

State-Federal Relations in the Economic Regulation of Energy

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During the 1980s, tensions increased appreciably between federal and state officials charged with regulating energy utilities.¹ The conflicts that caused these tensions can be grouped into two broad, though not mutually exclusive, categories.² The first category includes disputes that arose when economic determinations about the need to build an energy facility in a certain area (often made at the national or regional level) conflicted with local environmental, health, and safety concerns.³ The second category involves tensions that resulted from dual *economic* regulation where control was apportioned in some fashion between state and federal regulators. This apportionment may have entailed concurrent jurisdiction,⁴ or an attempted division of jurisdictional responsibilities into mutually

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1. See generally Vince & Moot, *Federal Preemption Versus State Utility Regulation in a Post-Mississippi Era*, 10 ENERGY L. J. 1 (1989) (cataloguing major legal events in this area).

2. See, e.g., LITAN & NORDHAUS, *REFORMING FEDERAL REGULATION* (1983).

3. One of the most striking examples of this type of conflict occurred in the cases of the Sohio and Northern Tier west-east oil pipelines where parochial environmental concerns in California and Washington thwarted a congressional determination that the pipelines were necessary for national security and economic reasons. Public Utility Regulatory Policies Act of 1978 (PURPA), Tit. V, Pub. L. No. 95-617, 92 Stat. 3117, 3157 (1978) (codified at 43 U.S.C. § 2001 (1982)).

4. Concurrent jurisdiction may entail overlapping authority, as in state and federal review of utility mergers, or an explicit effort to create complementary state and federal authorities, as in Section 210 of PURPA, 16 U.S.C. § 824a-3 (1988). This Section of the statute attempts to create a form of regulatory partnership between the Federal Energy Regulatory Commission (FERC) and public utility commissions (PUCs), resulting in distinctive roles that are integrated through a regulatory scheme outlined in the statute and elaborated by FERC. See *infra* Part I, Section E.2.

exclusive parts. In this category, the regulation was of the commerce itself.

This Article focuses primarily upon the second category of conflicts. It examines the two pervasively regulated energy industries that have been subject to sometimes overlapping federal and state control: electricity and natural gas. Jurisdictional tensions in both areas have intensified as these industries reeled from dramatic shocks largely caused by macroeconomic forces beyond the control of both regulators and regulatees.⁵ These forces, complemented by technological and legal changes, have reduced utility monopoly power and, consequently, weakened the pre-existing system of economic regulation created to utilize and control the exercise of that monopoly power. At the same time, legislators and regulators attempting to implement regulatory reform increasingly have used their influence to expand the role of competition in these industries. Increasing competition not only redraws the boundaries between market forces and regulatory constraints, it also forces state and federal regulators to rethink prior jurisdictional divisions.

This combination of greater competition and reduced monopoly power has forced policymakers to reconsider major parts of the traditional system of state and federal regulation that has dominated each industry for over 50 years.⁶ The successful operation of the pre-1970 regulatory system depended heavily on the ability of regulated entities to exercise effective monopoly power. Because of the near impossibility of setting efficient and timely rates, the entire system of an administratively-determined rate structure depended for its continued existence on the ability of a regulated firm to sustain its earnings in the presence of substantial differences between regulator-determined prices and efficient prices. Under these conditions, only firms with substantial economies of scale that are protected by strong legal barriers to entry can sustain earnings. Regulatory constraints and protections thus provided an important part of the economic framework that kept public utilities financially viable and regulators politically safe.

By allocating risks and rewards, these regulatory constraints and protections also critically affected the incentives for efficient operation and planning. For decades, the regulatory structure spawned high

5. These forces include increasingly volatile price inputs (especially fuels and the cost of money), changing macroeconomic policies, and greater interdependence with the world economy. *See infra* Part I, Section B.1.

6. Reconsideration has proceeded quite far in the natural gas industry, and somewhat less far in the electric power industry. *See infra* Part I, Section E and Part II.

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growth rates and major technological advances in the two industries. The economies of scale inherent in the technology, enhanced by monopoly franchise regulation, enabled regulated firms to make large, long-term capital investments with little fear of competition. However, starting in the late 1970s and lasting throughout the 1980s, macroeconomic, technological and, above all, public policy changes in both industries weakened these monopoly powers. Consequently, regulatory approaches that assumed the existence of substantial monopoly powers were less sustainable: monopoly power that had been eliminated could not be exercised.

This Article thus argues that the principal state-federal jurisdictional tensions have resulted from changing public policy objectives⁷ and dramatically altered market conditions, the former in large part a response to the latter.⁸ It suggests that these jurisdictional tensions are by-products of goal-seeking actions by both private and public parties in response to dramatically altered circumstances, and have not arisen in response to some overriding ideological preference to rely on competition. Utilities face increasing market pressures, and regulators at both the federal and state level have far less room than previously for making pricing mistakes.

These changes also altered the rewards and risks imposed on regulated firms. The pattern of risk allocation accepted by regulators prior to the 1970s was a pattern initiated and supported by regulated firms and their financiers. It was damaged, probably beyond rehabilitation, by the political controversies surrounding utility price increases in the 1970s and early 1980s. The pre-1970 pattern of risk allocation depended crucially on regulatory agencies using their authority, and regulated firms using their monopoly powers, to coerce end users into bearing the risks associated with building large, long-gestation plants. The promised gain to end users was a lower nominal price for utility services. The intensity of opposition to the unanticipated price increases in the 1970s and

7. For example, regulators now are more inclined to promote economic efficiency, and to rely on market discipline to do so, rather than to subsidize favored interests through the rate-making process. Given reduced monopoly power and greater competition, regulatory pricing mistakes are no longer acceptable. See *infra* Part I, Sections B.2 and F.

8. In particular, dramatically rising costs of production in the 1970s and 1980s produced glaring differences in average costs of utility systems (the basis upon which most services are priced). This, in turn, led to increased competition in trading between systems and more competition from independent or non-utility power generators for both wholesale and retail customers. These forces significantly weakened the monopoly power provided by utility franchises thereby forcing regulators to worry less about cross-subsidization and more about total cost. See *infra* Section B.2.

1980s, especially price increases for plants that were not needed, induced many regulators and legislators to shift risks from end users to utility stockholders by withdrawing regulatory barriers and thereby increasing competitive pressures on regulated firms.⁹ The pre-1970 pattern of risk allocation thus proved to be a fair weather pattern—it failed when it was really needed. The late 1980s have seen utilities, their financiers, and regulators struggling to find a sustainable pattern of risk allocation. Some seek to impose risks on end users more firmly than in the past, while others would like to place greater risks on utility stockholders. In the 1990s, intense bargaining is likely to occur among the utilities, regulators, legislators, suppliers serving regulated firms, and end-users over the issue of who will bear the risks created by regulated firms investing in capital-intensive, long-gestation projects, either directly or through long-term contracts.

This process of reallocation of risks between the regulated entities and end users is therefore likely to dominate many of the public policy debates in the 1990s. The risk reallocation induced by these public policy initiatives, in turn, will intensify state/federal tensions as agencies at both levels respond in diverse ways to macroeconomic, technological and legal events in the 1990s, partially replicating the patterns of the 1970s and 1980s.¹⁰

Part I of this Article examines these issues in the electric utility industry. Section A of Part I analyzes the two traditional models of electric power regulation incorporated within the federal legislation that established the current jurisdictional framework. Sections B and C consider how the effort to reconcile these potentially conflicting models through a bifurcated jurisdictional framework for regulating wholesale power sales failed in the 1980s to resolve some major state/federal tensions. Section D examines the emerging conflict over transmission jurisdiction. Section E briefly examines how the resolution of similar tensions fared under alternative jurisdictional frameworks in related areas of electric power regulation. Section F concludes that the acute state/federal tensions in the 1980s emanated

9. See, e.g., Gioia, *The Prudence Standard: Recent Experience and Future Relevance*, PUB. UTIL. FOR., Apr. 27, 1989, at 11-16.

10. Perhaps the most publicized example was the Middle South cases over regulatory treatment of the Grand Gulf nuclear unit. FERC action on the allocation of Grand Gulf costs served to curb, in the multistate holding company area, the ability of states to disallow recovery on plant capital expenditures on grounds of "imprudence." State regulators had used the prudence review process to systematically reallocate risks from end users to utility shareholders throughout the 1980s. See *infra* Part I, Section C.

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directly from the failure of the pre-existing regulatory system to respond to economic, technological, and legal changes.

Part II of the Article focuses on the evolution of state/federal tensions under the dual regulation scheme in the natural gas industry. Section A of Part II describes the four major legal changes or milestones in the evolution of gas industry regulation which marked substantial shifts in the boundary between federal and state regulation. Until about 1980, regulatory authority gravitated from state to the federal regulators; since 1980, the power flow has been reversed. Section B examines the system of interstate pipeline regulation created by the Federal Power Commission (FPC) in the two decades after passage of the National Gas Act of 1938.¹¹ Section C analyzes the failures that occurred in this system of regulation, arguing that they were caused in part by a landmark Supreme Court decision.¹² Section D describes the effect of the National Gas Policy Act of 1978 on state and federal regulators.¹³ Section E presents FERC's responses to the system failures, emphasizing the Order No. 436 reforms, which shifted some decisionmaking authority from FERC to markets and to state PUCs.¹⁴ Section F concludes that the market-oriented reforms promulgated by FERC's Order No. 436, and subsequent FERC orders pursuing Order No. 436 objectives, have created a more efficient industry and have reduced tensions between federal and state regulators.

The Article concludes by arguing that in the long run the evolution of competition, in both the electric and gas industries, should do more to relieve than to exacerbate state/federal tensions.

I. Electric Power Regulation: Regulatory Assumptions, Economic and Political Realities, and Competing Federal Legislative Models

In the 1980s, increased tensions between federal and state regulators often were attributed to efforts to permit greater competition, such as federal regulatory reform of wholesale markets.

11. Pub. L. No. 75-688, 52 Stat. 821 (1938) (codified as amended 15 U.S.C. §§ 717-717w (1988)).

12. *Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 682 (1954).

13. 15 U.S.C. § 3301-3432 (1988).

14. FERC Order No. 436, *Regulation of National Gas Pipelines After Partial Wellhead Decontrol*, FERC Stats. & Regs. ¶ 30,665 (1985).

Others attributed these tensions to utility corporate restructuring.¹⁵ While efforts to promote competition did contribute to federal-state tensions, Part I argues that most of the increased tensions resulted from the inability of the traditional regulatory system to adapt sufficiently to major economic and legal changes.

Economic forces dramatically reduced the rate of demand growth for electricity and increased the real costs and risks associated with building new generation capacity.¹⁶ The traditional regulatory system proved incapable of efficiently adapting its ratemaking model to use existing capacity efficiently and to create an efficient risk/reward symmetry for generation expansions in this new economic environment. The result was over-expansion of generating capacity in the face of declining demand, large and increasingly contested rate increase requests, disallowed recovery of utility capital expenditures, and a consequent aversion by utilities to major new capital expenses. These developments were accentuated by technological advances¹⁷ and highlighted the need for changes in the regulatory models that had been accepted for almost four decades. Recognizing the underlying causes of this tension is necessary to avoid distorting future efforts at regulatory reform because of misunderstanding about the source of state/federal tensions. Although commentators disagree as to which regulatory reforms are needed, they are all beginning to understand that the traditional regulatory system is no longer conducive to efficient utility supply planning and operation.¹⁸

In response to increased competition to supply power to utilities (both from existing surpluses and new plants), federal and state regulators have initiated significant regulatory change. The principal federal economic regulator, the Federal Energy Regulatory Commission (FERC) has promulgated a series of generic administrative initiatives, typically rulemakings, and has resolved a number of

15. See, e.g., TASK FORCE ON ELECTRICITY UTILITY REGULATION, COMMITTEE ON ENERGY AND ENV'T, NATIONAL GOVERNORS' ASS'N, AN ANALYSIS OF OPTIONS FOR STRUCTURAL REFORM IN ELECTRIC UTILITY REGULATIONS 24 (1983) [hereinafter NGA ELECTRIC REFORM REPORT].

16. See, e.g., *infra* note 84.

17. For instance, advances in transmission and control technologies created economies of scale that transcended balkanized retail franchises upon which the traditional system was based.

18. See, e.g., *The Electric Executives' Forum*, PUBLIC UTILITY FORTNIGHTLY, May 25, 1989, at 76-117 (comments of utility executives). For a broad view of where utility planning should be directed in the future, see Pfister, *Designing a Utility for the 21st Century*, 2 ELEC. J., No. 9 (1989), at 16.

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individual cases so as to promote regulatory reform.¹⁹ These reforms were intended to facilitate the development of efficient wholesale power markets. Because the stakes are high for the U.S. economy and its international competitiveness, Congress has also begun to show an interest in such reform.²⁰ Electricity has grown steadily as a proportion of total U.S. energy consumption, and projections suggest that this trend will continue.²¹ Rational policymakers must assume that the electric industry will become an increasingly important part of the industrial infrastructure, especially in some of the newer high-tech and service industries that rely critically on electric power.

As electricity use expands, the possibility of severe capacity shortages in the 1990s has increased. The capacity surpluses of the 1980s are disappearing in some regions, and demand growth has outstripped projections for several years.²² For example, troublesome

19. The first significant public step occurred in May 1985 with a Notice of Inquiry, Regulation of Electricity Sales-for-Resale and Transmission Service, Phase I, 31 FERC ¶ 61,228 (1985) and Phase II, 31 FERC ¶ 61,376 (1985).

In March 1988, FERC issued three notices of proposed rulemaking relating to reform of Section 210 of PURPA and to FERC regulation of "independent power producers" (IPPs). These are often described as the "PURPA reform NOPRs." Notice of Proposed Rulemaking: Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities and Interconnection Facilities, FERC Stats. & Regs. ¶ 32,457, 53 Fed. Reg. 9331 (1988); Notice of Proposed Rulemaking: Regulations Governing Bidding Programs, FERC Stats. & Regs. ¶ 32,455, 53 Fed. Reg. 9324 (1988); Notice of Proposed Rulemaking: Regulations Governing Independent Power Producers, FERC Stats. & Regs. ¶ 32,456, 53 Fed. Reg. 9377 (1988).

During the 1980s, FERC also approved two major multi-utility experiments in reform-oriented wholesale and transmission pricing. Public Service Co. of New Mexico, 25 FERC ¶ 61,469 (1983); Pacific Gas & Elec. Co. (Western Systems Power Pool), 38 FERC ¶ 61,136 (1987).

In a series of cases, FERC also has permitted liberalized wholesale pricing for jurisdictional utilities displaying no "market power" or a willingness to mitigate market power through transmission access. St. Joe Minerals Co., 21 FERC ¶ 61,323 (1982), *reh'g granted*, 22 FERC ¶ 61,211 (1983); Cliffs Elec. Service Co., 32 FERC ¶ 61,372 (1985); Citizens Energy Corp., 35 FERC ¶ 61,198 (1986); Howell Gas Mgt. Co., 40 FERC ¶ 61,336 (1987); Orange and Rockland Utils., Inc., 42 FERC ¶ 61,012 (1988); Pacific Gas & Elec. Co., 42 FERC ¶ 61,406 (1988), *order on reh'g*, 43 FERC ¶ 61,403 (1988); Pacific Gas & Elec. Co., 44 FERC ¶ 61,010, *order on reh'g*, 45 FERC ¶ 61,061 (1988); Ocean State Power, 44 FERC ¶ 61,261 (1988); Citizens Power & Light Corp., 48 FERC ¶ 61,210 (1989).

20. Senator Bennett Johnston, Chairman of the Committee on Energy and Natural Resources, U.S. Senate, has introduced a bill, titled the Competitive Wholesale Electric Generation Act, to "remove obstacles to competition in wholesale electric generation markets," amendment to S. 406, 101st Cong., 1st Sess. (1989).

21. In 1988, electricity comprised 35.8% of total energy consumed, up 3.6% from the 1980 figure. DEPARTMENT OF ENERGY, MONTHLY ENERGY REVIEW (JUNE 1989).

22. See TRANSMISSION TASK FORCE, FEDERAL ENERGY REGULATORY COMMISSION, ELECTRICITY TRANSMISSION: REALITIES, THEORY AND POLICY ALTERNATIVES 27 (1989) [hereinafter FERC TTF REPORT].

power supply shortages may be imminent in New England and the mid-Atlantic region.²³ Official U.S. government projections indicate a national need for substantial generating capacity additions by the Year 2000.²⁴ Yet the history of the last decade reveals that very few utilities have planned the major generation plant additions that predominated from the end of World War II to the early 1970s.²⁵

Utility executives argue that their reluctance to build results from the increasing risks imposed on utility stockholders by state legislators and regulators.²⁶ However, even if this capital averse climate changes, the gestation period for most such additions is so long that they will not contribute to the power supply for several years, perhaps as many as ten. The difficulty and expense of adding large, long-gestation generating plants on a timely basis will probably increase: environmental regulation of coal-fired facilities will tighten; nuclear licensing and siting proceedings may become even more hotly contested; and the siting of all generation and transmission facilities is also likely to take more time. Furthermore, quasi-judicial regulatory proceedings that attempt to decide complex substantive issues tend to favor due process concerns over timeliness and, hence, further exacerbate other delays.²⁷

Consequently, if power shortages are to be avoided, utilities will have to emphasize short-gestation oil and gas plants.²⁸ Since reliance on oil and natural gas is likely to create upward pressure on oil prices in the long run, the industry may shift to mid-gestation coal plants once demand uncertainties are lessened by experience.²⁹ Such coal plants will likely be much smaller than the 1000 to 1200 megawatt plants that predominated in the early 1970s.

23. *Id.*

24. FERC TTF REPORT, *supra* note 22, at 28-29.

25. For instance, the last new nuclear plant constructed (and not canceled) was ordered in 1976. Few major coal plants have been ordered in the 1980s. See EDISON ELEC. INST., ANNUAL ELEC. POWER SURVEY (1988).

26. See *The Electric Executives' Forum*, *supra* note 18, at 72-106.

27. See Stalon, *Analysis and Synthesis in Quasi-Judicial, Multimember Regulatory Agencies*, in *THE FUTURE OF ELECTRICAL ENERGY* (1986).

28. Excessive reliance on oil and natural gas was perhaps the most pervasive concern driving the post-1973 "oil crisis" mentality that led to the National Energy Act of 1978 (the generic name for five specific statutes, including PURPA). After initially shrinking in response to conservation efforts, oil imports have been rising steadily in the 1980s. They now account for a significant part of the nation's trade imbalance, and are rapidly approaching 50% of the nation's oil consumption. Projections are that this dependence on oil imports will increase. See UNITED STATES ENERGY ASS'N, U.S. ENERGY 1989, *THE THIRD ANNUAL ASSESSMENT OF UNITED STATES ENERGY POLICY AND PROSPECTS 2* (1989).

29. See Peoples, *Power Generation in North America in the Future*, PUB. UTIL. FORT., May 25, 1989, at 58-61.

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These observations indicate that regulatory reform is a pressing necessity. There is a growing consensus among regulators that this reform will have to recognize and adjust to recent efforts to increase competition in important sectors of the industry. A revised regulatory system also will have to allocate the risks associated with building new generating plants that may not be needed immediately upon completion. The legal controversies created by the price increases of the 1970s and 1980s, which were induced by plants that were not needed when completed, cast serious doubts on the sustainability of the traditional regulatory approach. A new model will almost certainly require that suppliers voluntarily carry some of these risks. Such a revised system probably will require some role for nontraditional generators.

Regulators are increasingly recognizing that competition can complement a system of regulation that takes efficiency as a principal objective. For example, competitive capacity markets, either accepted or encouraged by state regulators, have emerged in several regions.³⁰ Utility pricing flexibility and competitive discipline have produced substantial improvements in equipment utilization.³¹ These improvements probably would not have resulted under detailed regulation by FERC and state PUCs. For regulators who rank other objectives highly, such as price stability or low rates for preferred classes, competition may not be a welcome force. However, regulatory and managerial discretion will continue to be reduced as the monopoly power of franchise utilities continues to shrink. That consideration, as well as increasing procedural and decisional complexity associated with traditional regulation, may coerce regulators to accept efficiency as the only feasible objective, and competition as a necessary tool for achieving it.

Because FERC and the state PUCs share regulatory responsibility, effective state/federal cooperation is necessary to achieve rational reform. Yet, many of the forces that have undermined the effectiveness of traditional regulatory approaches have also led to troublesome tensions between state and federal officials. While some of these conflicts have been resolved in the courts, the legal results seldom have produced a climate for constructive cooperation.³² Instead, they have exacerbated a problem already present in the system: state and federal regulators protect jurisdictional turf at the

30. See generally NATIONAL INDEPENDENT ENERGY PRODUCERS, *BIDDING FOR POWER: THE EMERGENCE OF COMPETITIVE BIDDING IN ELECTRIC GENERATION* (1990).

