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NON-TECHNICAL IMPEDIMENTS TO POWER TRANSFERS

Edited by Kevin Kelly
Associate Director for
Electric and Gas Research

THE NATIONAL REGULATORY RESEARCH INSTITUTE
1080 Carmack Road
Columbus, Ohio 43210

<u>Contributors</u>

Alvin Kaufman, Consulting Economist
Robert E. Burns, Senior Research Associate, NRRI
Pfeffer, Lindsay & Associates, Inc.
Fred C. Schweppe, Meta Systems, Inc.
Casazza, Schultz & Associates, Inc.

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EXECUTIVE SUMMARY

This study examines the obstacles to electric power transfers, other than the limitations imposed by existing transmission system capacity. Four categories of non-technical impediments are identified: institutional, legal, regulatory, and economic. There are several specific impediments in each category. These are summarized in table ES-1.

If the level of power transfers is less than optimal, this is partly due to the impediments presented by the basic institutions for producing, delivering, and regulating electric service in the United States. Over 3000 electric utilities of various kinds, together with industrial cogenerators and small power producers, produce electricity or deliver it to retail customers. Many of these companies have an exclusive franchise from government to provide monopoly service to customers. An increase in power transfers often means more competition to serve a utility's historical retail and requirements customers. Such competition may be resisted as it tends to alter these insitutional arrangements.

National, state, and local laws in the U.S. may also impede power transfers. In fact, the Congress has always been careful to withhold or limit the authority of administrative agencies to force electric utilities to transmit power involuntarily. State authority to do this is constrained and uncertain because of the weak federal role. Conflicts between federal and state authorities in some areas and lack of authority by either side in other areas impede the development of power transfer policies.

Regulatory agencies can create roadblocks to moving power. Federal regulation of transmission and state regulatory treatment of transmission revenues may create disincentives to greater coordination of electric power generation. Perhaps more important, regulations covering the siting and licensing of new transmission lines can impede construction of new transmission capacity and limit the degree of coordination possible in the future.

Given the choice, utilities will not choose to transmit electric power unless transmission service is economically attractive. In the current environment, uncertainties about the regulatory calculation of wheeling costs and the design of wheeling rates weaken the economic incentives to provide transmission service that would be expected in an unregulated environment.

These four types of impediments--institutional, legal, regulatory, and economic--are discussed by four analysts, and each analyst identifies the more important impediments in his category. These are indicated by the asterisks in table ES-1. Each analyst also develops recommendations for overcoming the impediments in his category where appropriate.

Not all impediments should necessarily be overcome. For example, although one recognizes that the franchise system impedes some power transfers, a policy analyst may decide to preserve this system because of the natural monopoly character of electric service. Another policy analyst, of course, could decide in favor of competition and against some features of the present franchise system.

TABLE ES-1

NON-TECHNICAL IMPEDIMENTS TO POWER TRANSFERS

(Asterisks denote the more important impediments.)

I.

INSTITUTIONAL IMPEDIMENTS

Regulatory Institutions
* Federal-State Dichotomy
* Franchises
  Rate-of-Return Regulation

Organizational Institutions
* Diversity of Ownership
* Holding Companies & Power Pools
* Avoided Costs for Cogeneration
  Changes in Fuel Use Restrictions
* Mergers and Buy-Outs

Opposition to New Operational Institutions
  Competition and Bypass
* Mandatory Wheeling
  National Grid
  Spot Market

II.

LEGAL IMPEDIMENTS

Limited FERC Authority
* Over Wheeling
  Over Interconnections

State Authority Over Wheeling
  Limitations
* Uncertainty

Franchise Laws
  Monopoly Service Areas
  Cogeneration Sales Restrictions

Antitrust Laws
  Standards of Proof
  State Action Exemption

Laws Impeding Construction
* Siting
  Certification
  Eminent Domain

Loop Flows
  Neighbors' Right

III.

REGULATORY IMPEDIMENTS

FERC Regulations
  Filing Requirements
* Embedded Cost Pricing
  Rolled-In Costing
* Voluntary Agreement Uncertainty
  Multisystem Transmission Rates
  Fixed Equity Returns
* Termination of Contracts

State and Local Regulations
* Treatment of Transmission Revenues
* Siting and Licensing New Lines

Federal-State Jurisdictional Uncertainty
  Overlapping Authorities
  Weak Regulatory Authorities

IV.

ECONOMIC IMPEDIMENTS

Uncertainty about Wheeling Costs
  Costs by Type of Customer
  Costs by Type of Wheeling
  Operating, Network & Generation Capital Costs

Uncertainty about Wheeling Rates
  Embedded versus Marginal Costs
* Marginal Cost Measurement
* Rate Structure Determination
* Revenue Reconciliation

Uncertainty about Profit and Loss
* Buyer/Seller versus Wheeler Profits
* Losses for Bypassed Generating Plant
  Lost Trading Opportunities

Also, not all the impediments identified are equally important or are necessarily significant in practice. In order to get some indication of the relative importance of the various impediments in practice, three cases involving transmission conflicts were studied. One case involves attempts by investor-owned utilities to construct a new transmission line in Maryland. The second case deals with the wheeling needs of a municipal utility in Louisiana that wants to offer retail service to an industry outside the municipal service territory. The third case involves multiple attempts to obtain transmission service by a relatively new agency formed to increase the market buying-power of some two-dozen municipal utilities in Wisconsin. Among the conclusions drawn from the case studies are that in practice (1) many non-technical impediments are almost inseparable from important technical issues, particularly the loop flow issue; (2) transmission access issues often involve dividing up existing savings instead of creating new savings; and (3) decisions about transmission systems are often regional, affecting several states, and need to be addressed at a level appropriate to the region affected.

Among the five analysts, including the case studies' author, there is, of course, not complete agreement about the significance of all the impediments listed in table ES-1. All agree, however, that three major impediments are:

* Opposition to Mandatory Wheeling

  Many utilities oppose being required to provide transmission service, in part because of conflicts between franchise obligations and the desire for competition. At times, they may refuse temporary wheeling service for fear that, once started, it cannot be terminated.

* Roadblocks to Constructing New Lines

  Constructing a new transmission line can be seriously impeded by cumbersome legal and regulatory requirements for siting and licensing the line in the many state and local jurisdictions it traverses. While obtaining the necessary regulatory and siting approvals for building a new line must take some time, opponents of the line can repeatedly use the approval process and associated legal appeals to delay construction for an excessively long time.

* Incorrect Pricing of Transmission Service

  Traditional ratemaking for wheeling services does not provide the economic incentives for utilities to wheel power voluntarily. Further, prices may well be set below marginal costs and so discourage wheeling.

TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

FOREWORD

This is a follow-on report to our August 1987 study, Some Economic Principles for Pricing Wheeled Power. Like its companion study, the present report was prepared mainly at the request of the Strategic Issues Subcommittee of the NARUC Committee on Electricity. It considers the non-technical impediments to power transfers under four general groupings--institutional, legal, regulatory, and economic. In addition, three case studies involving different types of impediments are presented. Taken together we believe these reports advance commission knowledge of current policy issues surrounding the subject of wheeling and why more of it doesn't take place.

Douglas N. Jones
Director
Columbus, Ohio

September 4, 1987

ACKNOWLEDGEMENTS

Several groups and individuals contributed to the design and conduct of this study. The idea for the study originated with the Strategic Issues Subcommittee of the NARUC Committee on Electricity, led by Commissioner Ashley Brown of the Public Utilities Commission of Ohio. Members of this Subcommittee, members of the NRRI Research Advisory Committee, and other state commissioners and staff were particularly helpful in the selection of the case studies reported on in this volume, especially Commissioners Brown, William Badger (Maryland), Charles Thompson (Wisconsin), Michael Greer (West Virginia), and Brian (Ted) Stewart (Utah); also Whit Russell of Whitfield Russel & Associates, Mary Bane and Shef Wright (Florida PSC), Jerry Mendl (Wisconsin PSC), Roy Edwards (Louisiana PSC), and Robert Whitaker (New York PSC). (While they advised on case study selection, they did not review and do not necessarily agree with the case study reports that resulted.)

Special thanks go to Patricia Brower of NRRI who helped assembled the five papers into one unified volume.

PLAN OF THE REPORT

Kevin Kelly
Associate Director, NRRI

This study is intended to answer the question: When there is a difference in electricity generation costs between two utilities or power suppliers and there is no technical impediment to power transfer between them, why doesn't the power flow? This simple question can have many answers, depending on the circumstances of the parties; more than one impediment may exist in many cases.

The two companies may be directly connected or may require a third party to transmit, or wheel, the power between them. Two-party trading is less often at issue than three-party wheeling.

Background

The study was undertaken at the request of Strategic Issues Subcommittee of the NARUC Committee on Electricity. The Subcommittee takes as given the fact that many more opportunities exist for beneficial power exchanges than are taken advantage of, and so NRRI did not undertake a cost-benefit analysis to determine whether the current level of supply coordination is less than optimal.

An opportunity for beneficial power transfer exists when two conditions are met. First, adequate transmission capacity links the seller and buyer and is available for use without endangering system stability or service reliability. Second, the buyer's true avoided generation cost is greater than the sum of the seller's generation cost, the cost of energy lost in transmission, and any other real costs of providing transmission service. (Somewhat different conditions may apply to transferring power in emergencies.) Under these conditions, there is no technical impediment to power transfer, and if the power does not move there must be one or more non-technical impediments.

If a generation cost difference continues for several years, there should be time to construct new transmission capacity. This implies that any technical impediment can be overcome, given time, at some cost. If the benefits justify this cost, then the power should flow. Thus, one can argue that there are no long-term technical impediments to power transfer, only non-technical ones. Of course, in the short-run the technical problems of getting the most use out of existing facilities, within the constraints imposed by stability and reliability, are real and quite complex.

The Strategic Issues Subcommittee asked the Electric Power Research Institute (EPRI) to study technical impediments to power transfers and asked the National Regulatory Research Institute (NRRI) to study non-technical impediments.[1] The NRRI was also asked to develop recommendations for overcoming the impediments identified. The Subcommittee realized at the outset that one particular non-technical impediment is of special importance: the uncertainty about how to set rates for wheeling services. Unless the wheeling price accurately reflects the transmission cost, the second condition given above for beneficial power transfer becomes very difficult to apply. This is because the parties see the "cost" of transmission as the price of transmission service, which may or may not reflect the true cost. Hence, NRRI was also asked to do a separate in-depth study of how to price wheeling services. The EPRI and two NRRI studies are being issued at about the same time, August-September 1987. The companion NRRI report, <u>Some Economic Principles for Pricing Wheeled Power</u> (NRRI-87-7), was published in August 1987.

The companion report contains a transmission glossary, a discussion of the technology of power transfers, and an introduction to the technical limitations on power transfer capability. These are not repeated here. While this report on impediments is self-contained, some readers may wish to consult the companion report to become familiar with the technical terminology. For most readers, the introductory material provided in the first paper of this <u>Impediments</u> volume serves adequately to introduce the issues.

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[1] Some Subcommittee members may have stimulated the interest of other groups in transmission issues. The National Governors' Assocation issued a transmission policy report that emphasized state-level measures to facilitate power transfers. Federal policies are under consideration in studies now being conducted by the Federal Energy Regulatory Commission, the Congressional Office of Technology Assessment, and the General Accounting Office.

Organization

Four categories of non-technical impediments are identified: institutional impediments, legal impediments, regulatory impediments, and economic impediments. This study contains a paper addressing each of these. A fifth paper reports on three case studies of transmission-related conflicts in which the relative importance of some of the specific impediments is assessed.

The four impediments papers begin with the most general reasons for any inadequacies in national power sharing and move toward the most specific reasons. Institutional impediments arise from the basic ways that have evolved in the United States for supplying electricity. Some other nations, by contrast, have a single government-owned electric utility; others supply electricity through a half-dozen quasi-governmental agencies; and others rely on a few large privately-owned companies. The U.S. has over 3000 electric utilities. These consist of a great variety of sizes and ownership types--including ownership by the national government, city governments, electric consumers, and common equity investors. These electricity-providing agencies are overseen by an equally complex system of federal, state, and local government agencies. Clearly, the incentives and disincentives for optimizing power transfers with U.S. institutions are different from those with other institutions in other nations. The impediments to electric power transfers offered by current U.S. societal institutions for supplying electricity are the subject of the first paper in this study. This paper not only presents the institutional impediments but also introduces the papers that follow by providing the context within which the current debates about legal, regulatory, and economic impediments occur.

If one now assumes that these present societal institutions should not be changed, the next most fundamental type of impediment is those contained in federal, state, and local laws. Hence, legal impediments are taken up next, in the second paper. Some laws expressly limit or forbid power transfers. Other laws provide authority to order power transfers, but the authority is weak enough that these laws may be considered impediments to major power transactions. In still other cases, there are legal "vacuums," areas where there is no applicable law, and hence no authority exists for seeking administrative or judicial correction of any power coordination inadequacies.

Within the context of existing laws, the regulatory policies adopted by federal, state, and local government agencies may create disincentives to power transfers. These are impediments that could potentially be eliminated without any new legislation. The principal impediments are the policies and procedures of the Federal Energy Regulatory Commission, the state utility commissions, and state and local agencies that oversee the siting and certification of new transmission lines. These regulatory impediments are identified in the third paper.

Even with existing institutions, laws, and regulations, more power transfers might occur if the electric companies themselves would pursue power transfer opportunities more aggressively. Whether they do or not depends largely on the opportunities for profit--and the risks of economic loss--that an increased level of power trading would bring. The lack of a profit opportunity is an economic impediment to power transfer. So too is a risk of economic loss that is not outweighed by the possibility of gain. Two-party power trades between neighboring companies apparently occur as needed in most cases. More often at issue are the economic impediments to wheeling, especially the impediments as seen by the potential wheeler. Apart from the legal and regulatory impediments previously alluded to, the chief economic impediment to wheeling is the manner in which utilities calculate wheeling rates. The fourth paper treats economic impediments, with special emphasis on ratemaking for wheeling. The ratemaking analyses, especially those in the three appendices to this paper appearing at the end of this volume, are among the strengths of this paper. In particular, appendix C, "A Theory for Wheeling Rates," treats short-run marginal cost pricing theory in some detail and expands on the treatment of this subject that appears in the companion NRRI report on setting wheeling prices.

In each of these four papers, the approach is to try to identify as many potential impediments of each type as possible. Of course, not all these impediments will apply in every case where power flows are blocked. The impediments may be quite different in different cases; for example, they may differ (1) in cases with and without a need for new transmission capacity, (2) in different regions of the country, (3) between cases of interstate and intrastate power transfer, and (4) between cases involving only utilities and those involving cogenerators and requirements customers. In each of the four papers, the relative practical importance of various impediments identified is discussed.

To show how some of these impediments apply in practice, a fifth paper assesses the relative importance of the various impediments in three actual cases where power transfers are desired but are in some fashion blocked, delayed, contested, or otherwise impeded. One case involves attempts by utilities to construct a new line to facilitate power trading and enhance reliability. Another case involves the wheeling needs of a requirements customer and an industrial customer. In the third case, various small public power agencies that have banded together to increase their market power as buyers encounter difficulties in market participation, especially where long-term firm wheeling is required.

In the first four papers, the amount of overlap in coverage is held to a minimum, despite a natural relation between adjacent papers: our nation's laws are designed around our institutions; our regulations implement our laws; and economic incentives are closely related to regulatory policies, especially pricing policies. Some subjects come up in several papers, but are treated differently in each case. The concept of rate-of-return regulation, for example, is treated as a U.S. institution in the first paper. The focus here is on whether having or not having such an institution affects the level of power transfers. In the discussion of legal impediments the subject is taken up again, but here the focus changes to how the scope of rate regulatory authority under various current laws may act to limit power transfers. How the specific ratemaking policies and practices, adopted by regulatory agencies within the broad limits permitted by existing law, affect power transfers is taken up next. Finally, the economic impediments imposed by particular wheeling rate structures are considered.

Process

NRRI began this study by setting out these four impediments categories and giving examples of impediments in each category. These ideas were described in four requests for proposals to develop four of the five papers in this volume. Authors of papers were selected by competitive bid. The editor discussed with each author the content and scope of his paper. In June 1987, drafts of the four impediments papers were reviewed and discussed with the authors, and a meeting of all five authors was held at NRRI. At this meeting, ways of strengthening each paper were discussed, and the recommendations in each of the first four papers were critiqued by all.

At about the same time, the case studies' author presented NRRI with a list of candidate case studies. NRRI conferred extensively with the NRRI Research Advisory Committee (RAC) and the Strategic Issues Subcommittee about the selection of the three cases. The RAC suggested a case not on the original list (Stauffer Chemical), which became one of the final three. The fifth paper, covering the three case studies, was reviewed by the editor but not by the other four authors.

Development of Recommendations

Recommendations were developed by the authors for overcoming many of the impediments identified. The easiest to overcome may be economic impediments, since these recommendations typically require no major changes in current regulations, laws, and institutions. If these recommendations are deemed inadequate, one would look next to the recommendations for altering regulatory policies, then legal remedies. More fundamental changes to encourage power transfers involve new legislation or even changes in industry organization.

However, not every impediment identified needs to be remedied. It is quite important that mere identification of an impediment not be taken as a recommendation to remove that impediment. Several of the authors stressed this fact. For example, an investor-owned utility in the U.S. is granted a franchise to provide monopoly service to a certain territory. This arrangement, of course, intentionally prevents or inhibits another utility from competing to serve that territory. So the franchise system impedes some power flow transactions. Recognizing this fact does not necessarily mean that franchises should be done away with or that franchise terms should be amended. Some policy makers would prefer to retain the benefits of a system of franchised utilities, even if this means that some other benefits associated with an increased level of competition would be foregone.

Nevertheless, it is worth recognizing that the franchise system impedes power transfers so that the benefits of franchises are not inadvertently lost as policies to promote power transfers are pursued. Also, some policy makers may choose to amend franchise terms to promote competition if they see this approach as achieving a greater level of benefits.

Further, not all the power transfers impeded are necessarily beneficial to society as a whole. With good power transfers, aggregate electric system supply costs go down as high cost producers of electricity buy power from lower cost producers. By backing-off high cost generation and increasing low cost generation, overall costs decrease. However, power transfers that involve no new generation simply redistribute a fixed-cost supply to different parties. Then power transfers are a sort of a zero-sum game. One party's loss is another party's gain. Such power transfers, while beneficial to the new recipient of lower cost power, are not beneficial to all parties taken together. Policy makers may want impediments to such power tranfers to continue, or may be indifferent to whether they are removed.

Hence, one should not interpret a cataloguing of all non-technical impediments by the authors as an indication that these impediments are all undesirable and should be removed. Also, not all impediments are equally important. Within each impediment category, the author has judged the relative importance of the various power transfer barriers identified. Further, each author of the first four papers was asked to recommend steps for overcoming the principal impediments identified.

The task of developing recommendations was perhaps more challenging for the authors of the early papers than the later papers. This is because the authors of the early papers might prefer first to remove regulatory and economic impediments to power tranfers (but these avenues were outside the scope of their papers), but had to discuss instead possible changes in societal institutions and laws. In the first paper, Kaufman handles this problem by separating conclusions from recommendations. If one values competition highly enough, he concludes, one could seek to change a particular societal institution. He then goes on to present some specific recommendations of his own that involve more limited alterations to traditional institutions. Burns, in the second paper, divides his recommendations into two groups: recommendations to policy makers who want to seek legal remedies within the existing framework of laws and recommendations for those who would seek new legislation. Both Kaufman and Burns clearly separate the identification of impediments from their conclusions and recommendations, which are placed at the end of their papers.

A different approach is used in the third and fourth papers. Here, any recommendations for removal of impediments involve less drastic changes in traditional practice. The authors of these papers, therefore, take up options for overcoming impediment as each impediment is discussed; these recommendations are dispersed through the papers.

It is worth stressing that the recommendations in each paper are those of that author alone. The recommendations in each paper were discussed and critiqued by the editor and by the other authors during the June meeting at NRRI. This served to sharpen the reasoning and tighten the list of recommendations, but each author was the final judge of which recommendations would appear in his paper. They are not the recommendations of other contributors or of the NRRI.

Principal Impediments

At the June meeting, attended by all five authors, we attempted to find agreement among authors about which are the principal non-technical impediments to power transfers. There was a consensus on three. They are:

* Opposition to Mandatory Wheeling--Some discussion of this appears in each of the first four papers and in two of the three case studies.

* Roadblocks to Constructing New Lines--This impediment is discussed in two impediments papers and one of the case studies.

* Incorrect Pricing of Transmission Service--This impediment arises in two impediments papers and one case study.

INSTITUTIONAL IMPEDIMENTS

By Alvin Kaufman
Consulting Economist

Introduction

A major institutional issue in American society today is the role of government. There does not appear to be a consensus as to whether less government is best, or more is better. The electric utilities are, in a real sense, caught in the crossfire between those who envision a broad societal role for government, and those who envision a rather limited role. That is, a basic question that requires resolution is how society organizes itself to deliver electricity, and how to improve that delivery.

Thus, the question of whether to encourage bulk power transfers between utilities is "part and parcel" of the societal institutional issue. That is, the bulk power problem could be solved by changing the government's role in the electric power industry. For example, a government entity could own and operate the entire electrical system but lease it to private operators; or the system could be deregulated and left to operate at the discretion of private enterprise.

Thus, it is apparent that there are an infinite number of organizational ploys that can be utilized to eliminate the institutional bottlenecks. It is not our purpose, however, to opt for any particular one, but rather to note that the current arrangements should not be taken for granted. It is possible to change the system depending on society's goals.

It is unlikely, however, that major changes will be implemented in regard to bulk power transfers until there is a consensus in the United States on the societal role of government. The difficulties resulting from the failure to resolve that overarching issue are compounded, in the case of the utilities, by the overcapacity problem facing many electric companies.

The difficulties resulting from overcapacity have been compounded, in turn, by the high cost of building a new plant relative to the cost of existing units. The consequent cost pressures have induced the industry and its regulators to search for a way out of the rising cost thicket, primarily by avoiding new construction. This effort has involved a number of activities including encouragement of conservation and load management, and creation of stronger interties between systems and regions. Stronger interties permit greater bulk power transfers between intertied systems, and between a producer and a third party, resulting in the possibility of a measure of competition. The latter can result in a smaller governmental role, but its major benefit is held to be greater efficiency and, therefore, lower costs.

An additional spur to competition would be the development of a spot market for electric power as opposed to the normal long term contract, thus further encouraging bulk power transfers. Much of the movement toward greater competition, however, hinges on the availability of transportation services. That is, a viable spot market, or any bulk power purchase for that matter, requires the availability of transportation to move the purchased electricity to the buyer.

By the same token, various wholesale customers and independent generators of electricity feel their best interests, as well as those of the public at large, would be served if they were able to shop around for the best deal possible, regardless of location, and have assurance that transmission would be available. To be able to do so, of course, would also require the availability of suitable interties, possibly even a national grid.

On the other hand, many utilities feel the customer's ability to shop around for electricity is a violation of the implicit agreement between the state and the company. That is, the utility has agreed to provide adequate and reliable service to all comers at all times within an exclusive franchise area, while the state has agreed to permit recovery of legitimate costs without undue delay.

Despite the controversy surrounding bulk power transfers, it is generally considered by many regulators and scholars to be a necessary precondition for the improved efficiency of the electric utility industry. It is felt, however, that there are a number of economic, regulatory, and institutional impediments preventing the expansion of such power movements. In order to determine if this is correct, the National Regulatory Research Institute (NRRI) has launched a study of non-technical impediments to bulk power transfers.

This paper is part of that effort. In it we will concentrate on institutional impediments. In doing so, we define an institution as something created by society to carry out a function. It can be an established practice, law, custom, system or corporation.[1]

In this case, the institution is established for the purpose of producing, transporting, and distributing electricity. As such, it may be serving its purpose in an admirable manner, but it may also be an impediment to the expansion of bulk power sales. For example, the structure of the industry, the regulatory system, power pools, and so forth, are all institutions that are candidates for discussion.

To this end, therefore, we will first discuss the current electric utility institutions including the structure of the industry and the bulk power network, and then turn to a discussion of which might act as an impediment to bulk power transfers. We can now begin with our discussion of existing institutions.

Electric Utility Institutions Today

The Regulatory Overlay

The structure of the industry has evolved, in large measure, as a response to the regulatory system that has been imposed on the industry. That system is based on the assumption that electric utilities are natural monopolies. A natural monopoly comprises an industry with an inherent tendency toward declining costs over the long term, high threshold

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[1] Webster's New Universal Unabridged Dictionary, 2nd Edition, 1983, Dorset & Baber, p. 951.

investment, and technologic conditions that limit the number of potential entrants.

Under such circumstances, the "public interest theory of regulation" currently in vogue holds that it is more efficient for a single company to serve an area than for several competitors. This is so, since the high fixed costs can be spread over a larger number of units of output, therefore resulting in declining costs. In order to achieve this efficiency, the government restricts competition by granting a specific utility an exclusive franchise to serve an area, and thereby creates a monopoly.

A monopoly, however, has a tendency to seek monopoly profits. In order to protect the public from the abuses of monopoly power, economic regulation is instituted. This form of regulation is designed to assure that the declining costs of a natural monopoly, operating in a discrete franchise area, are passed through to the consumer.

The regulatory system is concerned with economic efficiency, tempered with the need for adequate and reliable service, and the need to assure equity. It operates on the assumption that a result equal to what would occur in a competitive environment can be achieved, in terms of economic efficiency, by permitting the utility to collect revenues equal to the cost of providing service, including an allowable rate of return. The latter is usually set at a level sufficient to attract capital. Under this theory of regulation, it is assumed the consumer will receive a price signal approximating what would occur under competition.

Economic regulation is instituted, therefore, because electric utilities are believed to be natural monopolies, as well as because of perceived disabilities in the competitive process. These disabilities include the potential for inferior service, and for discriminatory treatment of customers.

It is thus held that any competitive system devised for electric utilities is likely to be imperfect. As a consequence, competition will give imperfect results that are likely to be no better, and possibly worse, than the results under the present system.

This conclusion is, of course, controversial. The "coalition-building" theorists would hold that a competitive market would produce results superior to what they view as political action and reaction under the current system. The essential question, however, is whether an adequate degree of competition is possible in the electric utility industry.

Trebing has concluded that it is not likely that an adequate level of competition could be induced in the electric utility industry. He feels that competition will be restricted by the current high levels of concentration in industry, and by differentiated markets, the retaliatory pricing power of existing utilities, demand/supply imbalances that may cause prices to continue rising, and the difficulty of setting neutral pricing guidelines.[2]

In any case, the regulatory theory outlined above is implemented through a number of institutions. The major regulatory agencies include the state commissions and the Federal Energy Regulatory Commission (FERC). The latter is an independent agency in the U.S. Department of Energy (DOE). All of the regulatory groups operate as collegial bodies comprising three to seven commissioners.

In addition to these economic regulatory groups, there are a number of other regulatory agencies such as the Nuclear Regulatory Commission, the Environmental Protection Agency, and the Securities and Exchange Commission (SEC).

In this section, however, with the exception of the SEC responsibilities in regard to the Public Utilities Holding Company Act, we will only deal with the economic regulatory institutions, and those in a cursory fashion in order to avoid duplicating the more detailed discussion in the regulatory impediments section of this project.

<u>Federal Regulation</u>

The economic regulation of electric utilities is divided into two unequal segments comprising Federal and state activities. In this instance, the states have the leading role, with FERC playing a subsidiary part. The latter agency is limited to the regulation of electricity in interstate commerce. This includes: 1. approval of rates and standards for sales for

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[2]Harry M. Trebing. Apologetics of Deregulation in Energy and Telecommunications: An Institutionalist Assessment. <u>Journal of Economic Issues</u>, September 1986, p. 613-632.

resale (wholesale sales) in interstate commerce; 2. approval of rates promulgated by the Federal Power Marketing Administrations; 3. approval of terms and conditions, and; 4. administration of the provisions of the Public Utilities Regulatory Policies Act (PURPA) related to small power producers and cogenerators.

At the moment, the area covered by FERC regulation is a relatively minor part of the utility picture, with sales for resale comprising approximately 16 percent of total sales. Given, however, that bulk power sales are likely to increase, the importance of FERC's role is also likely to grow. Despite this potential, the major Federal role, at the moment, is as the regulatory pacesetter and innovator. That is, when FERC establishes a policy, the states will probably follow suit.

In addition to FERC, the Economic Regulatory Administration in DOE regulates international transmission connections, and licenses power exports. No authorization is required for the importation of electricity, but a permit is necessary for a line to cross the United States border.

State Regulation

On the other hand, the scope of state authority over utility activities is as diverse as the states themselves. At the least, this authority encompasses the establishment of retail prices, with most states granting authority over investment and incurrance of debt. At the other end of the spectrum, state regulators have authority over virtually all facets of utility operation, including plant siting.

In any case, it is within this complex regulatory structure that the industry must function.

Industry Structure[3]

Electric power in the United States is provided by a mixture of organizations owned by investors, consumers, local governments, and the

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[3]Based on information and data in Energy Information Administration. Annual Outlook for U.S. Electric Power 1986. U.S. Department of Energy, April 24, 1986, DOE/EIA0474 (86), pp. 1-4 and FERC. Power Pooling in the United States. November 1, 1980, FERC-0049, pp. II-1 to II-5.

Federal government. Of the 3,130 utilities active in 1986, more than 60 percent are publicly owned, and 30 percent are cooperatively owned. Only 236 are privately owned.

Investor-Owned Utilities

Despite the relatively small number of privately-owned utilities, as shown in figure 1, these comprise the bulk of the industry by virtually any measure. The investor-owned utilities (IOU) serve 76 percent of the customers, produce and sell three-quarters of the electricity, collect 74 percent of the revenues, own 77 percent of the generating capacity, and own the major portion of the bulk power transmission system. As a consequence of their preponderance, the privately-owned utilities are major suppliers of electricity to the publicly- and cooperatively-owned systems. IOU's are active in every state except Nebraska.

Public Utility Holding Companies

The majority of the investor-owned electric utilities are independent companies, although approximately one-fourth are subsidiaries of the nine holding companies organized under the Public Utility Holding Company Act of 1935 (PUHCA).[4]

Under the terms of the Act, holding companies with subsidiaries in the electric business must register with the Securities and Exchange Commission (SEC). A holding company is defined as one that controls, directly or indirectly, 10 percent or more of the outstanding voting stock of a public utility, or that, in the judgment of the SEC, can exercise sufficient influence over the affairs of a public utility to warrant regulation.

Not all holding companies, however, are subject to regulation under the terms of the Act. In fact, most holding companies are exempt. To be exempt a holding company's operations must be intrastate in character, or it must only operate in its own and contiguous states, or it must derive the majority of its income from non-utility businesses.

If subject to the provisions of the Act, the holding company must follow the anti-trust and regulatory rules promulgated by the SEC. Under

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[4] Karen Nelson. Electric Utility Diversification. Congressional Research Service, Issue Brief IB82060, Sept. 26, 1983, pp. 1-5.

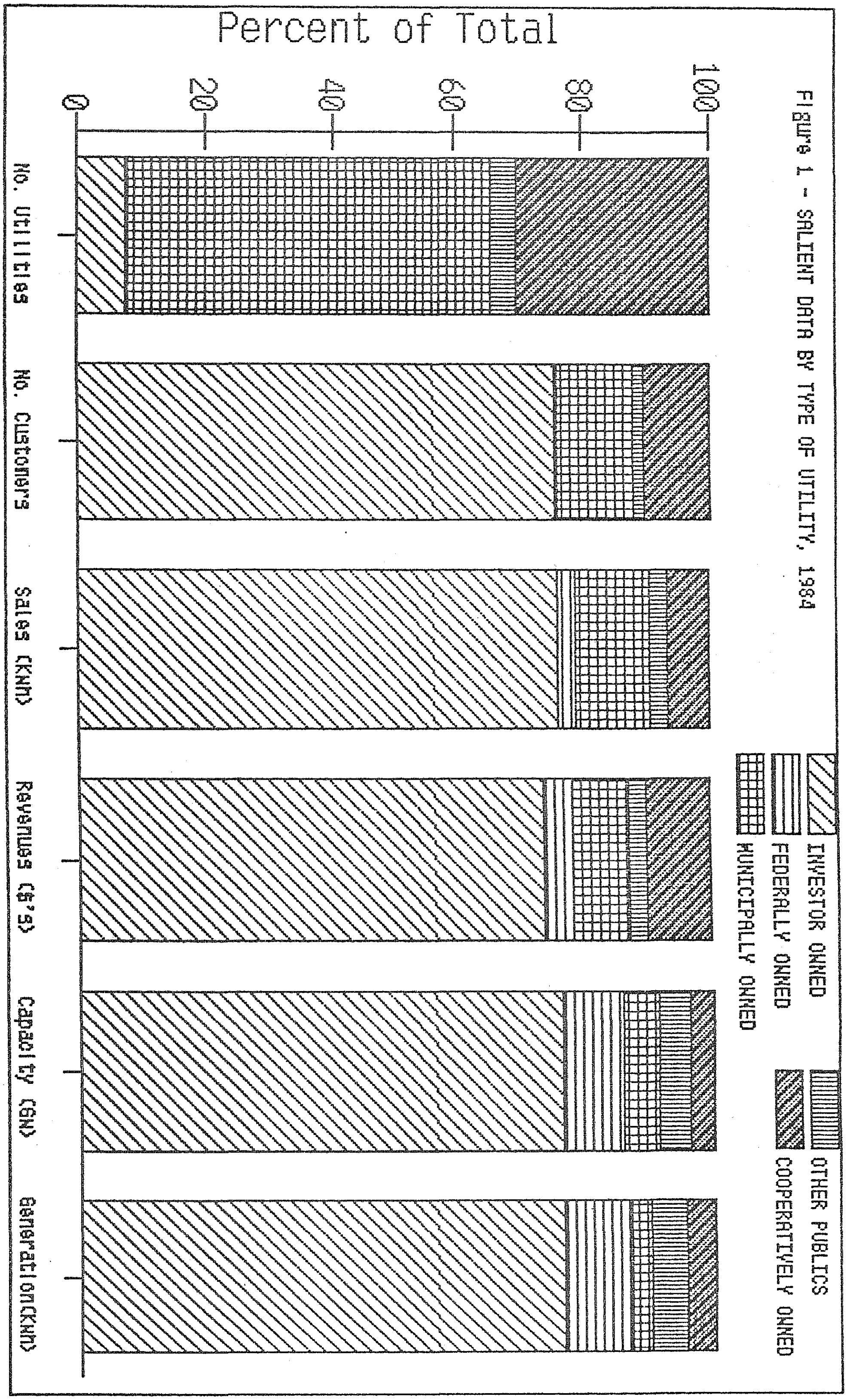

Figure 1 - SALIENT DATA BY TYPE OF UTILITY, 1984

these rules, the company must operate a single integrated utility system, and must maintain a relatively simple corporate and financial structure, although there are exceptions to these requirements.

In addition, the acquisition and sale of securities are controlled. This is accomplished by subjecting certain transactions to the approval of state authorities, and others, particularly long-term security transactions and the sale of utility assets, to the approval of the SEC. Further, the regulated holding company is subject to surveillance over internal operating practices, proxy solicitations, and contracts for services, sales and construction.

Based on data in the SEC Financial and Corporate Report, Registered Public Utility Holding Company Systems (March 31, 1986), the following electric utilities are subject to regulation under PUHCA (numbers in parentheses are the number of subsidiary utilities):

1. Allegheny Power System, Inc. (4)
2. American Electric Power Company, Inc. (12)
3. Central and South West Corp. (4)
4. Eastern Utilities Associates (3)
5. General Public Utilities (6)
6. Middle South Utilities, Inc. (6)
7. New England Electric System (5)
8. Northeast Utilities (5)
9. The Southern Company (5)

Federally-Owned Utilities

Federal installations produce approximately 10 percent of the electrical energy in the United States, primarily from hydroelectric installations operated by the Corps of Engineers or Bureau of Reclamation. This energy is marketed by the Power Marketing Administrations (PMA). These comprise the Bonneville PMA in the northwestern United States, the Southeastern PMA, the Southwestern PMA, the Western Area PMA, and the Alaska PMA. The latter also owns and operates hydroelectric facilities.

In addition, the Tennessee Valley Authority produces and sells energy to customers within the Tennessee Valley. It is a government-owned corporation operating within the equivalent of a franchised territory, and produces electricity primarily from coal- and nuclear thermal-generating plants.

Approximately 25 percent of the Federally produced electricity is sold to the ultimate customer. These are large industrials or federal installations. The bulk of the remaining electrical energy is sold to publicly- and cooperatively-owned utilities for resale. These wholesale customers have a legal preference right to federally-produced electricity. Only energy surplus to the preference right customer's needs is sold to the IOU's.

Municipally-Owned Utilities

Municipally-owned utilities are the largest group of electric utilities in the United States, but produce very little of their energy requirements. Some 72 percent of their sales are resales of electricity produced by others. Despite this lack of vertical integration, municipal utilities tend to have lower rates than IOU's. This is a result of not having to pay taxes or dividends, as well as having access to less expensive capital and to federal power.

In fact, municipal utilities tend to be concentrated in areas where load-centers are small and it is possible to exercise the preference right to federal energy. As a result, although municipal utilities exist in virtually every state, they are big in the southeastern and Pacific areas of the country. Hawaii is the only state that has no publicly-owned electric utilities.

Other Publicly-Owned Utilities

Aside from the municipal utilities, there are public power districts, state authorities, irrigation districts, and other state organizations. The power districts tend to be concentrated in Nebraska, Washington, Oregon, Arizona, and California. These utilities are somewhat similar to federally-owned utilities in that they produce more than they sell to ultimate customers. The remainder is sold to municipally- and cooperatively-owned utilities.

Cooperatively-Owned Utilities

These utilities are owned by their members (i.e., customers). In essence, there are two types of cooperatives (coops). One is a distributor, who may or may not own its electrical generation. The second type is a Generating and Transmission (G & T) cooperative. The G & T is a cooperative owned by the distributor coops, and organized to supply a part or all of their needs.

The cooperatives in total account for approximately seven percent of U.S. sales to ultimate customers, but they only produce four percent of electricity in the United States. The remainder of their requirements are purchased from others.

Newcomer To The Industry

Aside from the utility ownership arrangement discussed above, there is a possibility of mergers and buyouts, as well as the development of several nontraditional arrangements; among the latter are separate generating companies and cogenerators.

Utilities have, in several instances, created separate generating companies to operate a single plant, usually in cases of joint ownership by a number of companies. For example, two-thirds of the stock of Yankee Atomic Electric Company is owned by three utilities, with the remainder by a number of other companies.

In addition, there have been proposals recently to spin-off all of a company's generation as a separate entity. For example, Commonwealth Edison has requested the approval of the Illinois Commerce commission to transfer three of its nuclear units to a wholly-owned subsidiary, while Public Service Company of New Mexico has suggested restructuring the company into independent distribution and electrical generation companies. The latter would be exempt from regulation.[5]

In addition, in recent years several plants have come on the scene that are owned by non-utility companies. Generally, these are built by a utility for the owners, and then operated by the utility under a leaseback arrangement. This step is usually undertaken as a method of obtaining new plant while conserving capital. The plant, despite its ownership, tends to remain under utility control.

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[5]PSNM 'unbundling' plan may trigger more. Electrical World, April 1987, p. 17.

Cogeneration

Cogeneration, on the other hand, tends to be a form of supply outside the direct control of the utility. It occurs when there is a need for process heat and either a manufacturer or an independent contractor builds a plant to provide both heat and electricity. Electricity excess to the needs of the sponsor is sold to an electric utility; in some instances the plant may be built primarily to produce electric energy. In any case, the utility is required to purchase the electric output at its "avoided cost" of generation under the terms of the Public Utilities Regulatory Policy Act (PURPA).

In all cases until recently, cogenerator sales of electricity have been to local utilities. Recently, however, ENRON contracted to sell, over a 12-year period, 393 Mw out of 430 Mw at its Texas City, Texas, plant to Texas Utilities Electric Company in Dallas. This sale is possible because Texas utilities are required to wheel electricity from cogenerators when local utilities do not require the energy.

The growth of cogeneration has been concentrated in California and Texas, where regulation has been sympathetic, plentiful supplies of natural gas are available, and utility generation tends to be oil- or gas-fired. A gas-fired cogeneration facility costs approximately $400 per Kw compared with over $800 for a conventional unit, and usually takes less time to build. In addition, cogenerators are not subject to economic regulation.

In recent months, as a result of opposition from utilities with surplus capacity, coupled to a desire to assess the effect of reduced avoided cost levels resulting from lower fuel prices, there has been a slackening in the pace of the development of cogeneration facilities. In general, however, it appears that the reduction in avoided cost is balanced by the reduction in the price the cogenerator must pay for the fuel. As a consequence, it is expected that development will resume, with concentration in those regions heavily dependent on oil for electricity generation, primarily the northeastern United States and Florida.[6]

The recent elimination of the Fuel Use Act provision preventing utilities from burning gas under boilers may change this equation. In any

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[6]Cogeneration thrives in U.S. despite lower oil, gas prices. Oil and Gas Journal, January 19, 1987, pp. 15-18.

case, in 1984 there were 443 cogeneration units aggregating 13,555 Mw operating or planned. As of the end of 1987, as indicated in Figure 2, based on data in the Oil and Gas Journal, a total of 1683 Mw in new cogeneration projects were announced. These were plants for which planning was just starting.

Of these new projects, 45 percent were in California, 22 percent in Maryland, 16 percent in New Jersey, six percent in Pennsylvania, and three percent in Florida, with the remaining eight percent scattered among four states.

It is apparent that the growth of cogeneration facilities, all of which are independent of the utilities, introduces an element of competition into the electric generating sector. These units, therefore, can force a structural change in the industry.

Mergers and Buy-Outs[7]

Mergers and buy-Outs also have the ability to change the structure of the industry. These, however, have not been a major force to date. The most notable was the merger of Cleveland Electric and Toledo Edison. In addition, there was the buy-out of Alamito Corporation, a southwestern U.S. electricity wholesaler, by Catalyst Energy Development Corporation, the purchase of a number of smaller utilities by Utilicorp United; and the bid for Public Service of Indiana by an investment group. It has also been reported that Merrill Lynch Capital Markets has been advising a number of electric utilities regarding possible mergers and acquisitions.

For merger activity to take place, it is necessary to have people who want to buy, and the right financial and regulatory conditions. The latter involves excess cash generation relative to construction, undervalued assets, declining retail prices, and a perception of poor management. Insofar as the latter is concerned, there are undoubtedly a number of poorly-managed utilities.

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[7]Based on data and information in the following: Scott A. Fenn. Electric Utility Buyouts: A New Wall Street Imperative? National Society of Rate of Return Analysts 18th Financial Forum, October 28, 1986; and Raiders Are Getting A Charge Out of Utilities. Business Week, November 3, 1986, p. 126.

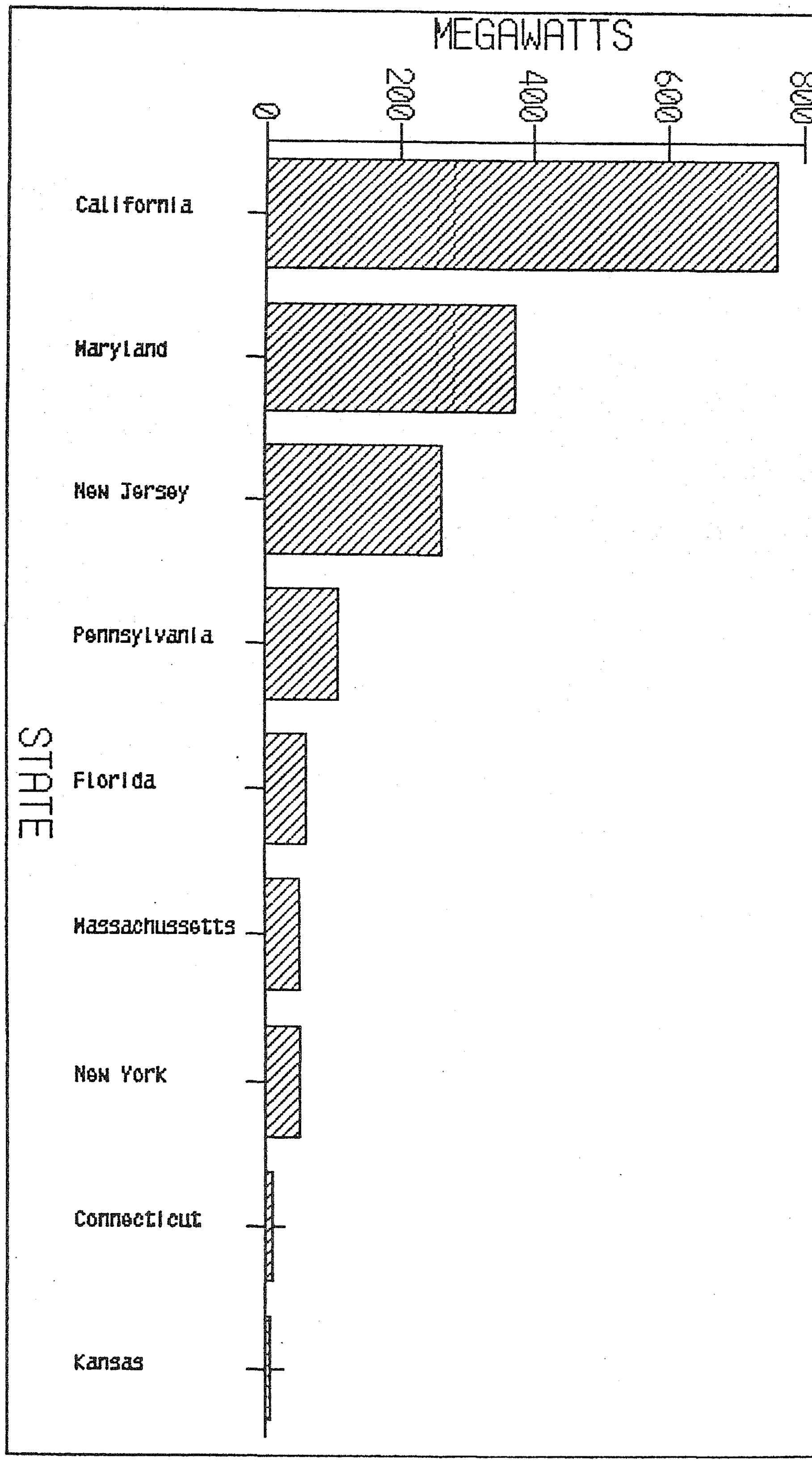

Figure 2 - Cogeneration Projects Announced, Yearend 1986

The question of retail prices is important, since it is easier to obtain regulatory approval for a buy-out if it is likely that rates will fall, than if they will rise. If fuel costs and interest rates remain stable or decline, operating costs may well drop, with rates also declining or at least remaining stable.

In addition, utility assets tend to be undervalued as a consequence of regulatory procedures (depreciated original value). This is particularly true of transmission facilities, utility-owned real estate, and the value of franchise and rights-of-way. The one problem, however, may be the relatively high price of utility stocks, many of which are selling at 10 to 11 times the per-share cash flow before dividends but after capital spending.

It is, however, the strong cash flows that make electric companies attractive to corporate raiders. In this regard, many utilities are now winding down their construction programs and, therefore, are in a strong cash position. An estimated one-third of investor-owned utilities now generate more cash internally than is required for their capital expenditures. In general, internal cash generation as a percentage of capital expenditures has increased from 41 percent in 1982 to 64 percent in 1986, and is expected to increase to 82 percent in 1988.

In 1986, there were at least six utilities with cash flow after capital expenditures in excess of $100 million. These companies were:

	Million $'s
Consolidated Edison	$403
Pacificorp	135
Pennsylvania Power & Light	329
Portland General	175
Public Service of Indiana	138
Wisconsin Electric Power	130

In addition, institutional investors have started to move into the industry. Institutional ownership has increased from 19 percent of outstanding shares in 1980 to 30 percent in 1985. This shift in ownership indicates a perception that profits are to be made in the electric utilities. It also makes it easier to buy out a company, since fewer owners need be contacted to obtain a controlling interest. Further, institutional investors tend to be more willing to sell their interest in a company than individual investors, assuming profits from the sale are perceived to be adequate.

From the above, it is apparent that many electric utilities are being scrutinized by investors as potential merger or buy-out candidates. If this scrutiny becomes reality, the structure of the industry could change dramatically resulting in fewer but larger companies. It is also apparent that the investor base of the industry may change from predominantly small investors to a number of very large investors.

The Interconnected Network[8]

The United States bulk power system has evolved into three very large networks. These consist of extra-high voltage connections between individual utilities designed to permit the transfer of electrical energy from one part of the network to another. These transfers are inhibited, on occasion, due to a lack of contractual arrangements and because of inadequate control systems.

The three networks comprise: 1. the Eastern Interconnected System consisting of the eastern two-thirds of the United States; 2. the Western Interconnected System consisting primarily of the southwest and areas west of the Rocky Mountains; and 3. the Texas Interconnected System. The latter is maintained as a separate system primarily to avoid federal regulation.

The western and eastern systems remain essentially unlinked because of the large interties needed to assure successful operation. The western area tends to concentrate its interconnections west and south of the Rockies because of the expense of building and maintaining transmission lines in the Rocky Mountain area, and because the low population density in that region requires long and expensive lines to link utility systems of any significant size.

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[8]Information in this section is based on the following publications, unless otherwise noted: 1. U.S.D.O.E. <u>The National Power Grid Study</u>, Volume 1 - Final Report. DOE/ERA-0056-1, January 1980, pp. 1-18; 2. EIA. <u>Inter-utility Bulk Power Transactions</u>. DOE/ERA-0056-1, October 1983, p. 98; 3. FERC. Power Pooling, previously cited.

Power Pools

Within the network areas, virtually every utility is intertied with its neighbors. In some cases, these interconnected companies operate as power pools. A power pool exists to assure reliability among the member systems, and to help with planning and development of future system additions. Some are formal, fully integrated organizations attempting to reduce costs by operating essentially as a single utility, and utilizing central economic dispatch of generation. At the other extreme are very informal pool arrangements, often with no contractual obligations. In addition, those holding companies owning contiguous utilities have formed intercompany power pools.

There are, at present, an estimated 30 power pools in the United States. Of these, the five holding company pools plus four others (N.Y., NEPOOL, PJM, MECS) comprise formal, fully-integrated organizations. In addition, there are eight other formal, but less-integrated pools, as well as a number of groupings that coordinate planning and in some cases operations.

Electric Reliability Councils

In addition to the power pools, the North American Electric Reliability Council has been created to promote reliability and adequacy of bulk power supplies. It achieves this goal through its nine regional councils, whose membership comprises virtually every utility in the country, as well as a number in Canada. These councils evaluate, for regional impact, the plans developed to meet future demand by the utilities, as well as assessing the overall reliability of existing and future systems. To an extent, the reliability councils have replaced some of the more informal power pools that existed primarily for the purpose of coordinating planning.

Bulk Power Transactions

Bulk power transactions comprise the sale, purchase, and interchange of electricity among utilities. There are two main types: coordination transactions, and requirements sales.

Requirements Sales

Requirements sales usually involve the sale of capacity by a company with a surplus to one with inadequate capacity, or that does not own generation, such as a cooperative or municipally-owned utility. This type of transaction is usually classified for statistical purposes as a sale for resale. The price to be paid by the buyer is generally established on a cost-of-service basis. Requirements sales often involve the wheeling of energy over the lines of a third party.

Coordination Transactions

Coordination transactions are undertaken for economy or reliability purposes. They are generally classified for statistical purposes as interchanges or as purchases. The assignment of coordination transactions to these two categories tends to be somewhat arbitrary.

Economy transactions are an effort to reduce operating costs by substituting the lower-cost generation of another utility for the higher-cost output of the buyer. These arrangements usually are priced through negotiations, with the price often based on the savings accruing to the purchaser.

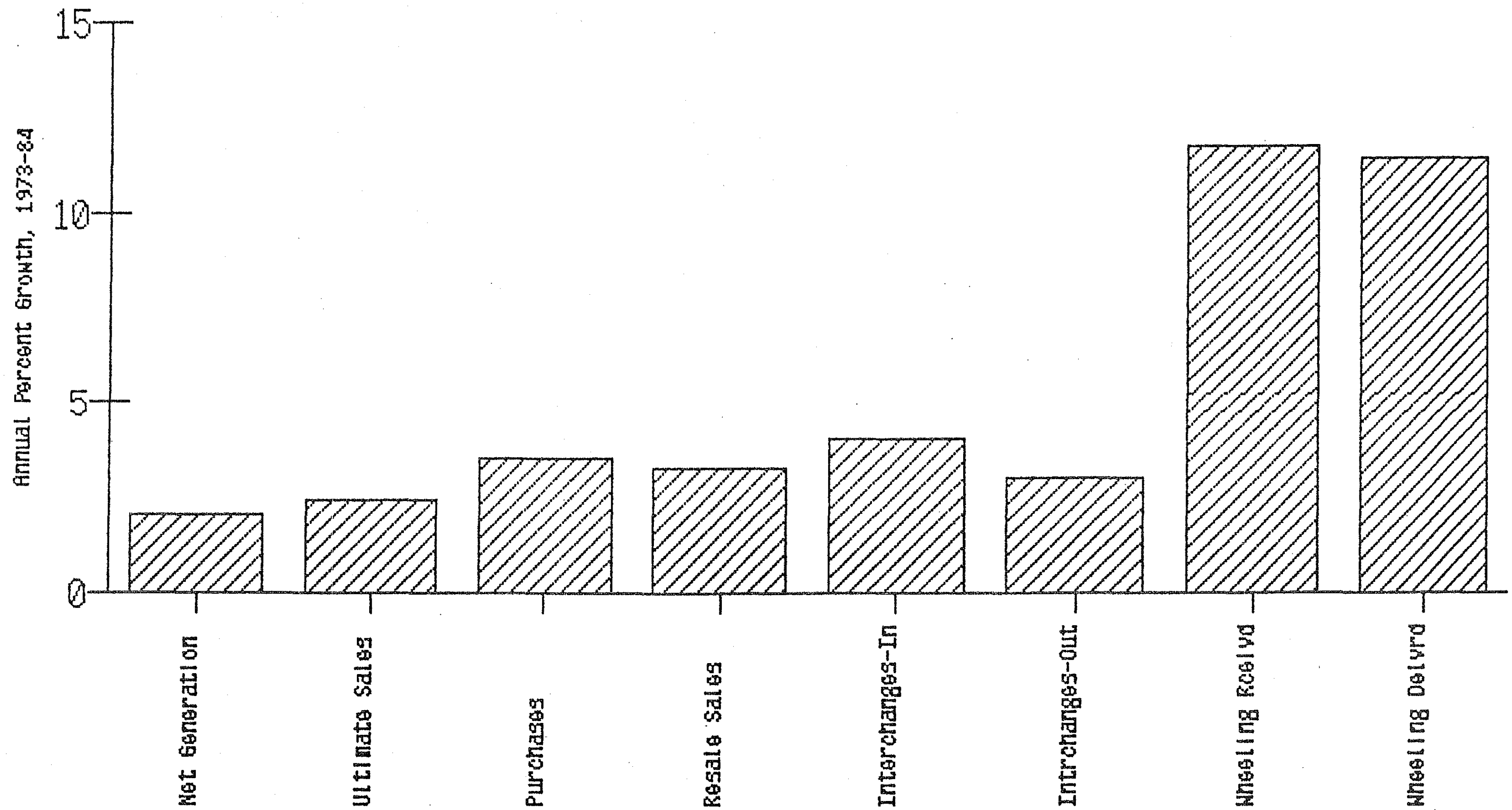
Reliability transactions are undertaken to meet an emergency, such as the forced outage of a unit, or to improve system operation or reliability. For example, in the latter case a utility with inadequate generating reserves might purchase spinning reserves from another utility.

Current Status

Bulk power transactions of all kinds, as shown in figure 3, have increased at a faster rate over the past ten years than either net generation or sales to ultimate customers. This occurred because of the disparity in oil and gas prices versus coal, and because of the high cost of new plant versus an overcapacity situation for many utilities. As a consequence, companies heavily dependent on oil- or gas-fired generation sought electric energy from coal-fired utilities, while those requiring additional capacity purchased their requirements from overbuilt utilities. The former was by far the more important type of transaction, since overcapacity tended to be endemic in the industry.

The economy transfers at one time threatened to overwhelm transmission capacity, with lines in some regions loaded to the point where reliability could be considered questionable. With the recent decline in oil prices, this form of activity has also declined. For example, average hourly imports of electricity into Florida, a state traditionally dependent on

FIGURE 3 - IOU BULK POWER TRANSACTIONS, GROWTH RATE 1973-84



Source: EIA. Annual Outlook for U.S. Electric Power 1986. DOE/EIA-0474(86) oil-fired generation, declined from close to 2200 megawatts (Mw) in April 1985 to approximately 1500 Mw in April 1986, a drop of close to 32 percent. This despite an increase in electrical demand.[9] Thus, Florida utilities were utilizing their own oil-fired generation to meet requirements. An increase in the relative price of petroleum could cause economy transfers to burgeon once again.

The fastest growing type of transaction, however, has been wheeling. This occurred for several reasons. The primary one is the need to support coordination transactions as utilities go further afield in the search for lower cost electricity. In addition, an expansion in wheeling was required to provide electricity to meet the increase in sales for resale, and to provide an outlet for production of cogenerators and small power producers.

The latter two groups have begun to introduce non-utility owned, dispersed generation into the industry. Considerable overcapacity in many areas of the country makes it difficult for cogenerators to sell their surplus electricity at a profit. As a consequence, many of these entrepreneurs would like to move their output via wheeling to more lucrative markets. This has been compounded by the desire on the part of some large industrial customers to shop around for electricity supplies.

In any case, in the foregoing sections we have attempted to outline the institutions that bear on the production, transmission, and distribution of electricity, with emphasis on those that have particular relevance to bulk power transactions. Having done so, we can now turn to a discussion of these institutions as they may impede such transactions.

Impediments to Bulk Power Transactions

The preceding sections have discussed the operational niceties involved in the generation, transmission, and distribution of electricity, with the accent on interutility bulk power transactions. These discussions have dealt with the factual background of those institutions that bear upon such transactions, either directly or indirectly. A bulk transaction can be

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[9]North American Electric Reliability Council. 1986 Reliability Review. p. 25.

defined as the purchase/sale, and transmission, of electricity between utilities that utilize the bulk network (lines in excess of 230 Kv). This would include requirement sales, coordination transactions, and wheeling involving a third party.

Among the institutions involved, there are undoubtedly some that impede bulk power transactions. An impediment in our case is an institution that obstructs, or hinders, bulk power movements. It may not completely eliminate such movements, but may simply make these difficult to accomplish.

For our purposes, however, we are not including in our definition those instances in which a regulatory body had deliberately established a policy and accompanying regulations that inhibit bulk power transactions. Such actions are a conscious decision on the part of the regulators to exclude such movements because these are, from their perspective, not in the public interest.

We are, in essence, considering two cases. In the one instance, we are dealing with those cases in which the impediment is, by and large, accidental in the sense that the institution was designed to serve some other public purpose, but in the course of accomplishing its original mission it impedes the transfer of bulk power. In other words, the policies needed to carry out the institution's mission, and those required to stimulate bulk power transactions are at cross purposes. In other cases, the impediment posed by an institution is subtle and, therefore, may not be obvious.

Thus, we can define an impediment as an institution that creates, in some fashion, a disincentive for the movement of bulk power from one utility to another. In order to pinpoint these disincentives we will review the pros and cons of each institution insofar as bulk power transactions are concerned.

In doing so, we will utilize the three institutional classifications developed earlier, namely regulatory institutions, organizational institutions, and operational institutions.

Regulatory Institutions

As noted earlier, economic regulation is based on the concept of a natural monopoly. To implement the theory, several institutions have been created. These include rate of return regulation, franchised territories, and a split between Federal and State regulation.

The Federal-State Dichotomy

The regulatory division between the federal and state governments does not generally inhibit bulk power sales, since FERC and many state regulatory agencies are in favor of such transactions. There is, however, a void in the Federal regulation of bulk power transactions. The United States Constitution reserves to the Federal Government the right to regulate interstate activities, but in this instance the legislative implementation of this right leaves FERC with rather limited authority. As a consequence, the Federal machinery for regulation of bulk power transactions tends to be rather limited as well.

In addition, there are several instances in which federal and state activities may conflict. For example, the Federal government sets wholesale rates, while the states oversee planning and policy. There is virtually no coordination between the two entities in regard to these activities. As a result, there is no assurance that the consumer will receive a consistent set of signals. It is possible that wholesale rates may be established with one set of objectives in mind, while planning and state policy proceed along a different path.

In this regard, some states establish retail rates on a marginal cost basis, while FERC sets wholesale rates on an average cost basis. This can cause problems in ratemaking, and can result in the consumer receiving an incorrect price signal.

Of greater importance in terms of bulk power, however, may be the reluctance of state commissions to lose control over a major cost item. That is, if bulk power sales increase substantially, rates for these would be established by FERC. These rates would be a "given" in establishing retail rates, thus making it difficult for the state regulatory agency to assure the efficiency of utility operations, and to control, insofar as it can, the pace of cost increases.

Further, many states permit the use of fuel adjustment clauses (FAC) that include purchased power. These pass-throughs allow rapid recoupment of costs by the utility, and in an inflationary environment act as an incentive for bulk power purchases. On the other hand, since scrutiny of costs included in an FAC by the state agency does not usually occur except after the fact, the state may find its control over this major cost element weakened.

As a consequence, some states might feel that this loss of ability to approve all utility-incurred costs might hamper the commission's efforts to regulate, and the regulators might, therefore, act to inhibit such transactions.

Franchises

By the same token, the creation of franchised territories results in a "Balkanization" of the electric utility industry. This is an incentive to bulk power transactions in that there are a number of utilities all looking to minimize costs, and thus there could be a number of buyers and sellers in the market at any point in time, depending on supply and demand.

Alternatively, since the natural monopoly theory holds that one company can serve an area at lower cost than several, there would appear to be some predisposition on the part of the utility and its regulators toward sufficient generation, transmission and distribution capacity to meet the anticipated demand within the franchise area. In such an instance, the transmission system will be built to carry electricity from utility-owned generation to its load centers, and will be sized to serve the utility's anticipated loads. Therefore, in most cases the system will not be designed, either in terms of capacity or geography, to permit the wheeling of energy for other parties. Further, in many instances interties will only be adequate to assure the reliabiliity of the system.

In addition, there will be a tendency for the utility to be self-sufficient in supply. This, together with a legal inability to seek out new customers outside its franchise area, will result, even in cases where interties are adequate, in the creation of a disincentive for bulk power transfers.

Rate of Return Regulation

Rate of return regulation also tends to provide a disincentive for bulk power transactions. Under this regulatory system, the utility's revenue requirement is derived by adding an allowable rate of return on permissable utility investment (rate base) to other costs. As a result, the bigger the rate base, the more dollars the utility earns at the same rate of return. It, therefore, has a financial incentive to own the required equipment and plant, rather than purchase supplies from others (the "A-J" effect).

