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THE NARRAGANSETT DOCTRINE: AN EMERGING ISSUE
IN FEDERAL - STATE ELECTRICITY REGULATION

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EXECUTIVE SUMMARY

Introduction and Background

This report examines recent developments in the electric power industry which may have the effect of encouraging electric utilities to restructure themselves in ways which would transfer regulatory authority over their operations from the state to the federal level. These developments relate to utility perceptions of a more favorable regulatory climate at the federal level and the use of innovative financing schemes designed to reduce the risk of new capacity construction.

For many electric utilities, regulation of wholesale rates by the Federal Energy Regulatory Commission (FERC) is increasingly being viewed as more "responsive" than the regulation of their retail rates by state commissions, and this provides an incentive for exploring alternative means of coming under FERC regulation. FERC policies and procedures are viewed as considerably more favorable in a number of key ratemaking areas such as use of a future test year, minimum suspension periods, fuel adjustment clauses, inclusion of CWIP in rate base, and rates-of-return more closely reflecting market conditions. Moreover, FERC regulation is reasonably removed from the exigencies of local political pressures that have led a number of legislative bodies in various states to insert themselves more directly into the day-to-day regulation of utilities within their states in such crucial areas as recovery of abandonment costs, treatment of "excess capacity," and "rate shock."

In addition to efforts to seek more responsive regulation, utility efforts to minimize growing financial risks--by negotiating joint ownership arrangements for new powerplants or by foregoing addition of new capacity in favor of more purchased power--may also have the effect of transferring jurisdiction over a growing portion of the utility's business from the state to the federal level. An increasing number of utilities have expressed a reluctance to initiate any new plant construction without some form of risk sharing such as that achieved through joint ownership arrangements with other utilities. Another approach increasingly under consideration is the separation of a utility's generating assets from the its transmission and distribution assets as a means of risk allocation.

The increased use of any of these ownership mechanisms could have the same effect of transferring jurisdiction over a significant portion of the utility's operations from the state to the FERC, under the "Narragansett doctrine," as would a corporate restructuring specifically

designed with that outcome in mind. This "doctrine" (as the general principle of the Narragansett decision is frequently referred to) holds that a state regulatory commission lacks jurisdiction to inquire into the "reasonableness" of a wholesale rate subject to FERC jurisdiction, and that the state cannot refuse to pass the wholesale purchase power costs on through the cost-of-service in a subsequent state regulatory proceeding. It is based on the Federal supremacy clause of the Constitution and the Federal Power Act preemption of state commission authority to regulate interstate wholesale prices subject to FERC jurisdiction.

Evolution of State and Federal Regulatory Responsibility for Electric Power

Prior to 1927, state regulatory commissions exercised ratemaking jurisdiction over all sales of electric energy--including energy transmitted across state lines. In the 1927 case of Public Utilities Commission vs. Attleboro Steam & Electric Co., the U.S. Supreme Court struck down, as a direct burden on interstate commerce, an attempt by the Rhode Island Public Utilities Commission to regulate the rates at which a Rhode Island utility could sell electric power to a Massachusetts distributor. The Court reasoned that even though a utility was engaged in sales of power across state lines, its retail sales were "essentially local" in character and thus subject to state regulation, but that its wholesale transactions were "essentially national" in character and--under the Commerce Clause--were subject to regulation only by the federal government. The Court held that if regulation of such interstate sales was required, it could only be attained by the exercise (or delegation) of the power vested in Congress by the Constitution to regulate interstate commerce.

The Supreme Court decided Attleboro at a time when there was no federal regulation of electric utility rates or corporate structure. The decision, accordingly, created a "regulatory gap" regarding interstate wholesale transactions in which the states could not regulate and the federal government did not regulate. Strong pressures from state regulatory agencies to "fill this gap" resulted in Congressional enactment of Part II of the Federal Power Act of 1935 which provided for creation of the Federal Power Commission to regulate the (interstate) wholesale transactions that Attleboro had held to be beyond the regulatory power of the states. At the same time, however, regulatory jurisdiction over the large numbers of wholesale transactions that were still generally perceived as essentially intrastate in nature was left to the state commissions. Following enactment of the Federal Power Act there was periodic debate as to whether particular bulk power transmissions and sales were in interstate or intrastate commerce (based on the wholesale/retail division of Attleboro). This same issue became a continuing element of litigation in the natural gas context through the early 1950's. To clarify the regulatory situation under the Natural Gas Act, in 1954 the Congress passed the so-called "Hinshaw Amendment" which reaffirmed state jurisdiction over the transmission and sale of natural

gas that was received within or at the boundary of a state and ultimately consumed within that state.

Prior to the Supreme Court's decision in the Colton case in 1964, state utility commissions continued to regulate most of the wholesale bulk power transactions taking place entirely within their respective states. Federal Power Commission regulation up to that time was largely confined to those sales taking place between the major utilities and, even then, to those transactions taking place across state lines.

The Colton case involved the sale of power by the Southern California Edison Company (SCE) to the municipal distribution system of the City of Colton. Colton argued that because of Edison's interstate interconnections and power purchases, the sale in question should be subject to the exclusive jurisdiction of the Federal Power Commission rather than the state. In a landmark decision, the FPC agreed with this argument and determined that the "sale to Colton is a sale of electric energy at wholesale in interstate commerce" subject to Commission regulation under the Federal Power Act. The U.S. Supreme Court ultimately affirmed the FPC determination of jurisdictional status for the Edison sale to Colton. The Court interpreted the Federal Power Act as granting to the FPC exclusive jurisdiction over all wholesale sales of electric energy in interstate commerce (not expressly excepted in the Act itself). The Court concluded that it was Congress' intent through the Federal Power Act to draw an easily ascertainable "bright line" between state and federal authority, making unnecessary a case-by-case analysis.

The political reaction to the Supreme Court's decision in Colton was quickly forthcoming. Almost immediately, an unusual coalition of the many investor-owned utilities who viewed themselves as operating primarily on an intrastate basis and whose wholesale transactions had suddenly been rendered "jurisdictional" under the Federal Power Act--and the state regulators who heretofore had been regulating these sales--appealed to Congress to adopt legislation similar to the Hinshaw Amendment that would reverse the major impacts of the Colton decision. Their contention was that both the Commission and the Courts had erred in their interpretation of Congressional intent (as stated in §201(a) of the Federal Power Act) which was to limit FPC jurisdiction "only to those matters which are not subject to regulation by the states." They argued that the Court's decision had rendered meaningless the "assurances" they thought had been given by Congress in enacting the Federal Power Act that federal authority was to be limited to the extent needed to fill the jurisdictional "gap" created by Attleboro.

The 88th Congress held extensive hearings in 1964 on amendments to the Federal Power Act designed to restore state authority over intrastate wholesale transactions but no action was taken, largely due to the strong opposition from the FPC and wholesale customers.

Recent Developments and Current Status in the Jurisdictional Debate

The debate over federal versus state authority over transactions which involved interstate sales of electricity remained relatively dormant for about a decade following the Colton decision. The jurisdictional issue reemerged in the late 1970's in a somewhat different format. Rather than attempting to argue the merits of who should exercise primary rate jurisdiction over interstate wholesale sales, several states attempted to exercise a form of "secondary" jurisdiction by asserting authority to review the inclusion of certain bulk power supply costs in the retail rates of their jurisdictional utilities (such costs presumably having been approved in the context of FPC approved wholesale rates). The issue was typically framed in terms of what authority state regulatory commissions possess in fixing retail rates to review the "reasonableness" of wholesale rates previously approved by the FPC for interstate bulk power sales. Until recently, the Courts consistently held that state commissions were automatically preempted from determining the reasonableness of costs for retail ratemaking if based on wholesale power purchases filed with the FPC. Several recent cases, however, have contributed to what some have characterized as a "blurring" of the bright line set forth in Attleboro and Colton as the basis for distinguishing federal and state jurisdiction.

The first major case challenging the notion of federal preemption pursuant to Attleboro culminated in a 1977 decision by the Rhode Island Supreme Court in the case of Narragansett Electric Co. vs. Burke defining the extent to which Federal Energy Regulatory Commission (FERC, successor to the FPC) action circumscribes the authority of a state regulatory commission in setting retail rates for the intrastate sale of electricity. The Rhode Island Commission maintained that it possessed the authority to investigate the reasonableness of the (purchased power) costs approved by FERC underlying a Narragansett rate increase and could thus prevent Narragansett Electric Company from flowing through to its retail customers any portion of those costs that were deemed "unreasonable." The Rhode Island Commission argued that it had the authority to investigate the propriety of the proposed retail tariffs since according to state law, the burden was on the utility to establish the "reasonableness" of expenses incurred through purchases from an affiliated company. The Rhode Island Supreme Court indicated, however, that FERC approval of wholesale rates charged to a retailer constituted a declaration that those purchased power costs should be deemed a reasonable operating expense, within the meaning of state authority to determine "just and reasonable" retail rates. The Court concluded that if the State Commission were permitted to examine and disallow those costs it deemed "unreasonable," it would effectively violate the concept of federal preemption. A series of succeeding cases adopted the general rule of the Rhode Island Supreme Court in Narragansett that, subsequent to FERC approval of a wholesale rate for the interstate sale of electric power, the state utility commission must accept the wholesale rate as a reasonable operating expense when setting retail rates for the purchasing utility.

In a fairly significant departure from the general rule concerning federal preemption articulated by the Court in Narragansett, a recent decision by the Pennsylvania Commonwealth Court concluded that state regulatory commissions may selectively inquire into the "reasonableness" of a wholesale sale for which FERC has approved the rate. In the case of Pike County Light & Power Co. vs. Pennsylvania Public Utility Commission the Court held that although the Commission is precluded from passing on the propriety of the FERC rate, it may ascertain whether the purchasing utility exercised prudence in deciding to purchase power at the approved rate. The Court observed that whereas FERC determines the reasonableness of a particular wholesale rate by analyzing the supplier's costs, the state commission determines whether it is reasonable for the buyer to purchase the power at that price in light of other available sources. In effect, the Court appeared to be saying that FERC approval only indicated that it was reasonable for those rates to be charged by the supplier, not that it was reasonable for the purchaser to incur the expense.

In several recent decisions with potentially far-reaching consequences, the U.S. Supreme Court has also reexamined the respective roles of the state and federal governments in the regulation of the electric utility industry. In the cases of FERC vs. Mississippi (1982) and in Arkansas Electric Cooperative Corp. vs. Arkansas Public Service Commission (1983), the Court may have blurred the long-standing Attleboro "bright-line" and provided for limited exercise of state jurisdiction in areas wherein federal authority was not clearly preemptive under the relevant statutes. In Arkansas the Court held that the mechanical, or "bright-line," jurisdictional test originally set forth in Attleboro has become "anachronistic." In rejecting Attleboro, the Court substituted what it characterized as a "more flexible standard" which necessitates consideration in each case of "the nature of the state regulation involved, the objective of the state, and the effect of the regulation upon the national interest in the commerce." In FERC vs. Mississippi, the Court upheld the authority of Congress, in the Public Utility Regulatory Policies Act (PURPA) to require state utility commissions to consider federal ratemaking standards in carrying out their retail regulatory activities. Whereas the Arkansas decision endorsed state involvement in a subject matter (i.e., wholesale rate regulation) that had previously been thought to be of exclusively federal concern, the Mississippi decision appeared to endorse federal involvement in a subject matter that was previously viewed as exclusively a matter of state concern.

In the view of some observers, these decisions by the Court appeared to reflect an evolving concept of shared--and perhaps even overlapping--regulatory responsibility for the electric utility industry, with more emphasis on balancing of competing interests and little or no reliance on mechanical tests. This view, some would argue, is supported by the Supreme Court's decision in Pacific Gas & Electric Co. vs. State Energy Resources Conservation and Development Commission (1983), where it concluded that although the Atomic Energy Act preempts state action with respect to nuclear safety, it does not do so with respect to economic and other aspects of nuclear power. Since the California statute at

issue in the case involved economic and not safety concerns, the Court held that state jurisdiction was not preempted by the federal statute.

It would be incorrect to conclude from these cases that the Supreme Court was declaring "open season" on FERC's wholesale rate jurisdiction in terms of endorsing comprehensive state oversight of wholesale transactions. Rather, it simply recognized the jurisdictional issue may not always be as clear as the Attleboro "bright-line" would suggest and that in certain situations the scope of federal statutory authority did not explicitly preempt the exercise of collateral state jurisdiction. In other cases, however, where the statute is relatively unambiguous concerning federal preemption (as would likely be the case for most wholesale bulk power transactions involving investor-owned utilities) nothing in these decisions suggests any substantial retreat from the Narragansett rule restricting the authority of state commissions to examine the reasonableness of wholesale rates filed with the FERC.

However, while the general thrust of court decisions has been to preempt the states in matters relating to bulk power sales made pursuant to FERC approved wholesale rate schedules, the cases noted above suggest that there is still a "gray area" relating to the scope of state authority to consider the prudence of the costs incurred by the purchasers in such transactions. The FERC in several recent cases has also taken the view that its acceptance of a rate schedule does not preclude a state commission from considering the prudence of the transaction with respect to the purchaser. The FERC has indicated in such cases that, in accepting a rate schedule, their determination is limited to whether the sale price is just and reasonable; it is not determinative of the issue of whether the purchase itself is prudent relative to other options which might have been available to the purchaser. Several cases in progress are likely to shed further light on the scope of state authority in this area.

Factors Contributing to Jurisdictional Transfer

Regulation by the FERC is perceived by many as having become increasingly more "responsive" from the standpoint of the regulated utilities compared with many state regulatory commissions. This has created growing incentives for a utility to seek transfer of regulatory jurisdiction from the state to the federal level. Specific differences in ratemaking policies and practices between the FERC and most state commissions that demonstrate this notion are found in such areas as (1) suspension periods, (2) fuel cost adjustment clauses, (3) test years, (4) treatment of construction work in progress, (5) treatment of cancellation costs, and (6) treatment of "excess" capacity.

The reasons for the differences in regulatory treatment between the FERC and the state commissions in these areas are complex but in general, are linked to the types of customers whose service is regulated, the proportion of a utility's total service and costs regulated, and the exposure of regulators to ultimate customers. Each of these factors can partially explain the perceived financial advantages of FERC regulation from a utility perspective.

A second development that could result in jurisdictional transfer relates to the new ownership arrangements that are being examined by some utilities as a means of sharing risks and getting new plants built. Under Narragansett, jurisdictional transfer could be an outcome because of the sale-for-resale aspects of bulk power transactions involving plants built under these new ownership arrangements. Holding company structures and a variety of joint ownership arrangements among several utilities are typical of the risk avoidance mechanisms which could result in jurisdictional transfer under Narragansett.

Methods of Jurisdictional Transfer

There are several approaches which historically have had the effect of transferring jurisdiction from the state to the federal level. These actions were historically undertaken primarily for purposes other than transferring jurisdiction (or were the outcome of factors beyond the utility's control) but might be used to achieve jurisdictional transfer on a prospective basis.

The various mechanisms which could result in jurisdictional transfer under Narragansett and subsequent court decisions are:

- Engaging in interstate interconnections and sales (thereby making the utility FERC jurisdictional under Colton).
- Creating a holding company structure with a generating subsidiary selling power to an affiliated distribution subsidiary (similar to the New England Electric System Model).
- Joint ownership arrangements for constructing and operating new capacity (such as the "Yankee" Atomic Model).
- The ESPRI Model (a variation on the joint stock company approach proposed by utilities in New York State in the 1970's to own and operate new generating capacity).
- Cost equalization agreements within a holding company power pool (making the bulk power costs of each of the participating systems subject to FERC jurisdiction).
- "Off-system" bulk power purchases and sales by individual utilities (which are subject to FERC jurisdiction).

While there are other mechanisms of achieving similar outcomes from a jurisdictional perspective (e.g., project financing of new powerplants), they typically can be shown to be a variation of one or more of the generic approaches listed above.

Among the principal options listed, utility efforts to create holding company structures with generating and distribution subsidiaries, efforts by various parties in FERC proceedings to impose cost equalization agreements within holding company pools, and the growing level of

"off-system" bulk power purchases pose the greatest likelihood of resulting in near-term jurisdictional transfers. Over the long-term, however, greater reliance on joint ownership arrangements to finance new generating capacity could result in a greater likelihood of such an outcome.

Future Directions of the Jurisdictional Debate

There is a growing level of activity but little in the way of a clearly focused agenda in the continuing debate over the jurisdictional transfer issue. There have been several legislative efforts to reverse this outcome and have Congress adopt some form of Hinshaw Amendment for electric power, but none has succeeded so far.

An important factor that could influence the jurisdictional transfer debate is how the Courts ultimately interpret the Narragansett doctrine with regard to state authority to consider the "prudence" of the purchaser in a FERC approved wholesale bulk power transaction. As noted earlier, several states have asserted authority to examine the prudence of the transaction itself in the context of alternative resource acquisition decisions that (arguably) could have been made by the utility. Future efforts by state commissions to expand the scope of their "prudence inquiries" under this reading of Narragansett could stimulate both judicial and legislative efforts by utilities to restore the "bright line" of demarcation between federal and state jurisdiction over wholesale electric rates.

The overall legislative environment could change very quickly, however, if there were major effort by utilities to use any of the various mechanisms listed above as a means of transferring jurisdiction to the FERC. Under such circumstances, Congress might be more sympathetic to legislative proposals designed at least restore to the status quo. Conversely, a narrowing of the perceived advantages of FERC regulation from a utility perspective could reduce the incentives for a utility to examine alternative means of jurisdictional transfer.

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FOREWORD

A part of NRRI's research products for FY84 was the commissioning of this report now published as an Occasional Paper. Having recognized regulatory experts outside the staff of the Institute produce such reports allows a broader source of viewpoints and is a useful element of outreach for NRRI. William W. Lindsay and Jeffrey L. Pfeffer of NPS Energy Management, Inc. are two such contributors. Each has distinguished service in public positions dealing with energy issues--Lindsay with FERC and Pfeffer with DOE.

We commissioned Occasional Paper No. 8 to be done knowing that the question of federal-state regulatory jurisdiction is an ongoing one and that when real or apparent shifts in the dividing lines between those jurisdictions arise, the subject is worthy of revisiting. In that light, this report on the "Narragansett Doctrine" and its implications for state commission regulation is presented.

We feel the clear statements of the issues and the lines of reasoning offered as ways to think about them will be helpful to state regulators--commissioners and staff. The views and opinions presented are, of course, those of the authors and do not necessarily reflect those of the NRRI, the National Association of Regulatory Utility Commissioners (NARUC), NARUC member commissioners, or The Ohio State University.

Douglas N. Jones
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December 31, 1984
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CHAPTER 1
INTRODUCTION

There are two important trends in place today which have the effect of encouraging electric utilities to restructure themselves in ways which would transfer regulatory authority over their operations from the state to the federal level. For many electric utilities, regulation of wholesale rates by the Federal Energy Regulatory Commission (FERC) is increasingly being viewed as more "responsive" than the regulation of their retail rates by state commissions, and thus provides an incentive for exploring alternative means of coming under FERC regulation. FERC policies and procedures are viewed as considerably more favorable in a number of key ratemaking areas such as use of a future test year, minimum suspension periods, fuel adjustment clauses, inclusion of CWIP in rate base, and rates-of-return more closely reflecting market conditions. Moreover, FERC regulation is reasonably removed from the exigencies of local political pressures that have led a number of legislative bodies in various states to insert themselves more directly into the day-to-day regulation of utilities within their states in such crucial areas as recovery of abandonment costs, treatment of "excess capacity," and "rate shock."

In addition to the perception of more responsive regulation by the FERC, utility efforts to negotiate joint ownership arrangements for new

powerplants (or to forego construction of new capacity and rely primarily on purchased power) in response to growing financial risks may also have the effect of transferring jurisdiction over a growing portion of the utility's business from the state to the federal level. An increasing number of utilities have expressed a reluctance to initiate any new plant construction without some form of risk sharing such as that achieved through joint ownership arrangements with other utilities. Another approach increasingly under consideration is the separation of a utility's generating assets from its transmission and distribution as a means of risk allocation.

Any of these mechanisms could have the same effect of transferring jurisdiction over a significant portion of the utility's operations to the FERC under the Narragansett doctrine as would a corporate restructuring specifically designed with that outcome in mind. This "doctrine" (as the general principles of the Narragansett decision are sometimes referred to) holds that a state regulatory commission lacks jurisdiction to inquire into the "reasonableness" of a wholesale rate subject to FERC jurisdiction, and that the state cannot refuse to pass the wholesale purchase power costs on through the cost-of-service in a subsequent state regulatory proceeding. It is based on the Federal supremacy clause of the Constitution and the Federal Power Act preemption of state commission authority to regulate interstate wholesale prices subject to FERC jurisdiction.

There are a number of possible ways of increasing the partial jurisdiction of the FERC over the costs and rates of a given utility. One possibility is a corporate restructuring of the utility in the

manner in which the New England Electric System (NEES) is currently organized. In this model all generating assets are owned by a single generating subsidiary which serves as power supplier to several affiliated distribution subsidiaries under rates regulated by the FERC. Several other utilities are known to be considering the option of creating such a holding company structure, though not specifically for the purpose of evading state regulation. Another possibility is an ESPRI-type model in which seven New York utilities in the mid-1970's proposed creation of a jointly-owned generating subsidiary for the purpose of constructing and operating new bulk power supply facilities. Any sales from such an enterprise to its affiliates would then have been subject to FERC jurisdiction. A third option would involve the creation of a joint stock company such as the various "Yankee Atomic" companies in New England to own and operate new facilities. Sales of capacity and energy from such a company to its participants are sales for resale subject to FERC jurisdiction.

A fourth possibility may be revision of pooling agreements of affiliated utilities in such a way as to roll together all of the bulk power supply costs of the affiliated utilities and share the total costs in accordance with each affiliate's respective kW and kWh usage. This model is employed by the Northeast Utilities group and by the Northern States Power Company group. Court decisions involving both groups of utilities have thus far appeared to support the notion that such agreements are "wholesale contracts" and the bulk power costs under such agreements are subject to FERC regulation and (under Narragansett) cannot be modified by a state commission.

In an ongoing case involving the pooling agreement of the Middle South System, the FERC staff (among others) has taken the position that bulk power supply costs of the pool participants should be rolled together for cost sharing purposes. The effect of such a cost equalization approach to all systems with the Middle South Group could be substantial reallocation of the cost responsibility for several major nuclear power plants in the Middle South service area. An argument that has been advanced against such a change in that case is that it would enable the FERC to assert jurisdiction over all of the bulk power supply costs of the four operating affiliates of the Middle South group--an argument rejected by many participants in the case.