31. See FERC TTF REPORT, *supra* note 22, at Appendix A.

32. See, e.g., *infra* Sections B.3 and C.

expense of urgently-needed reform.³³ These conflicts also distort the debate over the emerging role of competition and how it should be reconciled with individual state and federal economic regulation. Further conflict could lead to futile efforts to resurrect the traditional regulatory system whose economic underpinnings have been removed. Instead, the focus should be upon the complex task of designing a new regulatory scheme that efficiently combines competition and regulation.³⁴

Moreover, these state/federal tensions also threaten to impede efforts by entities within the industry to restructure their operations to compete more effectively in changing markets. For instance, some important efforts to restructure utilities have floundered in part over state PUC concerns over loss of jurisdiction.³⁵ These concerns need to be addressed; otherwise, increasingly bitter state/federal jurisdictional conflicts will undermine efforts at reform designed to address new industry realities.

A. *The Evolution of Dichotomous State/Federal Jurisdiction Over Electric Power Regulation*

The Public Utility Act of 1935, which established the jurisdictional divisions under which the electric utility industry has been regulated for over fifty years, contained two different and potentially conflicting models of economic regulation.³⁶ These models help

33. *Id.*

34. The failure to do so could lead to serious efficiency losses. See FERC TTF REPORT, *supra* note 22, at 73-79, 163-69.

35. Remarks by P.R. O'Connor, First Annual American Bar Association Conference on Electricity Law and Regulation, in Denver, Colo. (Apr. 7, 1988), entitled *The Current Trend in Utility Regulation: Utility Restructuring and the Rise of Independent Power Producers*, at 14-17.

36. The Act which established the basic jurisdiction division was comprised of two major parts: 1) the Public Utility Holding Company Act (PUHCA), and 2) the Federal Power Act (FPA). The latter granted to the Federal Power Commission (FPC), now FERC, authority over wholesale power and transmission transactions. 16 U.S.C. § 824 (1988). PUHCA established a complex regulatory regime for utility holding companies, to be administered by the Securities and Exchange Commission (SEC). 15 U.S.C. § 79 (1988). PUHCA was designed primarily to curb a series of corporate abuses resulting from utility holding company structures that were perceived as causing a variety of problems for investors, consumers, and state regulators. 15 U.S.C. § 79(a) (1988). These abuses included the pyramiding of holding company structures and excessive debt-leveraging. See U.S. SECURITIES AND EXCHANGE COMM'N, PROPOSALS TO AMEND OR REPEAL THE PUBLIC UTILITY HOLDING COMPANY ACT OF 1935, 14 (1982) [hereinafter 1982 SEC STATEMENT].

The 1935 Act divided federal regulatory authority between the SEC and FERC along the following broad lines. The SEC regulates the activities of the holding companies themselves, especially financial transactions and corporate structure, and certain of their

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to explain the increase in tensions between state and federal regulators in the 1980s, and to make sense of a series of agency and court decisions that have not adequately resolved a number of jurisdictional conflicts. Understanding these tensions is crucial in developing a rational approach to regulatory reform.³⁷

The first model described is the “single state rate base model.” The second is the “multistate integration model.” A brief history of the development of the regulatory structure and the legislative framework designed to reconcile the diverse perspectives inherent in these models is necessary to analyze the breakdown in that structure that occurred in the 1980s.

1. *The Single-State Rate Base Model*

Municipal governments were the first to regulate electric utilities; their regulatory efforts began in the 1890s. In the opening decade of the 20th century, a coalition of progressive reformers and industry leaders³⁸ successfully urged state legislators to preempt municipal control over investor-owned utilities (IOUs).³⁹ This legislation was designed to avoid the conflicting and excessively politicized local regulation that previously existed. By the mid-1920s, most utilities were operating under a state-sanctioned monopoly retail franchise with a general obligation to provide end-use service.

affiliate relationships. The FERC regulates the wholesale power and transmission transactions of the operating utility subsidiaries (and state PUCs regulate certain of their retail transactions). However, both FERC and many state PUCs regulate operating utility corporate and financial matters. There is some potential for overlap and conflict over jurisdiction. The FPA attempts to deal with this potential by requiring that, if a “person” is subject to both PUHCA and FPA requirements “with respect to the same subject matter,” only the former shall apply (unless the SEC has exempted that person from the requirements of PUHCA, in which case only the FPA shall apply). 16 U.S.C. § 825q (1988).

37. See Vince & Moot, *supra* note 1; articles cited *infra* notes 113, 126.

38. See F. McDONALD, INSULL (1962). This book describes the role played by utility executives, especially Samuel Insull, President of Commonwealth Edison, and controlling forces in several other utilities, in supporting the creation of state utility commissions.

39. The focus of this Section is upon the economic regulation of IOUs, which account for close to 80% of electric power sold in the United States. The Section does not deal with the Tennessee Valley Authority (TVA), which is accountable directly to Congress and is essentially unregulated; the federal power marketing agencies, which are regulated in a limited fashion by the FERC and overseen by the U.S. Department of Energy (DOE); the approximately 1,800 state municipal or local publicly-owned utilities; and the approximately 900 Rural Electrification Act (REA) cooperative utilities. See FERC TTF REPORT, *supra* note 22, at 32. The last two groups of utilities are not subject to FERC regulation (with one exception). See FPA §201(f), 16 USC § 824 (1988); and *Arkansas Elec. Coop. Corp. v. Arkansas Pub. Serv. Comm'n*, 461 U.S. 375 (1983). These municipal or cooperative utilities are subject to state regulation in some states, but left unregulated in others.

They were accountable to state PUCs who represented the interests of the state ratepayers.⁴⁰ This model of regulation thus recognized the natural monopoly characteristics in the electricity supply process.⁴¹

Almost from their inception, state PUCs began to rely on a "rate base" model of economic regulation. This ratemaking model identifies the utility system's actual or projected costs of providing service for the period in question, adds a reasonable rate of return on assets used to produce the regulated service rate base, and determines a total revenue requirement. If another state's retail, or FERC's wholesale, jurisdiction is involved, regulators allocate this revenue requirement among the separate jurisdictions. Each jurisdiction's share is then further allocated amongst its customer classes. Regulators then establish prices, or rates, to recover the revenue requirement allocated to each class. This process, described in somewhat simplified form, is called rate base regulation throughout this Article.

As new generation and transmission technology made inter-utility and interstate transactions common, state regulators began to assert direct jurisdiction over these sales to control local IOUs' activities effectively. The Supreme Court first addressed a constitutional challenge to such assertions in *Public Utility Commission v. Attleboro Steam & Electric Co.*⁴² The Court held that state control over interstate wholesale transactions imposed a direct burden on national commerce, in violation of the Commerce Clause of the U.S. Constitution.⁴³ Two related concerns drove the Court: (1) the potential for parochialism, and (2) the possibility of conflicting PUC determina-

40. The same structure exists today. Forty-nine states have PUCs that follow this model of regulation. The sole exception, Nebraska, has no IOUs to regulate as all its utilities are public power or rural cooperative entities. In a few cases, such as New Orleans, municipalities complement or locally supplant the state commission.

41. However, because most of the industry entities involved were providing integrated service, this model did not seek to identify which natural monopoly characteristics exist in each of the three broad functions of that service—generation, transmission, and distribution. This failure has served to confuse the current reform debate, much of which is driven by a perception that generation is not a natural monopoly function.

42. 273 U.S. 83 (1927).

43. In *Attleboro*, the Rhode Island PUC had upheld a rate filed by an instate utility which altered the terms of a 20-year contract to fulfill all the power needs of a Massachusetts utility. In this case, it was the purchasing utility's challenge to the Rhode Island PUC's *upholding* of a rate increase which interrupted a long-term contract in mid-course. The Court implicitly recognized the potential bias involved when Rhode Island administrative and judicial decisionmakers protected the interests of the instate utility and, indirectly, the instate ratepayers at the expense of out-of-state interests. The Court also explicitly recognized the potential of a conflicting Massachusetts PUC determination. *Id.* at 90.

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tions. Both concerns justified eliminating state jurisdiction over interstate wholesale power transactions on Commerce Clause grounds.⁴⁴ By analogizing to a series of Commerce Clause cases concerning state regulation of natural gas, the Court also incorporated a wholesale/retail transaction dichotomy as the proper basis for distinguishing when state regulation would unduly burden interstate commerce.⁴⁵ By limiting the ability of states to regulate interstate utility transactions, this decision created a regulatory gap. These interstate wholesale transactions purportedly required some economic regulation if retail ratepayers were to be protected from the monopoly power of the utility; yet, state regulation was forbidden under the Constitution. The underlying assumption was that economic regulation was the only available means to protect retail ratepayers; wholesale competition apparently was not considered to be an acceptable alternative.⁴⁶

Congress moved to fill this regulatory void by enacting Part II of the Federal Power Act of 1935 (FPA).⁴⁷ In the FPA, Congress gave the Federal Power Commission (FPC), now FERC,⁴⁸ broad authority⁴⁹ to regulate the rates, terms, and conditions of service for the "transmission of electric energy in interstate commerce and the sale of such energy in interstate commerce."⁵⁰ The Commission was also given broad, but not exclusive, authority to regulate various aspects of utility corporate, financial, and accounting matters.⁵¹ Nevertheless, Congress also intended to preserve the existing scope

44. Ironically, when the Court revisited the *Attleboro* decision 56 years later, it found the Commerce Clause reasoning in *Attleboro* dated and inappropriate, and it concluded that PUCs could regulate the wholesale transactions of REA co-ops, which were not covered by the Federal Power Act's preemptive provisions, nor preempted by the Rural Electrification Act itself. *Arkansas Elec. Coop. Corp. v. Arkansas Pub. Serv. Comm'n.*, 461 U.S. 375 (1983).

45. *F.P.C. v. Southern Cal. Edison Co.*, 376 U.S. 205 (1964). This case is often called the "City of Colton case," derived from the name of the municipal utility involved.

46. Note, however, that Justice Brandeis, in a dissent in *Attleboro*, recognized the ability of Congress through "silence" to command that the ". . . utility shall remain free from public regulation." *Public Util. Comm'n v. Attleboro Co.*, 273 U.S. 83, 91 (1927).

47. Federal Power Act (FPA), Tit. II, Pub. L. No. 74-333, 49 Stat. 838 (1935) (codified at 16 U.S.C. § 824 (1988)).

48. In 1977, the agency was renamed and formally made part of the U.S. Department of Energy, but retained most of the FPC's regulatory authority (and, as it turned out, its "independence") and acquired additional responsibilities. Department of Energy Organization Act, §§ 204, 401-407, 42 U.S.C. §§ 7134, 7171-77.

49. The FPC had been established in 1920 to administer Part I of the FPA which deals with hydropower licensees. Federal Water Power Act, Pub. L. No. 66-280, 41 Stat. 1063 (1920) (codified at 16 U.S.C. § 791 (1988)).

50. 16 U.S.C. § 824(a), (d), (e) (1988).

51. 16 U.S.C. §§ 824(b), (c), (g), 825, 825(a), (c), (d) (1988).

of state authority, stating generally that the FPC's authority should extend only to those matters that are not subject to regulation by the States,⁵² and by specifically limiting the Commission's jurisdiction to interstate transmission transactions.⁵³ This latter provision preserved state jurisdiction over generating plants, as well as over transmission facilities. Furthermore, transactions to transmit electricity "consumed wholly by the transmitter remained subject to state regulation."⁵⁴

This effort to preserve the then-existing scope of state regulation was reinforced by the other major component of the 1935 Act, the Public Utility Holding Company Act (PUHCA).⁵⁵ Prior to this legislation, the effectiveness of state PUCs apparently had been undermined by the inability of PUCs to penetrate complex holding company structures and by legal prohibitions against state control of the relationship between parent companies and their state-regulated subsidiaries.⁵⁶ PUHCA was successful in restoring the effectiveness of state PUCs in the ensuing years. Today, PUCs are a powerful regulatory force in most states, and their national body, the National Association of Regulatory Utility Commissioners (NARUC), is a powerful force in molding national policy.

In taking such obvious pains to protect state regulation in 1935, Congress appeared to be conscious of the increasing potential for federal authority to preempt state jurisdiction. The FPA thus protected state regulation by a structural division of authority. States would control all retail transactions and most generation and transmission plant certification and citing decisions, while the federal agency would regulate all wholesale transactions in interstate commerce. In filling the *Attleboro* gap, the FPA attempted to preserve the effectiveness of state jurisdiction by drawing a clear or "bright line" between state and federal jurisdiction.⁵⁷

Throughout the 1950s, technological advances led to an increasingly interconnected and interstate electric utility system, which began to exert pressure on the single-state regulatory model. One change producing such pressure was a greatly increased level

52. 16 U.S.C. § 824(a) (1988).

53. 16 U.S.C. § 824(b) (1988).

54. *Id.*

55. 15 U.S.C. § 79 (1988).

56. *Id.*

57. *FPC v. Southern Cal. Edison Co.*, 376 U.S. 205 (1964). As discussed below, that line is considerably less clear in corporate structure and financial regulation.

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of coordination transactions among IOUs,⁵⁸ which intensified in the 1960s, and continued into the 1970s.⁵⁹ State regulators initially responded to the emergence of these interconnected, multistate utilities by conceptually dividing these utilities into parts. They allocated revenue requirements and sometimes costs and assets among jurisdictions and treated the allocated sums as if each were a single-state utility. Ambiguous state laws that used the term "public utility" in one sentence to mean a legal entity, in the next to mean a subset of its assets, and in the next sentence to mean a subset of that entity's costs, accommodated such regulatory practices.⁶⁰ Furthermore, most major multistate utilities, which were often created by mergers of single-state utilities, found it convenient to preserve the facade of single-state regulation by retaining operating companies identifiable with single states, usually under a holding company structure.⁶¹

Hence, the single-state rate base model of regulation was kept intact for several decades, at least in form, even in the face of technological changes that were slowly undermining the economic and organizational justifications for such a model. That facade began

58. Such transactions range from short-term buying and selling of power to formalized agreements amongst groups of utilities, commonly called "power pools." Utilities design power pools to assure greater economy in and reliability of supply through reserve sharing, joint planning, coordinated operations, and even joint ownership of generation and transmission facilities. See generally FEDERAL ENERGY REGULATORY COMM'N, POWER POOLING IN THE UNITED STATES 2-14 (1981) [hereinafter FERC POWER POOLING REPORT]. By 1989, FERC regulated about 38% of all the kilowatt-hour (kwh) sales regulated in the country. FERC TTF REPORT, *supra* note 22, at 16-20.

59. For example, the share of the nation's generating capacity accounted for by power pools of unaffiliated utilities rose from 12% in 1960 to 50% in 1970. *Id.* at 9. The courts have generally responded to these trends toward interconnection by finding that most power flows on interconnected alternating current (AC) transmission grids are "in interstate commerce," see *infra* Part I, Section C, and that even contractually intrastate wholesale transactions are therefore subject to exclusive FPC (FERC) jurisdiction. *FPC v. Southern Cal. Edison Co.*, 376 U.S. 205 (1964).

60. See, e.g., ILL. REV. STAT. ch. 111 2/3, para. 401 (1988).

61. Good examples are the Middle South Utilities and American Electric Power holding company systems. The Middle-South System includes four operating utilities, two operating exclusively in Louisiana, one exclusively in Mississippi and one predominantly in Arkansas (with some operations in Missouri).

These systems still cling to the myth of self-sufficient single-state operating companies, theoretically accountable to their respective PUCs. The notion of self-sufficiency is preserved through equalization requirements in their system agreements that require each subsidiary, over time, to build to meet its native capacity needs. Under the economic pressures of the 1970s and 1980s, that mandate has become increasingly difficult to meet, resulting in protracted differences in capacity reserves and significant differences in average capacity costs.

to crumble under the intensified economic pressures on the industry in the 1980s.⁶²

2. *The Multistate Integration Model*

The language of the FPA also supports a very different model of regulation. Congress built into the FPA a series of regulatory mandates requiring FERC to encourage coordination and efficiency-enhancing integration between utility systems.⁶³ This mandate includes a general provision to "promote and encourage" the "voluntary interconnection and coordination of facilities for the generation, transmission and sale of electric energy."⁶⁴ The purpose of this grant of power is to assure "an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources."⁶⁵ The Commission is also given authority in certain limited circumstances to order interconnections between,⁶⁶ and the wheeling of energy over, utility systems.⁶⁷

The increasingly intersystem and interstate nature of the industry is also manifest in the regulatory response to the 1965 blackout of the Northeast as a result of failures in the interconnected transmission network. In the public furor that followed the blackout, the FPC was directed to analyze the failure and propose methods for avoiding a similar failure in the future. Rather than developing a new form of federal regulation, the FPC accepted industry proposals and recommended the establishment of nine industry-run regional Reliability Councils. The Councils would allow the industry to cooperate in maintaining the reliability of interconnected operations and the adequacy of regional supplies.⁶⁸ In addition, the industry established, in 1968, the North American Electric Reliability Council (NERC) to aid in coordination among the regional councils.⁶⁹ Hence, a form of industry self-regulation was instituted in lieu of potential

62. See *infra* Part I, Section C.

63. Some of these functions were transferred to the U.S. Department of Energy. See *supra* note 48. However, the broad jurisdiction of the Federal government to carry out these mandates remains intact. In fact, it has been subsequently enhanced. See *infra* note 78 and accompanying text.

64. 16 U.S.C. § 824a(a) (1988).

65. *Id.*

66. 16 U.S.C. §§ 824a(b), 824i (1988).

67. 16 U.S.C. §§ 824j, 824k (1988). Wheeling is the use of one utility system's transmission facilities to transmit power produced by another utility to a third party.

68. FERC POWER POOLING REPORT, *supra* note 58, at 3.

69. FERC POWER POOLING REPORT, *supra* note 58, at 2, 7.

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federal regulation to establish the technological rules-of-the-road for the interconnected utility systems.

While this Reliability Council structure has viewed its mandate as confined to assuring technical reliability,⁷⁰ its importance as a self-regulator has grown as wholesale markets have become more competitive. Moreover, the dichotomy between technical and economic objectives that NERC and the regional Reliability Councils have sought to maintain is not easily sustained. For instance, NERC typically establishes standards for utility reserve margins⁷¹ to meet accepted technical standards for reliability of supply. The appropriate level of reserves, however, may be central to a state PUC's determination as to how much utility plant should be in the rate base and hence should earn a return for the utility. Thus, the technological definition has large economic and regulatory consequences. Furthermore, recent indications suggest that FERC is starting to view issues such as the appropriate reserve margin as pertinent to its review of multistate holding company agreements.⁷² These developments portend a further blurring of traditional regulatory roles that Congress sought to keep distinct.

Throughout the 1960s and 1970s, FERC also used its powers to encourage the development of power pools and other forms of non-market integration.⁷³ In fact, the statutory provisions adopting a multistate perspective suggest an integrated regional utility approach to planning, building, and operating capacity that pays little regard to state boundaries. This paradigm is a reality in most interstate utility systems.⁷⁴ As major mergers continue, the list of such systems

70. See NORTH AMERICAN ELEC. RELIABILITY COUNCIL, 1989 RELIABILITY ASSESSMENT 2 (1989). Cf. Wilkinson, *Power Monopolies and the Challenge of the Market: American Theory and British Practice* (Sept. 1989) (Discussion Paper E-89-12, Energy and Environmental Policy Center, John F. Kennedy School of Government, Harvard University), at n.67 ("The outcry after the blackout of US northeastern states in 1965 and the New York blackout of 1975, and the political recriminations surrounding the U.K. blackouts of the 1960s, taught utility managers to err on the side of caution when considering the trade-off between cost and reliability. To justify this caution, reliability appears after to have been elevated from the realm of economics to the spheres of morality").

71. Reserve margins refers to the percentage by which the dependable generating capacity available to a utility exceeds its projected peak capacity requirements. Typically, certain levels of reserve are sought to provide a safeguard against unintended incapacitation or isolation of generation sources.

72. Central and South West Services, Inc., 48 FERC ¶ 61,197 at 61,731-34 (1989).

73. See, e.g., FERC POWER POOLING REPORT, *supra* note 58, at 3-4.

74. *Id.* Two common organizational forms that facilitate behavior in accordance with this paradigm are holding companies and multidivisional companies. While decisionmaking and operations may be essentially similar for these two, the decision to structure themselves as holding companies or as single corporate entities operating through various divisions makes a dramatic difference in their jurisdictional status. The former typically must be

will grow.⁷⁵ These statutory provisions providing for greater interstate coordination were central to FERC's conclusion that state PUCs could not perform "prudence review" of the supply decisions of multistate holding companies and their operating subsidiaries.⁷⁶ In the 1980s, these decisions increased state/federal tensions and often required judicial intervention.⁷⁷

Hence, in the 1980s, FERC interpreted the FPA as requiring greater coordination and limits on state authority that interfere with efficient inter-utility coordination and integration.⁷⁸ In some controversial and bitterly contested cases, the FERC exercised its preemptive authority to carry out its perceived mandates over strong protest from state PUCs.⁷⁹ The multistate holding company cases are

registered and falls under the web of SEC regulation under PUHCA, as well as some FERC and PUC regulation. *See supra* note 36. The latter typically are regulated solely under the FPA dichotomy between PUC and FERC jurisdictions.