This, however, is true primarily during a deflationary or economically stable period. During an inflationary period, the utility may perceive itself to be better off purchasing supplies than building new capacity. This would occur because the utility would receive the money expended for purchases with minimal lag through the fuel adjustment clause, whereas the capital expended for a new plant would be returned over a number of years in severely depreciated dollars. In this case, however, there would be a tradeoff between the declining value of the dollar, and a rising rate of return allowed by the regulators to compensate for inflation. The latter would be applied against a depreciated rate base, and might not be sufficient to balance for inflation.

In addition, during periods when real overall costs are rising or when new plants cost substantially more than existing plant, the utility would also find itself better off purchasing energy. In this case, it would be able to shop for the lowest cost energy, thus keeping its costs and consequent rates down. This would avoid further declines in demand in reaction to price increases, and would, as a consequence, keep revenues from declining. The lack of new plant would also negate the need to incur new debt at a higher cost, thereby avoiding an escalating embedded debt cost, and would also allow the utility to fund other capital requirements out of retained earnings.

From the foregoing it would appear that the impact of rate of return regulation, as an institution, on bulk power sales may be primarily dependent on economic conditions, and on industry circumstances. Given the current and foreseeable situation, it does not appear to be a major impediment. Of perhaps greater importance may be the way the industry is organized.

Organizational Institutions

The structural arrangement of the electric utility industry may have a substantial impact on the growth, or lack of same, of bulk power purchases. In particular, there are a number of institutions that appear to be of some importance in this matter. These include the type of ownership, PUHCA, the development of cogeneration, and the emergence of mergers and buyouts.

Ownership

As we have noted earlier, there are a number of different ownership types extant in the electric utility industry. By and large, this is probably beneficial insofar as bulk power transactions are concerned, in the sense that few of the publicly- or cooperatively-owned utilities have substantial generating capacity. Given the preponderance of investor-owned utilities in virtually every aspect of the industry, and particularly in generation, there is little built-in incentive for purchases between the non-investor-owned utilities and the IOU's. Thus, a major bulk power market is the sale of electricity by IOU's to publicly- and cooperatively-owned utilities. This marketing arrangement may make the IOU unwilling to wheel electricity from a third party to the publicly- or cooperatively-owned utility when it has sufficient capacity to serve that load. In this matter, the differences in ownership type may inhibit the wheeling portion of bulk power transactions.

The incentive toward bulk power transactions between IOU's and publicly- and cooperatively-owned utilities has been dampened somewhat by the development of generating and transmission cooperatives. The G & T are filling the role of supplier for the retail coops. By the same token, however, the G & T does not retail electricity, and thus all of its sales are at wholesale.

In the same vein, sales between the Federally-owned and publicly-owned utilities are virtually all bulk power sales. The preference right to federal electricity, however, tends to restrict wheeling, if not bulk power sales generally, by encouraging areas close to federal installations to create publicly-owned electric utilities in order to take advantage of that low cost energy. On the other hand, if wheeling were freely available, the preference clause might encourage areas somewhat remote from Federal installations to create publicly-owned utilities.

In any case, the preference clause encourages public ownership of electric utilities, and provides an incentive for the purchase of federally produced electricity. The latter, in turn, tends to restrict the need for utility-owned generation, and for transactions between utilities benefitting from the preference clause and non-federal entities. In an overall context, and depending on one's perspective vis-a-vis public power, these policies are not necessarily inappropriate. In terms of bulk power sales, other than exchanges between federally-owned facilities and the publicly-owned utilities, however, the preference clause does tend to serve as an impediment to competition in this market. It does so by providing a disincentive for interchanges between the IOU's and the federal facilities.

Given, however, the relatively slow growth of federal generating facilities compared with the growth of publicly-owned utility demand for electricity, the "public's" may be contributing more of an incentive to bulk power transactions than they are providing in the way of inhibitions. In general, the diverse ownership pattern of the industry does not appear to have a serious inhibiting effect on bulk power transactions, and in fact may be beneficial. Of greater importance may be the requirements of the Public Utility Holding Company Act.

Public Utility Holding Company Act

PUHCA can be said to have a relatively minor impact on bulk power transactions in that there are a limited number of registered holding companies. However, the subsidiaries account for approximately 25 percent of the IOU's and the companies tend to operate in an integrated manner. Thus, PUHCA is of some importance in that it forces all operations to be concentrated within the company territory and, therefore, generally excludes outsiders.

As a consequence, bulk power transactions tend to be between the subsidiaries, although in those instances where coal-fired overcapacity exists, the holding company may be active in selling to others.

In general, given that facilities are built to serve the needs of the holding company, and that economies of scale are probably available because of the consolidated nature of operations, bulk power transactions outside the company will be limited. Within that parameter wheeling is likely to be nonexistent since transmission capacity is likely to be limited, and if generating capacity is available it is likely the company will want to sell its surplus rather than wheel someone else's electricity.

Aside from the registered holding companies, as noted in an earlier section, the Act provides for exempt entities, under certain circumstances. This probably serves as a disincentive to bulk power transactions, since the exempt company must be intrastate in character, or only operate with a state or contiguous states. Thus, to maintain its exemption, the holding company might be unwilling to engage in any bulk power transaction that would raise questions regarding its intrastate character.

On balance, it would appear that PUHCA has an inhibiting effect on bulk power transactions outside of the holding company territory. The Act, together with its interpretation and enforcement, tends to encourage operations within the company territory. To a limited extent, however, these impediments may also derive from the method of operation and the form of ownership rather than the provisions of the Act.

Cogeneration and Non-Utility Generation

The development of cogeneration and small power producers (QF), as well as non-utility generation, introduces a measure of competition to the electric utility industry. It also, by definition, creates a need for bulk power transactions. That is, the purchase by a utility of electricity from these facilities constitutes such a transaction.

At the same time, the presence of these producers introduces pressure for the ability to wheel energy. In those instances where the avoided cost of the local utility is lower than the price that might be obtained elsewhere, the QF has an interest in selling its output in other markets, most of which would require wheeling its Kwh over third party lines. Conversely, in those instances where a large utility customer is not also the cogenerator, that customer might be interested in contracting directly with the QF for its output, thus utilizing the utility primarily for wheeling purposes.

Avoided Cost

Despite this salutary effect from cogeneration insofar as bulk power is concerned, the legal requirement for sales at avoided cost pose an impediment. FERC establishes the avoided cost standard, the states implement it, and bulk power may well be caught in the middle. That is, the FERC mandate to encourage cogeneration and small power may conflict with a state's policy to encourage wheeling by making the output of the QF too expensive relative to other sources, so that no one who is not required to do so may be willing to buy that production. The local utility would be legally mandated to purchase the output. The above discussion indicates that avoided cost can be a problem insofar as bulk power transactions are concerned.

Fuel Use Act

Aside from the problems outlined above, there may also be difficulties as a consequence of the provisions of the Fuel Use Act (FUA). That is, in the planning and development of generating facilities, the type of fuel that will be available is a major consideration. In the case of cogeneration, the availability of natural gas is usually of crucial importance.

These units have been exempt from those provisions of FUA prohibiting the use of natural gas under boilers. With the recent modification of the Act permitting such use by utilities and others, the impact of the availability of natural gas on bulk power sales may become negative. Not only will there be greater competition for available supplies of gas, but the ability to use this fuel may encourage utilities to build small gas-fired units close to load centers. This development would minimize the need for transmission, and possibly eliminate a substantial portion of the market for bulk power. The full effect of FUA modifications on such transactions will not be known with any certainty for some time.

From the foregoing discussion it is apparent that while cogeneration and small power, as well as non-utility generation, are advantageous insofar as bulk power sales are concerned, the avoided cost requirement poses an impediment to these transactions. On the other hand, the recent modification of the Fuel Use Act comprises a potential problem of unknown dimensions.

Mergers and Buy-Outs

The development of cogeneration and other non-utility generation, discussed above, is a new development in the electric utility industry. An equally new development is the spread to the electric utilities of the merger and buy-out craze that has infected other industries. In general, buy-outs will only involve a change in ownership at a single utility, and thus should have a minimal impact on bulk power. Mergers, however, are a different story.

This trend, if it continues, means fewer but larger utilities. Specifically, however, because of their size and the large territory served, these will tend to be self-sufficient in terms of generation and transmission, and thus less likely to enter the bulk power market. As a consequence, much of our earlier discussion related to holding companies also applies in this case.

In addition, it should be noted that most of the mergers will create large company networks which could be expensive and difficult to interconnect with other utilities, thus further inhibiting bulk power transactions.

The above assumes that the mergers involve utilities whose territory is contiguous. In the event that a merger occurs between non-contiguous companies, there could be an increased need to wheel electricity between the component utilities. It is expected, however, that most mergers will involve neighbors in order to obtain operating economies of scale, as well as savings in administrative costs.

Operational Institutions

Operational institutions include such items as power pools and their latter day potential extension into a national grid, a spot market, mandatory wheeling, and competition. All of these, with the exception of power pools, are institutions that are either not yet in existence, or in an embryo stage. Therefore, we will discuss each of these potential institutions in some detail below, and then take up the possible effect on bulk power transactions.

Potential System Changes

The potential for changes in the system are, by and large, the result of the introduction of a degree of competition into the generating sector, coupled with the heavy loading of existing transmission lines. These factors have set the stage for the creation of a competitive market. The arrival on the scene of these new institutions could have a profound influence on the way things are done, and on bulk power transfers. As a consequence, we will now take these up in an effort to determine their importance.

Competition

There are a number of people who believe that competition is the only way to solve the industry's problems. These people hold that competition will result in lower prices, do a better job of preventing monopoly power, and encourage creation of new markets, services, and technology. It is held that the elimination of restrictions on entry, exit, diversification, prices, and earnings will lead to substantial benefits to society.[10]

The suggestions for deregulation, in virtually all cases, deal with generation, and only occasionally with transmission. However, in almost every instance, FERC authority over wholesale rates would be eliminated, while retail service would continue to be provided by distribution firms subject to state regulation.

In some cases, the distribution entity would contract with generating companies and move the energy over the lines of a third party. In other cases, the transmission entity becomes a kind of broker, buying energy from a supplier and selling to the distributor; and in still other proposals, transmission and distribution comprise a regulated utility, while generation is deregulated.[11]

It has been noted by Trebing, however, that the debate over deregulation tends to compare the worst of regulation with perfect competition, and that flawed markets will not perform any better than flawed regulation. He concludes that the level of competition needed to assure economic efficiency will not emerge under deregulation because of the current high levels of concentration, differentiated markets, and the retaliatory pricing power of existing utilities, among other things.

Aside from these arguments, there are questions as to the fate of "adequate and reliable service." It would appear that efforts to assure the reliability of the system may require cooperative efforts on the part of generating unit owners similar to those undertaken by power pools, or perhaps long-term contracts between buyer and seller guaranteeing adequate reserves. Such arrangements might well eliminate a substantial degree of competition.

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[10]Harry M. Trebing. Previously cited.

[11]R.B. Braid and L.W. Rickert. Potential Institutional changes in the Electric Utility Industry. Oak Ridge National Laboratory, ORNL-6159, February 1986, pp. 34-36.

The concept of adequate and reliable service would be difficult, if not impossible, to continue. Not only would utilities be looking for low-cost supplies of electricity, but so would large customers. In this regard, a major issue may be the question of the rights that accrue to customers who bypass the system.

The Bypass Issue

Large customers will be encouraged to look for alternative sources of electricity because of the number of utilities with excess capacity, as well as because of the relatively easy access to non-utility generators. These large customers are generally among the more profitable for the utility, and their loss could make it difficult for the utility to cover its fixed costs, or at the least earn a low rate of return. In addition, the loss of load, if substantial, could throw capacity planning out of phase. As a consequence, the utility might find itself with plants under construction that are no longer needed.

In any case, it is likely that the utility would be unwilling to assure customers who left the system that they could come back, unless a backup charge were paid to cover the costs incurred. If such charges were levied on those who cause them, it might create a major barrier to competition by making it uneconomic for large users to shop for lower cost supplies.

At the same time, if such charges were not levied on those who cause them, the other customers would have to carry them, or the concept of adequate and reliable service would go by the board. In the latter event, small customers in inconvenient areas, or those in capacity tight regions, might find themselves without service. Given that electricity in modern society is a necessity, this lack of service could pose a substantial hardship.

Experiments in Competition

From the foregoing discussion, it is apparent that before competition is welcomed with open arms, a number of questions require more definitive answers. Specifically: 1. Will there be sufficient competition to protect the consumer from the excesses of monopoly power; 2. can reliabiliity be assured without inhibiting competition, and; 3. can small customers be assured of adequate and reliable service?

In an effort to obtain some answers as to what might occur, FERC authorized a two-year (1984-1985) demonstration in the Southwestern United States relative to the impact of regulation on the efficiency and competitiveness of bulk power exchanges. The Commission permitted the six cooperating utilities wide latitude in establishing the prices at which coordination sales would take place, permitted retention by the utility of a specific percentage of the profits, and essentially mandated wheeling for such sales.

Preliminary findings, based on the first year of operation, indicated gains in efficiency compared with the year prior to the experiment, but no significant change in volume of trades in Mwh or number per hour.

In regard to competitiveness, the results were somewhat inconclusive. However, it does appear that in the more realistic case tested, measured competitiveness increased between 1983 and 1984.[12] It may be that the increase in competitiveness was a consequence of the wheeling requirement.

In addition, FERC on March 12, 1987, issued an order (Docket ER 87-97-001) accepting a bulk power experiment in the western United States over a two-year period starting May 1, 1987. The Western Systems Power Pool will set up an electronic clearinghouse for buy and sell quotes, and will have broad pricing flexibility. The goal is to test whether the information exchange coupled with the pricing flexibility, will improve the utilization of generation and transmission facilities. The experiment will involve some 15 utilities in 10 states, and will cover a wide range of firm and non-firm services.[13]

It would appear that the success of these experiments may be dependent, in large measure, on the ability to wheel. In any case, we can now turn to a discussion of this topic.

Mandatory Wheeling

At the present time, no utility is legally required to wheel electricity for another company. In addition, the heavy emphasis on the economic

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[12]Jan Paul Acton, Stanley M. Besen. Regulation, Efficiency, and Competition in the Exchange of Electricity. Rand Corporation, October 1985, R-3301-DOE, p. 120.

[13]William J. Kemp. The Western Systems Power Pool: A Bulk Power Free Market Experiment. Public Utilities Fortnightly, April 30, 1987, pp. 23-27.

health of the wheeling utility coupled to the procedural requirement for case-by-case approval of wheeling applications by FERC imposes a substantial burden on those desiring to wheel. It is felt by some that this system is adequate for all appropriate requests, given the configuration and capacity of the existing transmission system.

There are those, however, who feel that the current voluntary arrangement is inadequate. These people view wheeling as the wedge needed to force the transmission sector to adapt to the momentous changes they see coming. It is, in this view, the precursor to deregulation. If this is assumed to be correct, there is a question as to the ability of the industry to cope with the effect of increased wheeling such as new load patterns and new uses of the transmission system.

In general, the argument over mandatory wheeling revolves around three major questions. These are: 1. the degree of appropriate competition; 2. the kinds and severity of impacts on the transmission system; and, 3, the price to be charged for wheeling services. The first item, in turn, raises the bypass issue.

The bypass problem was discussed earlier in the competition section. Essentially it boils down to what happens when the customer leaves the system for another supplier. If wheeling were mandatory this is liable to occur with some frequency. In such an instance, the utility would lose a portion of its load and consequently its revenues. In many instances, the lost load would be among the most lucrative. The result could be difficulty in meeting fixed costs, overcapacity, etc.

The system impacts tend to be largely technical and beyond the scope of this paper. Suffice it to say there are devices able to handle most of these difficulties. Unrestricted wheeling would require the electrical grid to adapt to demand changes in a market-based manner. This would imply a more market-oriented pricing system.

This could involve the use of marginal cost-based rates, or some proxy for these. For example, the incremental variable or total costs imposed on the system by the transaction could form the base for ratemaking.

In any case, it is apparent that mandatory wheeling would open the system to all comers, and raise a number of technical, regulatory, and economic problems. It would also probably force the creation of a national grid.

A National Grid

The creation of a national grid involves the interconnection of virtually all of the generating capacity in the country into a single grid or power supply system.

It is held that such a system would be able to take advantage of load diversity not utilized by existing interconnections. That is, since maximum demand occurs on individual systems at different times of the day and year, intertied systems can share capacity to meet the individual peaks. This permits greater use of base load generation, which generally has the lowest operating costs, over longer time periods than would be the case without interties. The higher plant utilization permits the high capital costs of these units to be spread over a greater number of Kwh, resulting in lower overall costs per unit of output.

In addition, an intertied system can reduce the need for generating reserves by spreading the risk of an outage among all of the members. The participating utilities can coordinate maintenance activities so that each is covered by the others when equipment is taken off line. In addition, the members of a grid can provide emergency capacity since it is unlikely that several units, located at different utilities, will suffer forced outages at the same time. Thus, a grid permits more effective use of reserves to maintain the reliability of the overall system.[14]

Alternatively, it is held that available economies have been exploited by the current level of interconnection. The creation of a national grid would encounter high costs and technical difficulties because of the size of the networks being connected together. Further, there is considerable uncertainty regarding the remaining untapped load diversity. This is compounded by efforts at load management, including time-of-use pricing. The economies available through interconnection are reduced as system load factor and equipment utilization improve as a result of demand modification methods.

In the DOE National Grid study referred to earlier, it was concluded that improved utility operational integration would result in

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[14]Alvin Kaufman, Barbara M. Daly, Gary J. Pagliano, and Russel J. Profozich. The National Electrical Grid - A Concept Whose Time has Come? CRS, Library of Congress, 78-99 S, May 2, 1978, pp. 8-10.

significant benefits, but the latter might be less than the costs required for the capture of those benefits.[15]

In general, the creation of a true national grid does not appear likely in the medium-term. It is regarded by some utilities as the first step toward the nationalization of the industry, and raises the question of public versus private ownership. As a consequence, the national grid is a highly controversial issue.

It is apparent, however, that the industry will continue to integrate and intertie local systems ever more tightly, so that regional networks virtually equivalent to power pools will evolve throughout the U.S., rather than being concentrated in a few areas of the nation.

A Spot Market

The creation of regional grids, many of which are also tied together at least for reliability purposes, makes the development of a spot market feasible. In the event that bulk power transfers are eventually deregulated to an extent, such a market would move from a possibility to a probability.

In fact, such markets are already active. The large number of coordination transactions are essentially a spot market at work. On a more formal level, however, is the Western Systems Power Pool discussed earlier, and the Florida Brokering System. Under the latter arrangement, each member utility submits hourly quotations indicating the quantity of energy available for sale or desired for purchase, together with the bid or asked price. Prices are based on each individual utility's incremental or decremental cost for specific blocks of power, and include transmission and wheeling costs. The quotations are matched in order, starting with the buyer with the highest decremental cost versus the seller with the lowest incremental cost, and proceeding downward until a predetermined cost differential is reached. Actual sales are voluntary, and settlement is on a split-the-savings basis. That is, the buyer pays the seller's incremental cost plus a percentage,

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[15] U.S.D.O.E. The National Power Grid Study. Cited earlier, pp. 65-66.

usually 50 percent, of what he saves by buying rather than generating his own electricity.[16]

This arrangement is a formalized version of the traditional electricity transaction. The major innovation is the use of a computer to match buy/sell quotes. As more independent generators enter the market, the Florida Broker might evolve into a true spot arrangement, assuming transmission can be arranged to non-local utilities.

From the foregoing discussion it is apparent that the bulk power market is in a transitional phase. Despite this, the various institutions can help or hurt the development of bulk power transactions.

The Effect

In any case, mandatory wheeling would be beneficial insofar as bulk power transactions are concerned, since it would open the transmission system to all comers. These types of sales would also be increased by a more competitive environment, particularly in the electric generating sector. An expression of this additional competition would be the creation of a spot market, which by definition would involve bulk power transactions. Such a market is beginning to develop in some areas. However, in order for a viable spot market to emerge, a national grid, or at least strong regional grids, are necessary.

Such regional grids exist in a limited number of areas as power pools. These could work against bulk power transactions, except among pool members, in much the same way as holding companies. That is, since the planning of the supply side of the equation is accomplished on a coordinated basis among the members of the pool, there is a tendency for the pools to be self-sufficient in terms of generation and transmission. Further, the legal arrangement between the members of a pool could tend to give them priority over outsiders and, therefore, could work against bulk power transactions outside the pool. There are, of course, many instances where such transactions are encouraged on an individual basis, or entered into on a poolwide basis, in order to minimize costs, assure reliability, or avoid plant construction.

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[16]EIA. Interutility Bulk Power Transactions. Cited previously, pp. 26-27.

Conclusions and Recommendations

At the outset of this paper, we noted that the major issue is the societal role of government, with the basic question, in terms of electricity, being the organizational pattern desired by society to deliver these services. We further noted that the existing societal organization for the delivery of electricity should not be taken for granted. There are a number of alternatives, and changes are possible over time.

In this regard, it would be our view that if greater competition, as expressed by more bulk power transactions, is considered an essential societal goal, then a radical restructuring of the industry would be necessary. This restructuring could take a number of forms, but from our perspective the most likely would involve the deregulation of generation, the change-over of transmission from an integral part of a utility to a common carrier, and the continuation of distribution in its current form.

Such an arrangement would not only encourage bulk power transactions, but would make these a necessity, since the current vertically integrated form of operation would no longer exist. Distributors would serve their franchised area, but would be required to seek out the lowest cost generation, and arrange for the transportation of the Kwh as dictated by load patterns. This would give rise to a spot market, and possibly eventually to the creation of a national grid.

Under such an organizational pattern, bulk power transactions would become a way of life. By the same token, many of the problems discussed in the competition and mandatory wheeling sections would require resolution. In particular, methods to assure the reliability of the system in a competitive market would have to be developed, and the concept of "adequate and reliable service" would have to be addressed.

In addition, the regulatory system would probably require a major overhaul. The states would probably continue to regulate distribution, but would lose direct control over the major cost items involved in transmission and generation. This loss would probably necessitate the development of oversight methods to assure the prudence of purchase and transportation arrangements, with this item becoming a major element in all distribution rate cases.

At the same time, it can be assumed that the regulation of transmission rates and policy will devolve upon FERC, which might regulate this segment of the industry through a number of regional offices, or perhaps regulation might be concentrated in regional agencies. In any case, the regulatory body would require far broader authority to set rates and compel wheeling than now exists. It might also be necessary to establish a regulatory procedure for the spot market in electricity somewhat akin to those utilized in the regulation of other commodity and futures markets.

The revolution discussed above, however, is unlikely to occur until, as noted in the introduction to this paper, agreement has been reached on the role of government in society. Such a concensus does not appear imminent. As a consequence, we can return to a less global discussion of institutional impediments.

Conclusions

In this regard, the foregoing sections have indicated that there are impediments within each of the major institutional classifications, although these vary in importance. In the discussion that follows, we draw no conclusions as to the merits of an institution in an overall sense or in regard to the specific purpose for which it was created. Our conclusions relate solely to bulk power transactions.

Our discussions below will be organized within the same three classifications (regulatory, organizational, and operational) as in earlier sections.

Regulatory Institutions

Rate of return regulation, as an institution, does not appear to be a major impediment to bulk power transactions; it is, however, discussed in some detail in terms of policy in another paper in this report. In fact, economic conditions and circumstances may be more important that this regulatory institution.

The franchise system, on the other hand, may be a major problem because it is an expression of the natural monopoly concept. Among other things, in return for an exclusive service territory, the latter means the utility must provide all comers with service at all times. It will, therefore, attempt to size its system to meet its expected demand, and will strive to be self-sufficient in terms of supply in order to assure its ability to provide service. As a consequence, its transmission system will usually be sized to serve its own load, with little excess capacity available to permit wheeling for others. At the same time, the utility is legally forbidden to look for new customers outside its area. As result, under normal circumstances, it will generally have minimal need for purchased capacity, and will have little available to sell to others. We can, thus, conclude that the franchise system is a major impediment to bulk power transactions.

The franchised utilities will generally be primarily subject to the control of state regulatory agencies. As bulk power transactions increase, however, the reach of FERC regulation will likewise increase. With the increased importance of such activity will come the need for expanded Federal authority, providing the states with an incentive to restrict such transfers in order to maintain control over a major cost item. Thus, the federal-state regulatory dichotomy can be considered to be an important institutional impediment to the movement of bulk power between utilities.

Organizational And Operational Institutions

Within the organizational and operational classifications, it seems apparent that the ownership pattern, as such, is not an inhibition to the transfer to bulk power, although there are several allied institutitions that appear to provide a disincentive. These include preference rights, cogeneration, power pools, PUHCA, and mergers.

The latter three institutions appear to be similar in impact. Holding companies are large, integrated operations, while mergers create large utilities usually serving contiguous territories, and power pools often operate on an economic dispatch system.

In any case, PUHCA tends to inhibit interutility bulk power transactions by encouraging operations within the holding company territory. It is likely that in such an instance what one subsidiary may lack another will have, making transactions outside the company problematic. In those instances, however, where the holding company has an excess of coal-fired electricity, it will attempt to sell that excess to others, thus aiding bulk power transactions, at least temporarily.

Of greater importance, however, may be the coordinated planning undertaken by the holding company on behalf of its subsidiaries, usually with the aim of self-sufficiency. By the same token, this planning function may also make power pools an impediment to bulk power transactions outside of the pool.

Mergers also tend to work against outside bulk power transactions since the amalgamation is presumably consummated because the utilities "fit" together in some way. This fit may be in terms of transmission and generation, as well as because of potentially more efficient operation. In any case, there would be a tendency toward self-sufficiency among the merged companies.

It would, therefore, appear that PUHCA and mergers, as well as power pools, all provide a disincentive for bulk power transactions outside of the company or pool area.

The preference right, on the other hand, tends to encourage bulk power transactions between publicly-owned utilities and federally-owned generation. It may, however, discourage wheeling by encouraging areas close to federal installations to create publicly-owned utilities in order to take advantage of the preference right.

At the same time, existing publicly-owned utilities, as a consequence of demand growth beyond the ability of traditional suppliers to serve, may be of benefit to wheeling. These utilities are looking for additional supplies, at lower cost, wherever these might be found. Thus, existing "publics" probably provide an incentive for bulk power transactions generally, and for wheeling specifically.

Cogenerators are probably in the same situation as existing publicly-owned utilities, except from the other end. That is, cogenerators have an interest in being able to wheel their output to those able to pay the highest price. Therefore, these producers provide a major incentive for bulk power transfers.

There is difficulty, however, in that the cogenerator must be paid the utility's avoided cost for his energy. This requirement may inhibit bulk power transfers, particularly those requiring wheeling, by making the cogenerated electricity too expensive for non-local utilities. The local utility is required by law to buy from the cogenerator.

Therefore, while cogeneration is advantageous to bulk power transfers, the avoided cost requirement can be considered an impediment. In addition, the recent modifications in the Fuel Use Act may also serve as an impediment to bulk power transactions, although these changes are so recent that it is difficult to judge the impact.

From the foregoing discussion, we can conclude that the following constitute, in some degree, institutional impediments to bulk power transactions:

1. Franchised territory;
2. Federal-state regulatory dichotomy;
3. PUHCA re transfers outside the company;
4. Power Pools re transfers outside the pool;
5. Mergers;
6. Avoided cost re sales to non-local utilities;
7. Preference right to Federally generated electricity.

Recommendations

Based on the above list of impediments, we present below some suggestions that may alleviate the difficulties. No suggestion is made in regard to franchises because the only feasible recommendation would be the elimination or modification of this arrangement. It is felt this would be too radical a recommendation without substantial study of the full ramifications of such a proposal.

In any case, we present the following suggestions as a way of ameliorating the various impediments to bulk power transactions:

1. The states should be drawn into decisions affecting bulk power sales at the federal level, or at least kept informed of such decisions. This might be accomplished by holding periodic regional discussions regarding bulk power policy between the various state regulatory bodies and FERC. In addition, the involved states could be invited to send an official observer to all FERC bulk power hearings, particularly those dealing with rates; or perhaps the states could be encouraged to participate in such hearings as a party to the case. In the latter instance, perhaps financial or technical assistance could be made available to help the states prepare their presentations. Alternatively, joint state-federal hearings might be considered, bar-

ring constitutional difficulties. In this regard, regional regulatory bodies might be established through Federal legislation, in lieu of FERC regulation, to oversee bulk power sales. These regional boards might be comprised of sitting state commissioners, and chaired by a Federally-appointed member.

2. PUHCA might be amended to minimize the emphasis on single company operation.

3. Planning on a broader regional basis than encompassed by the pool should be encouraged. To an extent this is underway through the various reliability councils, but these activities might be enhanced by involving state officials and others who might have a different perspective on goals and problems. In addition, state commissions might coordinate their planning activities, even though they might belong to different reliability councils. Further, power pools might be required, either through FERC rule making or through legislation, to consider potential bulk power purchases and sales of electricity on a par with generating facilities in their planning. In this regard, it should be noted that many pools do consider all available sources of electricity, but it might be useful to formalize the requirement. In addition, state commissions might exert their influence to assure that pool contracts do not penalize those who purchase capacity or energy outside the pool.

4. The avoided cost criteria for cogeneration sales might be eliminated, with the parties to a transaction given the right to negotiate a rate. However, because of the unequal position of the cogenerator versus the utility, the negotiated rate should be subject to state commission approval if both parties are within one state, or FERC approval if the transaction crosses a state line. Alternatively, a floor might be set under the negotiated rate by rule making; the utility would not be permitted to pay less than this amount for the output of the cogenerator. For example, the floor might be set at the utility's average cost of generation.

5. The effect of the modifications of the Fuel Use Act should be monitored, over the next several years, to determine the impact, if any, on bulk power transactions. This might be accomplished through a NARUC committee, or possibly by the FERC or DOE staff.

LEGAL IMPEDIMENTS TO POWER TRANSFERS

by Robert E. Burns, Esq.
Senior Research Associate
The National Regulatory Research Institute

Bulk power transfers among utilities can take many forms. The transfer of power can occur directly between two interconnected utilities, or between independent power producers (such as a cogenerator or small power producer) and an interconnected utility. When there is a willing seller and a contiguous willing buyer, these transfers are subject to few legal impediments that would prevent the transaction from occurring. Transferring bulk power between a seller and a buyer that are not directly interconnected, however, requires one or more intervening utilities to wheel the power. Here several significant legal barriers can occur, preventing the bulk power transfer from taking place, particularly if an intervening utility is unwilling to provide the necessary transmission services.

There are seven categories of legal impediments to bulk power transfers, and these are (1) the limited authority of the Federal Energy Regulatory Commission to mandate wheeling; (2) the limited authority of the Federal Energy Regulatory Commission to order interconnections and power pooling; (3) the uncertainty and limited scope of state authority to require bulk power transfers; (4) the operation of state franchise laws to prevent certain types of bulk power transfers; (5) the ineffectiveness of antitrust laws, as currently applied, to compel wheeling; (6) in some states, the statutory limitations on siting, certification, and eminent domain; and (7) the uncertain rights of neighboring systems that may bear loop flow costs.

Each legal impediment is separately described in the first seven sections below. In the final two sections, the author presents two sets of recommendations on how these legal impediments can be overcome or eliminated. The first set of recommendations details how legal impediments may be overcome even if existing laws are unchanged. The second set of recommendations offers an explanation of how new federal legislation could remove some existing legal impediments to wheeling.

Throughout this report, the author limits himself to describing and discussing legal impediments which would, as a matter of law, prevent or significantly impede bulk power transfers. Other types of impediments, such as a commission regulation that could cause a delay that might make bulk power transfers less convenient or economical or institutional problems that make wheeling less likely, are dealt with elsewhere in this study.

Limited FERC Authority to Mandate Wheeling

When a willing seller and a buyer who are not interconnected are unable to transfer power because an intervening utility is unwilling to provide them the necessary transmission service, the Federal Energy Regulatory Commission (FERC) is the first logical agency to seek help from because Part II of the Federal Power Act (FPA) grants the FERC jurisdiction over "the transmission of electric energy in interstate commerce."[1] The FERC's power to issue an order requiring wheeling is narrowly circumscribed. The FPA, as originally enacted, had no provision empowering the Federal Power Commission, FERC's predecessor, to require wheeling. This was affirmed by the United States Supreme Court in the famous Otter Tail Power case, when it concluded that[2]

> ...As originally conceived, Part II [of the FPA] would have ... empowered the Federal Power Commission to order wheeling if it found such action to be "necessary or

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[1] Federal Power Act, sec. 201(b), 16 U.S.C. sec. 824(b). The author does not discuss issues concerning tariffs for wheeling and transmission services because these issues are discussed in the regulatory impediments portion of the report.

[2] Otter Tail Power Co. v. United States, 410 U.S. 366, 374 (1973).

desirable in the public interest. These provisions were eliminated to preserve the voluntary action of the utilities."

From this, it is clear that Congress, when it initially enacted the FPA, did not intend to grant the Federal Power Commission the power to order wheeling.

However, Congress amended Part II of the Federal Power Act when it enacted sections 202, 203, and 204 of the Public Utility Regulatory Policies Act of 1978 (PURPA).[3] These sections grant the FERC limited authority to order interconnections and to order wheeling. Two federal circuit courts considered the FERC's authority to order wheeling to be limited by the provisions in PURPA.

In New York State Electric & Gas Corp. v. FERC, the Second Circuit Court of Appeals held that, although Congress intended FERC's new authority to serve as a tool for enhancing competition by facilitating bulk purchases of power, it also intended that FERC's power to order wheeling be stringently limited by the provisions in PURPA.[4] The Second Circuit held that the PURPA requirements reflect an intent of Congress to safeguard the voluntarism of the wheeling arrangement to the greatest extent possible, while assuring all persons that they would be treated fairly and compensated fully if compelled to wheel involuntarily.[5] The court held that the FERC cannot modify a contract for transmission, pursuant to its powers under FPA section 206, where the effect of the modification compels wheeling without following the requirements of PURPA.[6]

The Fifth Circuit Court of Appeals, in Florida Power & Light Co. v. Federal Energy Regulatory Commission, also made it clear that the FERC cannot require a utility that has a policy regarding the availability of wheeling to file a tariff that includes a policy statement concerning the availability of transmission services. Under FPA sections 206(a) and 205, the FERC can find a transmission tariff to be unjust, unreasonable, unduly

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[3] Public Utility Regulatory Policies Act of 1978, sec. 202, 203, and 204; Federal Power Act of 1935, sec. 210, 211, 212, 16 U.S.C. sec. 824i-k (as ammended, 1978).
[4] New York State Electric & Gas Corporation v. Federal Energy Regulatory Commission, 638 F.2d 388 (2d Cir. 1980).
[5] Id., at p. 402.
[6] Id., at p. 403.

discriminatory, or preferential and make changes in such a tariff. Nevertheless, the FERC cannot use these powers to overstep its authority and require involuntary wheeling, aside from compliance with PURPA sections 203 and 204. The court held that such a tariff filing requirement in effect imposes a common carrier status on the utility, and this is beyond the FERC's power.

The FERC can order wheeling either under PURPA subsection 203(a) or 203(b). Subsection 203(a) applies when an applicant seeks a FERC order to mandate wheeling of power by any other electric utility.[7] Subsection 203(b) applies in the special case where an applicant that wants to purchase electricity for resale seeks wheeling by the utility that historically supplied it wholesale power and that utility has given notice that it is unwilling or unable to continue to supply electric power to the applicant. In other words subsection (b) applies when a utility supplying wholesale electricity to the applicant utility cuts off generation service. Under both sections 203(a) and (b), the FERC can order the construction of additional transmission capacity necessary to facilitate the wheeling service.[8]

A willing buyer and a willing seller must exist before the FERC can exercise its limited authority to order wheeling. The FERC cannot use its

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[7] The author here is using the term "applicant" in its natural sense, i.e. one who applies or makes an application. The author does not intend in any way to suggest that the term "applicant" as found in section 203 is limited to an electric utility or federal power marketing agency. The FERC left that issue unresolved in Southeastern Power Administration v. Kentucky Utilities Co., Opinion No. 198, 25 FERC para. 61,204. In the Initial Decision, the Presiding Administrative Law Judge concluded that an "'applicant' is the entity to whom power will flow or the 'buyer' of the power." Initial Decision at 17. In that case, the federal power marketing agency (SEPA) made the application to wheel to eight municipally-owned utilities. The municipally-owned utilites were also considered to be applicants by the Administrative Law Judge. The FERC found it unnecessary to reach the issue. For more discussion on the debate over the term "applicant", see Tiano & Zimmer, "Wheeling for Congeneration and Small Power Production Facilities," 3 Energy L. J. 95, 103.

[8] Specifically, section 203(a) provides that the FERC may order any enlargement of transmission capacity, while section 203(b) provides that the FERC may provide for any increase of transmission capacity.

power to order wheeling to require utilities to enter into agreements to buy or sell power.[9]

PURPA sections 203 and 204 narrowly limit the circumstances when the FERC can order wheeling. The initial application requirements of subsections 203(a) and (b), the special requirements of section 204, and further limitations found in section 203(c) are discussed next.

The Application Requirements of PURPA Subsections 203(a) and 203(b)

To obtain a FERC order requiring a utility to wheel power, one must must apply for the order under PURPA section 203(a) or 203(b).[10] Under sections 203(a) and 203(b), three conditions must be met to obtain a FERC order requiring a utility to wheel. First, only certain parties can apply for an order to wheel. Both subsection 203(a) and 203(b) provide that only an electric utility or federal power marketing agency may apply to the FERC for a wheeling order. An electric utility is defined as "any person" or State agency that sells electricity. This term includes the Tennessee Valley Authority (TVA). A federal power marketing agency is any instrumentality of the United States (other than the TVA) that sells electricity. There is no mention here of ultimate customers, cogenerators, or small power producers, even though they are not specifically excluded from the definition of "any person".[11]

Second, there must be public notice and an opportunity to be heard at an evidentiary hearing before the FERC issues an order to wheel. Both

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[9] H.R. Rep. No. 1750, 95th Cong., 2d Sess. 91, reprinted in 1978 U.S. Code Cong. & Ad. News 7797, 7786 (hereafter Conference Report).

[10] The Conference Report makes it clear that Congress intended that applicants for transmission services are entitled to proceed under either section 203(a) or 203(b), or they may apply under both sections by pleadings framed in the alternative. Conference Report at 91.

[11] See Tiano & Zimmer. Here Tiano and Zimmer argue that it is an open question whether a cogenerator or small power producer is an electric utility which can apply for wheeling services. They note that "any person" is defined under PURPA section 3(4) merely as an individual or corporation. A cogenerator or small power producer would appear to meet that definition. However, they also note that the FERC has not adopted such a construction to date.

subsections require the FERC, upon receipt of an application to order wheeling, to provide public notice of the application and notice to each affected state public utility commission, utility, and federal power agency. The FERC must provide intervening parties the opportunity to be heard at an evidentiary hearing before issuing an order to mandate wheeling. The conference report states explicitly that an opportunity to be heard is to be provided to the utility being requested to wheel power, the utilities which are or would be the present and proposed seller and buyer in the arrangement, to all utilities whose systems, operations, costs, or revenues would be affected by the proposed order and arrangements, and to all customers of these utilities. These parties can participate in any evidentiary hearing under PURPA sections 203 or 204.[12]

Third, before issuing an order pursuant to subsection 203(a), the FERC must find the wheeling order would be in the public interest.[13] A public interest inquiry can be far-reaching. As defined in Black's Law Dictionary, the public interest is "[s]omething in which the community at large has some pecuniary interest, or some interest by which their legal rights or liabilities are affected. It does not mean anything so narrow as mere curiosity, or as the interests of the particular localities, which might be affected by the matters in question."[14]

The FERC must also find that an order issued pursuant to subsection 203(a) will either conserve a significant amount of energy, significantly promote the efficient use of facilities and resources, or improve the reliability of any electric utility system to which the order applies.[15] The FERC need find only one of these three alternatives to be true. The Conference Committee Report makes clear that the phrase "efficient use of facilities and resources" includes both existing and future facilities and resources, including capital resources.[16]

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[12] Conference Report at 93.

[13] Public Utility Regulatory Policies Act of 1978, sec. 203(a), Federal Power Act of 1935, sec. 211(a), 16 U.S.C. sec. 824j(a) (1978).

[14] Black's Law Dictionary, Revised Fifth Edition (West Publishing: St. Paul, Minn., 1979), at p. 1106.

[15] See footnote 13, supra.

[16] Conference Report at 91.

There are no similar public interest, conservation, efficiency, or reliability requirements in subsection 203(b). Under subsection 203(b) the FERC must instead determine that (1) the utility providing wholesale service has given actual or constructive notice to the applicant that it is unwilling or unable to continue to supply the wholesale service, and (2) the applicant has requested the utility to provide the wheeling services requested in the subsection 203(b) application.[17]

The Special Requirements of Section 204

Before issuing an order mandating wheeling under either subsection 203(a) or 203(b), the FERC must find that the order meets the requirements of PURPA section 204. Section 204 contains five requirements that can significantly impede FERC's issuance of wheeling orders covering most utilities.[18] After the five requirements are met, then the FERC can issue a proposed wheeling order. The five requirements and the process for the proposed wheeling order are set out below.

First of all, the FERC must find, based on evidence presented by the parties, that the wheeling order is not likely to result in a reasonably ascertainable uncompensated economic loss for any electric utility, or qualifying cogenerator or small power producer affected by the order.[19] Here, the conference report shows that Congress intended the FERC to evaluate the likelihood of a reasonably ascertainable loss occurring as the result of the order. Such a loss could occur at the time the order is issued or any time thereafter. If an uncompensated loss is determined to be likely, the FERC cannot issue an order mandating wheeling.[20] Presumably, the Congress did not expect the FERC to go to extraordinary lengths in determining whether an uncompensated economic loss would exist as a result

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[17] Public Utility Regulatory Policies Act of 1978, sec. 203(b), Federal Power Act of 1935, sec. 211(b), 16 U.S.C. 824j(b) (1978).

[18] There is an additional set of requirements that apply when the wheeling order under consideration would require the Tennessee Valley Authority.

[19] Public Utility Regulatory Policies Act of 1935, sec. 204, Federal Power Act, sec. 212, 16 U.S.C. sec. 824k(a)(1) (1978).

[20] Conference Report at 93.

of the wheeling order. The requirement is that the FERC look at only reasonably ascertainable losses. It is not clear at what point an economic loss asserted by one of the parties would not be considered reasonably ascertainable. For example, would the FERC require a load flow study to demonstrate an economic loss? Also, it is not clear what the FERC would consider an economic loss. For example, if a qualifying facility or a utility were unable to sell power because transmission lines are fully loaded, would that constitute an economic loss? Would there be an economic loss if a utility were unable to sell its power to a wholesale buyer because the wheeling order would make another company's power available to the wholesale buyer at a lower cost?

The second requirement is that the FERC must find that the requested order would not place an undue burden on any affected electric utility, qualifying cogenerator, or small power producer.[21] The FERC here must find no other, noneconomic undue burden for the order to be issued.[22] It is worth noting that there is no clear definition of what can be considered in this determination of whether the proposed wheeling order would create an undue burden. Nor is there any requirement that the FERC take into account only burdens that are reasonably ascertainable. It would appear that the FERC could look at system load studies here.

The third requirement is that the FERC must find that the requested order will not unreasonably impair the reliability of any electric utility affected by the order.[23] In the industry, reliability in a bulk power electric system is understood to mean "the degree to which the performance

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[21] Public Utility Regulatory Policies Act of 1978, sec. 204, Federal Power Act of 1935, sec. 212(a)(2), 16 U.S.C. sec. 824(a)(2) (1978).

[22] In the conference report, the conferees state that they intend the FERC not consider any loss covered by subsection 203(a)(1) under this subsection because the evaluation under subsection 203(a)(1) would have already taken it into account. Conference Report at 93. Presumably, this means that the FERC does not need to consider any reasonably ascertainable economic loss in its determination of whether the wheeling order would create an undue burden. While it is clear that the FERC is to consider noneconomic losses under this subsection, it is not clear whether the FERC is also to consider economic losses that are not reasonably ascertainable.

[23] Public Utility Regulatory Policies Act of 1978, sec. 204, Federal Power Act of 1935, sec. 212(a)(3), 16 U.S.C. sec. 824k(a)(3) (1978).

of the elements of the system results in power being delivered to consumers within accepted standards and in the amounts desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service."[24] Here, however, the requirement is that the proposed wheeling order not unreasonably impair the reliability of any electric utility that would be affected by the order. The Congress gave no guidance to the FERC on when an impairment of reliability would be unreasonable. Some would contend that any impairment of a utility's reliability is unreasonable. If the FERC cannot determine that the requested wheeling order would not unreasonably impair the reliability of any utility affected by the order, then presumably no order can be issued.

The fourth requirement is that the FERC must find that the requested order will not impair the ability of any electric utility affected by the order to render adequate services to its customers.[25] As commonly understood in the industry, for a bulk power electric system, adequacy means "the ability of the bulk power electric system to supply the aggregate electric power and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components."[26] Adequacy and security are considered the two basic components of reliability.[27] Although this requirement appears to be related to the reliability requirement, Congress here added adequacy of service as an additional requirement beyond that of not unreasonably impairing reliability.[28] No impairment of an electric utility's ability to render adequate services to its customers is permitted. Again, it should be emphasized that the requirement focuses on the ability of <u>each</u> electric utility affected by the order to adequately serve its customers.

The fifth requirement is that the applicant requesting the wheeling order must demonstrate that it is ready, willing, and able to pay the

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[24] North American Electric Reliability Council, <u>Reliability Concepts</u> (Trenton, N.J.: 1985), p.8.
[25] Public Utility Regulatory Policies Act of 1978, sec. 204, Federal Power Act of 1935, sec. 212(a)(4), 16 U.S.C. sec. 824k(a)(4) (1978).
[26] North American Reliability Council, p.8.
[27] Ibid.
[28] Conference Report at 94.

wheeler "the reasonable costs of transmission services, including the costs of any enlargement of transmission facilities that may be necessary."[29] Here, the conference report states that the FERC may, in appropriate circumstances, require the applicant to demonstrate that it is ready, willing, and able to reimburse the wheeler for any enlargement of transmission capacity prior to the utility's undertaking of the enlargement.[30] Further, the applicant requesting the wheeling order must also demonstrate that it is ready, willing, and able to pay the wheeler "a reasonable rate of return on such transmission service costs, as determined to be appropriate by the FERC."[31] Presumably, the FERC could also require the posting of a bond or other security when there might be some doubt as to the applicant's ability to pay.

After the above requirements of section 204 have been fulfilled, the FERC can issue a proposed order. The FERC will set a reasonable time for the parties to the proposed wheeling order to negotiate and agree to the terms and conditions under which the order would be carried out. The agreement among the parties would include the apportionment of costs among them and the compensation or reimbursment due any of them. The FERC may shorten the time limit set for negotiation and agreement when delays would jeopardize the attainment of the purposes of the proposed wheeling order. The terms and conditions agreed to by the parties are subject to the approval of the FERC.[32] In the conference report, the conferees made it clear that, the FERC should disapprove the terms and conditions agreed to by the parties only if they are inconsistent with PURPA sections 203 and 204 or would be detrimental to the ratepayers of one or more parties.[33] Only if the parties fail to reach a timely agreement is the FERC to prescribe the

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[29] Public Utility Regulatory Policies Act of 1978, sec. 204, Federal Power Act of 1935, sec. 212(b)(2)(A), 16 U.S.C. sec. 824k(b)(2)(A) (1978).
[30] Conference Report at 94
[31] Public Utility Regulatory Policies Act of 1978, sec. 204, Federal Power Act of 1935, sec. 212(b)(2)(B), 16 U.S.C. sec. 824k(b)(2)(B) (1978).
[32] Public Utility Regulatory Policies Act of 1935, sec. 204, Federal Power Act of 1935, sec. 212(c), 16 U.S.C. sec. 824k(c) (1978).
[33] Conference Report at 94.

terms and conditions in the final wheeling order.

There are still more limitations to the FERC's authority to order wheeling that occur in special cases. These are discussed next.

Additional Limitations in Special Cases

There are four additional limitations on the FERC's authority to order wheeling found in PURPA subsection 203(c) that apply in certain special cases. Perhaps the most significant of these additional limitations is found in subsection 203(c)(4), which prohibits FERC from ordering wheeling if the order would provide for transmission services to an ultimate customer,[34] that is, any end user. End users, of course, purchase retail power and include most industrial, residential, or commercial customers. FERC's authority, then, is limited to ordering wheeling to entities that resell electricity--in other words, to wholesale transactions. The significant implication here is the FERC cannot order wheeling to industrial customers. This prohibition precludes the FERC from order wheeling from a qualifying facility to an industrial customer even if the two are owned by the same entity.

The second limitation prohibits the FERC from ordering wheeling pursuant to subsection 203(a) if the order does not reasonably preserve existing competitive relationships.[35] This limitation has also proven to be significant. In <u>Southeastern Power Administration v. Kentucky Utilities</u>

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[34] Public Utility Regulatory Policies Act of 1978, sec. 203(c)(4), Federal Power Act of 1935, sec. 211(c)(4), 16 U.S.C. sec. 824j(c)(4) (1978).

[35] It is worth noting that this provisions does not prohibit the the FERC from issuing an order requiring wheel pursuant to PURPA section 203(b). Presumably, Congress saw no need to require that existing competitve relationships be reasonablly preserved in circumstances where the utility requested to wheel had given actual or constructive notice that it was no longer willing or no longer able to provide services to the applicant to whom it had provided wholesale service. In such circumstances, it is the utility itself that has caused a change in existing competitive relationships. Public Utility Regulatory Policies Act of 1978, sec. 203(c)(1), Federal Power Act of 1935, sec. 211(c)(1), 16 U.S.C. sec. 824j(c)(1)(1978).

Company, the only FERC opinion concerning its wheeling authority, the FERC held that it does not have the authority to require the Kentucky Utilities Company to wheel power from the Southeastern Power Administration to eight municipally-owned utilities.[36] The basis for the opinion was that an order requiring Kentucky Utilities Company to wheel another's power to its municipal customers would violate the requirement that existing competitive relationships be reasonably preserved.

In reaching its opinion, however, the FERC discussed the ambiguity of PURPA subsection 203(c)(1). The FERC noted first that this subsection is not clear. While the subsection directs the FERC to consider the changes that the proposed wheeling would make in the competitive relationships in a particular market, the particular market to be examined is unclear. Second, the key phrase, "existing competitive relationships," is ambiguous.[37] Further, the phrase "reasonably preserve" is imprecise, so that it is unclear what type of changes in competitive relationships would be prohibited.[38] To interpret the meaning of these phrases, the FERC turned to the legislative history of PURPA.

The FERC decided that the Conference Report provided some direction on what the phrase "reasonably preserve" means. The Conference Report states that:

> [t]he conferees do not intend that the Commission order wheeling which significantly alters the competitive relationships among the utilities in competition with one another for the same customers.[39]

Based on this, the FERC held that "reasonably preserve" means that existing competitive relationships must not be significantly altered.[40]

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[36] Southeastern Power Administration v. Kentucky Utilities Company, Opinion No. 198, 25 FERC para. 61,204 (Nov. 8, 1983).
[37] Ibid., at p. 61,530.
[38] Ibid., at p. 61,531.
[39] Conference Report at 92.
[40] Southeastern Power Administration v. Kentucky Utilities Company, at p. 61,532.

The FERC defined "existing competitive relationships" as competitive relationships for the business of the same customers. The FERC then limited this definition to those customers who would receive the energy to be transmitted pursuant to the requested wheeling order.[41] In reaching its decision, the FERC rejected the municipal utilities' contention that "same customers" means all the customers for whose business the utilities could compete. FERC's narrower interpretation is based on language in the Conference Report, which states that existing competitive

> relationships may involve, in addition to utilities mentioned in the order, utilities serving or seeking to serve the ultimate consumers of the electric energy transmitted pursuant to the order.[42]

The FERC notes the conferees' intent that FERC focus narrowly on the changes wheeling will make in the relationships between the utilities and the retail customers who are to receive the wheeled power. Because the Conference Report does not suggest a broader interpretation for wholesale competition, the FERC gave the term "existing competitive relationships" the same narrow meaning when dealing with wholesale competition.[43] The FERC buttressed its narrow interpretation of existing competitive relationships with two additional observations on the subsection's legislative history. First, the debate among conferees confirms that the purpose of PURPA subsection 203(c)(1) is to protect a wheeling utility from losing wholesale customers within its service area to other bulk power suppliers. Specifically, the the conferees' intent was to protect the wheeling utility's relationship with specific customers, not to protect the wheeling utility's ability to compete.[44] Second, the FERC observed that the Conference Report makes clear that PURPA is not designed to supplement the antitrust laws by providing the FERC with an additional means for remedying

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[41] Ibid., at pp. 61,532-3.
[42] Conference Report at 92.
[43] Southeastern Power Administration v. Kentucky Utilities Company, at p. 61,533.
[44] Ibid., at pp. 61,533-6.

anticompetitive conduct.[45] This means that PURPA subsection 203(c)(1) cannot be read to suggest that FERC has any additional authority to remedy anticompetitive conduct.

The significance of FERC's interpretation of the restrictions in PURPA subsection 203(c)(1) is that wheeling cannot be ordered when it would cause the wheeling utility to lose wholesale customers within its service area. The FERC's narrow definition of the relevant market makes PURPA subsection 203(c)(1) a major impediment for municipalities, cooperatives, and other wholesale customers trying to obtain less expensive bulk power than offered by their current supplier. As long as their current supplier does not indicate that it is unwilling or unable to continue to supply wholesale power, the wholesale customer cannot apply for wheeling services under subsection 203(b) and cannot successfully obtain wheeling services under 203(a) because of the restriction of subsection 203(c)(1).

Another special restriction, found in PURPA subsection 203(c)(2), prevents the FERC from requiring a utility to wheel electricity to replace its own electricity supply if this supply is required under a contract or a rate schedule on file with the FERC.[46] This restriction would preclude the FERC from issuing an order requiring wheel if the order would interfere with an existing contract for the sale of electricity. It would also preclude the FERC from ordering an electric utility to wheel if the order would provide for the transmission of electricity that would replace electricity currently provided by the electric utility to the applicant under to a rate schedule filed with the FERC. This prevents the FERC from ordering wheeling to a wholesale customer when the wholesale sales are covered by a filed FERC rate schedule.

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[45] Ibid., at pp. 61,536-9. The FERC does note that it might have the power to correct such anticompetitive behavior and to order Kentucky Utilities to wheel under sections 205 and 206 of the FPA. But, in an accompanying footnote, FERC states that whether it can order wheeling pursuant to FPA sections 205 and 206 is not entirely clear, even to remedy anticompetitive behavior. See Florida Power & Light Co. v. FERC, 660 F.2d 668, 679 (5th Cir. 1981); New York State Electric & Gas Corp. v. FERC. 638 F.2d 388, 402-3 (1980) <u>cert</u>. <u>denied</u>, 454 U.S. 821 (1981); but see, the pre-PURPA case of Richmond Power & Light Co. v. FERC, 574 F.2d 610, 624 (D.C. Cir. 1978).

[46] Public Utility Regulatory Policies Act of 1978, sec. 203(c)(2), Federal Power Act of 1935, sec. 211(c)(2), 16 U.S.C. sec. 824j(c)(2) (1978).

The fourth and final restriction of PURPA subsection 203(c) is a prohibition against the FERC issuing any wheeling order that is inconsistent with state laws governing the retail marketing of electric utilities.[47] The conferees stated that this provision is intended to bar the FERC from issuing a wheeling order that allows a utility to sell power to a retail customer who is within the service territory of another utility if the service territory was established by a state law.[48] For the most part, this prevents the FERC from issuing an order to wheel that is inconsistent with state franchise laws.

Summary

From the above discussion, the reader can see that the FERC's authority to require wheeling is limited. To summarize, before the FERC can issue an order requiring wheeling, the FERC must first check that the applicant is authorized to apply for an order requiring wheeling. Next, the FERC must provide public notice and an opportunity to be heard at an evidentiary hearing. Then, unless the electric utility requested to wheel and the applicant have been parties to a wholesale power sale, the FERC must make a public interest determination and find that the wheeling would either conserve energy, promote efficiency, or improve reliability. If the utility requested to wheel and the applicant have been parties to a wholesale power sale, the FERC must determine that the utility that provided wholesale service has given actual or constructive notice that it is unwilling or unable to continue to provide service to the applicant and that the applicant has requested wheeling services.

Then, the FERC must determine that an order requiring wheeling services is not likely to result in a reasonably ascertainable economic loss or place an undue burden on any electric utility, qualifying cogenerator, or small power producer affected by the order. The FERC must also determine that the order would not unreasonably impair the reliability or impair the ability of

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[47] Public Utility Regulatory Policies Act of 1978, sec. 203(c)(3), Federal Power Act of 1935, sec 211(c)(3), 16 U.S.C. sec. 824j(c)(3) (1978).
[48] Conference Report at 92.

any affected utility to render adequate service to its customer. The applicant for the order must also demonstrate that it is ready, willing, and able to reimburse the wheeler for the reasonable costs of the transmission service (including the costs of any enlargement of the wheeler's transmission lines and equipment) and to provide the wheeler with a reasonable return on its transmission costs as determined to be appropriate by the FERC. Only then can the FERC issue a proposed order, which is subject to negotiation between the parties. Only if the parties fail to reach an agreement within the reasonable time limit set by the FERC, may the FERC prescribe the terms and conditions of the final order requiring wheeling.

There are a four additional limitations to the FERC's power to order wheeling. They are that the FERC cannot order wheeling to an ultimate customer, the FERC cannot order wheeling to a wholesale customer that would upset an existing competitive relationship, the FERC cannot order wheeling that would replace power either required to be provided to the applicant because of a contract or currently provided to the applicant by the potential wheeler under a rate schedule on file with the FERC, and the FERC cannot order wheeling that would violate state laws that set up retail marketing areas.

Congress sought to guarantee two things: first, that any FERC order to require wheeling would not adversely affect any party without compensation; and second, that all affected parties have a say in the final order, thereby making the final wheeling arrangement as voluntary as possible. The result is that an applicant for a wheeling order from the FERC has little chance of clearing all the hurdles necessary to obtain a FERC order requiring wheeling from an unwilling utility. This is particularly true if wheeling is needed for an economy bulk power exchange of short duration, for example for a few hours during certain months. To date, no FERC order requiring an unwilling utility to wheel has ever been issued.

Limited FERC Authority to Order Interconnections and Pooling

When there is a willing seller but not a willing buyer, or a willing buyer and not a willing seller the FERC has some limited authority under PURPA to order interconnection between the buyer and the seller so that a sale can be made. The FERC also has limited authority under PURPA to preempt state laws and regulations that prohibit or prevent the voluntary coordination or pooling of utilities.

The FERC also has a limited authority to order interconnections under PURPA section 202. For the FERC to be able to order an interconnection under this section, it must receive an application for an interconnection from an electric utility, a federal marketing agency, or a qualifying cogeneration or small power production facility. The application for an interconnection may seek the physical connection of the transmission facilities of any utility with the facilities of the applicant. If the FERC orders the interconnection, it may also order (1) any action that may be necessary to make such a physical connection effective, if the connection would otherwise be ineffective due to inadequate size, poor maintenance, or physical unreliability of the connection, (2) a sale or exchange of energy, or other coordination, that may be necessary to carry out the purposes of the interconnection, and (3) an increase in transmission capacity as may be necessary to carry out the purposes of the interconnection. In addition, state public utility commissions may seek FERC orders for interconnections and the ancillary actions to make interconnections effective, and the FERC may issue orders on its own motion. However, the FERC may not issue an order with respect to a federal power marketing agency based on either the application of a state commission or the FERC's own motion.[49]

Upon receipt of an application seeking an interconnection, the FERC must issue a notice to each affected state public utility commission, federal power marketing agency, and qualifying facility, as well as to the public. The FERC must then give all the parties an opportunity to be heard at an evidentiary hearing. Before the FERC can issue an order requiring an interconnection, it must determine at the evidentiary hearing that the order would be in the public interest, and that it would either (1) encourage overall conservation of energy or capital, (2) optimize the efficiency of use of facilities and resources, or (3) improve the reliability of any

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[49] Public Utility Regulatory Policies Act of 1978, sec. 202, Federal Power Act of 1935, sec. 210, 16 U.S.C. sec. 824i (1978).

electric utility system or federal power marketing agency to which the order applies.[50]

In addition, the FERC must determine during the evidentiary hearing that an order requiring interconnection would comply with section 204 of PURPA. Recall that PURPA section 204 contains five special requirements that also apply to the FERC's authority to order wheeling. As they apply to an order requiring an interconnection, these are that the interconnection order (1) would not result in a reasonably ascertainable uncompensated economic loss for any affected electric utility or qualifying facility, (2) would not result in an undue burden on any affected electric utility or qualifying facility, (3) would not unreasonably impair the reliability of any affected electric utility, and (4) would not impair the ability of any affected electric utility to adequately serve its customers. The fifth requirement is that the applicant must demonstrate that he is ready, willing, and able to reimburse his share of the reasonably anticipated costs incurred because of the interconnection order. Here too, before issuing an order, the FERC must issue a proposed order and give the parties some reasonable amount of time to agree to the terms and conditions under which the interconnection order will be carried out. If the parties fail to reach an agreement within the reasonable time set by the FERC, the FERC may prescribe the terms and conditions in the final order.[51]

The FERC has the authority under PURPA section 205 to exempt electric utilities, in whole or part, from any provision of state law or regulation which prevents voluntary coordination of the utilities, including any agreement for central dispatch. The FERC may initiate the proceeding on its own motion or may act after application of any person or governmental entity. Before issuing an order providing such an exemption, the FERC will provide notice to the governor of the affected state and to the public and will provide an opportunity for a public hearing. To issue the order, the FERC must determine that the voluntary coordination is designed to obtain economical utilization of facilities and resources in the area and that the

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[50] Ibid.

[51] Public Utility Regulatory Policies Act of 1978, sec. 204, Federal Power Act of 1935, sec. 212(a),(b)(1), 16 U.S.C. sec. 824k(a),(b)(1) (1978).

state law or regulation is not required by federal law and is not designed to protect public health, safety, welfare, or the environment or to conserve energy, or to mitigate the effects of emergencies resulting from fuel shortages.[52]

In addition, under PURPA section 205, the FERC may recommend to electric utilities that they should voluntarily enter into negotiations to form pooling agreements where opportunities for conservation of energy, optimization in the efficiency of use of facilities and resources, and increased reliability exist. The FERC must report annually to the Congress regarding any such recommendations and subsequent actions taken by the electric utilities, the FERC, and the Secretary of Energy.[53]

Limited State Authority over Power Transfers

If the FERC's authority to order wheeling and bulk power transfers is for all practical purposes ineffectual, then the next logical place to look for an agency that can require an unwilling utility to wheel or to transfer bulk power would be at the state level. Indeed, several state public service commissions have asserted that they have the authority to require a utility to wheel power. However, if the state public utility commissions do have the authority to require a utility to transfer power, their authority to do so is limited by the Commerce Clause. Further, state commissions might not have the authority to order power transfers because of the possibility of federal preemption. At best, state commission authority to order power transfers is uncertain. The limited scope and uncertainty of state commission authority to order wheeling and bulk power transfers are discussed in the next two subsections.