A final possibility of achieving some degree of jurisdictional transfer involves long-term off-system purchases such as the purchase of large blocks of power and energy from the Southern Company System by several utilities in Texas and Florida. Short-term excess capacity which is projected to continue in many regions throughout the 1980's may tend to encourage efforts to arrange more such off-system purchase and sale transactions which would effectively be exempt from state jurisdiction once they are filed with the FERC. Indeed, a number of state commissions have encouraged their utilities to pursue such transactions as a means of reducing bulk power supply costs.

All of the possibilities described above (as well as others) would tend toward a reduction of the jurisdiction of state commissions over the retail rates of utilities operating within their states (by placing a substantial percentage of the utility's bulk power supply costs beyond the reach of state regulation). Most, if not all, state commissions may

oppose developments of this sort, although the extent of their authority to discourage if not directly prevent such actions is unclear. Nevertheless, the trade-off between corporate reorganization proposals or joint ownership arrangements which can be shown to reduce the costs of bulk power supply against the potential loss of jurisdiction over some portion of the utility's business could pose difficult questions for state regulators.

From a policy perspective, both the National Governors Association (NGA) and National Association of Regulatory Utility Commissioners (NARUC) have adopted resolutions opposing most such efforts. Indeed, the NGA recently submitted legislation to Congress which was supported by NARUC, providing for discretionary transfer of FERC jurisdiction over "purely intrastate" wholesale transactions back to the states.

It is important that state regulators and other concerned parties be aware of the extent to which there may be forces in motion creating incentives for utilities to seek jurisdictional transfers, the nature of these incentives and of the possible forms that such changes in jurisdiction might take. Thus, the purpose of this report is to provide an introduction to the various dimensions of the jurisdictional transfer issue including:

- (1) A review of the historical evolution of state versus federal authority over wholesale electric rate matters including the principal legislative actions and judicial decisions which resulted in the current regulatory scheme.
- (2) A review of developments leading toward increased incentives for utilities to transfer a greater share of regulatory jurisdiction to the FERC including the various actions that have created an increasingly favorable regulatory climate of the FERC (from the standpoint of the regulated utilities) and a brief survey of trends toward

tightening of regulatory requirements at the state commission level.

- (3) An analysis of the various means by which transfers from state to federal jurisdiction have been accomplished in the past and an examination of the relative effects that future use of each of these methods might have on the scope of state commission jurisdiction.
- (4) An examination of the extent to which financing and construction of new central station generation in the 1990's will require new ownership and operating structures that may lead toward further concentration of regulatory authority at the federal level.

This preliminary assessment of these issues should provide all concerned parties with a better understanding of what could be one of the more controversial regulatory policy issues in the years ahead.

CHAPTER 2

HISTORICAL PERSPECTIVE OF STATE VERSUS FEDERAL REGULATION OF ELECTRIC POWER

Introduction

The issue of federal versus state jurisdiction over wholesale electric power matters is of considerable current interest, but the origins of the issue actually predate the enactment of the Federal Power Act of 1935. In reviewing the recent debate in the subject, one quickly develops a sense of "deja-vu" in that many of the same arguments appear to have been resurrected from debate of 50 years prior. To develop a better understanding of the issues underlying this debate and how it relates to growing incentives for utilities to find opportunities of substituting one jurisdictional forum for another, it is important to understand the evolution of the existing federal/state regulatory scheme. In this section we briefly review the principal developments leading to enactment of a comprehensive system of federal regulation of interstate wholesale electric rates and how that system was implemented in the 30 years following enactment of the Federal Power Act with emphasis on federal/state jurisdictional allocation.

Evolution of State Regulation of Electric Utilities

There is a widespread misconception that state regulation of electric utilities was imposed over the objections of the utility

industry. In fact, state regulation of retail prices and market entry received the grudging support of some leaders of the electric power industry as early as 1898 as the lesser of several competing evils. Once those supporting state oversight were successful in establishing utility commissions in most of the states, the electric utilities vigorously defended the jurisdiction of these commissions against encroachment by municipal and federal authorities.

In 1898, Samuel B. Insull, President of Chicago's Commonwealth Edison Company and Chairman of the newly formed National Electric Light Association, first proposed the radical notion of state regulation of utility rates, standards of service, and market entry and exit. Insull's objective in accepting state regulation was to minimize destructive competition amongst a large number of new market entrants and protect the newly developed industry's growing capital investment through the award of exclusive service areas by state government agencies.¹

It was not until 1907, however, that Insull was able to persuade a majority of his industry colleagues that state regulation was preferable to municipal or federal regulation as a means of insulating the newly emerging industry from the risks of public ownership and destructive competition among a proliferating number of firms. In that year, the first state utility commissions were created in New York and Wisconsin. While the industry soon accepted the inevitability of state regulation as the only viable alternative to municipal regulation and ownership, it also sought to confine the scope of state regulatory authority as narrowly as possible. By 1915, nearly two-thirds of the states had

enacted some form of legislation creating regulatory commissions to monitor electric power companies operating in their jurisdiction. It was not until 1975 that the last of the states (Texas and South Dakota) formally enacted legislation establishing statewide regulation of utility rates and services.²

During the early period of the industry's growth there was relatively little concern with the issue of state versus federal regulation of interstate wholesale transactions or sales among affiliated companies operating in several states because of the relative self-contained and "electrically isolated" nature of most utility systems. In effect, electric utility operations during this period were almost entirely intrastate in nature, with limited relevance to "interstate commerce."

Changes in Industry Structure as A Factor in Federal Regulatory Jurisdiction

The structure of the U.S. electric power industry changed considerably after Insull first proposed state regulation of electric utilities in the early 1900's. Over the next several decades the structure of the industry evolved in the direction of greater concentration and vertical integration among a declining number of investor-owned systems. At the same time, there was a slow (but perceptible) increase in the relative importance of publicly-owned systems--a trend that has continued through the present day. In 1980, there were fewer than 250 investor-owned systems remaining within the U.S. out of a total of over 3,000 systems--the vast majority of which are municipally or cooperatively owned. This compares to a total of 2,800 investor-owned central-station electric plants in 1902 out of a total of 3,600

facilities. (As noted below, in many cases each plant was owned and operated by a separate system.)³

The increasingly multistate nature of utility system structure and operation and the growing importance of system interconnection and wholesale bulk power transactions have been a direct outgrowth of the changing technology and economics of bulk power supply. In the early 1900's, electric utility systems were relatively small (electrically isolated) operations with each company typically marketing on the output of a single generating plant and serving a limited number of customers in a local service area. Advances in steam-plant design, coupled with the introduction of alternating current and higher voltage electric transmission lines, facilitated development of larger and more efficient generating plants located at greater distances from utility load centers. Generating plants located in one state based on site availability or proximity to fuel supplies were increasingly used to provide power for customers in other jurisdictions. At the same time, scale economies and opportunities for coordination resulted in a gradual increase in the level of interconnection of previously isolated bulk power suppliers leading to extensive mergers among smaller companies and creation of larger holding companies. A 1927 Supreme Court decision which effectively left interstate sales unregulated also contributed to the rapid growth of holding companies in the late 1920's. By 1929, nearly 80 percent of the nation's installed generating capacity was controlled by a relatively small number of interstate holding company systems.⁴

Political reaction to the market concentration, multiple ownership tiers, and other financial problems arising from the holding company

structures of the late 1920's resulted in enactment of the Public Utility Holding Company Act of 1935 (PUCHA).⁵ Under the Holding Company Act, the Securities and Exchange Commission (SEC) was assigned jurisdiction over the restructuring of holding companies and all their subsidiaries (including electric utilities). Existing utility holding companies were required by the Act to reorganize and simplify themselves and limit their operations to single, integrated, geographically contiguous systems. This reorganization was essentially completed by the early 1950's. Thus, in contrast to their earlier dominance of the electric utility industry, the 12 holding companies still in existence today account for less than 20 percent of total U.S. generating capacity.

While reversing the trend towards consolidated ownership, however, the PUCHA did not change the fundamental economic and technological trends promoting greater system interconnection and the resultant intersystem coordination transactions which were designed to allow both affiliated and unaffiliated systems to capture a variety of scale economies.

The Emergence of Federal Regulation Over Interstate Sales

Once the structure of the electric power industry had evolved to the point of extensive interconnection and coordination among neighboring systems, increasing attention was focused on the "interstate commerce" aspects of these transactions and the issue of federal versus state jurisdiction over wholesale electric power sales. Prior to 1927, state regulatory commissions exercised ratemaking jurisdiction over all

sales of electric energy--including energy transmitted across state lines. In the landmark case of Public Utilities Commission vs. Attleboro Steam & Electric Co.,⁶ the United States Supreme Court (in 1927) struck down, as a direct burden on interstate commerce, an attempt by the Rhode Island Public Utilities Commission to regulate the rates at which a Rhode Island utility could sell electric power to a Massachusetts distributor. The Court reasoned that even though a utility was engaged in sales of power across state lines, its retail sales were "essentially local" in character and thus subject to state regulation, but that its wholesale transactions were "essentially national" in character and--under the Commerce Clause--were subject to regulation only by the federal government.⁷ The Court held that if regulation of such interstate sales was required, it could only be attained by the exercise (or delegation) of the power vested in Congress by the Constitution to regulate interstate commerce.

The Supreme Court decided Attleboro at a time when there was no federal regulation of electric utility rates or corporate structure. The decision, accordingly, created a "regulatory gap" regarding interstate wholesale transactions in which the states could not regulate and the federal government did not regulate. Strong pressures from state regulatory agencies to "fill this gap" resulted in Congressional enactment of Part II of the Federal Power Act of 1935 which provided for federal regulation of the (interstate) wholesale transactions that Attleboro had held to be beyond the regulatory power of the states.

In enacting the Federal Power Act, Congress in essence adopted the Court's "Attleboro test" for distinguishing the jurisdictional status of

a particular transaction by providing that the federal government would regulate wholesale power transactions in "interstate commerce," while retail transactions would remain subject to state regulation. As noted below, however, the real intent of Congress in providing for federal regulation of wholesale sales in "interstate commerce" was eventually to become a major point of conflict.

The Act created the Federal Power Commission, now the Federal Energy Regulatory Commission (FERC), and assigned to it "exclusive" authority to regulate the rates governing interstate transmission and rates of electricity sold for resale (i.e., interstate wholesale transactions). The Act presumably sought to establish a limited federal role in wholesale regulation when it declared:⁸

" . . . the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that federal regulation of matters relating to generation of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such federal regulation, however, to extend only to those matters which are not subject to regulation by the states." (Emphasis added.)

The Act further provided:

"The provision of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy . . ." (Emphasis added.)

The above noted language of the Act suggests that the primary intent of Congress was to "fill the gap" in regulation of interstate wholesale electric power sales created by Attleboro and thereby displace an uncertain and inconsistent state regulatory scheme with comprehensive federal regulation of interstate wholesale electric rates. At the same

time, however, regulatory jurisdiction over the large numbers of wholesale transactions that were still generally perceived as essentially intrastate in nature was left to the state commissions. It was more than 25 years before the considerably more comprehensive scope of federal authority over wholesale bulk power transaction was initially manifest in a decision by the Commission to assert jurisdiction over such "intrastate" wholesale sales.

There has been considerable speculation as to why, in selecting a remedy to correct the "regulatory gap" opened by the Court in Attleboro, the Congress took the path it did in enacting the Federal Power Act. For example, it could have delegated to the states that portion of the federal authority over interstate commerce necessary to regulate purely intrastate wholesale electricity transactions and the corporations therein engaged. That, however, was not the option selected. After lengthy hearings and debate, Congress decided that FPC regulation was preferable to state delegation for regulating both wholesale electric transactions and the corporations engaged in such transactions.

The absence of a clear definition of which transactions were in "interstate commerce" suggests that Congress had not really contemplated the potential problems arising from federal efforts to regulate those wholesale transactions that were viewed by utilities and state regulators as intrastate and "essentially local" in nature.

Why did Congress choose a federal commission to exercise wholesale rate regulatory authority rather than delegating federal authority to regulate interstate commerce to the several states? Although the record is not conclusive on this point, it appears that substantial doubts

existed in the minds of many senators and congressmen in the 1935 debate as to whether state commissions possessed the required technical expertise, scope of jurisdiction, and insulation from political pressures to effectively regulate large corporate entities extending across several states (especially in the political aftermath of the PUCHA and Congress' contemporaneous efforts to remedy the abuses of the holding company structures and force a dismantling of many of the largest of these multistate corporate entities).¹⁰

This view is supported by an examination of the Congressional debate preceding enactment of the Holding Company Act wherein members decried what they alleged was the undue influence of the holding companies on state efforts to regulate utility operations within their jurisdiction. In this regard, the Senate Committee Report on Title II of the Public Utility Holding Company Act of 1935 stated:¹¹

"In recent years the growth of giant holding companies has been paralleled by the rapid development of the electric business along lines that transcend state boundaries . . . local operating units have been tied together into vast interstate networks. As a result, the proportion of electric energy that crosses state lines has steadily increased. The decision . . . in Attleboro . . . places the interstate wholesale transactions of the electric utilities entirely beyond the reach of the states. Other features of this interstate utility business are equally immune from state control either legally or practically. The necessity for federal leadership . . . has been clearly revealed . . ."

Similarly, a review of the hearings and debate preceding enactment of the Federal Power Act leaves one with the impression that Congress intended to endow the Federal Power Commission with rate regulatory authority over interstate "wholesale" sales and numerous other aspects of utility structure and operation, because of an abiding conviction that the states, even had the power been conferred on them, could not

accomplish the task. At the same time, Congress does not appear to have contemplated that the courts would ultimately support a much broader application of this authority to encompass intrastate wholesale transactions that in 1935 were probably not viewed by most members as being within the "Attleboro Gap."

Application of the Attleboro Rule
in the Natural Gas Context

The complex issue of state versus federal jurisdiction in interstate energy sales was not solely restricted to electric power. Indeed, essentially the same issue addressed by the Supreme Court in Attleboro, had also arisen in the case of natural gas. Prior to 1953, in a series of related cases involving regulation of gas utilities, the Supreme Court held that: (1) the commerce clause permits a state to regulate the sale of gas directly to consumers even though it be drawn from interstate pipelines (Pennsylvania Gas Co. vs. N.Y. Public Service Commission);¹² (2) a state is prohibited from regulating the rate at which gas from out of state is sold to distributing companies for resale (Missouri ex rel. Barrett vs. Kansas National Gas Co.)¹³

Congress subsequently adopted the wholesale/retail test embodied in the Attleboro rule in enacting the Natural Gas Act of 1938.¹⁴ This congressional action reaffirmed state regulatory authority over local retail rates charged by gas distributors while simultaneously establishing a clear line of federal regulatory authority over interstate wholesale sales. As noted in a subsequent court decision:¹⁵

"the line of the statute was thus clear and complete. It cut sharply and clearly between sale for resale and direct sales for consumptive uses."

The Attleboro rule was applied by the courts to wholesale and retail sales of natural gas as well as to electricity sales. In Illinois Natural Gas Co.¹⁶ the Court noted that the Attleboro rule signified only one of two lines of cases setting out tests which had been used to determine the validity of state regulations. The Court noted that the Attleboro line set out the "mechanical rule" approach, looking only at whether the transmissions and sales were in interstate or intrastate commerce (based on the wholesale/retail division). The other line, the Court said, "has been less concerned to find a point in time and space where the interstate commerce in gas ends and intrastate commerce begins" and has concentrated on balancing the particular state and federal interests involved in each case.¹⁷ Such "balancing" became a continuing element of litigation in the natural gas context through the early 1950's, just as it was an underlying concern in many of the electric cases adjudicated by the Commission and the Courts in the same time frame. To clarify the regulatory situation, in 1954 the Congress passed the so-called "Hinshaw Amendment" which reaffirmed state jurisdiction over the transmission and sale of natural gas that was received within or at the boundary of a state and ultimately consumed within that state. In effect, federal jurisdiction over such pipeline sales ended and state jurisdiction expanded beyond the "city gate."

Extension of Federal Authority
to All Wholesale Transactions

The Supreme Court decision in Attleboro, supplemented by the Federal Power Act, clearly provided for federal preemption of state regulatory jurisdiction in the case of interstate bulk power

transactions. However, prior to the Supreme Court's decision in the Colton case in 1964, state utility commissions continued to regulate most of the wholesale bulk power transactions taking place entirely within their respective states. Federal Power Commission regulation up to that time was largely confined to those sales taking place between the major utilities and, even then, to those transactions taking place across state lines. There were, however, several cases prior to Colton wherein the Courts affirmed FPC jurisdiction over transactions that were viewed as essentially "intrastate" in nature.¹⁹

The Colton case involved the sale of power by Southern California Edison Company to the municipal distribution system of the city of Colton, all of whose customers were located entirely within the state of California.²⁰ Southern California Edison Company also served only customers located in southern and central California. However, Edison did receive a relatively small amount of its total bulk power supply from federal hydropower projects in Nevada and Arizona.

The rate for the sale of power by Edison to Colton had been regulated for many years by the California Public Utilities Commission. Indeed, it was a decision by the California Commission in 1958, allowing an increase in that rate, which led Colton to petition the Federal Power Commission to assert jurisdiction over the sale. Colton argued that because of Edison's interstate interconnections and power purchases, the sale in question was subject to the exclusive jurisdiction of the Federal Power Commission. In a landmark decision, the FPC agreed with this argument noting that the out-of-state energy from the government dams was "commingled" with energy generated by Edison from its own

California facilities and could (based on a "tracing procedure") presumed to be included in the energy delivered by Edison to Colton. Accordingly, the FPC determined that the "sale to Colton is a sale of electric energy at wholesale in interstate commerce" subject to Commission regulation under the Federal Power Act.

Edison appealed the FPC decision to the U.S. Court of Appeals based on the previously noted language of §201(a) of the Federal Power Act, which provides that regulation of interstate wholesale transactions under that act is "to extend only to those matters which are not subject to regulation by the states." Edison argued that this language limited FPC jurisdiction to those transactions beyond the scope of state regulation, and furthermore, that California Commission regulation of the sale to Colton was constitutionally permissible under the Commerce Clause. The Court agreed with Edison and set aside the FPC decision.

Ultimately, however, the U.S. Supreme Court reversed the Appellate Court and reinstated the original FPC determination of jurisdictional status for the Edison sale to Colton. The Court interpreted the Federal Power Act as granting to the FPC exclusive jurisdiction over all wholesale sales of electric energy in interstate commerce (not expressly excepted in the Act itself). It held that the quoted language in §201(a) was merely a "policy declaration . . . of great generality" which could not nullify the more specific grant of jurisdiction over wholesale transactions in Section 201(b).

The Court concluded that it was Congress' intent through the Federal Power Act to draw an easily ascertainable "bright line" between state and federal authority, making unnecessary a case-by-case analysis.

The FERC's authority was to be plenary in the area of wholesale sales of electricity in interstate commerce except those which Congress made explicitly subject to regulation by the states.²²

Efforts to Restore State Jurisdiction Over
"Intrastate" Wholesale Transactions

The political reaction to the Supreme Court's decision in Colton was quickly forthcoming. Almost immediately, an unusual coalition of the many investor-owned utilities who viewed themselves as operating primarily on an intrastate basis and whose wholesale transactions had suddenly been rendered "jurisdictional" under the Federal Power Act--and the state regulators who heretofore had been regulating these sales--appealed to Congress to adopt legislation similar to the Hinshaw Amendment that would reverse the major impacts of the Colton decision. Their contention was that both the Commission and the Courts had erred in their interpretation of Congressional intent (as stated in §201(a) of the Federal Power Act) limiting FPC jurisdiction "only to those matters which are not subject to regulation by the states." They argued that the Court's decision had rendered meaningless the "assurances" they thought had been given by Congress in enacting the Federal Power Act that federal authority was to be limited to the extent needed to fill the jurisdictional "gap" created by Attleboro.

The 88th Congress held hearings in 1964 on amendments to the Federal Power Act designed to restore state authority over intrastate wholesale transactions.²³ Supporters claimed these amendments would reaffirm the original intent of Congress to "supplement" rather than "supplant" state and local regulation. No action was taken in the 88th

Congress and similar legislation was introduced in the 89th Congress as S.218 (commonly referenced as the "Holland-Smathers Bill").

In introducing S.218, Senator Holland characterized the FPC decision in Colton as part of an "evangelistic program . . . to stretch and extend its power . . ." and as:²⁴

" . . . [a] typical bureaucratic assertion of authority and jurisdiction in a new effort [by the FPC] to include in the scope of its authority, power companies and their systems which were far removed from any state line and which had no direct connection with interstate business." (Emphasis added.)

S.218 was drafted so as to exempt from Federal Power Commission jurisdiction any company, including rural electric cooperatives, having all of its generating and transmission facilities within a single state and having no direct connections with the facilities of any public utility deriving the major portion of its electric revenues from sales in another state. (Exemption from FPC jurisdiction under S. 218 was not conditioned on the exercise of state jurisdiction; indeed, several states still had not established statewide rate regulation at the time of the Colton decision.) Under the bill, the FPC would have continued to exercise jurisdiction over companies having generating or transmission facilities in more than one state, as well as over the "single-state companies" which were directly connected with public utilities having their major operations in another state. The bill would also have provided an exemption for what was considered as essentially local sales to governmental bodies (cooperatives and exempt single-state companies). It was estimated by the FPC that upwards of 50 utilities representing over 25 percent of electricity sales would have been entirely exempted from federal jurisdiction under the bill.

The Holland-Smathers proposal received strong support from a diverse coalition of (intrastate) investor-owned utilities, some electric cooperatives and their respective state regulators (i.e., those groups most directly affected by the Colton decision). They argued that since the states have jurisdiction over retail rates, there was no logical reason why they should not also have jurisdiction over "local" wholesale transactions and transmission services which they viewed as an an integral part of the process of delivering energy to the ultimate consumer and in which no other state has any substantial interest."

Typical of the strong views expressed by state regulators were those of James A. Lundy, Chairman of the New York Public Service Commission who observed that:²⁵

"Colton came out of the Federal Power Commission in 1961 like a bolt from the blue. Its affirmance by the Supreme Court in 1965 was a shaft from on high. It is one which, unless promptly rectified, bids fair to produce nothing but chaos in the electric regulatory field. . . Sooner or later, unless the impact of Colton is rectified now, each state regulatory commission will become subservient to its federal 'big brother.' It will only be permitted to pick up with its regulation of electric sales at retail where the FPC leaves off with its regulation of each and every wholesale transaction, whether at or far within the state's borders. . . We sincerely believe that Congress did not, designedly at least, create the Federal Power Commission to perform any such function, FPC's illustrious spokesmen to the contrary notwithstanding. . ."

Lundy proceeded to attack the notion advanced by the FPC that wholesale regulation was "too complex" a task for the state commissions. He noted that:²⁶

". . . the Federal Power Commission has purported to advance certain logic and certain alleged needs for its new-found regulatory power expansion. Among other things it has quite clearly evidenced and espoused its notion of a superior qualification as an electric regulator over that of its sister state agencies. . . since the regulation of all other [i.e.,

intrastate] facets of the electric business--at wholesale and retail--has, until very recently, been the product of the respective state commissions, we simply do not understand how it can responsibly be said that the enactment of S.218 would mean the end of such responsible regulation. On the contrary, what we here seek simply is to insure the continuance of that responsible regulation, by restoration of the status quo ante Colton."