75. The recent merger of PacifiCorp and Utah Power & Light produced a single utility with significant operations in seven states. Utah Power & Light Co., 45 FERC ¶ 61,095 (1988), *order on reh'g.*, 47 FERC ¶ 61,209 (1989).

76. AEP Service Corp., 32 FERC ¶ 61,363 (1985); Kentucky Power Co., 36 FERC ¶ 61,227 (1986); Middle South Service, Inc., 31 FERC ¶ 61,305 (1985), 808 F.2d 525 (D.C. Cir. 1987). "Prudence review" typically involves an *ex post facto* PUC determination as to whether utility expenses were prudently incurred so as to justify their recovery in retail rates.

77. *See infra* notes 126-27 and accompanying text.

78. In 1978, the Congress reaffirmed FERC's mandate to encourage efficiency-furthering coordination by enacting, as part of the multifaceted National Energy Act ("NEA"), Section 205 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), Pub. L. No. 95-617, § 205 92 Stat. 3117 (codified at 16 U.S.C. §824a-1 (1988)). This Section gives FERC authority to "exempt electric utilities, in whole or in part, from *any* provision of State law, or from any State rule or regulation, which prohibits or prevents the voluntary coordination of electric utilities including . . . central dispatch." *Id.* (Emphasis provided.) "Central dispatch" is an operational procedure whereby outputs of a set of generating units are controlled to meet time-sensitive demands at minimum costs. FERC may exercise this authority if it "determines that such voluntary coordination is designed to obtain economical utilization of facilities and resources in any area." *Id.* Section 205 of PURPA is remarkable in that it overtly grants to FERC authority, arguably implicit in some of FERC's general coordination mandates in the FPA, to reach over the "bright line" and nullify traditional areas of state authority in order to meet the coordination goal of encouraging power pools. In fact, FERC has not exercised this authority to date. Any effort to do so would undoubtedly be controversial. FERC's refusal to exercise its "§ 205 authority" may be attributed to its focus in the 1980s on expanding competition in wholesale markets rather than on expanding power pools. FERCs may be reluctant to exercise its full authority because FERC appears to have found sufficient authority in the FPA to meet its coordination goals to date. However, as the technology of transmission and control advances, the emphasis on expanding power pools that was so prevalent in the 1960s and 1970s may return. This would increase the probability that Section 205 will be used. Moreover, there are increasing signs of tensions within certain power pools (some of them caused by state PUC concerns) that could threaten their existence and hence might induce FERC to use its Section 205 authority. *See, e.g.*, Public Service Co. of New Hampshire, 46 FERC ¶ 61,419 (1989).

79. *See infra* notes 126, 128.

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the most renowned examples.⁸⁰ Another important example, which may be a precursor to future trends in state/federal tensions, is the FERC's 1988 decision in *Utah Power & Light*, which conditions a merger between two utilities on their willingness to provide transmission services to potential competitors.⁸¹ That decision was also perceived by some as interfering with state prerogatives.⁸²

B. *Policing the Bright Line: The Erosion of the Rate Base Model and of the Traditional Jurisdictional Dichotomy*

In the years between enactment of the 1935 Public Utilities Act and the late 1960s, the two models of regulation built into the FPA coexisted comfortably. The combination of declining real production costs,⁸³ the strong monopoly power of vertically integrated utilities, and a stable economic environment where input prices and final demand remained constant for long periods of time, all provided the necessary conditions for this regulatory system to work effectively. These conditions produced increasingly comprehensive and reliable service at declining overall costs.⁸⁴

Through the 1950s and 1960s, productivity growth in the electric utility sector was consistently above the national inflation rate. As a result, utilities rarely requested rate increases. Although regulators occasionally demanded price decreases, they usually were satisfied to allow utilities to determine which prices were to be reduced the most. Utilities used this price flexibility to lower the rates charged to price sensitive industrial customers. This policy increased overall demand and allowed all customers to benefit from the economies of scale associated with larger power plants. Since new technology was lowering production costs, the utilities with the highest growth

80. See cases cited *supra* note 76.

81. *Utah Power & Light Co.*, 45 FERC ¶ 61, 095 (1988). See *infra* Section E.3.

82. *Id.* In the merger review area, the FERC and affected PUCs with review authority have concurrent jurisdiction, giving each the effective power to veto a proposed merger. See *infra* Section E.3.

83. In 1987, on a national average, generation investments accounted for 60% of total utility investment while transmission investment accounted for about 12%. FERC TTF REPORT, *supra* note 22, at 59-60. However, the individual percentages for generation and transmission can vary quite dramatically on individual utility systems.

84. Stated in 1984 dollars, the national average real price of electricity declined from 17.8 cents in 1929 to 4.0 cents per kilowatt-hour (KWH) in 1970, due principally to technological advances in thermal efficiency, increased coordination, and economies of scale in generation. Between 1970 and 1984, that real price rose to 6.2 cents per KWH, more than a 50% increase. Remarks by Jerry D. Geist, Chairman and President, Public Service Company of New Mexico, Chairman, Edison Electric Institute, 55th Annual EEI Convention, in Cincinnati, Ohio (June 8, 1987) (entitled *Place Your Bets: Three Paths to the Future*).

rates could incorporate the new technology most rapidly. Consequently, price reductions led to growth in quantity demanded, which led to further cost declines and the possibility of even more price reductions.

These steady real cost reductions masked the serious pricing flaws inherent in traditional rate-of-return regulation. Industrial customers who had other supply options usually were the beneficiaries of a pricing model that discriminated in their favor. As a result, they tolerated a system of regulation that occasionally overpriced services, confident that regulators would soon lower prices once again.

1. *Volatile Input Prices and Altered Patterns of Final Demand*

This virtuous cycle began to turn vicious in the late 1960s, partly as a consequence of macroeconomic developments outside utility control. Those developments included the OPEC oil shocks of 1974 and 1979, and the resultant increase in the rate of inflation, as well as a general decline in the rate of productivity growth. In addition, utility construction costs were pushed up by increasing environmental concerns and historically high interest rates. New plants became expensive in both real and nominal terms. With inflation outrunning productivity and newer plants entering the rate base at nominal costs above that of older plants, utilities were required repeatedly to request state PUC approval for price increases. Since formal PUC pricing proceedings mobilized political forces to protest the price increases, the utilities began to lose control of rate design and the ability to price discriminate. As a result of these changes, maintaining high capacity growth rates ceased to be a widely held utility objective. In fact, utility planners adopted the opposite goal: zero or negative growth. In this environment, demand-side incentives and load management became slogans to describe methods for lowering growth rates.

Although some of these economic forces affecting utility capacity planning probably will prove to be temporary, others will be permanent. Several factors are particularly likely to have a sustained impact. For example, beginning in the 1970s the global economy grew increasingly interdependent with both energy prices⁸⁵ and

85. Domestic oil and natural gas prices have been determined largely by world oil prices since the deregulation of oil production prices in 1980s. See *PURPA, Oversight Hearings before the Sen. Comm. on Energy & Natural Resources*, 100th Cong., 2d Sess. 12-13 (1988) (testimony of Charles G. Stalon) [hereinafter *Stalon testimony*], reprinted in *COMPETI-*

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interest rates being determined in volatile international markets. Furthermore, increased international competition has reduced the electricity demands of many traditional industrial customers.⁸⁶ Conversely, rising electricity costs have undermined the international competitiveness of industries heavily dependent on electricity and intensified their need to find other supply options. As a result, regulators can no longer set prices independently of demand conditions.

Another relatively long-term force affecting the industry stems from the late 1960s, when the general macroeconomic policy of the United States changed from one that had favored relatively low real interest rates to one favoring higher rates.⁸⁷ This change decreased the financial attractiveness of the long-gestation, capital-intensive generating plants that had dominated utility capacity expansions through the 1960s. This change in interest rate policy has fundamentally altered industry economics and sharply reduced the numbers of large baseload generating units constructed since the late 1970s.⁸⁸

Furthermore, the increasingly deep business cycles that have followed the first OPEC price shock also have undermined planning in the industry.⁸⁹ The resulting unpredictable patterns of demand create special problems for electric utilities with highly-leveraged capital structures and long lead times for completing major baseload units.⁹⁰ By the 1980s, forecasting failures had led utilities to build far

TION IN ELECTRICITY: NEW MARKETS AND NEW STRUCTURES 319-60 (J. Plummer & S. Troppmann eds. 1990).

86. Electricity can comprise up to three quarters of the total costs of production in some industrial enterprises, such as those in the air products industry. See Electricity Consumers Resource Council (ELCON), 34 ELCON Report (1986).

87. Moody's Aaa corporate bond rates that averaged 2.72% in the 1940s, 3.30% in the 1950s, and 4.35% in the first half of the 1960s, increased to 5.67% in the last half of the 1960s, to 8.29% in the 1970s and 12.93% in the first half of the 1980s. This rate fell to 11.37 and 9.02% in 1985 and 1986 respectively. ECONOMIC REPORT OF THE PRESIDENT 324 (1987). By June of 1987 this rate had risen to 9.32%. COUNCIL OF ECONOMIC ADVISERS, ECONOMIC INDICATORS 30 (July 1987).

88. See *supra* note 25.

89. *Stalon testimony*, *supra* note 85, at 11-12. The sustained expansion of the last several years may signal the end of this concern, but only an optimist would predict that the U.S. experience from World War II to 1973 is likely to be matched in the next 25 years. The U.S. record of not efficiently adjusting to shocks from the international economy makes it difficult to maintain such optimism.

90. *Id.*

more costly baseload capacity than they needed.⁹¹ In the 1990s, utilities may underestimate actual demand growth thereby producing a supply shortfall.

2. *Regulatory Breakdowns*

Traditional rate-of-return regulation proved inadequate to deal with these changing economic circumstances. Not only did regulators fail to establish prices that reflected differentiated demand conditions, they also produced a utility revenue recovery pattern unable to adapt to external economic realities. Perhaps the most poignant example of this rigidity is the front-loading of capital cost recovery that occurred under the traditional regulatory approach.⁹² This approach sets relatively high prices when a plant is new and relatively low prices when the plant is older.⁹³ Hence, when the economy was in recession in the early 1980s, and the older, energy-intensive industrial sector was in trouble, many utilities were requesting historically high rate increases⁹⁴ as new more expensive units came into the rate base.⁹⁵ A new term, rate shock, entered industry jargon. Moreover, given their financial condition, few

91. Much of the industry had planned for years on the basis of annual demand growth projections that averaged about 7%. Because of the long lead times in planning major generation plant additions, many utilities found that, by the late 1970s and early 1980s, they had planned for needs far in excess of actual demands. This led to costly postponements or cancellations, or building into significant and costly excess capacity situations. These developments were devastating to cost containment in an industry as capital-intensive as electric power production.

92. Under that model, while depreciation of capital expended on a plant is "straight-lined" over the projected life of the plant, the return on the undepreciated portion of the capital in rate base declines each year as depreciation is booked.

93. Furthermore, these price changes tended to be demand perverse. When demand falls, or fails to rise as forecasted, *ceteris paribus*, the model calls for price increases to cover costs, especially the scheduled capital recovery. Conversely, when demand rises, or rises more than expected, the model calls for lower prices as there are more units of output over which to spread the revenue requirement determined by the scheduled capital recovery. These price responses are, of course, the exact opposite of what economic efficiency normally demands. *See Stalon testimony, supra* note 85, at 13-14.

94. Some proposed increases were massive, exceeding 50% or even 100% of existing rates, sought either in a single rate case or in several cases "pancaked" over a few years. For example, Commonwealth Edison Company requested a series of large, general rate increases in the late 1970s and through the 1980s, resulting from the construction of six new nuclear units. *Illinois Commerce Comm'n v. Commonwealth Edison Co.*, Dkt. Nos. 78-0045, 79-0214, 80-0546, 82-0026, 83-0537, 84-0555, 87-0043, 87-0427.

95. Indeed, absent some creative adjustments to capital cost recovery to avoid extreme front-end loading of capital recovery, utilities not seeking full rate base recovery on new units were at risk of permanently losing recovery or earnings under the model.

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utilities were willing to defer revenue increases until after the recession, unless pressured to do so by state PUCs.

In response, some consumers, especially large, electricity-intensive industrials, began to seek alternate supply options.⁹⁶ Many industrials were able to plausibly propose self-generation, always a theoretical option,⁹⁷ and one rendered considerably more viable by Section 210 of PURPA.⁹⁸ Some consumers also were able to switch fuels, or bypass their traditional supplier by obtaining transmission access to another utility.⁹⁹ Other consumers threatened to close plants in the service territories of utilities that raised prices until more favorable terms could be negotiated.¹⁰⁰

Hence, state PUCs confronted a number of utility proposals that would have increased rates dramatically and that threatened to drive some consumers off utility systems, necessitating, under the traditional model, raising rates for remaining customers even more (the so-called "death spiral" effect). Some utility proposals were based upon costly generation capacity additions that would create considerable excess capacity in the near term. Other proposals reflected costs incurred for units cancelled because of declining demand and high construction costs. Confronted with industrial customers threatening to self-generate or shift production, state PUCs frequently reacted by intensifying their review of the prudence and usefulness of utility

96. Most industrial consumers have a traditional utility supplier within whose "service territory" they lie and upon whose transmission grid they typically rely upon to receive power.

97. On-site industrial generation represented 58% of total U.S. generation in 1900, but had dropped to 4% of total U.S. generation in 1974. U.S. DEP'T OF ENERGY, COGENERATION: TECHNICAL CONCEPTS, TRENDS, PROSPECTS 22 (1978).

98. Section 210 established regulatory guarantees that qualifying cogeneration or "small power production" facilities (QFs) would have a market for their surplus power. 16 U.S.C. § 824a-3(a), (b) (1988). Cogeneration is the joint, sequential production of both electricity and steam or some other useful energy form. 16 U.S.C. § 796(18)(A) (Supp. 1989). "Small power production facilities" are those whose maximum generating capacity does not exceed 80 megawatts and which use biomass, waste or "renewable resources" to produce electricity. 16 U.S.C. § 796(17)(A) (1988). For a comprehensive description of the Section 210 regulatory scheme, see Lock, *Encouraging Decentralized Generation of Electricity: Implementation of the New Statutory Scheme*, 2 SOLAR L. REP. 705 (1980). More important, Section 210 assured QFs that they could receive "backup" or supplementary power from their native utility at reasonable prices should the QF prove unable to meet its consumption needs. 16 U.S.C. § 824a-3(a), (c) (1988).

99. "Bypass" is also a major and controversial issue in natural gas regulation and a major concern to state PUCs in that arena. See *infra* Part II.

100. See Remarks by John A. Anderson, Electricity Consumer's Reserve Council (ELCON) Regulation Conference, at Iowa State University (May 20, 1987), at 17-18.

investments.¹⁰¹ Other states responded to these developments by exercising an increasingly active ex-ante role in utility capacity planning decisions. For example, some state PUCs turned traditionally uncontroversial need for power certification proceedings for new plants into active reviews of utility supply plans, while others created new state planning mechanisms by statute.¹⁰² In addition, state regulators recently have begun to modernize their oversight of procurement practices through the imposition of least cost planning requirements and competitive bidding schemes.¹⁰³ State regulators also have emphasized demand-side measures such as conservation, load management, and marginal cost pricing.

Another consequence of the large rate increases and attendant conservation responses of the 1970s and 1980s, and of expanded supply options for industrial customers, was a weakening of the franchise utility's distribution monopoly. Utilities were no longer able to pass cost increases on to traditionally captive core retail and wholesale customers without concern about the impact of rate increases on the quantity demanded. Price elasticities proved to be larger than utilities expected. Hence, state PUCs were less able to use their distribution monopoly power to achieve various social objectives that added taxes onto rates. Nor could they sustain certain cost-subsidies in rates. Moreover, increasing competition in wholesale markets threatened the market shares of utilities with escalating rates and made more obvious to PUCs and consumers the high cost of their retail service.¹⁰⁴

3. *Balancing Federal and State Regulatory Concerns*

This growing state role in utility planning has occurred in the midst of the industry's continued trend towards greater intersystem and interstate cooperation. Indeed, the rapid growth of the

101. See Pierce, *The Regulatory Treatment of Mistakes in Retrospect: Cancelled Plants and Excess Capacity*, 142 U. PA. L. REV. 497 (1984) (analyzing PUC review standards in context of economic changes in industry).

102. For an early but comprehensive review of such PUC actions, see ABA SPECIAL COMM. ON ENERGY LAW, *THE NEED FOR POWER AND CHOICE OF TECHNOLOGIES: STATE DECISIONS ON ELECTRIC POWER FACILITIES* (1981). This study surveyed the process for review of utility power supply planning in all fifty states and conducted a detailed case study of two states (California and Illinois). It drew some policy conclusions and made some general recommendations.

103. The term "least cost" planning is based in part upon concepts developed by R. SANT, *THE LEAST-COST ENERGY STRATEGY: MINIMIZING CONSUMER COST THROUGH COMPETITION* (1979).

104. See generally *Stalon testimony*, *supra* note 85.

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wholesale power market, primarily among IOUs, also was driven in large part by the industry's economic problems. Major power supply acquisitions, traditionally achieved by utilities building new plants under direct state supervision, were now being made through wholesale purchases. This switch gave FERC the exclusive authority under the FPA to pass upon the reasonableness of such wholesale prices. *Narragansett Electric Co. v. Burke* held that a state PUC could not investigate the reasonableness of the costs underlying a wholesale rate approved by FERC.¹⁰⁵ Hence, under *Narragansett*, the PUC must recognize the wholesale purchase as a cost item in retail rates. State regulators were forced to balance the undesirability of losing jurisdiction over local utilities that purchased from neighboring utilities against the increased risks associated with utilities' building their own capacity to meet local needs.

Unqualified, the *Narragansett* doctrine would have put serious constraints on the effectiveness of state regulation as wholesale markets expanded. However, limitations on the scope of the *Narragansett* doctrine were developed in a complementary doctrine defined by FERC in a series of decisions¹⁰⁶ and by a state court in *Pike County Light & Power Co. v. Pennsylvania Utility Commission*.¹⁰⁷ The *Pike County* doctrine holds that, while a PUC may not question the reasonableness of the selling utility's cost structure without violating *Narragansett*, it may question the prudence of the purchase decision by the buyer, at least in the light of other power acquisition options.¹⁰⁸

Hence, in response to a major challenge to state authority in implementing or policing the FPA bright line, FERC and the state courts established another dichotomy. This new dichotomy was based upon the perceived difference in function between FERC and the PUCs in monitoring wholesale power transactions. While the increasing role assumed by states in monitoring ex-ante utility

105. *Narragansett Elec. Co. v. Burke*, 119 R.I. 559, 381 A.2d 1358 (1977), *cert. denied*, 435 U.S. 972 (1978). For a description of the *Narragansett* case, its context and its progeny, see Vince & Moot, *supra* note 1, at 17-20. The *Narragansett* doctrine subsequently has been endorsed by the U.S. Supreme Court. *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953 (1986). *Mississippi Power & Light Co. v. Moore*, 108 S. Ct. 2428 (1988).

106. *Monongahela Power Co.*, 39 FERC ¶ 61,350 (1987); *Pacific Power & Light Co.*, 27 FERC ¶ 61,080 (1984); *Southern Co. Servs.*, 26 FERC ¶ 61,360 (1984); *Pennsylvania Power & Light Co.*, 23 FERC ¶ 61,006 (1983), *reh'g denied*, 23 FERC ¶ 61,325 (1983); *Southern Co. Servs.*, 20 FERC ¶ 61,332 (1982); 15 FERC ¶ 61,332 (1982); 15 FERC ¶ 61,264 (1982).

107. 77 Pa. Commw. 268, 465 A.2d 735 (1983).

108. *Id.* See also *Monongahela Power Co.*, 39 FERC ¶ 61,350 (1987); *Pennsylvania Power & Light Co.*, 23 FERC ¶ 61,325 (1983).

planning was not easy to reconcile with the rapid growth of wholesale markets, the *Narragansett/Pike County* dichotomy seemed to provide a workable accommodation between FERC and PUC regulatory prerogatives.