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[52] Public Utility Regulatory Policies Act of 1978, sec. 205(a), 16 U.S.C. sec. 824a-1(a) (1978).
[53] Public Utility Regulatory Policies Act of 1978, sec. 205(b), 16 U.S.C. sec. 824a-1(b) (1978).

The Limited Scope of State Authority

To the extent that state public utility commissions might have the authority to order wheeling or bulk power transfers, such authority would be limited in scope by the Commerce Clause. The most recent U.S. Supreme Court case interpreting the Commerce Clause in the context of electric utility regulation is Arkansas Electric Cooperative Corp. v. Arkansas Public Service Commission.[54] In that case, the Supreme Court abandoned the Attleboro test.[55]

The Attleboro test, as subsequently applied in the Colton case, created a "bright line" between permissible and impermissible state regulation. The "bright line" was the wholesale/retail line.[56] Under Attleboro, if state regulation involved a wholesale transaction, it would impose a direct burden on interstate commerce, in violation of the Commerce Clause. To fill the regulatory gap created by Attleboro, the Congress enacted the FPA. Enactment of the FPA had the general effect of shifting the Supreme Court's focus, in determining the permissible scope of state regulation, from the constitutional issues involving the Commerce Clause to statutory interpretation issues involving the FPA.

Arkansas Electric Coop., however, deals with the issue of whether a state public utility commission can regulate the wholesale rates charged by a rural cooperative to its member retail distributors, all of whom are located within a single state. The FPC determined in 1967 that it did not have authority under the FPA to regulate the wholesale rates charged by

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[54] Arkansas Electric Cooperative Corp. v. Arkansas Public Service Commission, 461 U.S. 375 (1983). In this case, the U.S. Supreme Court decided that the Arkansas Public Service Commission had not acted contrary to the Commerce Clause or the Supremacy Clause of the Constitution when it asserted regulatory jurisdiction over the wholesale rates charged by the Arkansas Electric Cooperative Corporation to its retail members, all of whom are located within the state of Arkansas.

[55] Id. at 389-393.

[56] While Colton was the first case to truly apply the wholesale/retail bright line to its own facts, Colton was based on a statutory interpretation of the FPA. See FPC v. California Edison Co. 376 U.S. 205 (1964). The court in Arkansas Electric Coop. distinguishes Colton as merely concerning a statutory interpretation and not a constitutional interpretation of the Commerce Clause. Id. at 392.

rural cooperatives. Also, nothing in the Rural Electrification Act expressly preempts state rate regulation of power cooperatives financed by the Rural Electrification Administration. The factual situation in Arkansas Electric Coop. thus removed federal preemption as the dispositive issue and allowed the Supreme Court to reexamine the permissible scope of state regulation of electric utilities under the Commerce Clause.

In addressing this issue, the Court first noted that, in the absence of congressional legislation, the Commerce Clause contains an implied limitation on the power of the states to interfere with or impose burdens on interstate commerce.[57] The Court noted that the mechanical line drawn by the Attleboro rule is based on a supposedly precise categorical division between direct and indirect effects on interstate commerce.[58] However, the Supreme Court reasoned that modern jurisprudence usually gives more latitude to state regulation than a categorical approach. As early as 1942, the Court had stated in Illinois Gas Co. v. Public Service Co. that

> [i]n the absence of any controlling act of Congress, we should now be faced with the question whether the interest of the state in the present regulation of the sale and distribution of gas transported into the state balanced against the effect of such control on the commerce in its national aspect, is a more reliable touchstone for ascertaining state power than the mechanical distinction [of the Attleboro test] on which appellee relies.[59]

The Court has thus been applying a balance-of-interest test to Commerce Clause cases over the last several decades. In recent years, it has rejected categorical tests akin to Attleboro in favor of balancing-of-interests tests.[60]

Recognizing that the "bright line" test of Attleboro is an anachronism, the Court in Arkansas Electric Cooperative Corp. adopted a balancing-of-interest test to determine the proper scope of state regulation of public

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[57] Id. at 389.
[58] Id. at 378.
[59] Illinois Gas Co. v. Public Service Co., 314 U.S. 498, 505 (1942), as cited in Arkansas Electric Coop. at 379-380.
[60] Id. at 390.

utilities under the Commerce Clause.[61] It said that the Commerce Clause prevents state public utility commissions from regulating a matter in interstate commerce unless the burden on interstate commerce caused by the state regulation is incidental and not clearly excessive in relation to the putative local benefits of state regulation.[62] To determine whether state regulation of a matter in interstate commerce would violate the Commerce Clause, the courts look at whether the state regulation serves a legitimate local purpose.[63] (Economic protectionism is an example of a local purpose that clearly is not considered legitimate.[64]) If a legitimate local purpose is found, then the court will engage in a balancing test to determine whether the burden imposed by the regulation is excessive in light of the local interest involved. The courts will also look at whether the local interest could be promoted with a lesser impact on interstate commerce.[65]

Applying this balancing of interest test to state regulation of transmission services would probably limit the ability of state public utility commissions to order wheeling or a bulk power transfer. First, state public utility commission authority to order wheeling or a bulk power transfer within its own jurisdiction would serve a legitimate local purpose. By ordering a local utility to wheel or transfer power, a state commission could help assure that local ratepayers received the lowest cost power available to them. For example, if the seller generated low cost power and the buyer generated high cost power, then a state commission order to make the transaction possible would help to lower electricity prices for the ratepayers in the state. Wheeling or bulk power transfer orders could also help balance areas of capacity shortage and excess capacity within a state. If the seller in the wheeling transaction were a qualifying facility, the state commission wheeling order might also serve the purpose of promoting cogeneration or small power production within the state. However, state commissions would only be able to order wheeling or bulk power transfers for

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[61] Id. at 391-393.
[62] Id. at 395.
[63] Id. at 394-395.
[64] Id. at 394.
[65] Id.

those utilities under their own jurisdiction. Also, it is unlikely that a state commission could order wheeling or a bulk power transfer for a transaction that would involve an out-of-state party. A state probably could not order wheeling if the buyer, seller, and utility were not all located in one state. Otherwise, the state commission order might represent an excessive burden on interstate commerce. Further, if the wheeling or bulk power transfer order by a state commission were to have an adverse effect on the reliability of an out-of-state utility, the order would probably violate the Commerce Clause. Thus, a state commission's authority to order wheeling or bulk power transfer would probably be very limited in scope due to these Commerce Clause considerations.

The Uncertainty of State Authority

Even if the Commerce Clause did not itself prevent a state public utility commission from exercising its authority to require bulk power transfers or wheeling by an unwilling utility, a state commission's authority to order wheeling or bulk power transfers is uncertain because of the possibility of federal preemption by the FERC. The FERC's jurisdiction over transmission services is found in subsection 201(b) of the FPA.[66] That section provides that Part II of the FPA applies to "the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce." In cases interpreting the meaning of "in interstate commerce" in the context of the wholesale sale of electricity, the United States Supreme Court has consistently given the term "in interstate commerce" a broad meaning. In 1968 in Federal Power Commission v. Southern California Edison Co., the Supreme Court held that the FPC had jurisdiction pursuant to the FPA over a wholesale sale of electricity between one utility within a state to another utility within the same state when some of the electricity originated out-of-state.[67] Later, in Federal Power Commission v. Florida Power & Light Co., the Supreme Court

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[66] Federal Power Act, section 201(b), 16 U.S.C. sec. 824(b).
[67] Federal Power Commission v. Southern California Edison Co., 376 U.S. 205 (1964).

found that the FPC has jurisdiction over wholesale sales even if the utility has no direct connection with another utility outside the state.[68] Instead, all that is necessary is that the utility be interconnected with another utility which in turn has interstate connections. The Supreme Court announced the test as one where it is not necessary to demonstrate that there is a unity in electromagnetic response on a system, rather it is sufficient if energy commingles in a bus with energy that is in interstate commerce.[69] Because all electric utilities in the 48 contiguous states, except the utilities that are a part of ERCOT in Texas, are interconnected with other utilities that are a part of an interstate grid, nearly all wholesale sales of electricity come under FERC's jurisdiction.

In the first case to address the subject, the FERC held that the rulings setting out the extent of FERC's authority over wholesale sales also apply to transmission service. The meaning of "in interstate commerce" is the same in both contexts. The FERC held in <u>Consolidated Edison Co. of New York</u> that the transmission of energy within a single state is subject to FERC jurisdiction if made on an interconnected interstate transmission grid.[70] Further, the FERC asserts that once its jurisdiction over transmission of electric power in interstate commerce is determined, its jurisdiction is exclusive and preempts the states from regulating the transmission of electricity in interstate commerce,[71] and that it has no discretion to reject jurisdiction under the FPA.[72]

The issue of whether the FERC's authority over transmission in interstate commerce preempts the authority of state public utility commissions to require wheeling was raised indirectly in <u>Florida Power and</u>

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[68] Federal Power Commission v. Florida Power & Light Co., 404 U.S. 453 (1972).
[69] Ibid., at 461-463.
[70] Consolidated Edison Co. of New York, Docket No. ER81-183-000, 15 FERC para. 61,174 (May 26, 1981).
[71] Florida Power and Light Co. and Florida Public Service Commission, et al., Docket No. EL84-27-000, 29 FERC para. 61,140 (1984) at p. 61,292, citing F.P.C. v. Southern California Edison, 376 U.S. 205, 216 (1964); and New England Power Co. v. New Hampshire 455 U.S. 331, 340 (1982).
[72] Id., citing City of Colton v. Southern California Edison Co., 26 FPC 223, 236 (1961), quoted with approval in FPC v. Southern California Edison Co., <u>supra</u>, at 209, n. 5.

Light Co., et al., a declaratory order by the FERC.[73] In that case, Florida Power & Light Company and the Florida Public Service Commission jointly filed a petition for a declaratory order concerning whether the FERC has jurisdiction over rates for wheeling of power from qualifying cogenerators and small power producers, and asked for a declaratory order on related matters as well. (Florida Power Corporation, Gulf Power Company, and Tampa Electric Company filed separate, but related petitions that were consolidated into the same proceeding by the FERC.) In answer to the petitioner's queries, the FERC concluded that the rates for wheeling of power produced by qualifying facilities are subject to its jurisdiction where the transmission occurs in interstate commerce and that state regulation of the rates for transmission is preempted.[74]

The petitioners asked two additional, key questions concerning wheeling authority that did not concern rates. The first question was whether the FERC construed its cogeneration regulations, specifically 18 C.F.R. sec. 292.303(d), to require the native electric utility (the one that is directly interconnected to the qualifying facility) to wheel a qualifying facility's power when the qualifying facility has agree to sell that power to another utility. Here, the petitioners asked the FERC to assume, for the sake of argument, that the Florida Public Service Commission's order requiring wheeling would be valid under state law in the absence of federal preemption. The Florida Public Service Commission argued that its rules, which require a native utility to wheel power, are consistent with FERC's regulations. The FERC stated that its cogeneration rules are intended to provide a qualifying facility with some flexibility in determining which utility receives its power; however, the FERC's cogeneration rules do not require a utility to wheel a qualifying facility's power over the utility's objections and do not require an electric utility to agree to sell or transport power from the qualifying facility to another utility.[75]

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[73] Florida Power and Light Co. and Florida Public Service Commission, et al., 29 FERC para. 61,140 (1964).
[74] Id., at 61,292-61,293.
[75] Id., at 61,293-61,294.

The second question was whether any provision of PURPA requires an electric utility to wheel the energy of a qualifying facility in its service territory solely at that facility's option. The FERC responded by noting that prior to the enactment of PURPA its authority to require wheeling was very limited, if not nonexistent. PURPA modified the FERC's authority to require a jurisdictional electric utility to wheel, which is now set out in PURPA sections 203 and 204. The FERC then explicitly noted that it had not addressed whether states have the authority to require wheeling, stating that that issue was outside the scope of the discussion.[76] Thus, in the only case involving the issue of whether state commissions have the authority to require a utility to wheel, the FERC declined to address this issue.

Because there has been no definitive answer by the courts or by the FERC concerning whether the states have the authority to order wheeling, the issue remains in doubt. There is substantial uncertainty as to whether there would be federal preemption of a state commission ordering an electric utility to wheel power, even if the entire transaction between seller, wheeler, and buyer were to occur in one state. For example, an expansive view of the FERC's ability to preempt wheeling can be made. The argument would be based on the presumption that the FERC's authority over transmission services in interstate commerce is absolute and preempts any state authority to order wheeling. The argument would go like this. First, there is no precedent on the issue of whether the FERC can preempt the state's authority to order wheeling. The FERC explicitly declined to address the issue in Florida Power & Light Co., et al. because the issue was not directly before it. No precedent was set. Next, should the issue be brought before the FERC or a court, it would be forced to consider whether the wheeling required by the state involved transmission services in interstate commerce. If the ordered wheeling involved a utility that was interconnected to an interstate grid, the transaction would almost certainly be considered in interstate commerce and subject to the FERC's jurisdiction under the FPA. Under the Supremacy Clause, the FERC would then preempt

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[76] Id. at 61,294.

state regulation of the transmission service, including state authority to order wheeling. If the requirements of PURPA sections 203 and 204 preclude the FERC from ordering wheeling, then one can argue that the restrictions on the FERC's authority to wheel embody the intent of Congress to make wheeling arrangements as voluntary as possible, not an intent to cede the authority to require wheeling to the States.

On the other hand, an argument can also be made in favor of allowing state commissions to order wheeling when the entire transaction would take place in one state. The argument could go something like this. First, there is nothing in PURPA sections 202 and 203 explicitly preempting the states from exercising an authority to require wheeling when a transaction takes place entirely in one state. Second, the restrictions in PURPA section 202 and 203 preclude the FERC from being able to order wheeling in most cases. Third, if the FERC is effectively precluded from ordering wheeling then, unless there is a federal decision to forego regulation, which implies an authoritative federal decision that the area be best left unregulated, then there is no preemption of a state exercising its authority to order wheeling as long as it does so within the confines of the Commerce Clause.[77] Finally, one would need to show that there is nothing in the language, history, or policy of the FPA to suggest such a conclusion. Another alternative argument might be made that the FERC in failing to preempt the states in Florida Power & Light Co., et al. created a regulatory vacuum within which state commissions could order wheeling.

Because the issue of federal preemption of a state's authority to require either wheeling or bulk power transfers has not yet been argued before the FERC or the courts, there is substantial uncertainty as to whether most state commissions' authority to require wheeling is preempt by the FERC under the FPA, as amended by PURPA. However, Florida Power & Light Company recently petitioned the FERC for a declaratory order that would void the Florida Public Service Commission order that established state

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[77] See Arkansas Electric Cooperative Corp. v. Arkansas Public Service Commission, 461 U.S. 375, 383-389 (1983) for a similar approach dealing with the issue of whether either the FPA or the Rural Electrification Act preempt state regulation of power cooperatives.

commission authority over the terms and conditions, other than rates, of transmission services for power being wheeled from independent power producers. The petition asks the FERC to assert exclusive jurisdiction over the terms and conditions of transmission service in interstate commerce as well as the rate itself.[78] In response, the FERC issued a declaratory order asserting exclusive jurisdiction over the terms and conditions of contracts for wheeling of power in interstate commerce. The FERC held that a wheeling transaction would be in interstate commerce when the transmission system is interconnected and capable of transmitting power across a state boundary, even though the contracting parties and the contract pathway of the transaction are all in one state.[79] However, the declaratory order by FERC in this case did not directly deal with the issue of whether a state commission has the authority to require wheeling. It might still be possible for a state to require wheeling without specifying the rates, terms, or conditions of the wheeling. If so, the issue then is whether a state could order a utility to wheel and also require the utility to file a wheeling tariff at the FERC. The only place where a state's authority to require wheeling and to set the rates, terms, and conditions of the wheeling transaction is not an issue is in Texas for those utilities that are a part of ERCOT and are not interconnected to an electric utility grid in interstate commerce.

State Franchise Laws Preventing Certain Power Transfers

State franchise laws, when enforced, can prevent certain types of bulk power transfers from taking place. State franchise laws establish service territories within which electric utilities have a monopoly over the retail

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[78] "Two Utilities Ask FERC to Overrule Actions on Interstate Wheeling," Electric Utility Week, April 13, 1987, pp. 17-18.
[79] See "FERC Asserts Exclusive Jurisdiction Over Wheeling Terms and Conditions," Electric Utility Week, July 29, 1987, pp. 1-2; and "FERC Reasserts Wheeling Authority; NGA Panel Pushes State Siting," Inside F.E.R.C., July 20, 1987, p. 4b.

market. The theory behind state franchise laws is this: utilities serve the public interest best when they are regulated monopolies and the duplication of facilities that would occur in the absence of state franchise laws would be inefficient.

State franchise laws could prevent a bulk power transfer from occurring any time an ultimate customer wants to receive power from someone other than its utility. If a state public utility commission chose to interpret its state franchise laws to preclude an ultimate customer, such as an industrial customer, from receiving power from a source other than the utility whose service territory the ultimate customer is in, the ultimate customer would be precluded from receiving the power. (Recall that PURPA section 203(c)(3) bars wheeling orders for purposes of sale by a utility to an ultimate customer who is within the service territory of another utility if the service territory is established by state law.)

State franchise laws can prevent an ultimate customer from receiving power produced by a cogenerator or small power producer that is a qualifying facility pursuant to PURPA section 201. The FERC decided in PRI Energy Systems Inc. that PURPA 210 does not affect a state's authority to permit or refuse to permit retail sales by qualifying facilities. State commissions can apply state franchise laws to determine whether to allow or disallow retail sales by qualifying facilities to ultimate customers.[80] The Florida Public Service Commission, for example, recently rejected two petitions by cogenerators to have their power wheeled to other affiliated facilities. Florida statutes allow this type of wheeling if the transaction is in the economic interest of all the ratepayers of the utility. In one case, the petitioner was unable to make this showing. In the other case, the petition was denied because the petitioner did not own the generating facility and therefore did not come under the statute allowing so called "self-service wheeling."[81]

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[80] PRI Energy Systems, Inc., Docket No. QF-84-31-000, 26 FERC para. 61,177 (Feb. 14, 1984).

[81] "Florida Nixes Two Requests for Wheeling to Sites Owned by Cogenerators," Electric Utility Week, April 13, 1987, p. 17.

One of the few times that an ultimate customer might have a choice on which utility would serve him is when the customer is within a dual-certified or noncertified service area.[82] In these cases, state commissions sometimes consider customer preferences in determining which utility will serve the customer.[83] However, commissions tend to disregard a customer's preference if it is in conflict with the public interest.[84] Also, some commissions use a "closest line to the point of service" rule as a factor in determining what is in the public interest.[85]

If an existing ultimate customer attempts to switch electric suppliers, it may find itself blocked. In an unusual case, the Lukens Steel Company attempted to buy a right-of-way so that it could buy cheaper power from a nearby utility. The steel company alleged that it had an absolute right to switch to a more economical supplier. The commission denied the move stating that it would not be in the public interest for several reasons. First, the transmission line that would be necessary for the service would be a redundant investment that would cause a duplication of service. Second, the commission felt that the fact that the utility had no point of delivery to the preferred company made the proposed investment too risky. Third, the commission stated that it would be inequitable to allow industrial customers to switch suppliers, when the same options are not available to residential customers. And finally, the commission found that lower rates were not a sufficient basis for allowing a change in service because future rates are unknown and may fluctuate.[86]

Finally, state franchise laws can prevent an independent power producer that is not a qualifying facility pursuant to PURPA section 201 from selling power to the electric utility. If an independent power producer is not a

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[82] Generally, see Diane Sponseller, "Customer Preference in Selecting Utility Service," Public Utilities Fortnightly, Aug. 2, 1984, pp. 49-53.
[83] For example, see Illinois Power Co. v. Illinois Commerce Commission, 73 PUR3d 317, 235 NE2d 614 (1968); Nishnabotna Valley Rural Electric Co-op v. Iowa Power & Light Co. 77 PUR3d 197, 161 NW2d 348 (Iowa, 1968); Re Public Service Co. of New Mexico, Case No. 480 (NMPSC, 1957).
[84] See, for example, City of Dover v. Delaware Power & Light Co., 3 PUR3d 181 (DelPSC, 1953).
[85] See for example Regulations Governing Service Supplied by Electric Utilities, Case No. U-6400, (MichPSC, 1982).
[86] Re Lukens Steel Co., 57 PUR4th 524 (PaPUC, 1984).

qualifying facility, it would not be exempt from state regulation concerning the organization, finances, or rates of electric utilities as are qualifying facilities. Also, there is no statutory requirement under PURPA section 210 that a utility offer to purchase power from a non-qualifying facility. Presumably, a state commission could use its regulatory authority to prevent a sale from a non-qualifying facility to a utility or another entity.

Ineffectiveness of Antitrust Laws

In theory, at least, antitrust laws can be used to compel companies to engage in economically attractive power transfers, but in practice these laws are hard to apply in power transfer cases. Under the Otter Tail case, the federal courts have the authority to require a utility to wheel power if an antitrust violation called monopolization is found under section 2 of the Sherman Act.[87] In Otter Tail, the United States Supreme Court pointed out that the FPC was not empowered to mandate wheeling. (The case was decided in 1973, before the enactment of PURPA.) The Court reasoned that, although Congress had rejected provisions in the FPA that would have empowered the FPC to mandate wheeling and had instead relied on the voluntary action of the utilities, there was no reason to conclude that FPC regulation was intended to substitute for antitrust law. The Court stated that

> [r]epeals of the antitrust laws by implication from a regulatory statute are strongly disfavored, and have only been found in cases of plain repugnancy between the antitrust and regulatory provisions.... Activities which come under the jurisdiction of a regulatory agency nevertheless may be subject to scrutiny under the antitrust laws.[88]

Thus, Otter Tail stands for the legal proposition that electric utilities are subject to the antitrust laws and the courts could compel wheeling when a violation of the antitrust laws is found to exist.

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[87] Otter Tail Power Co. v. United States, 410 U.S. 359, reh. denied 411 U.S. 910 (1973); remanded, 360 F. Supp. 451, affd. 417 U.S. 901 (1974).
[88] Id., at 372-375.

Until the enactment of PURPA, the courts were the sole entity that could compel wheeling. With the enactment of PURPA, however, the FERC was empowered to order wheeling under certain very limited circumstances. The limitations on FERC's authority to order wheeling were described earlier.

However, the enactment of PURPA did not supplant the authority of the state and federal courts to mandate wheeling when a violation of the antitrust law occurs. Rather, the enactment of PURPA supplemented Otter Tail and the associated line of cases. This is made clear in the legislative history of the law, which stated

> ...with regard to certain authorities to order interconnections and wheeling under Title II..., it is not intended that the courts defer actions arising under the antitrust laws pending a resolution of such matters by the [Commission] ... Courts have jurisdiction to proceed with antitrust cases without deferring to the Commission for the exercise of primary jurisdiction.[89]

Also, section 4(1) of PURPA clearly states that nothing in PURPA affects the applicability of the antitrust laws to any electric utility.[90] In the conference report, this is explained to mean that PURPA does not affect federal and state antitrust laws and that those laws continue to apply to electric utilities to the same extent as prior to the enactment of PURPA. Also, the jurisdiction of state and federal courts in actions under antitrust laws is preserved, whether or not the parties could have sought remedies under PURPA. The conference report states specifically, with regard to authorities to order interconnections and wheeling, that Congress does not intend that the courts should defer actions arising under the antitrust laws pending resolution of matters by the FERC. The jurisdiction of state and federal courts to resolve antitrust violations, such as an illegal refusal to wheel, still exists independent of the FERC; and the courts should be able to act whether or not action by the FERC can be

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[89] See House Conference Report No. 95-1750, 95th Cong., 2d Sess. 63, 1978 U.S. Code Cong. and Ad. News 7802.
[90] Public Utility Regulatory Policies Act of 1978, sec. 4(1), 16 U.S.C. sec. 2603 (1978).

requested or would be justified.[91] Thus, while the FERC has been given new authority under PURPA--the power to require wheeling and interconnections--that authority is limited to a very narrow set of circumstances and is not exclusive. The courts' authority to enforce antitrust laws is left undisturbed.

If all this is so, why do not more parties seek out the courts when there is an alleged refusal to wheel power or to transfer bulk power in ways that would have an anticompetitive effect? The answer is twofold. First, in most cases an antitrust remedy is not available from the courts quickly enough so that a willing buyer and seller cannot take advantage of short-term bulk power transfer opportunities to make economy energy sales. If these transactions do not take place, they are forever lost as opportunities for greater efficiency. Second, the state action exemption prevents the courts from overturning state laws that might inhibit bulk power transfers and wheeling. Each of these is discussed next.

Inadequacy of Antitrust Remedies

Many opportunities for long-distance bulk power sales are short-term in duration. These sales, typically called economy sales, involve a willing buyer and seller who seek to displace higher cost power with less expensive power. When the buyer and seller are not directly interconnected, the only way for the exchange to take place is for an intervening utility to allow wheeling across its lines. If the intervening utility refuses to wheel the power when approached by the buyer and seller, there might or might not be an antitrust violation. For example, if the intervening utility's refusal to wheel were based on concerns that the proposed wheeling would unduly lessen the reliability of its transmission system, then the refusal to wheel might be justified. However, if the utility's refusal to wheel power had nothing to do with protecting the interest of its own customers and the utility has excess transmission capacity, then the refusal to wheel might be anticompetitive behavior on the part of the intervening utility.

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[91] Conference Report at 68.

However, to maintain a successful action to compel wheeling, the buyer or seller must show more than the availability of power from a cheaper source and a refusal by the intervening utility to wheel. The seller or buyer must show that the recalcitrant utility somehow violated the antitrust laws. When a utility refuses to wheel power, the antitrust law most likely violated is section 2 of the Sherman Act. Section 2 concerns monopolization, attempts to monopolize, and conspiracies to monopolize. Because a conspiracy is unnecessary for a single utility to block a wheeling transaction by refusing access to transmission services, we are primarily concerned with the offenses of monopolization and attempts to monopolize.

The United States Supreme Court, in United States v. Grinnell Corp., defined the offense of monopolization as having "two elements: (1) the possession of monopoly power in the relevant market and (2) the willful acquisition or maintenance of that power as distinguished from the growth or development of a superior product, business acumen or historic accident."[92] It is worth noting here that it is not illegal to be a monopoly. Rather, the behavior prohibited by the antitrust laws is monopolization. Thus, if there is a natural monopoly in the transmission facilities, this is not in and of itself a violation of the antitrust laws.

The first element of monopolization is the possession of monopoly power in the relevant market. Monopoly power is the power to control price or to restrict competition unreasonably.[93] Monopoly power can be inferred from control of an essential resource or facility which gives the owner the power to control prices or to restrict competition.[94] The "essential facilities" doctrine and the "bottleneck theory" come into play here. The relevant market is defined both in terms of product or service and geographic area. In a case dealing with the refusal to wheel power the service in question is transmission service. The geographic market may be more difficult to define. One would assume that it would include the geographic area of transmission lines that could provide the desired transmission service. However, it is worth noting that at least one court has held that there is

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[92] United States v. Grinnell, 384 U.S. 563, 570-571 (1966).
[93] United States v. E.I duPont de Nemours & Co., 351 U.S. 377 (1956).
[94] United States v. Otter Tail Power Co., supra.

no need to define the relevant market and show market share to prove market power when the essential facilities doctrine is in effect because market power is inferred from the ability to exclude competitors.[95]

An essential facility is one which cannot be duplicated to which potential competitors need access in order to compete. If the utility owns most or all of the transmission lines in the relevant geographic area, then the lines are likely to be considered an essential (bottleneck) facility. Electric transmission lines have been held to be essential facilities because they cannot be easily duplicated because of environmental restraints and the limited number of rights-of-way available for siting the lines.[96] The significance of transmission facilities as essential facilities is that, while a monopoly can deal or refuse to deal with whomever it chooses as long as there is no intent to create or maintain a monopoly, a monopoly that controls an essential facility cannot deny access to a competitor. If a monopoly denies a competitor access to an essential facility, the courts presume that it has done so to illegally maintain or acquire a monopoly.

The Seventh Circuit has held that the elements to be established for a violation of the essential facilities doctrine are (1) a monopoly must control the essential facility, (2) a competitor must be unable to practically or reasonably duplicate the essential facility, (3) the monopoly denies access to the essential facility to the competitor, and (4) it is feasible for the monopoly to have granted access to the essential facility.[97] While the first three elements can be easily established when an electric utility refuses to wheel, the fourth element can be troublesome. The courts have held that access to essential facilities need not be granted if there is a technological reason making access impractical,[98] if it would impair the ability of the monopoly to serve its own customers adequately,[99]

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[95] See Denver Petroleum Corp. v. Shell Oil C., 306 F.Supp. 289 (D.Colo. 1969).

[96] See Otter Tail Power Company v. United States, supra; and City of Chanute v. Kansas Gas & Elec. Co., 564 F.Supp. 1416 (D.Kan. 1983).

[97] David C. Hjelmfelt, Antitrust and Regulated Industries (New York: John Wiley & Sons, 1985), p. 143, citing MCI Communications Corp. v. AT&T, 708 F.2d 1081 (7th Cir. 1983).

[98] Ibid.

[99] Hecht v. Pro-Football Inc., 570 F.2d 982 (D.C.Cir. 1977).

if there is insufficient space, or if the party requesting access is financially unsound.[100] Also, there may be a defense if providing access would cause a financial detriment that would be so severe that the defendant would be unable to serve its own customers.

If the plantiff cannot prove the offense of monopolization, then he might still be able to prove the offense of attempting to monopolize. The key difference between an attempt to monopolize and monopolization is that possession of monopoly power (an element of the offense of monopolization) is not an element of an attempt to monopolize. The elements of the offense of attempting to monopolize are (1) specific intent, (2) conduct, (3) a dangerous probability of success, (4) a relevant market, and (5) market power.[101] To show an attempt to monopolize requires one to prove that the defendant has possession of market power in the relevant market. Further, it is necessary to show that the utility has sufficient market power that the attempt to monopolize by refusing to wheel has a dangerous probability of success.[102] The plaintiff must also show that the defendant has a specific intent to control prices or to restrict competition and that the defendant engages in exclusionary conduct that is not merely a legitimate business practice.

In most cases an alleged refusal to wheel power has not been remedied by the courts. For example, in Borough of Lansdale v. Philadelphia Electric Co., the Third Circuit held that the utility refusing to wheel lacked monopoly power in the relevant market.[103] In City of Groton v. Connecticut Light & Power Co., the Second Circuit held that there was insufficient evidence, given the facts of the case, of any specific, as opposed to general, wheeling requests. Hence, there was no refusal of a specific request to wheel.[104] Similarly, the West District Court of Pennsylvania

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[100] Gamco Inc. v. Providence Fruit & Produce Bldg. Inc., 194 F.2d 484 (1st Cir. 1952), cert. denied, 344 U.S. 817 (1952).
[101] David C. Hjelmfelt, p.79.
[100] Alexander v. National Farmers Org., 687 F.2d 1173 (8th Cir. 1982).
[103] Borough of Lansdale v. Philadelphia Electric Co., 692 F.2d 307, 314 (3rd Cir. 1982).
[104] City of Groton v. Connecticut Light & Power Company, 662 F.2d 921 (2d Cir. 1981).

held that the plaintiffs never specifically requested wheeling services in Borough of Ellwood City v. Pennsylvania Power Co..[105]

An antitrust proceeding usually requires a lengthy evidentiary hearing. The hearing could involve a jury trial, depending on which federal circuit one is in, and would involve legal discovery and an opportunity to present and cross-examine witnesses. To win his case, the plaintiff must be able to make out the elements of a monopolization or an attempt to monopolize and show how he has been damaged. Treble damages are available under section 4 of the Clayton Act. In many cases, the opportunity to take advantage of a short-term economy sale has long since passed before these antitrust issues ever come to trial. Once an opportunity for an economy sale is lost, it is lost forever. Depending on the duration of the litigation and subsequent appeals, opportunities for long-term firm sales might also be lost, particularly in the case that subsequent appeals take years, as is not uncommon. In such cases, the treble damages could be substantial, but the loss to society is still there.

However, the implicit threat of antitrust litigation with its associated treble damages is often sufficient to cause a utility to make wheeling available to those seeking long-term firm transmission services if the utility has sufficient transmission capacity available. This is so because the even a remote possibility of treble damages makes antitrust litigation particularly unattractive when the direct economic damages for an illegal failure to wheel would already be substantial.

The only possibility for a buyer and seller to take advantage of short-term opportunities to exchange bulk power over long distances is to seek a preliminary injunction during the pendency of the antitrust litigation. Section 16 of the Clayton Act provides injunctive relief for a party if it is able to show a threatened loss or damage because of a violation of the antitrust laws and a showing that the danger for irreparable loss or damage is immediate.[106] In the one electric case that deals with this subject, the

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[105] Borough of Ellwood City v. Pennsylvania Power Co, 462 F. Supp. 1343, 1354 (W.D.Pa. 1979).
[106] Clayton Act, 38 Stat. 730 (1914), as amended, section 16, 15 U.S.C. sec. 26 (1973).

Kansas District Court in City of Chanute v. Kansas Gas and Electric Co. granted three cities a preliminary injunction requiring the defendant utility to wheel power to the three cities. In that case, the cities had been told by the defendant, their wholesale supplier, that it would no longer be able to supply the cities' growth requirements. The cities located another supplier, but could only receive the power through the defendant's transmission lines. The defendant agreed to transmit the power but only on the condition that the cities agree to contract changes raising the price of the wholesale power still supplied by the defendant.[107] On appeal the Tenth Circuit affirmed in part and reversed in part. The Circuit Court upheld the preliminary injunction for two of the three cities because they stood to lose their entitlements to preference power unless the power was taken by a specific date, an irreparable injury. However, the third city would not lose rights to preference power so that the damage to that city was limited to payments for power not received in the event of the defendant's refusal to wheel. The third city's damages were measurable and remediable, and therefore not irreparable. The Court overturned the preliminary injunction for the third city.[108]

The problem here is that the courts are looking at whether or not the plaintiff would suffer any irreparable damage from a refusal to wheel. That is the remedy provided for by the Clayton Act. However, the irreparable damage that is done is not to the defendant but to society as a whole. Every missed opportunity for an efficient bulk power exchange is an irreparable loss to society. Without a public interest test to protect society from these irreparable losses, not only is antitrust law not timely, but its remedies are inadequate to protect the public interest.

The State Action Exemption

The State Action Exemption to the Sherman Act has its genesis in Parker v. Brown, a 1943 United States Supreme Court case, that held that the

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[107] City of Chanute v. Kansas Gas and Electric Co., 564 F.Supp. 1416 (D.Kan. 1983).

[108] City of Chanute v. Kansas City Gas & Electric Co., 754 F.2d 310 (10th Cir. 1985).

Sherman Act does not apply to acts by a state, including restraints of trade imposed by a state as an act of government.[109] For a state agency, such as a public utility commission, to have the full protection of the state action exemption, the agency must act as an agent of the state and share in the attributes of state sovereignty. In most cases, regulation by a state public utility commission would seem to qualify. If it does not, for the state action exemption to apply to the conduct of a state agency, the United States Supreme Court has held that the conduct must meet the two-prong test of California Retail Liquor Dealers Association v. Midcal Aluminum, Inc. First, the conduct must be the result of a clearly articulated and affirmatively expressed state policy. Second, the conduct must be actively supervised by the state.[110] For a private action to fall under the state action exemption, an action must be compelled by the state. State acquiesce is not enough.[111]

In the case of state franchise laws that could prevent wheeling or bulk power transfers from occurring, the state action exemption would apply. The state agency is acting as sovereign in imposing a restraint of trade that is in the public interest, namely not allowing an ultimate customer to receive wheeled power. The restraint of trade is in the public interest because it prevents bypass that would burden the remaining captive customers at the distribution level and keeps these remaining customers from being saddled with the costs of the resulting stranded plant. Even if the state agency is not acting as sovereign, the state action exemption may still apply under the two-prong test of Midcal: state regulation of utility franchise areas is usually a well articulated and affirmative state policy that is actively supervised by the state in the course of its rate and service regulation. In either case, wheeling restrictions under state franchise laws would be immune from antitrust litigation.

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[109] See Hjelmfelt, pp. 274-275, citing Parker v. Brown, 317 U.S. 341 (1943).
[110] California Retail Liquor Dealers Ass'n v. Midcal Aluminum Inc., 445 U.S. 97 (1980).
[111] See Cantor v. Detroit Edison Co., 428 U.S. 579 (1976).

Laws Impeding Construction

Even if all the previously mentioned impediments to bulk power transfers were overcome, the transaction might not take place if the needed transmission line were not in place. Assuming that it would otherwise be economical to build a transmission line for the bulk power transfer to take place, the certification, siting, and eminent domain requirements in some states may impede, if not prevent, the construction of the transmission line. The recent report of the National Governors' Association (NGA), entitled Moving Power: Flexibility for the Future, points out several legal impediments that might prevent a transmission line from being built.[112] The most significant of these are that (1) the public interest criterion in some states requires that local benefits outweigh local costs; (2) in some states local political subdivisions have the authority to approve or disapprove a project, even if the project is approved at the state level; and (3) in some states, certification and siting do not necessarily guarantee that the utility can acquire the necessary right-of-way through eminent domain. Each of these legal impediments is discussed below.

For a transmission line to be constructed, a utility needs to have the line approved as being in the public interest by the appropriate state agency or agencies. Often this approval must be sought before the state public utility commission, although in several states there are state energy, land use, or special siting boards. Sometimes, a utility must also get the approval of a state environmental board. In a few states, no state approval in needed to build transmission lines.[113]

The most common way by which a utility is required to show that a transmission project is in the public interest is a balancing test. The

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[112] Mary Beth Zimmerman, Moving Power: Flexibility for the Future (Washington, D.C.: National Governors' Association, 1987), pp. 9-15. The author here concerns himself with only those types of legal impedements which would, as a matter of law, prevent a line from being built. Those legal requirements relating to procedures, which are merely inconvenient and cause delay, are considered regulatory impediments. The reader should keep in mind, however, that if regulatory impediments cause a long enough delay, a transmission line may become uneconomic or the opportunity for wheeling may have passed.

[113] Ibid., at p. 9.

utility must show that the benefits that would come from a proposed transmission line would outweigh the costs of the line. Specific siting issues can be raised concerning the health, environmental, aesthetic, and land use effects. For example, in a recent Texas case, the Texas Public Utility Commission denied a request of the Houston Lighting & Power Company, because the utility had failed to meet its burden of proving that the need for the proposed line outweighs the detrimental effects of the proposed route.[114]

In some states, only the local benefits of the line are measured. For a multi-state project, a utility might not be able to show that the local benefits of the line outweigh the local costs. This would be especially true if the line was built solely or primarily to wheel power for two out-of-state utilities. In such a case, the substantial local costs of siting might not be offset by the increased reliability that often results from additional transmission facilities.[115]

According to the NGA report, local political subdivisions in twelve states have the authority to approve or disapprove the portion of transmission line projects that crosses their jurisdictions. This could allow local, political subdivisions--such as a county, municipality, or in some cases a tribal entity--to block construction of a transmission line that is found to be in the public interest by the state agency in charge of certification.[116]

Finally, even with all necessary state and local approvals, the utility must still exercise its power of eminent domain to acquire the land and rights-of-way necessary to build the line. In most cases the utility has its own power of eminent domain to acquire land for siting, once the appropriate regulatory approvals are given. However, in a few states eminent domain can only be obtained through the courts, with the state certificate of need to be considered as only part of the evidence in an independent judicial inquiry concerning the public interest.[117]

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[114] "Texas PUC Turns Down HP&L Bid to Construct 345-KV Transmission Line," Electric Utility Week, March 2, 1987, pp. 15-16.
[115] Ibid., at p. 11.
[116] Ibid., at pp. 10, 28-30.
[117] Ibid., at p. 11.

The above difficulties are compounded by a great diversity of certification, siting, and eminent domain processes that make a multi-state transmission line project extremely difficult to complete.

Legal Rights of Neighboring Utilities

A utility's bulk power transfers or wheeling can sometimes create loop flow problems for a neighboring utility, which could lower its reliability and make it more difficult to serve it customers. If voluntary bulk power transfers or wheeling were to occur, neighboring utility systems might be forced to bear the additional costs and burdens caused by loop flow without any clear legal right or mechanism to recover those costs. (It might also be the case that a neighboring system might experience increased reliability because of the wheeling transaction.) Recall that, where interconnections and wheeling that are not voluntary but are ordered by the FERC, PURPA section 204 provides a mechanism for the affected utilities and qualifying facilities to apportion the otherwise uncompensated costs that can be associated with a wheeling transaction. The parties to a proposed interconnection or wheeling order would negotiate the terms and conditions of the final order, including an apportionment of costs. No similar mechanism exists to compensate neighboring systems subject to loop flow costs created by voluntary transactions.

However, the common law is capable of creating a cause of action to compensate neighboring systems for the loop flow costs caused by voluntary bulk power transfers. The necessary legal theory could go something like this: all of the electric utilities in an interconnected grid have a duty to maintain the reliability of the system. When one utility enters into a wheeling transaction that adversely affects its neighboring utilities on the grid, the utility entering into the wheeling transaction has a duty to compensate that member. This legal obligation would be based in the utility's service obligation. The agreements that utilities enter into in the reliability councils are evidence that the utilities recognize this fundamental obligation. The obligation itself is not based on contract, but on the utility's obligation to provide adequate and reliable service to its customers. In the alternative, the legal theory could be based on tort law or private or public nuisance theories. In such a case, a utility might seek damages for the diminution of value of its property, i.e., its transmission lines. If the injury is of a continuing nature, the utility might seek injunctive relief to stopped the transaction.

If a court of law were to recognize such a cause for action, then neighboring utilities would be able to sue to recover the costs of loop flow, thus further impeding voluntary bulk power transfers. If the injury were of a more permanent or continuing nature or could not be adequately compensated, injunctive relief might be available to prevent the transaction from occurring.

Recommendations

Two sets of recommendations are presented here for overcoming or eliminating the legal impediments identified. The first set of recommendations details how existing legal impediments might be overcome if existing laws remain unchanged. The second set of recommendations explains how new federal legislation might eliminate the existing legal impediments to wheeling and bulk power transfers.

Overcoming Impediments If Existing Laws Remain Unchanged

If existing laws remain unchanged, it might be possible with great difficulty to overcome some of the legal impediments to wheeling and bulk power transfers. For example, to overcome the legal impediment created by the FERC's limited authority to compel wheeling, one might begin by looking for an opportunity to challenge the holdings of the Second and Fifth Circuits that the FERC's authority to order wheeling is limited by the provisions of PURPA. The other federal circuits could reach a contrary conclusion if the issue were raised. Faced with conflicting holdings by the federal circuits, the United States Supreme Court could then reverse the holding in New York State Electric & Gas Corp. v. FERC and Florida Power & Light Co. v. FERC. Then, the FERC might be able to use its powers under FPA sections 206(a) and 205 to require that a utility provide transmission services on a nondiscriminatory basis if it chooses to provide transmission services at all. The FERC probably could not require that the utility provide transmission services to all comers because that would make the utility a common carrier, which is contrary to the intent of Congress as expressed in the Federal Power Act.

Another possibility would be to try to influence or to challenge the FERC's interpretation of PURPA sections 203 and 204. For example, if one were to view FERC's interpretation of "preserving existing competitive relationships," found in the earlier discussed Southeastern Power Administration v. Kentucky Utilities Company, then one might attempt to bring a similar case up before the FERC and seek a reversal of its previous decision. The argument that one would use would be similar to that employed by the "cities" in Southeastern Power Administration v. Kentucky Utilities Company. Namely, the relevant market to be examined for existing competitive relationships is broad. It should be determined in a way similar to that done in antitrust cases, with product and geographic markets in which the current and potential seller compete defined, market shares computed, and changes due to the wheeling order examined. Such an interpretation would be consistent with recent Supreme Court and First Circuit holdings that the FERC should take anticompetitive effects into consideration when determining policy. If that fails to work, then of course one could appeal. Other impediments found in PURPA sections 203 and 204 also might be overcome on a case-by-case basis.

Litigation could also be brought under current laws so as to minimize the impediments caused by the limited scope and uncertainty of state authority to mandate wheeling and bulk power transfers. For this uncertainty to be tested, there must be a state statute, state commission order, or commission regulation asserting commission authority to order a utility to wheel power for intrastate transactions within its own state. A state must then attempt to exercise this asserted authority over one of its utilities. Once there is a proper case in controversy, one could litigate whether or not the FERC's authority to order wheeling found in PURPA preempts the state from exercising a similar authority for intrastate transactions. Such litigation would involve testing the limits of the Commerce Clause and the Supremacy Clause, as discussed earlier. A state commission might be able to win its case if it could successfully argue that its authority to wheel (1) serves a legitimate local purpose, (2) is not excessively burdensome on interstate commerce in light of the local purpose served, and (3) is not preempted because the FERC is effectively precluded from ordering wheeling or interconnections and because there is no federal decision to forego regulation that implies that the area be best left unregulated.

To the extent that state franchise laws pose a legal impediment to wheeling or bulk power transfers, the state commission itself might choose to reinterpret its laws to allow wheeling and bulk power transfers where it is in the public interest. For example, if the state commission were to find that a wheeling transaction involving a sale to an ultimate customer would either provide a benefit to or not harm the customers remaining on the system it might choose to allow the wheeling to take place.

The ineffectiveness of antitrust laws is a legal impediment that may keep the courts from ordering wheeling in a timely fashion when there is an antitrust violation. Here again, litigation could provide a solution. First, the buyer or seller in a bulk power transaction, who is blocked because a utility refuses to wheel, could immediately seek a preliminary injunction by showing that the there is an immediate danger of irreparable loss if the transaction does not take place. A particularly compelling case could be made if the buyer is itself a distribution company or municipality with ratepayers who would irreparably lose the economic benefit of the transaction that does not take place. Should the state action defense preclude courts from overturning pervasive state regulation, such as state franchise laws making antitrust laws ineffective, state commissions can probably interpret their laws so as to not unduly discourage wheeling.

To the extent that siting and other laws impede construction, the lead agency for determining these issues can give due weight to the benefits of additional transmission capacity that include not only the benefits of wheeling itself but also the benefits of increased reliability. The benefits flowing from increased reliability would exist even if the benefits of the wheeling sales went to out-of-state customers. There is of course a problem if local approvals are necessary for a line or if there is an independent judicial inquiry into the public interest before eminent domain can be exercised.

The uncertain legal rights of neighboring utilities is also a matter that can be litigated before the courts. It is unlikely that a neighboring utility could actually bring an action in the courts to prevent a wheeling or bulk power transaction from taking place unless it could show that it would be irreparably harmed by the transaction and would be unable to serve its customers. Nonetheless, a neighboring utility might be able to plead a cause of action based on something akin to nuisance as a property tort theory. If the neighboring utility could show that the buyer, the seller, or the wheeler are engaging in intentional conduct that adversely affects the use of the neighboring utilities' own transmission lines, an action seeking damages might be possible. Injunctive relief might be available to stop continuing behavior. However, this is a totally unexplored area of the law which would require litigation to flesh out. Another alternative solution to this potential problem is for the utilities in a regional reliability area to enter into agreements similar to Mid-American Interconnected Network (MAIN) Guideline Number 1C, "Transmission Loading Relief Procedures." That guideline was developed because situations had arisen on the MAIN regional transmission system where normal transfers between two systems caused an overload on a third system. The MAIN Coordinating Center was empowered to request revisions in electricity transfer schedules to obtain the necessary relief. The guideline sets out the steps to be taken when such an overload occurs.[118]

As just noted, some of the legal impediments under current law might be overcome, primarily through litigation. However, litigation is expensive and is itself uncertain in producing the desired results. Those interested in encouraging power transfers might consider seeking new legislation to aid their cause.

Eliminating Impediments Through New Legislation

Because litigation is costly and uncertain, enactment of new federal and state legislation would be a more effective way to eliminate legal impediments to bulk power transactions and wheeling. Of course the risk associated with legislation is that what is proposed as legislation often bares little or no resemblance to what is enacted. Nonetheless, the

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[118] North American Electric Reliability Council, North American Electric Reliability Council: 1986 Annual Report (NERC: Princeton, N.J., 1987) p. 36.

legislative route offers an option for eliminating some legal impediments to wheeling and bulk power transactions.

Legislation to eliminate some legal impediments could provide for a federal agency (presumably, but not necessarily the FERC) to oversee power transfers. The agency would need to have the authority not only to set transmission rates, terms, and conditions for wheeling and other transmission services, but also to allocate and apportion the costs and benefits of a bulk power transaction so that neighboring utilities are compensated for any burden the transaction might place upon them. The federal agency would be empowered to compel wheeling when three conditions are met: (1) there is both a willing buyer and seller, (2) the wheeling would not adversely affect the ability of either the wheeling utility or neighboring utilities to provide adequate and reliable service to its customers, and (3) the transaction results in a true economic savings, and is not merely a transaction that reallocates the costs of service. Of course, state commissions might also seek a provision that would disallow wheeling when it would violate state retail marketing (franchise) laws. Other types of wheeling transactions might also be prohibited or restricted. For example, a requirements customer might only be allowed to engage in a power transaction if it could show that there is some economic savings as a result of the transaction. Also, a requirements customer might be required to pay a reservation charge for backup service from its original power supplier to guarantee reliable service.

To assess whether a transaction would adversely affect the reliability of a wheeling or neighboring utility and whether a transaction results in a economic savings would require data collection and modeling capabilities that are not currently available at any one private or public agency. It would therefore be necessary to upgrade the analytical capabilities of the federal agency if such legislation were enacted.

To be able to determine independently whether or not a proposed bulk power transaction would cause reliability problems, the federal agency would need to have data on the location, capacity, and usage of transmission facilities for the utilities in interstate commerce. The agency would also need to have the capability of quickly modeling transmission flows over an interconnected system so that loop flow costs can be apportioned and overburdening of transmission lines can be avoided. Without such information and modeling capabilities, the federal agency could not order wheeling without the risk of causing reliability problems.

An alternative to having the federal agency collect and maintain data on location, capacity, and usage of the transmission facilities for utilities in interstate commerce would be to rely on the various regional reliability councils of the North American Reliability Council to supply the data. The federal agency would still need some way to verify the data and would need modeling capabilities.

However, these legislative changes may not be necessary if the FERC puts in place the proper regulatory changes and economic incentives to engage in economic bulk power transfers. What might still be necessary, however, is legislation making it clear that the FERC has the authority to compel wheeling in those circumstances where the wheeling is being denied because of a utility's unreasonable anticompetitive behavior. Because of the reluctance of the FERC to consider anticompetitive behavior in wheeling situations (in part, because of the PURPA limitation that a FERC order to compel wheeling will not change existing competitive relationships), the Congress might wish to consider giving the FERC explicit authority to consider the antitrust laws in such circumstances.

The drafters of any legislation that is proposed should recognize that legislation cannot force transmission facilities to perform in a way contrary to the physical laws of nature. Problems associated with loop flow must be addressed before any agency is given an absolute authority to compel wheeling.

As noted above, state commissions can best assert and test their authority to compel intrastate wheeling and bulk power transactions in the courts by having legislation and/or commission rulemaking or orders that could help to bring the issues surrounding state authority to order wheeling and bulk power transactions to a head. Also, states might choose to enact new legislation concerning state franchise laws. Here a state might wish to consider whether it would be in the public interest to allow a bulk power transfer to an ultimate customer if the wheeling arrangement were made in such a way that the remaining customers are either left no worse off or receive a benefit.

States could enact their own legislation that would make certification, siting, and eminent domain more uniform. The National Governors' report previously cited recognizes that the myriad of state requirements for certification, siting, and eminent domain makes construction of a multistate transmission line extremely difficult. The delays that result from dealing with several different states statutory requirements can increase the cost of a project and make it uneconomical. A uniform or model state statute for certification, siting, and eminent domain would serve two purposes. It would reduce costs and delays, and it would help to change the public interest provision in state laws so that regional as well as local benefits can be taken into account when balancing interest against costs. When local benefits do not outweigh local costs but regional benefits do, some form of compensation might be made available to local entities.

Another alternative is for the states to petition the Congress for legislation that would permit joint federal-state boards to solve conflicts that might arise during state certification and siting of multistate transmission facilities. This concept, if implemented, should follow certain guidelines. Namely, representatives from the governments of affected states should be included and predominate on any joint federal-state board concerned with certification and siting. Further, such a board should not be empowered to waive environmental or substantive state laws. A joint board might be the proper forum to address the concerns of those states burdened by a transmission line that would be beneficial to a region as a whole. At such a forum, states could send representatives to negotiate and to reach binding agreements that advance the public interest without creating an uncompensated burden for the citizens of any state.

REGULATORY IMPEDIMENTS TO POWER TRANSFERS

by
Pfeffer, Lindsay & Associates, Inc.
Washington, DC

Power transfers among electric utilities generally reflect the outcomes of intersystem coordination arrangements which are designed to reduce costs and improve reliability of the network. While there is no direct relationship, per se, between the overall volume of power transfers and the efficiency of the bulk power supply system, the ability to transfer substantial volumes of power between and across power systems is essential to optimum efficiency. It is therefore important that any substantial barriers or impediments to intersystem bulk power transfers be minimized. The identification and mitigation of such impediments is the focus of this paper and several related efforts being undertaken for the National Regulatory Research Institute (NRRI).

Some of the more significant impediments to intersystem power transfers stem from the fact that such transactions are regulated by governmental authorities in various ways. These include certification of transmission facilities that are necessary to effect intersystem transfers, authority to direct coordination services and third-party transmission service (wheeling) under some circumstances, and regulation of the prices, terms, and conditions under which power transfers are made.

Most intersystem power transfers are between systems that are directly interconnected so that third-party wheeling is not required. The principal focus of this paper, however, is on the regulatory impediments to wheeling. Nonetheless, the types of impediments described in a wheeling context are generally similar to those applicable to bilateral transfers between directly interconnected systems as well.

The regulatory agencies whose activities may impede power transfers include the Federal Energy Regulatory Commission (FERC), state regulatory commissions, and various state and local agencies having siting and licensing authority with respect to transmission facilities. Impediments to cost-effective power transfers that derive from the regulatory requirements and activities of these agencies are outlined in the following sections accompanied by suggestions for eliminating or mitigating such impediments.

FERC Regulation of Sales at Wholesale for Resale and Transmission Service

FERC authority with respect to sales at wholesale for resale[1] and wheeling includes regulation of prices, terms and conditions of such services, authority to direct utilities to provide service under certain conditions, and limited authority to approve certain transmission facilities associated with hydroelectric projects requiring Commission license.[2] The authority to license certain transmission facilities associated with hydroelectric projects does not appear to have created any significant impediment to wheeling service or to the willingness of utilities to construct transmission facilities. The authority of the Commission to direct sales for resale and wheeling under selected circumstances is discussed in a subsequent section of this paper. The

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[1] Sales at wholesale for resale include requirements sales and coordination sales. Requirements sales are made to power distributors who rely wholly or partially on power from the supplier to serve the distributors' loads. Coordination sales are sales to other power suppliers to improve reliability or reduce costs.

[2] The authority of the FERC to license or certificate certain transmission facilities associated with hydroelectric projects licensed by the Commission is contained in Part I of the Federal Power Act. These lines are, in general, facilities necessary to transfer power from the licensed hydroelectric project to the interconnected transmission grid. They are licensed by the FERC in the same manner as the associated hydro projects.

most important impediments to power transfers stemming from FERC regulation derive from its regulation of rates, terms, and conditions of these services.

Under Part II (Sections 201, 205, and 206) of the Federal Power Act (FPA), the FERC has comprehensive authority to regulate agreements and tariffs for wholesale and wheeling services provided by jurisdictional utilities in interstate commerce. Practically all coordination and transmission service that involves high voltage transmission facilities has been construed to be in interstate commerce. Some of the more important impediments relating to the regulation of coordination and wheeling rate schedules are described below.

Filing Requirements

Current Statutory Requirements

Section 205 of the FPA requires that, "every public utility shall file with the Commission . . . [rate] schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission. . ." No changes in rates or terms and conditions of a rate schedule may be made except after 60 days notice unless this requirement is waived by the Commission.[3] Initial rate filings are governed by the same notice provisions as filings for changes in existing rates.[4] No rate may be charged for service subject to the jurisdiction of the Commission unless the rate has been accepted for filing by the Commission.

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[3] In reviewing applications for changes in existing rates, the Commission has authority to (1) reject the filing, (2) accept the filing, or (3) accept the filing, suspend it for up to five months and subsequently allow it to go into effect subject to refund. During such suspension period a hearing is convened in order that the Commission may assess the justness and reasonableness of the rate.

[4] The Commission may respond to the filing of an initial rate in one of three ways: (1) reject the filing, (2) accept the filing without an investigation as to its justness and reasonableness, or (3) accept the rate for filing and commence an investigation to determine if it is just and reasonable. Any modifications are applied prospectively after hearing (i.e., no refunds are required).

With rare exceptions, coordination and transmission agreements are filed at the FERC on a voluntary basis and most are accepted for filing without a formal review by the Commission.[5] Rate filings are submitted with cost support data required by Part 35 of the FPA regulations.

These filing requirements have created two types of problems for utilities in relation to intersystem power transfers. First, utilities may be precluded from providing transmission or coordination services on a timely basis. For example, short-term coordination transactions requiring third-party wheeling[6] may not be consummated if the wheeling utility does not have an appropriate wheeling rate schedule on file at the FERC. By the time an agreement is reduced to writing and a filing is made in accordance with FERC regulations, the economic incentive underlying the contemplated transaction may no longer be applicable. Second, Commission rules and practices have generally not provided sufficient flexibility in rate design to enable a utility to provide service in some short-term circumstances (without filing a change in rate) even though the price being offered by the buyer exceeds the seller's incremental cost so that the proposed transaction would have been beneficial to both parties.

The Commission has sought to reduce these problems in several ways. First, it has permitted abbreviated filings (i.e., filings with minimal-cost support) of coordination-type sales, including some transmission rates. In addition, the Commission has delegated authority to the Director of the Office of Electric Power Regulation (OEPR) to accept for filing all uncontested filings for initial rates or changes

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[5] Proposed increases in rates contained in existing agreements sometimes do trigger objections which require formal resolution by the Commission.

[6] Third-party wheeling is wheeling between a separate buyer and seller so that the wheeling utility constitutes the third party. It is contrasted with "second-party wheeling" between separate facilities of the same customer. For example, utility A may own part of a jointly-owned generating unit located on the system of utility W and require wheeling by utility W to the transmission system of utility A. Such wheeling by utility W would be second-party wheeling.

in existing rates and to waive the statutory notice requirements.[7] Neither of these mechanisms, however, has been sufficient to entirely eliminate impediments to coordination and transmission services which arise from the rigidity of Commission filing requirements.

Proposals to Mitigate Burden of Filing Requirements

In Phase I of a Notice of Inquiry (NOI) issued in May 1985,[8] the FERC sought comments on a variety of issues relating to its regulation of coordination transaction and transmission services. Among the questions raised in the NOI were whether the Commission's regulations impede voluntary coordination and transmission arrangements and what the Commission could do to promote more voluntary arrangements. Among the many responses to these questions were those filed by a substantial number of investor-owned utilities, pointing to the FPA's notice and filing requirements as impeding the offering of voluntary coordination and transmission services. These utilities stressed the need for the Commission to clearly define its policy with respect to filing requirements and the criteria used by the Commission staff to review coordination and transmission service arrangements. They generally advocated that the Commission should accept voluntarily negotiated agreements essentially as proposed by the parties involved in order to allow utilities to respond to short-term requests for service on a timely basis. In addition, many of the utilities that filed comments suggested that rates negotiated within the boundaries of a preapproved zone of reasonableness should be automatically accepted. The boundaries of various proposed pricing zones ranged from a floor set at the incremental cost of the wheeling utility to the value of service to the buyer. Among the many recommendations for revisions to Commission filing requirements were those offered by the Edison Electric Institute

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[7] FERC Regulations, Subchapter W, Revised General Rules, Section 375,308.

[8] FERC, Notice of Inquiry, Regulation of Electric Sales for Resale and Transmission Service, Docket No. RM85-17-000, Phase I (May 30, 1985).

(EEI), Arizona Public Service Company, and Pacific Gas and Electric Company.

EEI recommended that the Commission delegate additional authority to the Director of OEPR to authorize transactions in the absence of a formal filing, "based upon oral (telephone) representation of the parties." EEI recommended that the procedure be applicable in instances where all parties to the transaction are in agreement. The proposed procedure would require an "after-the-fact" filing and possibly the collection of rates subject to refund for a period of time to provide sufficient notice to interested parties and to allow for protests.[9]

Arizona Public Service Company (APS) recommended that the Commission adopt an "after-the-fact" filing procedure which would allow utilities to "take advantage of some short-term economic situations" with a high degree of assurance that the transaction will be favorably received by the Commission. To facilitate this type of filing procedure APS recommended that the Commission issue guidelines that would provide utilities maximum flexibility in responding to requests for service and at the same time minimize regulatory uncertainty.[10]

Pacific Gas and Electric Company proposed that the Commission establish a zone of reasonableness such that proposed agreements with rates within the zone would be "presumed just and reasonable."[11]

A variety of similar proposals were offered by other utilities to mitigate problems arising from Commission filing requirements.

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[9] Comments of the Edison Electric Institute, Regulation of Electricity Sales for Resale and Transmission Service, FERC Docket No. RM85-17-000 (Phase I) p. 49.

[10] Comments of Arizona Public Service Company, Regulation of Electricity Sales for Resale and Transmission Service, FERC Docket No. RM85-17-000 (Phase I) pp. 19-20.

[11] Comments of Pacific Gas and Electric Company, Regulation of Electricity Sales for Resale and Transmission Service, FERC Docket No. RM85-17-000 (Phase I) p. 22-8.

Western Systems Power Pool Experimental Rates

On March 12, 1987, the Commission issued an order[12] accepting, without hearing or suspension, experimental rates for coordination transactions and associated transmission service among 11 jurisdictional utilities and 4 nonjurisdictional public systems who were the participants in a new experimental coordination agreement designated as the Western Systems Power Pool (WSPP). The two-year experiment provides for flexible pricing of economy energy, unit power, firm power and energy, and associated transmission service within a preapproved zone. Power and energy sales are capped by the highest fully-allocated cost of resources among the participants during the prior year. The zone for transmission rates is capped at 33 percent of the difference between the highest and lowest decremental costs of the participants' generation in the previous year. The floor of the zone is a 1 mill/kWh reservation charge.