Similar views were expressed by other state regulators, one of whom expressed the additional concern:²⁷

". . . Unless restrained, efforts of the Federal Power Commission to extend its regulatory authority threaten an unnecessary and serious overlapping of regulatory jurisdiction, complicated and costly separation studies, and needless duplication of state and federal regulation. The resulting increased costs would, most certainly, add to the overall expense of regulation."

Representatives of investor-owned and cooperative utilities echoed similar themes to those of their state regulators. For example, a Florida utility executive observed that his state's interconnections with Georgia were solely designed to enhance system reliability and allow for the occasional exchange of surplus energy. Nevertheless, he observed that by virtue of "various technical theories" the FPC was attempting to assert jurisdiction over all wholesale transactions in Florida under the Colton doctrine. Aside from questioning the technical basis of the Commission's efforts to assert jurisdiction (i.e., there was no "proof" that the power sold in Florida was actually generated in another state), he further argued:²⁸

"To permit the FPC to interject its regulatory authority--and oust that of the Florida Commission--over these transactions would result in unnecessary fragmentation of state and federal jurisdiction, cause substantial extra expense to my company and its customers because of duplicate hearings and overlapping requirements regarding the filing of reports, and inevitable conflicts regarding proper accounting methods, the fairest method of allocating costs between different groups of

customers and varying theories regarding the fair rate of return under particular circumstances."

Opposition to the Holland-Smathers Bill was led by the FPC, the Justice Department, and public power systems and their Congressional supporters. FPC Chairman Joseph Swidler broadly asserted the importance of retaining Commission jurisdiction over all wholesale transactions without regard to the "interstate status" of the participating utilities. He insisted that the Commission decision in the Colton case was simply a reaffirmation of authority (i.e., over all wholesale transactions) that in his view had been "recognized from the outset as federal responsibilities under the [Federal Power] Act." Among his key arguments were the following:²⁹

- ° ". . . retail rate regulation is an exclusive province of the states and it covers by far the largest part of electric revenues. Federal regulation was conceived as a partnership with state regulation which would support the state commissioners and not supplant them. The existing statutory pattern leaves with the state commissioners by far the most important responsibilities for the protection of electric consumers. . . In sum, the act recognized that the states could better perform their important regulatory role with the assistance of a strong Federal Power Commission performing its own role in the interstate wholesale power sphere and aiding the states in accomplishing their responsibilities at the retail level."
- ° ". . . S. 218 would altogether exempt from "public utility" status, and therefore from every aspect of Federal Power Commission regulation, many electric companies engaged in interstate commerce (including members of interstate power pools) if they own facilities in only one state and sell or buy power in interstate commerce through an intermediary company. This exemption would be granted irrespective of the extent of the interstate transactions engaged in, irrespective of the size of the companies affected, irrespective of the number of wholesale customers dependent on them for power supply, and irrespective of whether they are otherwise subject to regulation of wholesale rates, uniform accounting, and other vital matters."
- ° "[The bill] would also [effectively] repeal the FPC's present jurisdiction over sales at wholesale to almost all of the

approximately 1,500 municipal, cooperative, and investor-owned systems which purchase all or part of their electric power requirements at wholesale. . . The bill withdraws federal responsibility only when the utility making the sale has "substantial" retail revenue in the state in which the sale is made. This revenue test, however, would have practically no effect under the operating circumstances of the industry today. . . except as to sales at wholesale by the few companies which were exclusively or almost exclusively in the wholesale business."

Of particular interest in the context of current debate over alleged efforts by utilities to restructure themselves so as to shift regulatory jurisdiction from the states to the FERC were Swidler's comments as to how the Holland-Smathers Bill would have had precisely the opposite effect. He noted that the proposed legislation would:³⁰

". . . exempt from all aspects of federal regulation any electric company which is so organized as to own facilities in only one state and which is permanently and directly interconnected only with utilities which derive the majority of their electric revenues from sales in the same state. S. 218 would exempt such companies even if they were integral parts of interstate power pools; even if they were wholly owned subsidiaries of interstate holding company systems, all tied together and operating as a unit under central management; and even if their basic function was to generate and supply energy to out-of-state utilities. . .

. . . Thus, the growing practice of forming a company to own a nuclear powerplant or a mine-mouth generating station which ultimately supplied energy to two or as many as a dozen or more states could nonetheless avoid public utility status under S. 218 if it were directly connected only to the facilities of a company deriving most of its revenues from sales in the state where the generating station was located. A present example of such a situation is the Yankee Atomic Electric Co. whose pioneer nuclear facilities are all in Massachusetts, and whose direct connection is with New England Power Co. a multistate utility which derives a majority of its revenues from sales in Massachusetts."

Swidler concluded by rejecting what he considered to be the "basic fallacy" of the legislative premise of Holland-Smathers that intrastate

wholesale transactions were matters "primarily of local concern." He argued strongly that the need for federal jurisdiction:³¹

" . . . becomes apparent if we examine the present-day operation of the companies which make up the electric industry. Today, to an even more marked degree than in 1935, the electric industry is one of interstate and even national character. . . . Thus, any company which owns generation facilities linked to an interstate power pool necessarily engages in interstate commerce with other members of the pool even if the facilities it owns happen to lie all in one state." (Emphasis added.)

Representatives of municipal power systems (whose complaint to the FPC had precipitated the Commission's decision in the Colton case) endorsed Swidler's arguments regarding the need for retaining FPC jurisdiction over "intrastate" wholesale transactions. They attributed the bill to the success of the FPC's efforts to "protect wholesale customers from the unfair practices of private utilities" and a desire by the latter to seek a more "favorable" regulatory environment at the state level. Alex Radin of the American Public Power Association (APPA) asserted:³²

" . . . the real drive for enactment of S. 218 stems from the fact that FPC regulation in recent years has proven to be an effective method of reducing wholesale electric rates and curbing restrictive provisions imposed by power companies on their wholesale customers. This is not adequate reason for repealing a statute which has been on the books for 30 years. On the contrary, it is an argument for strengthening the FPC with money and manpower so that it can do the kind of job which its duties demand. . . . The responsibility to protect the public interest was imposed on the FPC following congressional investigations which revealed that many private power companies were abusing their monopoly status and economic power, to the detriment of their consumers . . . S. 218 would terminate the regulatory reforms approved by Congress in 1935 to curb these abuses."

APPA's analysis of the impacts of the Holland-Smathers Bill closely paralleled that of the FPC, particularly in its conclusions:³³

"S. 218, if enacted, would (1) exempt from Federal Power Commission jurisdiction many of the electric utilities from whom small, publicly-owned systems derive their requirements at wholesale, and would provide a method by which most of those utilities could escape federal regulation by new corporate devices, and (2) would, by exempting from Commission jurisdiction most of the wholesale sales to municipalities, cooperatives, and some investor-owned utilities, deprive those purchasers of a forum in which to challenge rate and contractual inequities."

Notwithstanding extensive hearings and debate, the 89th Congress failed to take any action of legislative proposals to reverse the Court's decision in Colton. Confronted with the fundamentally opposing views of the relevant constituencies concerning potential (vs. actual) outcomes of the Colton case, there was no sense of political urgency requiring an immediate legislative solution. Thus, the Commission's decision to assert exclusive jurisdiction over all wholesale bulk power transactions was effectively codified and remained unchallenged until the late-1970's when the increased volume of wholesale bulk power purchases, coupled with court decisions which affirmed federal preemption in wholesale electric matters resulted in renewed state commission interest in finding ways of asserting some jurisdiction over wholesale electric rate matters. At the same time, many utilities, perceiving an increasingly unfavorable regulatory environment at the state level, began to seriously consider options for transferring jurisdiction to what they believed had now become a more "receptive" regulatory environment at the federal level (i.e., exactly the opposite of what had been the case during the 1960's).

Legislative efforts to reverse Colton and restore state ratemaking jurisdiction of intrastate sales did not end with the Holland-Smathers Bill. Changing times and circumstances have resulted in changing

attitudes on the issue of who should exercise ratemaking jurisdiction over intrastate wholesale sales. As will be noted in the concluding section of this report, almost 20 years after Holland-Smathers, the chairman of one of the nation's largest multistate electric holding companies proposed transferring authority for such transactions back to the states in response to the views expressed by the chairman of the FERC (in a report to Congress) outlining the pros and cons of such an approach. Finally, a new legislative effort to achieve this outcome was introduced by NGA and NARUC in the 98th Congress with the likelihood of being carried over to the next session.

CHAPTER 3

STATE EFFORTS TO REVIEW THE REASONABLENESS OF WHOLESALE RATES

Introduction

The debate over federal versus state authority over transactions which involved interstate sales of electricity remained relatively dormant for about a decade following the Colton decision. The jurisdictional issue reemerged in the late 1970's in a somewhat different format. Rather than attempting to argue the merits of who should exercise primary rate jurisdiction over interstate wholesale sales, several states attempted to exercise a form of "secondary" jurisdiction by asserting authority to review the inclusion of certain bulk power supply costs in the retail rates of their jurisdictional utilities (such costs presumably having been approved in the context of FPC approved wholesale rates). The issue was typically framed in terms of what authority state regulatory commissions possess to review the "reasonableness" of wholesale rates previously approved by the FPC for interstate bulk power sales in fixing retail rates. Until recently, the Courts consistently held that state commissions were automatically preempted from determining the reasonableness of costs for retail ratemaking if based on wholesale power purchases filed with the FERC.

Several recent cases, however, have contributed to what some have characterized as a "blurring" of the bright line set forth in Attleboro

and Colton as the basis for distinguishing federal and state jurisdiction. As will be noted later in this section, there is little reason to believe that the line has been substantially blurred in circumstances applicable to the large percentage of wholesale transactions wherein the scope of federal ratemaking authority is reasonably unambiguous and FERC authority is thereby preemptive of ex post state oversight. What is less clear, however, is the degree to which FERC preemption extends to state regulatory efforts to examine the prudence of a transaction from the purchaser's perspective in the context of efforts to flow-through such costs in retail rates.

The Narragansett Case

The first major case challenging the notion of federal preemption pursuant to Attleboro culminated in a 1977 decision by the Rhode Island Supreme Court in the case of Narragansett Electric Co. vs. Burke defining the extent to which federal regulatory action circumscribes the authority of a state regulatory commission in setting retail rates for the intrastate sale of electricity.³⁴ The Narragansett Electric Company of Rhode Island purchased its electrical power from the New England Power Company (NEPCO), an affiliated Massachusetts corporation. Subsequent to a FERC-approved rate increase for NEPCO, the Rhode Island Commission maintained that it possessed the authority to investigate the reasonableness of the (purchased power) costs underlying the rate increase and could thus prevent Narragansett Electric Company from flowing through to its retail customers any portion of those costs that were deemed "unreasonable."

The Rhode Island Commission argued that it had the authority to investigate the propriety of the proposed retail tariffs since according to state law, the burden was on the utility to establish the "reasonableness" of expenses incurred pursuant to purchases from an affiliated company. The Rhode Island Supreme Court indicated, however, that FERC approval of wholesale rates charged to a retailer constituted a declaration that those purchased power costs should be deemed a reasonable operating expense, within the meaning of state authority to determine "just and reasonable" retail rates. The Court concluded that if the State Commission were permitted to examine and disallow those costs it deemed "unreasonable," it would effectively violate the concept of federal preemption.

A series of succeeding cases adopted the general rule of the Rhode Island Supreme Court in Narragansett that subsequent to FERC approval of a wholesale rate for the interstate sale of electric power, the state utility commission must accept the wholesale rate as a reasonable operating expense when setting retail rates for the purchasing utility. For example, the Supreme Court of Massachusetts in Eastern Edison vs. Massachusetts DPU³⁵ reaffirmed the Narragansett doctrine--that an FERC-filed rate must be considered a prudently incurred reasonable power cost within the meaning of state laws which provide for regulatory investigation of a utility's retail purchased power adjustment clause.

In a subsequent commentary on the evolution of case law affirming federal preemption of wholesale ratemaking authority, it was observed:³⁶

"The Court [decision] in Eastern Edison provides a more solid foundation for the separation of powers established by the Narragansett Court. The Court there required the State Commission, as in Narragansett, to pass the questioned power

costs through to the utility's customers in an appropriate fuel charge. Furthermore, the Massachusetts Court asserted that the fact that the FERC rate was not final did not change its effect; the public utility commission must accord the same deference to a rate which the FERC has accepted for filing as it would to a rate which the FERC has approved after a hearing." (Emphasis added).

As will be noted below, however, there may still be some latitude for the states to address certain aspects of FERC approved wholesale rates in the context of determining the reasonableness of the purchase for retail ratemaking purposes.

The Northern States Case

In a recent case addressing the issue of state versus federal jurisdiction in wholesale rate matters (Minnesota Public Utilities Commission et al. vs. Northern States Power Co.), the U.S. Supreme Court denied a petition for certiorari from the State of Minnesota on a Minnesota Supreme Court decision. The State Court had rejected actions by the State PUC which had questioned FERC's exclusive jurisdiction to review and approve an amendment to the Coordinating Agreement among the two operating companies of the Northern States Power Company (NSP) System.³⁷

As a result of the abandonment of plans to construct the Tyrone nuclear power plant, NSP sustained substantial cancellation losses. NSP filed with FERC an amendment to its Coordination Agreement which sought to allocate the Tyrone abandonment losses between the two companies in accordance with standard allocation formulas. After FERC had approved the amendment, NSP instituted a proceeding before the Minnesota Public Utilities Commission (MPUC) to obtain approval of a proposed increase in

retail rates in Minnesota to recover the portion of the cancellation losses attributable to its Minnesota customers.

The Minnesota hearing examiner, concluded that the amendment established a "wholesale rate schedule" within the exclusive jurisdiction of FERC and that intervenors could not attack the reasonableness of those rates prescribed by FERC. He recommended that NSP be allowed to include Tyrone losses as expenses for power purchased. The Commission, however, reversed the hearing examiner on the grounds that the Wisconsin Public Service Commission decision which led to the abandonment of the Tyrone Plant was a "parochial" one based on consideration of Wisconsin needs alone. More importantly, they asserted that FERC's approval of the amended Coordination Agreement was merely an allocation of costs between NSP subsidiaries and thus did not preempt the MPUC's authority to review expenses allocated by the amended agreement for the purpose of retail ratemaking.

The case was subsequently appealed all the way to the Minnesota Supreme Court which rejected the MPUC decision. It concluded that the NSP amendment to the Coordination Agreement (notwithstanding its formulation in terms of allocation formulas) was still a valid wholesale rate and thus the MPUC was preempted (under the Narragansett doctrine) from examining its reasonableness.

The fundamentally different perceptions of the issue can be most readily observed in how each side stated the "question" to the U.S. Supreme Court. The State of Minnesota expressed the issue as follows:³⁸

"Whether the Federal Power Act permits an electric utility to evade state regulation of its retail rates by separately incorporating part of its generation and transmission system in a wholly-owned subsidiary and obtaining FERC approval of a

cost sharing agreement between the utility and the subsidiary as a wholesale rate."

NSP disagreed with the appellants' statement of the question and submitted that the Minnesota District Court (which had rejected the Minnesota Public Utilities Commission's position) correctly framed the issue as follows:³⁹

"The critical issue, dispositive of this appeal, is whether the FERC Order on the Tyrone Petition constitutes a federally approved wholesale rate as between NSP and NSP-W. If the Coordinating Agreement and its amendments constitute such a rate, then there is little dispute but that the PUC must, under the law cited, accept the Tyrone cost allocation established by FERC."

NSP argued that the underlying legal proposition (i.e., that a state ratemaking body must treat a FERC-approved rate as establishing the reasonableness of wholesale costs in determining a utility's operating expenses for purposes of setting an appropriate retail rate) was never seriously challenged by the MPUC, and thus there was no serious "federal question" warranting Supreme Court review. The Supreme Court denied the states' petition for certiorari without comment, and thus left standing the NSP contention that absent a showing to the contrary, the State was preempted from adjusting the wholesale rate by virtue of FERC's exclusive jurisdiction.

The Pike County Case

In a fairly significant departure from the general rule concerning federal preemption articulated by the Courts in the Narragansett and Eastern Edison cases, a recent decision by the Pennsylvania Commonwealth Court concluded that state regulatory commissions may selectively inquire into the "reasonableness" of a wholesale sale for which FERC has

approved the rate. In the case of Pike County Light & Power Co. vs. Pennsylvania Public Utility Commission⁴⁰ the Court held that although the Commission is precluded from passing on the propriety of the FERC rate, it may ascertain whether the purchasing utility exercised prudence in deciding to purchase power at the rate subsequently approved.

Pike County Light and Power Company (Pike) is a subsidiary of Orange and Rockland Utilities which provides Pike with its bulk power supplies under a wholesale agreement filed with the FERC. In a state investigation of a proposed retail tariff supplement filed by Pike, an Administrative Law Judge found that Pike's exclusive reliance on Orange and Rockland as a source of wholesale power was "imprudent" in that more economical supplies of electricity were available from other sources. The State Commission adopted the Judge's findings, and Pike appealed to the Commonwealth Court.

On appeal, Pike argued that the Commission's order was barred by federal preemption under the Federal Power Act. The Pennsylvania Court affirmed the State Commission's reasoning that it was the state's prerogative to inquire into the reasonableness of a utility's purchased power costs in the light of cheaper available alternatives. The Court agreed that the Commission's actions were justified on the basis that its investigation proceeded not from an analysis of the supplier's (i.e., Orange and Rockland's) cost-of-service data, but rather from an analysis of Pike's cost of service. The Court observed that whereas FERC determines the reasonableness of a particular wholesale rate by analyzing the supplier's costs, the state commission determines whether it is reasonable for the buyer to purchase the power at that price in

light of other available sources. In effect, the Court appeared to be saying that FERC approval only indicated that it was reasonable for those rates to be charged by the supplier not that it was reasonable for the purchaser to incur the expense. Therefore, the purchased power expenses were not automatically deemed reasonable as a matter of law, and their disallowance by the State Commission did not constitute a violation of due process nor was it precluded by federal preemption under the Narragansett rule.⁴¹

While there have been differing interpretations of the Pike County decision, on the surface it would appear to conflict with prior court decisions holding that elements of a FERC approved rate must be deemed reasonable for retail ratemaking purposes regardless of State commission opinion as to a utility's prudence or imprudence in purchasing power from a wholesale supplier.

There are several considerations which might suggest that while deviating from prior decisions, Pike County does not constitute a major departure from Narragansett. For example, the Court's decision in Pike accepted the Narragansett rule but explained its waiver of federal preemption by giving equal credence to the state's basic ratemaking statute authorizing the State Commission to investigate all aspects of the utility's retail cost of service. Such a rationale, however, can be challenged since it would effectively allow a state to take pro-forma notice of FERC's action in approving a particular wholesale rate filing but effectively nullify that outcome by disallowing those costs for retail ratemaking purposes. Some have also suggested that the Court's decision in Pike might somehow have been influenced by the affiliate

relationship between supplier and purchaser. Again, this line of reasoning may fail because of the essentially equivalent circumstances in prior cases where federal preemption was upheld.

In commenting on the Pike decision, one observer concluded as follows:⁴²

"The question remains whether Pike is a landmark case that reflects the recent trend in an area of federal preemption or is merely an error--an anomaly opposite from the [Narragansett and Eastern Edison] rules. Recent trends in constitutional law concerning the preemption of state regulation by federal agencies, through the Supremacy Clause, suggest that the answer to the question is the latter."

Other observers, however, are not as certain and believe that several recent decisions by the U.S. Supreme Court (discussed below) may also signal a willingness to provide state commissions with limited discretion to selectively encroach on regulatory matters previously thought to be reserved to federal agencies under the Commerce Clause.⁴³ In particular, the Pike case was decided after the Arkansas Electric Cooperative case (discussed below). The latter may, in part, explain the Pike decision. Indeed, the Pike decision cites the Arkansas case in relation to the scope of state jurisdiction. In effect, the Supreme Court may be signaling that whereas FERC approves the rate for sale it is not making any judgment on the reasonableness of the purchase or the price being paid by the purchaser relative to other alternatives. If this view turns out to be the case, Pike would reflect a slight narrowing of the preemption rule arising from Narragansett. In the remainder of this section, we shall examine several other recent decisions in the context of the federal/state jurisdictional issue and the extent of federal preemption in state consideration of wholesale bulk power supply costs.

The Concept of "Shared Jurisdiction"
in Recent Supreme Court Decisions

In three recent decisions with potentially far-reaching consequences, the U.S. Supreme Court has reexamined the respective roles of the state and federal governments in the regulation of the electric utility industry. In the cases of FERC vs. Mississippi⁴⁴ and in Arkansas Electric Cooperative Corp. vs. Arkansas Public Service Commission,⁴⁵ the Court may have blurred the long-standing "bright-line" rule traditionally used to distinguish between the relative spheres of state and federal regulatory authority over retail electric rates but did not substantially modify the Attleboro rule specifically as it affects the wholesale/retail distinction. The Court also ruled, in Pacific Gas & Electric Co. vs. State Energy Resources Conservation and Development Commission⁴⁶ that the construction and operation of nuclear power plants are not subject to the exclusive jurisdiction of the Nuclear Regulatory Commission under the Atomic Energy Act. As a result of these decisions, a more complex pattern of regulation appears to be evolving, which may allow the states to become involved in regulating matters once viewed as exclusive federal domain but where the scope of federal preemption is not absolute under relevant statutes.

The Arkansas case involved the Arkansas Electric Cooperative Corporation (AECC) a rural electric cooperative, established under the Rural Electrification Act of 1936. AECC is a generation and transmission (G&T) cooperative providing wholesale bulk power to its members who in turn provide retail electric service to rural consumers. Most of AECC's electricity is generated in Arkansas and is sold within the state to members, although AECC is also interconnected to other regional

utilities and engages in coordination transactions (which under Colton and subsequent decisions would place all of AECC's sales in interstate commerce).

In 1979, the Arkansas Public Service Commission (PSC) attempted to assert jurisdiction over AECC's rates for sales to local distribution cooperatives, relying on the same Arkansas statutes that authorize it to regulate retail rates of rural electric cooperatives within the state. AECC objected, but the PSC overruled the objections, holding both that its assertion of jurisdiction was consistent with Attleboro and that state jurisdiction was not preempted either by FERC or the Rural Electrification Administration (REA).