However, when PUCs attempted to review the purchase decisions of operating affiliates of multistate utility holding companies, the *Narragansett/Pike County* dichotomy was shattered. In a series of decisions relating to the allocation of costs among operating subsidiaries of the Middle-South and American Electric Power holding company systems, FERC limited the *Pike County* doctrine as applied to multistate transactions.¹⁰⁹ FERC concluded that PUCs had no authority to engage in prudence review or to impose disallowances on the pass-through of these costs into retail rates when FERC allocated costs among multistate subsidiaries.¹¹⁰ FERC's determination that the *Pike County* doctrine did not apply with respect to allocating the costs of an expensive nuclear unit built by the Middle South System caused a storm of protest that had to be resolved by the Supreme Court in *Mississippi Power & Light Co. v. Moore*.¹¹¹ The Supreme Court eventually upheld FERC's position, holding that states may not review the prudence of FERC allocations of costs among holding company subsidiaries.¹¹²

This Article will not analyze the various interpretations of the *Mississippi* decision or its impact on the *Narragansett/Pike County* dichotomy. That area has been intensely litigated and has received wide attention from legal scholars.¹¹³ Instead, this Section notes two central strands of reasoning behind the FERC and Supreme Court determinations that limit or preclude application of *Pike County* in the multistate holding company situation.¹¹⁴

- (1) Prudence review (a state PUC function under *Pike County*), and cost allocation/interpretation of the system agreement

109. See AEP Service Corp., 32 FERC ¶ 61,363 (1985); Kentucky Power Co., 36 FERC ¶ 61,227 (1986); Middle South Energy, Inc., 31 FERC ¶ 61,305 (1985).

110. See cases cited *supra* note 109.

111. 108 S. Ct. 2428 (1988).

112. 108 S. Ct. at 2440.

113. See, e.g., Vince & Moot, *supra* note 1; Duffy, *Will the Supreme Court Lose Patience with Prudence?* 9 ENERGY L.J. 83 (1988); Ercolano & Lesch, *Narragansett Update: From Washington Gas Light to Nantahala*, 7 ENERGY L.J. 333 (1986); Hobelman, *The Narragansett Decision and Its Aftermath*, 6 ENERGY L.J. 33 (1985); Nixon & Johnston, *Nantahala Affirms Narragansett—Whither Pike County?* 8 ENERGY L.J. 1 (1987).

114. It is unclear whether *Mississippi* applies only to units built or purchases made by the holding company system for its subsidiaries, and not to purchases by the subsidiaries from nonaffiliate sources, or whether it covers the latter as well.

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(FERC functions under *Narragansett*), are so interrelated that they cannot be separated. FERC expressed this view in the *American Electric Power* (AEP) line of cases.¹¹⁵ According to this argument, FERC cannot meet its obligations to encourage coordination through multistate power pools when states retain the authority to review for prudence. Such review could undermine power pool relationships altogether if states refuse to pass through system-allocated costs. In *AEP Service Corp.*, FERC also suggested that states would have no authority over a utility's decision to join the holding company in the first place.¹¹⁶

(2) Many of the FERC decisions,¹¹⁷ and the Supreme Court opinions in both *Nantahala* and *Mississippi*,¹¹⁸ reasoned that because FERC allocations of system power in these cases required the purchase of certain quantities of power, the operating subsidiaries had no legal choice but to make those purchases. This reasoning negates application of the *Pike County* doctrine, which implies some choice among purchase options.¹¹⁹

115. See *AEP Service Corp.*, 32 FERC ¶ 61,363, at 61,818 (1985); *AEP Generating Co.*, 36 FERC ¶ 61,226 (1986). That view was explicitly recognized in the dissenting opinion of Justice Brennan (Marshall and Blackman joining) [hereinafter Brennan dissent] in *Mississippi*, 108 S. Ct. at 2445.

116. *AEP Service Corp.*, 32 FERC ¶ 61,363, at 61,818. FERC based much of its reasoning supporting this conclusion on the plenary control by the SEC over the formation of holding companies under PUHCA. *Id.* Therefore, this conclusion may not carry over to utility decisions to join unaffiliated power pools, although the logic suggests that it should. The three dissenting judges in *Mississippi* based their dissent on strong disagreement with these FERC positions, suggesting implicit majority support for them. That interpretation could be supported by the majority's references to the inadmissibility of PUC disallowances leading to a trapping of costs, i.e., the sum of the costs recognized in rates by the states is less than the sum of the costs incurred by the utility. *Mississippi*, 108 S. Ct. 2428, 2439 (1988). However, the majority probably would not have asserted that states would have no authority over the initial decision to join the holding company pool; both *Mississippi* and *Nantahala* (on which the majority relied heavily) involved allocations of costs already incurred.

117. See, e.g., *AEP Generating Co.*, 38 FERC ¶ 61,243 (1987), *reh'g*, 39 FERC ¶ 61,158 (1987).

118. *Mississippi*, 108 S. Ct. 2428 (1988); *Nantahala Power & Light v. Thornburg*, 476 U.S. 953 (1986).

119. The Supreme Court appears to accept this logic. *Mississippi*, 108 S. Ct. at 2439-60. However, the logic is not flawless. Prudence review might meaningfully focus on whether any capacity needs to be purchased at all, rendering the absence of other supply options irrelevant.

Despite a hint of circularity in this reasoning,¹²⁰ this Article does not challenge its legality. However, this reasoning suggests that the holding company systems are so centrally planned and controlled that costs should be equalized among the operating subsidiaries.¹²¹ Yet, FERC has resisted this reasoning in its allocation decisions. Moreover, the structures of most of the holding company systems, including Middle South and AEP, still follow the single-state model by partly preserving the notion of the self-sufficient operating company accountable to its state commission's retail jurisdiction. Again, FERC protected this notion in determining that each of AEP's operating companies should build to meet its own capacity needs as opposed to relying permanently on purchases from its corporate siblings.¹²²

C. *The "Bright Line" Under Stress*

Middle South Energy, Inc. and other multistate holding company cases emanated from a direct conflict between the traditional regulatory objectives of FERC and of the state PUCs. The conflict had very little to do with emerging competition in the industry. Rather, it became intense as the economic assumptions underlying the traditional regulatory system broke down and state agencies felt the need to impose ex-post-facto discipline on the planning decisions of centrally planned holding company systems that had gone awry. FERC, pursuing its statutory mandate, sought to protect mechanisms, such as power pools and holding companies, designed to integrate and coordinate those multistate systems.¹²³ This potential for conflict, inherent in the traditional statutory structure, remains today. Indeed, the conflict may intensify as states attempt to strengthen their control over the utility supply planning process.

These multistate holding company disputes revolved around the question of which state's ratepayers should bear the cost of unneeded system capacity additions—in Middle South's case, an

120. See, e.g., *Nixon & Johnston*, *supra* note 113; see also *Mississippi*, 108 S. Ct. 2445, 2448 (Brennan, J., dissenting).

121. This logic led Judge Bork, in his partial dissent on the FERC's Grand Gulf decisions, to question whether there should be production cost equalization across the entire Middle South System. *Mississippi Indus. v. FERC*, 808 F.2d 1525, 1568-69 (D.C. Cir. 1987). This notion (which the FERC had rejected) would have required a fundamental reallocation of costs among the system's subsidiaries. See *System Energy Resources, Inc.*, 41 FERC ¶ 61,239 (1987).

122. *AEP Generating Co. & Kentucky Power Co.*, 38 FERC ¶ 61,243, 61,821 (1987).

123. See cases cited *supra* note 109.

expensive nuclear unit. The regional wholesale market was insufficient to absorb high-cost surplus capacity in order to reduce costs allocated to ratepayers, and the traditional regulatory pricing system only exacerbated the cost burden.¹²⁴ Furthermore, no effective dispute resolution mechanism existed at the state level to resolve the interstate conflict over the appropriate allocations of the cost burdens. Hence, FERC was forced to resolve this dispute between states in two fiercely contested proceedings.¹²⁵ However, once FERC interpreted the FPA as preempting the losing states from transferring the costs of the unneeded capacity from their ratepayers to the multistate system's shareholders, the nature of the dispute became state/federal.

As a policy matter, the legal result in *Mississippi* is unacceptable to most states.¹²⁶ It leaves them in the frustrating position of having to accept and pass through to their ratepayers substantial costs resulting from planning decisions over which they have had virtually no control. It also denies states that regulate subsidiaries of multistate companies the ability to influence utility supply planning, long viewed as a fundamental state prerogative. Furthermore, the Court did not decide whether the reasoning used in *Mississippi* extends to power pools that include unaffiliated entities, especially those that have achieved significant integration in planning and operation.¹²⁷ If states are concerned that utility participation in power pools may deprive them of jurisdiction over power supply planning, they may resist such participation, even when it enhances efficiency.¹²⁸

124. See *supra* note 93.

125. The Brennan dissent in *Mississippi* explicitly recognizes the necessity of FERC acting as the "neutral federal mediator." 108 S. Ct. at 2448.

126. For a trenchant presentation of state concerns, see Clinton, Johnston, Nixon, & Bratton, *FERC, State Regulators and Public Utilities: A Tilted Balance?* NAT. RESOURCES & ENV'T, Spring 1987, at 11. See also Nixon & Johnston, *supra* note 113; Johnston, Nixon, Copeland & Massey, *Escape from the Black Hole of FERC: A Proposal to Restore Pike Prudence Review*, 2 ELECTRICITY J. 12 (1989).

127. Another uncertainty is the exact scope of *Mississippi* within the multistate holding company context itself. Does it extend to *all* purchase decisions by the holding company and its subsidiaries, or only to those "purchases" internal to the system or made externally for the system as a whole?

128. See, *eg.*, Address by Peter A. Bradford, Maine PUC Chairman, Seventeenth Annual Conference of the Institute of Public Utilities, at Williamsburg, Va. (Dec. 9, 1985) (entitled Brought to You by the Brewers of Narragansett: FERC, Middle South and State Utility Regulation), reprinted in Public Utility Regulation in an Environment of Change, MSU Public Utilities Papers (1982). In commenting upon FERC's *Middle South* allocation decision, 31 FERC ¶ 61,305 (1985), Chairman Bradford observed: "I will certainly not allow any actions by a Maine utility that might expose them to retroactive equalization of the sort applied in the *Middle South* system. This may mean rejecting some otherwise attractive arrangements." (emphasis added). See also, Johnston & Nixon, Full Preemption in Holding Company

More generally, continuation of the policy impasse over jurisdiction may lead PUCs, fearing further loss of jurisdiction, to adopt an unduly defensive posture with regard to efficiency-enhancing utility restructuring proposals that accommodate new market developments. Symptomatic of this danger, two PUCs rejected major utility restructuring proposals that would have placed power generation assets in separate corporations to compete more effectively in the wholesale markets.¹²⁹ Underlying this resistance is a general fear of loss of jurisdiction to FERC and a concern that this loss can result from a simple change in corporate form.¹³⁰ Such concerns may create a climate in which restructuring, especially vertical deintegration proposals, will be evaluated by states less on their potential contribution to efficient electricity production and more on their perceived effect on state jurisdiction.¹³¹

Finally, the two major Supreme Court cases on this issue to date have cast doubt on the scope and viability of the *Pike County* doctrine. While both *Nantahala* and *Mississippi* recognize the doctrine in rather weak dicta,¹³² neither found it applicable to the cases before them. Nor were they clear as to exactly when it would apply.¹³³ This ambiguity has created concern among state PUCs that *Pike County* will not provide adequate prudence review authority, even outside of the holding company and power pool contexts. This concern has led PUCs to focus attention upon codifying or expanding the *Pike County* doctrine, perhaps as a precondition for any major legislative reform initiative in the electric power area.¹³⁴ Once again, arguably

Transactions—A Double Standard that Creates an Underclass of Consumers (August 11, 1987) (unpublished paper presented at the Annual Meeting of the American Bar Association, San Francisco California). Robert Johnston was Chairman of the Arkansas PUC at the time of this speech.

129. See *supra* note 35.

130. See *Nixon & Johnston*, *supra* note 113.

131. Vertical deintegration of some IOUs may be an important element in creating efficient wholesale power markets.

132. *Nantahala*, 476 U.S. at 972; *Mississippi*, 108 S. Ct. at 2440.

133. 476 U.S. at 972; 108 S. Ct. at 2440. Further doubt as to the viability of the *Nantahala/Pike County* dichotomy may have been raised by a recent Court of Appeals decision rejecting a FERC assertion of jurisdiction (*vis-a-vis* the SEC), based on a similar dichotomy, over coal sales by affiliates to holding company utilities. *Ohio Power Co. v. FERC*, 880 F.2d 1400 (D.C. Cir. 1989).

134. In July 1989, NARUC passed a resolution that expressed concerns about the impact of *Mississippi* on the state prudence review function. The resolution also conditioned removal of NARUC opposition to proposals to amend PUHCA upon inclusion of legislative provisions that would, *inter alia*, codify a general *Pike County* doctrine. A second condition proposed was a regional compact solution to the state review problem in multistate holding company situations.

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legitimate PUC fears over loss of jurisdiction threaten to hamper and distort necessary reform initiatives.

In conclusion, the legal result of *Mississippi* is not likely to resolve the conflict over regulatory policy inherent in most multistate disputes. Nor will it do much to ensure optimal state/federal progress on regulatory reform. Given the ease with which utilities can escape state prudence reviews by manipulating their corporate form, and given the uncertain status of the *Pike County* doctrine, states justifiably are concerned about jurisdictional issues. These concerns could encourage some states to resist the development of more efficient wholesale markets in order to limit FERC's jurisdiction and preserve their own. Such an approach would not only reduce efficiency, but also would undermine those very attempts to preserve state jurisdiction in the long run by reinforcing some of the inefficient features of the traditional regulatory system, such as industrial bypass, that have weakened state regulation. Indeed, the best long-term prospect for reducing end-use customer incentives to bypass is to create an efficient inter-utility trading system that will reduce the large differentials in average costs between supply systems.

D. *State and Federal Jurisdiction Over Transmission: An Emerging Conflict?*

The major disputes discussed above have focused upon state authority to review utility decisions to build generation facilities or to purchase power. Few state PUCs have reviewed the prudence of transmission investments or service contracts. However, any effort to analyze the evolution of state/federal jurisdictional relations in electric utility regulation would be incomplete without noting an emerging dialogue, if not yet a conflict, over jurisdiction in the transmission area.

Jurisdiction over transmission is currently allocated between state and federal agencies according to historical accident, rather than as the result of a reasoned assignment of jurisdiction.¹³⁵ States almost exclusively regulate the certification and siting of transmission lines.¹³⁶ FERC, however, has jurisdiction over "the transmission of electric

135. Brown, *The Balkans Revisited: A Modest Plan for Transmission Reform*, 2 *ELECTRICITY J.* 32 (1989).

136. See TRANSMISSION TASK FORCE, COMMITTEE ON ENERGY AND ENV'T, NAT'L GOVERNORS' ASS'N, *MOVING POWER: FLEXIBILITY FOR THE FUTURE* 9-14 (1987) [hereinafter *NGA TRANSMISSION REPORT*].

energy in interstate commerce."¹³⁷ The Supreme Court has interpreted this statutory mandate to give FERC exclusive and non-delegable authority over the pricing of unbundled (separately identifiable and priced) transmission service.¹³⁸ Yet, most revenues on utility transmission investments are still recovered through bundled state PUC retail rates for total service,¹³⁹ while others are recovered in bundled FERC wholesale requirements rates. Similarly, only FERC is explicitly granted authority to order utilities to provide wheeling service, or transmission access to another utility.¹⁴⁰ However, the findings necessary to make such an order are so formidable that FERC has never exercised this authority.¹⁴¹ States have no direct authority to order wheeling under the federal statutes. Nevertheless, some observers assert that states can mandate wheeling under their general ratemaking and planning authorities.¹⁴² They also assert that there are numerous less direct methods states can use, such as conditioning a utility's transmission facility certifications on its providing access, imputing revenues, or making rate base disallowances for possible wheeling revenues foregone.¹⁴³ Although these state actions may be preempted by the broad statutory authority granted to FERC under the FPA, state assertions of authority are growing rapidly and, so far, no court has resolved this issue.¹⁴⁴

The increased frequency of these assertions is closely related to the increase in independent generation, especially the development of QFs under Section 210 of PURPA, and in wholesale trading of power among utilities. Transmission access is increasingly viewed as a necessary ingredient in achieving efficient and competitive wholesale bulk power markets.¹⁴⁵ Many states appear to be exploring limited wheeling concepts similar to the wheeling in and

137. 16 U.S.C. § 824(b) (1988).

138. *New England Power Co. v. New Hampshire*, 455 U.S. 331, 340 (1982); *FPC v. Southern Cal. Edison Co.*, 376 U.S. 205, 209 n.5, 216. (1964) (*City of Colton*); *Florida Power & Light Co.*, 29 FERC ¶ 61,140 (1984) (*Florida Power I*).

139. The costs relating to all utility services provided including generation, transmission, and distribution, are "bundled" into a single "revenue requirement" for ratemaking purposes.

140. 16 U.S.C. §§ 824j-k (1988).

141. *See, e.g., Southeastern Power Admin. v. Kentucky Utils. Co.*, 25 FERC ¶ 61,204 (1983).

142. *Brown, supra* note 135, at 35.

143. *Id.*

144. *See, e.g., POWER SUPPLY POLICY GROUP, EDISON ELECTRIC INST., TRANSMISSION ACCESS AND WHEELING: A SUMMARY OF STATE LAWS AND REGULATIONS* (1989). This paper reports that nine state PUCs have asserted jurisdiction to mandate wheeling and that 31 states are active in the area. *Id.* at 1.

145. *See generally* FERC TTF REPORT, *supra* note 22, at 170-76.

wheeling out proposals in FERC's 1988 bidding NOPR.¹⁴⁶ However, because of the lack of federal initiative in defining access conditions, most state PUCs appear to be proceeding without apparent concern about the potential for preemption.¹⁴⁷

Ironically, it is in the pricing of unbundled transmission service, where FERC's exclusive authority is clearest, that states have been most actively exploring their ability to regulate. In *Florida Power I*,¹⁴⁸ the Florida Public Service Commission (FPSC) sought a declaratory order from FERC that the FPSC could establish a statewide rate for the transmission of QF power¹⁴⁹ and, more obliquely, that it could order the wheeling of QF power.¹⁵⁰ FERC concluded that the FPSC was preempted from establishing such a transmission rate, but FERC did not address the state's authority to order wheeling.¹⁵¹ In *Florida Power II*, the FPSC asked FERC to recognize a distinction between the rate in a filed transmission tariff, which is subject to exclusive FERC jurisdiction, and other terms and conditions of the service provided, which, it argued, the FPSC could regulate.¹⁵² FERC rejected the distinction, noting that its exclusive jurisdiction under the FPA extends to "terms and conditions" of service as well as to the rates themselves.¹⁵³ FERC also concluded that, to delegate authority over some of these terms and conditions to PUCs while leaving others at FERC (a NARUC suggestion in the case) would create the very sort of "overlap, confusion and potential for conflict" that the FPA's bright line sought to avoid.¹⁵⁴ In a related area, FERC also declined a suggestion by the Ohio PUC that the FERC should delegate to it the ability to rule upon a request to establish an

146. See *supra* note 144. The wheeling in proposal would condition a utility's participation as a potential supplier in a competitive bidding procurement scheme upon its providing wheeling service, if possible, to other potential suppliers in that scheme. Wheeling out would entitle a supplier within the utility's service area that loses a bid to wheel its power over that utility's transmission grid for sale elsewhere. *Id.* at 32,043-46; see also *Stalon Testimony*, *supra* note 85, at 49-50.

147. See sources cited *supra* note 144.

148. *Florida Power & Light Co.*, 29 FERC ¶ 61,140 (1984).

149. "QF power" is that power generated by facilities qualifying under Section 210 of PURPA, such as cogeneration facilities. 16 U.S.C. § 824(a)-(3)(f) (1988).

150. The petition inquired whether FERC rules, with which the FPSC claimed its rules were "consistent," required such wheeling. *Florida Power & Light Co.*, 29 FERC ¶ 61,140 (1984).

151. 29 FERC at 61,294.

152. *Florida Power & Light Co.*, 40 FERC ¶ 61,045 (1987) (*Florida Power II*).

153. 40 FERC at 61,119-21.

154. 40 FERC at 61,121

additional interconnection between an IOU and its wholesale utility requirements customer.¹⁵⁵

These examples suggest that PUCs have tried to assert greater authority over transmission rates and related "terms and conditions" than the law appears to permit. FERC's rebuff of these requests caused relatively little controversy, and nowhere near the rancor that accompanied its *Middle South* and *AEP* decisions: relatively few actual dollars were at stake in the Florida proceedings and states traditionally have taken relatively little interest in transmission facility planning.¹⁵⁶ Transmission facility additions typically have been viewed by utility planners and state regulators as adjuncts to the much larger generation investments.¹⁵⁷ However, the recent focus on transmission planning, especially to meet the needs of the expanding bulk power markets,¹⁵⁸ and the numerous calls to develop a cohesive national transmission policy¹⁵⁹ have created an environment in which the respective roles of state and federal jurisdiction over transmission are likely to be reevaluated.¹⁶⁰

The first major legal test of the efficacy and certainty of current jurisdictional boundaries may result from a recent order by the Wisconsin Public Service Commission (WPSC). The WPSC is requiring all Wisconsin utilities to enter into joint use agreements and to provide transmission service on their pooled transmission facilities to all Wisconsin utilities with a retail service obligation.¹⁶¹ The order also establishes a series of principles to be followed in the development of joint-use agreements.¹⁶² Wisconsin utilities have asserted that some of these principles relate to rates and terms and conditions of transmission service¹⁶³ and have petitioned FERC for a declaratory order preempting them.¹⁶⁴ The order has also been

155. *City of Piqua v. Dayton Power & Light Co.*, 46 FERC ¶ 61,143 (1989).