In order to facilitate both coordination transactions and transmission service, the Commission granted waivers of its regulations relating to filing requirements for changes in existing rates (Section 35.13 of the FPA regulations). The expected benefit of the suspension of filing requirements for all subsequent transactions under the experiment was summarized as follows in a filing by the Bonneville Power Administration supporting the experiment:[13]

> . . . the benefits lie in the greater use of transmission facilities and elimination of regulatory delay and uncertainty associated with filing new rates for each transaction by jurisdictional pool members.

Future Directions

By accepting the proposed zones within which rates may vary for WSPP participants, the Commission has effectively authorized any rates charged by such participants for the specified services that fall within such zones in the absence of complaint. This action by the Commission

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[12] Pacific Gas and Electric Company, Order Accepting Experimental Rates, FERC Docket No. ER87-97-001 (March 12, 1987).

[13] Ibid., p. 11.

essentially eliminates both the timing and flexibility problems created by the current filing requirements during the two-year experimental period. It does this without any requirement that the participating utilities provide wheeling service to one another as in the prior Southwest Bulk Power Market Experiment.

The Commission has also permitted pricing flexibility within a zone for selected types of coordination transactions outside the context of an experiment. Specifically, it has permitted reservation charges for short-term energy sales that allow parties to negotiate a price up to a preapproved ceiling based on either the supplier's system-wide, fully-distributed costs or the fully-distributed cost of the unit(s) committed to the service.[14] More recently, the Commission has accepted a number of filings for economy energy rates that may be negotiated up to the standard split-savings rate.[15] Both of these pricing policies allow utilities to negotiate a rate up to a preapproved ceiling without the need to make a new filing. This action by the Commission allows timely responses to changing market conditions and increases the likelihood that cost-effective coordination sales will be consummated.

Such a policy could be extended to transmission and other coordination services in various ways. For example, the Commission might consider a rulemaking under which it would preapprove without need for filing any transmission rate agreed to by the parties up to some specified ceiling (e.g., the level of fully distributed transmission costs). For transmission of economy energy, any rate might similarly be permitted up to a specified percentage of the gross savings from the transaction. Use of such ceiling rates could be subject to minimal subsequent reporting requirements (within 30 days of the commencement of

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[14] Among the ceiling rates currently on file at the FERC are Montana Power Company Tariff, Original Volume No. 1; Florida Power Corporation, Rate Schedule 88; Pennsylvania Power Company, Rate Schedule 75; and Connecticut Light and Power Company, Rate Schedule 324.

[15] See, for example, Illinois Power Company, Revised Rate for Economy Energy, FERC Docket No. ER86-169-000 (November 4, 1985); Arizona Public Service Company, Agreement for the Sale of Economy Energy to the City of Colton, FERC Docket No. ER86-695-000 (September 2, 1986).

the transaction) for specified information including, among other things, the names of the parties, nature of the service, amount, and price.[16] For rates higher than these preapproved limits, the procedure recommended by EEI involving telephonic approval by the OEPR Director subject to subsequent filing and possible refund requirements should remove any remaining impediments stemming from filing requirements while retaining sufficient regulatory controls to protect purchasers of these services.

Embedded Cost Pricing of Transmission Service

With limited exceptions the FERC has required the pricing of transmission service on an embedded-cost basis.[17] A recent example of this policy is a filing by Commonwealth Edison Company (Commonwealth) of a rate for transmission service to the City of Geneva, Illinois.[18] In this case Commonwealth filed a rate which it characterized as a marginal-cost proposal. The Commission found that the rate ". . . creates a real unremediable potential for undue prejudice and other anticompetitive effects," and directed the company to file a rate based on average system transmission costs.[19]

Embedded-cost transmission rates are generally developed by applying an appropriate fixed-charge rate to book (net or gross)

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[16] Such reporting requirements were required by the Commission (perhaps in greater detail than would be required for this purpose) in cases of transactions under blanket certificates (gas) issued by the Commission under Order No. 436.

[17] The Commission has also employed embedded costs in testing the reasonableness of rates for certain coordination services having a capacity component such as unit power, short-term, and intermediate-term power. For other coordination services involving primarily energy such as economy energy, surplus energy and dump energy, however, the Commission has looked principally to incremental costs as a basis for testing of the rates.

[18] Docket No. ER86-76-000, filed November 5, 1985.

[19] 34 FERC 61,115.

investment in transmission facilities and dividing the result by some measure of the use of the transmission system such as the annual peak load including the firm wheeling load on the transmission system. A rate per kW of firm wheeling service is developed based on some measure of the "responsibility" of wheeling customers for the investment in the transmission system such as usage at the time of peak load on the system.

Embedded-cost pricing reduces utilities' incentives to add transmission capacity for third-party wheeling transactions because in most circumstances they are unable to recover the incremental costs associated with providing such service. This means that existing transmission service customers (primarily retail customers) are required to subsidize new wheeling loads. State commissions are understandably reluctant to promote interstate wholesale transactions where rates to retail customers must be increased if utilities are to be fully compensated for the additional cost associated with such transactions. As stated by Pacific Gas and Electric Company:[20]

> . . . by today's standards, a utility cannot build until it can justify the reasonableness of the facilities to the statewide regulatory agency and its costs to both federal and state agencies. Even then, the utility has no guarantee that it will receive a return on its investment and no opportunity to earn a return commensurate with the risks taken in constructing the line.

In some cases, of course, embedded costs may exceed the incremental cost of the service provided. Under these circumstances, rates based on embedded costs may provide a disincentive to purchase wheeling service even though the transaction would be economically efficient if the wheeling rate were based on the incremental cost to the wheeling utility.

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[20] Comments of Pacific Gas and Electric Company, op. cit., pp. 22-1, 22-2.

A common view among electric utilities regarding the use of embedded cost-based transmission rates is reflected in the response of a major utility to FERC's NOI:[21]

> Although embedded cost pricing is probably incorrect in that it does not reflect the higher cost of new transmission facilities, the utility should be afforded the opportunity of supporting transmission services on the basis of such embedded costs. Embedded-cost pricing is so prevalent at the state and local levels that the utility will be criticized if it does not recover its embedded cost for use of its transmission system. Therefore, embedded-cost pricing should be established as a floor for transmission services in coordination arrangements.

While this kind of argument can be made with respect to firm wheeling service, especially where the utility is subject to an overall revenue constraint based on embedded costs, it would appear to have less validity with respect to nonfirm wheeling.

FERC Policy Regarding Nonfirm Wheeling Rates

The policy of the FERC with regard to pricing of nonfirm wheeling has not fully crystallized. In an opinion involving Kentucky Utilities Company the Commission rejected the utility's proposed allocation of demand-related transmission costs to nonfirm secondary energy service on the ground that the supplying utility had the ability to interrupt service at the time of its system peak, thereby allowing it to minimize transmission costs.[22] In the Florida Power and Light Company opinion, however, the Commission allowed the wheeling utility to allocate demand-related costs to wholesale customers for various nonfirm wheeling services.[23] The Commission based its decision on contractual terms which restricted the utility's ability to unconditionally interrupt

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[21] Comments of Southern Company, Regulation of Electricity Sales for Resale and Transmission Service, FERC Docket No. RM85-17-000 (Phase I) p. 11.

[22] Kentucky Utilities Company, FERC Opinion 116, 15 FERC 61,002 (1978).

[23] Florida Power and Light Company, Opinion No. 152, 21 FERC 61,070 (1982).

service so as to make the service "firm" once initiated. On appeal the D.C. Court of Appeals remanded the decision back to the Commission. The Court instructed the Commission to justify its departure from its findings in the Kentucky case, although not necessarily with the intention of precluding the allocation of demand-related costs to nonfirm wheeling service.[24] The case was ultimately settled prior to the issuance of a Commission order on remand.

In a more recent Florida Power and Light Company case[25] the Commission issued an order on rehearing in which it sought to justify the allocation of demand-related transmission costs to nonfirm interchange service. The Commission found that inclusion of fixed costs of transmission was <u>not</u> an allocation of fixed costs, but a necessary increment to provide the utility with an incentive to provide the service. Thus, the Commission appears willing to allow whatever increment is required to provide a potential wheeling utility with the necessary incentive so long as it does not exceed the seller's fully allocated cost of transmission service.

Utilities design rates for nonfirm transmission in two principal ways. Where the transaction is in economy energy, the most common rate design has been based on shared (i.e., split) savings. Under this method the wheeling utility typically receives incremental costs plus a share of the total saving from the total transaction. Such savings shares generally range from 15 percent up to 33 percent.[26] Evidently this form of pricing of nonfirm transmission does not involve the use of embedded costs and therefore avoids disincentives to buy or sell wheeling service of the type associated with embedded-cost pricing.

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[24] <u>Fort Pierce Utilities Authority v. FERC</u>, 730 F2d 778 (1984).

[25] Florida Power and Light Company, Order on Rehearing ER85-515-004, ER85-515-005 (October 31, 1985).

[26] In a Southern Company Services, Inc., agreement to provide wheeling service to Florida Power and Light Company, the rate to be charged by Southern Company for wheeling of "three-way" economy energy transactions, is one-third of the net economic benefit from the transaction. A recent Southern Company filing extended the "Economy Energy Participation Service" to Jacksonville Electric Authority.

The second type of rate design for nonfirm transmission service is one in which the rate for such service is derived directly from the rate for firm transmission (plus losses). Typically, this is accomplished by dividing the rate per kW for firm transmission by the number of hours per year, or by some lesser number of hours representing an estimate of the availability of the transmission system to provide nonfirm transmission service.[27] A rate derived in this way is likely to exceed the incremental cost of providing the service and may discourage purchasers in some instances from use-of-wheeling service which could otherwise be efficient. It may also exceed the incremental cost by an amount that is more than necessary to provide the wheeling utility with sufficient incentive to provide the service. To this extent, it can be said to constitute an impediment to otherwise cost-effective wheeling transactions.

<u>Alternatives to Embedded-Cost Pricing</u>

There are a variety of alternatives to traditional embedded-cost pricing of transmission service and other coordination services. The two principal options are (1) methods which employ incremental or marginal costs rather than embedded costs, and (2) negotiated rates within a specified range.

Incremental or marginal cost-based methods of pricing transmission and coordination services are grounded on the proposition that these are the only methods that can provide accurate price signals that lead to efficient electricity supply. The incremental cost of transmission service consists primarily of transmission losses, including line losses and transformation losses. Such losses vary considerably as the loads on the transmission system change and as the cost of generating the energy necessary to make up such losses changes from moment to moment.

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[27] The Commission recently accepted a filing by American Electric Power Company on behalf of its operating affiliates revising transmission rates in a number of interchange agreements including the pool-to-pool agreement with the Allegheny Power System wherein the daily rate for wheeling economy and nondisplacement energy is computed on the
(Footnote Continued)

Many transmission rate schedules currently in effect provide for recovery of the cost of transmission losses plus some additional increment.[28] As noted above, the typical method of pricing transmission of economy energy includes recovery of the cost of losses as well as some share of savings. Firm (as well as nonfirm) transmission schedules commonly make separate provision for compensating losses in addition to payments designed to recover operating, maintenance, and capital costs.

The principal difference between incremental cost-based methods of transmission service pricing and those based on embedded costs relates to the determination of the amount to be charged in addition to the cost of losses and other incremental costs. Rates based on embedded costs include an additional amount sufficient to recover carrying charges on the book investment including fixed operating and maintenance costs. In developing rates based on incremental costs, the added increment should be an amount at least sufficient to compensate for the opportunity costs of permitting the use of the transmission system for the wheeling transaction. In the case of wheeling service which is interruptible on very short notice, the opportunity costs would obviously be quite small. They would tend to increase, however, as the degree of interruptibility is reduced, and may become quite significant where the transmission service offered is as firm as the service to requirements customers. For long-term (firm) transmission service, incremental-cost pricing could produce results similar to pricing on the basis of long-run marginal costs.

The other principal regulatory alternative to embedded-cost pricing is flexible pricing within a specified range. As noted above, the FERC has been willing to permit pricing of various types of coordination sales employing negotiated rates subject to a cost-based cap. The only

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(Footnote Continued)
assumption of 16 hours of usage per day. See, Appalachian Power Company, et al., FERC Docket Nos. ER87-281-000 and ER87-355-000.

[28] The spot-pricing method proposed by Schweppe and others involves prices which recover the cost of losses plus "revenue reconciliation." See, Fred C. Schweppe, Roger E. Bohn, and Michael C. Caramanis, Wheeling Rates: An Economic-Engineering Foundation, DOE/PE/76019 (September 1985).

instance of flexible pricing of transmission service that has been authorized by the FERC thusfar, however, is among the participants in the previously discussed Western Systems Power Pool. In this experiment, participants are allowed to charge rates for transmission service within a sufficiently broad range so as to be almost tantamount to "deregulation" of those transactions. The experiment will thus provide some indication of the degree to which current regulation of wheeling of the specified coordination services is impeding efficient power supply in the western region. If wheeling of such services is determined to be workably competitive, the outcome of the experiment may provide a basis for some departure from the use of embedded costs in fixing rates for firm wheeling.

Transmission Rates Based on Rolled-In Costs

Rate Design Considerations

Through a number of transmission rate cases and wholesale requirements service rate cases relating to the recovery of transmission costs, FERC has evolved a policy which requires that transmission rates be based on the uniform allocation of total embedded transmission costs to customers based on their demand responsibility. This policy is based on the notion that wholesale requirements and wheeling customers are served by the entire integrated transmission system rather than some portion of the overall system. Therefore, it is argued, the rates paid by those customers should reflect an allocation of total transmission costs.

The rolled-in method of costing of transmission facilities can impede power transfers via wheeling service in several ways. First, it may increase the cost of wheeling service beyond the costs that would be assignable under alternative embedded-cost methods and may thereby discourage the purchase of wheeling service. Second, it precludes a utility from charging for a new transmission service on the basis of the cost of providing that service. Suppose, for example, that utility B is asked to consider building a high-voltage line across its system to accommodate power transfers between utilities A and C. B's embedded transmission costs amount to \$60/kW/year. The cost of the new line is estimated to be \$100/kW/year and, after construction of the line, the rolled-in total transmission cost would be $80/kW/year. Under rolled-in costing B could collect no more than $80/kW from A and C for transmission service costing $100/kW. It also means that if B is to recover its full costs, it must increase rates to its other customers by $20/kW even though the cost of serving those customers has not increased and the quality of service to those customers has not been appreciably improved.

The FERC has generally dealt with the transmission cost roll-in issue in the context of (1) radial lines used to transfer energy to load centers, or (2) lower voltage facilities. With respect to both of these issues, the Commission has consistently found the rolled-in approach appropriate in circumstances where the facilities in question are demonstrated to be an integral part of an entire transmission system. With respect to radial lines, the FERC has justified use of the rolled-in method on the ground that a transmission system is dynamic in nature so that a transmission line considered to be radial at present may ultimately become part of a looped system as the transmission system expands over time with load growth. The Commission has relied on this rationale in a number of transmission and wholesale requirements service rate cases.[29] For example, in an order issued in 1976 the Commission stated:[30]

> . . . At any particular point in time the rational and dynamic development of an integrated transmission system will appear "frozen," as if particular segments are used in the service of only one, or perhaps several, particular customers. This time-specific perspective, however, distorts reality. . . It is not, therefore, persuasive that currently the total cost of this facility--a facility which bears no planned relationship to the service needs of only that particular customer--should be borne by that customer until the planning and development of [the utility's] system achieves its designated objective. . .

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[29] Union Electric Company, Opinion 609, 47 FPC 144 (1972); Detroit Edison Company, Opinion 748, 53 FPC 1545 (1975); Florida Power and Light Company, 56 FPC 3981 (1976); Minnesota Power and Light Company, Opinion 12, 3 FERC 61,045 (1978); New York State Electric and Gas Company, Opinion 254, 37 FERC 61,151 (1986).

[30] Public Service Company of Indiana, Opinion 783, 56 FPC 3003 (1976).

In a separate series of cases the Commission has consistently found it appropriate to roll in low-voltage with high-voltage transmission facilities.[31] The basis for this treatment again reflects the notion that a transmission system is operated as an integrated whole. As such, lower voltage facilities are viewed as providing alternative paths for power flows which insure service continuity in the event of an outage. In a recent affirmation of this policy the Commission stated:[32]

> Two other factors weighing in favor of rolled-in costing are the undisputed integrated nature of the transmission system, and the fact that the lower voltage facilities appear to meet the technical definition of facilities which serve a "transmission" function. Where power lines operate in an integrated manner to perform a transmission function, we think it unnecessary and inappropriate to try to segregate selected lines and claim they do not benefit the entire network of lines. With an integrated transmission system such as Utah's, it would be almost impossible to trace individual lines and show that some of these lines do not benefit others by providing general back up, maximizing efficiency, and minimizing costs of the entire transmission network.

Notwithstanding its stated preference for the rolled-in method, the Commission has granted exceptions and provided general guidelines as to the circumstances wherein it would allow for a departure from this policy. In the Idaho Power case[33] the Commission ruled that a single transmission line extending 100 miles from the company's integrated system, which was installed solely to serve an isolated wholesale customer, should be treated on a specific assignment basis. Subsequently, in the Otter Tail case,[34] the Commission indicated that specific assignment may be appropriate in certain instances, and that

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[31] Florida Power and Light Company, 56 FPC 3,581 (1976); Kansas City Power and Light Company, 3 FERC 61,254 (1978); Alabama Power Company, 8 FERC 61,083 (1978); Utah Power and Light Company, 14 FERC 61,162 (1981); Utah Power and Light Company, Opinion 220, 27 FERC 61,258 (1984).

[32] Utah Power and Light Company, op. cit., 61,487.

[33] Idaho Power Company, Opinion 13, 3 FERC 61,108 (1978).

[34] Otter Tail Power Company, Opinion 93, 12 FERC 61,169 (1980).

the propriety of specific assignments would be considered on a case-by-case basis:[35]

> As is recognized by all parties to this proceeding, the Commission precedent strongly favors use of the rolled-in method of transmission allocation. Given a finding that the system operates as an integrated whole, transmission costs have generally been rolled in, absent a finding of special circumstances. The principal reason behind adoption of this methodology is that an integrated system is designed to achieve maximum efficiency and reliability at a minimum cost. While the rolled-in approach has generally been followed, the Commission has recognized that exceptions should be made in some cases and has held that it would continue to review facts of each case to determine the applicability of the rolled-in approach.

As with its treatment of radial lines, the Commission has defined circumstances that would permit the segregation of lower voltage facilities. Specifically, where a demonstration can be made that a low voltage (subtransmission) system exists for the sole purpose of serving a dispersed load and does not enhance system reliability by providing alternative paths for power to flow in the event of an outage, the exclusion of these costs from the total pool of transmission costs is considered appropriate.[36]

Alternatives to Rolled-In Costing of Transmission Service

Rolled-in costing is a procedure that is usually associated with the use of embedded costs so that the alternatives to embedded-cost pricing described in the previous section also constitute alternatives to rolled-in costing. Even where embedded costs are to be retained as the basis for development of transmission rates; however, there are alternatives to rolled-in costing. One such alternative is to eliminate from the total pool of allocable costs those costs associated with facilities that are considered to be "unnecessary" for the provision of wheeling service. Such facilities may include radial transmission lines

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[35] Ibid., 61,420.

[36] Minnesota Power and Light Company, Opinion 155, 21 FERC 61,233 (1982).

that serve only to transfer power from the integrated transmission system directly to load centers. They may also include costs associated with the transmission of power from specific generating plants to the integrated transmission system or the costs of lower-voltage transmission facilities that are unnecessary for the provision of the particular transmission service under consideration. The Commission's arguments for rolling in these costs under most circumstances have been partly technical and partly administrative (i.e., ease of computation, etc.) in nature.

Second, there are circumstances wherein a particular transmission service may be provided which involves use of only a relatively small definable part of the entire transmission system of the utility. In these cases a specific assignment procedure is sometimes used, i.e., the rate for wheeling is based upon the costs of the specific facilities employed in providing the wheeling service. In some cases this may result in a rate which exceeds the rolled-in embedded cost rate; generally, however, it is more likely to result in a substantially lower rate for wheeling.

In recent cases, it appears that the Commission has relied primarily on the rolled-in costing precedent established in earlier cases rather than a full examination of the facts and circumstances in each case. The FERC's reluctance to depart from rolled-in costing appears to be based on "administrative considerations" as much as on technical costing considerations. While administrative considerations are significant from the standpoint of the Commission's expeditious completion of its work, it should be recognized that in some circumstances the insistence on rolled-in costing may have the effect of impeding the use of wheeling for efficient power transfers.

Uncertainty Concerning FERC Regulation of Voluntary Agreements

Sources of Uncertainty

Section 206(a) of the Federal Power Act provides:

> Whenever the Commission, after a hearing had upon its own motion or upon complaint, shall find that any rate, charges, or classification demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the

> jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory, or preferential the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.

Thus, any voluntarily negotiated rate schedule filed with the Commission can be changed by the Commission upon complaint or upon its own motion, if it is able to make the appropriate findings.[37] Indeed, FERC's regulations do not provide utilities with the assurance inherent in Commission "approval" of a rate schedule except after hearing. Section 35.4 of the Commission's regulations provide:

> The fact that the Commission permits a rate schedule or any part thereof . . . to become effective shall not constitute approval by the Commission of such rate schedule or part thereof. . .

The Commission's practice in this regard may tend to create uncertainty on the part of the negotiating parties as to possible restructuring of the benefits and burdens of any transaction under consideration. To the extent that a utility perceives this as an unacceptable risk, it may decline to participate in an otherwise mutually beneficial transaction. The following description by PG&E

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[37] Prior to the passage of the Public Utility Regulatory Policies Act of 1978 (PURPA), the FERC had no authority to direct utilities to provide wheeling service. While Sections 211-212 of PURPA do provide the Commission with authority to order wheeling, that authority is quite circumscribed. Indeed, there have been very few petitions for wheeling orders under that authority and the Commission has found no occasion to date to order wheeling service under PURPA. Thus, practically all of wheeling rate schedules currently on file with the FERC are agreements that have been negotiated voluntarily between the parties, or are wheeling tariffs that have been filed voluntarily by the utilities. While the authority of the FERC to order wheeling service is quite limited, it does have comprehensive authority to regulate wheeling rate schedules once they have been filed. This includes authority to require filing of any proposed changes in the filed rate schedule. Most important, it includes authority to require modification of the filed agreement to the extent that the Commission finds it to be unjust, unreasonable, discriminatory, or preferential.

describes its experience with the Pacific Northwest-Southwest Intertie as an example of the type of risk that may be perceived by utilities in negotiating arrangements that require filing with the FERC:[38]

> In 1964-67 PG&E voluntarily entered into numerous contracts to affect the Pacific Northwest-Southwest Intertie. Those contracts were reviewed and approved by Congress, by the Department of the Interior, and by the Department of Justice. Even the Federal Power Commission (FPC) reviewed the contracts and found them to be reasonable. The FPC later "accepted" the intertie contract rate schedules for filing and denied requests for suspension and hearing.
>
> Ten years later, after major investments by PG&E to construct the intertie, the intertie contracts were subject to attack by intervenors and even by the Commission staff, but not because those contracts had been breached. Indeed, the contracts were not challenged by any of the parties to the contracts. Rather, the intervenors and staff were seeking to modify the original, approved, and accepted contracts under Section 206 of the FPA because they were allegedly no longer in the public interest, no longer "just and reasonable." The case is now awaiting a Commission decision on exception to an Administrative Law Judge Initial Decision which did indeed modify many of the Intertie contracts.

Section 35.17 of the Commission's regulations provides that a rate schedule suspended by the Commission may be withdrawn during the suspension period only with special permission by the Commission. It also provides that once a rate schedule is withdrawn it may be refiled within one year only with the approval of the Commission. As a result, the parties to a negotiated agreement have no assurance that the filing can be withdrawn if the mutually-agreed-upon terms and conditions are rejected by the Commission. If the Commission declines to permit withdrawal and revises the terms and conditions of the rate schedule, the utility may be forced to provide service on terms that it would not itself have accepted voluntarily. Rather than face this risk, a utility may simply opt not to offer the requested service.

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[38] Comments of Pacific Gas and Electric Company, RM85-17-000, op. cit., p. 22-3.

Proposals to Mitigate Uncertainty Associated with Treatment of Voluntarily Negotiated Agreements

A number of utilities responding to the Commission's NOI suggested possible means whereby the FERC might mitigate the uncertainty associated with Commission regulation of voluntarily-filed coordination or transmission agreements or tariffs. For example, the Potomac Electric Power Company (PEPCO) indicated that without reasonable assurance that an agreement will be accepted as filed, utilities will not respond to requests for wheeling that might place them at risk in the future. PEPCO recommended that the Commission adopt and codify procedures that would provide for automatic acceptance where there are no protests or interventions during the time allowed after the filing has been noticed.[39]

Duke Power Company (Duke) recommended that the Commission accept "and/or approve" rate schedules as filed. Duke urged the Commission to clarify its policy on approving versus accepting rate filings and to exempt all existing filings from future policy changes.[40] Southern California Edison Company (SoCal) stressed the necessity of treating a rate schedule as a unified document and that exposure to selective revision of specific terms and conditions may make consummation of the agreement excessively risky. Thus, it recommended that the Commission either approve or reject a filing in its entirety. Where a filing is rejected, the filing utility should be permitted to withdraw the filing and renegotiate it. Further, SoCal argued, the Commission should preclude itself from making "ex post facto modifications" to an agreement by approving it rather than accepting it for filing.[41]

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[39] Comments of Potomac Electric Power Company, Regulation of Electricity Sales for Resale and Transmission Service, FERC Docket No. RM85-17-000 (Phase I) p. 6.

[40] Comments of Duke Power Company, Regulation of Electricity Sales for Resale and Transmission Service, FERC Docket No. RM85-17-000 (Phase I) p. 3.

[41] Comments of Southern California Edison Company, Regulation of Electricity Sales for Resale and Transmission Service, FERC Docket No. RM85-17-000 (Phase I) p. 12.

The Edison Electric Institute (EEI) offered a number of recommendations relating to the treatment of voluntarily-filed agreements and tariffs. First, EEI urged the Commission to issue a policy statement containing guidelines under which it will review, accept, and approve rate filings that will not be subject to future review, and to exempt existing agreements from ex post revision as a result of future changes in policy.[42] Second, EEI recommended that the Commission revise Section 35.4 of its regulations in order to provide for approval rather than acceptance of filings by treating the period for public notice of filing as a "statutory hearing." If no adverse comments are received during this period the Commission could then approve the filed rate as "just and reasonable," according to EEI.

<u>Future Directions</u>

Uncertainty concerning FERC policy and potential Commission action tends to increase the cost of coordination and transmission services as well as reduce the willingness of utilities to offer such services. While protection of the public interest requires FERC regulation of the rates, terms, and conditions of service, it is also in the public interest that uncertainty concerning Commission policy and potential action be reduced to a minimum. An important first step in accomplishing this purpose would be a revision of Section 35.17 of the regulations to permit withdrawal of a voluntarily filed rate schedule (or change in rate schedule) within a reasonable period following suspension of the rate schedule (or change) by the Commission. This would at least relieve the utility of the risk of being "trapped" into providing a service under terms that it did not voluntarily offer. A second important step would be establishment of a procedure (in the form of a revision of Section 35.4 of the regulations) whereby a utility could apply for approval of a rate schedule when it is initially filed. The notice of such a filing would make clear that the application is for "approval" so that all parties including the Commission's staff would be

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[42] Comments of the Edison Electric Institute, FERC Docket No. RM-17-000, op. cit., pp. 36-37 and 57-59.

aware that subsequent involuntary changes in the rate schedule proposed by any party would carry a much heavier burden. This, in conjunction with the change in Section 35.17, would go a long way toward eliminating the uncertainties that utilities find most burdensome without a significant sacrifice of the Commission's ability to assure reasonable rates for coordination and transmission services. A Commission policy statement establishing forms of pricing and terms and conditions of transmission service that it finds acceptable would contribute further to the mitigation of uncertainty associated with the filing of transmission rate schedules.

Transmission Over Multiple Systems

Current FERC Policy

The typical method employed in the computation of rates for firm wheeling service is to divide total embedded transmission costs by the system peak load, including the firm wheeling load. The rate is then stated in terms of $/kW/month plus a charge to recover the cost of transmission losses. A rate for nonfirm transmission is typically determined by dividing the total embedded transmission costs by a number of kWh equal to the system peak load at 100 percent load factor. The nonfirm rate is stated in terms of mills/kWh plus a charge to recover the cost of transmission losses. Evidently, for rates determined in this manner, the charge for wheeling across two adjacent systems will be in the order of twice the charge for wheeling across a single system. Conversely, if the two systems are integrated or are parts of a single system, then the charge would be only about half the charge for wheeling across two systems (apart from losses). Some have argued that the transmission costs of all intervening facilities should be pooled and a "joint rate" should be computed to prevent cumulatively prohibitive wheeling charges.

The inability of utilities to consummate economic transactions as a result of the accumulation of wheeling charges over multiple systems is summarized in detail in the joint comments to the FERC's NOI (Phase I) submitted by the American Public Power Association and the National Rural Electric Cooperative Association:[43]

> In Florida, Wisconsin, and Kansas municipal utilities must pay "pancaked" double or multiple wheeling rates to two or more utilities--in contrast to New England's joint rates for transmission across the lines of multiple utilities. Kansas municipals anticipate an allocation of economical power from the Western Area Power Administration in 1985--but it must be wheeled through up to four utilities, each piling on charges with little relationship to cost. The result--WAPA water power may be unaffordable for some systems. In Wisconsin, Northern States Power demands that Wisconsin Public Power, Inc System (WPPI) pay double charges to NSP (Wisconsin) and NSP (Minnesota)--even though the two companies are fully integrated, both financially and operationally. WPPI and its ratepayers have thus foregone economical power supply arrangements available both from Manitoba Hydro and Minnesota Power Company.

Commission policy with respect to wheeling transactions across multiple systems has required that the wheeling customer pay each wheeling utility a rate commensurate with its individual cost of service.[44] In Richmond Power and Light v. FERC,[45] the court characterized the Commission's authority to order joint rates as follows:

> Since purchasers are always free to subscribe to the services of willing utilities at the separate rates, the Commission's failure to establish through [joint] rates can be deemed arbitrary only if individual rates were unjustly or unreasonably high and, as well, the utilities had a duty to wheel.

The Commission affirmed this policy in 1982 in a Florida case[46] wherein it was argued by a group of municipal utilities (Cities) that the use of individual rates for a single transmission service across the

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[43] Joint Comments of the American Public Power Association and the National Rural Electric Cooperative Association, Regulation of Electricity Sales for Resale and Transmission Service, FERC Docket No. RM85-17 (Phase I) p. 8.

[44] New England Power Pool Participants, 52 FPC 410 (1974).

[45] Richmond Power and Light v. FERC, 574 F.2d 610, D.C. Circuit Court of Appeals (1978).

[46] Florida Power and Light Company, Opinion 152, 21 FERC 61,070 (1982).

grids of two interconnected systems (Florida Power and Light Company (FP&L) and Florida Power Corporation (FPC)) was excessive and discriminatory, and a joint rate for power wheeled across the transmission system of the two utilities was proposed. The Commission concluded, however, that although the two utility systems providing the wheeling service engaged in frequent coordination transactions, they were distinct corporate entities which did not form an integrated system.

On appeal, Cities argued that the transactions should be viewed as a single transmission service on the combined FP&L/FPC networks performed in part by each utility for which each should receive part of a single joint rate. Cities contended that even if the individual rates accurately reflect a proper application of embedded costing, joint rates are required because FP&L and FPC fully integrate their transmission systems such that they in fact function as a single unified network. The Court stated:[47]

> The Commission's conclusion rested on the premise that wheeling transactions beginning and ending within the service area of a single utility do not use the adjoining utility's transmission network, while wheeling involving two utilities uses both. Cities argued in effect that the FP&L/FPC transmission systems are not like two adjoining reservoirs, but are instead like two sides of a single reservoir.

The Court acknowledged that if coordination between FP&L and FPC had become so extensive that the two systems operated as an integrated entity, then each utility's customers would in fact use both transmission systems. In this case, however, the Court found that the evidence was sufficient to support the FERC's premise that the two transmission systems were not functionally merged.

The Commission has dealt with the issue of appropriate transmission charges over multiple systems in a generic fashion in two other proceedings. These proceedings were an outgrowth of the 1977-78 coal strike which prompted significant intercompany interchange transactions.

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[47] Fort Pierce Utilities Authority, et al., D.C. Circuit Court of Appeals, 83-1286 (1984).

One of these involved "percentage adders;"[48] the other related to rate schedules for fuel conservation energy.[49]

In the percentage adders proceeding,[50] the Commission, upon investigation, concluded that charges for transmission service utilizing such adders resulted in a compounding of charges as each transmitting utility applied its percentage adder to the price of the purchased power to be transmitted.[51] The final rule adopted by the Commission limits such adders to 1 mill/kWh, unless the utility submits cost data supporting an adder in excess of 1 mill/kWh.[52]

Among the principal issues relating to transmission rates addressed in the Commission's 1978 proceeding involving Fuel Conservation Rate Schedules was the use of a single average "loss rate" for losses over multiple systems versus an additive or "pancaking" approach.[53] Specifically, wholesale customers argued that transmission losses should be computed on a point-to-point basis encompassing all systems involved in a particular transaction as opposed to a cumulative system by system

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[48] See, FERC Order 84, Percentage Adders in Electric Rates for Transmission Service, FERC Docket No. RM79-29-000 (1980).

[49] Order Establishing Principles for Fuel Conservation Rate Schedules and Providing for Filing, FERC Docket No. ER78-229-000, et al. (1980).

[50] An adder is a component of an electric rate designed to recover the difficult-to-quantify incremental costs associated with a transaction (in this instance--transmission). It may take the form of a fixed charge per kWh, or a percentage of identifiable incremental costs, including the price of purchased power, commonly referred to as a "percentage adder."

[51] See, Report of the Designated Officer, Investigation Into Wholesale Power Transactions During Time of Fuel Inadequacies (March 19, 1979).

[52] Order 84, Final Rule, Docket RM79-29 (May 7, 1980) p. 14.

[53] For a detailed discussion of the Commission's treatment of transmission-related fixed costs, and the appropriate methodology for computing losses (i.e., average or incremental) see, Edison Electric Institute, Current Practice and Emerging Issues in Transmission Rate Design (December 1985).

approach. In its order,[54] however, the Commission noted that most of the fuel conservation rate schedules already on file were schedules that had been developed on a pool basis by each of several major power pools in the eastern part of the United States. Thus, according to the Commission:[55]

> . . . the calculation of wheeling charges and transmission losses on a point-to-point basis, as Public Systems requests, and the concomitant avoidance of separate calculations and charges for each utility that might be involved in a long-distance transaction, is to a substantial degree achieved by these filings.

<u>Alternative Approaches to Wheeling Over Multiple Systems</u>

The Commission's Order Establishing Principles for Fuel Conservation Rate Schedules, suggests that circumstances may exist where joint rates are appropriate. The Court of Appeals arrived at a similar conclusion in affirming the Commission in <u>Florida Power and Light Company</u>.[56]

> We need not determine whether there will ever be circumstances under which two utilities have gone beyond extensive cooperation and have so completely integrated the operation of their transmission systems that any transmission by either utility makes use of the combined network. In that case, a transaction crossing corporate boundaries, like the transmission of water across a single reservoir, would be functionally identical to a transaction within corporate boundaries. Such unusual circumstances would present a stronger case that individual rates permitted overrecovery of costs and that joint rates were therefore required. (Footnote omitted.)

The Court also provided insight as to the circumstances where joint rates might be considered applicable:

> If the degree of coordination demonstrated by Cities between FP&L and FPC were sufficient to require the treatment of two transmission systems as a unitary network, the network would

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[54] Indiana-Michigan Electric Company, et al., Order Establishing Principles for Fuel Conservation Rate Schedules, 10 FERC 61,295 (1980).

[55] Ibid., 61,590.

[56] D.C. Circuit Court of Appeals, 83-1286, slip opinion (1984) p. 15.

seem to expand indefinitely with increasing regional coordination. FERC therefore shared the concern of FP&L and FPC over the consequences if Cities' version of joint transmission rates were applied to transactions over an increasing number of transmission networks. 21 FERC at 61,240. The virtually constant "average" rate called for by Cities' analysis would yield to each utility a diminishing return from joint rate customers with no corresponding decrease in costs. Of course, if the systems did operate as a truly unitary network, this objection would lose its force.

Recently, a number of proposals have been offered that suggest increased regional coordination in conjunction with the construction of transmission facilities as a means to increase intersystem transfers. A broad approach to the regional coordination issue and its subsequent benefits was expressed by the Ohio Edison Company in its comments in Phase I of the Commission's recent NOI:[57]

> The Companies also feel that this Commission should use its influence at both the federal and state levels to encourage the construction of regional transmission facilities. Participating utilities could share in the costs of said facilities, and share proportionately in the profits made from their use. A portion of the revenues generated through such facilities could also be used to compensate companies who suffered loss of transmission capacity and incurred energy losses due to unusual peripheral power flows. The availability of "regional" transmission facilities would encourage the movement of power between systems thus contributing to the efficiency of electricity markets.

A more detailed proposal advocating the use of joint rates was contained in the NOI comments of the "Public Systems Group" (Public Systems). This proposal was predicated on the assumption that existing "regional transmission grids" reflect a degree of coordinated planning and operation among utility systems which limits extreme surpluses or deficiencies in transmission capacity. Public Systems also assumed that utilities are capable of projecting the demand for transmission service within and through a regional grid and thus install or otherwise acquire

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[57] Comments of Ohio Edison Company, Regulation of Electricity Sales for Resale and Transmission Service, FERC Docket No. RM85-17-000 (Phase I) p. 5.

new transmission capacity for the dual purposes of serving native load as well as meeting transmission obligations associated with the regional grid. On the basis of these assumptions, Public Systems suggested the following rate treatment for transmission service within and across the regional grid:[58]

> Specifically, rates for firm transmission services within this "pool" should be based on fully distributed, embedded costs for the grid backbone transmission network (which assumes equalization of transmission responsibilities among the participants), divided by the projected regional load for the appropriate time period, i.e., days, weeks, months, etc. This matches responsibility for transmission capacity with the investment or financial contribution necessary for this inherently joint service.

According to Public Systems, rates for wheeling through (across) the regional grid should be computed as follows:[59]

> Postage stamp transmission rates should be available on a regional basis, based on fully distributed embedded costs for the regional transmission network. Rates for firm transmission service should be based on allocators which recognize all regional loads, are applied as a per kilowatt charge, and are offered for a variety of time periods (i.e., weeks or days as well as years or months). Interruptible rates should be set on a kWh basis equal to the firm rate divided by the number of hours in the period on which the firm rate is based.

The proposed rate design for transmission service through a "regional grid" endorsed by Public Systems is similar to the transmission rates currently in effect within the New England Power Pool (NEPOOL), a centrally dispatched pool. Under the NEPOOL agreement, if a member uses the high voltage pool transmission facilities (EHV-PTF) to transfer its entitlement share in pool-planned units, it pays the EHV-PTF rate. This rate is determined annually by rolling together all

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[58] Comments of Public System Group, Regulation of Electricity Sales for Resale and Transmission Service, FERC Docket No. RM85-17 (Phase I) p. 84.

[59] Ibid., p. 84-5.

of the costs of EHV-PTF owned by the members and dividing by NEPOOL generating capability.[60]

The Texas Public Utility Commission has adopted an alternative method for determining charges for transmission service through multiple utility systems. The Texas approach to designing rates for transmission is to determine charges based upon the changes in power flows on all affected systems measured on a megawatt-mile basis attributable to a specific wheeling transaction. Specifically, the percentage change in the loading of transmission facilities measured in megawatt-miles is applied to the embedded cost of the facilities for which there is a measured change in load flows subsequent to imposing a wheeling transaction on a system. Neighboring systems are entitled to compensation for measured usage of their transmission systems due to transactions between other systems.

Recent FERC filings have similarly provided rate mechanisms for such "inadvertent" effects of scheduled transactions on the transmission systems of other utilities. For example, the New York Power Pool and PJM Interconnection have agreed to certain compensation mechanisms for such inadvertent flows. As more transmission service arrangements involve multiple system transfers, and transactions affect a greater number of transmission systems outside the contractual path, disagreement over the appropriate method of compensating for inadvertent flows may tend increasingly to impede intersystem transfers. The establishment by the FERC of clear policies for resolving these issues would be an important step in minimizing such controversy.

Ratemaking for multisystem transmission would be much less problematic if wheeling rates were limited to incremental costs such as transmission losses and opportunity costs since these are clearly additive across systems. Where rates charged by individual systems are based on traditional embedded cost methods, however, ad hoc treatment may be required if undue inhibition of multisystem transmission is to be

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[60] A similar procedure is used for determining charges for use of lower voltage facilities (under 230 kV). See, New England Power Pool Agreement, FERC Rate Schedule No. 2, Sections 12-13.

avoided. An alternative rate treatment may involve the computation of some sort of joint rate that is sufficiently high to assure that each utility in the transmission path or affected region is fully compensated for losses and opportunity costs but perhaps not so high as to enable each utility to be compensated for its embedded cost of transmission service. For example, several systems in New England have transmission rates on file with the FERC that reduce the embedded cost-based PTF rate for firm transmission where the transaction involves wheeling by more than one system.[61] In these circumstances the schedules provide for a reduction in the monthly charges per kW that is the smaller of (1) amounts paid to other systems for wheeling of the same power, or (2) 50 percent of the charge.

Automatic Equity Adjustments in Cost-of-Service Rates

Cost-of-service rates have been employed by utilities and accepted by the FERC for many years for unit power as well as for transmission service and other types of utility services.[62] Until recently, such rate schedules have included a fixed rate of return on common equity. While all other changes in costs can be automatically recovered, any change in the cost of equity capital requires a filing with the Commission and is therefore subject to the notice and suspension provisions of the Commission's Regulations.

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[61] See, For example, Central Maine Power Company, FERC Rate Schedule Nos. 66 and 67. In Montaup Power Company, FERC Electric Tariff, Original Volume No. 2, the reduction in the PTF charge is limited to cases in which the rate schedules of the other utilities involved in the wheeling transaction provide for reductions in multisystem wheeling rates.

[62] A cost-of-service rate permits rates to adjust automatically to reflect changes in costs without a filing. This allows a utility to recover most of its costs on a current basis, thereby mitigating against earnings attrition. One of the earliest applications of cost-of-service rates in a schedule for transmission service was a filing by Arizona Public Service Company of a rate schedule for transmission service to Southern California Edison Company from the Four Corners plant in New Mexico to the California border.

Current FERC Policy

In a recent series of transmission-related filings, several FERC jurisdictional utilities have sought approval of automatic equity adjustment clauses for determining the equity return component in cost-of-service rates. Some of these filings contain adjustment clauses developed by the applicant; others have simply incorporated the quarterly adjusted FERC generic rate of return into the rate-of-return component of the cost-of-service rate. All such clauses have been rejected by the FERC on the ground that they violate the notice and filing requirements of the FPA, and are inconsistent with the procedures established for determining the Commission's generic rate of return.[63]

In a 1985 New England Power Company case the Commission established as a matter of policy that it will reject all filings that contain an automatic equity adjustment clause:[64]

> [W]e hereby announce our intention to reject all future rate filings which contain a formula rate which automatically adjusts the return on common equity. Automatic adjustment clauses are exceptions to the notice and filing requirements of the Federal Power Act. Even where we have permitted the use of a full cost-of-service formula, we have not allowed the equity return to be adjusted automatically.
>
> The use of an automatic formula rate for return on equity is inconsistent with our recent generic approach to equity return for electric utilities. . . In light of the fact that the Commission has so recently visited the question and selected a generic approach which does not include automatically adjusting equity returns, we believe it would be administratively wasteful to continue to consider this issue in case by case adjudications. We shall therefore reject filings containing automatic equity clauses at the threshold as patently deficient. See 18 C.F.R. § 35.5 (footnotes omitted).

Subsequently, acting on a complaint filed against Allegheny Generating Company requesting a reduction of the rate of return on equity in a

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63 Southwestern Electric Power Company, 31 FERC 61,389 (1985); Central Illinois Public Service Company, 33 FERC 61,331 (1985); Idaho Power Company et al., Staff Deficiency Letter Requesting Filing of Stated Rate of Return, FERC Docket No. ER87-107-000 (December 23, 1986).

64 31 FERC 61,378 (1985).

cost-of-service wholesale rate, the Commission rejected the proposal of the Consumer Advocate of the West Virginia Public Service Commission and the Maryland People's Counsel to incorporate the generic rate of return into the cost-of-service formula.[65]

This policy (i.e., of denying approval of automatic equity return adjustments) may reduce incentives to provide various coordination services and transmission service and may adversely affect financing of projects to install generating and transmission facilities, particularly joint projects involving high-risk participants. The problem was demonstrated recently in efforts by the New England Hydro-Transmission Corporation (NEHT) and the New England Hydro-Transmission Electric Company, Inc. (NEHE) to gain FERC approval of transmission rates incorporating an automatic equity adjustment clause prior to the commencement of construction of AC and DC high voltage transmission facilities to import energy to be purchased from Hydro-Quebec beginning in 1990. The request for rate approval prior to construction stems from the structure of the project's financing. Until project licenses and approval are obtained, 100 percent of NEHE's or NEHT's equity will be owned by New England Electric System (NEES). Thereafter, NEES will sell 49 percent equity interest to the other project participants (Equity Sponsors). As part of the agreement, Equity Sponsors will be required to guarantee the debt issued by those participants having below investment grade security ratings. Equity Sponsors will also be required to assume full responsibilities for any participant that defaults on its project obligations.

In January 1986 NEHT and NEHE filed a joint petition for a declaratory order requesting that the FERC direct the staff not to reject forthcoming transmission rate filings containing automatic equity adjustment clauses in spite of recent Commission rulings. NEHT and NEHE claimed that without prior assurance that the return paid on the project will be commensurate with the risk borne by the Equity Sponsors,

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[65] Consumer Advocate Division of West Virginia Public Service Commission, and Maryland Peoples Counsel v. Allegheny Generating Company, Docket No. EL86-37 etc., 36 FERC 61,763 (1986).

financing of the project would be jeopardized. NEHT and NEHE claimed that the acceptance of an automatic equity adjustment clause which tracks the Commission's generic rate of return would provide Equity Sponsors with adequate assurance that they will be compensated for the risk.

In a Declaratory Order, issued in July 1986, the FERC found the circumstances warranted consideration of an automatic equity adjustment clause "as a limited exception from the policy" established in the New England Power Company case. The Commission ordered that NEHT and NEHE file rates containing an automatic equity adjustment clause, and also ordered them to explore alternatives to such a clause.[66]

On August 11, 1986, NEHT and NEHE filed tariffs pursuant to the Commission's Declaratory Order. The filing was rejected by FERC for failure by the applicants to comply with the Commission's order that alternative financing methods be considered. Without such information, the Commission concluded it was unable to determine if this case warranted exception to the policy prohibiting such clauses.[67]

New Directions

In light of recent reductions in the cost-of-equity capital to utilities, the FERC has initiated several proceedings designed to

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[66] New England Hydro-Transmission Corporation and New England Hydro-Transmission Electric Company, Inc., Declaratory Order, 36 FERC 61,008 (1986).

[67] New England Hydro-Transmission Corporation and New England Hydro-Transmission Electric Company, Inc., Order Rejecting Proposed Facilities Agreements and Terminating Docket, FERC Docket No. ER86-629-000 (September 8, 1986). On April 16, 1987, NEHT and NEHE filed revised tariffs which the participants suggest eliminate the automatic equity adjustment clause. The proposed tariff for the AC facilities is a cost-of-service rate with the return on equity being that at the time of the filing and subsequently revised as accepted by the Commission in future rate proceedings. The proposed tariff for the DC facilities provides for two alternatives. The preferred alternative is an annually-determined "typical utility return on equity" plus a fixed 1.9 percent risk compensation adjustment. The "typical utility return on equity" would be filed annually by NEHT and NEHE for approval based on the Commission's generic rate of return.

determine whether or not the cost of equity in specified cost-of-service rate schedules should not be reduced. These include various rate schedules filed by operating subsidiaries of the Northeast Utilities system including the Northeast Utilities Generation and Transmission Agreement. In an order issued May 5, 1987, the Commission instituted a proceeding to determine whether the rates containing fixed equity components are unjust and unreasonable, and if so, to establish just and reasonable rates. In that order the Commission stated:

> Automatic changes in the equity return component have not been allowed because this aspect of a utility's rates requires an assessment of market conditions. (Citations omitted.) However, this results in formula rates not properly tracking equity costs. In view of this and of the fact that rate relief with respect to the equity return component of formula rates is available only on a prospective basis under Section 206 of the Federal Power Act, a modification in formula rates may be appropriate. Since formula rates require waiver of the notice and review provisions under the Federal Power Act, the Commission wishes to consider in the hearing ordered herein, whether it should henceforth condition the use of the NU companies' formula rates upon a requirement that the utility periodically justify the equity return component under a procedure which affords refund protection.

Thus, having denied utilities the right to use the FERC's own generic rate-of-return determinations as a basis for automatic adjustment in formula rates, the Commission now appears to be searching for another method of accomplishing a similar purpose. The Commission's method of dealing with this problem, however, could simply add another level of proceedings and litigation. By utilizing a procedure that the Commission has already put into place, namely its own determinations of generic rate of return, such litigation could be avoided. This is not to say that the rate of return contained in cost-of-service rates must be set equal to the generic rate of return. Rather, the periodic generic rate of return determinations of the Commission can be used as a basis for adjusting the rate of return contained in the cost-of-service rate in whatever manner is deemed appropriate by the parties and by the Commission. This would be an effective use of the Commission's generic rate-of-return determinations. Its use in cost-of-service rates would have the effect of eliminating one more impediment (future filings or litigation) to power transfer between utilities.

Notices of Termination

Current FERC Policy

Under current FERC policy, a utility's notice of termination of wholesale service is treated as a proposed change in an existing rate schedule. Termination of service is therefore subject to the Commission's notice and review requirements as well as suspension procedures.

In consequence of the policy, a utility that enters into an agreement to provide coordination or transmission service for a limited period has no assurance that it will be able to terminate the service at the end of that period. This creates a degree of uncertainty in bulk power system planning and may inhibit some utilities from entering into arrangements to provide such service. For example, the uncertainty relating to the ability to terminate wheeling associated with short-term coordination transactions limits the ability of utilities to plan opportunity-type transactions (sales, purchases, and transmission) beyond the termination dates of existing agreements. To the extent utilities perceive that they may be precluded from participating in more economic transactions in the future, they may not wish to provide wheeling in the present.

In its response to the FERC's NOI (Phase I), Pacific Gas and Electric Company presented the following example of the manner in which some short-term transmission arrangements may be hampered because of the Commission's policy with respect to termination of service:[68]

> In the Geysers geothermal area of northern California, transmission capacity is tightly linked to generation and it is risky for PG&E to offer short-term wheeling arrangements. PG&E has installed and owns all 2,100 MW of 230-kV transmission capacity, except for 275 MW held by the California Department of Water Resources, the Northern California Power Agency (NCPA), and the City of Santa Clara in a line owned jointly with PG&E. Because of planned additions in generation by PG&E, qualifying facilities (QFs) under PURPA and publicly-owned utilities, additional transmission capacity is required.

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[68] Comments of Pacific Gas and Electric Company, FERC Docket No. RM85-17 (Phase I) op. cit., pp. 22-4, 22-5.

Public utilities have proposed the 1,000 MW Geysers Public Power Line. After PG&E's reinforcements are completed in Fall, 1985, PG&E expects to have some available capacity for several years when some additional PG&E units are expected to come on line.

Requests for short-term wheeling at The Geysers confront PG&E with a serious risk to its multimillion dollar geothermal investment. This risk is created by the fact that transmission service, which is "short-term" by contract, may in reality become long-term because the Commission might not approve the termination of that service when PG&E needs it for its own units.

The basis for this impediment to bulk power transfers is found in two sections of the Commission's Regulations. Section 35.15 of the Commission's regulations, Notices of Cancellation and Termination, provides for the following notice and review procedures:

> When a rate schedule or part thereof required to be on file with the Commission is proposed to be cancelled or is to terminate by its own terms and no new rate schedule or part thereof is to be filed in its place, each party required to file the schedule shall notify the Commission of the proposed cancellation or termination on the form indicated in Section 131.53 of this chapter at least 60 days but not more than 175 days prior to the date such cancellation or termination is proposed to take effect. A copy of such notice to the Commission shall be duly posted. With such notice each filing party shall submit a statement giving the reasons for the proposed cancellation or termination, and a list of the affected purchasers to whom the notice has been mailed.

Section 2.4, Suspension of Rate Schedules, provides for the suspension of a request for termination of service:

> (b) The Commission can suspend any new schedule making any change in an existing rate schedule, including any rate, charge, classification, or service, or in any rule regulation, or contract relating thereto, contained in the filed schedule.
>
> (c) Included in such changes which may be suspended are:
>
> (4) Cancellation or notice of termination.

The authority of the FERC to disallow a request for termination of service was affirmed by the United States Supreme Court in a case involving its predecessor agency (the FPC) and the Pennsylvania Water and Power Company. In that case, the Court stated:[69]

> The act gives the Commission ample statutory power to order Penn Water and Consolidated to continue their long-existing operational "practice" of integrating their power output . . . Shortly after Part II of the power act was passed in 1935, Penn Water, as required by Section 205(c), filed with the Commission the contract here attached and then designated by the Commission as "Penn Water's Federal Power Commission Rate Schedule No. 1." Section 205(d) provides that "no change shall be made by any public utility in any such . . . service . . . or contract relating thereto, except after 30 days' notice to the Commission and to the public." Here instead of following the procedure for changing existing services and practices--a procedure which the Congress has authorized and which the Commission has supplemented by rules of its own--the company has rather tried to utilize a violation of the Sherman Act so as to nullify a rate-reduction order.

Subsequent to the Penn Water case, there have been few contested cases before the FERC regarding termination of service. In instances where the termination of service was opposed, there has generally been a settlement between the parties which results in the continuation of service under revised terms. For example, in a dispute over the termination of an agreement for partial requirements service between Nevada Power Company (NPC) and California-Pacific Utilities Company (CPUC), NPC assumed retail service responsibility for the CPUC load it formerly served at wholesale in exchange for a division of its retail operations served by power secured under a long-term contract with Idaho Power Company.[70]

A similar dispute arose in an effort by Public Service Company of Indiana (PSI) to terminate service under an agreement with the City of

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[69] Pennsylvania Water and Power Company et al. v. Federal Power Commission et al., 343 U.S. 414, 422-424 (1952).

[70] This settlement was negotiated after an Initial Decision was rendered in which the presiding Administrative Law Judge had ruled that the termination of service was in the public interest due to NPC's "bleak financial condition." See, Nevada Power Company, Order Authorizing Exchange of Electrical Facilities and Terminating Proceeding, FPC Docket Nos. E-9597 and E-9306, 1 FERC 61,325 (1977); Initial Decision, 1 FERC 63,004.

Logansport, Indiana (City).[71] Under the agreement PSI provided full service at a separate delivery point to four of the city's retail industrial customers not directly connected with City's main distribution system. The FERC accepted the termination notice for filing, established procedures for hearings, and suspended its effectiveness for the maximum five months on the basis of PSI's failure to demonstrate the termination was just and reasonable or in the public interest. Subsequently, in a report to the Commission, the presiding ALJ advised the Commission that PSI, the City, and the Commission staff had arrived at a stipulation preserving the status quo.[72]

Proposed Modifications to Current Regulations Governing the Termination of Service

The adverse effect of the FERC's termination of service procedures on utilities' willingness to provide both short-term and long-term wheeling was expressed by a number of respondents to the Commission's NOI. They generally advocated that the Commission should respect termination dates in voluntarily negotiated contracts. In addition, they recommended the adoption of automatic termination procedures. For example, the Edison Electric Institute suggested a revision to Section 35.15 of the regulations which would provide that coordination and transmission agreements automatically terminate on the date contained in the agreement without requiring any public notice.[73] Florida Power and Light Company urged the Commission to "respect" contract termination dates for coordination and transmission services by approval of the termination at the time of the filing. The company suggested that if the Commission finds a termination date unjust and unreasonable, it

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[71] Public Service Company of Indiana, Order Accepting Filing and Suspending Proposed Notice of Cancellation, FERC Docket No. ER80-202-000 (March 24, 1980).

[72] Public Service Company of Indiana, Presiding Administrative Law Judge's Report to the Commission, FERC Docket No. ER80-202-000 (May 28, 1980).

[73] Comments of the Edison Electric Institute, FERC Docket No. RM85-17 (Phase I) op. cit., p. 50.

could reject the entire filing and afford the parties the opportunity to make acceptable modifications.[74] Pacific Gas and Electric Company (PG&E) recommended that the Commission grant preapproval of service termination between parties that have agreed to such terms in a signed contract.[75] In addition, PG&E urged the Commission to implement this policy on an experimental basis for 3-4 years in order to assess its effectiveness in various regions of the country.[76]

Southwest Bulk Power Market
Experiment and Western Systems Power Pool

In its order accepting for filing the Southwest Bulk Power Experiment, the FERC preapproved the termination of the agreement so that upon completion of the experiment the participants would have no obligation to buy, sell, or wheel the experimental types of energy among themselves or to provide similar service to nonparticipants. This departure from existing policy was viewed as a necessary ingredient of the effort to test the extent to which an experimental competitive market might be developed. In its order authorizing the experiment, the Commission stated:[77]

> By approving the experiment, we will be granting the participating utilities a degree of pricing flexibility and a modified treatment of revenues. In return, they agree to provide the transmission service among themselves that is essential for the development of a competitive market . . . It would not be fair for us to leave open the possibility that the utilities might, at the end of the period, be required to continue to provide transmission service under the rate. Their contribution to the experiment is as vital as ours.

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74 Comments of Florida Power and Light Company System Control Center, Regulation of Electric Sales for Resale and Transmission Services, FERC Docket No. RM85-17 (Phase I) pp. 20-21.

75 Comments of Pacific Gas and Electric Company, FERC Docket No. RM85-17-000 (Phase I) op. cit., p. 22.

76 Ibid.

77 Public Service Company of New Mexico, et al., Opinion 203, Opinion and Order Finding Experimental Rate to be Just and Reasonable and Accepting Rate for Filing, FERC Docket No. ER84-155-000 (December 30, 1983) pp. 44-45.

> They should not face the possibility of having to continue theirs after we terminate ours.

The FERC also waived the notice of termination requirement in its recent order accepting for filing the Western Systems Power Pool (WSPP) experimental rate schedule. The waiver was based on the same reasons given in its order accepting the Southwest Experiment, namely, that the WSPP experiment is for a fixed duration and that the participants therefore should not be exposed to the possibility of having to continue service after the experiment is completed.[78]

Abandonment of Gas Service

Under the Natural Gas Act, gas companies subject to the jurisdiction of the FERC may not construct facilities or provide service in interstate commerce without having obtained a certificate of public convenience and necessity from the FERC. The act further provides in Section 7(b):

> No natural-gas company shall abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities, without the permission and approval of the Commission first hand and obtained after due hearing, and a finding by the Commission that the available supply of natural gas is depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity permit such abandonment.

Nevertheless, in several recent procedings, the FERC has promulgated rules which permit pregranted abandonment under specified conditions. For example, under rules adopted in Order 451 relating to elimination of the vintage pricing of certain old gas, the producer may file for a blanket certificate including pregranted abandonment if the producer fulfills certain requirements. The Commission characterized the rule as follows:[79]

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[78] Pacific Gas and Electric Company, Order Accepting Experimental Rates for Filing, FERC Docket No. ER87-97-001 (March 12, 1987) p. 55.

[79] Order 451, Final Rule, Regulations Preambles ¶30,701 at 30,264.

> It is reasonable to make certificate procedures more flexible to serve the purposes of this rule. In doing so, the Commission is simply adapting its regulations to respond to evolving industry and market conditions. Given the competitive environment of today's natural gas market, blanket sales certificates will encourage lower prices and better service nationwide.

Alternatives to Current Policy

As noted above, the principal concern of utilities with respect to termination of service is that the Commission may refuse to permit termination of service as provided in a contract between the utility and the purchaser of coordination or transmission service. There have been very few cases before the FERC in which the Commission has refused to permit termination of service. Nevertheless, to the extent that utilities view the suspension of notices of termination as a viable possibility, the rule can inhibit the offering of coordination and transmission services.

There are several ways in which this constraint might be eliminated. First, the FERC could change its regulations in such a way as to eliminate "cancellation or notice of termination" as a rate schedule change that may be suspended when the proposed change involves termination of a rate schedule (in the form of a signed contract) in accordance with the terms of the contract. To accomplish this change in the Commission's regulations, a revision of Section 2.4(c)(4) might read as follows:

> (4) Cancellation or notice of termination except where such cancellation or notice of termination is in accordance with the filed rate schedule in the form of a signed contract for coordination or transmission service (including a service agreement under a tariff).

Second, the FERC might permit utilities to include with the filing of any coordination or transmission rate schedule (in the form of a signed contract containing provision for termination of the service) a notice of termination of both the service and the rate schedule as of the date contained in the contract. This would require a change in Section 35.3 of the Commission's regulations such as the addition of a subsection (c) to Section 35.3:

(2) Notices of termination of rate schedules providing for coordination or transmission service may be filed and posted at the time the rate schedule providing for the service is filed.

Under this alternative the regulations should be further amended to make clear that if the Commission declines to accept the notice of termination at the time it acts upon the accompanying rate schedule filing, the latter may be withdrawn by the filing utility.

State and Local Regulation as a Factor in Intersystem Power Transfers

State regulatory commissions in some states have authority to regulate rates for coordination and wheeling services in intrastate commerce.[80] As noted above, however, such service is quite limited since nearly all high-voltage transmission facilities are considered by the FERC to be in interstate commerce and thus subject to federal regulation. State commission authority to regulate the terms and conditions in coordination and wheeling rate schedules and to direct utilities to provide such services is less clear, but is also likely to be quite limited.

Regulation of retail rates by state commissions can have a much greater effect on the willingness of utilities to provide coordination and wheeling services than any currently authorized direct state regulation of such services. The impact of retail rate regulation depends primarily on the manner in which revenues from coordination and wheeling services are treated by state commissions in fixing rates to retail customers as outlined below.

In most states, the state regulatory commission or some other state agency has authority to license bulk power transmission facilities and some generating facilities. Approval to construct such facilities is also required from local (municipal and county) authorities in some

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[80] National Association of Regulatory Utility Commissioners, 1983 Annual Report on Utility and Carrier Regulation, p. 416.

states. The requirements of these various agencies have an important bearing on the ability of utilities to construct needed facilities in a timely manner to sustain cost-effective bulk power transfers. This impediment is also described below.