A lower Arkansas Court set aside the PSC's order, but the Arkansas Supreme Court upheld the order asserting jurisdiction, concluding that, even though the AECC sales at issue were at wholesale and involved some interstate electricity, the business nonetheless was "decidedly local, having its paramount impacts and consequences in Arkansas and having little or no relation to any other place."⁴⁷

AECC, joined by other rural cooperatives and the REA, appealed to the U.S. Supreme Court arguing both that the Arkansas PSC's jurisdiction was preempted by the Federal Power Act and the Rural Electrification Act, and that in any event, the PSC's assertion of jurisdiction imposed a burden on interstate commerce.

The Court rejected both arguments, and in what some have construed as a departure from Colton, it ruled that a state may sometimes regulate wholesale electric power transactions in interstate electricity. Such regulation, according to the Court, is permissible if Congress did not

intend to preempt state regulation and if the burden on interstate commerce is incidental and "not clearly excessive in relation to the putative local benefits" of state regulation.

On the preemption issue, the Supreme Court readily concluded that state regulation of rural electric cooperatives was preempted neither by the Federal Power Act nor by the Rural Electrification Act (i.e., FERC had deferred to the REA and the latter had adopted a policy of requiring borrowers to submit proposed rate changes for state agency approval).

The constitutional issues dealing with interstate commerce provided more difficult determinations for the Court, especially in view of the seemingly controlling Attleboro precedent. Indeed, the Supreme Court candidly acknowledged at the outset of its discussion in the Arkansas case that:⁴⁸

"If the constitutional rule articulated in Attleboro were applied in this case, it would require setting aside the Arkansas PSC's assertion of jurisdiction over AECC, since AECC, like the electric utility in Attleboro, sells at wholesale electric energy transmitted in interstate commerce."

The Arkansas PSC had attempted to distinguish its effort to assert jurisdiction from Attleboro on the factual ground that the latter case involved a wholesale transaction with an out-of-state distributor whereas all of AECC's sales were to "local" distributors (and its interstate coordination transactions were "incidental" to this purpose). The Supreme Court, however, adopted a more sweeping approach to the problem of the Attleboro precedent. It noted that its approach to Commerce Clause cases had changed in the 50 years since Attleboro, and that the mechanical, or "bright-line," (wholesale/retail test) of Narragansett has become "anachronistic." The Court observed that the

Attleboro rule was established at a time when the Court was the sole authority safeguarding federal interests in the area of state utility regulation. The Court stated:⁴⁹

"Attleboro can no longer be thought to provide the sole standard by which to decide this case, and we proceed instead to undertake an analysis grounded more solidly in our modern cases."

In rejecting Attleboro, the Court substituted what it characterized as a "more flexible standard" which necessitates consideration in each case of "the nature of the state regulation involved, the objective of the state, and the effect of the regulation upon the national interest in the commerce." The relevant test in this case, the Court said, was that articulated in the case of Pike vs. Bruce Church Inc., which provided:⁵⁰

"Where [a] statute regulates evenhandedly to effectuate a legitimate local public interest, and its effects on interstate commerce are only incidental, it will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits. If a legitimate local purpose is found, then the question becomes one of degree and the extent of the burden that will be tolerated will, of course, depend on the nature of the local interest involved and in whether it could be promoted as well with a lesser impact on interstate activities."

In applying this test to the AECC situation, the Court found:⁵¹

- (1) The Arkansas PSC's assertion of jurisdiction was "evenhanded."
- (2) The regulation of AECC's rates was a matter of legitimate local public interest since as the Court noted, "AECC's basic operation consists of supplying power from generating facilities located within the State to member cooperatives, all of whom are located within the State."
- (3) The burden that PSC regulation might impose on interstate commerce was only incidental and "not clearly excessive in relation to the putative local benefits" (i.e., even though small amounts of power sold by AECC was received from out of state, the same was true of power sold at retail by investor-owned electric utilities clearly subject to state regulatory jurisdiction).

The AECC case, however, is only one of several recent Supreme Court decisions that some have argued have the effect of blurring traditional lines between state and federal authority in areas of interest to electric utilities. In the 1982 case of FERC vs. Mississippi, the Court upheld the authority of Congress, in the Public Utility Regulatory Policies Act (PURPA) to require state utility commissions to consider federal ratemaking standards in carrying out their retail regulatory activities. Whereas the Arkansas decision endorsed state involvement in a subject matter (i.e., wholesale rate regulation) that had previously been thought to be of exclusive federal concern, the Mississippi decision appeared to endorse federal involvement in a subject matter that was previously viewed as exclusively a matter of state concern. Although the view was expressed in Attleboro that regulation of retail electric rates had "merely an incidental effect upon interstate commerce," the Court concluded in the Mississippi case that Congress could prescribe national policy with respect to retail sales of electricity because "[It] is difficult to conceive of a more basic element of interstate commerce than electric energy."⁵² Thus, the Court appeared to suggest that both federal and state interests were involved in retail electric rate regulation--notwithstanding the wholesale vs. retail nature of the transaction.

In the view of some observers, these decisions by the Court appeared to reflect an evolving concept of shared--and perhaps even overlapping--regulatory responsibility for the electric utility industry, with more emphasis on balancing of competing interests and little or no reliance on mechanical tests. This view, some would argue, is

supported by the Supreme Court's most recent decision in a case involving California efforts to place a moratorium on the construction of nuclear power plants. In Pacific Gas & Electric Co. vs. State Energy Resources Conservation and Development Commission, the Court concluded that although the Atomic Energy Act preempts state action with respect to nuclear safety, it does not do so with respect to economic and other aspects of nuclear power. Since the California statute at issue in the case involved economic and not safety concerns, the Court held that it was not preempted by the federal statute. In this sense, the Court decision in Pacific Gas & Electric was consistent with its decision in Arkansas in terms of its more flexible approach to the jurisdictional issue where pervasive federal preemption was not clearly established.

Current Status of the Preemption Debate

It would be incorrect to conclude from the three cases discussed above that the Supreme Court was declaring "open season" on FERC's wholesale rate jurisdiction in terms of opening the field to comprehensive state oversight. Rather, it simply recognized the jurisdictional issue may not always be as clear as the Attleboro "bright-line" would suggest and that in certain situations (e.g., wholesale sales by non-jurisdictional utilities) the scope of federal statutory authority did not explicitly preempt the exercise of collateral state jurisdiction. In other cases, however, where the statute is relatively unambiguous concerning federal preemption (as would likely be the case for most wholesale bulk power transactions involving investor-owned utilities) nothing in these decisions suggests any substantial retreat from the

Narragansett rule restricting the authority of state commissions to examine the reasonableness of wholesale rates filed with the FERC.

Indeed, in the previously referenced Northern States case, which followed closely after the three cases noted above, the Supreme Court refused to review a Minnesota Supreme Court decision which struck down efforts by the Minnesota DPU to exercise oversight of a FERC approved wholesale rate. This decision by the U.S. Supreme Court to deny a writ of certiorari in Northern States means that the Court has not addressed the scope of the Narragansett rule especially in those areas where federal wholesale rate authority is clear and thus presumably preemptive.

A similar view was recently expressed by the U.S. Court of Appeals in the case of Middle South Energy, Inc. et al. vs. Arkansas Public Service Commission et al., in which the Federal District Court issued a judgment permanently enjoining Arkansas Public Service Commission from conducting further proceedings in a state administrative action requiring Arkansas Power and Light Company to show cause why the various contracts requiring it to purchase power from or pay for the construction of the Grand Gulf Project should not be voided.⁵³ The Court concluded that because the "subject agreements were inextricably bound to the wholesale sale of power in interstate commerce, they are subject to the exclusive jurisdiction of the FERC" under the Narragansett doctrine. (The jurisdictional implications of cost equalization provisions in holding company pooling agreements, such as the ones affecting Arkansas Power and Light Company, are discussed in Chapter 6.)

While the general thrust of recent federal court decisions is to preempt the states in matters relating to bulk power sales made pursuant

to FERC approved wholesale rate schedules, there is still a "gray area" relating to the scope of state authority to consider the prudence of the costs incurred by the purchasers in such transactions. As noted above in the context of the Pike County case, a state court has held that state regulators are not preempted from inquiring into the reasonableness of a wholesale transaction from the purchaser's perspective. In Pike County the Court noted that a FERC-approved tariff only addresses the reasonableness of a wholesale transaction from the perspective of the seller's costs and thus does not constitute a finding of reasonableness relative to the purchaser.

A similar line of argument was reflected in recent decisions by the Massachusetts Department of Public Utilities (DPU) and the Wyoming Supreme Court. In the Massachusetts case, the DPU ordered the Commonwealth Electric Company and Cambridge Electric Light Company to refund the CWIP portion of the revenues collected under a FERC-approved rate schedule for the purchase of Seabrook Unit 1 capacity.⁵⁴ The DPU, after reviewing relevant precedent, concluded that its authority to review the capacity purchase contract between Canal Electric Company and its affiliates, Commonwealth Electric and Cambridge Electric, was not preempted by FERC's acceptance of the contract as an initial rate. Hence, it held that it had the authority to determine the prudence of costs incurred by the purchasing utilities under that contract. This decision is being appealed by the relevant utilities and should provide further insight as to the scope of FERC preemption--specifically as it relates to the rate paid by the purchaser.

In the most recent of an emerging line of state cases dealing with the jurisdictional issue, the Wyoming Supreme Court, in the case of Spence vs. Smyth et al., has ruled that FERC approval of any wholesale electric rate increase requires a state commission to treat the pass-through increase as a reasonable operating expense at the intrastate retail level and that the state commission may not independently investigate the reasonableness of the wholesale rates. In this sense, the Wyoming decision is consistent with Narragansett and other court decisions affirming FERC preemption on the issue of the "reasonableness" of the wholesale rate. However, the Wyoming court also agreed with Pike County, and Massachusetts DPU decisions noted above, that assert the right of the state commission to disallow cost recovery for power purchased at FERC-approved rates on the narrow distinction that the state has independent jurisdiction to determine that the decision of management to purchase power was imprudent or arbitrary in the first place.

The state decisions noted above could signal a weakening of the Narragansett doctrine and substantially reduce the incentives discussed in the following chapters for utilities to restructure themselves in ways which would shift regulatory jurisdiction over their bulk power supply costs to the FERC (i.e., since the states could still exercise jurisdiction over the purchaser's end of the transaction). Future developments in this area are likely to be determined by federal court review of this emerging line of decisions on the scope of state regulatory jurisdiction under Narragansett.

CHAPTER 4

THE REGULATORY ENVIRONMENTS AT THE FERC AND STATE COMMISSIONS AS A FACTOR IN JURISDICTIONAL TRANSFER

Introduction

There have been minor differences in ratemaking policy exercised at the state versus federal level almost since the enactment of the Federal Power Act of 1935. However, in recent years the regulatory climate at the FERC is perceived by many as having become increasingly more favorable from the standpoint of the regulated utilities as compared with the climate at many state regulatory commissions. This is, in part, because of a perceived trend toward more favorable rules and ratemaking policies established by the FERC and in part because of a trend toward less favorable rules and policies established by state commissions in response to ratepayers concerns over the rising costs of electricity. In this chapter, some examples of these differences are described and some of the reasons for these increasingly divergent policy outcomes are set forth as a basis for understanding the growing incentives for a utility to seek transfer of regulatory jurisdiction from the state to the federal level. In Chapter 5 we examine some of the financial risk considerations which also could indirectly result in a utility increasingly coming under FERC jurisdiction.

Examples of Differences in Policies and Practices

The belief in more favorable regulation by the FERC is more than an abstract proposition. Specific examples of differences in ratemaking policies and practices as between the FERC and most state commissions which demonstrate this notion include: (1) suspension periods, (2) fuel cost adjustment clauses, (3) test years, (4) treatment of construction work in progress, (5) treatment of cancellation costs, and (6) treatment of excess capacity. Federal versus state policy with respect to each of these ratemaking issues is outlined below to illustrate some of the incentives which have evolved for a utility to come under FERC jurisdiction.

Suspension Periods

One of the more attractive features of wholesale electric rate regulation by the FERC relates to regulatory lag. The delay in granting proposed rate increases is an important source of earnings attrition. The Federal Power Act provides that the Commission may not suspend a proposed rate increase for more than five months. At the expiration of the suspension period, the increase must be permitted to go into effect subject to refund with interest. The Commission has determined in West Texas Utilities (1982) that in any case in which proposed rates exceed the FERC Staff's preliminary cost of service by more than 10 percent, it will suspend the increase for the full five months; otherwise, it will suspend for no more than one day.

Some utilities have sought recently to avoid the more significant effects of suspension by filing dual rate increase proposals. Under Commission rules, one of the two rate schedules can be filed for a

partial amount that will almost assuredly satisfy the Staff's preliminary analysis (using the "10 percent rule") and if intervenors object to the increase, therefore be suspended for only one day. The second rate increase can be filed for the full amount which the utility believes itself actually entitled to receive. Thus, if the latter is suspended for the full five-month period, the utility will at least be collecting the smaller increase under the other filing during that five month period.⁵⁶ By permitting such dual filings, the FERC has reduced significantly the adverse impact of regulatory lag for electric utilities. It is, of course, true that if a proposed rate increase is suspended and set for hearing, it may be a matter of several years before a final commission order is issued. The impact of this lag is mitigated, however, by the fact that a substantial portion of the proposed rates are collected subject to refund during this period. In addition, the Commission and its Administrative Law Judges have been making extensive (and at least partially successful) efforts to reduce the time required for litigation of formal cases through such mechanisms as use of a generic rate-of-return procedure.

Proposed retail rate increases, subject to state commission jurisdiction, require a substantially longer period (generally 9 to 12 months) between the time a proposed rate increase is filed and the time when the rates can begin to be collected from ratepayers. In part, this stems from a greater reluctance to permit rates to be collected (even if subject to refund) that have not been found just and reasonable after hearing. In part, it reflects the greater difficulty (both administrative and political) of making refunds to hundreds of thousands of

relatively mobile retail customers than to a much smaller number of non-mobile wholesale customers. In some instances, state commissions have sought to mitigate this problem by way of intermediate orders granting partial or emergency rate relief. Nevertheless, as a general proposition, regulatory lag and resultant earnings attrition have been much more severe at the state level than at the FERC.

Fuel Cost Adjustment Clauses

The FPC/FERC has for many years permitted utilities to include clauses in their wholesale rate schedules designed to automatically adjust charges to customers in response to changes in fuel costs. In 1974 the FPC revised that portion of its regulations⁵⁷ dealing with fuel clauses, providing specific guidance as to the principles that were to be followed in the development of an acceptable fuel clause.⁵⁸ Clauses filed in accordance with the rule enable utilities to pass through to customers on a current basis changes in fuel costs and related taxes. In a further modification of the rule, promulgated in 1984, the section of the rule dealing with the treatment of purchased power was revised to permit utilities to pass through the total cost of purchased "economic power."⁵⁹ Under the prior rule, however, pass-through of purchased power costs had been limited to net energy cost of energy purchased on an economic dispatch basis. Thus the FERC now has in place a fuel adjustment regulation that is perhaps as favorable to utilities as any that is applicable to retail rates anywhere in the country.⁶⁰

In contrast, such comprehensive fuel adjustment clauses are not applied to retail rates in a number of states. Where they are permitted, they have often been encumbered with various provisions designed to

create incentives to minimize fuel costs and improve efficiency such as provisions allowing something less than 100 percent pass-through. In some cases, revised charges reflecting changes in fuel costs may not be made effective until commission approval at interim hearings. In other cases, utilities are limited in full recovery of purchased power costs or in costs incurred in controlling pollution problems stemming from use of selected fuels.

Future Test Year

During a period of inflation, it is generally advantageous for a utility to utilize a test year that is as current as possible. Otherwise, the rates will be inadequate to cover the costs incurred during the period the rates are in effect, and the actual rate of return to stockholders will fall below that which was authorized by the state commission. Such "earnings attrition" became especially pronounced during the rapid inflation of the late 1970's and early 1980's, and remains a matter of real concern at the present time.⁶¹

Over a decade ago, the FPC revised its regulations to require the use of future years in most wholesale rate increase filings.⁶² Under present rules, the test year for wholesale rate purposes may begin up to three months beyond the date that the new rates are proposed to become effective. In contrast, most state regulatory commissions continue to employ test periods that are largely or entirely historical, although a few state commissions such as those in New York, Minnesota, and Iowa employ test periods based on projections in whole or in part of future costs.⁶³ While nearly all state commissions allow adjustments to historical costs for "known and measurable changes" such as annualization of

the effect of a wage increase that went into effect during the test year, they are generally not prepared to permit rates to be based on costs projected to be incurred during the period the new rates are in effect. The difficulties for utilities arising from such an approach are especially severe during periods of high inflation such as experienced in the late 1970's and early 1980's.

Construction Work in Progress (CWIP)

The most recent example of a difference in ratemaking treatment between state regulatory agencies and the FERC relates to the issue of whether CWIP should be included in rate base. This issue has become particularly significant in recent years because of the number of utilities with large plants under construction. Some have found it quite difficult to continue the financing of these projects in the absence of current cash earnings derived from inclusion of such projects in rate base.

On May 16, 1983 FERC issued a Final Rule⁶⁴ establishing its policy concerning treatment of CWIP. It provides that any public utility engaged in the sale of electric power for resale may include in rate base (in addition to all CWIP associated with pollution control and fuel conversion facilities as previously permitted) up to 50 percent of all other CWIP, subject to a rate impact limitation in the first two years.⁶⁵

Among the state commissions, there is great variation in the treatment accorded CWIP. According to a recent Edison Electric Institute summary,⁶⁶ 11 states allow no CWIP in rate base, 12 states require a full or partial AFUDC offset to any CWIP permitted in rate base, and

another eight states have required some level of AFUDC offset in some cases. Of the 18 states reported to have allowed some CWIP in rate base without AFUDC, all were partial allowances.

Treatment of Cancellation Costs

The rash of cancellations of large (mostly nuclear) power plants that has occurred in recent years has raised to some prominence the issue of the rate treatment to be accorded the costs associated with the partially constructed units. FERC's policy with regard to this issue, where there was no FERC finding of imprudence relating to the incurrence of these costs, was set forth in a 1979 decision involving New England Power Company.⁶⁷ The Commission permitted a five year amortization of 100 percent of the gross loss, although it did not permit rate base treatment of the unamortized loss. Except for one case, involving a relatively small amount of construction costs,⁶⁸ the Commission has not denied any recovery of cancellation costs based on imprudence.

The state commissions have tended to treat cancellation costs--even where there were no findings of imprudence--somewhat less favorably from the standpoint of the utilities. In a few cases, they have refused to permit any amortization of cancellation losses.⁶⁹ Cancellation costs have been amortized over periods as long as 10 to 15 years at the state level, whereas the FERC has more often accepted amortization periods of five years.⁷⁰ A longer amortization period, of course, is equivalent to the allowance of a smaller proportion of total cancellation costs where rate base treatment is denied. In the Tyrone case, the FERC permitted a variable amortization of between five and ten years whereas the Public Service Commissions of Minnesota, North Dakota, and South Dakota argued

for a 30-year amortization period for costs associated with the same plant.⁷¹ In a few cases the amount of the cancellation costs subject to recovery through amortization was reduced by the amount of AFUDC that had been accumulated. Finally, some state commissions have found some part of the claimed cancellation costs to have been incurred imprudently and disallowed recovery of such costs.⁷²

Treatment of Excess Capacity

The regulatory issue that has caused perhaps the most concern among many utilities in recent years has been the ratemaking treatment accorded by state commissions of generating capacity in excess of that which is required to meet peak load and provide a reasonable reserve margin. Declining rates of load growth have left many utilities with varying amounts of such short-term "excess capacity," often occurring in conjunction with the recent addition of a large coal or nuclear plant having a relatively high cost per kW.

Several state commissions have reduced rate base to reflect such "excess capacity," although in nearly all instances, the effect of this treatment has been mitigated to some extent either by permitting continued AFUDC until the plant is included in rate base, or by some procedure that effects a "sharing" of the burden between ratepayers and stockholders. The Iatan case in Missouri was one of the more widely publicized recent instances of rate base exclusion of a completed plant by a state regulatory agency on the grounds of "excess capacity." The most common device for such sharing is to permit no return (and associated taxes) on the common stock equity portion of that part of the rate base deemed by regulators to represent "excess capacity."

Perhaps the most extreme treatment of alleged "excess capacity" was accorded Montana Power Company's 30 percent share of Colstrip Unit No. 3 (a large coal-fired unit) by the Montana Public Service Commission (MPSC) in a case decided August 3, 1984.⁷³ In that case the MPSC determined that the unit was not "actually used and useful" as required by statute and eliminated the entire unit from the rate base. No provision was made for continued AFUDC or for other mitigation of the rate base deduction. This treatment was justified by the MPSC primarily on the basis of a "competitive marketplace standard," i.e., that the total per kWh cost of Colstrip No. 3 was in excess of the current price of alternative source of power in the region. The Massachusetts Department of Public Utilities has also indicated that it intends to deny any recovery of costs associated with incomplete or abandoned plant notwithstanding "prudence considerations".⁷⁴ The Massachusetts decision placing investors at risk for the total costs incurred in plant abandonment is prospective, however, as compared with the retroactive application of the competitive standard in Montana and what utilities have alleged is the exercise of "20/20" hindsight in other cases where they were penalized for "excess capacity."

Up to this point, the FERC has not reduced rate base as a result of a finding of "excess capacity" in any case, perhaps because the matter has not yet become an issue. It may become an issue, however, in a case filed recently by Montana Power Company involving wholesale rates to a cooperative in Montana. In this case the FERC may have to face the same set of issues dealt with by the MPSC either directly or in response to a price squeeze allegation.

Basis for the Growing Differences
in FERC Versus State Regulation

The reasons for the above outlined differences in regulatory treatment between the FERC and the state commissions are to be found partly in the types of customers whose service is regulated, partly in the proportion of total service regulated, and partly in the locus of the jurisdiction. For example, in reviewing a fuel adjustment clause, a state commission regulating 90 percent of the revenues of an electric utility needs to be concerned about the effect of the formula for cost pass-through on the incentives of the utility to minimize costs. The FERC, regulating only 10 percent of the revenues of the same utility, can presumably be more sanguine in permitting full pass-through without provisions designed to assure cost-minimization incentives. This is because the FERC can have some assurance that the incentives of the utility will be driven by the state fuel clause affecting 90 percent of its rates and that therefore the FERC fuel clause will have little or no impact on the utility's fuel procurement policies and practices.

The wholesale customers of an electric utility are in the electric power business themselves and are therefore likely to be not only more sophisticated in the structure, operation, terminology, technology, and economics of the utility industry, but also (in theory) more sympathetic to at least some of its problems. For example, while retail customers in many jurisdictions have objected vigorously to any fuel cost adjustment mechanism, such opposition is much less common among wholesale customers since most of these utilities have themselves incorporated fuel clauses in their retail rates. For similar reasons, wholesale customers are less likely to insist on removal from rate base of

reasonable amounts of temporary "excess capacity" or to object to amortization of prudently incurred cancellation costs. Wholesale customers are also less likely to oppose an increase in the level of rates simply on the ground that the rates are already "too high" as is often alleged in retail rate proceedings, or that the rates will be higher than rates paid by the customers of an adjoining utility, regardless of the level of earnings to the utility that present rates allow.

