-Maryland Interconnection (PJM) to restructure the power pool into an ISO, as well as a similar proposal by the tenth member of PJM.⁵⁴ The Commission directed PJM to revise the restructuring proposal to be consistent with the principles applicable to ISOs that the Commission had established in Order No. 888. The Commission's principal objection to the PJM proposal was that the ISO was not sufficiently independent of the public utility members of PJM. The Commission's concerns with respect to independence included committee membership, voting provisions, administrative oversight of ISO operations, the development of operating procedures, control over reliability issues, and the transfer and independence of employees.

The Commission also expressed concern that the proposal did not adequately explain the charges for transmission and distribution, leading to concern about a double recovery of costs. While the Commission endorsed the use of zonal pricing within PJM as a transitional measure to prevent cost-shifting, it stated that imposing higher charges on customers that designate network resources outside the customer's transmission zone was discriminatory. The Commission also expressed support for locational marginal cost pricing for transmission congestion, but required PJM to provide additional information on the details of the pricing proposal.

The Commission rejected a number of deviations from the *pro-forma* tariff, including higher priority for network service than for point-to-point service, higher priority for longer-term firm service, a limitation on point-to-point service to transmission-out and transmission-through transactions,

52. Other pending gas-electric mergers announced in 1996 include the acquisition by Texas Utilities Co. (an electric utility) of ENSERCH Corp. (the corporate parent of Lone Star Gas Co., a gas utility company), the combination of Enova Corp. (the corporate parent of combination utility San Diego Gas & Electric Co.) and Pacific Enterprises (the parent of gas distributor Southern California Gas Co.), and the acquisition by Houston Industries Inc. (the corporate parent of electric utility Houston Lighting & Power Co.) of NorAm Energy Corp. (a diversified energy company with large gas distribution subsidiaries).

53. Merger Policy Statement, mimeo, at 8.

54. *Atlantic City Elec. Co.*, 77 F.E.R.C. ¶ 61,148 (1996).

the market pricing of most ancillary services, and the allocation of costs of construction.

b. California

The Commission conditionally authorized the establishment of the California ISO, although it deferred decisions on most organizational, operational, and pricing issues pending the filing on March 31, 1997.⁵⁵ The Commission raised some concerns about the independence of the California ISO, although its concerns were not nearly as extensive as they were with respect to the PJM ISO proposal. The Commission also rejected the limitation on ISO board members to California residents as inconsistent with the regional nature of the ISO.

The Commission held that a proposal to price transmission within the ISO based on the cost of service of the entity owning the facilities at the point of delivery was acceptable for a two-year transition period, but required greater detail on pricing for transmission-dependent entities, the exclusion of certain transmission facilities from the ISO, and marginal pricing for losses. The Commission also held that the pricing of transmission across congested interfaces based on location differences in the marginal cost of energy was useful, but stated that its approval was preliminary and dependent on a demonstration that such pricing mitigated market power over energy and did not result in customers being charged both embedded costs and incremental costs.

The Commission also required that the ISO have the authority to direct transmission owners to transfer to its facilities the power necessary to operate the grid reliably. The Commission rejected market pricing of ancillary services as unsupported without a market power study. It also expressed concern with leaving responsibility for transmission expansion in the hands of transmission providers instead of transferring the responsibility to the ISO.

2. *Pro-Forma* Tariffs

a. Waiver of Requirements of Order No. 888

The FERC recognized that the requirements of Order No. 888 may be "particularly burdensome" for small utilities that own no generation and buy at wholesale on a radial line from another utility's grid.⁵⁶ Where the service territory of a small utility including a non-public utility such as a distribution cooperative financed by the Rural Utilities Service (RUS), an agency of the Department of Agriculture is embedded in the control area of another utility, then that small utility may be exempt from the requirements of Order No. 888. The FERC will also consider requests for waivers

55. *Pacific Gas & Elec. Co.*, 77 F.E.R.C. ¶ 61,204 (1996).