Ratemaking Treatment of Revenues Derived from Coordination and Transmission Services

Current Regulatory Treatment

Both FERC and some state commissions require that utilities credit revenue from nonfirm coordination and transmission services to the cost of service in developing rates for jurisdictional service. To the extent that utilities are required to flow through these revenues in determining rates to serve firm load and firm transmission service customers, there is reduced incentive to maximize such transactions. The FERC has recognized the disincentives associated with the revenue credit approach and has searched for alternatives. In a Public Service Company of New Mexico case the FERC stated:[81]

> Our staff is presently attempting to establish bulk power market experiments with interested utilities. One of the goals of these experiments is to encourage opportunity transactions. Such sales make use of otherwise idle capacity and enhanced electricity production efficiency. A key consideration for the experiments is creating utility management incentives to make opportunity sales. Balanced against this aim is the goal of minimizing customer rates. (Footnote omitted.)

Subsequent to its order in Public Service Company of New Mexico the Commission formalized a series of initiatives examining alternative regulatory treatment of coordination service revenue that would promote efficient bulk power transactions and provide for an equitable distribution of the benefits between ratepayers and stockholders. One of these led to an amendment to the FERC regulations governing the recovery of purchased power costs through the fuel adjustment clause in wholesale

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[81] Public Service Company of New Mexico, Opinion No. 146, FERC Docket No. ER80-313-001, 20 FERC 61,290 (September 17, 1982).

rates.[82] Under the preexisting rule, all charges other than fuel costs and the fuel portions of purchased power costs had to be recovered in base rates established in rate proceedings. Under the new rule, utilities are permitted to recover purchased power costs subject to two conditions: (1) the purchase must be less than the buyer's variable costs and be less than 12 months in duration, and (2) purchases made to maintain reserves or to otherwise eliminate capacity deficiencies are excluded--only economy-type purchases are included. Subject to these conditions, purchased power expenses may be flowed through the fuel clause including capacity or reservation charges, energy charges, and wheeling charges associated with economy-type purchases.

A second FERC initiative was authorization of the Southwest Bulk Power Market Experiment including an Experimental Adjustment Clause (EAC) designed to recover the buyer's costs related to experimental transactions. This clause allowed 75 percent of experimental sales and transmission revenues to be credited against fuel and purchased power expenses and the other 25 percent to be retained by the utility. The FERC's justification for permitting utilities to retain 25 percent of the revenue derived from transactions was as follows:[83]

> We tentatively find that, for purposes of this experiment, the proposed profit-sharing split of 75 percent to ratepayers and 25 percent to stockholders represents a reasonable balancing of interest. (Footnote omitted.) We wish to explore the effect of explicit incentives, but we are mindful that coordination transactions should lower ratepayers' bills. What we seek to discover is, of course, the level of incentive that will lower customers' bills the maximum amount.

Subsequent to the expiration of the Southwest Bulk Power Experiment, the FERC authorized the Western Systems Power Pool experiment which also involved the issue of treatment of revenue from coordination

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[82] Order No. 352, Final Rule, Treatment of Purchased Power in the Fuel Cost Adjustment Clause for Electric Utilities, FPA Regulations, Section 35.14.

[83] Public Service Company of New Mexico, et al., Opinion 203, "Opinion and Order Finding Experimental Rate Just and Reasonable and Accepting Rate for Filing," 25 FERC 61,469 (December 30, 1983).

and wheeling transactions. The initial application proposed that participants treat the benefits of trade by one of two methods: (1) use of the traditional revenue credit procedure, or (2) exclusion of projections of experimental transactions from future test year filings with the specific method of passing the benefits of a transaction to requirements customers to be proposed at the time a rate filing is made. In accepting the rate schedule for filing the Commission accepted the proposed methods of treating revenue with the following modifications:[84]

> Therefore, we shall accept either method of treating revenues as long as the jurisdictional utility proposes a mechanism to insure that at least 75 percent of the benefits attributable to an increase in the level of coordination sales under the WSPP, not already reflected in the utility's current requirements rates, are flowed through to the utility's requirements ratepayers. This revenue treatment would apply to coordination sales in both the energy commodities and transmission service. (Footnote omitted.)

It is clear that the FERC is committed to minimizing disincentives caused by regulatory treatment of revenues from coordination and nonfirm wheeling transactions and to exploring whether a specific distribution of benefits from coordination transactions and nonfirm transmission service will increase efficiency and competition in bulk power markets. However, the success of efforts to remove barriers to bulk power transfers as in the Southwest Experiment and later in the WSPP largely depend on the policies of the state commissions. If the state commissions flow through 100 percent of the benefits of coordination and wheeling transactions to retail ratepayers, utilities will have less incentive to engage in such transactions regardless of FERC policy since a disproportionate share of the total revenues of nearly all utilities are subject to state commission regulation. This point was emphasized in the NOI comments of Pacific Gas and Electric Company:[85]

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[84] Pacific Gas and Electric Company, Order Accepting Experimental Rate (March 12, 1987) p. 43.

[85] Comments of Pacific Gas and Electric Company, FERC Docket No. RM85-17-000 (Phase I) op. cit., p. 17-1.

> The [FERC] presently has little influence on the distribution of coordination trade benefits between PG&E's shareholders and retail requirements customers. The California Public Utilities Commission regulates the rates for more than 97 percent of PG&E's revenues. As a result, the California Public Utilities Commission has predominant control of coordination benefits, because the California Public Utilities Commission jurisdictional revenue requirement for power sales dwarfs the FERC-jurisdictional revenue requirement.

A sample of state commission treatment of revenue from sales of coordination services and wheeling for participants in the WSPP is shown in Table 1. Seven state commissions in the western region are represented in the table. While there is some variation in the manner in which sales revenues are treated, it is evident that flow-through of all (or nearly all) such revenue is most common. None of the utilities contained in Table 1 operates under state commission mechanisms that provide for a defined distribution of benefits to stockholders similar to that authorized by the FERC in the WSPP or in the Southwest Bulk Power Experiment.

Future Directions

The disincentive to utilities to provide coordination and wheeling services stemming from the regulatory treatment of revenue from these services is primarily an issue for state regulation. In most states, the regulatory treatment of such revenue creates little incentive to provide coordination and wheeling services.

In jurisdictions in which state commissions wish to create greater incentives for bulk power transactions, several alternatives are available. One such method would be to estimate nonfirm wheeling revenue at a sufficiently low level in fixing base rates so that the utility has a reasonable opportunity to profit from such transactions.[86]

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[86] Some state commissions have projected nonfirm revenue at a relatively high level on the ground that this creates an incentive for the utility to engage in coordination and wheeling transactions to a sufficient degree to avoid losses stemming from this rate treatment. This, of course, is in the nature of a penalty for failure to transact (Footnote Continued)

TABLE 1

RETAIL RATE TREATMENT FOR
WESTERN SYSTEMS POWER POOL PARTICIPANTS

Participant	Sales Revenues
Arizona Public Service Company	Flow-through
El Paso Electric Company	Flow-through for economy energy and wheeling; FERC revenue credit for remainder
Nevada Power Co.	Flow-through
Pacific Gas and Electric Company	91% flow-through; 9% test-year basis
Pacific Power & Light Co.	Test-year basis
Portland General Electric Company	Test-year basis plus flow-through of 80% of deviation from projection
Public Service Company Of New Mexico	Offset to costs of nonrate base plant
San Diego Gas and Electric Company	92% flow-through; 8% test-year basis
Southern California Edison Company	Flow-through

Note: Flow-through means that all actual costs and revenues are passed through in rates; "test-year basis" means that revenues or costs are projected on the basis of a historical or future test year, and only the projected amounts are included in rates.

Source: Transmittal letter dated November 7, 1986, to the Commission accompanying application for filing of the Western Systems Power Pool, p. 4.

The effectiveness of this method, however, depends on the ability to estimate the types and volumes of coordination and wheeling opportunities that may evolve in the relatively short-term future. By their nature, such opportunities tend to be relatively unpredictable.

A better method of providing needed incentives for wheeling at the state level (as well as at the federal level) would be to exclude such revenue from the calculation of base rates and provide for flow through of a limited proportion of such revenue as credits in the fuel adjustment clause. The FERC has insisted that at least 75 percent of such credits flow through the fuel clause for the benefit of ratepayers, with the remainder serving as an incentive to encourage coordination transactions and nonfirm wheeling. This method seems to have the advantage of providing a more direct incentive for cost effective transactions while at the same time assuring that control of the particular allocation of benefits remains with the regulatory agency. It may well be that ratepayers are better off under this treatment of revenue credits than flow through of all benefits; three-fourths of 200 is better than 100 percent of 100. On the other hand there is no solid evidence as yet that a 75 percent share is more or less than necessary to minimize total net costs. Experiments designed thus far are not likely to throw much light on this issue.

Siting and Licensing of New Transmission Lines as a Factor in Interregional Power Transfers

In addition to the ratemaking and related regulatory issues discussed in earlier sections which may serve as impediments to economic exchanges of power, the physical capacity and the operating and reliability limits of the high-voltage transmission network itself are additional considerations imposing constraints on the level of cost-

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(Footnote Continued)
rather than an incentive to seek further opportunities. A similar result could be achieved simply by lowering the rate of return.

effective interregional power transfers that can occur.[87] Most of the existing high-voltage transmission system was designed to link a utility's generation and load centers as well as interconnecting adjacent utilities to enhance system reliability and facilitate economic exchanges of power between adjacent utilities. With relatively few exceptions, existing transmission lines were <u>not</u> designed to accommodate sustained, long-distance transfers of power between utilities based on differentials in marginal generating costs whereby low-cost power is used to displace higher-cost power on the importing system.

In assessing the performance of the existing transmission network, it is important to recognize the specific functions it was designed to perform as well as those not contemplated. In assessing future policy options in relation to transmission network planning and design, one must also consider any additional functions which are suggested by the economic and engineering configuration of the present and future bulk power system. The ability to sustain increasing levels of economic interregional power transfers will be an important factor in the planning and design of new transmission capacity in selected regions. Thus, the task becomes one of identifying those transmission corridors where there appears to be a need to strengthen existing transmission capacity to sustain such economic transfers (based on projected long-term marginal generating cost differentials) as well as addressing the barriers to either strengthening or expanding existing capacity.

Much of the recent debate over "transmission access" relates to the availability of transmission services which would facilitate off-system purchases by existing wholesale and retail requirements customers.[88] There appears to be a greater degree of consensus, however, that transmission capacity utilization for economic energy transfers between

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[87] Physical transfer capacity limits may be due to a number of factors including current flow limits, voltage gradient concerns, phase angle criteria, etc.

[88] See, for example, comments filed in FERC Notice of Inquiry, Docket No. RM85-17 (Phase I) relating to policies governing Commission regulation of transmission access and pricing.

regions having differing marginal generating costs is already at (or close to) maximum feasible levels based on the existing capacity and transfer limits of the transmission network. In most of these cases, the transmission lines linking regions of high- and low-cost energy are heavily loaded over a high percentage of the time to maximize such economy energy transfers.[89] Reports by the North American Electric Reliability Council (NERC) indicate that as a result of such sustained high-level transfers, the interconnected bulk power system is more vulnerable to system disturbances and outages. Thus, constructing new transmission lines and upgrading existing transmission capacity would increase the capability of the interconnected system to transfer economy energy while at the same time reducing the system's vulnerability to outages and other disruptions arising from sustained operations at (or close to) maximum safe transfer limits.

The primary issues affecting the siting and licensing of new transmission lines as they affect bulk power transfers were examined in considerable detail in a recent study prepared by the Task Force on Electricity Transmission of the National Governors Association (NGA) as well as in a parallel study being prepared for NRRI.[90] The NGA report , Moving Power: Flexibility for the Future,[91] examined state certification and siting procedures and utility planning approaches as they may impede or enhance the economic transmission of electricity.

The NGA effort was undertaken by NGA staff and state agency participants through written surveys of utilities and utility trade

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[89] See, for example, North American Electric Reliability Council, 1986 Reliability Review, Princeton (1986). Also, see, NERC, ECAR/MAAC Interregional Power Transfer Analysis, prepared for U.S. Department of Energy (1985).

[90] Because of the parallel treatment of institutional impediments to increased power transfers by another ongoing NRRI study, the discussion here will be relatively abbreviated and focus only on major issues and themes.

[91] National Governors Association Task Force on Electricity Transmission, Moving Power: Flexibility for the Future, Washington, DC (1987).

groups, a review of regulatory documents and related literature and interviews with selected utility and regulatory agency representatives. The final study provides a reasonably comprehensive and objective assessment of the current system of transmission system planning, siting, and licensing at the state level and outlines a number of options for improving current institutional arrangements.

The study identifies a number of "impediments to further development of transmission capacity," some of which involve state processes for certifying and siting new lines.[92] Of those, NGA concludes that the "lack of a definitive time table for the regulatory process appears to be one of the biggest causes of delay."[93] It also cites (a) the involvement of multiple state agencies, (b) poor coordination among relevant agencies, (c) a lack of clarity regarding regulatory requirements, and (d) local jurisdictional hurdles as other important sources of delay in obtaining timely approvals of needed transmission lines. For multistate lines, NGA notes that differing state and/or state-federal requirements are additional important factors contributing to delays and discouraging line development. NGA argues that there is a "legitimate and important role" for the states in the approval of generating and transmission capacity. Such an approval process, however, in NGA's view, must be well coordinated with the utility planning and development programs.

The NGA report is implicitly critical of utility planning efforts for their consideration of needs <u>within</u> rather than <u>between</u> individual utility systems. The report observes that, "the fact that transmission lines are generally developed and owned by the utility within whose service territory they reside, but will be used by nonowners as part of the system, creates economic and regulatory disincentives to the optimal development of the transmission grid." Thus, NGA concludes that "larger-scale transmission projects, which better reflect the needs of the overall system rather than its individual components, may only be

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[92] Ibid., p. 23.

[93] Ibid., p. 23.

achievable if regulatory requirements actually promote greater inter-utility coordination and cooperation on transmission development."[94]

The initial set of "policy options" recommended by the NGA Task Force to address the above-mentioned impediments included the following:[95]

(1) Streamlining and clarifying state approval procedures.

(2) Integrating planning and approval processes.

(3) Encouraging multi-state siting and certification.

(4) Enhancing state planning efforts.

(5) Requiring more thorough development of transmission options in utility planning.

(6) Promoting multi-state planning efforts.

(7) Eliminating structural impediments to transmission development.

(8) Building on-going informal communication among state and federal regulators, utility representatives, and public interest organizations.

As a result of concerns expressed both by utilities and regulators in response to the draft NGA recommendations and continuing consultations with other relevant constituencies, the task force subsequently issued a revised set of policy recommendations. The revised recommendations (outlined in Draft No. 3 dated May 6, 1987) were as follows:

(1) Simplify state approval procedures.

(2) Develop more comprehensive and coordinated transmission system planning and development processes both at the utility and regulatory levels.

(3) Coordinate planning and review of multistate transmission lines.

(4) Ensure that rate regulation promotes efficient transmission development.

(5) Institute a system for arbitration of disputed projects.

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[94] Ibid., p. 23.

[95] Ibid., pp. 25-7.

The various policy options formulated by the NGA Task Force provide a useful framework for briefly examining the potential impact of selected modifications in existing institutional arrangements so as to minimize impediments to economic power transfers.

Simplify State Procedures

The first option, which calls for simplifying state siting and certification procedures for new transmission lines includes provisions for consolidation of state authority to consider new lines into a single agency, establishing time limits for each stage of the approval process, developing clear statutory and regulatory guidelines for approval of new lines, and provisions for state preemption of local requirements for lines which traverse a number of local jurisdictional boundaries. The above recommendations would appear to constitute the single most important set of efforts that could be undertaken at the state level to allow for timely development of new transmission lines that would increase the ability of the existing transmission network to sustain interregional power transfers. Similar recommendations for streamlining the regulatory process, however, have been considered previously in a variety of contexts and in a variety of jurisdictions. Even those states which have adoped so-called "one-stop siting" laws with fixed time limits for each stage of the process and have consolidated siting and licensing responsibility into a single agency as recommended by NGA have yet to deal effectively with the emotionally-charged political conflicts which inevitably seem to arise whenever proposals are made for new high-voltage transmission lines. Simply "shuffling" bureaucratic agencies and providing strict statutory guidelines governing the approval process is not enough. What is needed is a firm commitment on the part of the legislative and executive branches of each jurisdiction to assure that statewide and regional considerations receive full considerations in addition to local concerns when addressing specific proposals for new or upgraded transmission facilities.

Integrating Transmission System Planning and Regulatory Approvals

The second NGA recommendation which deals with integrating both the planning and approval processes for new transmission lines specifically seeks to require utilities to provide a designated state agency with advance information on potential right-of-way requirements so that needed review and approval efforts can be undertaken on a coordinated and expedited basis. A review of the literature suggests, however, that most states already have such mechanisms in place which provide for coordinated review and approval of utility right-of-way acquisition efforts in relation to new transmission line construction.[96] In many cases, these review efforts are addressed in the context of state need-for-power and facility certification proceedings.

The NGA also recommends a form of "resource banking" where needed rights of way could be acquired by utilities on an advance basis so as to expedite future siting and certification efforts. The concept of advance right-of-way acquisition, however, is one that creates a variety of problems from a public policy perspective. In certain cases where it is clear that new transmission lines will be needed within a reasonably short time frame, such "resource banking" may be an effective means of expediting the process of siting and licensing approvals. At the same time, however, if the future need for new transmission capacity is problematic (as it typically will be), there is a risk to the utility of incurring substantial costs in the process of acquiring proposed rights of way and undertaking needed engineering and environmental studies and subsequently having such costs challenged as "imprudent" in the event the proposed line is not constructed. It also may result in substantial amounts of productive land being held idle at a net cost to society and individual landowners. Thus, any requirements for "resource banking" must be addressed on a case-by-case basis and would have to include provisions to protect both the utility and other concerned parties against the economic costs of a future decision not to construct the

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[96] See, for example, American Bar Association, Need for Power and Choice of Technology, Washington (1981); and Pfeffer, Lindsay & Associates, Inc., Strategies for Advance Power Plant and Transmission Line Review and Certification, prepared for the Michigan Energy Administration (April 1985).

proposed transmission line. Assuring future benefits is a difficult task and may involve risks that most utilities would be reluctant to incur under the current regulatory scheme of risk/reward allocation.

Multistate Coordination of New Lines

The third NGA recommendation relates to coordination of multistate siting and certification efforts and contemplates a number of options for integrating state review and approval requirements for new transmission lines with an emphasis on joint filings and hearings for those lines which traverse several jurisdictions. As noted in the NGA report itself, as well as in numerous other studies of regulatory barriers to new transmission (e.g., NERC Reliability Review, etc.), the ability of individual states to delay or in some cases preclude the construction of new transmission lines which would have a net regional economic benefit is clearly the major problem in getting many new lines constructed.[97] It is difficult enough to obtain approval for new transmission lines which would traverse and presumably benefit a single jurisdiction. These difficulties are multiplied by an order of magnitude when the principal benefits of a new multistate line accrue to states other than those whose siting approval is being sought. Thus, the concept of developing formal coordination mechanisms for multistate review and approval of new transmission line approvals would appear to have substantial merit.

The problem with formal multistate coordination mechanisms (e.g., regional compacts, etc.) is that absent a demonstrated willingness on the part of the participating states to subordinate their own siting and certification authority to that of a regional or multistate body, a requirement for multistate coordination could easily translate into additional layers of bureaucratic review without any assurance that the ultimate outcome reflects regional rather than local parochial interests. Thus, the NGA recommendations also include provisions for informal meetings among the relevant states to coordinate both long-

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[97] See, for example, NERC, Impediments to Transfers, report prepared for the NARUC Committee on Electricity (May 30, 1984).

range planning efforts at the regional level as well as working to overcome specific bottlenecks to increased interregional and intraregional transfers. Efforts to formalize state review and coordination efforts beyond those already in place should only be undertaken in parallel with a demonstrated commitment among the participating states (which would generally require new legislation) that would explicitly subordinate their own decision making authorities to final decisions made by some newly created regional or multistate body.

Removing Ratemaking Disincentives

The fourth NGA recommendation deals with structuring state and federal utility ratemaking to assure that purchased power and transmission options are considered on an equivalent level with investment in new generating capacity. It also includes a variety of wholesale ratemaking mechanisms that would seek to increase coordination arrangements among utilities and provide incentives for intervening systems to cooperate in the development of needed transmission capacity.

We have previously addressed certain aspects of the NGA recommendations which relate to ratemaking incentives for increased power transfers and development of new transmission lines and will not comment on them at length in this discussion. Among the additional rate-related recommendations noted in the NGA report is the notion that FERC should insure that the costs and risks associated with transmission capacity serving wholesale markets should be entirely reflected in wholesale electric rates. FERC policy already provides that transmission costs associated with serving wholesale requirements customers are reflected in the costs of wholesale service, so it is unclear as to what changes, if any, the NGA contemplates. The NGA group also recommends that costs associated with state siting requirements should be reflected in wholesale rates for the use of those lines. The cost of state siting requirements would also presumably be recognized by FERC as a legitimate and prudently incurred cost of developing new capacity and thus would also be included in the cost of service used by FERC in setting wholesale electric rates.

A third rate-related recommendation of the NGA group is that FERC should develop an efficient means for compensating utilities for substantial, unintended power flows over their lines. Among the rate options that appear to address this matter are the previously discussed megawatt-mile method recently adopted by the Texas Public Utility Commission in setting transmission rates and related schemes adopted by the New York Power Pool and PJM. These approaches recognize the burdens that interconnected operations and wheeling transactions may impose on the transmission networks of utility systems that are not direct parties to the transaction and seek to compensate such utilities. If it can be shown that lack of compensation for unintended power flows is creating widespread imbalances in burdens and benefits that are impeding valuable power transfers, the matter should be addressed by the FERC.

Arbitration of Disputed Projects

The final NGA recommendation relates to the institution of a process for "arbitration" of disputed projects. The NGA recommends that in cases where there is an apparently irreconcilable disagreement among states regarding the need for a particular line, some sort of arbitration board should be established to consider the merits of the project. Such a board, for example, might be invoked at the request of the governor of a particular state or determination by the FERC that the project would have significant national and regional benefits, that sufficient time had elapsed for state-by-state review of the project, and that arbitration appears to be the only means of resolving disputed issues. The NGA contemplates a board with representation from all the affected states as well as the FERC with the authority to approve, deny, or condition a project with its decision binding on the relevant states in which line would be located. The NGA also strongly rejected the notion of any federal agency (e.g., the ill-fated Energy Mobilization Board proposed by the Carter Administration in the late 1970s) which would have the authority to preempt state decision making in matters related to transmission corridor selection and right-of-way acquisition.

The NGA's preliminary endorsement of some sort of arbitration process to address the problem of regional transmission line siting is a recognition that absent some effort to address the ability of an individual state to block a project which has significant regional and national benefits, the effectiveness of its other recommendations may well be negated. It is unclear, however, whether there is sufficient support among the various states so that the "arbitration board" recommendation will ultimately be adopted by the NGA as a formal position.[98] There still appears to be some reluctance among individual states to yield authority over transmission line matters to a regional board. This would appear to be especially true in the context of those states which anticipate that there is a potential for significant transmission line development across their boundaries, although their ratepayers may not necessarily benefit from the transactions consummated over such new lines.

Federal Siting and Licensing Issues

In addition to state regulation of transmission line development there are a number of federal statutes which may govern the acquisition of right-of-way for new transmission corridors and the development of new transmission lines along such corridors. Federal jurisdiction can arise under several sets of circumstances. First, any transmission right-of-way over federal lands would require the approval of the relevant federal agency (which in most cases would be the U.S. Department of the Interior). This would include both those lands directly owned by the Federal Government as well as other lands wherein there is a significant federal interest (e.g., Indian reservations). In such cases, acquisition of right-of-way for new transmission line construction (or possibly even the upgrading of an existing line) would either require a determination that the proposed line would have no significant environmental effects or more likely, the completion of an environmental impact statement under the National Environmental Policy Act of 1970 (NEPA). Historically, intervenors have effectively used the EIS process to delay or, in some cases, successfully block the acquisition of right-of-way for new transmission capacity. Such issues as the

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[98] This view is sustained by a subsequent version of the NGA recommendations which was issued as this paper was being finalized wherein the "arbitration" option had been changed to "mediation."

environmental and aesthetic effects of the proposed line, the health effects of high-voltage electric power transmission, the existence of an endangered species within the proposed right-of-way, etc. have been successfully invoked by intervenors in their opposition to the development of new transmission capacity.

In addition to the generic EIS process which would be applicable to virtually any federal agency decision relating to utility right-of-way acquisition for new transmission capacity, there are other circumstances in which federal jurisdiction might arise. For example, under a 1953 Executive Order, electric utilities must obtain Presidential permits for the construction, operation, and maintenance of transmission facilities crossing U.S. borders (i.e., with Mexico and Canada). The issuing of such permits has been delegated to the U.S. Department of Energy which considers the environmental and reliability effects of the proposed transmission line addition. Any transmission line crossing a navigable waterway would likely come under the jurisdiction of the Army Corps of Engineers (Corps) whose concerns would include the effects of the proposed line on navigation as well as a variety of environmental concerns which the Corps is required to consider under various federal statutes. The FERC has responsibility for approval of transmission lines associated with licensed hydroelectric facilities under the Federal Power Act. The FERC's jurisdiction extends to "primary lines" that link a hydroelectric facility to the balance of the utility's transmission grid.

A variety of other federal agencies could theoretically become involved in transmission line approval as a function of the location of the line and its ownership. Any line, for example, that is proposed by one of the federal power marketing agencies (e.g., Bonneville Power Administration, Western Area Power Administration, etc.) would require both successful completion of the EIS process noted above as well as congressional budgetary authorization. The Department of Defense (DOD) might also become involved in the approval process for any proposed line crossing a major military installation or other area deemed essential to national security by DOD. In most cases, such federal regulatory approvals are made independently of the state regulatory oversight discussed earlier in this section.

The principal issue regarding federal transmission line jurisdiction is whether federal certification authority (perhaps in the Department of Energy or the FERC) is essential to assure full and fair consideration of proposals for high-voltage facilities having high value to the region but marginal value to some of the states or localities through which they must pass. As of this writing, the states have failed to agree on any reasonable alternative that will assure that decisions with respect to such proposals will fairly balance national, regional, and local concerns.

Uncertainty Concerning State Versus Federal Jurisdiction of Coordination and Transmission Rates and Services

FERC rate regulatory authority is limited to rates for sales at wholesale for resale and transmission in interstate commerce by utilities subject to its jurisdiction.[99] It has authority to order such utilities to interconnect and to sell or exchange energy with other utilities under some circumstances and some authority to order wheeling service by "electric utilities"[100] under more limited circumstances. It has no authority to regulate retail rates and no authority to order wheeling to ultimate customers. A number of state commissions have authority under state law to regulate rates for sales to other utilities for resale and rates for transmission service.[101] In these states there

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[99] The Commission's rate jurisdiction under the Federal Power Act extends to any person who owns or operates facilities for the transmission or sale of electric energy at wholesale in interstate commerce, except that it does not extend to "the United States, a state, or any political subdivision of a state, or any agency, authority, or instrumentality of one or more of the foregoing. . ." Federal Power Act, Part II, Section 201.

[100] The Public Utility Regulatory Policies Act, which amends the Federal Power Act to provide the FERC with limited authority to direct wheeling service, defines "electric utility" as "any person or state agency which sells electric energy; such term includes the Tennessee Valley Authority, but does not include any federal power marketing agency.

[101] National Association of Regulation Commissioners, op. cit.

may be some overlap between state and federal jurisdiction. The resultant uncertainty on the part of the utilities as to which authority has jurisdiction in some circumstances may create disincentives to engage in bulk power transfers.

Sources of Uncertainty

One source of uncertainty relates to possible overlap of state/federal jurisdiction stemming from the fact that FERC jurisdiction is limited to transactions in interstate commerce. Under the Federal Power Act, ". . . electric energy [is] held to be transmitted in interstate commerce if transmitted from a state and consumed at any point outside thereof; but only insofar as such transmission takes place within the United States."[102] The courts have held that the test of whether a transaction is in interstate commerce is an engineering test of actual power flows rather than a matter of contractual arrangement.[103] While some transactions are clearly in interstate commerce, others may be problematic because of difficulties associated with tracing the paths of particular energy flows.[104]

A second source of uncertainty relates to the authority of the FERC to regulate nonprice terms and conditions in wheeling rate schedules. In a 1984 decision in response to a petition for declaratory order by Florida Power and Light Company and the Florida Public Service Commission, the FERC asserted its exclusive jurisdiction over rates for transmission service in interstate commerce including transmission service ordered by a state commission.[105] Several years later, another

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[102] Part II, Section 201(c).

[103] Federal Power Commission v. Florida Power and Light Company, 404 U.S. 453 (1972).

[104] See, Arkansas Electric Cooperative Corporation v. Arkansas Public Commission, 103 S. Ct. 1905, 1911 (1983).

[105] Florida Public Service Commission, Florida Power and Light Company et al., Declaratory Order, Docket No. EL84-27 (1984).

petition for declaratory order was filed by Florida Power and Light Company relating to terms and conditions in wheeling rate schedules.[106] This petition was filed in response to recent rules issued by the Florida Public Service Commission (FPSC) relating to the development of cogeneration.[107] Among these rules is a requirement that utilities wheel QF power to other utilities in Florida, as well as provide self-service wheeling for QFs.[108] The rule requires all utilities in Florida to file a tariff for intrastate wheeling containing charges, terms, and other conditions applicable to wheeling QF-produced power. The current petition requests the FERC to formally exercise its exclusive jurisdiction over nonprice terms and conditions of jurisdictional rate schedules.[109]

A third source of uncertainty relates to the authority of a state commission to direct a utility to provide wheeling service. This uncertainty stems from the apparent reluctance of the FERC to clarify the extent of the authority it has under the Federal Power Act. In its 1984 order asserting exclusive jurisdiction over rates for transmission service in interstate commerce ordered by a state commission, as described above, the FERC had the opportunity to address the issue of state commission authority to order wheeling.[110] FERC declined to address the issue, however, since it found the issue to be beyond the

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[106] Florida Power and Light Company, Petition for Declaratory Order, FERC Docket No. EL87-19-000 (March 11, 1987).

[107] Florida Administrative Code, Rules 25-17.80 through 25-17.89.

[108] Self-service wheeling is the wheeling of QF power from the generating facility to a second industrial site of the QF for ultimate consumption.

[109] In a recent order (July 20, 1987) the FERC resolved this issue finding that all terms and conditions contained in rate schedules for transmission service in interstate commerce are subject to the inclusive and "nondelegable" regulation of the FERC. This decision is discussed in the accompanying paper by Robert Burns.

[110] Florida Public Service Commission, Florida Power and Light Company, op. cit.

scope of the specific questions posed by the petitioners in their request for a declaratory order.

The FERC has a further opportunity to address these issues in a pending case involving Sierra Pacific Power Company (Sierra).[111] Sierra has filed a petition for a declaratory order in response to a Nevada Public Service Commission (NPSC) order preventing Sierra from terminating a wheeling agreement with the Bonneville Power Administration for the delivery of power to a cooperative utility under its express terms without prior approval of the NPSC. The FERC, as previously described, treats a filing for termination of service as a change in an existing rate schedule subject to the notice and review requirements of the Commission's regulations. On May 20, 1987, the Commission issued an order granting in part and denying in part Sierra's petition.[112] In the order the Commission affirmed its "exclusive jurisdiction" over transmission service in interstate commerce. However, it did not act on the merits of Sierra's proposed termination of the agreement with BPA since the company had not filed a notice of termination of service as required under Commission regulations.

A fourth source of uncertainty related to state/federal jurisdiction stems from conflicting interpretations of the authority of the FERC to constrain the retail ratemaking jurisdiction of state commissions by way of wholesale rate regulation. This is essentially a question of the reach of the so-called "Narragansett Doctrine," i.e., the principle that a state may not fix retail rates in such a way that a "public utility" is prevented from recovering costs of wholesale service at a rate authorized by the FERC.[113]

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[111] Sierra Pacific Power Company, Petition for Declaratory Order, FERC Docket No. EL87-16-000 (February 12, 1987).

[112] 39 FERC 61,176 (1987).

[113] See, Jerry L. Pfeffer and William W. Lindsay, The Narragansett Doctrine: An Emerging Issue in Federal-State Electricity Regulation, Occasional Paper No. 8, The National Regulatory Research Institute, The Ohio State University (1984); The Narragansett Doctrine: A 1986 Update, The National Regulatory Research Institute (1986).

While the principle of the "Narragansett Doctrine" was affirmed recently by the U.S. Supreme Court,[114] at least one avenue of exception was left open, namely the prudence exception. According to the Court:[115]

> Without deciding this issue, we may assume that a particular <u>quantity</u> of power procured by a utility from a particular source could be deemed unreasonably excessive if lower-cost power is available elsewhere, even though the higher-cost power actually purchased is obtained at a FERC-approved, and therefore reasonable, <u>price</u>. (Emphasis in original.)

This is consistent with the position taken by the FERC in various cases to the effect that FERC's responsibilities in regulatory wholesale power rates do not extend to the question of whether the purchaser has purchased wisely or made the best deal available. It is also consistent with the conclusions of the Pennsylvania Commonwealth Court in the case of <u>Pike County and Power Company v. Pennsylvania Public Utility Commission</u>. There 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 <u>supplier's</u> costs, the state commission determines whether it is reasonable for the <u>buyer</u> to purchase the power at that price in light of other available sources.

More recently the FERC has had occasion to revise its position relating to the prudence issue at least in cases where the transactions involve holding company affiliates participating in a comprehensive coordination agreement. In the AEP Generating Company case,[116] the Commission sought to determine whether a participant in the AEP System Agreement that has become capacity deficient, is permitted under the

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[114] <u>Nantahala Power and Light Company et al. v. Thornburg, Attorney General of North Carolina et al.</u>, slip opinion No. 85-568 (1986).

[115] Ibid., p. 19.

[116] AEP Generating Company, Kentucky Power Company, FERC Docket Nos. ER84-579-006 and EL86-10-001.

agreement to purchase its capacity shortfall from other members on a permanent basis. The Kentucky Public Service Commission (KPSC) had found that the purchase by Kentucky Power Company (an AEP affiliate) of a share of the Rockport Generating Station (from other AEP affiliates) was imprudent on the ground that it could have purchased its capacity shortfall from other members more cheaply as deficiency capacity; the KPSC then calculated retail rates on the assumption that the capacity shortfall was purchased in that manner. The FERC determined that the intersystem agreement did not permit the purchase of deficiency capacity on a permanent basis. In the words of the Commission:[117]

> . . . we do not agree that the prudence inquiry of the Kentucky Commission, culminating in its December 4, 1984, order disallowing the cost of Rockport capacity in KEPCO's retail rates to the extent it exceeded the capacity equalization charge under the Interconnection Agreement, was a valid exercise of the State Commission's authority.

It is apparent that the prudence of the purchaser is considered by the FERC to be outside the purview of the FERC in some cases; in those cases the state commissions are presumably free to fix retail rates which do not reflect wholesale rates accepted by the FERC. In other cases, however, where the buyer and seller participate in a coordination agreement, the FERC may consider that the prudence of the purchaser is not necessarily outside its purview. In such cases a utility is likely to consider itself less exposed to reduction of retail rates on prudence grounds than in the case of a pure arms-length purchase and sale. Evidently, however, there will be many potential transactions in which the utility will be uncertain as to its exposure to the Pike County exception, and such uncertainty will reduce any incentive to participate in transactions of these sorts.

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[117] AEP Generating Company, Kentucky Power Company, Opinion No. 266, 38 FERC 61,243.

Removal of Uncertainty

It requires little insight to conclude that impediments to bulk power transfers can be reduced by removal of the uncertainties outlined above insofar as possible. Removal of such uncertainties, however, is more easily accomplished in some cases than in others. For example, the issue of the FERC's authority with respect to terms and conditions in rate schedules was readily resolved. Removal of uncertainty as to whether any particular transaction is in interstate or intrastate commerce may be more difficult to accomplish.

With respect to the prudence exception to the Narragansett Doctrine, at least three possible courses of action are available to the Commission. The Commission could reconsider the basic proposition that the prudence of the buyer is not to be considered (apart from at least some coordination arrangements) except in the context of Commission review of the <u>wholesale rates</u> of the buyer. Alternatively, the Commission might seek to address as many factual situations as are presented to it within a reasonably short period in an effort to reduce uncertainty to a minimum. A third, and probably preferable, alternative would be a policy statement developed via a rulemaking proceeding establishing with as much specificity as possible the circumstances under which the Commission will consider the prudence of the buyer in its regulation of wholesale electric rates.

Assessment of the Significance of Regulatory Impediments to Bulk Power Transfers

Earlier sections of this paper have reviewed many of the impediments to intersystem bulk power transfers that stem from federal and state regulation. It is important to recognize that regulation, per se, is only one of several sources of potential impediments to bulk power transfers and indeed may not be the most important impediment. Over the past two decades there has been a substantial increase in the volume of bulk power transfers and wheeling services among utilities in virtually all regions of the U.S. This increase occurred during a period in which the regulation of such transactions was certainly not being relaxed.

Overall, there is little empirical evidence now available to demonstrate that the removal or mitigation of regulatory impediments would lead to substantial increases in economic bulk power transfers.

The closest approximation of a test of the effects of relaxing regulatory burdens in the electric power industry has been the Southwest Bulk Power Experiment. Under this experiment, a group of publicly- and privately-owned utilities in the southwest were permitted to engage in bulk power transactions at essentially unconstrained negotiated rates without any requirement for filing of rate schedules with the FERC. In exchange for this transactional flexibility, the utilities agreed to permit use of their transmission facilities by other participants for transmission of experimental services to the extent transmission capability was available. The prices fixed for transmission service were quite nominal under the experiment. Nevertheless, the reported results of the Southwest Experiment do not provide any real evidence of significant increases in bulk power transactions as a result of relaxation of regulatory constraint. The limited nature of the experiment, however, precludes reaching any conclusion as to the effects of regulatory relaxation under other circumstances or in broader markets.

A more definitive test of the effect of mitigating regulatory constraints is currently being undertaken in the context of the newly-formed Western Systems Power Pool (WSPP). In its order authorizing this two-year experiment, the Commission made clear its interest in assuring that appropriate data are collected during the course of the experiment to permit objective evaluation of the effects of a relaxed regulatory environment on the volume of transactions. If such data are collected, it should provide some basis for making a more definitive assessment of the effect of deregulation of certain types of bulk power transactions on the level of transactions that are actually consummated.

Apart from siting and licensing problems, there is little consensus concerning the relative significance of individual impediments to bulk power transfers. Indeed, there is little agreement as to whether some of the regulatory practices noted earlier constitute impediments at all.

Utility representatives tend to emphasize burdensome filing requirements and the ability of the FERC to modify voluntarily-negotiated coordination and transmission service agreements as among the more significant impediments to interregional transfers. As suggested above, the timing and flexibility problems created by filing requirements can be substantially mitigated by use of preapproved ceiling rates subject to minimal subsequent reporting requirements together with a procedure for telephonic approval by appropriate FERC staff. The disincentives stemming from the FERC's termination of service procedures can be removed by a revision of the Commission's regulations exempting coordination and transmission services from the requirement for filing of a notice of termination where the termination date is contained in a rate schedule in the form of a signed contract. The problem of uncertainty stemming from the authority of the FERC to modify a filed rate schedule can be dealt with by several means. As suggested above, an important first step would be revision of the Commission's regulations to permit withdrawal of a voluntarily filed rate schedule (or rate schedule change) within a reasonable period following suspension by the Commission.

Wholesale customers, on the other hand, tend to emphasize FERC's insistence on the roll-in of total embedded transmission costs in fixing firm wheeling rates as well as the inability of wheeling customers to obtain joint rates (except in limited circumstances) as among the more important regulatory impediments.[118] The Commission's policy of insistence on the use of rolled-in embedded costs in fixing practically all firm wheeling rates should be reconsidered, perhaps in the context of a rulemaking proceeding. The Commission should also consider exploring the issue of rates for firm transmission over multiple systems, perhaps in the context of a more extensive examination of the role of embedded costs and marginal costs in the development of transmission rates.

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[118] Wholesale customers, of course, emphasize their inability to obtain access to wheeling service as perhaps the most important factor limiting the volume of power transfers via wheeling. To the extent that this is a significant impediment, it is largely beyond the capability of the regulatory agencies to correct, and therefore probably better characterized as a legal impediment.

role of embedded costs and marginal costs in the development of transmission rates.

There is general agreement among utilities, wholesale customers and others that siting and licensing problems are among the most significant barriers to expanded bulk power transfers. Indeed, if at least some of the other impediments to bulk power are removed, and experiments such as the WSPP are successful in stimulating a much larger volume of intersystem bulk power transfers, the resultant need for additional transmission facilities may only serve to emphasize the true dimension of siting and licensing problems as an impediment to such transfers. As noted in our discussion of the NGA Task Force efforts, however, it may be difficult to achieve a consensus on the best means of mitigating these problems. The proposal for a multistate arbitration process to address the problem of regional transmission line certification emphasizes the reluctance of some states to yield authority over such matters. In light of this, creation of a federal certification process should be given serious consideration (perhaps vesting such authority in the FERC) as a means of dealing with proposals for regional EHV transmission projects. In the absence of such authority the economic and reliability benefits of some such projects may prove difficult, if not impossible, to obtain for the benefit of consumers of electricity.

ECONOMIC IMPEDIMENTS TO POWER TRANSFER

Fred C. Schweppe, Consultant
Meta Systems Inc.
Cambridge, MA

Introduction and Summary

Introduction

Two classes of power transfer on an electric power network are:

- o Wheeling
- o Simultaneous buying and selling between utilities.

This paper concentrates on wheeling. Webster's Third New International Dictionary (1969) has many definitions of the word "wheel", the last one is:

- o To convey or transmit electric power through or over transmission lines

This paper discusses economic impediments to wheeling from a regulatory commission point-of-view. Emphasis is on understanding the issues and available options.

Assumptions

The relationships between the buyer, seller, wheeling utility, and regulatory commission assumed in this paper are:

- o Voluntary Wheeling: The wheeling utility can decide whether or not to wheel.
- o Regulated Wheeling: The wheeling rates and conditions imposed by a wheeling utility are under the jurisdiction of a regulatory commission.
- o Voluntary Buying and Selling: The buyer and seller are free to make any arrangements between them; even if either or both are

under the jurisdiction of a regulatory commission.

The question of whether any wheeling utility profits should benefit the wheeling utility's stockholders or customers is not addressed in this paper. The question of whether federal or state regulatory commissions should regulate wheeling rates is also not addressed in this paper.

Goal of Regulatory Commission

The assumed goal of a regulatory commission is to help establish a relationship between the buyer, seller and wheeling utility which contains:

- o Economic impediments which discourage undesirable wheeling.
- o No economic impediments which discourage desirable wheeling.

The definitions of desirable and undesirable wheeling involve overall production efficiency and recovery of the wheeling utility's costs.

Three Key Issues

The three key issues facing a regulatory commission who has to determine a wheeling policy are:

- o Issue I: What costs should be covered by the wheeling utility?
- o Issue II: How should the profits (economic rents) of wheeling be shared?
- o Issue III: What rate structure should be used?

All three involve policy questions (political and social concerns) as well as technical issues.

Outline of Paper

The three key issues are discussed separately in Sections 3, 4, and 5. Section 2 provides background material by discussing the various types of wheeling and some of the basics which have to be understood before the overall problem can be addressed.

Section 6 contains a summary discussion.

Three appendices are provided. Reading these appendices is not essential but they furnish more background. Appendices A and B summarize aspects of power system analysis, control and operation which can impact wheeling discussions. Appendix C summarizes a theory for computing marginal cost based wheeling rates and long-term contracts.

SUMMARY

Wheeling is a mongrel concept that results when deregulation-competition type principles are mated to the structure of a publicly regulated, privately owned utility. As a result, wheeling presents a major challenge to regulatory commissions by requiring difficult policy decisions. This paper defines such policy issues related to economic impediments to wheeling. Recommendations are provided for some, but not all issues.

The paper provides background on concepts such as

- Money Wheeling: Money changes hands without effecting the generation pattern or network flows.
- Simultaneous Buying and Selling: There is no physical difference between wheeling and a utility simultaneously buying and selling.
- Relationship Between Buyer, Seller and Wheeling Utility: The existence of an "obligation to serve" can have a major impact on the wheeling rates to be charged.

The goal of a regulatory commission is to foster economic conditions which encourage desirable wheeling while discouraging undesirable wheeling. The paper defines "Desirable Wheeling" and "Undesirable Wheeling" in terms of both economic efficiency (as measured by overall production costs) and whether the wheeling revenues cover the wheeling utility's costs. Unfortunately some types of wheeling cannot be classified as being either desirable or undesirable. Furthermore the goal cannot be completely achieved primarily because of the effects of revenue reconciliation associated with embedded capital costs.

The three key policy issues discussed here are:

Issue I What Costs Should be Recovered by the Wheeling Revenues?

Issue II How Should the Profits of Wheeling be Shared?

Issue III What Rate Structure Should be Used?

Relative to Issue I, it is assumed that network capital costs and changes in the operating costs of the wheeling utility will always be recovered. However capital costs associated with generation require a regulatory policy decision. This paper recommends that the capital costs of

generation be included in wheeling revenues if the wheeling utility has an obligation to serve (by selling to or buying from) either of the two parties for whom the wheeling is being done. This recommendation can have a major impact on the wheeling rates. This paper also recommends that a utility who builds a new transmission line primarily for wheeling be given a financial incentive to compensate the utility for the risks associated with possible non-recovery of their capital investment.

Relative to Issue II, the amount (if any) a wheeling utility (and hence its own customers) should share in the profits resulting from wheeling depends entirely on the regulatory goals. Since the decision can definitely effect the wheeling utility's willingness to wheel, this paper recommends that some profit sharing be allowed.

Relative to Issue III, this paper recommends that a self-consistent menu of marginal cost based wheeling rates be established, ranging from those that vary each hour to long term contracts involving both actual wheeling and the right to wheel. This paper recommends that an additional term be added to achieve revenue reconciliation (i.e. recovery of embedded capital costs) even though the revenue reconciliation term can, under certain circumstances, prevent desirable wheeling from occurring.

What is Wheeling?

Webster's definition of wheeling is not complete enough to provide a sufficient basis for a fully rational discussion. Wheeling is a term that means different things to different people. It has different meanings in different contexts.

Four Types of Wheeling

There are many different types of wheeling depending upon the relationships between the buyer, the seller and the wheeling utility. The four types explicitly discussed in this paper are:

o Type I: Regulated Utility to Regulated Utility: This is the most common form occurring in the United States today.

o Type II: Regulated Utility to Private User or Requirements Customer: Here a requirements customer or a private user such as an industrial customer purchases energy from a regulated utility that does not service the customer's geographic location.

o Type III: Private Generator to Regulated Utility: This is reverse of the above case where a private generator sells to a regulated utility whose service territory does not cover the geographic location of the generator.

o Type IV: Private Generator to Private User: It is assumed here that both the private generator and the private user are located in a single utility's service territory.

There are, of course, other possible types such as a private generator in one utility wanting to sell to a private user in a different utility but the above four are sufficient to cover the needs of this paper. In all four cases, the wheeling utility is assumed to be a regulated, investor-owned utility with its own generation and transmission system. However most of the ideas apply, with at most minor modifications, to other types of wheeling utilities such as a government owned generation-transmission or pure transmission utility.

The four types have different relationships between the wheeling utility and the buyer and seller in terms of "obligation to serve" (by either providing or buying energy). This relationship determines the types of capital costs the wheeling utility should be allowed to recover (Issue I), as will be discussed in more detail in Section 3.

Money Wheeling Versus Energy Wheeling

It is often assumed that wheeling involves changes in energy flows over a transmission system and/or in the generation patterns. However, this assumption is not always true. There is a possibility of "wheeling money" wherein funds change hands even though there is no physical impact on either generation patterns or transmission flows. As one example, consider Type IV wheeling (private generator to private user). Assume (as will often be the case) that the private generation level is independent of whether selling directly to the utility or to the private user, and similarly that the private usage level is independent of whether buying from the utility or from the private generator. Then the wheeling has absolutely no physical effect. Money is being wheeled; energy is not being wheeled. Similar situations can occur in a large power pool with central dispatch. Wheeling arrangements within such a pool between utilities (Type I) or utilities and private users, requirements customers, or generators (Types II and III) often effect only money transfer; there is no change in generation patterns or transmission flows.

Money wheeling is one of the reasons Issue II (who shares the profits of wheeling) has to be addressed by regulatory commissions. This will be discussed in more detail in Section 4.

Wheeling Versus Simultaneous Buying and Selling

Consider the simple case of three utilities where the buying utility (Utility B) is connected to the "wheeling" utility (Utility W) which is connected to the selling utility (Utility S) where Utilities B and S are not directly connected. Assume Utility S is exporting 500 MW while Utility B is importing 500 MW. This situation could occur in one of two ways:

- o Utilities B and S have made an arrangement and Utility W is wheeling 500 MW.
- o Utility S is selling 500 MW to Utility W while simultaneously, Utility W is selling 500 MW to Utility B.

This example illustrates, that physically, there is no way to distinguish between wheeling and simultaneous buying and selling. The difference lies in how the transactions were evolved and who gets how much money (Issue II). In this paper the term "wheeling" is used to denote situations where the buyer and seller have negotiated among themselves and the wheeling utility is charging a rate for the wheeling service.

Economic impediments to simultaneous buying and selling between utilities are not explicitly considered in this paper as most non-technical impediments to such wheeling are regulatory or institutional in nature.

Wheeling: A Regulatory Mongrel

Wheeling presents major challenges to regulatory commissions because it is a "mongrel" concept resulting from mating two inherently different economic concepts; an ideal world of regulated utilities and a deregulated-competitive marketplace. Wheeling would not exist at either extreme.

In an "ideal" regulated utility world, there would be no utility to utility wheeling (Type I). All utilities would simultaneously negotiate the best possible buy-sell agreements with their immediate neighbors and would operate as if there was a single "centralized pool dispatch" (see Appendix B for discussions on economic dispatch, unit commitment, etc.). In the "real" world, such optimum operation is rarely achieved for a variety of institutional and other regulatory related reasons. Utility to utility wheeling hopefully encourages a closer approximation to the ideal.

In an "ideal" regulated utility world, wheeling involving private users or generators (Types II, III, IV) would not exist. The customers would all buy their energy from the regulated utility or sell to the utility under rates determined by the regulatory agency. Wheeling involving private parties introduces competition between the utility and private parties.

There are many possible scenarios for deregulation of the electric power system but under at least one "pure form of deregulation", wheeling again would not exist. A regulated transmission distribution (T&D) utility would be combined with private, deregulated generators and users. There would be no wheeling because the private generators would sell their energy to the regulated T&D company while the private users would buy their energy from the regulated T&D company, both at prices determined by an open marketplace.

Wheeling is receiving a lot of attention because of a desire to introduce some competition into the electric marketplace without giving up its basic regulated structure; i.e. partial deregulation. Its mongrel nature does not imply that wheeling is a bad concept. After all, the offspring of a mating of regulated and deregulated concepts could be healthier than any pure breed. The key point is that attempts to combine regulation and competition results in difficult regulatory challenges.

Desirable Versus Undesirable Wheeling

The goal of a regulatory commission is to take actions which remove unnecessary economic impediments to "desirable" wheeling while simultaneously discouraging "undesirable" wheeling. Unfortunately, the definition of desirable and undesirable is not trivial.

Since wheeling is a mongrel offspring of regulation and competition, there are several, sometimes conflicting criteria to be considered such as

- o Overall Economic Efficiency
- o Recovery of Wheeling Utility's Costs

In an ideal world, economic efficiency would be measured in terms of social welfare, i.e., benefits of use minus cost of supply. However for this paper, economic efficiency is defined in terms of production efficiency where

- o Production Efficiency: Production efficiency is improved if the overall generation pattern is changed such that the overall demand is met at a lower production cost.

The definitions of desirable and undesirable wheeling used in this paper are

- o Desirable Wheeling: Increases overall production efficiency, subject to constraint that wheeling utility at least recovers its costs.
- o Undesirable Wheeling: Either decreases overall production efficiency or does not satisfy the constraint that the wheeling utility recovers its costs.

These definitions are not "complete" as some types of wheeling cannot be classified as being either desirable or undesirable. One example is money wheeling which does not change either efficiency or costs.

It is important to note that undesirable wheeling (as defined) may be "desired" by the buyer and seller. For example, consider Type II wheeling where the buyer is a private user in the wheeling utility's service territory and the seller is another utility. Assume

	Marginal Operating Costs
Selling Utility	6 cents/kWh
Wheeling Utility	5 cents/kWh

Wheeling Utility Sells to Private Buyer at 10 cents/kWH (because of revenue reconciliation).

In this case the selling utility and the private buyer would be willing to deal, at say 8 cents/kWH, but such a transaction would be undesirable as overall production efficiency decreases.

What Costs Should Be Recovered?

The first policy issue (Issue I) facing a regulatory commission is to determine which of the utility's costs should be recovered by the revenues that the utility receives for wheeling. Three major cost categories are:

- o Operating Costs
- o Network Capital Costs
- o Generation Capital Costs

A related issue is whether capital costs should cover past embedded costs, future costs, or some combination thereof.

Operating Costs

Almost everyone agrees that a wheeling utility should receive revenues which cover the impact of the wheeling on its operating costs. These costs can be divided into three categories:

- o Losses: Transmission of electric energy always involves losses.
- o Generation Redispatch: The existence of wheeling can force the wheeling utility to redispatch its generation to maintain acceptable line flows, bus voltage magnitudes, spinning reserves, etc.
- o Transactions Costs: A wheeling utility incurs metering, billing, communication, computation, etc. costs necessary to take care of the transactions associated with wheeling.

The losses and redispatch costs can actually be positive or negative. For example, wheeling can reduce the losses on the wheeling utility's system or allow it to redispatch generation in a more economical fashion. Hence the revenue to be recovered could be negative (this is discussed further in Section 5 on rate structures).

Capital Costs: Embedded Versus Future

As discussed in Section 2, wheeling (especially involving private users and/or generators) is a regulation-competition mongrel. However this paper assumes that the basic regulated philosophy still applies so that the utility should receive revenues which recover its capital costs (as well as operating costs).

There is still the policy issue that has to be answered by the regulatory commission of whether these capital costs should be embedded costs, future costs or some combination thereof. From a theoretical point of view, the use of future capital costs can be appealing. However, the calculation of future capital costs requires the use of forecasts of future load growth, cost of capital, availability of fuel, environmental standards, new technology, etc. A basic rule which has been repeatedly proven to be true in the past is:

- The Forecast is Always Wrong!

Given this rule, the recommendation of this paper is to include only embedded capital costs in the revenue to be recovered.

Network Capital Costs

Embedded network capital costs associated with transmission lines, transformers, switches, circuit breakers, variable reactance, etc. are relatively easy to evaluate. The question of how to recover them through the rate structure is discussed in Section 5.

A more delicate and elusive capital cost associated with the network is the var support provided by the generators (needed because of the nature of ac power transmission). It is a difficult task to separate the total capital costs of a generator into those associated with real power and those associated with var (reactive power) support. There are ways this problem can be addressed but they are too technical to be discussed here.

Generation Capital

The question of whether or not generation capital costs (associated with generation of real power) should be recovered from wheeling revenues is a difficult regulatory policy decision. The key issue is the relationship between the wheeling utility and the buyer and seller relative to the concept of obligation to serve.

The approach recommended by this paper is:

- o If the wheeling utility has an obligation to serve either the buyer or the seller, then embedded generation capital costs should be recovered from the wheeling revenues (by inclusion in the revenue reconciliation term discussed in Section 5).

Relative to the four types of wheeling definitions in Section 2

	Type	Wheeling Utility Has Obligation to Serve
I:	Utility to Utility	Neither
II:	Utility to Private User	Private User
III:	Private Generator to Utility	Private Generator
IV:	Private Generator to Private User	Both

More discussion on this classification is given in Appendix C.

The inclusion of generation revenue reconciliation can have a major impact on wheeling revenues. Therefore, since the obligation to serve can have a major impact, some private generators or users might want to renounce their "obligation to be served". The meaning of such an act, how to do it, and its implications are fascinating to think about; unfortunately such discussions are beyond the scope of this paper.

Fear of Future Costs, Risks, Uncertainty

A utility might not want to enter into a particular wheeling arrangement even if all its costs were recovered (even with a profit as will be discussed further in Section 4). The utility might fear the arrangement would result in future costs that would not be recovered. As one example, the utility might fear that a simple wheeling arrangement with low transactions costs might establish a precedent that would require the utility to enter into many complex wheeling arrangements whose transactions costs would not be recovered.

As another example, a utility might fear that accepting wheeling would impose a new type of "obligation to serve" wherein the utility is forced to build new transmission facilities primarily to wheel energy. Such construction would have associated risks resulting from the possibility of the anticipated "wheeling sales" either not materializing or disappearing before the capital investment was recovered.

In an ideal world where the utility completely trusted its regulators to allow recovery of all prudent costs, such fears would be groundless. However, in today's world, this fear of potential future costs that would not be recovered cannot be ignored.

Recommendation

A necessary condition for a utility to voluntarily wheel energy is that the utility believes that at least its wheeling costs are being recovered. Wheeling revenues should:

- Ensure recovery of operating costs and network capital costs.
- Ensure the recovery of embedded generation capital costs for private buyers and sellers whom the utility has an obligation to serve.
- Provide a financial incentive to compensate a utility for the risks associated with building a new transmission line primarily to accommodate wheeling.

Who Should Share the Profits?

A buyer and a seller want a utility to wheel energy for them because there is a profit to be made by the buyer and seller. In many cases, the wheeling utility will want to share in these profits.

As a first example, consider Type I wheeling (utility to utility) where

	Marginal Operation Cost
Buying Utility	6 cents/kWH
Wheeling Utility	5 cents/kWH
Selling Utility	4 cents/kWH

If the wheeling costs are much less than 1 cent/kWH, the buyer and seller utilities can make a profit from a wheeling transaction. However, the wheeling utility would prefer to share in the profit by simultaneously buying (from the seller utility at say 4.1 cents) and selling (to the buyer utility at say 5.9 cents/kWH). Similar situations arise in the other three types of wheeling.

As a second example, consider money wheeling (as defined in Section 2). The wheeling utility would obviously want to get a share of the money being exchanged.

This "who gets the profits" can pose a regulatory dilemma if the regulatory commission is forced to decide. If in the above utility-to-utility example, the wheeling utility gets all the profits, the buyer and seller utilities would not bother. If the wheeling utility got none of the profits, it could decide not to wheel.

One possible approach is for the regulatory commission to choose some criterion. Two extreme cases are to:

- o Maximize Wheeling: Allow wheeling utility just enough profit to make it want to wheel
- o Maximize Benefit to Wheeling Utility: Allow buyer and seller just enough profit to make them deal

The existence of wheeling across state lines and multiple state regulatory commissions can complicate the problem. A given regulatory commission might want to maximize wheeling for transactions within its own state but maximize benefits for the wheeling utility if the buyer and seller are in a different states.

It is important to note that the profit sharing issue is not addressed by the definition of desirable and undesirable wheeling given in Section 2. In the above three utility example, desirable wheeling occurs if the selling utility (with marginal costs of 4 cents/kWH) increases its generation, while the buying utility (with marginal costs of 6 cents/kWH) decreases its generation. This can occur in many ways.

Lost Opportunities

A variation on the profit sharing issue is the case where a utility does not want to wheel because such wheeling would prevent the utility from entering into some other profitable transactions. For example, if a wheeling transaction put a set of transmission lines at their limits, the utility might not be able to sell its excess generation capacity to any otherwise willing buyer.

This "lost opportunity" impediment can be very real with many present day types of wheeling rates. However its tends to go away if the marginal cost based wheeling rate structure recommended in Section 5 is adopted.

Recommendation

The wheeling utility should be allowed to share in the profits. No recommendations on the formulae to be used are provided. As noted earlier, the issue of how such profits should be divided between the utility's stockholders and customers is not addressed in this paper.

What Rate Structure Should Be Used?

The third basic issue facing a regulatory commission is to specify a structure for the wheeling rates. The basic criterion is that the wheeling rates should encourage desirable wheeling and discourage undesirable wheeling where desirable and undesirable are defined (in Section 2) in terms of utility cost recovery and overall production efficiency.

In order for wheeling to take place, the buyer and seller must decide that it is to their economic advantage and the wheeling utility must agree to wheel. If the profit sharing issue is ignored, the wheeling utility will agree if its costs are covered. This can be done in many ways. However, the rate structure should also "send the correct price signal" to the buyer and seller so their decisions will tend to improve overall production efficiency. The best way to do this is to use wheeling rates that are based on the marginal wheeling costs of the wheeling utility.

The discussion of wheeling rate structures will defer addressing the effects of profit sharing (Issue II) until the end.

The discussions of this section are based on a theory of marginal cost based wheeling transactions that is summarized in more detail in Appendix C.

Marginal Cost of Wheeling

The marginal cost of wheeling to the wheeling utility is given by

$$\text{Marginal Wheeling Cost} = \frac{\text{Change In Wheeling Utility Costs}}{\text{Small Change In Amount Wheeled}} \text{ (cents/kWH)} \qquad \text{Eq. (1)}$$

The calculation of the marginal wheeling costs of Eq. 1 is a non-trivial task because of the nature of power system behavior. As discussed in Appendix A, an "AC load flow" (or an approximation therefore) is required to evaluate the effects of Kirchoff's laws which determine the flows in the network. As discussed in Appendix B, the marginal costs at a given hour can depend on other hours because of "unit commitment". Also as discussed in Appendix B, it is necessary to impose constraints related to system security. However, even though the evaluation of Eq. 1 can require a lot of calculations, the necessary computer programs are standard tools used by power system engineers both in operation and planning. Therefore for this discussion, it is assumed that Eq. (1) can be evaluated.

When Eq. 1 is evaluated subject to system security constraints, the result is

$$\begin{matrix}\text{Marginal} \\ \text{Wheeling} \\ \text{Cost}\end{matrix} = \begin{pmatrix}\text{Marginal} \\ \text{Fuel} \\ \text{Costs}\end{pmatrix} \times \begin{pmatrix}\text{Marginal} \\ \text{Change In} \\ \text{Losses}\end{pmatrix} + \begin{pmatrix}\text{Quality} \\ \text{of} \\ \text{Supply}\end{pmatrix} \qquad \text{Eq. (2)}$$

The marginal fuel costs and changes in losses are those of the wheeling utility. The "quality of supply" term is the result of system security constraints. It enters, for example, if a transmission line within the wheeling utility at its load carrying limits.

The marginal wheeling costs of Eqs. 1 and 2 may be positive or negative. They could be negative if, for example, the wheeling causes the losses of the wheeling utility to decrease. However, because of the marginal nature of the wheeling costs, the utility does not lose money as the total change in its costs is never negative, even if Eq. 1 yields a negative number.

Revenue Reconciliation

The discussion in Section 2 on costs included both operating costs and embedded capital costs. However, embedded capital costs have no effect on the marginal wheeling costs of Eq. 1. Thus if the decision (made on Issue II) is to include revenue reconciliation based on embedded capital costs, something else has to be done.