The differences in suspension procedures, in part at least, also reflect the differences between numbers and types of wholesale versus retail customers. It is relatively easy for a utility to keep track of refunds due to a few wholesale customers and to locate and reimburse them if a refund is ordered. While computers have greatly simplified the process, it is still costly to keep track of refunds due to hundreds of thousands and sometimes millions of customers in various retail classes. It may be far more costly to locate and reimburse them if a refund is ordered. Finally, it is much more difficult to explain to retail customers than to wholesale customers why they should have to pay rates (even temporarily) that have not been formally approved by the regulatory commission.

In addition to the differences in the types of service regulated and the types of customers served, it is also apparent that the more direct relation between state commissions, retail customers, and utilities has been a factor in the growing differences between state and federal regulation. The FERC is located in Washington, D.C., while the state commissions are located much closer to the ratepayers. The FERC Commissioners almost never hear a rate case directly and rarely hold

oral argument in a rate case. In contrast, it is common practice for state commissioners to hear cases directly. While this may not give them any better grasp of the technical issues involved, it does give them a better feel for the economic, social, and political problems resulting from higher rates. In addition, it puts the state commissioners into direct contact with the representatives of increasingly well-funded citizens groups, business groups, environmental groups, and public advocates that have been growing recently in both numbers and their sophistication in dealing with electric power issues.⁷⁵ These considerations, combined with the nature of the appointment process make state commissioners in retail rate proceedings much more sensitive to local political concerns. At the FERC, even the Administrative Law Judges (ALJ) deal primarily with counsel (usually Washington-based) in rendering initial decisions in rate cases. The FERC Commissioners deal primarily with briefs or exceptions filed to ALJ decisions and have little direct contact with the general public affected by their decisions.

A final factor that has probably had some effect on the growing differences on state and federal policies is the relation of FERC electric rate regulation to national energy policy objectives. There is a concern within the Department of Energy (DOE) and elsewhere within the Administration that overly restrictive regulation can create disincentives for utilities to make the necessary investments to assure adequate, reliable service in the years ahead.⁷⁶ There is also a desire to lessen federal regulatory burdens wherever possible. DOE, however, is caught between its rhetorical support for more responsive state

regulation and a strong philosophical position within the Administration opposing any form of federal preemption of state ratemaking authority--whatever the outcome of the latter. Federal policy concerns are thus limited to being expressed in low-profile presentations advocating more favorable regulatory treatment for utilities in both state and federal regulatory proceedings. These efforts, however, are more likely to register at the federal level than at the state level. Also, federal officials still view FERC as a potential "role model" whose regulatory policies are to be emulated at the state level. Indeed, this argument has been repeatedly made in numerous rulemakings before the FERC including those dealing with a generic rate of return for wholesale ratemaking and the new rule on treatment of construction work in progress. In each case, those supporting the proposed changes in the Commission's rule cited the positive "spill-over" benefits of having similar "progressive" ratemaking policies adopted at the state level.⁷⁷ As a practical matter, however, there is little evidence in recent years suggesting that state commissions actually look to the FERC for policy guidance on key ratemaking issues.

CHAPTER 5

PROBLEMS OF FINANCING NEW GENERATING FACILITIES AS A FACTOR IN JURISDICTIONAL TRANSFER

Introduction

Recent cancellations of a number of plants under construction coupled with severe financial problems affecting those utilities struggling to complete the large plants still under construction have occupied much of the attention of industry executives, utility regulators, and members of the financial community. This short-term focus on getting plants under construction into commercial service has tended to defer serious consideration of the long-term problem of how the industry will meet the need for new generating capacity in the 1980's and beyond.

While there will be an increasing reliance on industrial cogeneration and a variety of dispersed (renewable) power sources, most utilities believe that the major share of new capacity in this period is still likely to be in the form of central-station coal and possibly smaller scale nuclear powerplants--each costing in excess of a billion dollars. New ownership arrangements are being examined as a means of sharing risks and getting new plants built. Such efforts to implement innovative approaches to financing needed capacity could also have the corollary effect of transferring jurisdiction over such facilities from the state to the federal level. Such an outcome would also tend to offset the growing feeling among utilities that "unpredictable" and

sometimes "unfair" state regulation is itself a principal source of risk that must somehow be dealt with in the design of new approaches to powerplant development. In this section, we shall examine how utility efforts to deal with the risks of new powerplant construction could affect the allocation of regulatory responsibility between the state and federal levels.

Problems in Financing New Plant

Because of the growing financial and regulatory risks associated with constructing any large new generating facility, the possibility exists that even some of the larger investor-owned utilities will be reluctant to initiate new construction without some means of reducing these risks to more acceptable levels.⁷⁸ This gives rise to the growing emphasis on developing innovative ownership forms and institutional mechanisms to allow such "risk-sharing" in new plant construction. (There may also be some limited opportunity for adapting such risk sharing measures to units already under construction or those which have been deferred; but the thrust of this discussion will be on new facilities and how such approaches will relate to the jurisdictional concerns of state regulatory agencies.)

Another threshold consideration is the distinction between risk sharing during the construction phase of a new power plant and risk-sharing during the commercial operation stage. In recent years, both have become important concerns to utilities. For purposes of this discussion, however, we focus on the considerably greater level of risks during the planning, design, construction, and licensing phases of new generating facilities and how efforts by utilities to minimize and

spread such risks might affect the jurisdiction of state commissions over such facilities.

A final consideration is the identity of those entities with which the risks of new facility construction may be shared. These include: (1) other investor-owned utilities, (2) other publicly or cooperatively-owned utilities, (3) independent (non-utility) investors such as vendors, architect-engineers, etc. (4) ratepayers, and (5) agencies of federal, state, and local government (other than publicly-owned utilities).

Alternative Approaches to Risk Sharing

To some degree, each of the approaches to risk sharing mentioned above has been adopted or at least considered at some point in time in the context of existing plants and has some application to future project financing needs. For example, to the extent that losses stemming from cancellation of proposed powerplants are deductible for federal and state tax purposes, and to the extent that the constructing utility has taxable income from other sources, there is already a "sharing" of the risks of cancellation with the Federal Government (by virtue of tax write-offs which allow the utility to reduce its taxable income by the amount of losses.) In such cases, there are no direct jurisdictional implications other than IRS guidelines which direct the ratemaking treatment of selected tax benefits (e.g., investment tax credits).

In a limited sense, risks are also "shared" with utility ratepayers to the extent that Construction Work in Progress (CWIP) is included in rate base (assuming future commissions adhere to a policy of allowing

recovery of construction costs if cancellation subsequently becomes necessary) or to the degree that the full costs of abandoned plant are recoverable from ratepayers (an uncertain proposition).

Some utilities have attempted to restructure themselves in a manner wherein the major segments of their electric power operations (i.e., generation and transmission, distribution, and fuel supply) are structured as separate entities with similar risk profiles and financing needs. The New England Electric System is typical of these holding-company structures, although many other utilities have adopted or are exploring similar corporate organizations where inter-affiliate power sales are subject to FERC rather than state jurisdiction.

The risks associated with new power plants are already being shared among investor-owned utilities (as well as among municipal and cooperative systems) by means of various kinds of joint-ownership arrangements which are discussed in greater detail in the concluding sections of this report. The three principal types of joint ownership arrangements relevant to investor-owned systems are (1) jointly-owned stock companies, (2) tenancies-in-common, and (3) the ESPRI Model (The distinctions between these alternatives are discussed in greater detail in Chapter 6). Among the principal examples of the joint stock company form are the four Yankee nuclear organizations in New England and the recently created corporate entity designed to allow completion of Seabrook Unit No. 1. In each of these cases, the common stock of the company is owned by the various participating utilities while outstanding debt is distributed among independent investors. Entitlements to power from the projects are allocated to participants in direct

proportion to common stock subscriptions. Thus, financial risk is shared not only with the other participants in the stock ownership of the company but also with the bond holders as well.

Tenancy-in-common is another joint-ownership option available to utilities whereby they can spread the risk of new powerplant construction but not necessarily transfer regulatory jurisdiction to the federal level. Under this arrangement, participants own undivided interests in direct proportion to their investment in the project. Examples of this type of ownership approach include several large coal-fired powerplants built in the western states, the proposed Sterling Nuclear Plant, and recent joint ownership arrangements for generating and transmission facilities negotiated among subsidiaries of the Southern Company and a group of cooperatives and municipal systems in Georgia. Among the various organizational approaches to risk-sharing through joint-ownership, tenancies-in-common are by far the most prevalent.

Another innovative approach to risk sharing is the ESPRI concept which was proposed by seven New York utilities in the mid-1970's and which would have provided for the creation of a new stock company to be jointly-owned by all of the participating utilities. The ESPRI approach differed from the joint stock company noted above in several important areas including being restricted to utilities within a single state, providing a financing vehicle for constructing multiple plants, and sponsor exposure to joint and several liability.

The principal benefits of the ESPRI approach included higher leverage and lower-cost financing, greater financial flexibility, assurance against all risks, and economies of scale in plant design and

operation. As discussed below, its rejection by the state reflected regulatory concerns over both the loss of jurisdiction to the FERC as well as failure of the proposed "all events" tariff structure to provide adequate incentives for efficient construction and operation of new plants built by ESPRI. (An "all events" tariff assures recovery of project costs through rates paid by utility customers even in the event of the non-completion or the failure of the project to perform as projected.) It is fair to assume that these objections (which made the concept so attractive from a financial perspective) would arise in the context of any future proposals for ESPRI-type generating corporations.

Other proposals for various types of regional generating companies have appeared in the literature and in recent studies of industry structure. Most of these proposals involve an extension of the basic ESPRI concept for building large scale baseload powerplants to serve the needs of utilities in a multistate region. The financial risks in such projects, as discussed in the next section, would be shared not only by including a large number of utilities as participants in the regional generating company, but also through the sale of debt at lower cost (as well as possible sale of equity interests to private investors).

Another extension of a form of risk sharing incorporated in the ESPRI concept is the generic notion of "project financing". This would typically involve financing of a new project by a group of independent investors based on the revenues generated by the project rather than relying upon the credit-worthiness of the individual sponsors. The non-completion risk of such projects would not be transferred if the participating utilities were only required to enter into take-or-pay

contracts rather than an "all-events" purchase agreements (such as those approved by FERC to facilitate construction of the Great Plains Coal Gasification Project in North Dakota).⁷⁹ Power sales from such a project financing venture would be governed by wholesale rate contracts filed with the FERC and thus would not be subject to state review under Narragansett.

There is considerable question, however, as to the willingness of independent investors to embark upon a major powerplant project in the absence of an "all-events" contract. Conversely, it may be possible to develop limited or conditional take-or-pay contracts that would essentially shift certain risks of the project to the independent investors (e.g., non-completion) to the extent that they were willing to assume such risks and were fairly compensated, while other risks (e.g., regulatory problems) were shifted to ratepayers. Such "take-or-pay" contracts, however, have themselves been the subject of recent controversy in the natural gas industry where many customers have sought to invoke "market out" provisions to relieve themselves of the obligation to purchase contracted supplies that are priced well above current market levels.

There are very few precedents for involving "non-utility" entities in the financing of new central-station generating capacity. This option was considered, for example, in the case of several financially troubled nuclear plants threatened with cancellation. The more traditional approach is the joint venture with other utilities--both public and private--as discussed earlier. Recent development of certain smaller-scale generating projects under PURPA (so called "qualifying

facilities") may serve to heighten investor familiarity and interest in the electric power market assuming arguendo that current regulatory risks can somehow be mitigated and a competitive return is available to non-utility entities considering such investments. The FERC, for example, has recently granted qualifying facility status to a cogeneration project wherein more than 50 percent of the equity was contributed by a utility-owned subsidiary, although the non-utility participant effectively maintained ownership control.⁸⁰

The Role of Public Ownership and
Cogeneration in Transferring Jurisdiction

Unless utilities are able to successfully adopt some combination of the risk sharing measures outlined above, there is the possibility of a gradual transition to public ownership for a growing percentage of the large bulk power supply facilities built in this country. Almost one-third of the new generating capacity constructed during the 1980's will be financed through some form of public ownership or government financing guarantees. Private investors may be less willing to bear the growing financial risks inherent in the current economic and regulatory environment affecting electric power unless such risks can somehow be mitigated. (Recent investor interest in electric utility stocks is closely correlated with those companies having little or no major construction on the horizon.)

As noted earlier, transferring jurisdiction to the FERC is increasingly viewed as one means of risk avoidance or minimization. While the pros and cons of public versus private financing of new generating facilities are beyond the scope of this report, it is clear that a shift

to public financing will also result in a gradual erosion of state regulatory authority since publicly-owned utilities are generally self-regulated and are subject to limited jurisdiction of most state regulatory commissions or are altogether exempt. Similarly, the long term growth in cogeneration and small power development under Title II of PURPA could also limit state regulatory oversight with respect to a significant portion of the bulk power supply costs of some utilities. Although such purchases presumably occur under guidelines promulgated by state regulators, it is unclear how much real control regulators will exercise over such purchases when they are made pursuant to long-term contracts with purchase rates indexed to current fuel prices, cost of purchased power, etc.

CHAPTER 6

METHODS OF TRANSFERRING RATEMAKING JURISDICTION FROM THE STATE TO THE FEDERAL LEVEL

Introduction

The incentives for transferring ratemaking jurisdiction from the state to the federal level have varied over time as a function of how the respective regulatory climates are perceived by utilities and investors. In the past, however, such jurisdictional transfers were typically the outcome of either (1) corporate restructuring efforts (whose objectives were not focused on transferring regulatory jurisdiction) or (2) changing interpretations of statute initiated by parties other than the relevant utility (e.g., the Colton decision), rather than deliberate efforts to seek such a jurisdictional transfer. Indeed, as noted in earlier sections, investor-owned utilities were among the principal opponents of FERC efforts to assume jurisdiction over intra-state wholesale transactions. The times, however, have changed and so have utility attitudes towards state versus federal jurisdiction.

In a previous section we outlined several of the more positive features of FERC regulation from the perspective of many utilities. Because of this growing "spread" between federal and state regulatory climates as perceived by investor-owned utilities, "jurisdictional transfer" has increasingly become a significant element in the strategic planning efforts of some utilities--especially those attributing their

recent financial problems to the consequences of "unresponsive" state regulation. While proposals for utility corporate restructuring or innovative ownership arrangements have always been assessed on their economic and technical merits, it is increasingly likely that the opportunities created for jurisdictional transfer will become a major element of such assessments in the future. While the issue may be publicly framed in terms of promoting "risk avoidance" or achieving "more predictable financial results," the real outcome being contemplated is still the transfer of regulatory oversight for as much of the utility's revenues as possible to what is increasingly perceived as the more favorable regulatory environment at the FERC.

In this section we shall examine several approaches which historically have had the effect of transferring jurisdiction from the state to the federal level. We have framed the issue in these terms since, as repeatedly noted, such mechanisms were historically undertaken primarily for purposes other than transferring jurisdiction or were the outcome of factors beyond the utility's control. In each case, we shall also examine how such mechanisms might be used in the future, with particular emphasis on how they would affect the existing scope of state commission ratemaking jurisdiction.

The various mechanisms of jurisdictional transfer discussed in this section include:

- ° Interstate Interconnections and Sales.
- ° Generating and Distribution Company Subsidiaries: The New England Electric System Model.
- ° The ESPRI Model.
- ° Joint Ownership Arrangements.

- Joint Stock Companies (the "Yankee" Atomic Model).
- Tenancy-in-Common (the "Four-Corners" Model).
- ° Cost Equalization Agreements Within a Holding Company Pool.
- ° "Off-System" Bulk Power Purchase.

While there are probably other mechanisms of achieving similar outcomes from a jurisdictional perspective (e.g., project financing of new powerplants), they typically can be shown to be a variation of one or more of the approaches listed above.

Interstate Interconnections and Sales

The most obvious, albeit unintended, approach for transferring jurisdiction from the state to the federal level was that which resulted in the wholesale sales of Southern California Edison Company becoming jurisdictional under the Colton case in the early 1960's. In that situation, the transfer resulted from the FPC's assertion of jurisdiction in response to a petition from one of Edison's wholesale customer's. As noted earlier, the FPC based its claim of jurisdictional status on Edison's interstate interconnections and limited wholesale purchases of bulk power from outside the state. Subsequent to Colton, virtually all of the wholesale transactions of the nation's interconnected utility systems became jurisdictional on the theory that all energy in the grid was "commingled" and there was no basis for isolating "purely intrastate" energy flows among utility systems that were interconnected across state lines. The only exceptions ultimately, were the utilities in the ERCOT portion of Texas which remained "electrically isolated" from other states.

Because of the highly interconnected nature of today's utility systems, there is little likelihood of many additional jurisdictional transfers which might result from an assertion that a currently non-jurisdictional utility (i.e., one that was not interconnected) is now engaged in sales for resale within "interstate commerce." With the exception of the ERCOT systems in Texas, all of the investor-owned utilities located in the continental U.S. are already subject to FERC wholesale rate jurisdiction (pursuant to Colton) by virtue of their interconnected operations within either the Eastern or Western grids (which effectively link all major utilities in the continental U.S.) The ERCOT utilities appear to prefer state regulation over the FERC for the near term and have recently negotiated D.C. interconnection arrangements that allow them to exchange power with utilities in other states but still operate non-synchronously with adjacent systems. In the long term, however, if projected economic and reliability benefits appear to warrant the establishment of A.C. interconnections and synchronous operation with utilities in other states, the wholesale transactions of the ERCOT systems would presumably come under FERC jurisdiction. Such action might also be triggered if the ERCOT systems perceived a long-term unfavorable regulatory environment at the state level and were willing to "take their chances" with FERC regulation by deliberately establishing interstate synchronous operations.

In addition to ERCOT, the investor-owned utilities in Hawaii and Alaska are also exempt from FERC jurisdiction (by virtue of their geographic and electrical isolation). Absent legislative changes, there

is little likelihood of these systems becoming subject to FERC rate jurisdiction.

Generating and Distribution Company
Subsidiaries: The NEES Model

The organization of a utility into corporately separate generation and distribution companies through a holding company arrangement has the effect of assigning regulatory responsibility for the major percentage of retail revenues from the state to the federal level. This result is achieved because all bulk power sales from the generating company to affiliated distribution companies are considered "sales for resale in interstate commerce." Perhaps the most notable illustration of this form of corporate structure is the New England Electric System (NEES) which serves customers in Massachusetts, Rhode Island, and New Hampshire.⁸¹

NEES itself is technically considered a "voluntary association" created under Massachusetts law in 1926, and is a registered holding company under the Public Utility Holding Company Act of 1935. NEES owns all the common stock of four electric utility operating subsidiaries (a generating and transmission company and three distribution companies) and several other subsidiaries involved in fuel supply and energy services.

The facilities of NEES' four electric operating subsidiaries (New England Power (NEPCO), Massachusetts Electric, Narragansett Electric, and Granite State Electric) constitute a single integrated electric utility system which is interconnected with other utilities in the New England region as well as with utilities in New York State. NEPCO

supplies the full electric energy requirements of NEES's three distribution subsidiaries as well as supplying power to certain municipal and cooperative systems and other investor-owned systems in New England.

In 1983, over 75 percent of the systems' electric utility revenues flowed through NEPCO, whose wholesale rates for sales to NEES' retail subsidiaries are subject to regulation by the FERC.⁸² The retail rates of the distribution companies are subject to the jurisdictions of the state regulatory commissions in Massachusetts, Rhode Island, and New Hampshire. Each of their retail rate schedules contains a purchased power cost adjustment (PPCA) which allows these subsidiaries to pass on to their customers any increases or decreases in purchased power expense resulting from changes authorized by the FERC in NEPCO's rates. Under the Narragansett rule, the various state commissions are precluded from examining the "reasonableness" of purchased power expenses incurred by NEES subsidiaries pursuant to FERC approved rate schedules.

The inability of state regulators to exercise direct control over such a large percentage of NEES' revenues has been a major source of concern among state regulators and legislators in New England dating back to the Narragansett case and even earlier. (The regional sense of "disenfranchisement" is further compounded by the presence in New England of several other companies with substantial wholesale business and the joint ownership arrangements applicable to several regional nuclear generating units--all of whose sales are also FERC jurisdictional). As a result, New England public officials have been among the leading advocates of previously mentioned efforts by the National Governors Association (NGA) and others to enact legislation transferring

regulatory responsibility for "intrastate" wholesale transactions back to the states and creating new regional compact agencies to regulate interstate wholesale transactions.⁸³

Indeed, the increasing prospect of replication of the "NEES model" by other utilities was of sufficient concern to the NGA that in 1983 it formally adopted a resolution opposing any legislative efforts that might facilitate the organization of similar corporate structures.⁸⁴ A report by the NGA Task Force on utility regulation which examined alternative models for restructuring electric power regulation observed:⁸⁵

"This option, which has received some attention in the Department of Energy's policy process and in some industry circles, would involve amending the Federal Power Act and the Public Utility Holding Company Act to make it easier for utilities to organize into regional generating companies (with distribution and transmission subsidiaries). These holding companies would then come under FERC wholesale jurisdiction rather than under a state retail jurisdiction. The NEES is an example of this type of structure. Such a change would, in effect, give utilities the choice of whether they are regulated by FERC or by the states." (Emphasis added.)

The NGA report acknowledged several of the economic and efficiency benefits which might result from creation of a NEES-type structure at the regional level. It observed:⁸⁶

"This approach would reduce but not eliminate the ratemaking conflicts problem for any utility system that elected to go under federal jurisdiction. While different states could still treat the rate requests of the holding company's subsidiary differently, it is less likely. This option would also provide utilities with some leverage to press states to regulate them uniformly and possibly more favorably from the utility's perspective. . . . By encouraging more tight pool arrangements, it could capture some of the lost efficiencies in potential interconnection. . . ."

From a political perspective, however, the option of creating separate generating and distribution companies scored poorly with the

NGA. While acknowledging its attractiveness to the industry, the NGA speculated that it would face "violent opposition from consumer groups and political leaders" because it would provide utilities with a means "to search for the best opportunity to get higher rates" as well as allowing utilities to "opt out of any state where regulation was not friendly."⁸⁷

After balancing the pros and cons of this option, the NGA adopted a resolution:⁸⁸

". . . opposing any amendments to the Federal Power Act or the PUHCA which are designed to make it easier for utilities to organize as regional holding companies as a means to avoid state rate regulation. Any such changes could increase FERC jurisdiction and reduce state authority which is undesirable." (Emphasis added.)