156. NGA TRANSMISSION REPORT, *supra* note 136, at 15-17.

157. In 1987, on national average, transmission accounted for only about 12% of total utility investments, in contrast to 60% for generation. FERC TTF REPORT, *supra* note 22, at 59-60.

158. See NGA TRANSMISSION REPORT, *supra* note 136.

159. FERC TTF REPORT, *supra* note 22, at 1-4.

160. See, e.g., Brown, *supra* note 135, at 34-39.

161. Advance Plans for Construction of Facilities as filed with the Commission for Review and Approval Pursuant to Section 196.491, Wisconsin Statutes (Apr. 6, 1989). This order was issued pursuant to an explicit statewide power supply planning authority granted by state statute. WIS. STAT. ANN. § 196.491 (West 1989).

162. *Id.*

163. Northern States Power Co., Petition for a declaratory Order, Dkt. No. 89-40-000.

164. *Id.*

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challenged in state court.¹⁶⁵ Unlike the *Florida* cases discussed above, however, the WPSC order is based on a specific state statute granting the WPSC authority in a general area, supply planning, that is at the core of traditional state authority. If FERC preempts the WPSC order, the resulting dispute would represent a major conflict between two basic sets of regulatory objectives, each firmly grounded in tradition and statute.

E. *Alternative Models for Dual Economic Regulation*

The preceding discussion reveals that state and federal regulators increasingly have pursued different objectives and protected different interests. Moreover, they are increasingly employing different approaches as wholesale bulk power markets become more competitive. The single-state utility rate base model, with the state granting the utility a monopoly franchise in return for an obligation to serve, imposes an inevitable parochialism or insularity on state regulation.¹⁶⁶ As a result, the single state approach encourages planning decisions that are increasingly at odds with federal regulation,¹⁶⁷ which attempts to increase the overall efficiency of wholesale bulk power markets. Finally, FERC is limiting its use of the rate base model in regulating bulk power trades while this method is still pervasive at the state level.

The strong monopoly powers of vertically integrated utilities also have enabled states to pursue social objectives other than economic efficiency. For example, rate stability generally has been an overriding goal of state regulators. Moreover, some states have used utility rates to levy taxes, subsidize technologies supported by strong interest groups, and encourage conservation and environmental measures.¹⁶⁸ A few states have explicitly sought to redistribute income

165. *Wisconsin Pub. Serv. Corp. v. Public Serv. Comm'n*, No. 89CV-716, *consolid. with Northern States Power Co. v. Charles H. Thompson*, No. 89CV309, (Wis. Cir. Ct. of Brown County 1989).

166. See *Brown*, *supra* note 135. While FERC has also traditionally used that model for wholesale requirements service, it represents a small and declining percentage of gross electricity revenues.

167. It must be noted, however, that contrary trends, i.e., market-oriented trends, are developing within state PUC regulation. See *infra* section F. See generally FERC TTF REPORT, *supra* note 22, at chs. 3 & 6 and cases cited *supra* note 19.

168. The literature on these subjects is massive. See Samuels, *Public Utilities and the Theory of Power* (especially Pt. 3.D) and *Regulation Used by Those Who Control It*, in PERSPECTIVES IN PUBLIC REGULATION: ESSAYS ON POLITICAL ECONOMY 13-23 (Milton Russell ed. 1973); see also Phillips, *Public Utilities as Tax Collectors*, in THE REGULATION OF PUBLIC UTILITIES: THEORY AND PRACTICE 264-65. For a survey, see Thompson & Jones, *The*

through "lifeline" rates and payment limits.¹⁶⁹ All of these objectives often are subsumed under the rubric of equity as a goal of public utility regulation.¹⁷⁰ However, as economic conditions change, state equity concerns are increasingly conflicting with FERC's efforts to promote economic efficiency in bulk power markets.¹⁷¹ These differences in regulatory objectives and methods will put additional pressure on any mechanism for sharing jurisdiction between federal and state agencies. Nevertheless, other statutory models, such as the federally imposed "regulatory partnership" contained in Section 210 of PURPA,¹⁷² may be better suited to reconcile some federal/state tensions than the bright line approach of the FPA.

1. *Evaluation of the Bright Line Model*

The bright line model of the FPA has encouraged two types of responses to the intensifying state/federal conflicts manifest in situations such as *Middle South*.¹⁷³ First, FERC and the courts have drawn increasingly fine distinctions in defense of the bright line. Second, the desire to preserve the bright line approach has tended to encourage the resolution of state/federal conflicts in highly contested judicial or quasi-judicial proceedings. While these proceedings have produced a series of all-or-nothing jurisdictional decisions, such as the *Middle South* cases, they have not reconciled the differences in regulatory approaches between the states and FERC.¹⁷⁴ Moreover, these cases have placed far too much emphasis on who is to regulate a particular transaction, and far too little on defining regulatory objectives.¹⁷⁵ Differences in regulatory objectives and methodologies create incentives for regulated firms to manipulate

Politics and Prospects for Regulatory Reform, in REGULATORY POLICY AND PRACTICES: REGULATING BETTER AND REGULATING LESS 93-119. Thompson and Jones cite many of the foundation papers on this topic.

169. "Lifeline" rates generally assure certain minimum amounts of service to customers, usually at discount rates.

170. For an excellent introduction to the pressures on PUCs to recognize equity issues in utility pricing, see E. ZAJAC, FAIRNESS OR EFFICIENCY: AN INTRODUCTION TO PUBLIC UTILITY PRICING (1978).

171. A poignant example is the furor over FERC's decision not to permit states to subsidize QF power in their implementation of Section 210 of PURPA. See text accompanying *infra* note 210.

172. 16 U.S.C. § 824a-3 (1988).

173. Some state officials went as far as asserting that the FERC's decisions over the Grand Gulf unit would seriously damage the economies of some of the poorest states in the nation. See Vince & Moot, *supra* note 1, at 8-9, 31.

174. See *supra* notes 105, 113, 117.

175. *Id.*

corporate structure so as to select the desired forum.¹⁷⁶ The fear of this phenomenon may encourage state regulators to protect their jurisdictional turf, rather than evaluate restructuring proposals on economic efficiency grounds.¹⁷⁷

A broader concern with the bright line model is that it has not produced a climate in which regulation is capable of adapting to fundamental changes in the industry. This concern may be symptomatic of a problem inherent in any effort to statutorily divide jurisdiction with a bright line. As conditions change, the bright line needs to be drawn in different places. Vested economic and political interests, however, consolidate around an existing bright line.

2. *The PURPA Model*

Congress enacted Section 210 of PURPA as part of the broad panoply of legislation comprising the National Energy Act of 1978. Section 210 encouraged qualifying cogeneration and small power production facilities (QFs).¹⁷⁸ These facilities were perceived to have been neglected under the traditional regulatory system, largely because independent producers could not overcome the entry barriers maintained by utilities with strong monopoly and monopsony powers.¹⁷⁹ Congress resolved this problem by requiring utilities to purchase QF power, and to provide supplementary and backup power to QFs when necessary.¹⁸⁰ Furthermore, Congress gave FERC wide discretion to exempt QFs from most aspects of public utility regulation,¹⁸¹ a discretion FERC used liberally to deregulate QFs in most respects. Nevertheless, most commentators at the time of enactment expected QFs to provide a relatively small adjunct to the traditional utility supply.

However, once the Section 210 scheme as implemented by FERC survived major challenges to its legality,¹⁸² QF capacity grew rapidly, far exceeding initial expectations. Coinciding with reductions in utilities' demand projections and the general aversion of utilities to

176. See *supra* note 74. See also NGA Electric Reform Report, *supra* note 15, at 14-15, 24.

177. A powerful illustration of this fear was the rejection of a restructuring proposal by Public Service Company of New Mexico.

178. See *supra* note 98.

179. See *supra* note 99.

180. 16 U.S.C. § 824a-3(a)-(c) (1988).

181. 16 U.S.C. § 824a-3(e) (1988).

182. FERC v. Mississippi, 456 U.S. 742 (1982); American Paper Inst. v. American Elec. Power, 461 U.S. 402 (1983).

building capital intensive plants, QF power became a major contributor to new power supply in some regions.

The essence of this success lies in the fact that the PURPA model permitted a new contracting regime for power supply. In this regime, the risks and rewards of power production could be allocated more efficiently between QFs and purchasing utilities in the light of changing economic conditions. Although some of the early risk allocations under PURPA had problems (they passed too much fuel risk downstream to consumers, or they permitted over-leveraged QF capital structures), this approach generally has allowed utilities to compensate QFs for bearing supply risks traditionally passed to consumers under the rate base model.¹⁸³ Because of its superior ability to allocate risk, the PURPA model has provided a useful framework for developing an unregulated generating sector in an industry dominated by regulated entities. The PURPA model thus offers a template for efforts to restructure both the electric industry and the division of labor among regulators.¹⁸⁴ This model establishes a fundamentally different relationship between state and federal regulation in monitoring new power supply additions. Without Section 210, QF sales to utilities would be wholesale transactions subject to exclusive FERC jurisdiction, while most utility sales of supplementary and backup power¹⁸⁵ to QFs would be a retail transaction subject to state PUC regulation. Instead of reinforcing the FPA regulatory dichotomy, Congress attempted to create a partnership between FERC and PUCs for implementing Section 210. The statute requires FERC to define QF status¹⁸⁶ and to establish the standards under which QFs may buy from and sell to utilities.¹⁸⁷ It also requires state PUCs to implement FERC rules.¹⁸⁸ Section 210 thus gives PUCs the frontline, day-to-day function of regulating both QF sales to and purchases from utilities, and a variety of related issues, such as interconnection requirements and compensation. Hence, the partnership grants FERC authority over a discrete part

183. Indeed, the two biggest problems with this approach have occurred when regulation has supplanted negotiation: 1) when states set administratively determined "avoided cost" rates for purchase of QF power, and 2) when FERC has certified QFs. The emergence of state bidding schemes and all source bidding are direct responses to these two problems.

184. The PURPA model has been considered or adopted by other countries, such as the United Kingdom, Australia, New Zealand and Thailand, contemplating a greater role for independent power producers.

185. *Supra* note 145.

186. 16 U.S.C. § 824a-3(a), (e) (1988).

187. *Id.*

188. 16 U.S.C § 824a-3(f) (1988).

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of retail ratemaking and delegates a significant portion of federal wholesale authority to state PUCs.¹⁸⁹

The PURPA model is also a departure from traditional utility regulation in that it focuses rate regulation on the *purchasing* utility rather than the *selling* utility. Since state prudence review typically focuses on the purchasing utility, giving states a large role in setting the purchaser's procurement policies appears intuitively rational. Subsequent developments, such as the evolution of competitive procurement schemes under state regulation, support this intuition.

The PURPA model, implemented at the state level through generic rulemaking and case-specific decisions, has provided a detailed system of regulation. State PUCs have proven capable of responding to major regulatory mistakes and changing economic conditions, especially in setting prices for utility purchases of QF power.¹⁹⁰ In its implementing rules,¹⁹¹ FERC had determined that these prices should be based on the purchasing utility's full avoided costs, i.e., the marginal cost the utility would incur in meeting the increment of supply provided by the QF if the QF purchase were not available. Many PUCs have already updated their avoided cost calculations to account for utility long-term capacity purchases which displace plans to build locally. Moreover, where incorrect forecasts led to higher than efficient prices, as in California, PUCs moved quickly to correct such errors. Some states have learned from the mistakes of others, giving credence to the notion of a fifty-state regulatory laboratory, a notion used to justify the substantial initial discretion given by FERC to states.¹⁹²

Perhaps the most important adjustment to the PURPA scheme was the relatively quick recognition, by both FERC and the PUCs, that Congress' original assumption, that PURPA would be only a

189. More dramatically, however, Section 210 effectively conscripted PUCs to implement federal policy under Section 210. This aspect of the statutory scheme was challenged by the State of Mississippi, which argued that Section 210 (as well as Title I) of PURPA violated the Tenth Amendment. The Supreme Court rejected this assertion. *FERC v. Mississippi* 456 U.S. 742 (1982).

190. FERC has been less successful in adapting its definition of QFs to changing conditions. In certifying QFs, FERC has had to draw increasingly fine and artificial distinctions, seldom conforming with economic or engineering efficiency, to separate those facilities that "qualify" from those that do not. Most of this response has been dictated by the statutory definitions.

191. FERC Regulations With Regard to Small Production and Cogeneration, 18 C.F.R. § 292.101 (1988).

192. In its 1980 implementing rules, FERC afforded PUCs "great latitude in determining the manner of implementation of [its] rules." Section-by-Section Analysis, Implementation by State Regulatory Authorities and Non-Regulated Electric Utilities, FERC Implementation, 18 C.F.R. § 292.401 (1989).

small adjunct to traditional utility supply, had not proven accurate. By 1986, it was apparent in some states that QFs were offering more capacity than utility systems needed.¹⁹³ Indeed, a major complaint of utilities was that they were being required by PURPA, or by state implementation of PURPA, to pay capacity credits to QFs when they did not need capacity.¹⁹⁴ In response to this and other complaints about PUC implementation,¹⁹⁵ voiced in Congressional hearings on PURPA in 1986, FERC undertook in early 1987 a review of its PURPA rules. This FERC review culminated in four Notices of Proposed Rulemaking (NOPRs) in 1988 on administered avoided costs ("AdFAC"),¹⁹⁶ "Bidding,"¹⁹⁷ independent power producers ("IPPs"),¹⁹⁸ and QF certification.¹⁹⁹

The most profound adjustment to PURPA appeared in the "bidding" NOPR, which contemplated permitting a competitive procurement mechanism to determine which QFs should receive capacity credits in cases where more QF capacity was offered than a utility needed.²⁰⁰ Advocates of this approach argued that it would not only produce a more accurate assessment of the utility's true avoided costs than would a regulator's estimate, but also would ensure that the more efficient QFs came into production first.²⁰¹ In order to avoid concerns about a "QF ghetto," and to escape the technological constraints of QF certification, FERC advanced the notion that all of a utility's supply needs should be subject to some form of competitive procurement and not be reserved for certain

193. California, Texas, and some major mid-Atlantic states, such as New York, New Jersey, and Virginia, showed this phenomenon early in the scheme's implementation history. See *BIDDING FOR POWER*, *supra* note 30.

194. This assertion, however, does not find support in FERC's implementing rules. See FERC Regulations, *supra* note 191.

195. Many utilities also asserted that state PUCs were setting rates above their true "avoided costs." QFs raised a variety of concerns, such as rates below avoided costs, excessive interconnection charges, denial of transmission service, and utilities unduly protracting negotiations.

196. Notice of Proposed Rulemaking: Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities, FERC Stats. & Regs. ¶ 32,457, 53 Fed. Reg. 9331 (1988).

197. Notice of Proposed Rulemaking: Regulations Governing Bidding Programs, FERC Stats. & Regs. ¶ 32,455, 53 Fed. Reg. 9324 (1988).

198. Notice of Proposed Rulemaking: Regulations Governing Independent Power Producers, FERC Stats. & Regs. ¶ 32,456, 53 Fed. Reg. 9377 (1988).

199. Notice of Proposed Rulemaking: Regulations Governing the Public Utility Regulatory Policies Act of 1978, FERC Stats. & Regs. ¶ 32,465, 53 Fed. Reg. 31021 (1988).

200. Bidding NOPR, *supra* note 197.

201. *Id.*

groups of producers.²⁰² FERC also proposed that states should have the option of all source bidding in their implementation of Section 210 of PURPA.²⁰³

While the "Bidding" NOPR itself was not promulgated as a final rule, the concept of competitive procurement was quickly adopted by state PUCs in their implementation of PURPA. The PUCs built upon the experience of a few states that had experimented with the concept prior to the issuance of the NOPR, and upon the ideas in the NOPR itself.²⁰⁴ The concept of competitive procurement apparently meshes well with a growing state trend towards "least cost" planning.²⁰⁵ While these mandates vary widely in approach, this development is part of a more general trend towards states assuming a more active role in monitoring utility power supply planning rather than relying on ex-post-facto prudence review to discipline utility supply planning.²⁰⁶

The experience of state PUC efforts to implement FERC's PURPA rules demonstrates the adaptability of both the PUCs and the Section 210 scheme itself to changing industry conditions. The metamorphosis of the avoided cost concept is also remarkable. It is quickly evolving from one that relies on traditional utility and regulatory forecasting of costs, to one that relies on a market-determined price. This evolution supports the optimistic view that bidding can lead to more efficient supplier choice decisions than any regulatory allocation or first-come, first-served scheme.

Many of the daily state/federal tensions in implementing the PURPA model were resolved in the dialogue engendered by FERC's various PURPA review hearings and other informal exchanges. This is especially notable in an era of great uncertainty over the future of the industry in which regulators are confronted with difficult issues in reconciling emerging competition with traditional economic regulation. Indeed, PURPA has apparently contributed greatly to creative PUC thinking in resolving that tension as well as related state/federal tensions. This intellectual climate also may have helped

202. *Id.* A "QF ghetto" might occur if all QFs were required to bid for only a part of a utility's power needs, thus driving down the price of QF power, but not subjecting the utility's other supply options to the same competitive discipline.

203. *Id.*

204. At the time of writing, at least 36 utilities in at least 17 states are known to be implementing or considering bidding mechanisms. FERC TTF REPORT, *supra* note 22, at 29-30.

205. See Sant, *supra* note 103. At least 40 states have adopted this approach.

206. See, e.g., text accompanying *supra* note 149.

avoid some potential jurisdictional conflicts within the PURPA scheme. However, this approach could not resolve two disputes.

The first dispute occurred in 1988. In an early draft of the AdFAC NOPR, the FERC staff proposed that rates for purchases of QF power by multistate utilities should be the same in each state because the utility has a single avoided cost. Although the provision did not appear in the NOPR itself, it caused a furor among PUCs, who asserted that it would unduly interfere with their ability to tailor PURPA implementation to conform to distinctive state conditions and policies.²⁰⁷ This concern quickly led to broader charges that the three-part NOPR package issued by FERC in March 1988²⁰⁸ was unduly preemptive of state authority.²⁰⁹ The real issue was one of balancing the degree of latitude FERC should leave to state PUCs in implementing Section 210 against a national need to prescribe standards to ensure overall efficiency. In the end, the PUCs prevailed in their quest for continued broad discretion to implement PURPA.

Another furor emerged from a 1988 FERC decision limiting the ability of state PUCs to require utilities to pay rates to QFs in excess of the full avoided costs level under PURPA.²¹⁰ The New York State legislature had imposed a minimum six-cent-per-kilowatt-hour rate for purchases from QFs even when this rate was higher than actual avoided costs.²¹¹ The State PUCs objected vigorously to the FERC decision to overturn the New York law, arguing that FERC had intruded upon state authority without furthering overall efficiency. While FERC did not reverse the decision, it did stay the decision

207. See Bidding NOPR, *supra* note 197, Opinion of Commissioner Trabandt, Concurring in Part, Dissenting in Part [hereinafter Trabandt NOPR dissent], FERC Stats. & Regs. ¶ 32,455, at 32,080-81 (1988).

208. This package consisted of the AdFAC, Bidding, and IPPs NOPRs, *supra* notes 196, 197, and 198.

209. See generally Trabandt NOPR dissent, *supra* note 207, at 32,061. In fact, the use of the term preemptive in this context is legally inaccurate. FERC was exercising its statutory authority under Section 210(a) of PURPA to prescribe, and revise when needed, the standards by which state implementation of the federal scheme under Section 210(f) was to occur. No independent state authority was being preempted by FERC's exercise of that authority, even if it were exercised in the overly prescriptive manner asserted by FERC's critics. For a fuller discussion of this issue, see Concurring Statement of Commissioner Stalon in Orange & Rockland Utils., Inc., 43 FERC ¶ 61,067 (1988). In fact, most of the assertedly over-prescriptive provisions appeared in the "guidance" rather than the mandatory parts of the AdFAC and Bidding NOPRs.

210. See, e.g., Orange & Rockland Utils., Inc., 43 FERC ¶ 61,067 (1988).

211. *Id.* at 61,185.

pending resolution of the broader policy issue in the context of the AdFAC NOPR.²¹² That resolution has not yet occurred.

The rancor produced by these two FERC actions was disproportionate to their importance. However, they illustrate two conclusions from the experience of implementing Section 210 of PURPA to date. First, PUCs quickly and aggressively asserted an entitlement to broad latitude in implementing the Section 210 scheme. Efforts by FERC to prescribe new standards created controversy. Second, the fundamental policy conflict in these two situations was created by FERC's desire to shape state regulation so as to promote efficiency in wholesale bulk power markets, while at the same time leaving state PUCs the flexibility to pursue broader regulatory objectives. While there has been a clear intellectual shift in many state PUCs towards encouraging more efficient and competitive wholesale power procurement, state PUCs predictably are reluctant to forego traditional regulatory prerogatives.