There are theoretical ways to achieve revenue reconciliation which enable the use of Eq. 1 without modification, such as the use of revolving funds or surcharges-refunds. Unfortunately, such approaches have many practical difficulties which seem to rule out their real world use. The most practical way to achieve revenue reconciliation is to add an additional "revenue reconciliation term" to Eq. 2. This revenue reconciliation term can be positive or negative depending on whether marginal cost pricing leads to over or under recovery of capital costs.

Impact of Revenue Reconciliation Term

The addition of a revenue reconciliation term to the marginal wheeling cost of Eq. 1 greatly complicates the "life of a regulatory commission" for two major reasons:

- o It introduces a difference between the four types of wheeling (utility to utility, etc.) and forces a close look at the obligation-to-serve concept.
- o It yields wheeling rates that do not always encourage an increase in production efficiency.

The following discussions address the second reason.

To illustrate the problem, consider a case where Eq. 1 yields

$$\text{Marginal Wheeling Cost} = 1 \text{ cent/kWH}$$

The revenue reconciliation term can be either positive or negative so consider the two cases, where because of revenue reconciliation

Wheeling Rate = 2 cents/kWH (Revenue reconciliation of + 1 cent/kWH)

or

= 0.5 cents/kWH (Revenue reconciliation of - 0.5 cent/kWH)

Assume the buyer and seller are both utilities (Type I wheeling) with marginal fuel costs of

Buyer = 6 cents/kWH

Seller = 4 cents/kWH

If the wheeling rate is the marginal wheeling cost of 1 cent/kWH, the buyer and seller are encouraged to make a deal which would both increase overall production efficiency and cover the wheeling utility operating costs; i.e., desirable wheeling would occur. If the wheeling rate is 2 cents/kWH, there is no incentive for the buyer and seller to deal even though such a deal would improve overall production efficiency. If the wheeling rate is 0.5 cents/kWH, the buyer and seller are encouraged to deal even though the wheeling utility's actual operating costs may not be covered.

This basic problem is a direct result of the mongrel nature of the wheeling concept. Regulation implies recovery of capital costs and this is not always consistent with the desire for competition to encourage overall production efficiency. The existence of this problem by no means invalidates either the concept of wheeling or the use of marginal cost based wheeling rates as the combination can yield (under appropriate conditions) a major improvement over today's system.

What Class of Transactions Should Be Encouraged?

The marginal wheeling cost of Eq. 1 can vary each hour depending on the internal load, network condition and generation availability within the wheeling utility. This, however, does not mean the actual wheeling rates should vary accordingly. The effects of transaction costs have to be considered. There are two types of transaction costs:

- The billing, metering, etc. costs of the wheeling utility
- The negotiation, billing, etc. costs of the buyer and seller

As discussed in Section 3, the wheeling utility's transaction costs are assumed to be covered by the wheeling rates.

High transaction costs (either of buyer-seller or wheeling utility) can discourage desirable wheeling from occurring. However, unlike revenue reconciliation effects which impose a fundamental problem, the transaction cost effect can be at least partly handled. The basic idea is to design a set of wheeling transactions that are based on the marginal wheeling costs but have lower transaction costs and/or better meet the needs of the buyer and seller.

Four examples of possible wheeling transactions are:

- 1 Hour Update: Rate is specified at beginning of each hour depending on forecasts of marginal wheeling costs for the next hour
- 24 Hour Update: Rates vary each hour but are posted 24 hours in advance depending on forecasted costs.
- Interruptibles: A flat rate is specified months or a year in advance with specified conditions under which the wheeling utility can interrupt the wheeling.
- Long Term Contracts: Fixed rate contracts involving a fixed amount of wheeling energy which can cover times ranging from days to multiple years in the future. These contracts can be written in

terms of either actual wheeled energy or the right to have a specific amount of energy wheeled if desired.

These long term contracts could lead to a "futures market" in wheeling rights. A wheeling utility could offer a menu of different types of transactions.

Impact of Profit Sharing

If the regulatory commission decides to allow the wheeling utility to share in any profits realized from wheeling, a suitable mechanism has to be designed. Unfortunately, as with most aspects of wheeling, there is no ideal approach.

A simple mechanism is to modify the wheeling rate by adding a constant "profit sharing term" to the marginal operating cost and revenue reconciliation terms. This, however, could have the effect of discouraging some types of desirable wheeling. For example, if a constant profit of 0.5 cents/kWH for the utility is imposed, buyer seller transactions where the total available profit is less than 0.5 cents/kWH would not occur.

A second mechanism would be to have the wheeling utility share in a fixed percentage of the profits. This, however, introduces many administrative problems as the buyer and seller are required to state accurately what the value of electricity really is to them. Such a percentage procedure forms the basis for the "split the difference" rule used in regulated utility to regulated utility economy transactions but its general applicability to all four types of wheeling is questionable.

A third mechanism is for the regulatory commission to allow the buyer-seller and wheeling utility to negotiate between themselves to determine the profit shares. This negotiation approach has many advantages for wheeling transactions involving a large amount of energy. However, it could become very unwieldy for multiple wheeling involving small buyers and sellers.

A fourth mechanism is to include a profit component to the revenue recovery term used in the revenue reconciliation calculations.

Recommendations

A self-consistent menu of marginal cost based wheeling rates ranging from those that vary each hour to long term contracts should be established. The marginal cost based wheeling rates should include a revenue reconciliation component and a profit sharing term.

The Regulatory Dilemma: A Summary

This paper addresses economic impediments to wheeling. A basic premise is that, for voluntary wheeling, there are no economic impediments if the wheeling utility is allowed to recover sufficient revenues. This turns the problem into one of specifying wheeling rates which encourage desirable wheeling and discourage undesirable wheeling, as defined in terms of overall production efficiency and recovery of the wheeling utility's costs.

The basic regulatory dilemma is that there is no way to completely achieve the goal. Wheeling is a mongrel offspring of two different concepts, regulation and competition. The two major problems are

- o Inclusion of revenue reconciliation (recovery of embedded capital costs) can lead to decreases in overall production efficiency
- o There is no "best" way to share the profits.

The problem is complicated by the existence of many different types of wheeling. The previous sections provided some explicit (and some not so explicit) recommendations on the issues of cost recovery, profit sharing, and wheeling rate structures.

A recommended approach to addressing the basic overall regulatory dilemma is to establish a "wheeling forum" wherein all interested parties (utilities and representatives of potential private buyers and sellers) could meet and exchange views and positions. The first phase of the forum would involve presentations and discussions of the ideas expressed in this paper. The goal of the first phase is to make sure everyone (hopefully) understands what the issues really are and what options are available. The second (and controversial) phase of the forum would allow each party to express their opinions on how the regulatory commission should resolve its basic dilemma. It is unlikely that a complete consensus would result. However, the degree of unhappiness over the final regulatory decisions should be reduced if everyone understands the nature of the problems and has had a chance to argue for her/his own position.

The fact that there are no simple regulatory answers does not make wheeling a bad concept. On the contrary, it can be very desirable compromise between "old time regulation" which may be dying and complete deregulation which is fraught with uncertainties. However, under wheeling, the regulators will really have "to earn their pay" and make arbitrary decisions which will make someone unhappy.

THREE CASE STUDIES OF

IMPEDIMENTS TO POWER TRANSFERS

By Casazza, Schultz & Associates, Inc.
Arlington, Virginia

Three case studies were performed as part of the report on Non-Technical Impediments to Power Transfers, to illustrate the range of impediments that exist in specific situations.

Summary of the Cases

The following cases were studied:

The Washington Loop case concerns the delays in completing the last section of a 500-kV transmission loop around Washington, D.C. The target completion date was late 1980. The utility now expects completion in 1994, and even this is not certain. The need for the last section of the line and the choice of its route were discussed very thoroughly at hearings before the Maryland Public Service Commission, which eventually agreed to the need for the line and chose a routing. However, the parties opposed to the construction and/or the siting of the line have been able to delay it through a lengthy series of legal maneuvers, particularly appeals to the court system. At this time, the utility, having won the appeals to the Commission and the courts, is preparing to request zoning special exceptions and variances at the county level. This may involve further litigation and delays.

The Stauffer Chemical Company case is a conflict about the use of wheeling rights to enable an industrial customer of a regulated utility to buy cheaper power from a competing municipal utility. The St. Gabriel plant of the Stauffer Chemical Company is located a few miles outside the city of

Plaquemine, Louisiana, but not in that city's electric service territory. Formerly a customer of Gulf States Utilities (GSU), Stauffer arranged to buy power at a lower cost from Plaquemine, which in turn bought it from the City of Lafayette. Plaquemine designated the Stauffer plant as one of its own connection points, and GSU was requested to wheel the power from Lafayette to this new connection point. GSU has an agreement with Lafayette which requires GSU to wheel power from Lafayette to other utilities such as Plaquemine. GSU originally refused to wheel the power, referring to Plaquemine's involvement as a sham designed to make GSU wheel power from Lafayette to an industrial user, which GSU is not required to do. The wheeling service is presently being provided under a consent preliminary injunction.

The Wisconsin Wheeling case concerns a municipal joint action agency's attempts to obtain firm and long-term wheeling rights from a large investor-owned utility. Wisconsin Public Power Inc. System (WPPI) is a joint action agency of municipal utilities in Wisconsin. It has been trying to obtain firm wheeling of power from sources west of Wisconsin, on lines owned by Northern States Power Company (NSP). While NSP has been wheeling economy power for WPPI, it has declined to provide firm wheeling or make long-term commitments to wheel. NSP claims that it cannot do so because of limitations on the firm transfer capability of its transmission system. There have also been disputes about wheeling rates charged by NSP, although the parties have come to an agreement. The owner of the line, NSP, bases its refusal to provide firm or long-range wheeling to WPPI on technical studies and on well-established rules of power system planning. WPPI, however, is not convinced. Suspicions arise from a lengthy history of disputes, perceived neglect, and misunderstandings, some of which are rooted in different forms of ownership and perhaps in the lack of technical staff by WPPI. One particular instance of the technical-institutional interface problems is the potential for honest disagreements about the proper criteria for planning and operating a power system. The long range firm wheeling service requested is not being provided.

Conclusions

The following conclusions have been drawn from the case studies:

- o Even technical impediments to power transfers ultimately have non-technical causes; conversely, many non-technical impediments are almost inseparable from important technical issues.
- o A small number of determined individuals, given sufficient financial and legal resources, can use the legal appeals system to delay almost indefinitely the construction of transmission lines.
- o Important issues concerning the electric power supply to a state or region should be resolved once, and at a level appropriate to the area and population affected.
- o It is important to distinguish between those power transfers that improve the total economy of power supply, and those which only redistribute costs without improving the total economy. The test for distinguishing between them is whether the physical output of any generators are changed as a result of the power transfer.
- o When transmission capability is limited, the question of transmission access is often not one of creating additional savings, but of dividing up the savings that are available.
- o There is a serious conflict between the right of individual entities to compete for power resources in the marketplace, and the needs of regulated utilities, with the obligation to serve within their territory, for a stable customer base.
- o Decisions affecting transmission systems must take into account that they are regional by nature. Justification of new lines and decisions about access to existing lines affect, and are affected by, conditions in other states in the entire region.
- o Loop flows are an important factor in determining the amount of power that can safely be transferred over a transmission system. The capacity of individual lines is only one element in determining transfer capacities, which involve complex engineering and operating considerations.
- o New competitive attitudes and practices among utilities may make it more difficult for them to cooperate in planning a transmission system that will optimize the overall area economy and reliability.

Methodology

The case studies were performed in three steps, as follows:

- o Selection of cases
- o Interviews with involved parties
- o Analysis of the cases and report preparation

The individual steps were carried out as follows:

Selection of Cases

The investigators developed a list of ten potential cases and presented them to the National Regulatory Research Institute, which selected three. The criteria of choice included:

- o A variety of fundamental issues
- o A variety of types of utilities and customers involved
- o Geographical balance or, at least, a variety of locations

Once three leading contenders were picked, a check was made to determine whether all or most of the parties would be willing to cooperate in the case studies by participating in interviews and discussing their points of view. In one case, one of the major parties involved decided not to participate on the advice of its legal counsel, and an alternate case was selected.

Interviews With Involved Parties

After a brief examination of the main issues in each case, interviews were arranged between the investigators and any party to the case that wished to participate. Appendix A lists the parties interviewed and the specific participants.

The ground rules for the interviews were designed to allow the maximum frankness, by relieving the respondents' possible fear of being misquoted or misunderstood, or of accidentally saying something that could be used against their interests. The rules provided that:

- o No tape recorders were to be used.

- The interviewers would write a summary of their discussions, and submit their summaries to the respondents for any corrections or elaborations that they felt appropriate.
- The authors would use only materials from the corrected interview summaries and published documents.

This process was found to work well. In many cases, the reviews by the respondents resulted in considerable elaborations and in providing additional documentation.

Analysis and Report Preparation

Documents made available by parties in the cases and also other materials available to the public were examined. For each case, the various contentions of the parties were examined. Facts, opinions, and points of view were identified. There were few apparent contradictions as to questions of fact, and these were resolved by identifying differences in definitions or conflicting opinions confused with facts. Once the facts in each case were established, the underlying issues were fairly well identified. Differences of opinions and in points of view, and conflicting interests, were identified and explained as the reasons for the disputes. The possible impact of the conflicts with the interests of the community at large was examined.

Case 1: Closing the Washington Transmission Loop

Nature of the Case

In 1972, Baltimore Gas and Electric Company (BG&E), Potomac Electric Power Company (PEPCO), and Virginia Electric and Power Company (VEPCO) signed an agreement to complete a loop of 500-kV transmission around the city and suburbs of Washington, D.C., in order to relieve limitations on economic and emergency power transfers. The original projected in-service date was December 1976. For a variety of reasons, including a significant decrease in the growth of demand for electricity following the oil embargo, the utilities delayed the projected in-service date. In July 1976, PEPCO filed for a Certificate of Public Convenience and Necessity to construct one of the last remaining segments necessary for completion of the loop. At that time, the projected in-service date was December 1980. As of now, the loop has not been closed because those opposed to the location of this particular segment of the loop have been able to use the regulatory and legal processes for lengthy delays. Appendix B shows a chronology of the events concerning PEPCO's efforts to obtain the authorizations needed to complete that segment.

The Utilities' Objectives

The 500-kV loop is needed in order to provide sufficient transmission capacity between three major regional groupings of electric utilities.

- MAAC, composed of utilities in New Jersey, Pennsylvania, Maryland, Delaware and the District of Columbia.
- VACAR, covering North Carolina, South Carolina, and most of Virginia
- ECAR, covering West Virginia, Ohio, Indiana, Michigan, most of Kentucky, and the rest of Pennsylvania, West Virginia, and Maryland.

The location of these groupings is shown in Figure 1.

FIGURE 1

ELECTRIC RELIABILITY COUNCILS

ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interpool Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

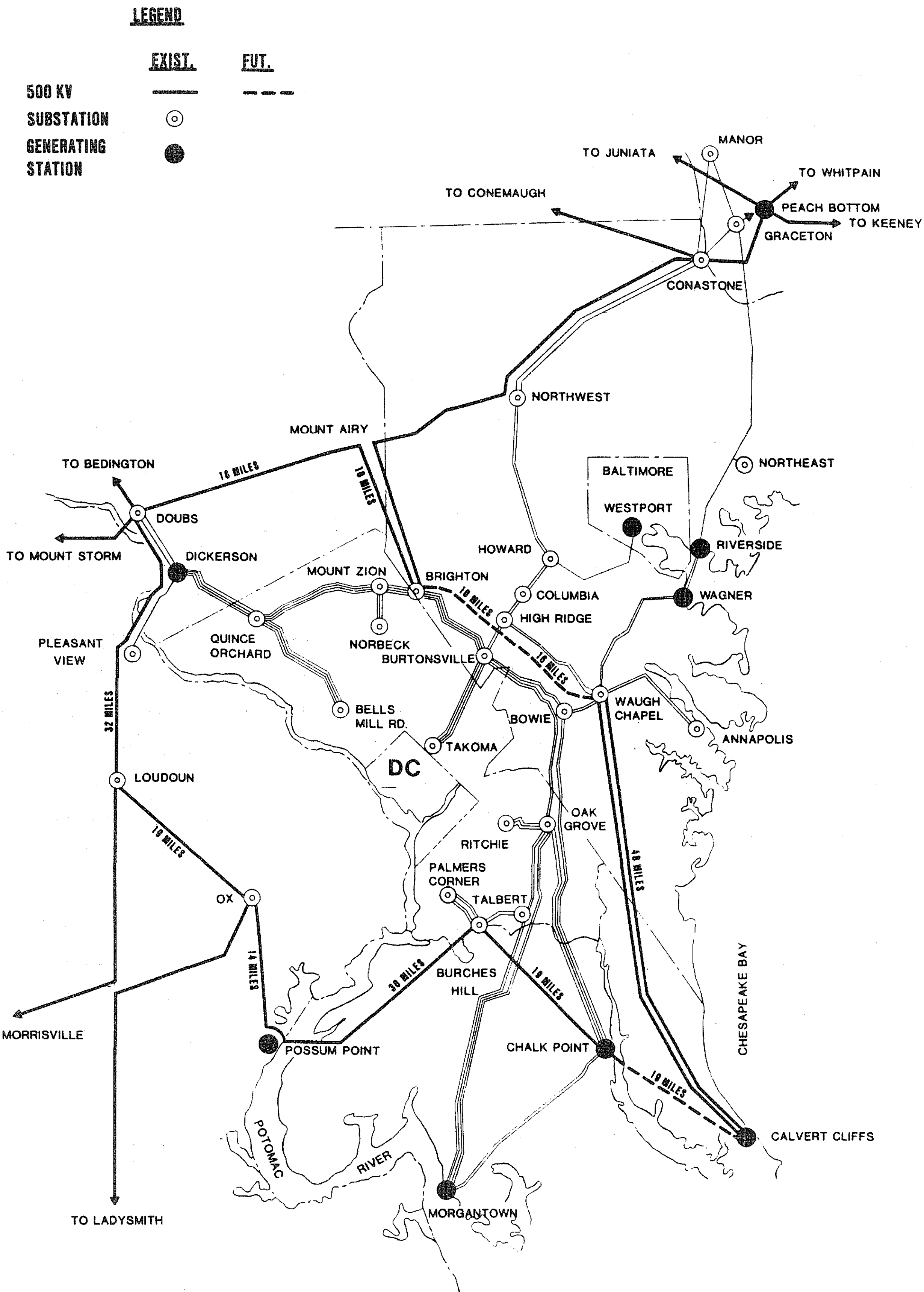
The Need for the Line

The proposed 500-kV loop was intended to fulfill two roles: to provide a path for economy power interchange, and to enhance system reliability by providing a path for emergency power transfers which may be required during major generation and transmission failures. In an interconnected system such as those covering North America, the full physical capacity of the transmission system cannot be devoted to economy interchanges. Instead, operation standards require that these power transfers must be limited so that the transmission system will still not be overloaded if certain possible emergencies occur, such as the sudden loss of one generator or a transmission line.

The loop is required to be at 500 kV in order to interconnect with other 500-kV transmission systems which form the main inter-pool transmission system in the region. A loop is needed because it provides an alternate path for large power transfers in case any single segment of the loop is out of service.

The goal of the utilities in advocating the loop is to provide a total transfer capacity of 5000 MW between the MAAC and ECAR systems and also between the MAAC and VACAR systems. This total transfer capability requirement is based on past operating experience. It consists of 2000 MW for economy interchange capability and 3000 MW for emergency transfer capability. The need for these two types of capability is additive; i.e. there is a need to have emergency transfer capability at the time the economy interchange is being made. If an emergency occurs, there is generally not enough time to arrange to stop the current economy transfers.

The segments of 500-kV transmission which compose the loop are shown in Figure 2. Some of them pre-existed the design of the loop, and others were to be built to complete it. Three sections have not been constructed at this time. The Brighton-High Ridge and High Ridge-Waugh Chapel segments are still awaiting local zoning and building permits. Thus, these two segments have become the key to the completion of the loop. The third, from Calvert Cliffs to Chalk Point, has received all the necessary certificates and permits, but has not been built because its construction, in the absence of the other unbuilt sections, would cause operating problems.



NOTE: LINES ARE SHOWN FOR GENERAL CONCEPT, AND DO NOT INDICATE ACTUAL ROUTE LOCATIONS.

ADAPTED FROM MAP PROVIDED BY PEPCO

Figure 2

The Washington 500-kV loop

The need for the loop is illustrated by Table 1, extracted from the Hearing Examiner's Proposed Order in the Brighton-High Ridge Certificate proceeding, which shows the Emergency Transfer Capability predicted for 1980, both with and without the proposed transmission loop. For each transfer interface, the limiting facility is identified as the transmission line that would reach its maximum loading if a specific outage, which is also identified, would occur.

The specific unbuilt portion of the loop that has been the subject of greatest contention, the Brighton-High Ridge section, is needed mainly because it is the key to completing the loop as a whole. As explained earlier, the completion of the other segments is contingent on the authorization of the Brighton-High Ridge line (actually the Brighton-High Ridge and High Ridge-Waugh Chapel segments form one physical line).

Moreover, even if the Calvert Cliffs-Chalk Point segment were built, VEPCO would not agree to tie their system to the partial loop. This is because if the two 500-kV lines on the Calvert Cliffs-Waugh Chapel right-of-way were to be interrupted, the power from the 1819 MW Calvert Cliffs nuclear plant, unable to travel north on these two lines, would instead flow to Chalk Point, where it would divide into two paths: part would flow north on the 230-kV lines through Oak Grove and Bowie, but an unacceptably large part would flow clockwise through Burches Hill, Possum Point, and the VEPCO system. With the loop completed from Waugh Chapel to Brighton, more power would go north from Chalk Point and the amount going through VEPCO would be reduced to an acceptable amount.

The tie to VEPCO provides an important reliability asset; without it, an outage of all the 230-kV lines on the Bowie-Oak Grove right-of-way could lead to cascading outages. Cascading outages are occurrences in which each of a sequence of outages causes another, leading to a major system breakdown and blackouts. The New York blackout of 1965, for example, was the result of cascading outages. The loss of an entire right-of-way is classified as a "Maximum Credible Outage" which, according to accepted planning practice, must not lead to cascading outages, although limited service interruptions may be acceptable.

The need for completing the loop is also reflected in VEPCO's agreement of November 1, 1985 which provided for the sale of PEPCO's Northern Virginia service territory to VEPCO. An article was added to this agreement,

TABLE 1

1980 TRANSFER CAPABILITY SUMMARY

BG&E/PEPCO/VEPCO 500 kV Loop Update

(With and Without Loop)

Transfer	ETC* (MW)	Limiting Facility (Rating MVA)	Outage
ECAR to MAAC			
W/O Loop	4650	Dickerson-Quince Orchard 230 kV (672)	Brighton-Doubs 500 kV
W/ Loop	6500+	No limit found within the reasonable range of extrapolation	
VACAR to MAAC			
W/O Loop	3700	Dickerson-Quince Orchard 230 kV (672)	Brighton-Doubs 500 kV
	3800	Loudoun-Pleasant View 230 KV (927)	Doubs-Loudoun 500 kV
W/ Loop	6350	Ox-Ladysmith 500 kV (2100)	Loudoun-Morrisville 500 kV
	6400	Loudoun-Pleasant View 230 kV (927)	Doubs-Loudoun 500 kV
ECAR to VACAR			
W/O Loop	2550	Dickerson-Pleasant View 230 kV (1000)	Doubs-Loudoun 500 kV
W/ Loop	5800	Pruntytown-Mt. Storm 500 kV (2600)	Black Oak-Hatfield 500 kV
MAAC to VACAR			
W/O Loop	1400	Dickerson-Pleasant View 230 kV (1000)	Doubs-Loudoun 500 kV
W/ Loop	3600	Dickerson-Pleasant View 230 kV (1000)	Burches Hill-Possum Point 500 kV
MAAC to ECAR			
W/O Loop	3150	Dickerson-Pleasant View 230 kV (1000)	Doubs-Loudoun 500 kV
W/ Loop	6500+	No limit found within the reasonable range or extrapolation	

* ETC - Emergency Transfer Capability

specifying that if PEPCO's efforts in closing the loop are not successful and a significant economic detriment to VEPCO results, PEPCO will reimburse VEPCO or provide a satisfactory economic solution. The amount of the potential reimbursement has been estimated at $5,000,000 per year. (Ref: Appeal Memorandum of Maryland PSC, in the Circuit Court for Howard County.)

Utility Studies

The need for the 500-kV loop was established in studies performed in the mid- to late 1960's by several inter-utility study groups which included representatives of power pools, reliability councils, and individual companies with an interest in the development of the electric power system in the middle Atlantic seaboard.

The first activity that eventually led to the decision to construct the loop took place in 1965, when a study group called the East Central Coordinated Interregional Study Group (ECC-IRS) was formed. It included representatives from APS, AEP, VEPCO, and PJM systems. The ECC-IRS group was formed to study potential problems associated with the integration of the EHV systems of the respective parties. One of the potential problem areas that was found in the group's initial study was the PEPCO, VEPCO, and Appalachian Power System (APS) interface in the vicinity of the Washington metropolitan area.

In late 1966, the ECC-IRS initiated the "Chesapeake-Potomac Area Bulk Power Study" of the planned 1972 system to develop plans, from a regional standpoint, to relieve problems found at the interface. In October 1967, study results were issued that included a recommendation that serious consideration should be given to an EHV loop in the Washington-Baltimore load area. The study also indicated the need for an additional step-down point from the 500-kV system into the eastern PEPCO load area by 1972.

As a result of the October 1967 recommendation, PEPCO, VEPCO, APS, and BG&E made a joint study to coordinate the plans for bulk power system requirements in the Baltimore-Washington-Northern Virginia Area. The report, issued in January 1969, concluded that "The extension of the 500-kV EHV transmission with underlying reinforcement in the Baltimore-Washington-Northern Virginia Area is the best solution for developing a higher reliable bulk power system capable of supplying the anticipated future area load demands."

In October 1969, a study by BG&E and PEPCO personnel also showed the need for the 500-kV loop. In essence, these studies determined that the Emergency Transfer Capabilities between the three areas were inadequate. Emergency Transfer Capability was defined by the National Electrical Reliability Council as: "the total amount of power (above the net contracted purchases and sales) which can be scheduled with assurance of adequate system reliability for inter-regional or multi-regional transfers over the transmission network for periods up to several days based on the most limiting of the following constraints.

1. All transmission loadings initially within long-time emergency ratings and voltages initially within acceptable limits.
2. Bulk power system capable of absorbing the initial power swings and remaining stable upon the loss of any single transmission circuit, transformer, bus section, or generating unit.
3. All transmission loadings within their respective short time emergency ratings and voltages within emergency limits after the initial power swings following the disturbance but before the system adjustments are made (in the event of a permanent outage of a facility transfer schedules may need to be reviewed)."

Nature of the Impediment

The present impediment to power transfers is PEPCO's inability, so far, to build the Brighton-High Ridge segment of the loop for lack of zoning special exceptions and variances required in Howard and Montgomery counties in Maryland. Hearings on PEPCO's application for these variances are scheduled in the fall of 1987 for both counties.

Maryland law, unlike that in some other states, does not specifically state that, once a utility has obtained a Certificate of Public Convenience and Necessity, it does not have to obtain zoning special exceptions and variances to build the line. PEPCO maintains that it does not, but it has applied for them as part of its strategy for obtaining a building permit as quickly as possible.

In a broader sense, the problems in obtaining the required authorizations for completing the loop represent an impediment to power transfers that has existed since at least 1979, when the hearing examiner for the Maryland Public Service Commission issued his Proposed Order. These delays have been due to a series of maneuvers in regulatory and legal proceedings which have successfully delayed the granting of required authorizations for this entire period.

The line has been opposed by a number of residents of the area in which the line was to be built, acting individually, and as organizations created for the purpose of fighting against the transmission line, and through the governments of the respective counties. The various routes proposed at different times for the line go through Montgomery, Howard, and a small portion of Prince Georges counties of Maryland. All of these counties are bedroom communities for Washington, D.C. and, in the case of Howard county, also for Baltimore. In general, the counties are affluent and already contain a number of transmission lines. In 1983 Montgomery County was ranked 10th, and Howard County 52nd, in per capita income out of 3100 counties and independent cities nationally.

Despite repeated efforts, the investigators were unable to discuss the case with any representatives of the opponents of the line and of its proposed routings. This is probably due to reluctance to discuss matters which may still be litigated, to lack of interest on the part of attorneys to spend time discussing terminated cases, and also to the loosely organized, ad hoc nature of some of the opposing groups. However, the investigators believe that the opponents' motivations can be reasonably deduced from the briefs and testimony that they have submitted.

It was to be expected that an appreciable amount of time would be required for the approval process for the line, especially since it is to be located in the affluent and densely populated corridor between Washington and Baltimore. The proceedings before the Maryland Public Service Commission, as such, did not take much longer than one would expect in a case with such a large number of intervenors, multiple alternative routes, and complex technical issues. What is unusual is the extraordinary delay that occurred after the Hearing Examiner issuing his findings.

History and Summary of Litigation

Procedural Requirements

In the State of Maryland, electric utility companies that want to build transmission lines of voltages in excess of 69,000 volts must first obtain a Certificate of Public Convenience and Necessity from the Maryland Public Service Commission. According to Section 54A of the Public Service Commission Law:

> "No electric company may begin the construction in Maryland of a generating station or any overhead transmission line designed to carry a voltage in excess of 69,000 volts, or exercise the right of eminent domain in connection therewith, without having first obtained from the Commission a certificate of public convenience and necessity for the construction of the station or line...The Commission shall hold a public hearing on each application for a certificate of public convenience and necessity in the area in which any portion of the construction of a generating station or an overhead transmission line designed to carry a voltage in excess of 69,000 volts is proposed to be located, together with the local governing bodies of each such area, unless any governing body wishes not to participate in the hearing...The Commission shall take final action only after due consideration of the recommendations of such governing bodies, the need to meet present and future demands for service, effect on system stability and reliability, economics, esthetics, historic sites, aviation safety as determined by the State Aviation Administration and the administrator of the Federal Aviation Administration, and, when applicable, the effect on air and water pollution."

PEPCO takes the position that after a Certificate of Public Convenience and Necessity is obtained from the Public Service Commission, utilities do not need to obtain zoning special exceptions and variances from the county governments. However, as mentioned earlier, the law in Maryland is not explicit on this point. PEPCO says that it is requesting these authorizations because they consider this to be ultimately the fastest way to obtain the building permits that they will need to construct the line.

Procedural History

While initially the loop was intended to be in service in December 1976, the first actual formal application for a Certificate of Public Convenience and Necessity for the last remaining segment, the Brighton-High Ridge Line, was filed on July 26, 1976 by PEPCO, indicating an intended in-service date of December 1980.

The delay in the in-service date goal at the time of the filing, compared to the goal of 1976 set in 1972, is ascribed by PEPCO to repeated reductions in load forecasts resulting from the oil embargo of 1973 and subsequent decreases in load growth rates.

In its application, PEPCO provided a detailed description of the proposed route of the line and of two alternative routes considered for the project. The total length of the line was to be 10.5 miles, with 3.7 miles to be located in Montgomery County and 6.8 miles to be located in Howard County. On April 7, 1977, PEPCO filed an amended application for the line which reflected a realignment of the preferred route of the line in an effort by PEPCO to satisfy the numerous interests concerned with the construction of the line. The application also described additional routes that had been considered, although PEPCO did not favor them. PEPCO stated that the revised application had been developed after discussions and field inspections with every individual and group, including representatives of state and county agencies, citizen groups, and landowners, that was willing to speak to them.

On June 29, 1977, the Maryland Department of Natural Resources (MDDNR) made an initial finding that no unavoidable adverse impacts had been identified which would necessitate the denial of the certificate for the line. The Department of Natural Resources is the lead agency for transmission line and power plant siting for the State of Maryland. Its role is to coordinate input to the process from all state executive department agencies and to present its recommendations concerning siting problems. On July 11th of the same year, hearings concerning the transmission line began. At the July 11th meeting, the Maryland Department of National Resources and others requested that PEPCO study the possibility of building the line on an existing 230-kV corridor. PEPCO agreed to study this route, and the hearings were adjourned until October 17, 1977 to permit PEPCO to notify the newly-affected property owners along the new alternative route. When the hearings resumed, PEPCO presented two additional alternative routes, both of which involved extensive paralleling of the existing 230-kV line.

The hearings were eventually concluded on May 23, 1978. They involved 36 individual hearing dates, over 6,000 pages of testimony, over 250 exhibits, nine witnesses testifying for PEPCO, and 65 witnesses testifying on behalf of the intervenors. At two special evening sessions held for the purpose of hearing from the public, 47 persons appeared and made statements about the line and its route. The rest of 1978 was taken up with the filing of legal briefs concerning the line.

The position of Howard County was that PEPCO was asking permission to "gold plate" its system in that the Brighton to High Ridge line would not provide any substantial benefit to the 500 kV system, and that completion of the 500-kV loop was not needed "to derive the capability of handling inter-regional transfers or needed to provide additional reliability to PEPCO's and BG&E's system." Howard County further held that if the line was to be built at all, the most reasonable routing for it would be along the existing 230-kV corridor (Path ABLMXYK in Figure 3). It should be noted that paralleling this existing corridor would mean placing almost the entire line in Montgomery County. The position of the Patuxent Valley Conservation League, one of the major organizations opposing the line, was very similar to that of Howard County. In its brief of November 20, 1978, the League held that a certificate should not be granted because public convenience and necessity was not established, but if the Commission found the line to be necessary it should parallel the existing 230-kV corridor.

The position of Montgomery County, however, was quite different from those of Howard County and the Patuxent Valley Conservation League. Montgomery County found the line to be needed, and backed the PEPCO preferred route as being "the most appropriate, rational and fairest route of all the proposed alternates". Concerning the proposal to have the 500-kV line parallel the existing 230-kV line, Montgomery County said in its brief:

> "Most significantly, the parallel route creates more problems than its solves; it is longer, most costly, visually impacts the largest number of persons and has the potential of requiring either the taking of many homes or extensive compression which greatly lessens the reliability and stability of the system. While the witnesses of Howard County and Patuxent Valley extolled its virtues, i.e., the avoidance of opening a new transmission line corridor, the evidence clearly reveals that its real virtue lies only in remaining outside their area of concern."

PEPCO's position was that the line was needed and that all of the alternative routes it proposed were buildable, including the routes that

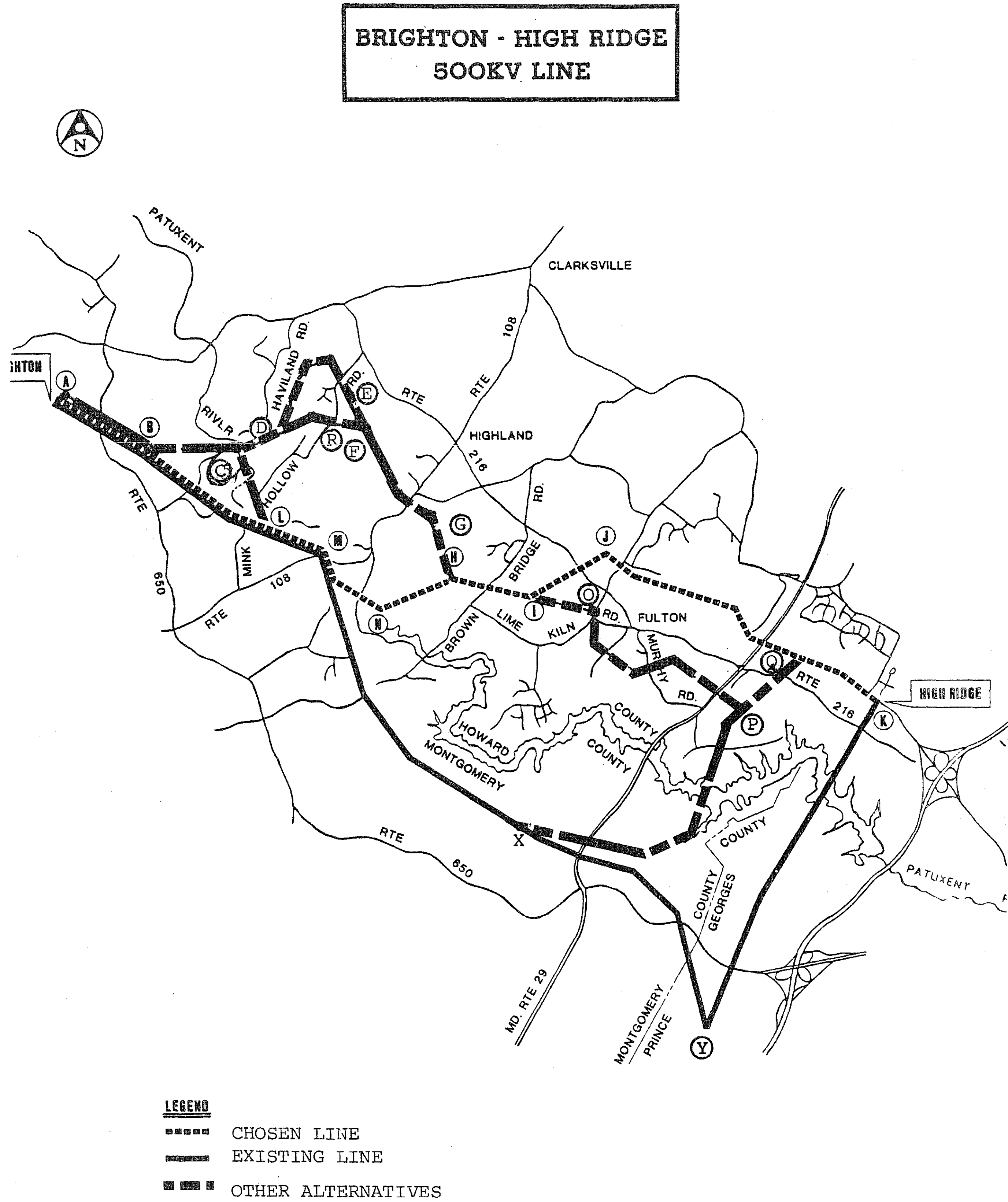


Figure 3

Alternative Routings

ADAPTED FROM MAP PROVIDED BY PEPCO

involved extensive paralleling of the existing 230-kV line. Some of the proposed routes involved "compaction," which is the crowding together of two lines on a right-of-way sized for one; this is generally achieved by building one line above the other, so that the structures are higher than they would otherwise be. Although PEPCO considered the parallel routes buildable, it did not favor the routes, partially on the grounds that such routes would degrade the overall reliability of the system by increasing the number of lines exposed to common hazards on one right-of-way, and, if compaction was involved, by increasing the exposure to lightning due to greater line height.

On November 16, 1978, the Maryland Department of Natural Resources made its final recommendations concerning the routing of the line. It recommended route ABLMNHIJK, as shown in Fig. 3, a route in Howard County, and rejected extensive paralleling of the existing 230-kV corridor on the basis that the advantages of the parallel route do not overcome its significant disadvantages. The MDDNR found the parallel route objectionable in part because it involved crossing the Patuxent River at a particularly scenic location where the view from an attractive reservoir would be harmed.

On April 6, 1979, the PSC Hearing Examiner issued a proposed order granting a Certificate of Public Convenience and Necessity to PEPCO and designating a route for the line. The route designated was PEPCO's sixth-rated choice and that recommended by the Maryland Department of Natural Resources. As a condition for obtaining the certificate PEPCO was required to submit to the Commission evidence that formal agreement has been reached with VEPCO to connect PEPCO's transmission facilities in southern Maryland with that of VEPCO's at Possum Plant; this has been done.

In the State of Maryland, if there is no appeal of a proposed order issued by a Hearing Examiner, it becomes final in 30 days. On May 5, 1979, (the 29th day) the Hearing Examiner's order was appealed to the full Maryland Public Service Commission by the Patuxent Valley Conservation League, Howard County, and others. In March 1980, the Maryland Public Service Commission upheld the Hearing Examiner and issued an order adopting his proposed order. The next recourse for those opposed to an order of the Commission is to file a motion for rehearing with the Commission. In fact, several such motions were filed by April 4, 1980. However, on April 3, 1980, the Commission's order was appealed to the Montgomery County Circuit Court by intervenors John and Virginia Hanlon. Under the "doctrine of exhaustion of administrative remedies," this step would be considered out of sequence. That doctrine, however, is not always strictly applied in Maryland, and courts have been known to entertain such out-of-sequence appeals. Later that month, on April 22, the Commission recognized the superior jurisdiction of the Montgomery County Court and issued an order holding the motion for rehearing in abeyance until the courts could rule. The fact that the Hanlons' appeal to the court was out of sequence apparently had no bearing on the Commission's jurisdiction over it. According to Maryland case law, the Commission must yield to the courts at any time when an appeal is filed with the courts, even if out of sequence. For reasons unknown to the investigators, the court had not taken any action on the appeal when, 13 months later, on May 11, 1981, the Hanlons withdrew their appeal. The Commission then took up the appeal again and on July 2, 1981, the Commission dismissed the motion for rehearing. The out-of-sequence appeal of the Commission's ruling to the courts had resulted in an avoidable delay of 13 months in processing the case.

Following the Commission's dismissal of the motion for rehearing, on July 2, 1981, appeals were filed by various parties to the Circuit Courts of Howard, Montgomery, and Prince George's counties. These appeals were consolidated in Howard County Circuit Court in March of 1982. In August of the same year, in conjunction with the court case, the Patuxent Valley Conservation League requested to take oral depositions of individual commissioners who had participated in the Commission's decision to grant PEPCO's certificate. The Maryland Public Service Commission was very concerned with any precedent that would permit the deposition of commissioners in the lawful execution of their duties. Consequently, the Commission decided to contest the position that its commissioners could be deposed. As it was unclear in Maryland state case law as to whether or not deposition of sitting commissioners is allowable, a prolonged legal proceeding ensued. The proceedings concerning the deposition issue were finally resolved on July 12, 1984 when the Court of Appeal reversed a lower court ruling and found that depositions could not be taken of individual commissioners except in special situations, such as specific accusations, which did not apply. The ordinary course of the appeals process could now proceed again, after an interruption of 23 months due to the deposition issue.

The Howard County Circuit Court upheld the Public Service Commission's order granting the Certificate to PEPCO on October 14, 1985. Land acquisition for the line began in 1986 and, in 1987, PEPCO began to file for the zoning special variances needed for the line. At the moment, there is some question as to whether or not a need for these variances can be used by counties to halt the line. The Maryland Public Service Commission's point of view is that counties cannot stop a line that has received a certificate from the commission.

The Siting Issue

From Figure 3, it can be seen that many routings were considered in this proceeding. However, the key to the siting issue is the effort on the part of Howard County forces to get the 500 kV line routed along an existing 230-kV line. This would place the 500 kV line primarily in Montgomery County. The Howard County forces were favorably disposed towards two possible routings of the line. One of these paralleled the 230-kV line to point X and then proceeded on a separate right-of-way to the High Ridge substation at point K. This routing alternative was presented by PEPCO as a buildable, although not preferable, alternative. The second routing alternative proposed by the Howard County forces is one where the 500 kV line would be routed parallel to the 230-kV line to the Prince Georges county border at point Y, and then paralleling a Baltimore Gas & Electric 230-kV line to point K, the High Ridge substation. Although testimony was presented at the hearings concerning this alternative, it was not formally presented by PEPCO because, at the time of the hearings, Baltimore Gas & Electric Company had not given permission to PEPCO to parallel its line.

The Howard County forces attempted to show that the parallel routes were feasible and that it was inherently better not to create additional transmission rights of way. Although PEPCO formally presented two partially parallel routes, ABLMXK and ABCLMXK, as buildable and feasible, it presented evidence that paralleling an existing line would degrade system reliability by exposing several lines to common hazards. System reliability would be further degraded if the parallel line were required to be compacted on the existing right-of-way. This compaction would require the use of high vertical structures where the conductors were supported one above the other, instead of one next to the other. These high structures would significantly increase the lightning outage rate of the lines.

Ultimately, the Hearing Examiner and the full Commission agreed with the PEPCO position. According to the Commission order No. 64227 dated March 5, 1980:..."While the Hearing Examiner was willing to compress through Brinkwood for 1.1 miles...he was not willing to make further compression of the ROW when the alternative routes were overall less detrimental. Accordingly, even if BG&E would have agreed to share its ROW corridor from Burtonsville to High Ridge, we find that extensive paralleling from M, X, P, Q, K or M, X, Y, K is unacceptable. It is therefore unnecessary to allow additional evidence concerning Howard County's and Patuxent Valley's proposed route of M, X, Y, K."

The route that was finally selected by the Hearing Examiner, a route through Howard County, was one that was recommended by the Maryland Department of Natural Resources. In making this recommendation, the Department considered aesthetic impacts, electrical effects, and the relative suitability of the various route alternatives. In reviewing the Howard County forces' routing preferences, one can see no convincing evidence that their proposed route or routes is preferable to that selected by the Maryland Department of Natural Resources and subsequently adopted by the Hearing Examiner and then the full Commission. The primary motivation for the Howard County forces appears to be not a better routing overall, but an effort to get the transmission line out of their county.

According to the brief on behalf of the Maryland Public Service Commission filed in the Howard County court, "..A final word should be added to the discussion on routing. Understandably, the Iagers, Howard County, and the various persons grouped under the Patuxent Valley umbrella do not want any of this transmission line to be located in their county, or on or near their properties. Talk about the impact of the line on farm land or residences applies to each and every routing proffered in this case, even the total parallel route."

Conclusions

This case illustrates the ability of a relatively small group to delay action required for the benefit of the public as a whole. Those opposing the construction of the line, neighbors and home owners of the area directly affected, are specifically and directly involved and feel a direct and personal threat; their opposition is intense and creates great pressure and enthusiasm. The benefits of the line to the general public, while amounting to considerable sums and to important reliability considerations, are relatively diffused; they do not produce comparable pressure and enthusiasm. When the prospective neighbors are relatively sophisticated and possess considerable legal, financial, and political resources, they are able to take full advantage of all the opportunities given by the legal system to delay action for very long periods of time. These opportunities were numerous and resulted in a long and extended procedural delay. Tactics such as a premature appeal of the commission's order to the courts, filing of appeals of the Commission's order in multiple counties, and the battle concerning the ability to depose commissioners of the Public Service Commission have all resulted in extending an estimated in-service date from 1980 to 1994.

Delay as a Tool

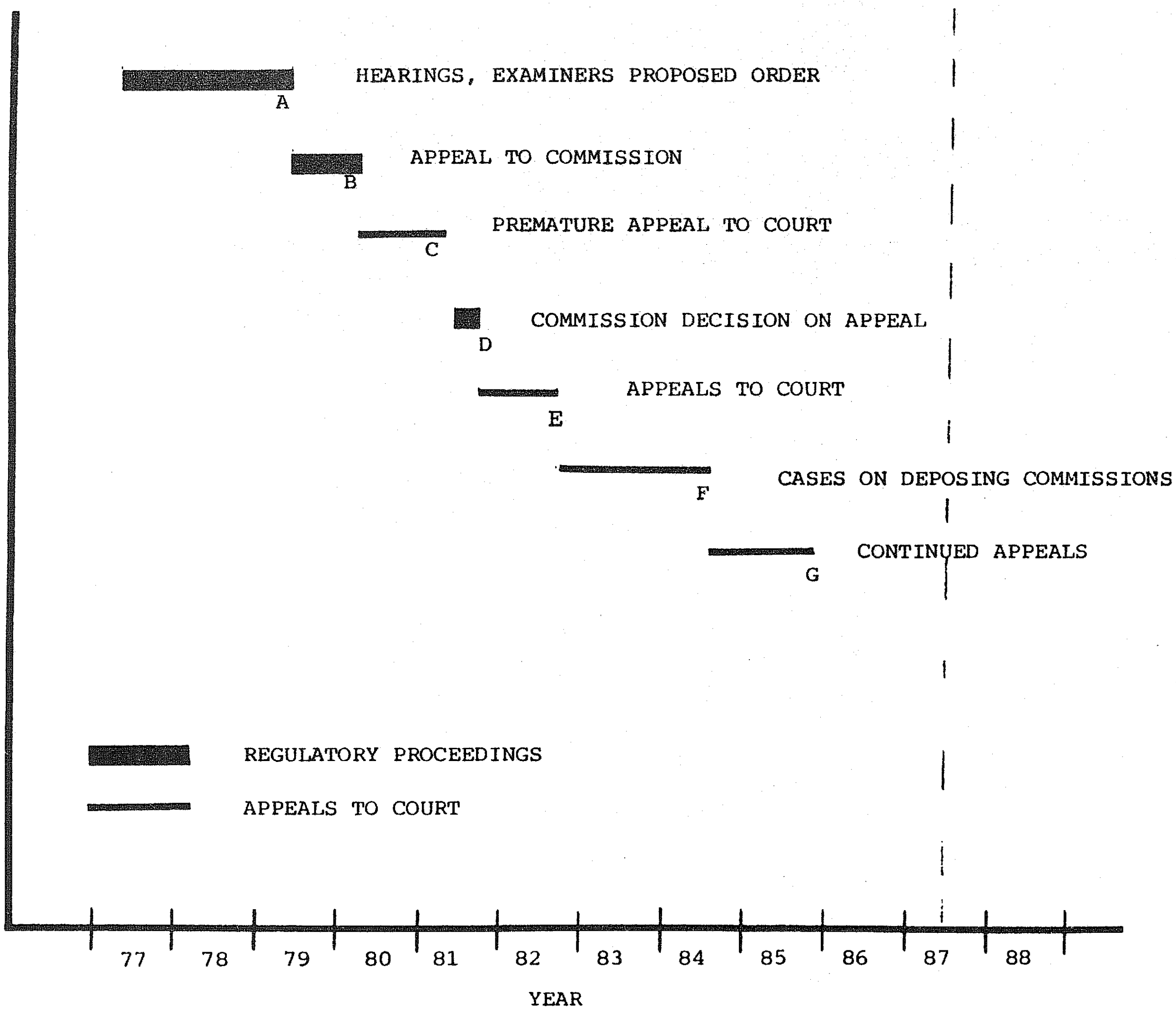
The problem in this case is not the outcome, but the delay in reaching the outcome. Figure 4 illustrates the time spent in various proceedings. It may be noted that appeals to the court system, rather than hearings, deliberations and appeals before the PSC, have taken up nearly two-thirds of the ten years that have passed so far.

The proceedings before the PSC concerned, for the most part, disputes on matters of substance although, necessarily, procedural disputes did occur and take up time. The matters of substance were, principally:

- The need for the line
- The best location for the line
- Environmental considerations

The appeals to the courts, on the other hand, involved both questions of substance and of procedure. Where matters of substance were discussed, they appear to be essentially repetitious of the arguments presented before the PSC, even though the Maryland law provides that the courts cannot reverse the decisions of the PSC if these decisions have at least some logical basis in the evidence; an argument that there is more evidence in opposition to the

FIGURE 4



CHRONOLOGY OF REGULATORY AND LEGAL PROCEDURES
WASHINGTON 500-kv LOOP
BRIGHTON - HIGH RIDGE SECTION

NOTES:

A. Hearing Examiner issues Proposed Order

B. PSC issues Order

C. J. and V. Hanlow withdraw appeal

D. PSC dismisses motion for rehearing

E. Patuxent Valley requests Commissioner's depositions. Appeals interrupted pending decision on this issue.

F. Court of Appeals dismisses request for despositions. Appeals process resumes.

G. Circuit Court upholds PSC order

Commission's decision is not valid. The issues concerning procedure questioned many aspects of the process before the PSC, including such points as:

- Who should, or should not, have been heard
- Whether the Commission resolved all motions, objections and issues.
- Whether the Commission should have re-opened the hearings for "new evidence"
- Whether the Hearing Examiner was fair and impartial
- Whether the Commission considered all possible routings

An observer might get the impression that the tactics of the objectors and intervenors were:

- intended to cause delay, rather than reverse the decision, or
- based on the theory that, lacking a good case, a shotgun volley of objections, none with a good chance of success, might result in one successful "hit".

The "shotgun approach" did not succeed in causing a reversal of the decision. However, if delay was a goal, it did succeed remarkably well. As mentioned earlier, the two maneuvers that were most effective in causing delay were:

- An appeal to the Court by the Hanlons, made before the usual appeal to the Commission was exhausted, which delayed the latter for 13 months until the Hanlons withdrew their appeal and the appeal to the Commission could proceed.
- The dispute concerning the deposition of the Commissioners, which delayed the normal appeals process by 23 months.

The issue of time is crucial. Opponents of any project often believe, not without some reason, that if they delay the final decision often enough and long enough, the proponent may tire, run out of money, or in desperation accept an inferior alternative. Through losing a long enough series of battles he may win the war.

The fault in fact may not be with the laws themselves as with the speed at which the mechanisms set up under the laws work. After all, once the courts ruled on the appeals of the Public Service Commission's order it was upheld. Further, the Maryland Public Service Commission law does seem to be set up to limit judicial review to very specific areas such as clearly arbitrary decisions not supported by any evidence or violations of constitutional provisions.

Where is the balance between the need to efficiently site and build transmission lines for the general public good and the need for due process? This leads to the key question in this instance, which is "how much due process is enough"? It is clear in our minds that the process, and especially the resolution of legal appeals, must be speeded up if the objective, to build the facilities that are needed after a thorough review of their need, is to be met.

Local Control

The next step for PEPCO appears to be to obtain zoning special exceptions and variances at the county level, although PEPCO takes the legal position that this is not required by Maryland law. The need for obtaining local approvals exists in a number of states. It seems to contradict a logical principle that issues should be resolved at the level at which all the concerned interests are represented. The need for the transmission loop affects the reliability of electric service to the whole area but the opposition represents very local concerns. It is difficult to see how the needs of the area can properly be matched against the wishes of a local area in a proceeding before a local body which represents only the narrow locality.

Technical and Non-Technical Causes

At first glance, the lack of a needed transmission line is a technical impediment. However, if the causes of this lack are themselves examined, they are found to be mostly non-technical. In this case the slowness of the appeals process, and the need to review the same arguments in several proceedings at different levels are non-technical impediments of a legal and regulatory nature.

Case 2: The Stauffer Chemical Case

General Nature of the Case

This case concerns a dispute about a utility's obligation to wheel power from another utility to a former customer who switched power suppliers in order to secure power at a lower cost.

The case involves, directly or indirectly, elements of a number of long-standing controversies in the power field. These include:

- investor-owned versus municipal utilities
- large utilities versus small ones
- the regulatory compact versus the application of market forces
- the use (or misuse, depending on the parties' point of view) of anti-trust laws to resolve territorial and economic disputes
- the right of one utility to take over willing customers of another

The different parties take different views as to what fundamental principles are involved in this dispute. Also, there are different opinions as to whether this case represents impediments to power transfers and, if so, what they are.

Historical Development of the Case

In Louisiana, investor-owned utilities are regulated by the Public Service Commission, as are cooperatives whose members have requested regulation. The other cooperatives, and all municipal utilities, are not. These facts play a significant part in the Stauffer Chemical case.

The Stauffer Chemical Company's St. Gabriel plant is a large chemical plant producing, principally, caustic chlorine through a highly electricity-intensive process. The plant is located south of Baton Rouge, on the east side of the Mississippi River, across from and four miles down-river of the city of Plaquemine, LA. Until the beginning of this dispute, the Stauffer plant had been a retail industrial customer of Gulf States Utilities (GSU) for many years. Figure 5 shows the location of the entities involved in the dispute.

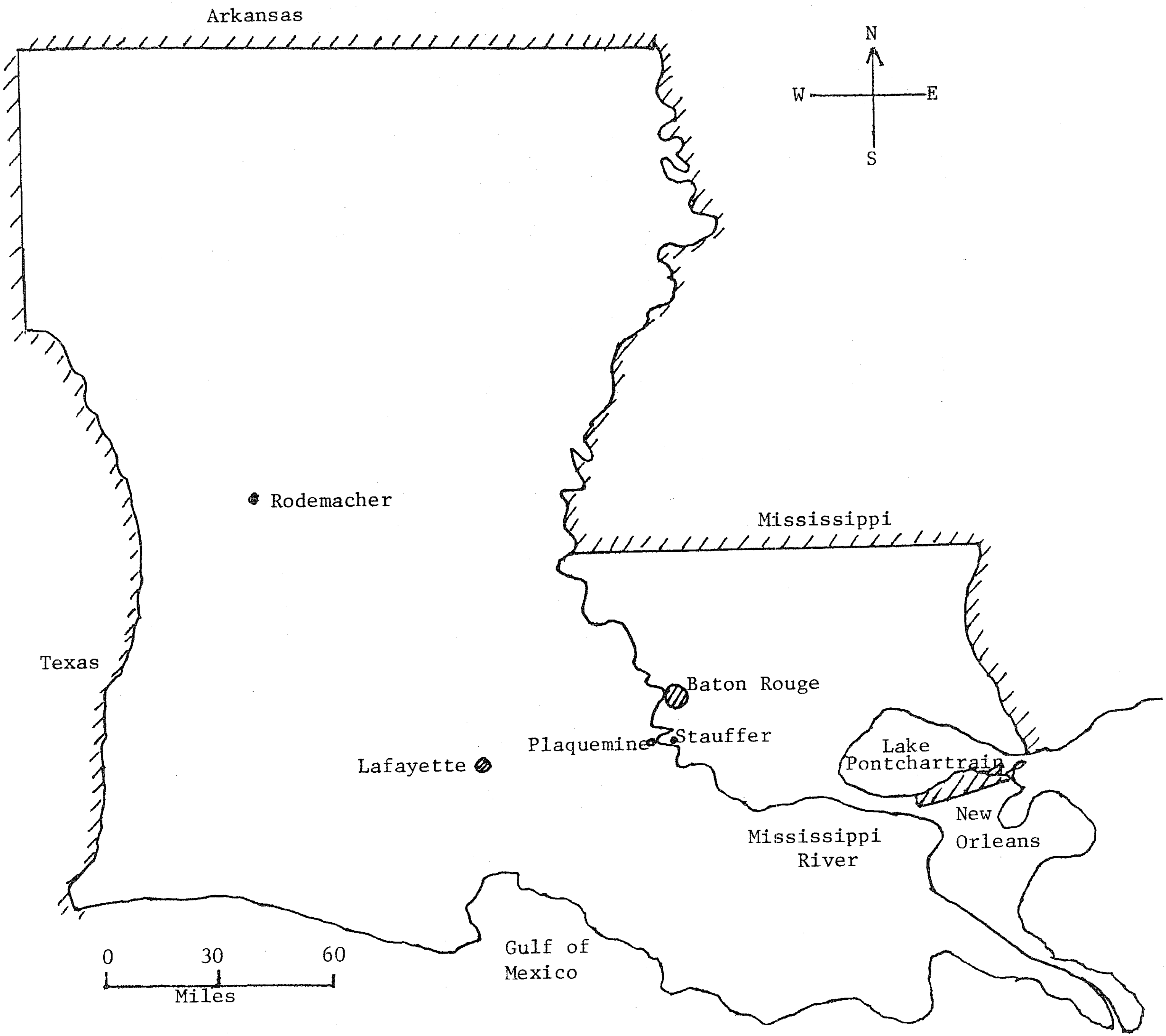


Figure 5 Map of Louisiana

The dispute began when it became clear to Stauffer that GSU's electric power rates were going to rise rapidly in coming times. Stauffer was concerned about the effect of these high rates on the viability of its highly electricity-intensive operation and, according to some parties, feared that it might be forced to shut down the plant. Therefore they searched for a lower-cost alternative supply of power. Stauffer's efforts resulted in developing a three-party transaction; the city of Plaquemine would sell power to Stauffer. Since Plaquemine did not have a low-cost power source of its own, it would buy power from the Lafayette Utilities System, about 50 miles to the west. Lafayette would produce the power from its generating units, in particular the Rodemacher No. 2 unit, located about 90 miles northwest of Lafayette, of which it owns a 50% share, and which produces relatively low-cost power from burning coal.

Lafayette and Plaquemine do not have their own transmission systems, but they are connected to the GSU transmission system. They have an agreement with GSU which obligates GSU to wheel power from one utility to another, but not to a private user like Stauffer. Therefore their proposed arrangement called for GSU to wheel the power from Lafayette to Plaquemine. However, there was still the problem of bringing the power to the Stauffer plant; Plaquemine did not have transmission to the plant, which was connected to the GSU system. To solve this problem, Plaquemine designated the Stauffer St. Gabriel substation as one of its delivery points; the substation is owned by GSU, but Stauffer leased the receiving end of its electrical facilities to Plaquemine, to further establish the Stauffer plant as a Plaquemine delivery point.

In summary, Lafayette was selling power to Plaquemine, to be delivered by GSU at Plaquemine's new delivery point at the St. Gabriel site, and Plaquemine was selling the power to Stauffer directly at that location.

Having made this arrangement, the parties came to GSU and requested it to perform the required wheeling. GSU refused to do so on the grounds that:

- The involvement of Plaquemine was, in GSU's view, a sham designed to disguise the fact that Lafayette was actually trying to sell power to Stauffer and asking GSU to wheel that power, although GSU had no obligation to wheel from a municipal utility to a distant retail customer;
- GSU objected to being asked to wheel power in order to permit a non-regulated competitor to take away one of its established customers;

- GSU feared that this transaction would set a precedent for other customers to shop around for low priced power from other utilities, leaving GSU with stranded investments in facilities whose carrying charges would have to be paid by its remaining customers, thus aggravating an already bad situation of escalating electric rates.

Stauffer threatened to sue GSU for a violation of the anti-trust laws. It cited the precedent of the Otter Tail case, in which the court found a utility guilty of an anti-trust violation because it refused to wheel or supply power to a municipal utility. The latter, a former customer of Otter Tail, had taken over Otter Tail's distribution facilities within its municipal boundaries, and had requested Otter Tail to wheel low-cost power from a distant source. GSU, contending that the Otter Tail Case did not apply to the present situation, requested the Federal District Court to issue a declaratory judgement to the effect that GSU was not required under the anti-trust laws to wheel in this situation.

While this case was pending in the court, the Louisiana legislature passed a law that, henceforth, prohibits a municipal utility from taking on new customers outside of its existing service territory unless it has the transmission facilities to serve that customer. This, of course, prevents a future repetition of the circumstances of this case in Louisiana. The Plaquemine-Stauffer situation was specifically exempted from the operation of this law, thus "grandfathering" that relationship.

In the litigation about the declaratory judgement in the Federal District Court, a consent preliminary injunction was issued and accepted by all parties. It provided that, pending a resolution of the case, GSU would perform the wheeling requested by Lafayette, Plaquemine, and Stauffer. For its part, GSU reserved the right to file a tariff for the wheeling service with the appropriate commission. As a result of this action, Stauffer would suffer no damages and therefore, would have no occasion to claim triple damages in an anti-trust action.