While several utilities have actually adopted the generating company concept for specific purposes or have expressed interest in restructuring their operations along the lines of separate generating and distribution companies, none has actually done so with the stated intent of transferring regulatory jurisdiction to FERC. The American Electric Power Company, for example, established separate generating companies to facilitate financing of specific powerplants (e.g., Cook Nuclear Plant and Ohio Electric) but, folded these entities back into established operating subsidiaries once these plants were completed.

The Virginia Electric and Power Co. (VEPCO), which recently underwent a corporate reorganization creating Dominion Resources (as a holding company of VEPCO), has filed plans with the Virginia State Corporation Commission indicating its intentions to examine further restructuring--including the possible creation of a separate generating company that would construct or acquire new generating facilities to

meet future capacity needs.⁸⁹ The near-term restructuring would involve spinning off VEPCO's gas and fuel supply operation into separate subsidiaries, creation of a service company, and implementation of a new accounting system. The objective of these changes would be to separate existing lines of business with substantially different "operating requirements, risks, markets, and financing needs" so as to increase efficiency and reduce costs.⁹⁰

While emphasizing that VEPCO has no current plans for any new generating capacity to be owned by a generating company (or transferring any of the company's existing generation or transmission assets to such an entity), VEPCO has argued that because of the potential cost savings from ownership of capacity by a generating company, such an option should not be foreclosed by the Virginia Commission, but should be evaluated if and when a specific proposal is made. VEPCO has characterized the issue in the following terms wherein it openly acknowledged the jurisdictional transfer aspects of its proposal:⁹¹

"We believe it would be a mistake to decide now that certain possible alternatives to meeting future generating requirements should be foreclosed forevermore from any consideration whatsoever. That includes certain possible alternatives . . . such as the establishment of separate generating companies or other arrangements that might involve some sharing of rate-making jurisdiction with the FERC. A separate generating company could, we believe under some circumstances, be advantageous to both the utility and to the Virginia ratepayer. Fundamentally, this is so because of the more highly leveraged capital structure possible for a generating company but not possible for VEPCO. The greater leverage can produce lower costs for the customer, even while the return to the utility is improved . . ." (Emphasis added.)

Notwithstanding VEPCO's repeated disavowals of any specific plans to form a separate generating company, Commission staffers remain skeptical. They have expressed concern that because FERC regulation is

perceived as "more generous" than that of the states, VEPCO might seek to place all of its existing generating assets (\$3.5 billion out of a total of \$5.8 billion) into a separate generating company and not just limit itself to new plants.⁹² This, they note, would effectively create a NEES-type situation with only very limited state authority over the retail rates that would be charged by VEPCO's newly created distribution subsidiary. There is currently no clear timetable for any final Commission response to the VEPCO filing and the company is continuing in its efforts to demonstrate the benefits of its proposal for both ratepayers and investors.

The VEPCO scenario is still the exception among utility companies but is no longer unique. At least 20 major electric utilities have recently restructured themselves into holding companies or announced plans for doing so (in addition to the ten systems already operating as registered holding companies subject to SEC regulation and many others which are "exempt" from SEC regulation). Few, however, have discussed the generating company option as openly as VEPCO. While opportunities for "diversification" into new lines of business is ostensibly the primary objective of creating a holding company, subsequent restructuring into separate generating and distribution companies may be an option for some of these companies if the economic benefits (e.g., cost and risk allocations, lower financing costs) are sufficient and if state regulation is perceived as unresponsive to the company's continuing need for adequate revenues and earnings to meet its service obligations. The outcome in each case, however, is likely to be determined by a combination of the utility's perceived motivation in restructuring and the

benefits thereof, and the extent of state authority under existing law to restrict such restructuring efforts.

The real extent of state authority to prevent or "condition" the creation of new holding company structures by investor-owned utilities is relatively unclear but varies considerably among states.⁹³ In recent testimony opposing utility industry efforts to repeal the Holding Company Act, NARUC testified:⁹⁴

- (1) Many states have no laws governing the creation of holding companies by utilities within their jurisdiction, relying instead on federal regulation under the PUCHA and the Federal Power Act.
- (2) Even if the states had the requisite statutory authority, they lack the expertise and resources to effectively regulate such entities and transactions among affiliates.
- (3) The full extent of federal preemption in the case of interstate holding companies is unclear, but would probably limit state control over the activities of any out-of-state affiliates.

At the federal level, creation of a new holding company structure (or generating subsidiary within an existing structure) would be subject to the jurisdiction of both the SEC and the FERC. While further discussion of the scope of their jurisdiction is beyond the intent of this report, a review of the literature indicates that there are no fundamental impediments under the statutory criteria governing either agency's decision making which would preclude the creation of generation and distribution subsidiaries as a mechanism to transfer ratemaking jurisdiction to the FERC.⁹⁵

The ESPRI Proposal
General Concept

Empire State Power Resources, Inc. (ESPRI) was a consortium proposed in 1974 by the seven investor-owned utilities in New York to jointly construct all future generating facilities planned by these utilities beyond 1980.⁹⁶ The concept evolved from the severe financial problems encountered by the utilities following the 1973 OPEC oil embargo. The ESPRI approach was intended to spread the financial risk of new generating plants among the participating companies, ensure rapid recovery of costs as a plant goes into service, and provide significant cost advantages in financing and constructing new units. ESPRI projected highly leverage financing (80 percent debt/20 percent equity) with the individual companies purchasing allocations of the ESPRI power and energy on an average ESPRI system cost basis under FPC wholesale rate schedules. All rate increases approved by the FPC were to be passed along to the sponsoring companies customers through an automatic adjustment clause in their retail rate structures. This automatic flow-through provision was seen as crucial to obtaining the high degree of leverage proposed.

ESPRI was to have full responsibility for construction and operation of its units, but during its initial years it contemplated short-term contracts with one or more of the sponsors for various support services. Ultimately, ESPRI was to employ its own staff to supervise the design, construction, maintenance, operation, and quality assurance of its units.

Under a "Capital Funds Agreement" the sponsors of any unit would have been required to furnish a proportionate share of the equity

capital necessary to construct the unit. Other funds for the financing of the unit would be obtained by ESPRI, by short-term borrowings which would be refunded by long-term debt issued by ESPRI and by pollution control bonds issued by governmental authority. The proposed capitalization for ESPRI was 60 percent long term bonds, 20 percent pollution control bonds, and 20 percent common equity.

Under individual "Power Contracts" each sponsor would be responsible for payments for capacity based on the sponsor's portion of the capacity that it had contracted for. These would be based on the sponsor's pro-rata share of the total ESPRI system costs, whether or not the sponsor's capacity is producing energy. Energy charges would likewise be based on total ESPRI system energy related costs. Each sponsor would be responsible for arrangements for transmission of its ESPRI power and energy to its own system.

Relation to Other Utility Systems

ESPRI contemplated operating as an "independent entity" in parallel with its sponsors, the Power Authority of New York (PASNY) and a number of municipal systems. Once ESPRI became a viable entity, it expected to become a member of the New York Power Pool (NYPP) and to participate in its planning and operational functions, particularly with regard to the siting, design, construction, and operation of new base load units. Operation of these units would have been coordinated with other units of members of the NYPP on an economic dispatch basis.

Regulatory and Political Response

In December 1974, a proposal was filed with the New York Public Service Commission (PSC) to obtain permission to purchase ESPRI common

stock by the seven sponsors.⁹⁷ A similar application was made before the FPC for authority under Section 203 of the Federal Power Act to acquire securities.⁹⁸ No action was taken on the FPC filing since ESPRI was not a "public utility" pending its approval by the PSC and acquisition of electric generating facilities making it a "public utility."

Following extensive hearings during 1976-77, the PSC ordered further studies to explore alternatives to ESPRI that might conceivably achieve the purposes of ESPRI but with "greater benefit" to ratepayers. A key alternative proposed by the PSC staff was to restrict the highly leveraged debt/equity ratios for individual companies and allow for limited automatic flow-through of costs while retaining PSC oversight of major expenditures. The real concern of PSC Staff and intervenors, however, appeared to have been the prospect of the PSC losing regulatory control over the sponsoring companies' retail rates through the power purchase and resale arrangements implicit in the ESPRI proposal (which would have been subject to FPC jurisdiction).

In a discussion of the jurisdictional aspects of the ESPRI proposal, a State Legislative Institute report noted:⁹⁹

"The utilities themselves argue that they prefer PSC regulatory control, and to this end, they have proposed the electric utility version of the so-called 'Hinshaw Amendment' to the Natural Gas Act. This amendment puts interstate gas wholesalers outside the jurisdiction of the FPC and therefore within the regulatory province of their respective state commissions. An analogous amendment for electric utilities would alter the Federal Power Act so as to relegate jurisdiction over sales entirely within one state's boundaries to that state's regulatory commission."

Notwithstanding the industry's support for amendments to the Federal Power Act which would have retained state control over ESPRI sales to the sponsoring companies, the PSC, State Legislators, and many

intervenors apparently remained skeptical over the likelihood of actually getting Congress to enact such legislation.

The FPC attempted to remain "neutral" in the debate over the merits of the ESPRI proposal--particularly with reference to the jurisdictional transfer issue. The FPC Staff consistently took the position that "ESPRI was in the formative stages" and did not own or operate any electric facilities. Thus, under Section 201(e) of the federal Power Act, ESPRI was not a "public utility" and the Commission did not have jurisdiction over the acquisition of the "securities" of ESPRI by other "public utilities." Such jurisdiction, they noted, would not begin until ESPRI owned or operated facilities for the sale of wholesale or transmission of electric energy which is generated in one state and consumed outside the state in which it is generated.

At the same time, however, the FPC Staff followed the ESPRI developments with considerable interest--especially in the context of the above referenced proposals to legislate a "Hinshaw Amendment" to exempt intrastate electric wholesale sales from Commission jurisdiction. In commenting on this legislative option, the FPC Staff memorandum made the following observations:¹⁰⁰

"Such an amendment would substantially reduce the sales for resale presently subject to FPC jurisdiction including most sales to municipalities and cooperatives since many utilities operate entirely within one state. The stated reason for seeking the amendment is that state commissions might block cooperative ventures like ESPRI which would remove regulatory authority from their jurisdiction due to the emergence of FPC jurisdiction once sales for resale occur. . . Although a "Hinshaw Amendment" would solve the PSC's concern with respect to ESPRI, it would also eradicate the FPC jurisdiction over many rates which do not involve cooperative coordination ventures."

In April 1979 the New York PSC denied the ESPRI petition on the grounds that (1) the "automatic revenue assurance mechanism" (i.e., full cost-of-service tariff) sought by the sponsors would not provide incentives for efficiency, (2) that FERC assumption of ratemaking jurisdiction over a growing portion of the sponsors cost-of-service was objectionable, and (3) the financial benefits of ESPRI (e.g., lower costs of capital) were "overstated" and any nonfinancial benefits such as cost savings from in-house engineering could be derived from a service company which did not own or finance its units.¹⁰¹ That decision effectively terminated any further efforts to create a joint-ownership arrangement in New York although, as noted below, the New York companies continued to explore joint ownership arrangements on a project level basis.

The principal benefits of an ESPRI-type of generating company which might attract future interest in this approach in other jurisdictions include:¹⁰²

- ° The sharing of capital costs which reduces the financial risk of large capital outlays faced by any one utility.
- ° The ability of participating companies to "add" new capacity in smaller increments.
- ° Reduction of total capital costs through the ability to leverage with a higher debt equity ratio than possible for any individual investor-owned utility.
- ° The ability to reduce reliance on the equity markets thereby reducing the risk of dilution of common stock when the utility's stock is selling below book value.
- ° The ability to create a stronger financial entity through back-up provisions should any one company default.
- ° The financing of capital requirements externally (i.e., project financing) made possible through a "revenue assurance clause," such as proposed by the ESPRI utilities to the New

York commission. Under this clause, ratepayers were fully obligated for all ESPRI costs under any possible eventuality).

- ° Flexibility in reallocation of ownership interests (as compared to the inflexible mortgage bond indentures of tenancies-in-common).
- ° Reducing construction and operating costs by having a centralized planning, engineering and construction management capability within the generating and transmission company.

One should note, however, that the same state commission objections to high leveraging, loss of jurisdiction, reliance on an "all-events" tariff, etc. which resulted in rejection of the ESPRI model in New York, are likely to arise in any other jurisdiction(s) where it is proposed.

Joint Ownership Arrangements
Joint Stock Companies: The Yankee Atomic Model

Collective ownership of a generating facility by several utilities whose power output is purchased by the participants in the joint-venture has become a relatively common approach to financing large new baseload facilities. While the joint ownership option is most common among municipal systems (joint-action agencies) and rural cooperatives (G&T's), its use by investor-owned systems is of principal interest to this discussion. The various Yankee Atomic Companies in New England are illustrative of joint-stock companies owning generating facilities.¹⁰³

Each of the four Yankee Atomic Companies is a corporate joint-stock company organized by a group of New England investor-owned utilities (the participants) for the purpose of owning and operating a specific nuclear generating facility (the plant). The voting securities of the Yankee companies are distributed among participants who are entitled to purchase the output of each unit in the same percentages as its ownership (less small entitlements taken by municipal utilities).

Purchases are made under a wholesale power contract filed with the FERC which requires each purchasing company to pay an amount for its share of the output equal to its share of total fixed and operating costs, (including decommissioning costs of the plants) plus a return on equity. The stockholders of the Yankee companies have agreed, subject to certain conditions, to provide for any current or future capital requirements (either through stock purchases, capital contributions, or loans) in the same proportion as their ownership percentages of the particular Yankee company. Failure of one participant to meet its capital obligations does not excuse others from meeting their obligations.¹⁰⁴

Participants' obligations with respect to payments to be made to Yankee are essentially "take-or-pay" contracts (i.e., not limited by or dependent on the actual output of the plant). While a participant is not excused from performing under its Power Contract by reason of the failure of another participant to perform, it is not obligated to purchase the defaulting participant's percentage of the capacity and output of the plant (i.e., there is no provision for joint and several liability such as was the case in ESPRI).¹⁰⁵

Any amendments to either the Power Sales Contracts or the Capital Funds Agreements require unanimous consent of the participants. A Stockholder Agreement further provides that a participant partially defaulting in its capital funds contribution obligations must reduce its power entitlement percentage to a level equal to the reduced capital participation percentage.

The sale of power from any of the Yankee companies to participants (or others) is considered a sale for resale subject to FERC jurisdiction. The power contracts (and possibly capital funds agreements) used by joint stock companies to collateralize project financing are subject to approval by the FERC.¹⁰⁶ Such actions may also require state regulatory agency approval. The FPC may condition such approval on financial structure conditions. The same jurisdictional situation would presumably apply to power sales from any joint stock generating company selling in interstate commerce.

On a prospective basis, joint stock companies such as the Yankees could be an attractive approach for financing new generating plants serving utilities in several jurisdictions while transferring rate jurisdiction for its output to the FERC. It was used most recently as the model of the new corporate entity being formed to complete the construction of Seabrook Unit No. 1 in New Hampshire. It is also one of the options considered by the Southern States Energy Board as a basis for creating a regional generating company to construct new baseload plants in the Southeast.¹⁰⁷ In general, joint stock companies share many of the same advantages and disadvantages as noted above for the ESPRI approach to risk sharing through joint-ownership.

Tenancy-in-Common

Tenancies-in-common are a form of cost and risk-sharing arrangement wherein the participants ("co-tenants") are considered as direct owners (for tax purposes) in proportion to their interests in a particular facility (i.e., the arrangement is considered as a type of "partnership" rather than a corporate entity).¹⁰⁸

In a common form of this arrangement, several electric utilities have constructed mine-mouth coal-fired power plants (e.g., Four Corners) under a co-tenancy ownership agreement and an operating agreement. One of the parties is designated as the operating agent under the operating agreement, although neither the venture as thus constituted nor the operating agent has any right to market the electric power produced. All energy generated by the plant is taken and marketed separately by the participants, each of which has exclusive marketing rights with respect to its respective percentage of the project.

Participants' contributions to fixed costs are fixed by the co-tenancy agreement; variable generating costs are paid by participants on the basis of the amount of power purchased. Transmission services needed to deliver power from the plant are furnished separately by each participant. Like the Yankee model, there is no joint and several liability among the co-tenants. However, unlike the Yankee stock company arrangements, tenancy-in-common agreements need not be filed with the FERC as wholesale rate schedules since they do not involve a sale for resale in interstate commerce. If, however, any participant in a tenancy-in-common wishes to sell power from its entitlement to another utility (whether it be another participant or not) such a contract is a wholesale rate schedule subject to regulation by the FERC.

In one of the early applications of the concept, four New York investor-owned utilities executed the Sterling Nuclear Agreement in 1975 creating a tenancy-in-common to construct and operate a proposed nuclear plant.¹⁰⁹ The structure of the Sterling Agreement suggested the possibility that some of the advantages of risk sharing, capital outlay

limitation, matching of capacity requirements to needs, and the planning efficiencies which had been attributed to the ESPRI-type arrangements being considered by the New York PSC in the same time frame, might also have been obtainable through tenancies-in-common.

Another recent example of the tenancy-in-common approach to joint ownership are the ownership arrangements negotiated between Georgia Power Company and Ogelthorpe G&T and between Georgia Power and the municipal utility group in Georgia (MEAG). These tenancies-in-common include undivided interests in the Hatch Nuclear Plant and Wonsly Coal Plant and have also included interests in other generation and transmission projects under construction. In each of these cases Georgia Power has retained more than 50 percent interest in the project.

The tenancy-in-common approach is one of the more easily implemented joint-ownership arrangements because it provides many of the benefits of scale economies, financial flexibility, and risk sharing as do the other types of joint-ownership agreements, while not necessarily resulting in any loss of state jurisdiction. Projects held by tenancies-in-common are subject to FERC jurisdiction only to the same extent that the tenants otherwise would be pursuant to the Federal Power Act, were the projects separately owned by each of them individually. There have been instances of state regulatory agencies exercising jurisdiction over investments in a tenancy-in-common by companies subject to their jurisdiction in projects located outside their jurisdictions.

Cost Equalization Agreements
Within a Holding Company Pool

An evolving approach to structuring bulk power supply arrangements among affiliates within a holding company pool may have the effect of shifting regulatory jurisdiction over such sales from the states to the FERC. (This approach is distinct from the NEES model in which a separate generating subsidiary sells to affiliated distribution subsidiaries.) In most holding company pools, each subsidiary is essentially responsible for meeting its internal capacity and reserve obligations with its own generating resources which are subject to state regulation. Purchases from affiliates to meet deficiencies or sales of excess power to affiliates are covered under a system pooling or coordination agreement filed as a wholesale rate schedule with the FERC.

There are, however, several cases of pooling agreements among affiliated utilities which have been designed in such a way as to "roll together" some or all of the bulk power supply costs of the affiliated utilities and thereby "equalize" the unit costs of power purchased (with each company billed in accordance with its kW and kWh usage). This model is employed by the Northeast Utilities System (NEUS) and Northern States Power (NSP). The operation of this model in the context of the jurisdictional transfer issue was noted earlier in the discussion of the Northern States case.¹¹⁰

NSP (Minnesota) is an exempt holding company serving a four-state area in the upper midwest. The NSP group includes Northern States Power (Minnesota) and its wholly-owned subsidiaries, Northern States Power (Wisconsin) and the recently-acquired Lake Superior District Power Company. NSP participates as a single company in the MAPP Pool.¹¹¹ The

utilities in the NSP group participate in a comprehensive cost sharing arrangement incorporated in a "Coordinating Agreement" among the three utilities filed with the FERC. Fixed charges are shared in accordance with "participation ratios" computed on the basis of each company's rolling five-year (previous four years and an additional projected year) average contribution to coincidental summer and winter peak demands of the total system. Each party makes separate payments to the other two parties to cover its share of the other two parties' respective fixed charges. Variable operating and maintenance costs relating to general facilities and power transactions are shared in accordance with energy ratios based on kWh usage.

The provisions of this agreement that generated so much controversy in the context of the previously discussed Northern States case are its reliance on "formula" rates (i.e., procedures for allocating the bulk power supply costs of the integrated system among the affiliated companies and computing monthly charges in unit energy and capacity costs). In the case in question, these formula rates would have determined the amounts to be paid by retail ratepayers in Minnesota even though the costs to be allocated included the cancellation costs of the Tyrone Nuclear Plant which the Minnesota PUC believed had been brought on solely by the "parochial actions" of the Wisconsin Commission. The objections of the Minnesota Commission to having these cancellation costs subsequently charged against retail ratepayers in Minnesota pursuant to the Coordination Agreement was the event which initiated the case.

The initial finding of the MPUC in the Northern States case was that the Coordinating Agreement was not a wholesale rate and thus the

state could legitimately exercise rate jurisdiction over NSP's costs (in this case those related to the Tyrone Cancellation). In support of this position in subsequent litigation, MPUC made several claims. First, they asserted that the Coordinating Agreement merely operates as a contract to apportion investment costs and expenses between two affiliated companies. As a corollary to this first argument, they asserted that because NSP-M and NSP-W are affiliated and are effectively operated as a single entity, the charges between them cannot be considered wholesale rates.¹¹² Finally, they asserted that because NSP-W does not and cannot sell power to NSP-M, the Coordinating Agreement cannot be considered a "wholesale rate" (at least insofar as charges from NSP-W to NSP-M are concerned).

The Minnesota Supreme Court, however, rejected each of these assertions ruling that the Agreement was a legitimate wholesale rate schedule and that the State was preempted under Narragansett.

In seeking Supreme Court review of this decision, the State of Minnesota raised the question of other utilities using the NSP model as a prototype to evade state jurisdiction. As noted in their petition for certiorari:¹¹³

"Having found the Coordinating Agreement to be a wholesale rate, the Minnesota Supreme Court concluded that it preempted state jurisdiction. In finding the agreement to be something which it is not, a wholesale rate, the Minnesota Supreme Court has upset the delicate bright line balance which Congress and the opinions of this Court have long recognized. The enormity of the Minnesota Supreme Court's error can be seen from examining what the Coordinating Agreement really is. If such a general open-ended cost-sharing formula is a wholesale rate it will become the prototype for agreements between utilities and their subsidiaries all over the country whose purpose is to evade state jurisdiction." (Emphasis added.)

The State went on to speculate on the long-term consequences of this outcome--both in Minnesota and for the rest of the country:¹¹⁴

"The future application of this particular Coordinating Agreement as a device to circumvent state regulatory authority is confined only by the limits of the imaginations of NSP's attorneys. Pursuant to the Minnesota Supreme Court's reasoning, virtually any item of cost, expense, or investment could be passed through the Coordinating Agreement to the preclusion of the Minnesota Commission's independent consideration of it in a retail ratemaking proceeding.