56. The FERC has borrowed the Small Business Administration's definition of "small utility": a utility that has annual sales of no greater than 4 million MWh or \$120 million to \$180 million in annual sales.

of the requirements from utilities other than small utilities, and will apply the same standards to all such waiver requests.

The FERC, through a series of orders,⁵⁷ has set forth standards by which to evaluate requests for waivers. The FERC will grant a waiver of the requirement to file a *pro-forma* tariff (Order No. 888) if the requesting utility can show that:

- it does not own transmission facilities; or
- the facilities it owns, operates or controls are “limited and discrete” (provided, that it must file a *pro-forma* tariff within 60 days of receiving a good faith request for transmission service from an eligible customer).

b. Waiver of Requirements of Order No. 889

The FERC will grant a waiver of the requirement to establish and maintain an information system (*i.e.*, an OASIS) and standards of conduct requirements (*i.e.*, separation of merchant and transmission functions and employees) of Order No. 889 if the requesting utility can show that:

- it does not own transmission facilities;
- it owns, operates or controls only “limited and discrete” facilities; or
- it is a “small utility”, whether or not it operates an interstate grid, so long as it is not a member of a “tight pool” and there is no other reason to deny the waiver.

The FERC will waive the OASIS requirement for utilities that do not have a control area.⁵⁸

The OASIS requirement will be waived “unless and until an entity evaluating its transmission needs complains that it could not get information necessary to complete its evaluation.” The standards of conduct will be waived “unless and until an entity complains that the public utility has used its access to information about transmission to unfairly benefit a public utility’s own or the public utility’s affiliate’s sales.”⁵⁹

c. Conformance with Non-Rate Terms and Conditions

The Commission generally took a hard line with respect to proposed modifications to the non-rate terms and conditions of the *pro forma* tariff.⁶⁰ The Commission allowed regional deadlines for scheduling point-to-point transmission service that varied from the *pro-forma* tariff, as well as changes in the scheduling provisions that benefitted transmission customers. However, the Commission rejected essentially all other proposed devi-

57. See *Northern States Power Co. (Minn.)*, 76 F.E.R.C. ¶ 61,250 (1996) (First Waiver Order); *UtiliCorp United Inc. (W. Va. Power Division)*, 77 F.E.R.C. ¶ 61,027 (1996) (Second Waiver Order); *Central Elec. Coop., Inc.*, 77 F.E.R.C. ¶ 61,076 (1996) (Third Waiver Order); *Midwest Energy, Inc.*, 77 F.E.R.C. ¶ 61,208 (1996) (Fourth Waiver Order); *Black Creek Hydro, Inc.*, 77 F.E.R.C. ¶ 61,232 (1996) (order on reh'g) (Fifth Waiver Order).

58. See, e.g., First Waiver Order, 76 F.E.R.C. ¶ 61,250, at 62,293, 62,296-97 (Golden Spread Elec. Coop., Inc.).

59. Fifth Waiver Order, mimeo, at 5 (quoting First Waiver Order, 76 F.E.R.C. at 62,297).

60. *Atlantic City Gas & Elec. Co.*, 77 F.E.R.C. ¶ 61,144 (1996).

ations from the *pro-forma* tariff, including deviations proposed by intervenors. The Commission also did not permit litigation of issues relating to available transmission capacity (ATC), although it did require transmission providers to describe the methods for computing ATC, and deferred litigation on service agreements for network service and network operating agreements until the filing of customer-specific agreements.

The Commission also suspended for five months several rate filings that were made after the July 9, 1996, compliance filings that varied the terms of the *pro-forma* tariff.⁶¹ The proposed modifications included the treatment of all points of receipt as a single point of receipt for billing purposes, so as to permit sales of system power using firm point-to-point transmission service with a charge based on a single transmission path; provisions for non-firm point-to-point transmission service customers to designate alternate points of receipt and delivery without additional charge; changes to force majeure and indemnification provisions; and, the elimination of proportionate curtailment of firm point-to-point transmission service and network integration transmission service customers.⁶²

d. Tariff Implementation

The Commission clarified its requirement that rates for transmission service and ancillary services be unbundled. It required that market-based power sales tariffs state that, when the seller obtains transmission under its own open access transmission tariff, it will separately state the prices for generation, transmission, and ancillary services in quarterly reports for short-term transactions and in service agreements for longer-term transactions.⁶³ The Commission also required transmission providers to file service agreements providing for them to take service under their own transmission tariffs when they provide transmission service in connection with third party sales.⁶⁴