GSU then filed a "retail wheeling tariff" applying specifically to the Stauffer situation. This tariff refers to wheeling from Lafayette to Stauffer, thus maintaining GSU's position that the role of Plaquemine was not that of a true party to the transaction. This tariff is the same, in actual dollars, as the wholesale wheeling tariff under which GSU had agreed to wheel the power according to the terms of the consent preliminary injunction. This permits each side to claim that the wheeling is being performed under its terms while avoiding a dispute about the actual money to be paid.

In answer to GSU's filing of a retail wheeling tariff with the Louisiana commission, Stauffer filed an "exception to jurisdiction." This states that the Louisiana Public Service Commission (PSC) did not have jurisdiction over wheeling transactions, and that these are subject to the Federal Energy Regulatory Commission (FERC) jurisdiction only. The PSC has not yet ruled on whether it considers itself to have jurisdiction, and hearings on the substance of the matter have not been held, except for a set of hearings about the question of jurisdiction only.

The present situation is quiescent. No further legal actions are expected unless one of the parties moves to do so. The Lafayette/Plaquemine/Stauffer contract will expire in 1989. GSU will probably not challenge the contract further unless the parties attempt to renew or extend the contract. GSU says that it may eventually attempt to recover some costs or losses if the court confirms the correctness of its position that it was not obligated to wheel the power.

The Parties' Points of View

There are no significant disagreements about the events that occurred in this case. However, the various parties see these events in a different light, and feel that different principles of justice, law, and regulatory practices are most important and should be given precedence.

The investigators were not able to discuss this case with representatives of the Stauffer Chemical Company, although they made serious attempts to do so. We can therefore only assume their point of view from their actions. It would appear that Stauffer, faced with serious financing problems in a difficult competitive market, considered it very important for their survival, or at least for the economic viability of the St. Gabriel plant, to find a lower-cost power source than was being offered by GSU. Therefore, they were pleased to find an acceptable and, in their opinion, legal means of obtaining cheaper power. The most important principle for Stauffer seems to be their right to shop for power in an open market situation.

Plaquemine sees the Stauffer transaction primarily as an effort to keep the Stauffer plant from being shut down. The loss of jobs would hurt

Plaquemine both directly, since some of the employees live in the city or in its surrounding electric service area, and indirectly by the effect of the closing on general economic activity in the area. These are difficult times economically for Louisiana. With several major industries and agriculture in a depressed condition, every job counts. Plaquemine also has derived a substantial direct income from the transaction. Plaquemine considers it an important legal concept that GSU should not be allowed to use its effective monopoly on transmission facilities to prevent competition from others in selling power to industrial customers in GSU's service territory.

Lafayette clearly shares Plaquemine's and Stauffer's views as to the importance of the right to wheel power on GSU's transmission system.

GSU sees an entirely different principle involved: "whether a regulated utility, with the obligation to serve its territory, can be forced to use its facilities to allow a non-regulated competitor to take away its customers." To GSU, the duty to be prepared to serve a customer, and to invest in expensive facilities to do so, is not compatible with the right of competitors to lure customers away with lower prices. To have to provide the use of its own facilities for the transaction makes it particularly wrong in its view. GSU feels that it is left with the obligation and expense of maintaining and operating the transmission system, which often includes running high-cost but strategically located generation to maintain voltages on the transmission lines, so that Lafayette can sell power to Stauffer. GSU has little sympathy for Stauffer's plight, and views it as at least partly due to Stauffer's management. It feels that any special treatment for Stauffer would be prejudicial to Stauffer's competitors.

The Issues

The issues raised by the various parties may be defined as follows.

There is disagreement as to whether the Lafayette/ Plaquemine/Stauffer transaction has really saved jobs. Some, considering the consequences of competition, think that it may have kept jobs with Stauffer but prevented the expansion of a more successful competitor elsewhere. GSU questions whether this transaction is not in effect favoring Stauffer, an enterprise that they say has failed to continue investing in its plant, over other competitors who did invest in their plants to make them less energy intensive and therefore, more efficient.

Another disagreement concerns the true status of Plaquemine as a participant in the transaction. The three participants in the transaction claim that it is three-sided: Lafayette sells to Plaquemine and Plaquemine sells to Stauffer. GSU maintains that this is a sham: Lafayette is selling to Stauffer, and Plaquemine merely adds a legal coloration. The facts are simple. Plaquemine does not participate in any physical action, but it does bill Stauffer and receive and pay Lafayette's bills, and draws a substantial net revenue from its participation. We will not attempt to resolve the legal questions of whether the transaction is two- or three-sided. We will refer to it in this case study as the Lafayette/Plaquemine/Stauffer transaction for identification purposes, and this is not intended to imply our agreement with either side in the dispute.

At the heart of the dispute is the fundamental relationship between regulated utilities, their customers, and the regulating authorities. In the past, the utility was granted a monopoly of supplying electricity to a specific territory; in exchange, it was granted the right to a reasonable profit, and was required to provide adequate service, including the readiness to serve all customers and potential customers in that territory. To do so, it invested large sums of capital in generation, transmission, and distribution. The amount of this investment was one of the principal factors in determining the amount of revenues and profits that the utility was permitted to collect through its rates. GSU maintains that it cannot fulfill its service obligations if, at the same time, a competing non-regulated utility can force GSU to use its transmission facilities and help its competitor "steal away" a customer, leaving GSU with the obligation to continue maintaining the transmission system and even to be ready to take back the "errant" customer anytime the competitor's rates should become higher than those of GSU. The participants in the Lafayette/Plaquemine/Stauffer transaction, on the other hand, point to the value of competition and a free market as a force for reducing the cost of electric power, as it does for other commodities.

GSU's concern about a municipal utility's ability to take away a customer of a regulated utility has been substantially resolved in Louisiana for future cases by the new statute which prevents a repetition of this situation.

Questions of jurisdiction are involved, as in many disputes in this area of jurisprudence. While, in general, the Federal Energy Regulatory Commission has jurisdiction over all bulk power transmission, the specific area of jurisdiction of the Louisiana PSC is still unresolved. There have been instances of the FERC accepting state jurisdiction over intrastate wheeling under limited conditions.

Impediments to Power Transfers

The existence of impediments to power transfers, past, present, or future, is in dispute. For this specific case, there is no impediment to power transfer at this time, since the Lafayette/Plaquemine/Stauffer transaction is being carried out and the power is being wheeled at the participants' request.

Some might contend that GSU's initial refusal to wheel power for the Lafayette/Plaquemine/Stauffer transaction was an attempt to impede a power transfer. Whether indeed this is so depends on one's definition of a power transfer. In parts of this report prepared by others, the distinction has been drawn between "good power transfers" which actually change the generation pattern and power flows of a system so as to increase the total economy of power generation, and others which do not affect the overall generation pattern and, therefore, the overall economy, but only rearrange the amounts that various parties pay, the sum remaining the same.

According to GSU, this transaction is not in the category defined above as "good wheeling." Lafayette, GSU, and other generating utilities in the region all routinely interchange power to increase low-cost generation and decrease high-cost generation until the marginal costs are substantially equal. This is accomplished partly by automatic dispatch systems and partly by bilateral transactions arranged by the dispatchers of the various systems.

If this process is 100% effective, and Lafayette always sells all the surplus power that can physically replace power from a higher cost source, then the wheeling of power from Lafayette to Plaquemine/Stauffer is purely a reallocation of the cost of generation. The power is delivered by Lafayette, along with any other surplus generation, to GSU's transmission system which, along with other interconnected transmission systems, supplies all the loads of the region. Stauffer receives the same amount of power (less some losses) from that same transmission system. This power is fungible, i.e., indistinguishable from other power being transmitted on the common transmission system. If, on the other hand, Stauffer had remained a customer of GSU, Lafayette would generate the same low-cost excess power and deliver it to GSU's transmission system, but this time the power would be sold to GSU or to another interconnected system. Stauffer, on its part, would receive the same amount of power from the transmission system as before, but this time billed by GSU. Since the amount of power going into the transmission system from Lafayette and the amount going from the transmission system into Stauffer would be the same, the overall generation pattern, and therefore the generation costs, would not change. The only difference would be who pays Lafayette for its power sales, and who bills Stauffer for its power consumption, and how much, and the financial effect on Plaquemine.

It may be that the economic dispatch system that involves Lafayette, GSU, and others, is not completely efficient, and that due to various problems, Lafayette does not always generate and interchange power exactly to the extent called for by the overall incremental cost. In that case, and only to the extent of these inefficiencies, the wheeling may have a physical and overall-economic character. However, we would judge that the transaction probably has little physical effect on the overall generation and load flow patterns, and that it should therefore be defined to a very large extent as a reallocation of costs. This type of transaction benefits some parties at the expense of others; no real overall savings are created.

Depending on the point of view of those involved, some of the other circumstances of the situation may be considered power transfer impediments. For example, the new statute that limits the rights of municipal systems to expand beyond their borders may be considered by these systems as a limitation on their ability to transfer power to some potential customers. Assuming that the location and the power usage of these potential customers is not a function of who supplies the power, this restriction would again represent, at most, a reallocation of costs with no overall economic advantage.

Conclusions

It was pointed out earlier that the present situation of the Stauffer case represents no present restrictions on power transfers, and that GSU's initial refusal to wheel would have impeded a fairly pure case of reallocation of costs. Absent any judgement as to whether any of the participants is more worthy of incremental income than any other, there would not be any occasion to make any recommendations designed to increase beneficial power transfers and thus improve the overall economy.

This is not to say that reallocation of costs is, per se, undesirable. Whether it is, or not, is a decision suited to the political process. Our contribution to this controversy can only be limited to clarifying the issues and effects.

In the same context, it is important to recognize the question of principle raised by GSU, referring to the conflict between the "regulatory compact" and the right of every power consumer to shop for the cheapest power. Can, and should, a regulated utility be required to provide reliable service in a given territory if individual customers are free to choose other supplies whenever these offer lower costs? If so, can and should the regulated utility be compensated for the share of its investment made on behalf of that customer, and how can this share be determined? Should that utility be required to provide the use of its own transmission facilities to facilitate this transaction? These are policy questions which need to be resolved in light of the consequences of each alternative solution on the economics and reliability of service to all consumers, including those not directly involved in the controversy.

It would seem, however, important to resolve such questions as raised by the conflict between the general advantage of free market forces on the one hand, and the need for the "regulatory compact" on the other.

Case 3: The Wisconsin Wheeling Case

General Nature of the Case

The focus of this case study is the inability of Wisconsin Public Power Inc. System (WPPI) to obtain long-term firm wheeling from Northern States Power Company (NSP). This central issue is, however, part of a larger relationship between the two entities as players in the bulk power marketplace. This relationship is marked not only by friction, but also by negotiated agreements, such as two short-term interruptible wheeling contracts that now exist between NSP and WPPI.

The central issue in this case has not been entirely settled. Consequently, the parties involved have been cautious in discussing all of the details of the case with the investigators lest this case study affect the final decision.

Background

Wisconsin Public Power Inc. System is a joint action bulk power supply agency created in 1980. Its members are 26 of the 83 municipal utilities in the state of Wisconsin. WPPI itself does not own any of its own generation or transmission facilities, although five of its members own generation. Since its conception, WPPI has sought to minimize the power costs to its members by actively pursuing all of the options open to it. According to WPPI, it has "...sought to purchase power and energy for its loads from the most economic sources of supply available, rather than being restricted to the control area utility for particular WPPI delivery points. WPPI has pursued this objective by investigating supply switches, securing wheeling tariffs or rights with each of the suppliers with which it deals, and by purchasing power and energy from utilities located outside of Wisconsin for portions of WPPI's load for which such power and energy can be used economically. All these actions are designed to lower our members' short and long term costs either directly, or indirectly, by inspiring competition."

All except two of WPPI's members have full or partial requirements contracts with the investor-owned utilities in whose service territory they are located, and have assigned these contracts to WPPI. The cities of Kaukauna and Manasha are the exception. They purchase 60 MW of partial requirements from WPPI for their combined load. WPPI obtains this power through capacity contracts with Wisconsin Electric Power Company (WEPCO) and Cliffs Electric Service Company, and with economy energy purchases when the costs are favorable, from:

- o Cliffs Electric Service Company - Michigan;
- o Madison Gas & Electric Company - Wisconsin;
- o Minnesota Power Company - Minnesota; and
- o Basin Electric Power Company - North Dakota.

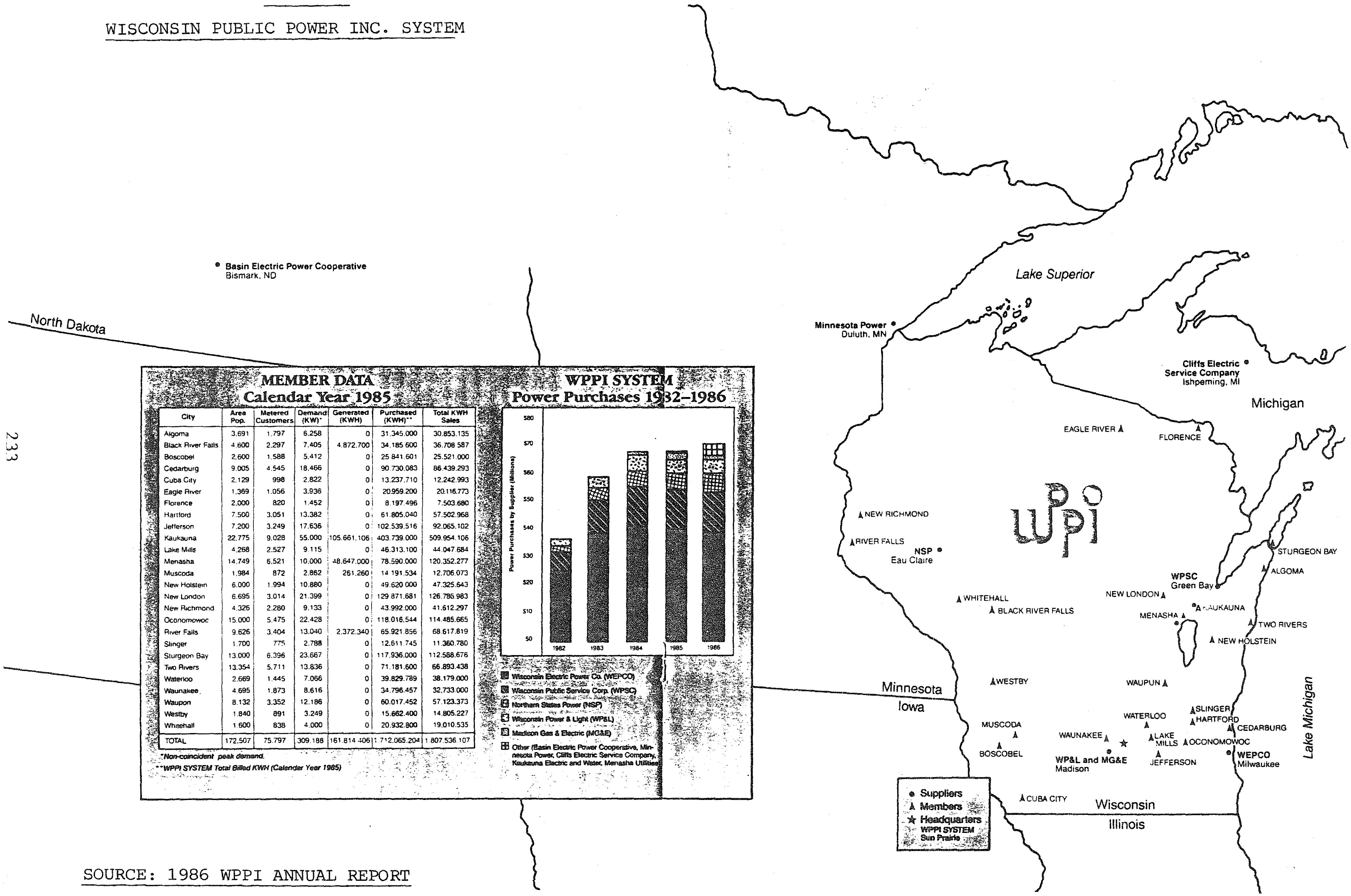
Most of the economy energy purchases are now made from Madison Gas & Electric Company and Basin Electric Power Company (BEPC). These purchases are presently resulting in significant savings for WPPI members. NSP must wheel the energy purchased from BEPC and Minnesota Power Company through its system (See Figures 6 and 7) to eastern Wisconsin where it is delivered to Manasha and Kaukauna by Wisconsin Electric Power Company.

NSP wheels for WPPI under two wheeling contracts that were signed in June 1986. These contracts provide for non-firm interruptible wheeling service to be scheduled on a day-by-day basis. NSP can curtail the wheeling unilaterally at any time on one hour's notice. The contract can be terminated by either party on one year's notice. The service provided under these contracts has, to date, been generally satisfactory. According to WPPI, however, wheeling has been denied on a few occasions, and there have been occasional interruptions of wheeling service.

WPPI is now concerned that the present buyers' market in wholesale power which, until now, has permitted WPPI to make significant savings may eventually dry up as generation surpluses turn into deficits. It is therefore attempting to secure long-term sources of power supply. In many cases, these long-term sources are located to the west of Wisconsin, so that WPPI needs long-term wheeling service through NSP's system to receive their power. According to WPPI, it has attempted to obtain long-term firm wheeling from NSP, but NSP has declined to provide this service on the grounds that the transmission system is not capable of providing it. According to NSP, under the present mode of operation of area generation and existing transmission,

FIGURE 6

WISCONSIN PUBLIC POWER INC. SYSTEM



MEMBER DATA
Calendar Year 1985

City	Area Pop.	Metered Customers	Demand (KW)*	Generated (KWH)	Purchased (KWH)**	Total KWH Sales
Algoma	3,691	1.797	6.258	0	31.345.000	30.853.135
Black River Falls	4.600	2.297	7.405	4.872.700	34.185.600	36.708.587
Boscobel	2.600	1.588	5.412	0	25.841.601	25.521.000
Cedarburg	9.005	4.545	18.466	0	90.730.083	86.439.293
Cuba City	2.129	998	2.822	0	13.237.710	12.242.993
Eagle River	1.369	1.056	3.936	0	20.959.200	20.116.773
Florence	2,000	820	1.452	0	8.197.496	7.503.680
Hartford	7.500	3.051	13.382	0	61.805.040	57.502.968
Jefferson	7,200	3.249	17.636	0	102.539.516	92.065.102
Kaukauna	22.775	9.028	55.000	105.661.106	403.739.000	509.954.106
Lake Mills	4,268	2.527	9.115	0	46.313.100	44.047.684
Menasha	14,749	6.521	10.000	48.647.000	78.590.000	120.352.277
Muscoda	1,984	872	2.862	261.260	14.191.534	12.706.073
New Holstein	6.000	1.994	10.880	0	49.620.000	47.325.643
New London	6.695	3.014	21.399	0	129.871.681	126.786.983
New Richmond	4.326	2.280	9.133	0	43.992.000	41.612.297
Oconomowoc	15.000	5.475	22.428	0	118.016.544	114.485.665
River Falls	9.626	3.404	13.040	2.372.340	65.921.856	68.617.819
Slinger	1.700	775	2.788	0	12.611.745	11.360.780
Sturgeon Bay	13.000	6.396	23.667	0	117.936.000	112.588.676
Two Rivers	13.354	5.711	13.836	0	71.181.600	66.893.438
Waterloo	2.669	1.445	7.066	0	39.829.789	38.179.000
Waunakee	4.695	1.873	8.616	0	34.796.457	32.733.000
Waupon	8.132	3.352	12.186	0	60.017.452	57.123.373
Westby	1.840	891	3.249	0	15.662.400	14.805.227
Whitehall	1.600	838	4.000	0	20.932.800	19.010.535
TOTAL	172.507	75.797	309.188	161.814.406	1.712.065.204	1.807.536.107

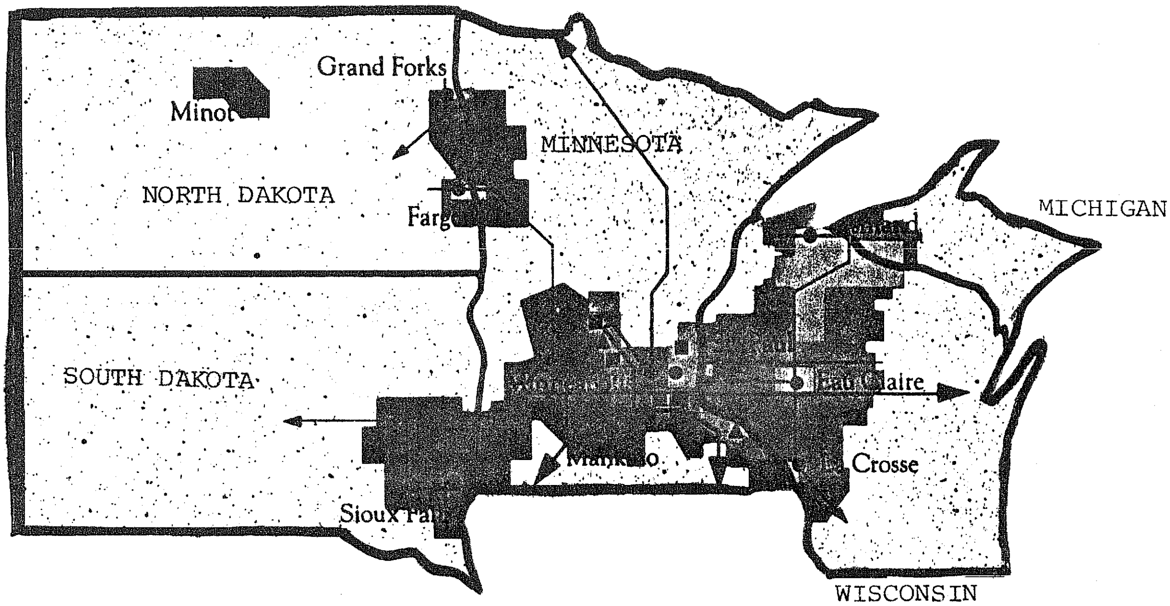
*Non-coincident peak demand.

**WPPI SYSTEM Total Billed KWH (Calendar Year 1985)

SOURCE: 1986 WPPI ANNUAL REPORT

Figure 7

NORTHERN STATES POWER COMPANY SYSTEM



MAJOR CITIES
MAJOR GENERATING PLANTS
NUCLEAR
COAL
TRANSMISSION LINES
500-345 kv
230 kv

SOURCE: 1986 NORTHERN STATES POWER
ANNUAL REPORT

transmission limitations have and continue to occur frequently enough that NSP cannot make any long-term guarantees for continuous transfers of power to eastern Wisconsin.

As can be seen from Figure 8a and 8b, the direct transmission connection between the Twin Cities area and eastern Wisconsin is limited to a single 345-kV circuit running through Eau Claire, Wisconsin, and a few lower voltage lines. Both eastern Wisconsin and Northern States Power Company are, however, interconnected through several indirect paths. The closest of these runs south of the Twin Cities area, east through Iowa and Illinois, and then north along Lake Michigan to the eastern Wisconsin area. These lines do not belong to NSP.

The key question then becomes, "Is the limited connection between NSP and eastern Wisconsin as limited as Northern States Power Company contends?" While WPPI has been very careful not to make any specific accusations, their suspicion is clearly that it may not be and that NSP could be using the technical limitations as an excuse for not providing the requested wheeling. It must be carefully reemphasized that this "suspicion" is the investigators' perception of WPPI's point of view.

The Parties' Points of View: Issues Other than the Availability of Long-Term Firm Wheeling

In order to understand the relationship between WPPI and NSP over long-term firm wheeling, it is important first to understand the other aspects of their relationship. There have been several areas where the two organizations have disagreed. In some cases, they have resolved their disagreements, and in others they have not, resulting in irritation or even friction.

Attempted Long-Term Firm Capacity Purchase

In 1982, WPPI requested to purchase 20 MW of firm long-term generating capacity from NSP. NSP declined to make the requested sale on the grounds that the transmission system to deliver the power to eastern Wisconsin was limited and that the requested sale would require the curtailing of some existing transactions.

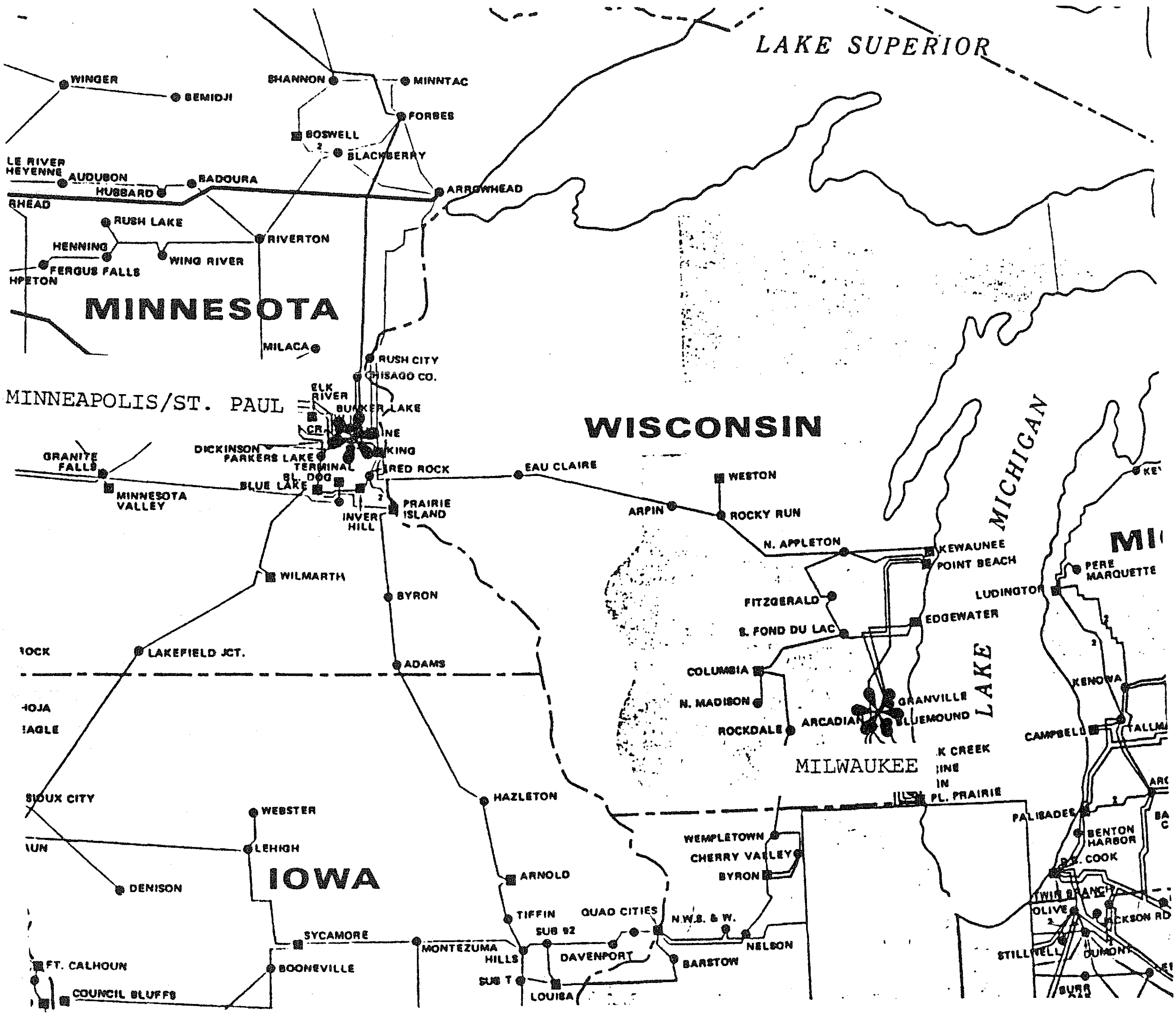


FIGURE 8A

TRANSMISSION SYSTEM
230 kv AND HIGHER

EXTRACTED FROM A MAP OF NERC

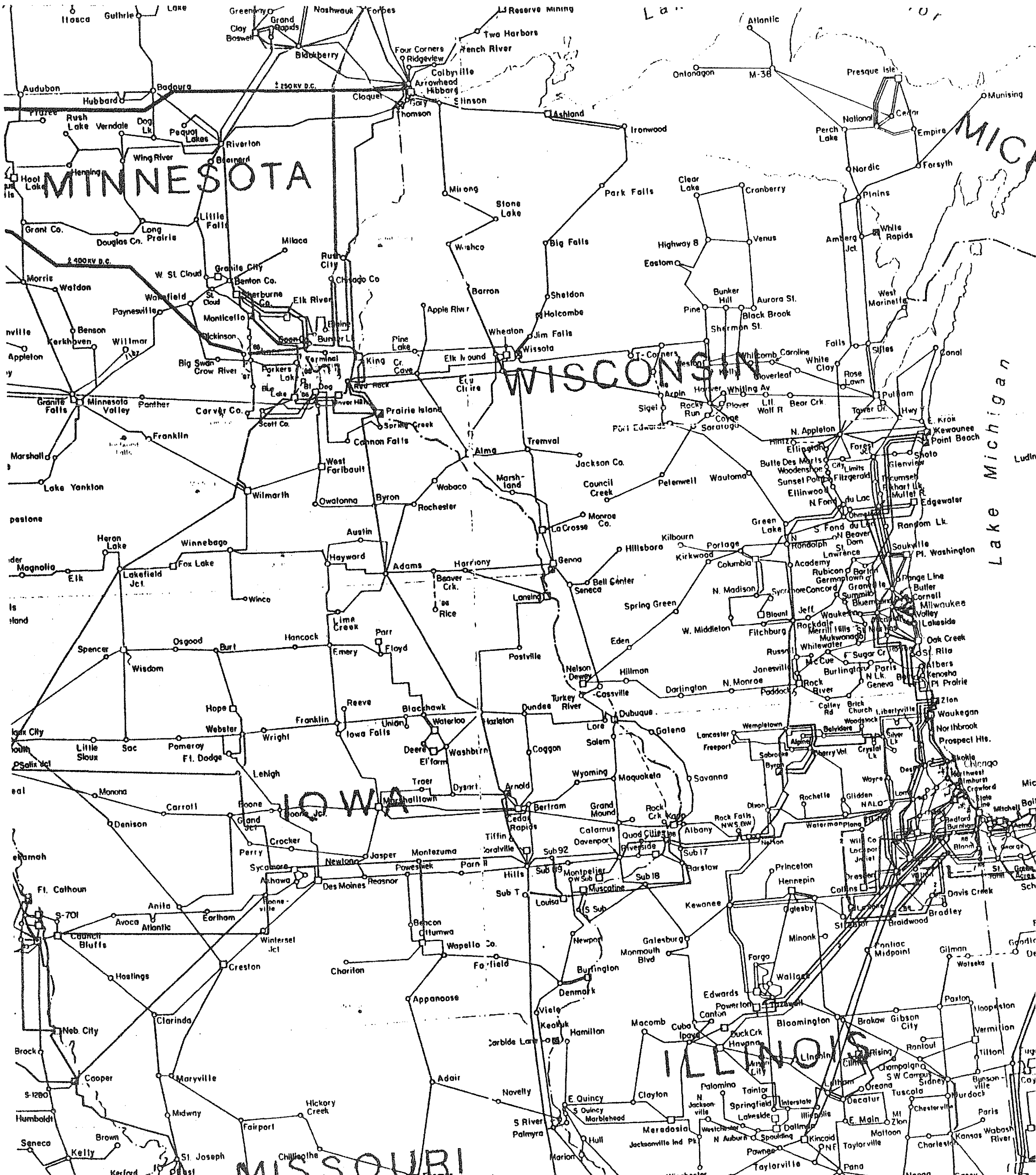


FIGURE 8B

DETAILED TRANSMISSION SYSTEM

115kv AND ABOVE

SOURCE: MAP OF MID-CONTINENT AREA POWER POOL

Wheeling Charges

In the negotiations for the short-term interruptible wheeling contract signed in June 1986, there was a disagreement as to whether or not Northern States Power Company is one company or two companies (NSP-Wisconsin and NSP-Minnesota) for the purpose of determining wheeling charges. This is important because FERC Order 84 limits wheeling charges on a per-company basis; thus if NSP were to be considered two companies, the allowable wheeling charges would be higher than if it were considered a single company.

WPPI's position was that the two-company argument is simply a device by NSP to charge higher wheeling rates. After all, NSP-Wisconsin is a wholly-owned subsidiary of Northern States Power and Northern States Power-Wisconsin is planned and operated on an integrated basis with Northern States Power-Minnesota. NSP's position is that it is, in fact, two separate companies and the wheeling rates should reflect this. The transmission and generation resources of the two NSP companies are owned by the two companies individually and there is an interchange agreement between them. While NSP-Wisconsin is dispatched out of the NSP-Minnesota Control Center, there is a NSP-Wisconsin Operations Center where certain switching and other functions are handled.

The final wheeling agreement treated NSP as two companies and set the charge at 3.9 mills/kWh. From WPPI's point of view, this rate compares unfavorably with the 1.7 mills/kWh short term interruptible wheeling rate that it is receiving from Wisconsin Electric Power Company. According to WPPI, the 3.9 mills/kWh rate is higher than the FERC Order 84 rate would be for NSP treated as a single company, but less than the Order 84 rate if NSP is treated as two separate companies.

Full Requirements Service

WPPI has been trying to position itself so that it is the full requirements customer for all sales eventually destined for its members. NSP has refused to accept this arrangement and has held that it will make embedded costs full requirement sales only to the ultimate wholesale customer and that it will not sell full requirements service to "middlemen" like WPPI. NSP's reasons for this position is that WPPI is a "power supplier who would in turn sell power to its municipal members." NSP considers such a power supplier to be "entitled to NSP's regular interchange service and interconnection agreements, and not municipal wholesale service." The issue was resolved in NSP's favor by the Federal Energy Regulatory Commission in 1983.

The NSP full requirements service contracts are now with the ultimate municipal customer. These customers, however, assign these contracts to WPPI as their agent. NSP's refusal to recognize WPPI as the full requirements customer seems to be one of several sources of continuing friction between the two organizations.

Access to Manitoba Power

Manitoba Hydro (MW), in Canada, has a surplus of hydro power at the present time as well as substantial hydro power resources that can be developed in the future. WPPI is a potential user of both of these, but has encountered obstacles in each case.

Concerning the near-term aspects, NSP, by virtue of its transmission connections with Manitoba Hydro and its contract with Manitoba Hydro, has right of first refusal on virtually all energy not needed by Manitoba Hydro to serve Canadian loads or not committed to other utilities with transmission connections to Manitoba Hydro. NSP makes maximum use of this energy for its own benefit, so that it is in a position to buy and resell any available MH energy that it does not need for its own use and for which there is a customer. WPPI has sensed a reluctance on the part of MH to deal directly with it. It has not pursued the matter actively because it sees no real advantage in doing so, as against its available alternatives to the west. The transmission facilities that carry MH power to Wisconsin are often fully utilized so that the impediments to power transfer appear to be mostly technical in nature, at least in the short term.

For the long term, WPPI would like the opportunity to obtain MH power as one of its future power resources. This would require participation in a new MH power development and associated transmission to bring it to Wisconsin. MH has been negotiating with two groups of utilities, one consisting mostly of Minnesota systems and the other, which includes WPPI, mostly in Wisconsin. WPPI's access to MH power in the future is thus tied in with that of the other Wisconsin utilities. It appears that a competitive situation exists for future MH power and that, if WPPI and other Wisconsin utilities do not obtain this power, it will be because another group's bid was found more attractive by MH.

Refusal by NSP to Sell Economy Energy to WPPI

According to WPPI, NSP "has not in the past expressed serious interest in selling economy energy" to it. NSP's answer to this is that "until a few months ago, WPPI did not ask NSP for economy energy." NSP indicated that it "appreciates the opportunity to pursue a sale to WPPI." The investigators find it difficult to entirely reconcile the two statements, partially because of the guarded way in which the parties involved discussed this dispute. The fact that they do not agree as to whether WPPI asked for economy energy indicates, if nothing else, very poor communication between the two parties. The fact remains that they are now considering the issue of economy energy.

Inability to Avoid Wheeling Charges for NSP-Minnesota

WPPI wants to purchase power from United Power Association (UPA), a Minnesota G&T cooperative which, according to WPPI, has a joint transmission use agreement with NSP-Minnesota and, therefore, avoid the wheeling charge for the NSP-Minnesota portion of the wheeling transaction. This alternative, however, according to WPPI, is now not available because NSP, in arranging its joint transmission use agreements in the Twin Cities area, specifically configured them so as to exclude their use for exporting power eastward. NSP's position is in essential agreement with this WPPI assertion. According to NSP, the joint use agreements (which NSP says have not yet been executed) are for the purpose of serving the load in the Twin Cities area; other portions of the NSP transmission system, such as the very short Minnesota portion of the line from the Twin Cities through Eau Claire to eastern Wisconsin, are specifically excluded from the agreement.

This issue is apparently not resolved. WPPI has expressed an interest in obtaining a credit to its NSP-Minnesota wheeling charge for transmission over third party joint-use transmission facilities.

springs correspond to the power flowing over the lines.

AC Load-Flow

An "AC load flow" is a computer program which calculates the real and reactive powers flowing through the transmission lines of a given network for some specified bus conditions; such as real and reactive power or voltage magnitude and real power. The network's structure and parameters (plus Kirchoff's Laws) yield a set of $2N_b-1$ (N_b = number of buses) simultaneous nonlinear equations. An AC load flow solves these equations iteratively.

DC Load Flow

An approximation called the DC load flow can sometimes be used instead of the full AC load flow. This approximation yields a linear set of equations relating real powers injected into the buses to real powers flowing over the lines.

The term "DC load flow" arose because the linear relationship between injections and line flows is analogous to the relationship between current and voltage in a direct current network which contains only resistors. "DC analog" circuits were used to solve for the line flows in the days before large digital computers were available.

Optimum Load Flow

An optimum load flow is a computer program that tries to find the set of bus power injections, voltage magnitudes, etc., that minimize some criteria subject to constraints. For example, the criterion might be to minimize losses where the real power flow through given lines is not power flowing over a given wire also oscillates at 60 Hz. For most studies, only the time average characteristics of the power is of concern. This "steady state" time average has two components:

- o Real Power: Magnitude of average of power flowing into a load (or out of a generator) which performs useful work.
- o Reactive Power: Magnitude of power flowing into and out of a load (or generator) during one cycle. Time average is zero (sometimes called imaginary power).

The network is designed to carry real power to the loads but both the real and reactive power levels affect the voltage magnitudes and the losses on the lines.

Kirchoff's Laws

Given a set of real and reactive powers injected into the buses, (assuming total generation equals total load plus network losses), the power flowing over individual lines is determined by physical relationships called Kirchoff's Laws. The power cannot be directed to flow over any particular line. Furthermore it is impossible to say (except in special cases) that the power into a given load "comes from" any given generator. In general, a change in injection (say load) at a given bus effects the flows in all the lines on the network; albeit lines "farther away" are effected less.

A crude analogy for power flows on a network is as follows. Consider a set of springs (each representing one line) connected together at the buses. Assume the generator buses "pull down" on the network of springs while the load buses "push up". The resulting tensions on the

APPENDIX A POWER SYSTEM ANALYSIS AND CONTROL

This appendix summarizes some of the key ideas in the analysis of network flows and power system dynamics. It also discusses various local controllers that are on the power plants and scattered throughout the network. Appendix B discusses centralized control and operation.

Section A.1 Network Flows

In general, electric power from the generators flows over a transmission network and through a distribution system to the loads where on a typical large utility:

Transmission: 138 kV and higher voltage

Distribution: 69 kV and lower voltage

Some utilities also define "subtransmission voltages". The following discussions implicitly assume that the transmission system is being discussed. However much also applies to distribution as the physical laws governing both are the same.

A transmission line carries "three phase power". There are three separate wires, each carrying sinusoidal varying current that are 120^{o} out of phase.

A transmission network is modeled for many studies by a "one line" diagram; i.e. there is a single line (on the diagram) presenting all three lines. Buses are nodes of the network where power is injected or removed (or where lines meet). The physical characteristics of each line is represented by impedances (resistance, inductance, capacitance) which depend on the line`s physical structure and length. Other network elements such as transformers are similarly modeled.

The voltages and currents vary sinusoidally. Therefore the real

ECONOMIC IMPEDIMENTS
APPENDICES

The three appendices which follow are a portion of the Economic Impediments paper.

Appendices A and B provide a highly simplified overview of certain aspects of electric power systems that have a bearing on wheeling. The material can provide useful background for the reader with limited a priori knowledge of power systems. Appendices A and B are modified versions of similar appendices to be found in Spot Pricing of Electricity by F. Schweppe, M. Caramanis, R. Tabors and R. Bohn, to be published by Kluwer Press, 1988.

Appendix C contains a summary of the basic equations underlying the rate structure discussions of Section 5. More detailed discussion and mathematical derivations can be found in "Wheeling Rates: an Economic on Engineering Foundation", F. Schweppe, R. Bohn, M. Caramanis, MIT Lees, September 1985, TR85-005. Closely related discussions can also be found in the book "Spot Pricing of Electricity".

1983

March	Hearing on deposition issue held in Court of Appeals.

1984

July 12	Court of Appeals reverses Circuit Court, denies request to take depositions of individual Commissioners.

1985

Oct. 14	Circuit Court for Howard County affirms Public Service Commission's Order.
Nov. 12	Howard County files an appeal of Order to the Maryland Court of Appeals.
Nov. 26	Howard County withdraws its appeal.

1986

Nov.	Land acquisition begins.

1987

March 2	PEPCO files zoning special exception petitions for transmission line and for substation modification in Montgomery County.
March 30	PEPCO files petitions for special exception and variance with the Director of Howard County's Office of Planning and Zoning for filing. Director requests opinion on legal issues from County's Solicitor before processing these petitions.

1979

April 6	Proposed Order issued by Hearing Examiner granting PEPCO's application and designating route of line.
May 5	Appeal of proposed order to full Commission by Patuxent Valley Conservation League, Howard County and others.

1980

March 5	Public Service Commission issues order adopting proposed order of Hearing Examiner.
April 3	Appeal of Commission's order to Montgomery County Circuit Court by the Hanlons.
April 4	Motion for rehearing filed with the Commission by Patuxent Valley Conservation League, Howard County and others.
April 22	Commission recognizes superior jurisdiction of Montgomery County Circuit Court and issues order holding motion for rehearing in abeyance.

1981

May 11	Hanlons withdraw their appeal.
July 2	Commission dismisses motion for rehearing.
July 15-Aug. 3	Appeals by various parties to Circuit Courts of Howard, Montgomery and Prince George's County.

1982

March 29	All appeals consolidated in Howard County Circuit Court.
July 28	Pretrial memoranda filed by appellees.
Aug. 10	Request filed by Patuxent Valley Conservation League to take oral depositions of individual Commissioners who participated in decision granting PEPCO's Certificate.
Aug. 27	Hearings on deposition held in Howard County Circuit Court. Commission asserts that depositions of individual Commissioners can not be taken. Commission loses.
	Commission appeals deposition decision to Court of Appeals.

APPENDIX B

CHRONOLOGY OF BRIGHTON - HIGH RIDGE 500 kV LINE, MARYLAND PUBLIC SERVICE COMMISSION CASE 7004

1976

July 26	PEPCO files application for Certificate of Public Convenience and Necessity for Brighton - High Ridge Line.

1977

April 7	PEPCO files amended application for Certificate of Public Convenience and Necessity for Brighton-High Ridge Line. The amended application reflects a realignment of the preferred route in an effort by PEPCO to satisfy the numerous interests concerned with the construction of the line.
June 29	MD Department of Natural Resources makes initial finding that "no unavoidable adverse impacts have been identified which would necessitate denial of a Certificate of Public Convenience and Necessity" for Brighton-High Ridge Line.
July 11	Hearings begin. Hearings recessed until October 17th so that an alternative route, paralleling an existing 230 kV line, not proposed by PEPCO could be studied.
Oct. 17	Hearings resume. Hearings recessed from time to time to accommodate interested parties.

1978

May 23	Hearings end.
Oct. 3	Applicants' briefs filed.
Nov. 16	MD Department of National Resources makes final recommendation that PSC grant Certificate for Brighton-High Ridge segment. Department specifies route ABJLMNHIJK.
Nov. 20	Intervenors' brief filed.
Dec. 4	Reply brief filed.

Case	Date	Location	Persons Interviewed	Interviewer*
3	7/14/87	Madison, WI	D.M. Dasho Elect. Engr. D. Schoengold Director, System Analysis J.E. Mendl Div. Admin, System Planning L. Smith Dir. of Elect. Bureau T. Nicolai Dir. of Elect. Rates, Public Service Commission of Wisconsin	MEG
3	7/14/87	Madison, WI	L.L. Thilly (Atty) Boardman, Suhr, Curry & Field P. Steitz, Asst. G.M. Wisconsin Public Power Inc. System	MEG
3	7/15/87	Eau Claire, WI	J.L. Larsen Asst. Mgr. Transm. Planning, NSP A.G. Shuster VP, Power Supply, NSP C.J. Moeller Mgr. Power Supply Services Northern States Power Company	MEG

* SRC: Steve R. Cumbow
MEG: Martin E. Gordon
HDL: Herbert D. Limmer

APPENDIX A

LIST OF INTERVIEWS

Case	Date	Location	Persons Interviewed	Interviewer*
1	6/2/87	Baltimore	O.R. Bourland, III, Hearing Examiner PSC of Maryland	MEG, HDL
1	6/2/87	Washington, D.C.	J.R. Templeton, Manager, Energy Planning, PEPCO	MEG, HDL
2	6/1/87	Washington D.C.	W.E. Brand, Esq. Brand & Leckie (Atty for City of Plaquemine)	MEG, HDL
2	6/9/87 6/11/87	Baton Rouge, LA	Roy F. Edwards Chief Auditor Louisiana PSC	SRC, HDL
2	6/10/87	Plaquemine, LA	S.B. Hebert, Mayor M. Albritton, Electr. Supt, City of Plaquemine	SRC, HDL
	6/10/87	Lafayette, LA	Sylvan Richard, Manager LA Energy & Power Authority	SRC, HDL
2	6/10/87	Lafayette, LA	T.J. Labbe Director of Utilities E. Leonard (Atty) Lafayette Utilities System	SRC, HDL
2	6/11/87	Baton Rouge, LA	L.P. Bourne Exec. Asst. to the VP GSU Tom F. Phillips (Atty) F.R. Tulley (Atty) Taylor, Porter, Brookes & Phillips	SRC, HDL

* SRC: Steve R. Cumbow
MEG: Martin E. Gordon
HDL: Herbert D. Limmer

of whether the transmission system is capable of providing such service. This is additionally complicated by the existence of loop flows, different views as to the correct criteria for planning and operating a power system, and different understandings of the term "firm."

The loop flow phenomenon is just one manifestation of the fact that the power system is regional in nature. Events in one state usually affect several other states. For the same reason, major transmission additions must be considered on a regional basis.

Access to Manitoba Hydro power is not one of WPPI's major concerns for the short term. WPPI's access to this resource is restricted by limited transmission connections. The transmission is often fully utilized at present, with NSP using or reselling any energy that is not subject to higher priority commitments by MH. For the long term aspect, WPPI is participating with other Wisconsin utilities in a competition for power from future MH developments.

According to the Wisconsin Public Service Commission staff, the competition at the wholesale level in the State is increasing. This increased competition, however, could make the utilities in Wisconsin more concerned about their competitive position when they meet with other utilities in the state to plan the best transmission system for the state as a whole. The state commission is aware of this possibility. It is instituting a process that will lead to a statewide transmission plan, developed jointly by the utilities, which would approach transmission planning on a combined single-system basis.

NSP's wheeling rates could be an impediment, in the short run, to power transfers. We cannot say if they are unreasonable, but it is clear that they would discourage any interchange where the marginal saving from a transaction is 3.9 mills/kWh or lower.

Resolution of whether or not long-term firm wheeling is in fact really available depends not only on what is meant by "firm" but also on a review of potential future conditions on the power system. A key factor in the resolution of such issues is an agreement among all the parties involved as to what are the proper planning and operating criteria for the system.

We see the relatively weak ties between eastern Wisconsin and the Twin Cities area as the primary impediment to power transfer. An additional transmission line would have to be at high voltage. Therefore it would have a large capacity and be expensive. In most instances, such lines are economically justified only if they will be used over their life for reliability as well as for economic interchanges. This issue is presently being addressed by the Wisconsin Public Service Commission. At the Commission's request, the western Wisconsin and eastern Wisconsin utilities are jointly studying the west-to-east transfer capability limitations. The Commission will closely monitor the progress of the study, but will not participate directly. The Commission is relying upon the utilities to provide the proper input to the study concerning the interstate effects on the power system, and has not indicated any plans to coordinate directly with the Commissions of neighboring states.

The relatively constant 200-300 MW loop flow over the Eau Claire line is not only an impediment to power transfers but also a complicating factor in assigning transfer capabilities. The phenomenon of loop flow is a consequence of the laws of physics and the interconnected nature of the power system in the United States today. The contractual relationship between utilities must take this phenomenon into account.

Conclusions

Above all else, this case illustrates the impossibility of drawing a clear line between the technical and institutional impediments to power transfers. The institutional and economic issue of whether NSP is correct in not providing long-term firm wheeling service is tied to the technical issue the Eau Claire line, even if there are no west-to-east transfers scheduled between NSP and eastern Wisconsin. The balance of the west-to-east transfer capability is allocated first to serving NSP's own loads, then to fulfilling its reliability obligations to the Mid-American Interpool Network of which it is a member, and then last to providing wheeling and economy energy transfers; these priorities are not unreasonable. Whether any firm transfer capability is available depends, from a technical viewpoint, on the many uncertainties that determine transmission capacity and on the need to provide transmission reserves for these uncertainties. For instance, NSP's planning criterion is that, when a line trips out and the flows are instantaneously redistributed throughout the rest of the system, the loadings on the remaining lines should be within their long-term ratings. Obviously the basis for determining these ratings is very important in determining the available transmission capacity. It is impossible to say, however, whether NSP is being overly conservative without fully understanding its power system, how it defines and determines line ratings, and its needed transmission.

Impediments to Power Transfers

There are several possible impediments to power transfers among the issues discussed above. They are WPPI's inability to secure long-term firm wheeling, NSP's wheeling rates, the claimed lack of transfer capability, and the indirect or loop flows. For all of these, the question that must be asked is "Are there advantageous transfers that could be made that are now not being made?" In the case of the long-term firm wheeling versus the short-term interruptible wheeling that is now being provided to WPPI, the answer is, in most cases, no - not at the present time. Whether a particular transfer is labeled as firm or interruptible is, from the point of the view of the system generation pattern, irrelevant. If the same generation pattern exists for a transfer labeled as firm and for a transfer that is labeled as non-firm, then the same transfers are being made. The ability to secure firm transfer capability is, of course, important, but it is important from the point of view of who obtains the benefits; as long as the transmission is used to the limit of its safe capacity, the total benefits are not affected.

The only major direct transmission connection between the Twin Cities area and eastern Wisconsin is the 345-kV line passing through Eau Claire. If the portion of this line east of Eau Claire should trip out, possibly for such reasons as a lightning stroke to the line or damage to the towers, the power flows would instantaneously be diverted to the rest of the network. Without this 345-kV line, the only direct connection is a single 115-kV line which would immediately be overloaded. This line, therefore, is automatically tripped out as soon as the Eau Claire line trips out. This forces most of the flows that had been on the Eau Claire line to be diverted south through Iowa, east to Illinois, and north to eastern Wisconsin. Since NSP has no contractual rights to this transmission path, the transfer schedules would have to be curtailed as soon as possible after the loss of the Eau Claire line. This means that west-to-east transfers cannot be maintained when the Eau Claire line is lost. Thus, if the term "firm" means the ability to maintain the transfers even after the loss of the Eau Claire line, then there is no firm capacity available between the Twin Cities area and eastern Wisconsin. WPPI personnel seem to agree with this analysis. They agreed that, if the 345-kV connection was lost, there would be a problem in maintaining firm west-to-east transfers.

There is, however, no universal definition for the phrase, "firm transmission capacity." The term "firm" has a technical meaning in some cases but is used to establish contractual priorities in others. Technically, it can mean that amount of power that can be transmitted over a path such that if a line is lost, the remaining power system will not be overloaded beyond its emergency limits, the system will remain stable, and voltages will be acceptable. Under the contractual definition, the word "firm" is used to establish the priority of the service being rendered, usually in comparison to non-firm service.

One of the key factors in determining how much firm transmission capacity is technically available is the phenomenon of indirect flows or loop flows. In a large complicated interconnected power system, the power flows divide among the many lines according to their impedances. Flows cannot be directed along a single specific line. Thus, when Commonwealth Edison in Chicago buys power from Iowa, about 15% of this transfer will flow across the Eau Claire line. These indirect flows, resulting from this and other transactions, apparently result in a rather constant 200 to 300 MW flow from west to east on

Lack of Responsiveness

WPPI has characterized NSP as slow to respond to its requests. NSP does not particularly dispute this characterization, but it gives two reasons for its slowness. First, the demands by WPPI were so unreasonable as to constitute harassment and therefore NSP did not feel obligated to respond; second, as NSP is two companies it takes extra time to coordinate a response.

The Parties' Points of View: Availability of Long-Term Firm Wheeling Capacity

The above list is really nothing more than the litany of frustrations on the part of a relatively new joint action agency in trying to establish itself in its dealings with an investor-owned utility which is very careful to look out for its own interests first. Given this history, it is not surprising for WPPI to question whether NSP is using technical impediments as an excuse not to provide a service, in this case long-term firm wheeling, that it may not wish to provide for other, possibly economic, reasons. As possible support for its suspicions, WPPI mentioned an incident that happened several years ago. In 1983, a study entitled, "Report on Transmission Capacity Available on Manitoba-Twin Cities to Eastern Wisconsin System for the Short Range Period," was issued. Initially, the study was to be a joint study by NSP and other Wisconsin utilities, including WPPI. The representatives of the eastern Wisconsin utilities on the Transmission Task Force of the study, however, did not agree with the report and therefore did not sign it. The report was eventually issued as an NSP report only. WPPI's reading of this is that since the eastern Wisconsin utilities disagreed with the report, they therefore disagreed with NSP's technical analysis of the availability of Minnesota-to-eastern-Wisconsin transfer capability. NSP confirmed that such an incident did occur, but characterized the eastern Wisconsin utilities' decision not to sign the report as being based on the fact that most of the analysis in the report was done by NSP. NSP does feel, however, that there is a misunderstanding of the facts about the west-to-east transfer capability and that a lack of communication about how the Wisconsin and Minnesota systems function has contributed to this misunderstanding.

The incremental (marginal) cost of generation is given by

$$\text{Incremental Cost} = \frac{\partial E}{\partial P} = C\,\frac{\partial H}{\partial P} \qquad (\$/\text{kWh})$$

The curves of Figure B.2.1 are smooth functions. In practice, such curves can be much less well behaved. One example is the "value point loading" issues associated with many fossil steam power plants. Incremental heat rate curves for such plants can look like "saw tooth" functions.

Economic Dispatch

The economic dispatch problem is to find the particular output levels for each available generator that minimizes the total fuel costs while meeting all of the loads plus line losses. Because of network losses, less efficient generators ($/kWh) located close to the loads may be used more than more efficient generators located far from the loads. Typically, economic dispatch optimizations are recalculated every 5 to 10 minutes with a linear extrapolation (based on a very short term load forecast) used in between times. "Raise and lower pulses " are sent to some generators every 2 to 20 seconds by the AGC system (See Section B.4).

The equations for economic dispatch are closely related to the marginal wheeling rate equations discussed in Section 5.

Unit Commitment

The unit commitment problem considers longer time scales; say, hour by hour for one day or one week. Not all of the generators are needed at certain times of the day. Unit commitment specifies the daily on/off

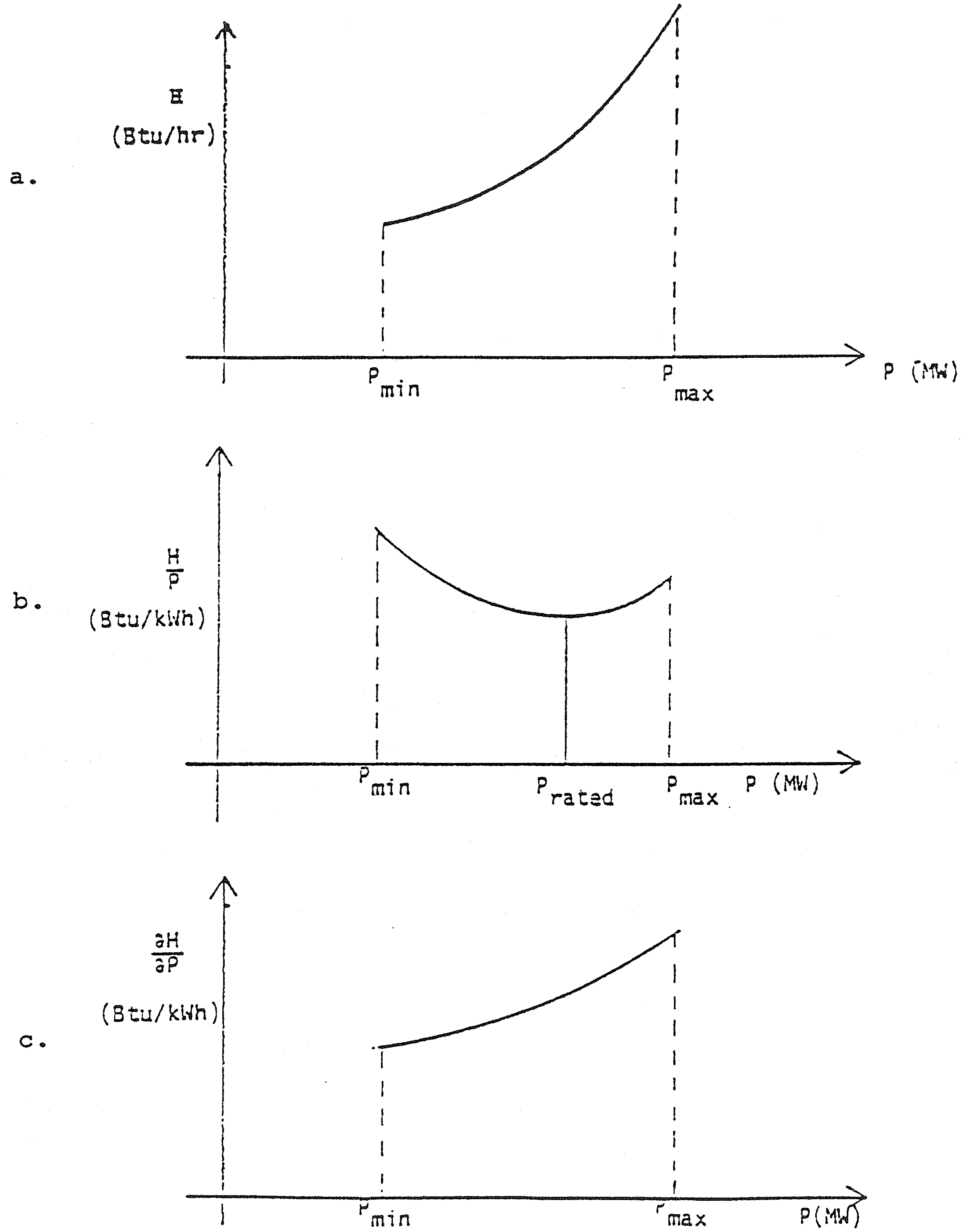


Figure B.2.1
Curves Relating Efficiency and Costs

"heat build up" dynamics.[1] Some types of short range load forecasting models "look different" but (B.1.4) illustrates the basic ideas.

The forecast of (B.1.4) is easy to implement once a weather forecast for hour t is available. In practice, the biggest source of error in short range load forecasts is often the effect of errors in the weather forecasts.

Section B.2 System Economics

Power system dynamics cover time scales ranging from fractions of seconds to many minutes. The system economics functions to be discussed cover time scales which range from 5 minutes to many months.

Economics of Thermal Power Plants

Define for a thermal power plant

H = Heat input into the plant (Btu/hr)

C = Fuel cost per unit of energy ($/Btu)

F = (H) (C) ($/hr)

P = Electrical power output (kW)

Figure B.2.1 shows typical curves relating these quantities with variations in output power; B.2.1a shows the input-output relation of the plant, B.2.1b is the "heat rate" (H/P) where the heat rate is the inverse of efficiency and B.2.1c is the incremental heat rate. The horizontal axis in the three curves is the actual power going into the grid. The total electrical power out of the generator is about 5% higher than P. This extra 5% is used to run the power plant itself (pumps, fans, etc.).

---

[1] Actually other exogenous variables such as an industrial strike, a world series baseball game, etc. can also effect total demand but we restrict discussion to weather and time effects.

independence is a reasonable assumption.

Define

Total Demand d(t): $d(t) = \sum_{k} \sum_{j} d_{jk}(t)$ (B.1.2)

N_d: Total Number of Devices

By virtue of the elemental independence assumption, it can be shown that (to a good approximation)

$$\frac{\text{Standard Deviation of } d(t)}{\text{Mean of } d(t)} = \frac{C}{(N_d)^{1/2}} \quad \text{(B.1.3)}$$

where the constant C is not much greater than one. The fact that N_d for any reasonable sized utility is very large leads to the key and very important conclusion that

- o The randomness introduced by the independent variations of the individual usage devices can be ignored when considering total demand behavior.

Weather and Time Dependence

One simple model structure used for forecasting demand during hour t is

d(t) = Periodic Component plus Weather Dependent Component (B.1.4)

Periodic Component: Time function with 24 hour period.

Weather Dependent Component: Nonlinear function of methodological conditions.

Real world complications have the periodic component varying with day of week and season of year and a weather dependent component that includes

APPENDIX B POWER SYSTEM OPERATION

This appendix summarizes the key functions performed by a modern central control system of a large utility with both generation and transmission. Small utilities and/or municipal or corporative utilities will usually have control systems with fewer functions.

The brains of a generic central control system consist of highly trained operators with extensive digital computer support. There is also an extensive communications system that uses telephone lines and utility owned microwave to gather measurements and information from around the system and to send commands.

Section B.1 Short Term Load Forecasting

A key input to the system economics and security functions (to be discussed in subsequent sections) is a forecast of what future demand will be, say hour by hour for the next week, or day by day for next month or year.

Diversity

Diversity of customer demand is absolutely essential to the operation of today's electric power systems. Define

$d_{jk}(t)$: Demand for electricity during hour t for the jth usage device (air conditioner, motor, lighting, etc.) of the kth billing entity (customer). (kWh)

A key assumption is

Elemental Independence: At hour t and for a given set of meterological (temperature, humidity, etc.) conditions, the $d_{jk}(t)$'s are statistically independent over j and k. (B.1.1)

There are special cases which violate this assumption but, relative to the present level of discussion and for most applications, elemental be started up or a blackout results. Generators have under and over frequency relays which prevent them from operating at too low or too high a frequency for any period of time as such operation can cause vibrations which damage the generator.