The precedent created by the Minnesota Supreme Court opinion, moreover, goes well beyond this particular case and this particular coordinating agreement. Utility companies operating integrated systems will now immediately see the advantage of establishing affiliates. Numerous contracts and agreements will then be created between the affiliates which will deal with most or all of the costs, expenses, and investment aspects which have traditionally been the subject of state retail utility ratemaking. In short, all will be a wholesale rate determined by FERC. There will be nothing left for state retail ratemaking determination." (Emphasis added.)

The Minnesota concerns as expressed in its petition to the Court may have been framed in terms designed to elevate the issue from one of "local" concern to one of national significance. These concerns, however, were shared by many other states. At least 15 states filed briefs in support of the Minnesota petition for certiorari. A brief filed jointly by several states, speculated further as to how the NSP model would serve as a pattern for other utilities seeking to evade state regulation. The states' brief observed:¹¹⁵

"If the action of the Minnesota Supreme Court in up-holding a Coordinating Agreement amendment as a wholesale rate and not subject to state review is not challenged, then state regulation of utilities as it exists today will be destroyed. One effective way might be for utility companies across the country to designate one or more of their generating plants located outside the corporate headquarters in another state as separate subsidiaries which could sell electric power or fuel back to the holding company or to another subsidiary. "Coordinating Agreements" could be established with the FERC.

These "interstate" transactions would then be subject to FERC which would establish wholesale rates. The subsidiaries would sell electricity at this wholesale rate back to the holding company which then would pass that rate directly to rate-payers, and thereby avoid all state utility commission scrutiny." (Emphasis added.)

Several states made specific reference to jurisdictional preemption problems which could arise in their states if the NSP model were applied in the context of troubled nuclear plants owned by affiliated companies (e.g., New Jersey concerns regarding GPU's Three Mile Island Plant, and Ohio concerns regarding AEP's Zimmer Plant).

Virginia and North Carolina both expressed the fear that VEPCO's (previously discussed) corporate reorganization scheme might be used to circumvent state legislation if the Northern States decision was not reversed. Virginia's brief noted:¹¹⁵

"Virginia customers have a unique and immediate interest in this case. VEPCO has suggested that its parent, Dominion Resources, Inc., may create a separate subsidiary to own electric generating facilities which would in turn sell power at wholesale to VEPCO. The resulting corporate structure would be very similar to the Northern States Power Company corporate structure at issue here. The Virginia State Corporation Commission has already begun an investigation to determine whether a separate generating subsidiary is in the public interest."

The Virginia brief also raised the possibility of "two-way jurisdictional forum shopping" by utilities in the context of the following scenario:¹¹⁷

"Under the Minnesota Supreme Court's rationale, to oust State jurisdiction, the utility could simply divide itself into one-half owning generating facilities and the other half owning distribution facilities. The halves of the former whole could then purportedly engage in wholesale sales of power subject to federal jurisdiction. The State's authority would become a mere form because of the degree to which the distribution company's power costs, and therefore retail rates would already be determined by preemptive wholesale rates. The Federal Power Act cannot fairly be read to intend such a

complete elimination of effective State regulation of retail rates.

Nor can the act be read to permit unlimited forum shopping between federal and state commissions, but the result in this case would allow it. Any utility could reverse the structure described above to subject itself to greater state jurisdiction if it judged state regulation to be more advantageous to it. The "bright-line" drawn by the Federal Power Act between wholesale and retail sales is functionally related. It should not be susceptible of manipulation by mere changes in corporate organization without real changes in the functional operation of the business.

One of the consequences of coming under FERC jurisdiction where bulk power supply costs are rolled together and equalized in the context of sales among affiliates is evidenced in an ongoing case involving the pooling agreement of the Middle South Utilities System (MSU).¹¹⁸ In that case, FERC Staff (and other intervenors) have taken the position that bulk power supply costs of the pool participants should be rolled together for cost-sharing purposes. The impact of this change in the agreement among the affiliates of MSU would be a substantial reallocation of the cost responsibility for several major power plants in the Middle South service area. Opponents of this approach have argued that such a change would enable the FERC to assert jurisdiction over all of the bulk power supply costs of all of the operating affiliates of the Middle South group, an outcome opposed both by the Middle South Company and its respective state commissions.

Prior to the Middle South case, the FERC had never required the use of any "cost equalization" formula in holding company pooling agreements although such formula is employed by at least one other holding company group in addition to NSP (i.e., the Northeast Utilities System uses such an agreement to cover all of its bulk power supply costs). It is also

employed by MSU for certain of its transmission costs including all such costs related to voltages of 230KV and above. Recently, the American Electric Power Company has filed with the FERC to equalize costs in its transmission at voltages of 345KV and above. Finally, in a case involving a proposed operating agreement among the operating affiliates of the Central and South West Corporation (C&SW), the FERC staff has proposed that the high voltage transmission costs of the C&SW System (345 KV and above plus all D.C. transmission) be equalized.

If the FERC were to impose system-wide bulk power supply costing in the MSU case, the other holding company groups in the U.S. could eventually be exposed to similar treatment.¹¹⁹ It is reasonable to assume that the "cost-equalization" issue would arise in rate cases dealing with most, if not all, of these other holding company groups, since the customers of at least one constituent utility of each group will likely be better off with "rolled-in" costing than they would be under the existing cost allocation approach used in most pools which is based on "reserve-sharing" (i.e., surplus or deficiency in excess of reserve requirements). This outcome stems from the fact that when costs are reallocated among companies in a holding company group, some will end up better off and some worse off even though the total system costs do not change (cost reallocation within a holding company group essentially involves a "zero-sum" game).

The holding company groups potentially exposed to such cost reallocations include 17 operating electric utilities serving in fourteen state jurisdictions (not including MSU). If system-wide bulk power supply costing were imposed on holding company groups, it is probable

that the state commissions regulating the retail rates of the constituent members of the group would no longer regulate the level of bulk power supply costs chargeable to retail customers under the Narragansett doctrine. Thus, for the major percentage of the total costs of such companies that are covered by retail rates (bulk power supply costs typically account for 75 percent of total costs), FERC regulation could preempt state regulation.

Off-System Bulk Power Sales and Purchases

Another mechanism of transferring jurisdiction over a portion of a utility's business from the state to the FERC is really the de facto outcome of the growing market in off-system bulk power purchases and sales. Much of the recent growth in off-system sales has been the result of large amounts of short term "excess capacity" in certain regions as a result of lower than anticipated load growth. Many utilities found it to be more economic to complete plants already under construction and market the excess capacity under long-term sales agreements with other utilities who are able to utilize this power to displace higher cost oil and gas-fired generation or forego the risks of new construction to meet near-term growth. Such agreements must be filed as wholesale rate schedules with the FERC thereby preempting state regulatory revision under the Narragansett doctrine.

Off-system power sales have been a feature of the U.S. electric power industry for many decades, but typically did not constitute a major share of a utility's overall business. Thus, most state commissions were relatively indifferent to the preemptive effects of FERC jurisdiction over such transactions. What is new, however, is the rapid

increase in such transactions over the past several years as utilities seek to exploit the current excess capacity situation as a means of reducing their overall costs of bulk power supply. Sellers are anxious to obtain some contribution to the fixed costs of such excess capacity while also "protecting" themselves against efforts to have such capacity excluded from rate base. Purchasers see the availability of firm power from other systems as a low-cost and relatively risk-free alternative to new powerplant construction. As these transactions increase in magnitude, a larger percentage of a company's overall costs are transferred from state to federal jurisdiction. The impetus for negotiating off-system sales has come from the state commissions themselves who are primarily concerned with the benefits of such transactions for rate-payers and have not thus far expressed concerns over the jurisdictional transfers inherent in off-system purchases and sales.

Some of the most extensive of these off-system sales contracts have been recently negotiated by the Southern Company System and its operating affiliates as a means of dealing with an excess capacity situation arising from completion of several large coal and nuclear units in a period of lower than forecast growth in demand. The operating affiliates of the Southern System have contracts for the sale of non-firm capacity to certain neighboring utilities on a system availability basis which generally extend through 1986. Under these contracts, 8.0 billion kWh were sold in 1983 providing revenues in excess of \$250 million.¹²⁰ The operating affiliates have also entered into contracts with Gulf States Utilities Company, Jacksonville Electric Authority, and Florida Power and Light Company regarding sales of capacity from specific

coal-fired generating plants. These contracts call for substantial purchases by such utilities through the mid-1990's.

Indeed, Southern's 1983 off-system sales (i.e., to nonaffiliate utilities) exceeded its sales to full and partial requirements wholesale customers located within its service area. The decline of wholesale sales reflects the fact that many wholesale customers--primarily municipal and cooperative systems are producing an increasing portion of their own energy requirements and are becoming less dependent on purchases from investor-owned systems. Similar trends are prevalent elsewhere in the country. A growing percentage of wholesale bulk power sales in future years is likely to be among investor-owned companies. In this context, some companies have adopted a policy of meeting their future capacity needs through a combination of cogeneration and small power production with any supplemental requirements purchased from other utilities.

In some cases, such a strategy constitutes a deliberate effort to avoid the financial risks noted earlier that are implicit in virtually any new powerplant construction. In other cases, however, a combination of economic and environmental regulatory constraints has left utilities in a position wherein they feel that off-system purchases are the only realistic option available in the foreseeable future. This perception is reflected in the capacity expansion plans of investor-owned utilities in states such as California where they contemplate substantial power purchases from utilities in the Northwest and Southwest in lieu of any efforts to construct any conventional baseload facilities within California. A similar perception of the futility of attempting to

construct new baseload generation locally has been a key factor in recent efforts by New England utilities to negotiate long-term purchases of Canadian power.

From a regulatory perspective, the selling utility in a major intersystem bulk power transaction is reasonably well insulated from state efforts to review the reasonableness of the sales price under the preemptive effects of the wholesale tariff covering such transactions. From the purchaser's perspective, however, recent decisions in several state proceedings (e.g., Pike County) present a more uncertain prospect in relation to federal preemption. If the courts interpret the Naragansett doctrine as allowing state regulators to inquire into the reasonableness of a wholesale bulk power transaction relative to the prudence of the purchaser, then one of the major incentives for entering into such purchase arrangements (from the utility's perspective) will have been eliminated since the purchaser will have no assurance of recovering the full costs of purchased power through its retail rates. Future developments in this area are likely to be a function of how the courts ultimately decide the issue of the scope of FERC preemption in wholesale electric power purchase agreements. This matter is briefly addressed in the concluding section of this study.

CHAPTER 7
RECENT DEVELOPMENTS AND FUTURE DIRECTIONS
OF THE JURISDICTIONAL DEBATE

Introduction

There is a growing level of activity but little in the way of a clearly focused agenda in the continuing debate over the jurisdictional transfer issue. The evolving body of case law examined in earlier sections of this report suggests the following:

- (1) Federal preemption of state authority to examine the reasonableness of wholesale rates filed with the FERC, at least from the perspective of the seller's cost-of-service is relatively absolute. In this respect, the Narragansett doctrine is still operative and would be a valid presumption in any joint-ownership or corporate reorganization scheme wherein a utility contemplated marketing excess power to other systems and wished to have those sales subject to the jurisdiction of the FERC.
- (2) The scope of federal preemption of state authority to examine the reasonableness of wholesale rates filed with the FERC is also reasonably clear under the Narragansett doctrine. What is unclear, however, is the degree to which a state may examine the prudence of the purchase (e.g., relative to alternative sources of supply available to the purchaser). Recent state court decisions in this area (Pike County, Commonwealth Electric et al.) suggest that the states are increasingly likely to take the position that state commissions are not preempted from making such prudence inquiries under the Federal Power Act. Furthermore, as noted below, the FERC has increasingly emphasized that its regulatory oversight of wholesale rate filings extends only to the seller's cost-of-service and does not address the prudence of the transaction from the purchaser's perspective.
- (3) Federal preemption of state authority over what have sometimes been considered as essentially "intrastate"

wholesale transactions is also relatively clear under the Colton doctrine. There have been several renewed legislative efforts by NGA and NARUC to reverse this outcome and have Congress adopt some form of Hinshaw Amendment for electric power. As discussed below, such amendments to the Federal Power Act are strongly opposed by most public and private utilities as well as the FERC. At this point, the outlook for such legislative efforts is highly uncertain.

Evolving FERC Policy Relating to State Oversight
of Wholesale Bulk Power Transaction

The FERC in several recent cases has taken the view that its acceptance of a rate schedule does not preclude a state commission from considering the prudence of the transaction with respect to the purchaser. The FERC has indicated in such cases that in accepting a rate schedule, their determination is limited to whether the sale price is just and reasonable; it is not determinative of the issue of whether the purchase itself is prudent relative to other options which might have been available to the purchaser.

One of these cases involved the previously referenced sale from Southern Company to Gulf States Utilities (GSU) in which Dow Chemical Co. intervened alleging a discriminatory purchase on the part of GSU affecting its avoided cost rates under PURPA. The FERC determined that the proper forum for considering the avoided cost issue was the state PUC and further stated that:¹²¹

"All we have considered, is whether the sale is just and reasonable. We have not determined whether it was a prudent purchase by GSU. As such, our approval of the sale is not conclusive of the [discrimination] question before the state commission." (Emphasis added.)

This recent case followed two earlier cases wherein the Commission took essentially similar positions. The first involved a sale from

Philadelphia Electric Co. (PE) to Jersey Central Power and Light Company from PE's Salem No. 2 Nuclear Plant. In its order accepting the agreement the FERC stated:¹²²

" . . . our decision to accept the contract rate and service arrangement is not predicated on a determination that, over the initial term of the contract, PE could have done no better selling to someone else, or that the transaction over this period will redound to the benefit of the retail and wholesale requirements customers of the two respective parties to the contract. It does appear that PE's other customers will realize a net benefit from this transaction over the initial term of the contract; but we do not mean by this order to prejudge, for our own purposes or those of the respective state commissions, a determination of the prudence of either party in entering into this transaction. (Emphasis added.)

This same rationale was followed in a case involving a sale by Pennsylvania Power and Light Company (PP&L) to Atlantic City Electric Company of a portion of the capacity and energy of PP&L's Susquehanna Nuclear Units. In its order approving the sale, the Commission reiterated the language of the Philadelphia Electric case (cited above) in noting its acceptance of the rate filing. However, in this case, the Commission set forth its own criterion for evaluating the prudence of a wholesale transaction. It noted that:

"...power supply arrangements are often negotiated on a long-term basis. It requires many years to build a generating plant and the building utility must be able to rely on long-term sales contracts in making its own capacity plans just as the purchasing utility must be able to rely on long-term contracts for stability of supply. Demand forecasts may change dramatically and quickly, as we have seen in recent years. The prudence of a sales arrangement, therefore, should be judged on the circumstances prevailing at the time such a contract is entered into. If a state commission, this Commission, or a utility itself could release a party to a contract from its contractual commitments simply because the contract based on hindsight and demand forecasts in later years, no longer appears economical, the utility industry would have not supply stability or reliable basis for constructing plant. We therefore suggest that evaluation of the prudence of a 1979 power contract on the basis of 1982 demand forecasts is

neither fair nor appropriate. Thus, while we commend the New Jersey Board for its concern in protecting the ratepayers within its jurisdiction, we do not believe that this protection can be at the expense of Pennsylvania ratepayers and utilities. The latter are entitled to rely on the fact that New Jersey utilities will honor their contractual commitments to purchase capacity built at least partly to fulfill their contractual demand." (Emphasis added.)

Recent Legislative Developments
and Near-Term Prospects in Relation
to Jurisdictional Transfer

The issue of federal preemption of state authority over wholesale rates has also gained additional attention in Congress in recent years. In the aftermath of Congressional unwillingness to adopt the previously discussed Holland-Smathers bill in the mid-1960's, other legislative proposals providing for similar transfer of jurisdiction over all-requirements intrastate wholesale sales (from the FERC to the state regulatory commissions) have been suggested from time to time but no action was taken. The issue received a new "lease-on-life" in a 1980 report to Congress by Chairman Charles Curtis of the FERC as required under Section 207(b) of the Public Utilities Regulatory Policies Act of 1978.¹²⁴ In that report, the arguments on both sides of the jurisdictional transfer issue were summarized, but no specific recommendation was made. The arguments noted by the Chairman in favor of transferring wholesale rate jurisdiction to the states include the following:¹²⁵

- (1) Dual regulation is wasteful of time, effort and resources, and creates anti-competitive price discrimination.
- (2) State regulatory commissions would be at least as effective as federal regulators.
- (3) Wholesale all-requirements rate regulation (i.e., where all of a customer's energy requirements are provided by a single supplier) is a matter best handled at the state

rather than federal level by virtue of the local nature of the issues addressed.

- (4) Because of the diversity of utility circumstances throughout the U.S., jurisdiction over all wholesale electric rates is too broad and complex a responsibility for a single agency.

The Curtis Report also outlined the following arguments against such a transfer of jurisdiction:

- (1) Wholesale regulation involves difficult issues relating to the maintenance and encouragement of competition. In such specialized matters, federal regulators are much more likely to be sensitive and knowledgeable than their state counterparts.
- (2) Such jurisdiction is necessary to enable the federal commission to assemble and maintain an expert staff so that it can perform its other regulatory responsibilities and promote national interests through innovative regulation.
- (3) Wholesale customers cannot get fair treatment from retail-oriented state commissions that are "overly influenced by" parochial (i.e., local) considerations.
- (4) Concentration of regulatory jurisdiction in a federal agency enables wholesale customers to take advantage of a Washington-based legal and technical consulting community oriented toward customer interests. This support structure would not survive if customers had to litigate wholesale rate issues in 50 state jurisdictions.
- (5) The delay in the present system of federal regulation can be substantially reduced through various procedural changes, or if these are inadequate, by creation of a new federal agency that would concentrate on electric matters.

In response to the Curtis Report's reopening of the jurisdictional transfer debate, the president of one of the nation's largest investor-owned utilities expressed skepticism over Curtis' interim suggestion for jurisdictional reallocation (i.e., submitting intrastate wholesale rates by mutual consent of the parties to the state commissions for a fixed period, subject to review by FERC).¹²⁶ Instead, Herbert Cohn of the

American Electric Power Company proposed an alternative model which would amend the Federal Power Act to provide that wholesale electric power transactions would be exempt from FERC jurisdiction and subject to state regulation in cases where all of the following conditions were met:¹²⁷

- (1) The purchaser and substantially all of its retail customers (and, if it has any wholesale customers, they and substantially all of their customers) are located within a single state.
- (2) The seller has substantial retail revenues in the same state and its retail rates within such state are regulated by the regulatory agency of that state.
- (3) The sale takes place within such state.
- (4) The regulatory agency of such state has jurisdiction to and does, in fact, regulate such wholesale sales.

Cohn anticipated that under his model, a rate case before the state commission would cover--in the same applications and proceeding--not only retail rates but also the wholesale portion of a company's business that would have become subject to state commission jurisdiction. This, he felt, would, "eliminate a great deal of the duplication of effort and expense (currently) associated with dual regulation, dual applications, and dual proceedings." Cohn's proposal never received much support from within the investor-owned segment of the industry and was strongly opposed by the various public power constituencies.

As noted in earlier sections, the issue of jurisdictional transfer of FERC wholesale rate authority to the state commissions emerged most recently in the context of "regional regulation" legislation (H.R. 5766) proposed by the National Governors Association (NGA) with support from NARUC. H.R. 5766 would have provided advance Congressional approval for

the creation of voluntary interstate compacts to coordinate regional power supply planning and certain aspects of utility regulation.

Title II of the proposed legislation would have granted new authority to the states to regulate rates for selected intrastate wholesale electricity transactions currently subject to FERC jurisdiction under the Colton doctrine. The only limitations imposed on such transfer of authority were that the state must demonstrate that it has the requisite statutory authority to regulate wholesale rates and the retail sales of the (wholesale) customers involved in the proposed jurisdictional transfer must be located entirely within the state requesting the transfer. Hearings were held on H.R. 5766 during the 98th Congress, but no action was taken.¹²⁸ Investor-owned utility opposition to the jurisdictional transfer provisions of the bill was based on the following considerations:¹²⁹

- ° The proposed legislation would have eliminated the current uniformity in interstate wholesale rate regulation and introduced a variety of jurisdictional conflicts which would inhibit intersystem coordination and result in inequitable allocations of costs between customers in neighboring jurisdictions.
- ° Under the bill, a state could regulate wholesale sales even though the customers of the seller are located in other states. This could create substantial inequities in cost allocations since the state commission regulating the transaction would presumably have an incentive to hold that rate down as much as possible (to benefit customers in its own state) even though this would penalize the retail customers of the seller who are located in another state.
- ° Under the bill, a power pool or other form of coordination agreement would be subject to state regulation only if all of its members were located in the same jurisdiction. This would create an incentive for the state commission to limit any expansion of the pool outside the state and thereby limit cost-effective interstate coordination opportunities.

Public systems, while expressing support for the regional power supply planning and mandatory wheeling provisions of H.R. 5766, were strongly opposed to provisions of Title II dealing with jurisdictional transfer. The American Public Power Association summarized its opposition to transfer of wholesale rate regulation to the states in the following terms:¹³⁰

- (1) Bulk power transactions, even in cases where the retail sales of the purchasing system are entirely within one state, are essentially interstate in nature.
- (2) Many state commissions have limited staff and a multiplicity of functions (and lack the resources to handle any additional functions such as wholesale rate regulation).
- (3) It is the regulators and not the regulatory framework which have given rise to wholesale electric regulatory problems. The regulatory framework, if adhered to properly and fairly, can and should provide adequate protection from unjust, unreasonable, and discriminatory rates being set for wholesale customers.
- (4) Local public power systems continue to place a high value on their authority to regulate their own retail rates. The transfer of regulation over wholesale rates to the state commissions could result in a consolidation of jurisdiction over both wholesale and retail rates of local public power systems.
- (5) There is strength in numbers. With wholesale rate regulation concentrated at the federal level, wholesale purchasing systems acting in concert have a greater opportunity to influence wholesale rate policy issues, both administratively and legislatively.

The FERC also expressed its opposition to Title II of the proposed legislation citing concerns over the possibility of discrimination problems and regulatory inefficiencies which might arise under such a reallocation of regulatory responsibilities.¹³¹ Overall, there appeared to be very little support for the jurisdictional transfer provisions of

H.R. 5766 except for the two sponsoring organizations (i.e., NGA and NARUC).

While the outlook for similar legislation in the 99th Congress is unclear, strong opposition to the jurisdictional transfer provisions of the bill is likely to continue among each of the constituencies cited above. An exception may be those few cases where (a) the percentage of a company's overall business that is subject to FERC jurisdiction is relatively small, (b) both buyer and seller are intrastate systems, and (c) both parties agree to the proposed transfer of jurisdiction on the basis of regulatory efficiency (i.e., avoiding the costs of dual filings, etc.) Possible support for limited transfer of jurisdiction for "intrastate" wholesale transactions to the states was expressed by Secretary of Energy Donald Hodel in a recent presentation to NARUC.¹³² His comments, however, were framed in terms of options for further consideration rather than explicit endorsement of any particular jurisdictional transfer proposal.