B. The Commoditization of Electricity

The Commission disclaimed jurisdiction over electricity futures contracts, holding that they did not constitute securities under section 3(16) of the FPA.⁶⁵ The Commission noted that it would have jurisdiction under sections 205 and 206 of the FPA over any futures contracts that go to delivery that involve the sale for resale by a public utility of electricity in interstate commerce.

61. *Tucson Elec. Power Co.*, 76 F.E.R.C. ¶ 61,235 (1996).

62. In orders issued in January 1997, the Commission rejected most of the proposed modifications that were not justified by regional practices. *Commonwealth Edison Co.*, 78 F.E.R.C. ¶ 61,090 (1997); *Arizona Pub. Serv. Co.*, 78 F.E.R.C. ¶ 61,083 (1997).

63. *Plum St. Energy Mktg, Inc.*, 76 F.E.R.C. ¶ 61,319 (1996); *Montaup Elec. Co.*, 77 F.E.R.C. ¶ 61,059 (1996).

64. *Public Serv. Elec. & Gas Co.*, 78 F.E.R.C. ¶ 61,119 (1997); *PacifiCorp*, 77 F.E.R.C. ¶ 61,280 (1996).

65. *New York Mercantile Exch., Inc.*, 74 F.E.R.C. ¶ 61,311 (1996).

C. PURPA Enforcement

The Commission denied a petition under section 210 of the FPA to require the Tennessee Valley Authority (TVA) to submit data on its avoided costs in conjunction with a potential bid by a group of Qualifying Facilities (QFs) to sell power to the utility.⁶⁶ The Commission held that the petition raised fact-based implementation questions that the Commission does not pursue. The Commission stated that the application of PURPA requirements should be left to the states, and that it was particularly reluctant to intercede with respect to issues related to cost data, which could exacerbate the TVA's concern for the integrity and confidentiality of its data. The Commission also stated that the absence of a state regulatory authority that could review the TVA data did not compel a different result since it did not want to become entangled in administering or reviewing power procurements.

The FERC also established a new policy to govern rates for power sales during periods when a QF fails to comply with PURPA and the FERC's implementing regulations.⁶⁷ The FERC held that a utility purchaser need not pay the contract rate for purchases during any period in which a QF fails either to comply with the QF standards or obtain a waiver from the FERC. The FERC explained that if the contracting parties had contemplated that QF status would be maintained during the entire term of the contract, and had not negotiated an alternative non-compliance rate, the utility would be required to pay the higher of the contract price or the utility's economy energy (incremental) cost for power purchases during the entire period of non-compliance.

The FERC applied this policy in *Megan-Racine Assoc., Inc.*⁶⁸ and *New Charleston Power I.*⁶⁹ In *Megan-Racine*, the QF failed to comply with both the operating and efficiency standards in 1991-92, and with the efficiency standards in 1993-94. The *New Charleston* case involved a manure-fueled small power facility that burned natural gas in violation of the FERC's 25% fossil fuel use limitation. In these cases, the FERC refused to excuse the non-compliance and ordered the QF to make refunds to its utility purchaser.

ELECTRIC UTILITY REGULATION COMMITTEE

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Thomas L. Blackburn, Vice Chair

66. *Tennessee Power Co.*, 77 F.E.R.C. ¶ 61,125 (1996).

67. *LG&E-Westmoreland Southampton*, 76 F.E.R.C. ¶ 61,116 (1996).

68. 76 F.E.R.C. ¶ 61,354 (1996).

69. 76 F.E.R.C. ¶ 61,282 (1996).

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