The latter tension is inherent in any shared jurisdictional system. Moreover, it is a tension that may become more acute as the need for greater efficiency in bulk power markets increases. However, although FERC cannot push the logic of efficiency in this regulatory partnership too far without incurring a serious political backlash, the PURPA Section 210 scheme has forced FERC and the PUCs into a closer day-to-day relationship, characterized by a dialogue that takes place outside of a quasi-judicial context. That dialogue has tended to ease tensions and to permit the continued viability of the PURPA scheme. It has also heightened state sensitivity to the need for greater efficiency in the bulk power markets, a concern central to many of FERC's initiatives.

3. *The "Concurrent Jurisdiction" Model*

A third model for sharing state and federal regulatory authority exists in an area closely related to economic regulation, the regulation of utility corporate structure and finance. Section 203 of the FPA requires utilities to obtain FERC authorization prior to making major acquisitions or mergers.²¹³ Many states have similar requirements.²¹⁴ The FPA, however, does not provide a mechanism for

212. *Orange & Rockland Utils., Inc.*, 43 FERC ¶ 61,547 (1988).

213. 16 U.S.C. § 824b (1988).

214. For instance, all but two states require prior PUC approval of mergers or consolidations, and all but three require prior PUC approval for sales of generating units. NARUC, ANNUAL REPORT ON UTILITY AND CARRIER REGULATION 529 (1988).

allocating state/federal jurisdictional authority or resolving disputes.²¹⁵ Hence, each affected jurisdiction has an effective veto power over a proposed merger or acquisition. Nor does the FPA prescribe any procedural mechanism for reconciling inconsistent orders. A merger could be approved at the state level, approved subject to certain changes at the federal or another state level, and then returned to the original state for reapproval and further modification.

Recently, federal/state tensions arose over a proposal to merge two large Pacific northwest utilities, PacifiCorp and Utah Power & Light Company. The seven state commissions involved with the merger had granted initial approval before FERC acted on the proposal. After a detailed administrative proceeding, a FERC Administrative Law Judge (ALJ) concluded that the proposed merger posed too great a threat to competition to receive federal approval.²¹⁶ The Commission, though accepting the factual findings of the ALJ, nevertheless approved the merger subject to the stringent condition that the merged company would permit access to its transmission grid at cost-based prices, conditions which both companies subsequently accepted.²¹⁷ Despite major concerns by the Utah PUC that the FERC-imposed conditions would damage the interests of Utah's ratepayers, the company was able to persuade all the PUCs that the benefits of the merger would outweigh any detriments caused by FERC's conditions.²¹⁸

This case vividly illustrates the potential for conflict between FERC's regulatory objective of enhancing the efficiency of the wholesale bulk power markets and the more parochial objectives of state PUCs in protecting the interests of retail ratepayers. In the Utah case, FERC's interest arose from the possibility of one of the merging companies using its monopoly power over bottleneck transmission paths to gain for itself and its ratepayers a portion of the rents associated with interstate power transactions.²¹⁹ The PUCs concerned, however, recognized these differences in regulatory objectives as well as the legitimacy of FERC's role in protecting the efficiency of interstate markets. In future transactions, other states

215. In contrast, FERC's authority to review security issuances and assumptions of liability is only applicable where the utility's "security issues are [not] regulated by a State Commission." 16 U.S.C. § 824c(f) (1988).

216. Utah Power & Light Co., 43 FERC ¶ 63,030 (1988).

217. Utah Power & Light Co., 45 FERC ¶ 61,095 (1988).

218. The PUC most concerned, the Utah Public Service Commission, agreed that the benefits were likely to outweigh the costs, but nevertheless placed the risk on the utility.

219. 45 FERC ¶ 61,095 at 61,287-89.

also could exercise monopoly power over transmission paths which would damage their neighboring states and reduce the overall efficiency of the wholesale power markets that benefits all states in the long term.

F. *Conclusion: The Impact of Competition*

The growth of the wholesale power markets, and the breakdown of traditional regulatory systems, have spawned competitive forces within the traditionally monopolistic electric power industry. Competition, in turn, has engendered regulatory responses that are likely to encourage its further development. As a result, regulatory reform that encourages greater competition has been at the heart of many recent debates over the future of electric power regulation.

Many traditionalists have expressed deep concerns about whether competition in the electric industry will undermine the traditional industry structure and the efficiencies that structure has provided. However, regulators are not likely to reign in competitive forces absent a broad political consensus involving the industry, regulators, and legislators.²²⁰ Competition in wholesale power markets, at least between franchised utilities, seems to be widely supported.²²¹ In this environment, QFs and IPPs are likely to gain increased access to bulk power markets, thereby intensifying competition in the generating sector of the industry.

Nevertheless, regulators must guide competitive forces carefully to assure efficient results.²²² Furthermore, clear rules-of-the-road must exist for transmission access to assure the technical integrity of the grid, particularly as bulk power markets become more competitive. Such rules will be crucially important to maintaining reliability and economic/engineering efficiency of increasingly complex intersystem transmission grids. These rules will become more critical as the informal agreements that currently sustain cooperation are superseded by open rivalry between the utilities that control transmission.

Some of the concerns over emerging competition expressed by

220. There appears to be a weak consensus that competition is not desirable in distribution, and there are few advocates for increased competition for transmission service.

221. Most political opposition to competition emanates from a group of IOUs concerned about independent power producers rather than greater competition in inter-utility trading of excess capacity. See *The Competitive Wholesale Electric Generation Act of 1989, Hearings before the Sen. Comm. on Energy & Natural Resources, 101st Cong., 1st Sess. 27-28 (1989)* (testimony of the Electric Reliability Coalition) [hereinafter *ERC PUHCA Testimony*] (concerning the Public Utility Holding Company Act—PUHCA).

222. See generally FERC TTF REPORT, *supra* note 22.

traditionalists have been based, in significant part, on fears that competition at the wholesale level will inevitably lead to an undisciplined common carriage regime and to bypass at the retail level.²²³ However, wholesale competition has the potential to enhance significantly the overall efficiency of power production and to lower the differentials between different utilities' average costs that tend to encourage bypass.²²⁴ In contrast, retail bypass might initially shift cost burdens among retail customers, threaten the financial viability of some utilities, and impose inequitable burdens on captive customers while perhaps not significantly enhancing efficiency.²²⁵ Regulators might therefore be tempted to limit the enormous potential efficiency gains from greater wholesale competition due to misplaced fears that this will encourage bypass. Fortunately, the fear of bypass seems to be dissipating. Utilities which were previously concerned about the danger of competition and bypass are today making conceptual proposals that would advance competition at the wholesale level while resisting it at the retail level.²²⁶

A perennial concern of many PUCs is that growing competition at the wholesale level, especially from QFs and IPPs, may result in reduced state and increased FERC jurisdiction.²²⁷ Although their concern is in one sense valid,²²⁸ this jurisdictional shift already had begun under FERC's traditional coordination regulation, well before QFs or IPPs were evident.²²⁹ Hence, FERC jurisdiction will likely increase as a result of wholesale market growth even if QFs and IPPs are blocked from the market.

223. See, e.g., *supra* note 221, *ERC PUHCA Testimony* at 27-28. For a statement of concerns over the reliability and economic effect of partial bypass, see Porter & Maliszewski, *Technical and Economic Constraints on Competition in Electric Power Supply*, 122 *Pub. Util. Fort.*, No. 10, at 20 (1988).

224. See *Stalon Testimony*, *supra* note 85, at 25-28, 30-34.

225. *Id.*

226. An excellent example is the proposal on transmission pricing and access policy of the so-called "Group of 5," consisting of five major IOUs, made to FERC in August 1989 for discussion purposes. The proposal delineates very different sets of issues related to wholesale and retail transmission access, and views the former as a primary vehicle for enhancing competition. See *FERC TTF REPORT*, *supra* note 22, at 307.

227. See, e.g., *NGA ELECTRIC REFORM REPORT*, *supra* note 15.

228. As utilities meet more of their future supply needs through wholesale purchases of power rather than building plants themselves, direct state control over the rates for new plant additions will be replaced by FERC regulation of wholesale sales. However, the critical authority of states to review the prudence of wholesale purchases will (outside the multistate holding company context) remain.

229. These coordination markets became inevitably more competitive themselves as utility capacity surpluses grew and demand growth dropped, the result of the recession of the early 1980s and of planning or forecasting errors under the traditional system.

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This growth in federal jurisdiction does not necessarily weaken effective state control. Just as state PUCs have typically reviewed ex-post-facto the prudence of generation expansions, they can now review the prudence of utility purchases. The more competitive the markets in which those purchases are made, the more effective state review will be, since PUCs will be able to review purchases in the context of a series of openly-priced competitive options. This will almost certainly be an easier task and produce more efficient results than attempting to review the long and complex construction history of a large nuclear or coal plant, which was typical of many of the construction prudence reviews in the 1980s. Similarly, more efficient wholesale markets should facilitate ex-ante prudence reviews, or monitoring of utility purchase—the review of currently available market alternatives should be more effective and less speculative than an effort to project the costs of a long-gestation generating plant.²³⁰

Moreover, a shift in the focus of state regulation from power generation to distribution and procurement would not undermine the franchise utility structure and the accompanying obligation to serve—both are closely associated with the distribution function. The nature of traditional regulation supports this view: state regulators typically reviewed capacity expansions when utilities attempted to include the costs in retail rates, not when utilities planned or commenced construction of these plants.²³¹ Indeed, FERC has designed many of its proposed reforms, such as the Bidding and IPPs NOPRs, to give states the ability to expand utility procurement options to more effectively fulfill their prudence review function. In addition to exposing utilities to more competitive discipline at the generation level,²³² these changes might also expand the range of generation technology options at a time when environmental and financial constraints may be limiting the utilities' own abilities to build traditional coal and nuclear plants. The speed with which PUCs are adopting competitive procurement underscores the importance of these expanded options.

With the expanded importance of state PUC control of utility procurement options, the *Pike County* doctrine becomes crucial in

230. As noted previously, errors in forecasting construction costs, especially of nuclear units, led to serious economic problems for utilities in the 1980s. See *supra* note 102 and accompanying text.

231. See text following *supra* note 41.

232. Most of the major rate increases in the 1980s, which led to rate shock, were caused by new generation plants built by utilities.

ensuring that state PUCs can review the prudence of utility purchases. The development of efficient bulk power markets will require the PUCs to have a strong prudence review ability at the distribution level. To date, no one has suggested that the distribution function will be deregulated or exposed to significant competition. Distribution is still a natural monopoly function in which competition is likely to be destructive. Hence, it is likely to be subject to traditional regulation for the foreseeable future. As long as retail competition is not used as a means of ensuring efficient procurement of supply by distribution utilities, it is important that PUCs should have the ability, through prudence reviews, to prevent utilities from passing the costs of inefficient procurement decisions through to ratepayers. Since efficient procurement is a critical ingredient of efficient wholesale markets, FERC as well as state PUCs should have a strong interest in preserving the *Pike County* doctrine.²³³ Furthermore, FERC has recognized the importance of *Pike County* since its decisions that originated the doctrine.²³⁴ The multistate holding company cases should be seen as an exception to this rule, driven by other FERC regulatory concerns that loomed large in that particular context.

Changes in emphasis in FERC's fulfilling its FPA coordination mandates are likely to influence the development of the *Pike County* doctrine. Previously, FERC emphasized nonmarket integration devices such as power pools; now FERC tends to focus on market devices such as transmission access and liberalized pricing. The process of change is unsteady as FERC struggles with adapting new concepts, such as "market power" and "workably competitive markets," to an evolving regulatory context and rapidly changing industry. This process is one that involves tension between cooperation-inducing nonmarket mechanisms, and competition-inducing market mechanisms.²³⁵ Although this tension at times makes FERC regulation seem somewhat schizophrenic, it should be viewed as part of a necessary evolution.²³⁶

233. See *infra* note 261 and accompanying text.

234. An important recent confirmation of this principle was made in *Southern Company Services, Inc.*, 26 FERC ¶ 61,360 (1984). Recognition of FERC's interest in preserving a strong *Pike County* doctrine is also clear in the natural gas area.

235. That tension had become evident in certain power pools, such as NEPOOL, where utility members were finding it more profitable to trade around rather than through the pool mechanisms.

236. Our analysis above and below reveals a notable difference between the history of the "bright line" under the FPA and the NGA. Under the FPA, the "bright line" has largely been viewed as a constraint on regulatory jurisdiction on both sides, subject to

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State PUCs are more likely to lose effective control over generation prices to competitive markets than to traditional FERC economic regulation.²³⁷ For those who believe further pervasive economic regulation is necessary for the continued efficiency of the industry, this may be a disturbing result; for those who see competitive supply markets as efficiency enhancing, it may be welcome.

II. The Evolving Boundary Between Federal and State Regulation of the Natural Gas Industry

A. Introduction

Four major legal changes have influenced the jurisdictional boundaries between federal and state regulatory authority over natural gas utilities. This introduction briefly describes each of these changes.

The first major legal change, The Natural Gas Act of 1938 (NGA),²³⁸ symbolized the transformation of the gas industry from a local industry relying primarily on coal gas to an interstate industry based largely on natural gas. The development of high-tensile steel pipe had made possible efficient, long-distance carriage thereby increasing the importance of natural gas in the nation's economy. Recognizing this transformation in the nature of the gas industry, the NGA transferred significant regulatory authority from the states to the federal government. Nevertheless, the Act attempted to preserve a major role for states by imposing federal jurisdiction only on the interstate activities of natural gas companies.²³⁹ Although many pipelines were integrated upstream with producers and downstream with local distribution companies (LDCs) and sold gas both for resale and directly to end-users, the NGA limited FPC jurisdiction over pipeline gas services to sales for resale in interstate

occasional judicial or quasi-judicial efforts to redraw it to conform to pressing current realities. In contrast, under the NGA, we have seen a greater ability, largely conscious, of FERC to move the effective parameters of the "bright line" through a series of administrative reforms that greatly alter the state/federal relationship. There may be some lessons in this NGA experience for electric power regulation—doubtless a factor that heightens industry concerns over FERC administrative reform initiatives in the electric power area.

237. Insofar as state regulators are starting to rely on competitive mechanisms, such as bidding schemes, to discipline utility procurement practices, they are apparently willing to rely on market forces where these offer clear efficiency gains over the traditional system of supply planning and procurement review.

238. Pub. L. No. 75-688, 52 Stat. 821 (1938) (codified at 15 U.S.C. § 717 (1988)).

239. *Id.*

commerce. Pipeline company direct sales to end-use customers, primarily large industrial customers, were not subject to FPC price regulation.²⁴⁰ The transportation of such gas, however, was subject to FPC jurisdiction. This sale-for-resale definition of federal jurisdiction preserved PUC jurisdiction over LDCs.²⁴¹ The Hinshaw amendment to the NGA,²⁴² enacted in 1954, affirmed the intent of Congress to preserve an important role for state regulation.²⁴³ This amendment permitted pipelines taking gas from an interstate pipeline at a state border to sell for resale within the state, unambiguously an interstate activity, and not be subject to FPC/FERC jurisdiction if the state regulated the activity.²⁴⁴ This amendment provides legal support for the current structure of the California gas industry, which has no interstate pipelines except those affiliated with California LDCs.

The NGA differs from the FPA in one important respect. The FPA preserved almost completely the plenary authority of states to determine generation, transmission, and distribution needs and to control plant siting in the electric industry. In contrast, Section 7 of the NGA requires natural gas companies to obtain a certificate of public convenience and necessity (PC&N) from FERC before initiating new, or abandoning old, services and facilities. Two exceptions were made: (1) The NGA explicitly denies FERC jurisdiction over natural gas distribution facilities and production or

240. Some states created a regulatory fiction that such direct sales customers were actually customers of a nearby LDC; the pipeline billed the LDC for gas delivered to the direct-sale customer, and the LDC billed the customer at rates determined by the state PUC. This fiction also was used by farmers who received gas directly from the pipeline.

241. One troublesome ambiguity in the allocation of jurisdictional responsibility arose in those LDCs that serve two or more states, e.g., Washington Gas & Light which serves a part of Virginia, a part of Maryland and the District of Columbia. This ambiguity became especially troublesome when LDCs unbundled their services and provided transportation services across state borders. In 1988, Congress amended the NGA to reverse certain FERC decisions and to clarify the division of responsibilities between local and federal regulators. See Uniform Regulatory Jurisdiction Act, Pub. L. No. 100-474, 102 Stat. 2302 (1988).

242. Pub. L. No. 83-323, 68 Stat. 36 (1954).

243. 15 U.S.C. § 717(c) (1988). "The provisions of this act shall not apply to any person engaged in or legally authorized to engage in the transportation in interstate commerce or the sale in interstate commerce for resale, of natural gas received by such person from another person within or at the boundary of a state if all the natural gas so received is ultimately consumed within such state, or to any facilities used by such person for such transportation or sale, provided that the rates and service of such person and facilities be subject to regulation by a State Commission."

244. Hinshaw pipelines, thus, are interstate pipelines regulated by states. In the terminology of this Article, they are not included as "interstate pipelines." FERC has ruled that Hinshaw pipelines are LDCs in the context of NGPA Section 311. Order No. 63, FERC Stats. and Regs. ¶ 30,118 (1980).

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gathering facilities,²⁴⁵ and (2) limits its authority to order a pipeline company to initiate new construction or services.²⁴⁶ On the other hand, the Commission has broad authority to establish conditions before approving a certificate of PC&N.²⁴⁷

The second milestone in the evolution of gas industry regulation was the 1954 U.S. Supreme Court decision in *Phillips Petroleum Co. v. Wisconsin*.²⁴⁸ *Phillips* held that producers who sold natural gas in interstate markets were natural gas companies under the NGA and, therefore, were subject to price regulation by the FPC. Later decisions expanded on *Phillips*, holding that all gas from the outer continental shelf (OCS) and all pipelines connecting the OCS to the mainland were subject to FPC/FERC jurisdiction. Producers who dedicated non-OCS gas to an intrastate market, however, were not regulated by the FPC. They were free to sell at regulated or unregulated prices as determined by the state in which the gas was located. Dedication might be by well, share of a well, or by field, as determined by the contract between the producer and the purchaser.

The Natural Gas Policy Act of 1978 (NGPA)²⁴⁹ constitutes the third milestone in the evolution of the gas industry. This Act, one of five parts of the National Energy Act of 1978, changed the border between state and federal regulation in two important ways. First, Congress set in law, by formula, a ceiling price for almost all gas at wellheads, including intrastate gas formerly unregulated or regulated by states.²⁵⁰ This Act thus relieved FERC of most of its responsibilities for pricing gas and put in place a schedule for deregulating all wellhead prices, thereby initiating a phased reversal of the *Phillips* decision.²⁵¹ Second, the Act granted intrastate pipelines certain rights to engage in interstate transactions while escaping most of the regulatory burdens associated with interstate status.²⁵² However, some

245. See NGA § 1(b), 15 U.S.C. § 717(b) (1988).

246. See NGA § 7(a), 15 U.S.C. § 717f(a) (1988).

247. See NGA § 7(c), 15 U.S.C. § 717f(c) (1988).

248. 347 U.S. 682 (1954).

249. Pub. L. No. 95-621, 92 Stat. 3351 (1978) (codified at 15 U.S.C. § 3301 (1988)).

250. NGPA, Tit. I, 15 U.S.C. § 3311 (1988). Two exceptions to this generalization are Sections 104(b)(2) and 107(b). Both Sections granted the Commission power to raise prices for the described categories of gas.

251. NGPA Title I, 15 U.S.C. § 3311. In 1989, the Congress enacted the Natural Gas Decontrol Act of 1989 (Section 2 of P.L. No. 101-60, July 26, 1989) which repealed Title I effective January 1, 1993, thereby accelerating the schedule for removing wellhead ceiling prices.