This legislative environment could change very quickly, however, if there is a major effort by utilities to invoke any of the various strategies outlined in this report as a means of transferring jurisdiction to the FERC. Under such circumstances, Congress and the Administration might be more sympathetic to legislative proposals designed to restore the status quo. Conversely, a narrowing of the perceived advantages of FERC regulation from a utility perspective would reduce the incentives for a utility to examine means of coming under FERC regulation.

Another development which could possibly affect the legislative situation regarding jurisdictional transfer is how the Courts interpret the Narrangansett doctrine with regard to state authority to consider the prudence of the purchaser in a FERC approved wholesale bulk power transaction. As noted earlier, several states have asserted authority to examine the prudence of the transaction itself in the context of alternative resource acquisition decisions that (arguably) could have been made by the utility. In at least one instance, the state's authority to initiate such inquiries has been upheld by a state court. Furthermore, a series of recent FERC decisions seems to support the notion that such an examination by a state commission of the purchaser's prudence in entering into a particular wholesale transaction is consistent with Narrangansett.

The current reading of Narrangansett, as upheld by the federal courts, is that a state commission inquiry into the "reasonableness" of a wholesale rate filed with the FERC is preempted by exclusive federal jurisdiction under the Federal Power Act. However, under the Pike County, Massachusetts DPU, and Wyoming Supreme Court decisions discussed earlier and the above noted FERC decisions, a state commission may still have authority to determine whether a utility should have pursued alternatives to a particular wholesale purchase. In this sense, a state may not disallow recovery of the costs of such a purchase unless it finds the transaction itself to have been "imprudent." Future efforts by state commissions to expand the scope of their "prudence inquiries" under this emerging interpretation of Narrangansett could stimulate both judicial and legislative efforts by utilities to remove the uncertainty

and restore the "bright line" of demarcation between federal and state jurisdiction over wholesale electric rates.

NOTES

¹For example, between 1882 and 1905, the City of Chicago and its suburbs awarded no less than 47 service franchises to competing electric power suppliers.

²For a more comprehensive review of the evolution of industry structure and state utility regulation see, Richard L. Gordon, Reforming the Regulation of Electric Utilities, Lexington, Mass., 1982.

³Ibid.

⁴The holding company structure was first introduced into the industry by electric machinery manufacturers, to provide small utilities with the capability to finance purchases of generating equipment. (This motive became less significant as operating companies grew large enough to gain independent access to capital markets.) Some holding companies were formed to bring contiguous operating companies in adjoining states under common control, in instances where states had created legal obstacles to merger or operation of utilities by corporations organized in other states. Such consolidation was rationalized in terms of providing centralized services and achieving economies of scale in system design and operation that were beyond the reach of individual companies. The growth of holding companies was also spurred by the regulation gap created by the 1927 Attleboro decision. See, Duke Power vs. FPC, 401 F.2d 930, 934 (D.C. Cir. 1968).

⁵15 U.S.C. 79 et., seq; 49 Stat. 803 (1935). The ideal utility envisioned by the Act was a company with a simple organizational structure, engaged predominately in the electric utility business, with all its electric utility operations conducted as an integrated system concentrated in a contiguous geographic area confined to one or a few states. Ongoing regulation by the SEC is designed to preserve this structure. Registered holding companies (whose subsidiaries are already subject to financial and accounting regulation by FERC and state commissions) are also subject to comprehensive financial and accounting regulation by the SEC.

⁶273 U.S. 83 (1927).

⁷Ibid.

⁸Federal Power Act, §201(a), 16 U.S.C. 824.

⁹Ibid.

¹⁰This view of Congressional intent regarding federal jurisdiction over wholesale transactions is outlined in G. Philip Nowak and Charles Cochran, "Court Blurs Bright Line in Utility Regulation," Legal Times, August 29, 1983, p. 14.

¹¹Senate Report 621, 74th Congress, 1st Session (1935), p. 17.

¹²252 U.S. 23, 40 S. Ct. 279 (1920).

¹³265 U.S. 298, 44 S. Ct. 544 (1924).

¹⁴15 USC §717, et seq. (Supp. 1982).

¹⁵Federal Power Commission vs. Southern California Edison Co., 376 U.S. 205, 52 PUR3d 321, 327, (1964) quoting Panhandle Eastern Pipe Line Co. vs. Indiana Public Service Commission, 332 U.S. 507, 71 PUR NS 97, 102, 103, (1947).

¹⁶314 U.S. 498, 62 S. Ct. 384, (1942).

¹⁷Ibid.

¹⁸68 Stat. 36 (1954), 15 U.S.C. Sec. 717(c).

¹⁹In 1942, a lower federal court upheld the FPC's jurisdiction over the accounting practices of a company generating and operating locally but interconnected with other companies beyond the state [Hartford Electric Light Co. vs. FPC, 2 FPC 359, affirmed 131 F. 2d 953 (1942)]. This "expensive" interpretation of interstate commerce was enlarged a year later when Commission jurisdiction over the Jersey Central Power and Light Company was sustained. This company was purely an intrastate utility but it occasionally sold power to another intrastate company, which in turn interchanged power with a company in New York. The basis of the Court's decision in this case, was the fact that the company's facilities were used in interstate transmission, not that the company itself was directly engaged in interstate commerce, Jersey Central Power and Light Co. vs. FPC, 319 U.S. 61 (1943).

²⁰Federal Power Commission vs. Southern California Edison Co., 376 U.S. 205, reh. denied, 377 U.S. 913 (1964).

²¹Ibid.

²²Ibid.

²³Eighty-Eighth Congress, 2nd Session, S. 2028 and S. 3038.

²⁴Senate Commerce Committee, Hearings on S. 218, "Exemption of Certain Public Utilities from Federal Power Commission Jurisdiction," statement of Senator Spessard L. Holland, 89th Congress, May 12, 1965, p. 5.

²⁵Statement of Farner H. Lundy, Chairman of the New York State Public Service Commission, Hearings on S. 218, op. cit., p. 151.

²⁶Ibid.

²⁷Statement of Edwin L. Mason, Chairman of the Florida Public Service Commission, Hearings on S. 218, op. cit., p. 100.

²⁸Statement of H.L. Culbreath Jr., of Tampa Electric Company, Hearings on S. 218, op. cit., p. 183.

²⁹Statement of Joseph Swidler, Chairman of the Federal Power Commission, Hearings on S. 218, pp. 62-69.

³⁰Ibid.

³¹Ibid.

³²Statement of Alex Radin, President of the American Public Power Association, Hearings on S. 218, op. cit., p. 288-89.

³³Ibid., p. 301.

³⁴119 RI 559, 381 A2d 1359 (R.I. 1977), cert. den. 435 U.S. 972 (1979).

³⁵446 NE 2d 684 (Mass. 1983).

³⁶Thomas Pietronto, "The Preemptory Effect of an FERC Rate Approval," Public Utilities Fortnightly, August 16, 1984, p. 55.

³⁷Minnesota Public Utilities Commission, et al. vs. Northern States Power Co., No. CX-82-1130, (Minn. S. Ct., Jan 27, 1984).

³⁸Petition for writ of certiorari filed by State of Minnesota, Minnesota PUC vs. Northern States Power Co., op. cit.

³⁹Brief in opposition to petition for writ of certiorari filed by Northern States Power Co., Minnesota PUC vs. Northern States Power Co., op. cit.

⁴⁰465 A2d 735 (Pa Commonwealth 1983).

⁴¹Ibid.

⁴²Pietronto, op. cit., p. 56.

⁴³See, for example, Nowak and Cochran, op. cit. Also Andrew J. O'Neil, "Retail Electric Rates: Drawing the Line Between Federal and State Authority Under the Commerce Clause," Public Utilities Fortnightly, October 27, 1983, p. 52.

⁴⁴456 U.S. 743 (1982).

⁴⁵103 S. Ct. 1905, 51, U.S.L.W. 4539 (1983).

⁴⁶103 S. Ct. 1713, 51, U.S.L.W. 4449 (1983).

⁴⁷Arkansas Electric Cooperative vs. Arkansas Public Service Commission, 618 S.W. 2d 151, (1981).

⁴⁸Arkansas Electric Cooperative Corp., op. cit.

⁴⁹Arkansas Electric Cooperative Corp., op. cit.

⁵⁰397 U.S. 137, 142 (1970).

⁵¹Arkansas Electric Cooperative Corp., op. cit.

⁵²FERC vs. Mississippi, op. cit.

⁵³No. LR-C-84-778 (E.D. Ark., September 14, 1984).

⁵⁴Mass. D.P.U., Docket No. 84-3B-2 (May 10, 1984) (Appeal filed).

⁵⁵Spence vs. Smyth et al., 686 P2d 597, August 29, 1984.

⁵⁶See, for example, order issued October 15, 1984, in Southwestern Public Service Company, Docket No. ER84-604, 29 FERC ¶61,056.

⁵⁷Regulations under the Federal Power Act, 18 CFR 35.14.

⁵⁸These principles included a specific "Adjustment Factor" formula together with specifications of the costs and kWh sales to be employed in the formula, and treatment to be accorded losses, taxes, etc.

⁵⁹Economic Power is defined as "power or energy purchased over a period of twelve months or less where the total cost of the purchase is less than the buyer's total avoided variable cost." 18 CFR 35.14(a)(11)(i).

⁶⁰The FERC has also permitted other types of automatic adjustment mechanisms in wholesale rates including tax adjustment clauses and "cost of service rates" which adjust for changes in all costs.

⁶¹Charles River Associates and Pfeffer, Lindsay and Associates, Economic Analysis of Electric Utility Earnings Attrition, prepared for the Office of Coal and Electricity Planning, U.S. Department of Energy, Washington, November 1984.

⁶²In a subsequent revision, the Commission now permits the use of an historical test year where the filing is for an increase of less than \$1,000,000 per year, or the customers have consented to the increase.

⁶³See Minnesota Public Service Commission, Order E-015/GR-76-408, (1976); New York State Public Service Commission, Opinion No. 80-11, Case 27533, (1980); Iowa State Corporation Commission, Order Approving Stipulation, Docket Nos. RPU79-10, RPU80-4(1981).

⁶⁴FERC Order No. 298, Docket No. RM81-38, May 16, 1983.

⁶⁵The Commission's order has been appealed to the U.S. Court of Appeals for the District of Columbia Court. Oral argument was heard in November 1984 and a decisions is being awaited.

⁶⁶Edison Electric Institute, "State Commission Policy on Construction Work in Progress in Rate Base: A Survey of Investor-Owned Utilities," Washington, August 5, 1983.

⁶⁷FERC, Opinion No. 49, Docket Nos. ER76-304, ER76-317, and ER76-498.

⁶⁸FERC, Opinion No. 62, Re Southern California Edison Co., Docket No. ER76-205, 1978.

⁶⁹For example, Arizona Commission, Decision No. 51009, Re Arizona Public Service Co., Docket No. U-1345, 1980.

⁷⁰See for example, Massachusetts order in Boston Edison Co., Mass DPU No. 906, issued April 30, 1982 (13 years); North Carolina PCU order in Carolina Power & Light, issued September 24, 1982, (10 years); Indiana PSC in NIPSCO, order issued August 11, 1982 (15 years); and FERC Opinion No. 49 in NEPCO, issued July 9, 1979 (5 years).

⁷¹FERC Opinion No. 134, issued December 3, 1981, 17 FERC ¶61,196.

⁷²See for example, Massachusetts DPU order issued April 30, 1982, in a proceeding identified as DPU 906, affirmed by the Supreme Judicial Court of Massachusetts in Attorney General vs. Department of Public Utilities, 390 Mass. 208, 455 N.E.2d 414 (1983). For a comprehensive review of state ratemaking treatment of abandonment costs see, Edison Electric Institute, Regulatory Treatment of Cancelled Plants, March, 1984.

⁷³Montana Public Service Commission, Order No. 5051C, Docket No. 83.9.67.

⁷⁴Massachusetts Department of Public Utilities, Final Order in Western Massachusetts Electric Co., DPU 84-25, July 31, 1984.

⁷⁵A more detailed understanding of how local political considerations enter into state regulatory decisionmaking from an investor's perspective can be derived from a review of the ranking process of state regulatory agencies used by Argus Research, Salomon Brothers, and other Wall Street investment advisory firms.

⁷⁶This view was most clearly reflected in the report of the DOE Electricity Policy Project, The Future of Electric Power in America, DOE/PE-0045, June 1983. A sharply contrasting perspective of the financial problems of the industry was presented in a recent study by the General Accounting Office, Analysis of the Financial Health of the Electric Utility Industry, GAO/RCED-84-22, June 1984.

⁷⁷ See, for example, comments of the Edison Electric Institute in FERC Docket Nos. Rm 81-38 (CWIP), and RM 80-36 (Generic Rate-of-Return). Conversely, in the CWIP proceedings, several state commission specifically noted they would not be influenced by the proposed changes in FERC policy and indeed were concerned that the resultant conflicts between state and federal ratemaking policies would lead to a "price squeeze" situation.

⁷⁸ Department of Energy, op. cit.

⁷⁹ See, George Hall, "Regulation and the Commercialization of Synthetic Gas," Public Utilities Fortnightly, Vol. 108, No. 10, November 5, 1981, pp. 24-30.

⁸⁰ FERC, Docket No. QF 84-121, April 19, 1984, 27 FERC ¶61,094.

⁸¹ Eastern Utilities Associates which operates in Massachusetts and Rhode Island is another example of this type of structure.

⁸² New England Electric System, Form 10-K, filed with the Security and Exchange Commission, 1983, p. 10.

⁸³ See, for example, Testimony of Rhode Island Governor John Garrahy, before the House Energy Conservation and Power Subcommittee, Hearings on H.R. 555, February 7, 1984, p. 7.

⁸⁴ National Governors Association, Committee on Energy and Environment, Statement of Proposed Changes in Policy, Annual Mid-Winter Meeting, February 28, 1983, pp. 15-21.

⁸⁵ NGA Task Force on Electric Utility Regulation, An Analysis of Options for Structural Reform in the Electric Utility Industry, January 1983, p. 14.

⁸⁶ Ibid., p. 14.

⁸⁷ Ibid., pp. 14-15.

⁸⁸ National Governors Association, op. cit., p. 17.

⁸⁹ Dominion Resources, The Organization of Dominion Resources, Issue Paper issued June 29, 1984.

⁹⁰ Ibid., p. 2.

⁹¹ Ibid., p. 15.

⁹² Washington Post, "VEPCO Ponders Plan to Put It Beyond States Regulatory Grasp," Washington, September 12, 1983.

⁹³ For example, in one recent case, the State of Maryland invoked a 70-year old statute originally intended to restrict utility takeovers by

outside interests to block a proposed reorganization of the Baltimore Gas and Electric Company into a holding company structure. Maryland Public Service Commission, Case No. 7686, Order No. 66254, June 16, 1983. In another recent case the Massachusetts Department of Public Utilities (MDPU) rejected a proposal dealing with reorganization of Boston Edison Company, MDPU, Order No. 850, February 9, 1983. In both of these cases, however, the primary objective of the proposed reorganizations were diversification into new lines of business and not jurisdictional transfer.

⁹⁴House Subcommittee on Energy Conservation and Power, Hearings on H.R. 5220 et al., (Bills to amend or repeal the Public Utility Holding Company Act), Testimony of Stanley York, Chairman of the Wisconsin PSC on behalf of the National Association of Regulatory Utility Commissioners (NARUC), June 9, 1982, pp. 680-690. Also, see Testimony of Floyd W. Lewis, Chairman of Middle South Utilities Inc. on behalf of Edison Electric Institute, Appendix A, Effect of State Laws and Regulations on Utility Diversification, pp. 327-377.

⁹⁵For a comprehensive overview of SEC and FERC regulatory authority over electric utility holding companies see Edison Electric Institute, "Effect on Electric Utility Diversification of the Federal Power Act and Related Laws," Hearings on H.R. 5220, op. cit., July 1981, and "Statement of U.S. Securities and Exchange Commission Concerning Proposals to Amend or Repeal the Public Utility Holding Company Act of 1935," pp. 540-675.

⁹⁶Some of the descriptive information on the ESPRI model and other types of joint ownership arrangements discussed in this section is derived from a report prepared by Gordian Associates, for the Federal Energy Administration, Structural Reforms in the Electric Power Industry, FEA/G-76-323, Washington 1976.

⁹⁷Petition to New York PSC by ESPRI Sponsors under Section 69 of New York Public Service Law dated December 17, 1974. The ESPRI proposal was considered by the PSC as Empire State Power Resources Inc., New York State Public Service Commission, Case No. 26798.

⁹⁸Federal Power Commission, Docket No. ES 76-7.

⁹⁹New York State Legislative Institute, The New York Utilities' Plan to Form the Empire State Power Resources Consortium, June 1977, Part II, p. 6.

¹⁰⁰FPC (Bureau of Power) Staff Memorandum dated March 19, 1976, p. 2.

¹⁰¹Decision of the New York PSC, Case No. 26798, April 1979.

¹⁰²Jacob J. Worenklein, "Project Financing of Joint Ventures," Public Utilities Fortnightly, December 3, 1981. Theodore Barry and Associates, A Study of Aggregation Alternatives in the U.S. Electric

Utility Industry, as summarized in U.S. Department of Energy, DOE/RG/10295-1, December 1982.

¹⁰³The Yankee Companies include: Yankee Atomic Electric Company, Vermont Yankee Nuclear Power Corporation, Maine Yankee Atomic Power Company, and Connecticut Yankee Atomic Power Company each which owns a single nuclear generating unit.

¹⁰⁴A recently enacted Maine statute provides that, if both a newly created trust fund and Maine Yankee have insufficient assets to pay for plant decommissioning, the owners of Maine Yankee are jointly and severally liable for the shortfall. The definition of owner under the statute covers all participants in the plant.

¹⁰⁵ESPRI's investment bankers did not believe the consortium could be financed without joint and several liability among participants. New York State Legislative Institute, op. cit.

¹⁰⁶In Maine Yankee, for example, the FPC's order permitting the power contracts to become effective as rate schedules, specified that changes in Yankee's capital structure resulting in an increase of its common equity to more than 40 percent of total capitalization would constitute a change in its filed rate schedule, requiring a timely filing in accordance with FPC regulations.

¹⁰⁷Southern States Energy Board, Region-Specific Study of the Electric Utility Industry, November 1983, p. 28.

¹⁰⁸Rev. Rul. 344, 1968-1 Comm. Bull. 569.

¹⁰⁹The Sterling Agreement consisted of a Basic Agreement, Construction Agreement, and Operating Agreement among Rochester Gas and Electric Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., and Central Hudson Gas and Electric Corporation. The agreement was executed in September 1975 and terminated in early 1980's following cancellation of the proposed plant.

¹¹⁰Northern States Power Company, op. cit.

¹¹¹The parent company, NSP (Minnesota), accounts for about 85 percent of the aggregate load with the balance split among the two subsidiaries.

¹¹²NSP-W is separately incorporated as required by Wisconsin law and thus is a separate public utility under the Federal Power Act, Section 201(e). Likewise, NSP-M is a separately incorporated entity in Minnesota. The two companies, even though affiliated, are legally prohibited from exchanging electricity except through a coordinating agreement or some other form of FERC regulated rate schedule.

¹¹³State of Minnesota, Brief in Support of Petition for Writ of Certiorari, op. cit., pp. 12-13.

¹¹⁴State of Minnesota, Brief in Support of Petition for Writ of Certiorari, op. cit., pp. 16-17.

¹¹⁵Brief Amicus Curiae in support of Petition for Writ of Certiorari, State of Minnesota vs. Northern States Power Company, filed by the states of Connecticut, Hawaii, Illinois, Kansas, Louisiana, Michigan, Mississippi, Missouri, New Jersey, Ohio, Rhode Island, South Carolina, Texas, Vermont, and Wyoming.

¹¹⁶Brief Amicus Curiae in Support of Petition for Writ of Certiorari, Minnesota vs. Northern States Power Company, op. cit., filed by the States of Virginia and North Carolina.

¹¹⁷Ibid.

¹¹⁸Middle South Service, Inc., FERC Docket No. ER82-483.

¹¹⁹The affiliated groups can be subdivided into (a) holding company pools that are not themselves members of other power pools, and (b) other affiliated groups that are members of non-affiliated power pools. The principal holding company pools that are not members of other power pools and that are subject to the jurisdiction of the FERC are (a) Allegheny Power System, Inc. (APS), (b) American Electric Power Co., In., (AEP), (c) Middle South Utilities, Inc. (MSU), and (d) Southern Company System (SOCO). Each of these includes between three and seven operating electric company subsidiaries which, in most cases, operate in separate state jurisdictions. Each is centrally dispatched. Each has one or more committees that are responsible for coordination of the operation and/or planning of the constituent systems. Each also has a service company, which is a separate subsidiary of the holding company, and which is generally responsible for, or participates in, the coordination of the planning and operation of the total system.

These principal holding company groups that are members of non-affiliated power pools include: General Public Utilities (GPU), Eastern Utilities Associates (EUA), New England Electric System (NEES), Northeast Utilities (NEU), and the Northern States Power Group (NSP). NEES, NEU, and EUA are members of the New England Power Pool (NEPOOL). Each group participates as a single member of its respective pool although its subsidiaries operate in several states.

¹²⁰Data on Southern Company off-system sales are derived from its 1983 Annual Report and its 1983 Form 10-K filed with the Securities and Exchange Commission.

¹²¹28 FERC ¶61,350 (1984).

¹²²15 FERC ¶61,264 at 61,019 (1981).

¹²³23 FERC ¶61,006 at 61,019 (1983).

¹²⁴ Charles B. Curtis, Decisional Delay in Wholesale Rate Increase Cases: Causes, Consequences and Possible Remedies, Federal Energy Regulatory Commission, Washington, 1980, pp.105-110.

¹²⁵ Ibid.

¹²⁶ Herbert B. Cohn, "The Regulation of Electric Power Wholesales," Public Utilities Fortnightly, March 1, 1979, pp. 54-57.

¹²⁷ Ibid., pp. 56.

¹²⁸ House Subcommittee on Energy, Conservation and Power, Committee on Energy and Commerce, Hearings on H.R. 5766, 98th Congress, 2nd Session, June 26, 1984.

¹²⁹ Comments of the Edison Electric Institute, Hearings on H.R. 5766, op. cit., pp. 12-13.

¹³⁰ Testimony of the American Public Power Associates, Hearings on H.R. 5766, pp. 4-5.

¹³¹ Testimony of Raymond J. O'Connor, Chairman of the Federal Energy Regulatory Commission, Hearings on H.R. 5766, op. cit.

¹³² Remarks by Donald Paul Hodel, U.S. Secretary of Energy to the 96th Annual Convention of the National Association of Regulatory Utility Commissioners, November 27, 1984.