252. NGPA § 311, 15 U.S.C. § 3371 (1988).

federal regulation of intrastate pipeline transportation rates was imposed.²⁵⁵

The fourth milestone, FERC Order No. 436, promulgated in October 1985,²⁵⁴ initiated a major shift in regulatory boundaries. With Order No. 436, FERC attempted to build the post-NGPA natural gas industry around market-disciplined producers by changing the role of interstate regulated pipelines and LDCs. After the Order, pipeline company gas merchants would be required to compete with non-jurisdictional merchants and LDCs would be required to accept responsibility for selecting the gas merchants from which they would buy. In reviewing Order No. 436, the D.C. Circuit noted that

The Order envisages a complete restructuring of the natural gas industry. It may well come to rank with the three great regulatory milestones of the industry: The passage of the Natural Gas Act in 1938, the imposition of price controls on independent producers' wellhead sales under *Phillips Petroleum Co. v. Wisconsin*, and adoption of the Natural Gas Policy Act in 1978.²⁵⁵

This Order reversed many of the key principles upon which the FPC had regulated interstate pipelines during the previous 40 years. It encouraged pipeline companies to unbundle their transportation services and to ship gas on a nondiscriminatory basis.²⁵⁶ It also attempted to reduce greatly the barriers to constructing new pipeline facilities,²⁵⁷ and to change the guiding principle for rate design from a primary emphasis on equity to economic efficiency.²⁵⁸ In addition, Order No. 436 provided a signal that FERC intended to shift crucially important decisionmaking powers to state PUCs and to markets. (At the same time Order 436 redrew the boundaries between markets and regulation in a dual regulated industry it also redrew boundaries between state and federal regulatory jurisdictions.) Finally, since monopoly power in regulated firms is often mutually reinforcing, by weakening monopoly power in one segment

253. *Id.*

254. Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, FERC Stats. & Regs. ¶ 30,665 (1985) [hereinafter Order No. 436].

255. *Associated Gas Distribs. v. FERC*, 824 F.2d 981 (D.C. Cir. 1987), *cert. denied*, 108 S. Ct. 1468 (1988) (citations omitted).

256. Order No. 436, *supra* note 254, at Preface Part IV(A)(1-9).

257. *Id.*, Part IV (C).

258. *Id.*, Part IV (A)(1)(C), (A)(10).

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of the industry, Order No. 436 has tended to reduce monopoly power throughout the industry.

The evolving boundary between federal and state regulatory jurisdictions currently consists of dissolving segments of the industry created by pre-NGPA regulatory and court decisions and crystalizing those segments created by the NGPA and by post-NGPA regulatory and court decisions. That evolving boundary can best be described by tracing its origins and shifts.

B. *The Natural Gas System Before Phillips*

Before the Supreme Court's *Phillips* decision, and for some time afterwards, the FPC defined its task as essentially promotional. This role developed naturally out of the economic circumstances of the early industry: natural gas was found largely as a by-product of the search for oil. Consequently, optimal pricing of gas was not seen as a serious regulatory objective. The potential gains from using this by-product gas in remote locations were large, but so were the risks. One of the FPC's primary responsibilities was to allocate these risks among industry participants.

Building long-distance, long-lasting pipelines raised two risks: (1) the risk that gas supplies would not be sufficient to fill pipelines for a period long enough to recover their construction costs, and (2) the risk for individual pipelines that end-use markets would be lost before construction costs were recovered. In order to allocate these risks among the risk-averse LDCs, pipelines, and financial markets, the FPC adopted a three-part strategy.

1. *The FPC's Strategy*

First, the FPC permitted interstate pipelines to offer a bundled service. They were not required to offer transportation services to downstream LDCs or end-users who might want to buy gas directly from producers. Since most pipelines offered only a bundled service, they used the monopoly power inherent in transportation to create a monopoly over the sale of gas in many downstream markets.

Secondly, on the supply side, the FPC required each pipeline to demonstrate that it had large reserves of gas under contract before that company could construct a new line, extend an old line, sell gas in new markets, or to sell more gas in old markets from existing assets. Since these gas supply contracts were usually for twenty-year terms, the FERC's requirement assured LDCs that the interstate pipeline had supplies that were adequate to justify the local expense

of shifting from coal gas to natural gas. They also assured end-users that investments made in gas-using equipment could be amortized over long periods.

Finally, on the demand side, the FPC limited access of competing pipelines to certificated end-use markets thereby assuring incumbent pipelines of protected markets for their gas reserves. In particular, the strategy required LDCs to contract for pipeline capacity on a long-term basis. To further strengthen each pipeline's monopoly power, the FPC also approved tariffs for sales to LDCs that contained minimum bills and, in some cases, sole supplier requirements. Minimum bills effectively required LDCs to pay pipeline companies a regulatorily-determined return on pipeline company assets whether or not any gas was taken. In many cases, minimum bills also required LDCs to pay for some volumes of gas whether or not such gas was taken. Pipeline sole supplier tariff provisions gave preferred rates to selected LDCs that agreed not to purchase gas from another pipeline.

2. *Consequences of the Strategy*

Four important consequences resulted from this three-part regulatory strategy, a strategy which still struggles for survival despite the FERC's repeated efforts over the last five years to effect fundamental changes. The first three consequences can be called the key planks in the FPC-created system of bundled-service regulation. The creation of these planks, and their subsequent undoing by Order No. 436, produced major changes in the boundary between state and federal jurisdictions.

One major effect of FPC regulation was to strengthen the natural-monopoly powers inherent in the transportation of natural gas and to extend those monopoly powers over sales of pipeline company gas in interstate markets. Regulation also strengthened the pipeline companies' monopsony powers in some wellhead markets in which they purchased gas. This system of relatively strong monopolies balkanized interstate natural gas markets. Price differences between two points in space could substantially exceed the cost of shipping gas between those two points since the space arbitrage mechanisms for reducing those differences existed only at the sufferance of pipelines—often pipelines with relatively high prices. Furthermore, since gas prices were determined largely in long-term contracts, and FERC-jurisdictional pipelines mostly were required to sell gas at the price at which they purchased it, time arbitrage, or a gas futures market, effectively was suppressed.

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Secondly, this regulatory regime placed pipeline companies at the center of the interstate natural gas industry. Producers were denied direct access to LDCs and end-users, and LDCs and end-users were denied direct access to producers. Producers had to look to pipelines to market their gas, and LDCs and end-users had to look to pipelines for assurances of adequate supplies.

Thirdly, governmental regulation shifted the risks of the pipeline industry downstream to end-users. The combination of strong monopoly powers, limited market entry, minimum bills, and sole supplier tariff provisions virtually guaranteed pipelines comfortable earnings on their assets.

Finally, this regulatory system was acclaimed almost universally. Financiers liked the assured earnings produced by strong pipeline monopolies; therefore, they were willing to finance pipelines with low equity ratios. Producers desperately wanted pipelines to be constructed in order to sell the by-product gas that was nearly worthless if sold near the field. LDCs found natural gas a much cheaper fuel than coal gas, permitting them to expand their operations and to displace coal in most major urban markets. The FPC liked the system because the strong monopoly powers of pipelines permitted a highly judicialized decisionmaking process using traditional public utility regulatory methods. With strong monopoly power in the hands of pipeline companies, timely decisions were not essential. Due process—as defined by regulatory procedures—could be honored in the belief that a refund was an adequate remedy for mispricing. Because the key interest groups profited under this regime, the politicians representing these interests also liked the system.

One essential ingredient in this risk allocation strategy was what later came to be called the *Narragansett* doctrine.²⁵⁹ The crucial holding in *Narragansett* was that a PUC could not question the reasonableness of rates set by a federal regulatory agency. Consequently, the decision assured LDCs that costs incurred for pipeline company services could be recovered from LDC customers. As a result, FPC regulation not only enabled pipeline companies to shift the risks of their long-term contracts with producers to LDCs, it also assured LDCs that those risks, and the risk of owning pipeline assets, could be shifted to the LDC's customers. This regulatory

259. *Narragansett Electric Co. v. Burke*, 119 R.I. 559, 381 A.2d 1358 (R.I. 1977), *cert. denied*, 435 U.S. 972 (1978). The relevance of this doctrine is discussed *supra* notes 105-116 and accompanying text.

strategy relieved most LDCs of the responsibility of creating a supply portfolio, a freedom that some LDCs liked, and which led some of them to oppose the Order No. 436 reforms.

Nevertheless, the *Narragansett* doctrine was not sufficient to support the FPC risk-allocation strategy. Another essential element was constricting the scope of what later became known as the *Pike County* exception to the *Narragansett* doctrine.²⁶⁰ Under *Pike County*, a PUC can challenge the prudence of an LDC's purchasing decision when the LDC has a choice of supply options. However, sole supplier tariff provisions, minimum bills, and certification barriers served to limit LDC choices and thereby to protect them from gas purchasing prudence challenges by state PUCs.

Critics protested the unnecessary link between transportation and sales, the monopsony power of pipelines in wellhead markets and their monopoly power in city-gate markets, and the high costs borne by consumers of carrying unnecessarily large gas reserves.²⁶¹ However, one can argue that the FPC's regulatory strategy worked well for several decades to move the system towards maturity. Although market forces might be distorted by monopsony power, monopoly power, and unnecessarily long-term, price-inflexible contracts, they were not fully suppressed. Gas prices could still respond to demand and supply forces, and could, therefore, play their important equilibrating role.

C. *The Natural Gas System After Phillips*

The history of natural gas regulation between the 1954 *Phillips* decision and the passage of the NGPA can be treated briefly. The development of a system of vintaged wellhead prices,²⁶² the failure

260. *Pike County Light & Power Co. v. Pennsylvania Util. Comm'n*, 77 Pa. Commw. 268, 465 A.2d 735 (1983). The *Pike County* case was an electricity case, but, it was applied to the gas industry in *Kentucky West Virginia Gas Co. v. Pennsylvania Pub. Util. Comm'n*, 791 F.2d 1111 (3rd Cir. 1986). See text following *supra* note 107.

261. FERC jargon, which is reflected in the language of this Article, emphasizes three types of gas transactions: wellhead, city gate, and burner tip. The jargon, by implication, reveals the pre-NGPA system of regulation, which largely equated wellhead transactions with transactions between pipelines and producers, city-gate transactions with transactions between pipelines and LDCs, and burnertip transactions with transactions between pipelines or LDCs and end users. Since transactions between LDCs, or end users and producers were uncommon in the interstate market, there was no special term for them. The terms are, however, still useful to indicate the transportation point at which ownership changes.

262. The vintage price system was the FPC/FERC method for reconciling the objectives of cost-based wellhead prices and adequate supplies in interstate markets. Producers were not required to remain producers, nor were they required to sell new discoveries, other than OCS discoveries, into interstate markets. As a result, given the below

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of the FPC to create wellhead prices sufficiently high to avoid a gas shortage, the demise of the FPC, the creation of FERC, and the passage of the NGPA are all interesting chapters. This topic, however, does not require an extensive analysis. What is essential for this discussion is a recognition that many of the decisions made in the post-*Phillips* period still have vitality and continue to influence the practices of LDCs, FERC, and the pipeline companies. Four topics are particularly relevant.

First, the political consensus that supported early FPC regulation broke down when the FPC, acting under the *Phillips* mandate, extended controls to wellhead prices. Many producers found regulation to be a severe constraint on their earnings, and consuming entities found their interests pitted against producers. FPC/FERC proceedings became bitter battlegrounds between producer and end-user interests with respective states and PUCs closely aligned. The split spread to Congress, where the delegations of the consuming states of California, the East, Northeast, and Upper Midwest were brought into conflict with the delegations of the producing states of the Middle South, Southwest, and Plains.²⁶³

Second, the balkanization of natural gas markets worsened substantially after *Phillips*. The vintage pricing system induced significant differences in gas prices from pipeline to pipeline. Consequently, customers of pipeline companies with a large proportion of old, low-priced gas in their portfolios, demanded that such companies be severely limited in their abilities to sell gas off system, to anyone other than old customers. To further preserve old, low-priced gas to existing interstate customers, the FPC determined that once identified gas from a producer was sold into an interstate market, it was committed to interstate markets even after expiration of the contract in which the commitment was made. Producers who sold gas into intrastate markets could, after their contract obligation expired, sell that gas into an interstate market.

market FPC/FERC-determined prices pipeline companies had difficulties attracting new supplies. Raising the regulated price for "new" gas to reflect increases in production costs, while leaving unchanged the price of "old" gas that was committed to interstate markets earlier "when costs were lower," led to two different contract prices for gas entering a pipeline at the same time at the same receipt point. After the regulated price for "new" gas was raised several times, there were many prices. Generally, the later the year of contracting, the higher the price of gas, at least until the early 1980s. The FPC/FERC policy required pipelines to sell gas at a rolled-in price, i.e., at a weighted average of the contract prices, where the weights were the relative quantities of gas flowing under each contract.

263. This regional conflict is described in E. SANDERS, *THE REGULATION OF NATURAL GAS: POLICY AND POLITICS, 1938-1978* (1981).

However, when the contract for sale in the interstate market expired, the gas remained committed to interstate markets. Arbitrage between intrastate and interstate markets became a one-way flow. Hence, producers with choices logically developed a preference for selling in intrastate markets.

After the 1984 OPEC-induced increases in oil prices, gas prices in intrastate markets rose commensurably since their prices were not constrained by economic regulation. Prices in interstate markets, however, were restrained by application of a regulatory model which based gas prices on historical costs. Not surprisingly, a shortage developed in interstate markets while intrastate markets had abundant supplies for those willing to pay market-determined prices.

Third, the system of federal regulation in the post-*Phillips* period developed into a certification quagmire. To control wellhead prices and the flow of old vintage gas, the FPC evolved a complex system of certifying pipeline construction and pipeline services. The objectives were fairly straightforward: to ensure an adequate supply of gas to interstate markets and, almost equally difficult, to ensure that old vintage low-priced gas was not diverted from the particular interstate pipeline to which it was assigned by contract.

Finally, as the probability of a natural gas shortage grew in the 1970s, the FPC/FERC was required to prioritize uses and end-users of gas.²⁶⁴ FERC's authority to allocate the scarce gas supplies of interstate pipelines, when quantity demanded was greater than quantity supplied at the regulated price, was extended to allocations to direct sales customers of the pipeline, to LDCs served by the pipeline, and to customers of LDCs who were served indirectly by the pipeline.

Before proceeding with the analysis, it is useful to summarize the characteristics of the industry's structure and the regulatory system that existed at the time of the passage of the NGPA.

By 1978, the natural gas industry had reached maturity. It consisted of pipelines with strong monopoly and monopsony powers and of LDCs with strong monopoly powers. Consequently, highly balkanized markets existed at wellheads and city-gates, rather than a national market for gas with space and time arbitrage inducing efficient allocations of natural gas.²⁶⁵ The interstate system was, with

264. The current FERC curtailment rules, which reflect Title IV of the Natural Gas Curtailment Policies Act (NGPA), are found in 18 C.F.R. § 281 (1989).

265. While there were intrastate gas markets in many states only five were large: Texas, Louisiana, Oklahoma, Kansas and California. Furthermore, all but California were major exporters of gas.

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many qualifications, a set of vertically integrated markets that were horizontally unintegrated. Furthermore, the absence of a futures market for gas meant that only producers could engage in profitable and constructive speculation.

In addition, by the mid-1970s a large proportion of natural gas was being found through a deliberate search for gas. Associated gas—gas found intermixed with oil and usually discovered in the search for oil—was not sufficient to meet demand. Consequently, because of nonassociated gas's sensitivity to selling prices, efficient wellhead prices became crucially important for an efficient gas industry.

Furthermore, the risks of gas price volatility, which the FPC shifted to end-users with its bundled-service regulatory strategy, were growing over time. In 1960, the average burner-tip price was comprised of 23 percent wellhead price, 43.5 percent LDC margin, and 33.5 percent pipeline margin.²⁶⁶ The 1970s brought large changes in these numbers, with the producers' share rising steadily. By 1978, when the NGPA was passed, the producers' share was 41.4 percent while the LDC's share had fallen to 33.9 percent, and the pipelines' share to 25.7 percent. This trend continued into the 1980s. By 1982, the producers' share had increased to 55.1 percent while the pipelines' share had fallen to 25.8 percent.²⁶⁷ The LDCs' share had fallen even more, to 19.1 percent.²⁶⁸

This change in relative value added, together with the incentive structure that regulators had created, made losses for pipeline companies in their merchant roles more likely than in their transportation roles. Consequently, pipeline companies possessed strong reasons for using their monopoly powers over transportation to protect themselves from merchant losses, even at the expense of efficient operation of pipeline transportation and storage assets. Denying transportation services to competing sellers of gas became an increasingly important element in most interstate pipelines' profit strategy.

266. See AMERICAN GAS ASS'N, *GAS FACTS 1985: A STATISTICAL RECORD OF THE GAS UTILITY INDUSTRY* (1986).

267. Furthermore, while pipelines in 1982 contributed approximately 25% of value added in the natural gas industry, FERC did not regulate all pipelines. One estimate, floating at FERC in 1984 and 1985 when Order No. 436 was being formulated, was that the pipelines regulated by the FERC contributed less than 15% of the value added by the natural gas industry.

268. Recent years have seen a return to numbers similar to 1978. However, the 1982 numbers are likely to be representative of the future of the industry when the natural gas "deliverability bubble" ends.

D. *Regulation After the NGPA*

The NGPA was important both for what it did explicitly and for some of its unanticipated consequences.²⁶⁹ It did two important things explicitly. First, it made major changes in the regulation of gas pricing by removing almost all of FERC's authority to set prices. It exaggerated the vintage pricing system by creating very high congressionally-determined prices for some new gas, and it extended federal regulation over wellhead prices to intrastate gas.²⁷⁰ It also, in effect, reversed the *Phillips* decision and initiated a process of phased deregulation of wellhead prices.²⁷¹ As old gas was depleted and replaced by new gas, the wellhead market was to assume an increasing role in determining the price of natural gas. The Act, therefore, removed from FERC the role of determining adequate price incentives for the production of optimal quantities of gas.²⁷² As market forces strengthened, the legal and economic justification for much of FERC's certificate regulation would disappear—most obviously with respect to producer/wellhead certification.²⁷³ Less obvious, but of equal importance, much of the certification regulation, based on the need to allocate scarce pipeline supplies to end-users and end-users by FERC- and Congressionally-determined priority classifications, would also disappear.

Secondly, with Section 311, the NGPA opened a door for integrating state and national markets, and for separating the transportation and merchant roles of interstate pipelines.²⁷⁴ In

269. This position has been adopted in hindsight. Two provisions of the NGPA considered important at the time were Title II—Incremental Pricing, and Title IV—Natural Gas Curtailment Policies. Events of the 1980s have eliminated, at least temporarily, the significance of both Titles. The two Titles reflect different, but complementary, exercises of federal authority to influence uses of gas. Title IV was discussed above. *See supra* note 264. Title II can be succinctly and fairly described, despite the complexity of its language, as directing FERC to discriminate in prices against customers using gas as a boiler fuel and other industrial gas users defined by FERC. Title II was repealed by Section 2 of P.L. No. 100-42, May 21, 1987.

270. 15 U.S.C. § 3315 (1988).

271. 15 U.S.C. § 3311 (1988).

272. One qualification to this statement is the responsibilities assigned to FERC in 15 U.S.C. § 3317 (1988) to create incentive prices for high-cost gas.

273. After *Phillips*, the FPC required that producers who wanted to sell gas in interstate markets obtain a certificate of PC&N.

274. The relevant Subsections of Section 311 are:

(a)(1)(A) In General—The Commission may, by rule or order, authorize any interstate pipeline to transport natural gas on behalf of (i) any intrastate pipeline; and (ii) any local distribution company.

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implementing Section 311, the Commission allowed certain transactions to go forward on a self-implementing basis without the detailed FERC review process that was customary in certification proceedings under Section 7 of the NGA.²⁷⁵ In Order No. 60, the Commission also permitted interstate pipelines to transport natural gas on behalf of other interstate pipelines.²⁷⁶ While the Congressional drafters of Section 311 probably intended to provide supply-deficit interstate markets with opportunities to tap the abundant supplies in intrastate markets, the language they used was broad and permanent. By encouraging pipelines to transport gas—to provide an unbundled service—one of the key planks in the FPC-created bundled-service system of regulation was weakened. Customers who had choices could partially escape the monopoly power over gas sales formerly held by the pipeline company. In so doing, the risk bearing role of the customer could also be reduced.²⁷⁷

The important, unanticipated consequences of the NGPA came about when the 1982 recession occurred. The demand reductions induced by the recession increased dramatically the size of the deliverability bubble and led to falling gas and oil prices. Gas price reductions, however, were concentrated in intrastate markets and the rapidly developing spot market. Because of regulatory and contract rigidities, interstate pipelines could not quickly lower their prices. These prices had risen dramatically after passage of the NGPA as interstate pipelines had attempted to buy new gas to meet demands and to increase reserves.²⁷⁸ Meanwhile, big end-users, resisting prices charged by pipelines for gas that exceeded fuel oil prices, demanded

(a)(2)(A) In General—The Commission may, by rule or order, authorize any intrastate pipeline to transport natural gas on behalf of (i) any interstate pipeline; and (ii) any local distribution company served by any interstate pipeline.

(b)(1) In General—The Commission may, by rule or order, authorize any intrastate pipeline to sell natural gas to (i) any interstate pipeline; and (ii) any local distribution company served by any interstate pipeline.

275. FERC implemented Section 311 in Order Nos. 30 (7 FERC ¶ 61,170), 46 (9 FERC ¶ 61,724), 60 (9 FERC ¶ 61,224), 63 (10 FERC ¶ 61,003), 234-B (24 FERC ¶ 61,099), and 319, (24 FERC ¶ 61,100). Order No. 436 expanded the scope of Section 311 still further.

276. FERC Stats. & Regs. ¶ 30,107 (1979).

277. This weakening of pipeline company monopoly powers also meant the weakening of LDC monopoly powers and state powers that relied on such monopolies. For example, those states that levied gross revenue taxes on LDC sales saw shifts of large customers to transportation-only services since such a shift saved the customer the gross revenue taxes on out-of-state gas purchases.

278. Gas supplies are customarily measured in both stock and flow terms. Proven reserves is the stock variable, and deliverability, i.e., the capability to withdraw from proven reserves, is the flow variable. The excess supply in the 1980s was, and is, in deliverability. Whether there is an excess or shortage of proven reserves is hotly contested.

price discounts or, alternatively, transportation privileges in order to gain access to spot market gas. Since many big users had alternate fuel capability, pipelines had to meet these demands or lose these customers to fuel oil. Intrastate pipelines, with NGPA Section 311 rights to sell their surplus gas into the interstate market, were also pressing for transportation rights on interstate pipelines.

FERC, responding to pipeline requests and large end-user bargaining power, approved several programs to deal with this problem. Despite the patchwork nature of these programs, they were important in broadening and deepening spot markets. Many of these programs were merely straightforward pipeline company discount sales programs aimed at price-elastic markets. More important, however, were those programs that made it possible for end-users to buy directly from producers and have pipelines carry the gas.

Order No. 234-B and the Special Marketing Programs (SMPs) deserve special mention.²⁷⁹ Order No. 234-B was a temporary, experimental program that permitted pipelines to obtain blanket certificates to transport gas to low priority end-users. The SMPs permitted pipelines, producers, and marketers to obtain certificates to transport or sell gas that was committed to a pipeline, if the pipeline released the gas.²⁸⁰ Order No. 319 established a permanent program that allowed pipelines to transport gas for high priority end-users.²⁸¹ These programs complemented NGPA Section 311 and helped initiate significant steps towards disintermediation in natural gas markets. End-users and producers increasingly bypassed pipeline company merchants and negotiated directly with each other.

These programs, with the possible exception of Order No. 319, systematically discriminated against residential and commercial customers. While pipelines and producers were eager to implement special programs in order to lower prices to customers who could use other fuels, they were not eager to permit residential and commercial customers to gain such privileges. These captive customers were expected to remain tied to a bundled service so that

279. The Order No. 234-B program, 24 FERC ¶ 61,099 (1983), was originally scheduled to expire on June 30, 1985. The D.C. Circuit ruled the program to be unduly discriminatory on May 10, 1985, but allowed the program to continue through October 12, 1985. *Maryland People's Counsel v. FERC*, 761 F.2d 768 (D.C. Cir. 1985) (MPC I); *Maryland People's Counsel v. FERC*, 761 F.2d 780 (D.C. Cir. 1985) (MPC II).

280. The SMP programs were also experimental and expired on October 31, 1985, after the D.C. Circuit Court in the MPC I and MPC II cases held the programs to be unduly discriminatory.

281. Order No. 319, 24 FERC ¶ 61,100 (1983), was issued on the same day as Order No. 234-B.

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pipelines and producers could convey to them the high-cost gas contracted for before the deliverability surplus developed. Not only were these prices higher than the market would absorb if free purchasing were permitted, but in many cases these prices were indexed to rise despite falling demand. As late as January 1, 1985, many people were fearful that such indexing would push prices significantly upward despite a large and increasingly prolonged deliverability bubble.

FERC attempted to increase opportunities for LDCs to gain access to spot markets and other relatively low-priced gas through two actions. First, in May 1984, in Order No. 380, FERC reduced somewhat the burden of minimum bills by prohibiting pipelines from recovering variable costs for gas not taken;²⁸² and (2), in its revised special marketing program orders, FERC required pipelines participating in such programs to allow LDCs to purchase up to ten percent of their contract demands from spot markets.

Although Order No. 380 still required LDCs to pay minimum bills sufficiently large to cover pipelines' fixed costs, it did increase the ability of LDCs served by two or more pipelines to shift sources of supply.²⁸³ In so doing, LDCs increased competitive pressures on pipelines and encouraged them to renegotiate gas-purchase contracts wherever possible.

By May 1985, when the D.C. Circuit ruled on the *Maryland Peoples' Counsel* cases,²⁸⁴ the FPC-created system of bundled-service regulation was still largely intact, but it was cracking and crumbling. The *Narragansett* doctrine remained the dominant instrument for pipelines to shift risk, and, with few exceptions, bundled services were the only services available to LDCs. The *Pike County* doctrine, however, was assuming greater importance as LDCs' alternatives increased.

E. FERC's Order No. 436

FERC intended Order No. 436, promulgated in October 1985, to facilitate economic efficiency through intensified competition.²⁸⁵ The

282. Elimination of Variable Costs From Certain Natural Gas Pipeline Minimum Commodity Bill Provisions, FERC Stats. & Regs., ¶ 30,571 (1984). A minimum bill, as the name suggests, required the customer to pay the pipeline for a minimum quantity of gas when the LDC took less than that quantity from the pipeline. See *supra* Part II, Section B.2.

283. On a case-by-case basis, FERC has largely eliminated minimum bills.

284. See *supra* note 279.

285. See *supra* note 258.

drafters of Order No. 436 thought that by redrawing the boundaries between market forces and regulatory controls, they could also alter the jurisdictional boundaries between federal and state regulators. In particular, Order No. 436 limited the range of discretion in the pricing of LDC services. By inducing interstate pipelines to allow others to compete with pipeline company merchants, FERC expected that pipeline incentives would change. The fortunes of the pipeline companies would depend more on their transportation services and less on their merchant services. Also, allowing others to use pipeline assets to carry and store gas would create horizontal gas markets to complement and discipline the traditional vertical markets. As a result of the competitive forces released by Order No. 436, FERC hoped that LDCs would be compelled to assume greater responsibility for their gas supplies. Furthermore, by expanding the choices available to LDCs to include opportunities to deal directly with producers, Order No. 436 gave state PUCs a more important role in evaluating the gas portfolio decisions of LDCs under the *Pike County* doctrine. Consequently, LDCs and PUCs gained responsibility to make decisions on the *degree* of security for which they would be willing to pay, while FERC shed its responsibilities in this area.²⁸⁶ FERC's Order No. 436 was intended to induce the players—LDCs, pipelines, large industrial gas users, electric utilities, and PUCs—to seek an allocation of gas-supply risks that was acceptable to all. In appreciation of the magnitude of the problem and the deficiencies of federal regulators in making such decisions, FERC's Order No. 436 was emphatic: FERC would not use federal powers to force LDCs to assume these risks. Consequently, Order No. 436, when fully implemented, will eliminate the three key planks of the FPC-created system of bundled-service regulation.

Order No. 436 also encouraged competition between pipelines and LDCs in ways that promised to alter fundamental relations between LDCs and their large customers. After the issuance of Order No. 436, many states required their LDCs to offer unbundled transportation services. Consequently, just as LDCs were bypassing pipeline company merchant services and buying gas directly from producers and non-jurisdictional merchants, large customers of LDCs were bypassing both LDC and pipeline mer-

286. This transfer of responsibilities did not occur upon issuance of Order No. 436. That order contained a contract demand conversion schedule that limited the LDCs' abilities to cease purchasing gas from the pipeline. Complete abandonment of pipeline company merchant services was scheduled to take five years, although each pipeline was free to allow its customers an accelerated schedule. See *infra* note 288.

chants to buy from producers and non-jurisdictional merchants. More troublesome to LDCs, and to many PUCs, however, were actions by large customers of LDCs to connect directly to an interstate pipeline and bypass the LDC entirely.²⁸⁷

The D.C. Circuit Court reviewed Order No. 436 in *AGD v. FERC*.²⁸⁸ One issue in that review was whether the order unduly weakened the abilities of PUCs to deter bypass of LDC merchant and transportation services. The Court rejected arguments by LDCs and PUCs that FERC should exercise its regulatory powers to preserve the PUCs' powers to maintain economically inefficient prices. The language used is strong:

If states choose to require LDCs to continue service to non-paying customers, those states must address the consequences. They can extract the cost from price-inelastic customers, primarily the solvent residential customers; they can seek to extract the cost from industrial customers, at the peril of driving them off the system; they can fund the expense out of tax revenues; they can use their power under [*Panhandle Eastern Pipeline Co. v. Michigan Public Service Commission*, 341 U.S. 329, 336 (1951)] to thwart the possible bypass, accepting the economic consequence that their industrial gas users may be unable to compete with firms in other states. All these choices may involve some pain—like all true choices. But that hardly requires the Commission to abandon its effort, required under the NGA, to facilitate the flow of competitively-priced gas into the hands of gas consumers everywhere.

287. For a detailed discussion of the effect of Order No. 436 on LDC bypass, see Broadman & Kalt, *How Natural is Monopoly? The Case of Bypass in Natural Gas Distribution Markets*, 6 YALE J. ON REG. 181 (1989). For a discussion of the theory of optimal bypass, see MacAvoy, Spulber & Stangle, *Is Competitive Entry Free? Bypass and Partial Deregulation in Natural Gas Markets*, 6 YALE J. ON REG. 209 (1989).

288. See *Associated Gas Distribs. [AGD] v. FERC*, 824 F.2d 981 (D.C. Cir. 1987). Despite a vigorous endorsement of the power of FERC to adopt and implement the principal objectives of Order No. 436, the Court vacated the Order because of dissatisfaction with FERC's handling of the "contracts problem," that is, the take-or-pay problems of pipelines arising from their contracts with producers. The Court also demanded better justification from FERC for its grant of privilege to LDCs to reduce unilaterally their contract demand obligation to pipelines in accordance with a schedule determined by FERC. In August 1987, FERC repromulgated the substance of Order No. 436 in Order No. 500, *Regulation of Natural Gas Pipelines After Partial Wellhead Control*, 52 Fed. Reg. 30,334 (1987). Extension and interpretations are contained in Order Nos. 500-A, -B, -C, -D, -E, -F, -G, and -H. For simplicity of language, the term Order No. 436 should be understood to include all of these when the context suggests a post-August 1987 period.

Physical bypass has not been a frequent phenomenon since *AGD v. FERC*, but it occasionally has happened. It was quickly observed that the *Panhandle* case cited in *AGD v. FERC* did not offer PUCs much ability to deter bypass of an LDC's merchant function.²⁸⁹ A 1989 case, *Michigan Consolidated Gas Co. v. Panhandle Eastern Pipeline Co.*,²⁹⁰ confirmed this view. In that case, the Sixth Circuit upheld FERC's right to permit an interstate pipeline to bypass an LDC. The Court held that the Panhandle to National Steel bypass of Michigan Consolidated Gas "involves merely interstate transportation of natural gas . . . and not local distribution."²⁹¹ The Court also rejected the argument that the authorization of the bypass was an abuse of FERC powers because the bypass allowed the pipeline to engage in the functional equivalent of local distribution. It said, "Given the careful and continuing attention that Congress has focused on the natural gas industry, we are of the view that if Congress had intended to except the 'functional equivalent' of 'local distribution' from federal jurisdiction, it would have stated so by now."²⁹²

F. *Summary of Natural Gas Industry Regulation*

Although many state PUCs have protested parts of Order No. 436, including FERC's decision to allow LDC bypass, the overwhelming majority have not. That reaction, other PUC responses, and direct communications from state commissioners support the conclusion that PUCs are generally more willing to lose their discretion to market forces than to FERC. The contrast between PUC reactions to FERC's *Middle South* and *AEP* decisions and their response to Order No. 436 decisions offers further support for this conclusion.

The principal conclusion drawn from this survey of gas industry regulation is that the Order No. 436 reforms, especially the creation of a competitive interstate market for natural gas, have created the possibility of a division of labor between federal and state regulators that will be tolerable to both sets of regulators, the legislators, the

289. See Address by Wendell H. Adair, Jr., ABA annual meeting (1987) (entitled *The Constitution and Energy: Supremacy, Federalism and Energy Policy*).

290. 887 F.2d 1295 (6th Cir. 1989).

291. The Court added, "In this case it is undisputed that the retail sale of natural gas occurs in Oklahoma, where National Steel purchases it for its use at its plant in Detroit." 887 F.2d at 1300.

292. 887 F.2d at 1300 (footnote omitted).

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courts, and all segments of the industry. The three most obvious qualifications to this optimistic view arise from concerns that (1) FERC will not sustain its efforts to create and preserve a competitive natural gas market, (2) FERC will not develop an LDC-bypass policy that distinguishes between efficient and inefficient bypass that satisfies PUCs, and (3) the participants in the industry will fail to develop a system of risk allocation that satisfies regulators and legislators.

Since all these concerns seem manageable within the existing framework of Order No. 436, a forecast of a diminution of the past and current level of tension between federal and state regulators on issues relating to the natural gas industry seems plausible.

Conclusion

The last two decades have been years of turmoil in the American economy. Historically high inflation rates, historically high nominal and real interest rates, serious recessions (by post-World War II standards), productivity increase slowdowns, economic growth slowdowns, and increasing integration of the economy into the international economy have marked these decades. It is not surprising, therefore, that the 1970s and 1980s also have been tumultuous ones for the natural gas and electric industries, their financiers, and their economic regulators. After twenty-five years of what utilities and their financiers might call the Golden Age of economic regulation, the 1970s and 1980s became years of testing. Investment strategies, pricing policies, risk allocation policies, and decision-making procedures have been tested in the crucible of political controversy. All have been found wanting to varying degrees. The fundamental institutions, however, both public and private, have survived surprisingly well, albeit with modifications and with wounds that will not soon be forgotten.

During the 1970s and 1980s, the earlier intellectual discontent with the performance of economic regulation matured into a political cause. The twenty-five or so years following World War II were not seen as a Golden Age of economic regulation by economists evaluating industry performances against the standard of economic efficiency. By the mid-1970s "regulatory reform" and "deregulation" had become useful slogans for both major political parties. Furthermore, technological change, especially in computers and telemetering, continued at a rapid rate during the 1970s and 1980s. In the sense captured well by Joseph Schumpeter's phrase "creative destruction," this technological improvement complemented the macroeconomic changes to undermine the status quo in the electric

and natural gas industries. In the electric industry, the degree of balkanization of the industry into free standing, vertically integrated utilities continued to diminish as economies of scale in transmission increased and as the cost of coordination among utilities decreased. In the natural gas industries, the improvements in telemetering, in computational technologies, and in telecommunications complemented the changing relative value-added contributions of the segments of the industry to encourage the unbundling of pipeline company services leading to new allocations of risks.

All these forces, and the chosen responses of regulators and regulatees to the forces, produced a testing of the inherited boundaries between state and federal regulatory jurisdictions and between regulated and non-regulated activities. The analysis herein suggests that the testing will continue and will likely cause significant movements in both boundaries.

The exogenous forces emphasized in the analysis were those most closely related to dislodging the jurisdictional boundaries between state and federal regulatory agencies. Some of these forces were recognized as, in principle, reversible while others are, in principle, non-reversible. The major non-reversible exogenous forces are the technological changes in telecommunications, telemetering, and computational abilities; the increased economies of scale in electricity transmission; and the internationalization of the American economy. The major exogenous forces that are reversible in principle are the emergence of inflation rates significantly higher than productivity increase rates, and the emergence of real and nominal interest rates significantly higher than those traditionally used when justifying large, long-gestation generating plants and pipelines. Reversibility in principle is not a forecast that a reverse will occur. The productivity slowdown, when combined with regulatory lag, converted the virtuous cycle of the Golden Age of economic regulation into the vicious cycle of the last two decades. The high real interest rates reduced emphasis on capital-intense production strategies in both the electric and natural gas industries. In the electric industry, this relative factor-cost change is especially important since it diminishes the significance of past economies of scale in generation. This diminution in economies of scale may reduce the monopoly power of regulated firms and, consequently, limit the pricing and investment discretion of regulators.

The major policy decision that molded regulatory agencies' responses to these exogenous forces was to expand the role of competition in selected segments of these regulated industries. Many minor policy decisions, made in particular cases, complemented or

qualified this major decision. A direct consequence of this policy stance was to shift certain powers from regulators, both those who made the decisions and those in other jurisdictions, to markets. A secondary consequence of this policy stance was to require regulators to respect market forces somewhat more when making pricing and investment decisions within their discretion; it was difficult to urge competition in some dimensions and refuse to promote efficiency in others. However, this shift to efficiency as a regulatory objective also arose because increasing competition in certain activities limited regulatory discretion in other areas. Monopoly power that is eliminated cannot continue to be exercised.

In the natural gas industry, the Order No. 436 decisions have greatly reduced both the scope of FERC's regulatory authority and the range of discretion in most of the areas it continues to regulate. In contrast, by diminishing the practical significance of the *Narragansett* doctrine and expanding the practical significance of the *Pike County* doctrine, the Order No. 436 decisions greatly expanded the scope of state PUCs' regulatory oversight of LDC procurement decisions. Simultaneously, however, these orders set in motion competitive forces that will severely limit the range of PUC discretion in the exercise of those authorities.

Regulators and legislators who believe that the important objective of regulation is the creation and perpetuation of prices and services that cannot be sustained in the presence of strong competitive forces will consider the Order No. 436 decisions a serious infringement on state prerogatives. In contrast, those who think that economic efficiency is an important objective of economic regulation will view these decisions as properly redrawing the boundaries, both the boundaries between state and federal regulators, and between market forces and regulatory constraints.

In the electric industry, FERC has adopted potentially conflicting policies that reflect the current schizophrenia in the industry. On one hand, it has promoted competition in wholesale markets to utilize existing plants more efficiently, hastened the entry of IPPs into wholesale markets, and encouraged states to create bidding systems to discipline offers of incremental generating capacity from non-traditional suppliers. By doing this, FERC has used the *Pike County* doctrine to expand the scope of PUC jurisdictions. Simultaneously, however, the developing competition limits the range of regulatory discretion available to states who endorse competitive acquisition. On the other hand, FERC has protected multistate holding companies from PUC actions that might have intensified competition among operating subsidiaries of the holding company,

and between those companies and companies outside the holding company. This policy has narrowed the scope of the *Pike County* doctrine. Both FERC policies tend to limit, but do not eliminate, the abilities of states to use their utilities as instruments in statewide planning of generating capacity.

State and federal cooperation and conflicts in the regulation of the natural gas industry are of special interest because they highlight the types of tensions to be expected if competition in electricity wholesale markets continues to spread and intensify. In both industries, the proportion of value-added at the distribution level is small—below twenty-five percent. With such small markups, a significant part of which must be devoted to paying variable costs, distribution companies can allow themselves to become major risk-bearers for upstream segments of the industry only if their monopoly power is sufficient to support substantial price increases when required. Only when FERC demonstrated a clear preference for routing gas sales through LDCs, by discouraging bypass, did LDCs have such monopoly power. In the electric industry, the vertical integration of the industry—especially the ownership by the distribution company of the transmission assets needed for bypass—currently provides the distribution companies with such monopoly power.

If FERC continues to encourage competition in the generating sector, and moves to grant generous transmission access rights to generators and distribution utilities, electricity distribution companies will be required to adjust—as most gas distribution companies already have adjusted—to less pricing discretion to avoid the constant threat of bypass. Distribution companies with small markups that cannot coerce their customers to bear significantly higher prices than available in an adjoining area cannot permit themselves to become major risk-bearers for upstream segments of the industry.

The principal conclusion drawn from this study of the electric industry is that, despite the efforts of many states to increase their influence over electric utility planning, the states²⁹³ will lose much of the discretion they now possess in determining electric industry prices, investment strategies, and fuel mixes. While their influence over the distribution sector of the industry will remain great, even there the possibility of bypass will restrain the exercise of pricing discretion. Some of the influence lost by states will accrue to FERC (or perhaps to new regional bodies), but much of it will be lost to

293. With the obvious exceptions of Alaska, Hawaii, and perhaps the Electric Reliability Council of Texas (ERCOT) area of Texas.

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markets. The march of technology seems uni-directional in this industry. Telemetering, computational abilities, and decreasing real costs of transmission services have already created spans of operational control far larger than all but the largest states. The nation will exploit the resulting productivity gains either by mergers of existing vertically integrated utilities into larger firms that can promise to deliver those gains by systems of command and control, or by the creation of competitive generating markets and broadly defined transmission rights for generators and distribution companies. In the former case, influence will shift from the states to FERC, if the holding company form of organization is adopted. In the latter case, influence will shift from states and from FERC to markets, with states retaining influence over the purchasing decisions of distribution companies. The former approach will probably intensify state/federal conflicts, certainly if the holding company form of organization is adopted. The latter holds the promise of creating a sustainable division of labor between state and federal regulators. The latter would parallel the current evolution of the gas industry and is in rough conformity with the PURPA Section 210 model that already operates in the electric industry. Furthermore, the competitive approach holds a promise that the responsibilities remaining on regulators might be small enough for them to fulfill effectively even under current procedural constraints.