Such long term dynamic behavior for a multiple generator system can often be modeled by a basic swing equation like (A.3.1) except that H_j is replaced by the sum of the inertias of all the generators; $P_{mech,j}(t)$ by the sum of the mechanical power outputs of all the turbines; $P_{elec,j}(t)$ by the total load plus losses; and $f_j(t)$ by an average (over space and time) system frequency. Turbine and boiler dynamic modeling is very important for long term dynamics studies while the faster transients considered in transient and some dynamic stability studies are usually ignored. Long term dynamic studies can last from seconds to many minutes. They are usually done by numerical integration of the nonlinear differential equations. Only a relatively few AC load flows are needed.

It is usually studied and analyzed by linearizing the nonlinear differential equations such as those used in transient stability studies about an operating point and then doing "eigen value - eigen vector" analysis. In general, dynamic stability involves slower dynamics than transient stability. Turbine dynamics are usually included while boiler dynamics are usually ignored.

Long Term Dynamics

Long term dynamics looks at transients that are much slower than either transient or dynamic stability. To illustrate consider a two-generator system where

At t = 0 -, Both generators supply the load

At t = 0, Generator 2 is tripped off due to some fault, then

At t = 0 +, Generator 1 supplies all the load using the inertial energy stored in the rotating turbine and generator.

This causes the frequency at Generator 1 to drop.

The mechanical input power of Generator 1 then increases due to turbine action using thermal energy stored in the boiler of Generator 1 to try to match the electrical load. The firing rate of the boiler at Generator 1 then increases to try to reach a level which can meet the electrical load.

If the turbine and/or boiler does not respond fast enough, load-shedding, under-frequency relays drop some load in order to decrease the rate of frequency drop, giving the turbine and the boiler more time to increase mechanical power. The dropped loads are energized again one by one. Finally, a new steady state is reached. If Generator 1 is not large enough to meet all of the load by itself, other generators have to power input to the jth generator cannot change within cycles, the right side of the swing equation is positive. This implies a positive acceleration, i.e., the jth generator starts to speed up relative to the rest of the system. If the fault is not cleared in time, the generator's speed (frequency) increases so much that it "pulls out of step," i.e., losses synchronism with the rest of the system.

The crude spring analogy for line flows discussed in Section A.1 can be extended to give a "feel" for transient stability. Assume a mass is hung on each bus with a generator and, for simplicity, that the load buses remain fixed. A fault has the effect of giving one or several of the masses (generators) an initial velocity. The resulting motion of all of the masses (and tensions on the springs) is similar to the swings between the actual generators.

Transient stability is usually studied by numerical integration of the nonlinear swing equations plus other differential equations of the generator-voltage regulator models. An AC load flow is done at each time step to evaluate the effects of network coupling between the generators and loads. Boiler and turbine dynamics are often ignored. For large interconnected systems (say more than 100 generators), such numerical integrations can run much "slower than real time" even with powerful digital computers.

Dynamic Stability

Large interconnected power systems with relatively weak transmission links can exhibit small amplitude, low frequency (1 to 10 second period) sustained oscillations. This is called the dynamic stability problem.

equations. The dynamics of the network are so fast compared to the dynamics of the generators that the steady state model is assumed to hold during transients; i.e., the network transients are usually ignored.

Load Dynamics

Load dynamics are not really understood and so are usually modeled algebraically, i.e., transients are ignored. Typical models are; constant impedance, constant power, frequency sensitive, and voltage sensitive.

Section A.4 Power System Dynamics

Three types of power systems dynamics with different time scales of concern are discussed.

- o Transient Stability: Very fast; cycles to ten seconds. Nonlinear.
- o Dynamic Stability (also called Steady State Stability or Small Signal Stability): Slower; 1 to 10 seconds. Linear.
- o Long Term Dynamics (also called Slow Speed Dynamics): Slowest; seconds to minutes. Nonlinear.

Transient Stability

If a short circuit occurs on a transmission line, the protective relays "clear" the fault within cycles, as discussed in Section A.2. During this time, the abnormal conditions cause mechanical transients in the generators which are governed by the swing equation (A.3.1). If the jth generator is close to the fault, then as long as the short circuit exists, its electrical power output is zero (or very small), because it is trying to supply a load with zero impedance. Since the mechanical is controlled is to visit one.

A.3 Mathematical Models for System Dynamics

Power Plant Dynamics

The number of differential equations used to model the boiler of a steam power plant and its controllers varies from 2 to 200. Time constants for boiler transients range from seconds to 20 minutes.

A turbine is often represented by 2 to 4 differential equations whose time constants range from 1 to 15 seconds.

The generator (with excitor and voltage regulator) is often approximated by a set of 2 to 5 differential equations with time constants from 0.01 to 0.1 seconds.

A key equation of motion for the jth generator is given by Newton's second law to be

$$H_j \frac{df_j(t)}{dt} = P_{mech,j}(t) - P_{elec,j}(t) \tag{A.3.1}$$

H_j: Inertia of the generator rotor and turbine

$f_j(t)$: Frequency of generated power which is close to being proportional to the speed of rotation of the generator

$P_{mech,j}(t)$: Mechanical power from the turbine to the generator

$P_{elec,j}(t)$: Electrical power from the generator to the grid

This equation is known as the "swing" equation.

Transmission Network Dynamics

As explained in Section A.1, a transmission network in steady state can be represented by algebraic equations; i.e. the AC load flow

Power Plant Relaying

Relays are used to protect the power plants by "turning off the plant" when they sense a problem. Because of the massive capital investment associated with any given power plant, these relays are set conservatively; i.e., it is better to "cry wolf" than to damage the plant. It is the job of the central controllers discussed in Appendix B to make sure that the sudden loss of any one power plant does not effect the service being provided the customers.

Power Plant Controllers

The power plant operators are the most important controllers. A modern power plant control room has a vast array of displays and switches for the operators' use. Digital computer driven display and diagnostic systems are playing an ever increasing role.

There are also many automatic control loops within a power plant. To illustrate, consider a fossil steam power plant.

The voltage regulator controls the excitor in order to maintain output voltage magnitude at the desired set point.

The governor controls the steam flow into the turbine so that the frequency does not drop "too much" as load increases (as will be discussed in Appendix B, the local power plant governors do not attempt to maintain exactly 60 Hz).

Boilers have extensive automatic firing control loops to maintain pressure and temperature within acceptable limits while providing the needed steam flow to the turbine.

The best way to really appreciate what a power plant is and how it

The following is one possible sequence of events:

At t = 0 the short circuit occurs.

At t = 4 cycles,[1] each relay determines the location of the fault.

At t = 8 cycles, relays R3 and R4 open circuit breakers C3 and C4.

At t = 0.5 sec,[2] relays R3 and R4 reclose circuit breakers C3 and C4.

At t = 0.5 sec + 8 cycles, relays R3 and R4 reopen the circuit breakers if the fault is still there.

The circuit breakers C1 and C2 did not trip because their impedance relays R1 and R2 determined that the fault was not within their zone of protection. In this example, the fault is in the zone of protection of R3 and R4, but not R1 and R2. However, if C3 and C4 fail to open for some reason, R2 will trip circuit breaker C2 after a preset time delay.

Network Controllers

Tap changing transformers, switchable capacitors, synchronous condensers, etc. may be installed at various points on the network to help control voltage magnitudes. Many of these operate automatically under their own local controllers which adjust the taps, switch the capacitors, etc. to try to maintain the voltage magnitudes near some prespecified set points. The set points are adjusted as needed by the central control system discussed in Appendix B.

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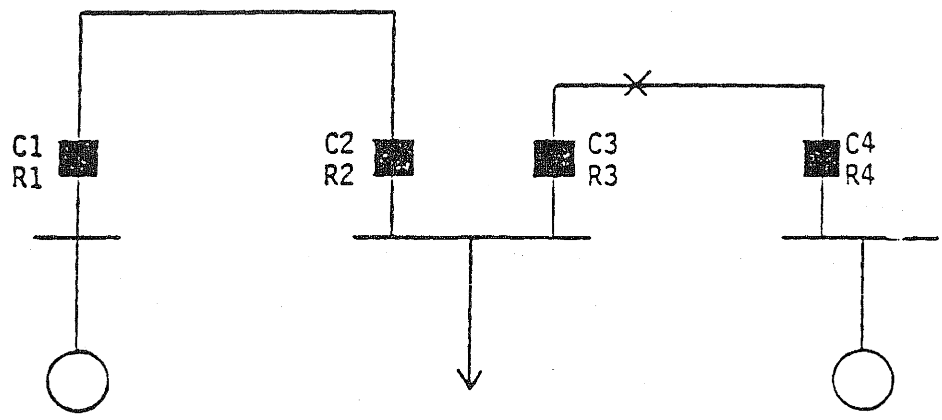
1 A cycle is a measure of time equal to 1/60 second assuming the power system operates at 60 Hz. In many parts of the world, power systems operate at 50 Hz.

2 The ionized path from the line to ground should go away in 0.5 seconds.



X: Location of Fault

Figure A.2.1

Three Bus System Used to Illustrate Protective Relaying allowed to exceed prespecified values. Optimum load flows can be important in system operation relative to economics and security (see Appendix B).

Section A. 2 Local Controllers

A power system is controlled and operated by a hierarchy of local and central control systems. Local controllers at the individual power plants and scattered throughout the transmission network are discussed in this section. Distribution network local controls are somewhat different. Higher level central controls are discussed in Appendix B.

Network Relaying

Relays are extensively used on the network. A relay contains the logic that decides to open or close a circuit breaker if certain locally measured conditions are met. Two commonly used network relays are overcurrent relays and impedance relays.

To illustrate the sophistication of network relaying, consider the three bus network of Figure A.2.1. Four circuit breakers C1 to C4 are shown. Each has an associated impedance (also called distance) relay, R1 to R4, which detects the presence of a "fault" and estimates its location by measuring the voltage and current at the relay's location. The 'x' on the transmission line of Figure A.2.1 represents a fault, which in this case is a short circuit due to a lightning strike which established an ionized electrical path for current flow to ground (or between phases). This path is sustained if the potential difference between the line and ground is high enough.

and maintenance scheduling. It also allows for central control of operating reserves and system security.

In practice most power pools actually use a hierarchal control structure in place of a single central control system. A central power pool center coordinates the actions of separate utility level (or multiple utility level) central control systems.

Power pool operation requires the use of some mechanism to balance the books; i.e. to transfer funds between the pool members so they pay or are paid for energy obtained from or sent to other pool members. One approach involves variations on the split the difference formulas used for independent operation. A more sophisticated approach uses the concept of an "own load dispatch." With this approach, the power pool central office determines, say each week, how much each utility ought to receive or pay for the energy transactions performed during the week by evaluating:

- o The cost of running Utility A in a way that it would meet its own load without purchases from or sales to the pool.
- o The actual costs Utility A has incurred.

These numbers determine the amount of money that Utility A receives or pays.

Power pool operation does not stop members from having separate long term contract arrangements among themselves. For example, Utility A may agree to sell Utility B the output from a given plant for a period of one year. Then the two utilities simply inform the power pool office of the arrangement, so that the capacity of A is decreased and the capacity of B is increased by the same amount. System operation is not affected.

Most electric utilities in the US are operated as part of an interconnected grid to

o Allow purchases and sales which are beneficial to all.

o Provide mutual support during emergency conditions.

There are various degrees of interconnected cooperation. Two extreme cases are discussed; independent operation and power pools.

Independent Operation

Consider a bevy of independent but interconnected utilities. A wide variety of economic transactions can occur between them.

Economy: If Utility A's marginal operating cost λ_A (\$/kWh) is greater than Utility B's λ_B for the next hour, Utility A may purchase energy from Utility B instead of generating the energy itself. The price is often based on a split the difference rule; i.e., the sale price is $(\lambda_A + \lambda_B)/2$. Such economy transactions take place each hour and are made by telephone calls between the system operators. Utility A may be buying from Utility B while simultaneously selling to Utility C.

Contracts: A wide variety of longer term purchase and sale contracts are negotiated between utilities. Examples are firm contracts for a fixed amount of energy for the next day; contracts for the right to buy energy for the next day; and contracts for the percentage of the output of a given power plant for the next year.

Power Pool

A simple power pool uses a single central control system that determines how energy is to be dispatched from all the utility members' generators to minimize the total operating cost of all the utilities in the pool. This enables centralized economic dispatch, unit commitment, Each utility raises or lowers its overall generation proportional to the time integral of its own ACE(t). We will not go through the analysis here, but the overall result is the desired behavior.

The beauty of this control logic is that each interconnected utility's AGC system uses only measurements made on its own system. The only overall interconnected system coordination needed is to make sure each utility's net scheduled interchange is correct; i.e., that they all sum to zero.

The AGC systems make no attempt to control individual tie line flows (unless there is only one tie line). An AGC system controls only the sum of the tie line flows.

Control of Time

The AGC systems keep the overall system frequency close to nominal but time, as measured by the integral of frequency, can drift. Thus one utility is assigned the task of comparing the integral of frequency to a time standard and sending time correction signals to the other utilities say once or twice a day. In normal operation, USA utilities try to keep the difference between the integral of frequency and true time to within 3 seconds (usually it is much closer but in rare cases it can be much worse). In general, electric clocks tend to run a little slow during the day and a little fast at night.[5]

[5] This makes the working hours for most people a little longer than they should be; unless they use their own watches.

electrically interconnected. Because of short term economy transactions and longer term contracts (see Section B.5), each utility specifies its net scheduled interchange; which is the total amount of power that is to flow out (in) along the tie lines connecting the utility to its neighbors.

Consider two Utilities, A and B. The role of Utility A's AGC system is

- o In normal conditions, to maintain the sum of the power flowing out (in) over all of Utility A's tie lines close to Utility A's scheduled net interchange. Thus if Utility A's generation is greater than its total load plus losses plus its scheduled net interchange, Utility A's AGC reduces Utility A's total generation.
- o To maintain frequency close to the desired 60 Hz.
- o Under emergency conditions when Utility B has lost a major power plant(s) due to local relay actions, to increase Utility A's generation to provide emergency support by increasing power flow into Utility B. This energy is paid back by Utility B later on.

Utility B's AGC system works the same way.

This seemingly difficult control task is accomplished by having each utility compute its own area control error (ACE) given by

$$ACE(t) = B[f(t) - f_o] + P_{TL}(t) - P_{sch} \qquad (B.4.1)$$

where

$P_{TL}(t)$ = Sum of all tie line power flows (measured and communicated to the central control system in real time)

P_{sch} = Net scheduled interchange

$f(t)$ = Locally measured frequency

f_o = Desired frequency

B = Frequency bias setting.

to loads by a network that is not electrically interconnected to other utilities. In this case the role of the AGC is to

o Keep frequency close to the desired 60 Hz

Each power plant has a governor[3] which uses locally measured electrical frequency (or turbine speed) to increase energy output when frequency goes down (i.e., when the mechanical power driving all the turbines is less than the power delivered to the loads and losses). These governors are built with a "droop" characteristic. Thus, if frequency is initially 60 Hz, then after an increase in load, generation increases to meet the new demand but the resulting frequency is less than 60 Hz. This droop characteristic is needed to prevent the local, independent governors from fighting each other.

For an isolated utility, the AGC readjusts the set points of the local governors to bring frequency back to the desired level. Raise and lower pulses may be sent to the local power plant governors,[4] every 2 to 10 seconds.

Choice of a particular power plant's share in any needed total energy output change is determined by the economic dispatch logic of Section B.2. Thus, in addition to maintaining frequency, the AGC also tries to keep the generation levels as close to the optimum economic dispatch as possible.

Interconnected Operation

Life gets more interesting when several independent utilities are

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[3] Governor action may not exist on large base loaded units.

[4] In practice, only certain power plants are usually under AGC. Base load may not see AGC signals. Neither do most gas turbine peaking plants.

power in less than 10 minutes.

System Dynamics

System dynamics, as discussed in Section A.4, cannot be ignored. In practice, however, little in the way of real time modeling and analysis is done to protect the system from undesirable dynamics.

Transient stability problems have time constants that are too fast for a central system to handle (today's technology). Conceptually, transient stability contingency analyses could be done on line but, in practice, suitable models are not available. Dynamic stability contingency analyses could conceptually be done on line but are rarely implemented. Instead, off line, planning type studies of transient and dynamic stability can lead to transmission line flow limits which are then handled in the various system security functions just as if they were, for example, thermal line overloading limits.

Long term dynamics (which determine the required operating reserve) are usually not evaluated by any on line mathematical model either. Operating reserve requirements are usually based on predetermined rules developed from engineering judgement and off line planning type studies.

Section B.4 Automatic Generation Control (AGC)

Automatic generation control[2] (AGC) provides a bridge between the power system dynamics and the economic-security functions of Sections B.2 and B.3.

Isolated Utility

Consider an isolated utility whose power plants are tied together and

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2 Also called load frequency control (LFC).

Contingency analysis has to consider the effect on other interconnected utilities. For example, the line flow changes within a given utility resulting from a line outage within the utility depend on the status of the network and generation patterns of the other interconnected utilities. In the case of extreme dependence, the neighboring utilities may share real time information on the state of their respective systems. Otherwise external equivalent models are used (developed from off line studies or identified from measurements).

<u>Operating Reserves</u>

The term "operating reserves" denotes the generator reserve the utility has to maintain to prevent blackouts (or major frequency and/or tie line flow deviations) in case of the sudden loss of some generation or tie line support.

To understand the operating reserves problem consider again the three-plant example of Figure B.2.2. If Generator #1 fails at 4 am, a blackout will occur as no reserve generation is available to take over. Operating reserves is one way to avoid this. If Generator #2 shares the load with Generator #1, but is not at its maximum output, failure of Generator #1 at 4 am might not cause a blackout, if the operating reserve of Generator #2 is large enough and can react fast enough.

Operating reserve is sometimes associated with spinning reserve. However, the term "spinning reserve" actually refers to generators which are connected (synchronized) to the network but which are not operated at their maximum output levels. In practice, utilities may also maintain other types of operating fast-acting reserve such as fast start gas turbines, pumped and regular hydro, etc. which can be brought up to full system if transmission lines are overloaded or voltage magnitudes are not acceptable. This is usually done by rescheduling the power generation and/or adjusting generation voltage magnitudes, tap changing transformers, switchable capacitors etc. Sometimes it is necessary to shed loads.

Such rescheduling of real power generation and voltage magnitude can be done using an optimum load flow (see Section A.1) which minimizes total operating costs subject to the network constraints. However, in practice, it is often done by combining sensitivity analyses with operator judgement.

Contingency Analysis

Contingency analysis addresses "what if" questions concerning potential failure of an important part or parts of the system, e.g., how would a transmission line outage affect the rest of the network? In principle, the analysis is simply an AC load flow program that is run assuming various prespecified, possible transmission line outages. If these simulations show that a line is drastically overloaded by some outage, the operators can apply corrective control before the fact so that, if the event happens, the rest of the system will not be in danger. Obviously, there is a trade off in doing corrective control just in case something happens. By doing so, the system is more reliable but, by definition, is no longer dispatched in the most economical way. Often corrective control is not actually applied before the fact since outages are not too frequent. The contingency analysis simply gives the operators a priori guidelines on how to proceed in case a key outage does occur.

Voltage magnitudes, power flows (real and reactive), circuit breaker status (i.e., open or closed) are monitored by measuring instruments scattered throughout the system. These measurements are sent to the central control system using the real time communication system.

The information received is processed by digital computers and presented to the operators via display monitors. The computer compares the incoming measurements with previous ones and upper and lower operating limits. It warns operators in case of irregularities in the data or measurements that lie outside of safe operating regions.

State Estimation

State estimation is a procedure which converts network measurements into an estimate of the state variables, i.e., the voltage magnitudes and phase angles at the buses. Redundant measurements are used to counter the effect of metering errors and bad data arising from, say, meter failure. The most common criterion consists of minimizing the weighted sum of squares of the differences between the measurements themselves and the values of the measurements as computed from the estimated state variables. A state estimation program can be viewed as a type of AC load flow.

System monitoring can be done using the estimated network conditions rather than the raw measurements. For example, once the state variables have been estimated, it is easy to compute all the line flows and to test whether they and all the voltage magnitudes lie within safe operating regions even if they were not directly measured.

Corrective Control Actions

Corrective control involves changing the operating conditions of the maintenance taking into account seasonal demand variations, availability of maintenance crews, etc. A maintenance schedule determined in January for the rest of the year may be changed completely in April if a major power plant is forced out in April and requires extensive emergency maintenance. This can affect maintenance on other plants (as well as the forced out plant).

Maintenance scheduling optimization is of the integer programming type. However, it is usually done using heuristic optimization logics and/or the judgement of experienced operators.

Maintenance scheduling can be combined with nuclear refueling decision logics (for a utility with nuclear power plants that is). Nuclear refueling optimization involves complex nonlinear relationships covering long term fuel cycle costs (which can span several years). For many nuclear power plants, maximum capacity is reduced at the end of a fuel cycle if it is desired to get the most energy out of the fuel.

Section B.3 System Security

Section A.2 discussed local relay logics which act to avoid damage to the equipment. This section discusses system level procedures used to protect the system in the event of a failure. As an example, assume a heavily loaded transmission line is automatically withdrawn from the system by local protective devices. If the overall system is not prepared for such an event, other lines may become overloaded, and their overload relays may trip them out of the system as well. This could cascade into a blackout.

System Monitoring

erosion of river banks, to allow irrigation of cultivated areas downstream, to allow navigation, for sewage control, etc.

Weather Conditions (short term): If a storm is forecasted, the water level of a reservoir and the rate of water flow may have to be constrained to prevent floods.

Weather Conditions (long term): Snow falls in the mountains and the depth of the snow pack influence hydro operation many months into the future.

There is no standard optimization logic for hydrothermal scheduling because each system is different. One approach involves iteration between a pure thermal optimization (for a fixed hydro schedule) and a pure hydro optimization (for a fixed thermal unit commitment).

Pumped Storage

Pumped storage hydro plants present special economic scheduling problems. A typical one week schedule starts on Monday morning with a full reservoir. Some of the water is used to help meet Monday's peak demand. On Monday night, thermal plant energy is used to partially refill the reservoir. This cycle is repeated throughout the week until by Friday afternoon, the reservoir is at its lowest allowable level. The reservoir is then completely refilled over the weekend. Pumped storage decisions can be built into the unit commitment logic.

Pumped storage can be used to reduce the peak demand seen by the thermal generators; to help compensate for thermal start up costs and limited ramp rates, etc.; and for operating reserves.

Maintenance Scheduling, Nuclear Refueling

Power plants have to be removed from the line for routine maintenance (2 to 4 weeks per year for a large fossil power plant). This leads to maintenance scheduling which looks a year in advance to schedule particular system. System operators with experience and a good knowledge of the system can be very effective. Alternately, heuristic optimization logics are incorporated into a computer program.

Dynamic Programming: Conceptually dynamic programming is tailor-made for the unit commitment problem as it is an ingenious way of finding the optimal path between two states given a finite number of possible paths. However, pure dynamic programming introduces dimensionality problems. In practice, a combination of dynamic programming and priority list heuristics can yield an excellent computer program.

Fuel Purchases

Most utilities purchase some or all of their fuel (e.g., oil and coal) on the open market. This leads to another type of optimization problem. Issues related to determining fuel contracts and purchases include: prices of different suppliers, transportation costs, storage capabilities, purchasing conditions, etc. Fuel contracts can be signed for time spans of months and years with possible provisions for small weekly adjustments. Linear programming can be an effective tool for optimizing fuel purchases.

Hydrothermal Systems

The economic operation of a system with hydroelectric as well as thermal plants is much more complicated than that of a pure thermal system. Hydroelectric generation introduces a large number of new technical, economic and social constraints such as:

Variation of Water Levels in Reservoirs: A large variation can hurt recreation facilities that developed in the area and have adverse impacts on lake life.

Rate of Water Flow: Flow rates are constrained to avoid fish kill,

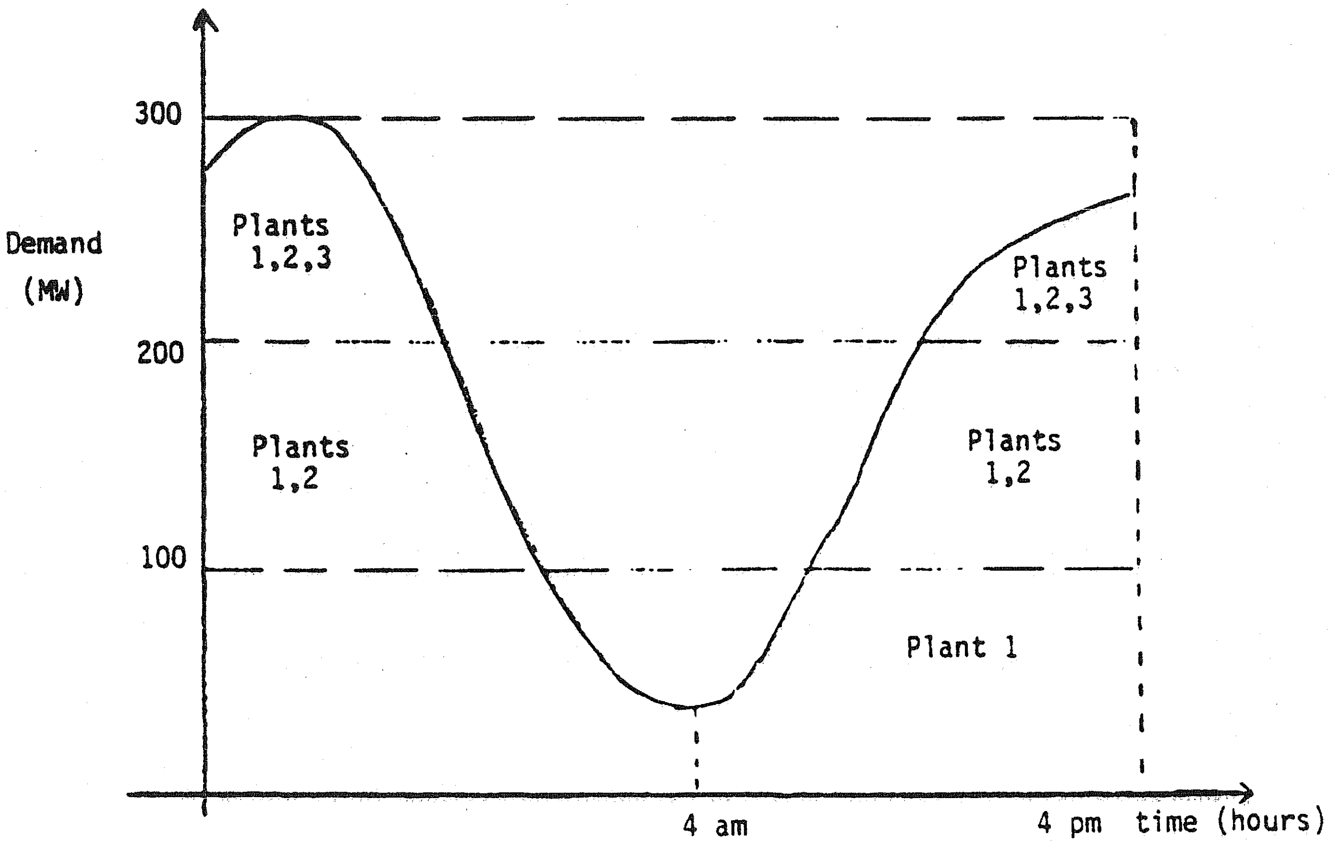

Figure B.2.2
Simple Illustration of Unit Commitment

schedule of generators.

A simple example is illustrated in Figure B.2.2 for a system with three generators each rated at 100 MW. If the operating costs of the power plants increase from Generator #1 to Generator #3, the most economical way to operate the system is as shown in Figure B.2.2.

The simple picture of Figure B.2.2 becomes more complicated when real life constraints regarding each generator are considered such as:

Minimum Up Times: The generator must run for a minimum time.

Minimum Down Times: If shut off, the generator must remain in that state for a minimum time.

Start Up Costs: It takes fuel to heat up a cold boiler.

Ramp Rates: It takes time to go from zero to full load.

Crew Availability: If a plant has two or more generators, the operators may be able to start only one at a time.

There are also system wide constraints such as transmission line capacity limits and the need to carry operating reserves (see Section B.3).

Taking all the real world constraints into account, unit commitment becomes a very complicated problem. Note that economic dispatch is a subproblem of unit commitment; i.e., in theory, for each possible combination of generators that can supply the load, an economic dispatch must be run.

Two of many approaches to the unit commitment problem are discussed.

Priority Lists: Given a set of power plants and their operating costs, the generators with cheapest operating costs are first committed as much as possible. The effects of the constraints are then incorporated. This heuristic method requires a lot of insight about a

m_{buy}: Value when utility is buying from customer

It can be shown that after a few approximations

$m_{sell} = - m_{buy}$

so that if

$\rho_{sell,k}(t)$: Spot price for selling energy to customer

$\rho_{buy,k}(t)$: Spot price for buying energy from customers

then

$$\rho_{sell,k}(t) = (1 + m) \ [\gamma(t) + \eta_k(t)]$$

$$\rho_{buy,k}(t) = (1 - m) \ [\gamma(t) + \eta_k(t)]$$

If m = 0.2,

$$\frac{\rho_{sell}}{\rho_{buy}} = \frac{1.2}{.8} = 1.5$$

which is a 50% difference.

Section C.8 Spot Wheeling Rates

Section 2 of the main text defined four types of wheeling. Type IV wheeling between a private generator and a user usually is "bus to bus" wheeling; i.e. only two buses (nodes) of the network are involved. The other types usually involve "area to area" (as in Type I, utility to utility) or "area to bus" wheeling wherein many buses of the network are involved. The discussions to follow consider only the bus to bus case. The area cases are more complicated but the same basic concepts apply.

Spot prices vary over space to reflect the different values of electric energy at different buses. Given this spatial variation, a "reasonable way" to specify a bus to bus wheeling rate is

$$\rho_k(t) = (1 + m)\ \tilde{\rho}_k(t)$$

The reconciliation multiplier is a constant which is adjusted until the expected annual revenues equal the annual target revenue. Thus the value of m is specified by the condition.

$$(1 + m) \sum_{t=1}^{8760} \sum_{k} \tilde{\rho}_k(t)\ d_k(t) = \text{(Annual Target Revenue)}$$

where the left hand side should actually be written in terms of the expected value of $\tilde{\rho}_k(t)\ d_k(t)$. If demand response to price is considered, $d_k(t)$ is a function of $\rho_k(t)$ which is a function of m so an iterative solution for m is required.

Section C.7 Buy Back Rates

PURPA requires that a utility "buy back" electric energy from its customers. Thus an hourly buy back spot price is needed. The operating and quality of supply hourly spot price components are independent of whether the customer is buying from or selling to the utility. However, revenue reconciliation destroys this symmetry. Revenue reconciliation increases the hourly buy back spot price when the utility is over recovering revenue and vice versa.

In Section C.6, the hourly spot price with revenue reconciliation is

$$\rho_k(t) = (1 + m)\ (\gamma(t) + \eta_k(t))$$

This same basic formula applies to both buying and selling except the value of m changes. Define

m_{sell}: Value when utility is selling to customer

H_{ik}: A constant if the DC load flow approximation (see Appendix A) is used.

Section C.6 Revenue Reconciliation Components

Electric utilities are usually run by a government agency or by private industry that is regulated by a government agency. Hence there is usually a need for revenue reconciliation to insure that they do not make or lose (too much) money. Approaches to this revenue reconciliation include

- o Use of surcharge or refunds
- o Use of revolving funds
- o Modifying the spot price

For an ideal world, the use of revolving funds or certain types of surcharge/refunds is recommended as they do not change the hourly spot price. However, such approaches present many practical implementation problems. Therefore we will discuss here the approach of modifying the spot price through the use of revenue reconciliation components.

The basic idea is to modify the prices paid by the customers so that the utility's revenue over some time interval (say one year) covers its operating and embedded capital costs plus a reasonable rate of return on investment. This gives rise to the revenue reconciliation components, $\gamma_R(t)$ and $\eta_{R,k}(t)$.

One structure which is a special case of the "Ramsey" or "second best pricing" theory is "multiplicative" in nature, i.e.

$$\gamma_R(t) = m\,\gamma(t)$$

$$\eta_{R,k}(t) = m\,\eta_k(t)$$

which yields an hourly spot price with revenue reconciliation given by run to meet the demand, the resulting prices are

- o At Base Load Bus $\rho = 5$ ¢/kWh
- o At Peaking Plant Bus $\rho = 10$ ¢/kWh

which is achieved by using $\eta_{QS,2} = 5$ ¢/kWh.

Section C.5 Spot Prices Without Revenue Reconciliation

For subsequent developments, it is helpful to summarize the operating and quality of supply components of the hourly spot price.

Define

$\tilde{\rho}_k(t)$: Hourly spot price without revenue reconciliation component.

Then

$$\tilde{\rho}_k(t) = \gamma(t) \qquad \text{[Generation Components]}$$

$$+ \eta_k(t) \qquad \text{[Network Components]} \tag{C.5.1}$$

$$\gamma(t) = \lambda(t) + \gamma_{QS}(t)$$

$$\eta_k(t) = \eta_{L,k}(t) + \eta_{QS,k}(t)$$

The network components $\eta_k(t)$ of (C.5.1) can be written as

$$\eta_k(t) = \sum_i \xi_i(t) \; H_{ik} \tag{C.5.2}$$

$$H_{ik} = \frac{\partial z_i(t)}{\partial d_k(t)}$$

$$\xi_i(t) = \gamma(t) \; \frac{\partial L_i[z_i(t)]}{\partial z_i(t)} \qquad \text{[Losses]}$$

$$+ \mu_{QS,\eta,i}(t) \qquad \text{[Quality of Supply]}$$

demand starts to exceed its critical level, $\gamma_{QS}(t)$ goes up to 90 ¢/kWh so that $\lambda(t) + \gamma_{QS}(t) = 100$ ¢/kWh.

Network Quality of Supply: $\eta_{QS,k}(t)$

By analogy with $\gamma_{QS}(t)$, $\eta_{QS,k}(t)$ becomes large in magnitude when the capacity of the network to transport energy is being approached. The recommended ideal world approach for network quality of supply is one of "market clearing" involving both generation and demand changes. However, other approaches such as allocation of network capital expansion costs can be used if desired.

Assume one particular line, say line i, with flow $z_i(t)$ is overloading. Then

$$\eta_{QS,k}(t) = \mu_{QS,\eta,i}(t) \frac{\partial z_i(t)}{\partial d_k(t)}$$

$\mu_{QS,\eta,i}(t)$: A (Lagrange) multiplier which is adjusted until customers and generators "respond" to change the usage and generation patterns so that the line overload goes away.

Spot prices are affected at buses throughout the network even if only one line (line i) is being overloaded.

As an example, consider two buses with one loss-less line connecting them. Assume one bus has a base load generator with marginal fuel costs of 5 ¢/kWh while the other bus has a peaking plant with marginal fuel costs of 10 ¢/kWh. Assume all load is at the bus with the peaking plant and the load is less than the base load unit's capacity. Thus if the line can carry all of the demand, the peaking plant generation is zero and

- o $\lambda = 5$ ¢/kWh, $\eta_{QS,k} = 0$
- o At both buses $\rho = 5$ ¢/kWh

If the line capacity is less than the demand and the peaking plant has to be dominate the hourly spot price.

Generation Quality of Supply: $\gamma_{QS}(t)$

One possible structural form for $\gamma_{QS}(t)$ is

$$\gamma_{QS}(t) = \theta_{QS,\gamma}(t)\ b_\gamma(t)$$

$b_\gamma(t)$: Potential loss of load indicator

$$b_\gamma(t) = \begin{cases} 1 & d(t) > d_{crit,\gamma}(t) \\ 0 & \text{other} \end{cases}$$

$d_{crit,\gamma}(t)$: A critical demand level based on available generation capacity and spinning reserve requirements.

$\theta_{QS,\gamma}(t)$: Generation quality of supply price (\$/kwh).

The $\gamma_{QS}(t)$ is random because the values of both $d_{crit,\gamma}$ and $d(t)$ are random.

Three methods for quantifying $\theta_{QS,\gamma}(t)$ are

- o Market Clearing Price: Set $\theta_{QS,\gamma}(t)$ to be the value that causes customers to reduce demand down to $d_{crit,\gamma}$. This value depends on the amount of load reduction required.
- o Value of Unserved Energy: Set $\theta_{QS,\gamma}(t)$ such that the resulting spot prices equal the cost to the customer of unserved energy.
- o Allocation of Peaking Plant Capital: Set $\theta_{QS,\gamma}$ to be a constant such that over a year, the $\gamma_{QS}(t)$ component recovers revenue equal to the annualized capital cost of a new peaking plant.

We recommend use of the market clearing price approach where feasible. However the other two approaches can be easier to implement in the real world. The value of unserved energy is related to but not necessarily equal to the market clearing price.

As an example, consider a utility whose marginal fuel and maintenance costs (i.e. λ) reach 10 ¢/kWh when demand is large. Assume the cost of unserved energy is 100 ¢/kWh and ignore all network effects. Then when

$$\underbrace{\sum_{t=1}^{8760} R\, z^2(t)}_{\text{Annual Losses}} = 0.05 \underbrace{\sum_{t=1}^{8760} z(t)}_{\text{Annual Flows}}$$

Assume

$$\begin{aligned} z(t) &= 500 \text{ MWh for } 5000 \text{ hours} \\ &= 1000 \text{ MWh for } 3000 \text{ hours} \\ &= 1500 \text{ MWh for } 760 \text{ hours} \end{aligned}$$

Then

$$R = \frac{(0.05)\,[(500)(5000) + (1000)(3000) + (1500)(760)]}{(500)^2(5000) + (1000)^2(3000) + (1500)^2(760)}$$

$$= \frac{(0.05)(66.4)(10^5)}{59.6\ (10^8)}$$

$$\approx 5.5\ (10^{-5})$$

When the line is heavily loaded, i.e. z = 1500 MWh,

$$\begin{aligned} \eta_L(t) &= [\lambda(t) + \gamma_{QS}(t)]\ 2(5.5)(10^{-5})(1500) \\ &= [\lambda(t) + \gamma_{QS}(t)]\,[0.165] \end{aligned}$$

Thus even though average losses are 5%, at times of heavy loading the marginal network loss component is 16.5% of $\lambda(t) + \gamma_{QS}(t)$.

Section C.4 Quality of Supply Components

The generation and network quality of supply components, $\gamma_{QS}(t)$ and $\eta_{QS,k}(t)$ can be quantified in different ways. All approaches yield behaviors characterized by very small or zero levels most of the time with a large, rapid increase when the generation or network capacity is being approached. During such critical times these quality of supply components square of line flows. Assuming a quadratic dependence of losses on line flow, $\eta_{L,k}(t)$ becomes

$$\eta_{L,k}(t) = [\lambda + \gamma_{QS}(t)] \frac{\partial L(t)}{\partial d_k(t)}$$

$$= [\lambda(t) + \gamma_{QS}(t)] \sum_i 2R_i \; z_i(t) \frac{\partial z_i(t)}{\partial d_k(t)}$$

$z_i(t)$: Power flowing in line i

$L(t)$: Total Losses $= \sum_i L_i[z_i(t)]$

$L_i[z_i(t)]$ = losses in line i

$= R_i \; z_i^{\,2}(t)$

R_i: Constant depending on resistance of line i

The marginal network loss component can be quite important at times of high demand even if annual percentage losses are relatively small.

As an example consider a two bus, one line system with all generation on one bus and demand on the other. There is only one flow $z(t)$ so

$$\frac{\partial z(t)}{\partial d_k(t)} = 1$$

$$L(t) = R \; z^2(t)$$

Assume average losses over a year are 5% so

$$+ \quad \eta_{R,k}(t) \qquad \text{[Network Revenue Reconciliation]}$$

Quality of supply components arise when generation or network capacities are being approached. Thus they serve as "curtailment premiums" or "capacity charges". The components of (C.1) are often combined into groups

$$\lambda(t) = \gamma_F(t) + \gamma_M(t) \qquad \text{[System Lambda]}$$

$$\gamma(t) = \lambda(t) + \gamma_{QS}(t) \qquad \text{[Marginal Cost of Generation]}$$

$$\eta_k(t) = \eta_{L,k}(t) + \eta_{QS,k}(t) \qquad \text{[Marginal Cost of Network Operation]}$$

The complexity of the equations which define the individual spot price components depends on the level of aggregation used in modeling the generation, the network and the customers.

Section C.3 Operating Cost Components

The operating cost components of the hourly spot prices are

Generation Fuel and Operations: $\lambda(t) = \gamma_F(t) + \gamma_M(t)$

Network Losses: $\eta_{L,k}(t)$

Generation Marginal Fuel and Maintenance: $\lambda(t)$

The system lambda, $\lambda(t)$, component of the hourly spot price is the derivative of generation fuel and maintenance costs with respect to demand. It is the output of the "economic dispatch" and "unit commitment" generation dispatch logics used in most modern electric power system generation control centers.

Network Losses: $\eta_{L,k}(t)$

This component arises from the energy losses resulting from transmission and distribution. Losses tend to be proportional to the

Now change the conditions and assume the customer benefit is 15 ¢/kWh instead of 5 ¢/kWh. Then for both pricing schemes

Demand = 1100 MW

Customer Benefit = $165,000

Utility Cost = $30,000

Social Welfare = $135,000

The utility's revenues (price times demand) are

	Utility Revenue ($)	Utility Revenue Minus Costs ($)
If customers pay spot prices, then	110,000	80,000
If customers pay average operating cost, then	20,000	0

The $80,000 "profit" made by the utility under spot pricing can be used to pay the capital costs of the two generators; however, this may either over or under recover the actual capital costs of the plants.

Section C.2 Components of Hourly Spot Prices

The hourly spot price associated with the kth customer during hour t is viewed as the sum of individual components defined by[3]:

$$\begin{aligned}
\rho_k(t) = \; & \gamma_F(t) && \text{[Generation Marginal Fuel]} \\
+ \; & \gamma_M(t) && \text{[Generation Marginal Maintenance]} \\
+ \; & \gamma_{QS}(t) && \text{[Generation Quality of Supply]} \qquad \text{(C.1)} \\
+ \; & \gamma_R(t) && \text{[Generation Revenue Reconciliation]} \\
+ \; & \eta_{L,k}(t) && \text{[Network Marginal Losses]} \\
+ \; & \eta_{QS,k}(t) && \text{[Network Quality of Supply]}
\end{aligned}$$

[3] A notational convention should be obvious, gammas are used for generation quantities, etc.

A Simple Example of Spot Prices

Consider a utility with two generators where

	Capacity	Operating Costs
Generator 1	1000 MW	2¢/kWh
Generator 2	100 MW	10¢/kWh

Assume the generators are optimally dispatched (i.e. Generator 1 is used until demand exceeds 1000 MW). Then, ignoring losses and capital costs, it follows that

	Utility Operating Cost ($/hr)	Average Op. Cost (¢/kWh)	Spot Price (¢/kWh)
If Demand = 1000 MW, then:	20,000	2	2
If Demand = 1100 MW, then:	30,000	2.73	10

Assume customer demand has the following characteristics

- o Maximum demand = 1100 MW
- o Benefit customers receive from using electric energy is 5¢/kWh

Define short term social welfare as

Short Term Social Welfare = Customer Benefit - Utility Operating Costs

Assume customers behave in their own best interest, i.e. are not willing to pay 10 ¢/kWh for a benefit worth only 5 ¢/kWh. Then it follows that

	Demand (MW)	Benefit ($)	Costs ($)	Social Welfare ($)
If customers pay spot prices, the demand will be cutoff at 1000 MW and:	1000	50,000	20,000	30,000
If customers pay average operating costs, then:	1100	55,000	30,000	25,000

Hence short term social welfare is higher if customers see spot prices instead of average operating costs.

$$\rho_k(t) = \frac{\partial}{\partial d_k(t)} \text{ Total Cost of Providing Electric Energy to all Customers} \qquad (C.1.1)$$

The derivative of (C.1.1) is evaluated subject to constraints such as

Energy Balance: Total generation equals total demand plus losses.

Generation Limits: Total demand during hour t cannot exceed the capacity of all the power plants available at hour t.

Kirchoff's Laws: Energy flows and losses on a network are specified by physical laws.

Line Flow Limits: Energy flows over a particular line cannot exceed specified limits without damaging the line and/or causing other system operating problems.

Revenue Reconciliation

The basic definition of (C.1.1) involves only marginal costs without consideration of revenue reconciliation; i.e. consideration of embedded capital costs and rate of return on investment.

A key property of marginal cost based spot prices is

- They tend to recover both operating and capital costs.

Since generation is assumed to be dispatched optimally, marginal costs exceed average variable operating costs. Thus charging customers at marginal costs yields revenues that exceed total variable operating costs; and this difference can be applied towards the capital costs. An "optimum" power system's marginal costs yields revenues which exactly match operating and capital costs. Unfortunately, in the real world, this difference will usually cause either over or under recovery of capital costs.[2] Mechanisms for revenue reconciliation are discussed in Section C.6.

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[2] Considering the massive uncertainty utility planners have to face, it is almost an accident if the generation mix, etc. happen to be "optimum" at any given time.

APPENDIX C

A THEORY FOR WHEELING RATES

Section 5 of the paper discussed issues associated with the establishment of a structure for wheeling rates. This appendix summarizes an explicit approach which is consistent with the general discussion of Section 5.

The approach to be presented is based on the spot price of electricity at a given hour. Therefore spot prices are discussed first before wheeling rates are considered.

Section C.1 Definition of Spot Prices

Define

$\rho_k(t)$: Spot price seen by kth customer during hour t ($/kwh)

$d_k(t)$: Electrical energy used by kth customer during hour t (kwh)

Then

$$\text{kth customer annual bill} = \sum_{t=1}^{8760} \rho_k(t)\ d_k(t)$$

An hourly spot price can be quantified in various ways. The basic approach used in this book is:

$\rho_k(t)$: Marginal (or incremental[1]) cost of providing electric energy to customer k during hour t taking into consideration both operating and capital costs. ($/kwh)

<u>Definition of Marginal Cost</u>:

The hourly spot price (without revenue reconciliation) is given by the marginal cost i.e.:

[1] At this level of discussion, marginal means the same thing as incremental. In actual implementation, there is a difference.

Power pools often have free flowing tie lines. In this case, the utility members do not have individual AGC systems and there is one AGC system for the entire pool.

Power pools may engage in purchases and sales with other power pools or independent utilities just as if the power pool was a single utility. Utilities within the pool may also make purchases and sales agreements with utilities outside the pool.

Reverse Flow Wheeling

$L = R\ (d - W)^2$

where for both flows

$g_1 = d + L$

The following numerical values are used

$\lambda_1 = 5$ ¢/kWh

$\lambda_2 = 10$ ¢/kWh

$d = 1000$ MWh

$W = 200$ MWh

$R = 5(10^{-5})$

This value of R yields 5 % losses when z = 1000 MW because

Percent Loss $= \frac{L(z)}{z} = 5(10^{-5})\ (1000) = 0.05$

Substituting these numerical values yields when there is no wheeling,

$W = 0$

$L = 50$ MWh

$g_1 = 1050$ MWh

Forward Flow Wheeling

$L = 5(10^{-5})\ (1000 + 200)^2 = 72$ MWh (losses go up)

$g_1 = 1000 + 72 = 1072$ MWh

Reverse Flow Wheeling (losses go down)

$L = 5(10^{-5})\ (1000 - 200)^2 = 32$ MWh

$g_1 = 1000 + 32 = 1032$ MWh

Ideal Revenue Reconciliation: Wheeling Rates

With Ideal revenue reconciliation, the general formula for $\tilde{\omega}_{BS}$

Note that definitions of Buses B and S change in the two cases. The swing bus, however, is always located at Bus 1. For simplicity assume $d > W$ so that for the Reverse Flow case, the flow z does not change sign.

We make the following simplifying assumptions:

$\gamma_{QS}(t) = 0$	No generation capacity limits or generation quality of supply costs
$\eta_{QS}(t) = 0$	No network quality of supply costs
$\lambda_j(t) = \lambda_j$	Incremental cost of generation is constant, independent of generator level g, j = 1, 2

Assume

g_1: A base load plant

g_2: A peaking plant

so

$$\lambda_2 >> \lambda_1$$

For most of the cases to be discussed here, there are no constraints; so $g_2 = 0$ since generation at bus 1 is so much cheaper. However in the last case of this example, we will introduce a constraint on the line flow z which will cause the peaking plant g_2 to become positive.

A quadratic model for the line loss is assumed so

$$L(z) = R z^2 \quad \text{(Line Loss)}$$

When $g_2 = 0$, the losses are given by

Forward Flow Wheeling

$$L = R \ (d + W)^2$$

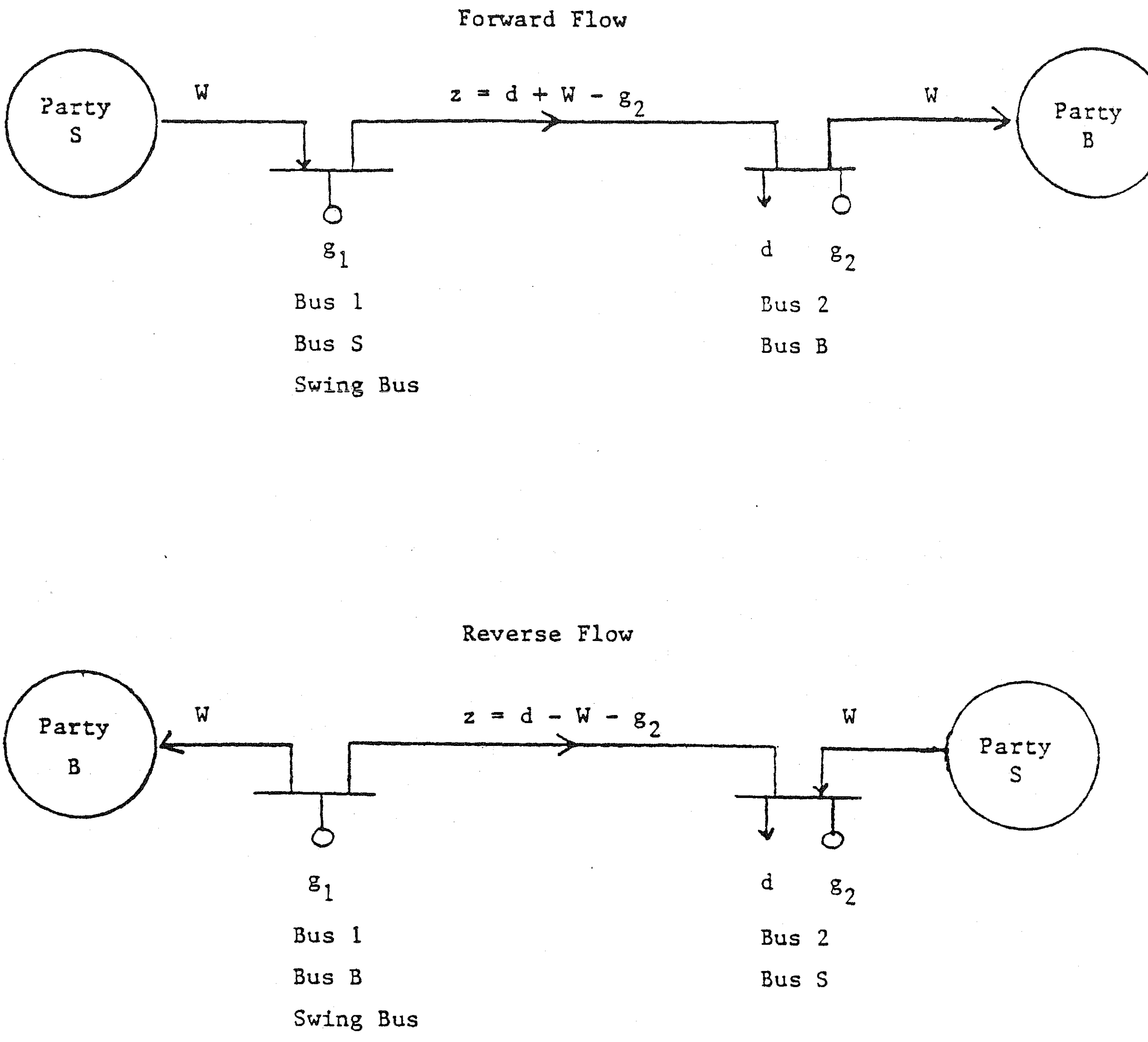

Figure C.11.1
Two Wheeling Configurations to be Studied

of revenue that occurs when Ideal Reconciliation is used.

Section C.12 2 Bus Example

The general nature of the preceding sections is academically pleasing but obscures understanding. In this section, we explore a two bus example which leads to equations and numerical values that are simple to interpret.

Formulation of Example

Figure C.11.1 summarizes the two wheeling configurations to be considered. We consider only one hour and drop the time dependence from the notation.

The wheeling utility owns the two generators and the single line. Customer demand d is located at Bus 2. The amount wheeled is W. The two types of wheeling flows of Figure C.12.1 are:

Forward Flow: S interconnects at Bus 1, and B interconnects at Bus 2. Wheeling W from Party S to Party B increases line flow z.

Reverse Flow: S interconnects at Bus 2, and B interconnects at Bus 1. Wheeling W from Party S to Party B decreases line flow z.

the buying party, the recommended wheeling rate is

$$\omega_{BS}(t) = \tilde{\omega}_{BS}(t) + m[\gamma(t) + \eta_B(t) + |\eta_S(t)|] \qquad (C.10.10)$$

The motivation for the Class ON (C.10.10) is

$$\omega_{BS}(t) = \rho_B(t) - \rho_S(t)$$

$$\rho_B(t) = \gamma(t) + \eta_B(t) + m\ [\gamma + \eta_B(t)]$$

$$\rho_S(t) = \gamma(t) + \eta_S(t) - m|\eta_S(t)|$$

Section C.11 Net Benefit: Bus to Bus

The spot wheeling rates of the preceding section can be either positive or negative. For example, the rate for Ideal reconciliation, $\tilde{\omega}_{BS}(t)$, will be negative if wheeling energy from Bus S to Bus B reduces the utility's losses. Revenue reconciliation effects depend on the sign of the multiplier m. However, a negative wheeling rate does not necessarily mean the wheeling utility is "losing money" by wheeling. Define

$B_W(t)$: Net benefit to wheeling utility of wheeling $W_{BS}(t)$ at a rate $\omega_{BS}(t)$ during hour t

$$B_W(t) = \Delta C(t) + \omega_{BS}(t)\ W_{BS}(t) \qquad (C.11.1)$$

$\Delta C(t)$ = Change in utility operating costs due to wheeling

For the case of Ideal Reconciliation where $\omega_{BS}(t) = \tilde{\omega}_{BS}(t)$, the net benefit $B_W(t)$ is never negative. If the gross wheeling revenues $\tilde{\omega}_{BS}(t)\ W_{BS}(t)$ are negative, the change in operating costs $\Delta C(t)$ is positive and exceeds the negative revenue in magnitude. This happens simply because $\tilde{\omega}_{BS}(t)$ is the marginal cost.

When the revenue reconciliation terms are incorporated into $\omega_{BS}(t)$, the net benefit defined by (C.11.1) can become negative if m is negative. This means that the wheeling parties are getting a "share" of the over-recovery

Class O Wheeling

For Class O wheeling (obligation to serve both parties) the recommended wheeling rate is

$$\omega_{BS}(t) = \tilde{\omega}_{BS}(t) + m\ [2\gamma(t) + \eta_B(t) + \eta_S(t)] \qquad \text{(C.10.8)}$$

This can be motivated in terms of the utility purchasing energy from the seller at Bus S and reselling it to the buyer at Bus B; i.e. (C.10.8) is the result of using

$$\omega_{BS}(t) = \rho_B(t) - \rho_S(t) \qquad \text{(C.10.9)}$$

where when revenue reconciliation is included, (C.7.2) yields[5]

$$\rho_B(t) = (1 + m)\ [\gamma(t) + \eta_B(t)]$$

$$\rho_S(t) = (1 - m)\ [\gamma(t) + \eta_S(t)]$$

which substituted into (C.10.9) yields (C.10.8).

The presence of the generation related price component $\gamma(t)$ in the Class O $\omega_{BS}(t)$ of (C.10.8) can result in wheeling rates that are radically different from the Class N rates of (C.10.7). The $\eta_B(t)$ and $\eta_S(t)$ also enter (C.10.7) and (C.10.8) in different ways but this difference is not of as much importance.[6]

Class ON Wheeling

For Class ON wheeling where the utility has obligation to serve only

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[5] We are assuming in this report that $\tilde{\rho}_K(t)$ is positive. Theoretically, in special cases, $\eta_K(t)$ can become so negative that $\rho_K(t)$ becomes negative. If that happens, the correct equation to use is

$$\rho(t) = \tilde{\rho}_K(t) + m|\tilde{\rho}_K(t)|$$

[6] One modification of (C.10.8) is that the revenue reconciliation accounting can be done independently for generation and transmission. This will lead to different values of m for multiplying the generation and network terms. This is important in practice but not a major conceptual point, hence not used here.

$$\eta_k(t) = \sum_i H_{ik}\, \xi_i(t) \qquad \text{(C.10.5)}$$

Thus (C.10.4) becomes

$$\tilde{\omega}_{BS}(t) = \sum_i \xi_i(t)\ [H_{iB} - H_{iS}] \qquad \text{(C.10.6)}$$

$\xi_i(t)$: Marginal cost of line flows $z_i(t)$ associated with losses and flow limits of line i (\$/kWh)

$H_{iB} - H_{iS}$: A constant which shows how the energy added to Bus S and removed from Bus B affects the flow in line i.

Since both $\xi_i(t)$ and $(H_{iB} - H_{iS})$ can be positive or negative, $\tilde{\omega}_{BS}(t)$ can also be positive or negative. The ideal wheeling rate will be positive if and only if the spot price at the buyer's bus is higher than at the seller's bus. Negative wheeling rates correspond to situations where wheeling reduces losses or other operating costs for the utility.

Class N Wheeling

For Class N wheeling (no obligation to serve either party), the recommended wheeling rate is

$$\omega_{BS}(t) = \tilde{\omega}_{BS}(t) + m|\tilde{\omega}_{BS}(t)| \qquad \text{(C.10.7)}$$

where the revenue reconciliation multiplier m is

- o m > 0 if the utility is under-recovering without revenue reconciliation.
- o m < 0 if the utility is over-recovering without revenue reconciliation.

Equation (C.10.7) is reasonable because

- o If m > 0, the utility's wheeling revenue increases
- o If m < 0, the utility's wheeling revenue decreases.

The $\omega_{BS}(t)$ of (C.10.7) depends only on the network dependent terms $\eta_B(t)$ and $\eta_S(t)$ of the hourly spot price. Thus no generation embedded costs are included.

Ideal Revenue Reconciliation

Define

$\tilde{\omega}_{BS}(t)$: Wheeling Rate Assuming Ideal Reconciliation

Then the key equation of wheeling is

$$\tilde{\omega}_{BS}(t) = \tilde{\rho}_B(t) - \tilde{\rho}_S(t) \qquad \text{(C.10.1)}$$

where $\tilde{\rho}_B(t)$ is the optimal spot price at bus B (C.5.1) at time t; and the same for $\tilde{\rho}_S(t)$. This price is multiplied by the amount wheeled to give the amount B and S should pay:

$$\begin{pmatrix}\text{Gross}\\ \text{Wheeling}\\ \text{Revenue}\end{pmatrix} = \tilde{\omega}_{BS}(t)\; W_{BS}(t) \qquad \text{(C.10.2)}$$

Thus for ideal reconciliation, use of the wheeling rate of (C.10.1) is equivalent to the utility,

- o Purchasing $W_{BS}(t)$ from the Seller on Bus S at $\tilde{\rho}_S(t)$
- o Reselling $W_{BS}(t)$ to the Buyer on Bus B at $\tilde{\rho}_B(t)$

This is a very simple and intuitively pleasing result.

Equation (C.5.1) is

$$\begin{aligned}\tilde{\rho}_k(t) &= \gamma(t) \quad &&\text{[Generation Related Price Components]}\\ &+ \eta_k(t) &&\text{[Network Related Price Components]}\end{aligned} \qquad \text{(C.10.3)}$$

Thus (C.10.1) yields

$$\tilde{\omega}_{BS}(t) = \eta_B(t) - \eta_S(t) \qquad \text{(C.10.4)}$$

i.e. there are no generation related price components explicitly in the wheeling rate (although $\eta_k(t)$ does depend on $\gamma(t)$ because of losses).

From (C.5.2)

- o Aggregate Network: All lines, transformers, etc. aggregated together.
- o Decomposed Network: Embedded capital costs of individual lines or sets of lines treated separately.

One of the key assumptions underlying the wheeling rates in this report is:

- o Ideal reconciliation (pure marginal costs) is not appropriate for wheeling under present regulatory institutions.[4]
- o Class N wheeling (no obligation to serve either party) should use Network Only reconciliation.
- o Class O wheeling (obligation to serve both parties) should use Generation and Network reconciliation.

In other words, wheeling parties who have an obligation to be served have to see the impact of the embedded generation costs. This is a foundation of the present regulatory system.

Section C.10 Spot Wheeling Rates: Bus to Bus

The bus-to-bus spot wheeling rate equations are now presented and discussed.

Define

Bus S: Location of Selling Party

Bus B: Location of Buying Party

$W_{BS}(t)$: Energy to be wheeled during hour t (kWh)

$\omega_{BS}(t)$: Wheeling rate during hour t ($/kWh).

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[4] A centrally dispatched power pool of many utilities could be viewed as doing wheeling under ideal reconciliation because embedded capital costs are accounted for in a fashion which does not affect the hourly spot price. If similar agreements can be worked out between utilities not in the same pool, then ideal reconciliation can be used for utility-to- utility wheeling.

be willing to give up something in exchange for what the utility is giving up. This affects the treatment of revenue reconciliation in wheeling rates, as we will discuss below. Basically we argue that under current regulatory arrangements, customers should pay revenue reconciliation for investments made to serve them. Three basic classes of wheeling logically follow:

Class N: Wheeling between two parties which the wheeling utility has no obligation to serve.

Class O: Wheeling between two parties, both of which the wheeling utility has an obligation to serve.

Class ON: Wheeling between one party which has no obligation to be served and one which the wheeling utility must serve.

Utility to Utility wheeling (Type I of Section 2) is an example of Class N wheeling. Customer-to-Customer wheeling (Type IV of Section 2) would usually be Class O. Type II and III of Section 2 would usually be Class ON.

The following discussions tend to concentrate on Class O and N rates as Class ON lies "in between".

Revenue Reconciliation

The three basic revenue reconciliation philosophies addressed here are:

- o Ideal Reconciliation: An "ideal world" approach where revenue reconciliation is done without modifying the hourly spot prices (by a revolving fund or ideal surcharge-refund).
- o Network Only Reconciliation: Revenue reconciliation done by modifying the spot prices considering only the network related revenues and embedded capital costs.
- o Generation and Network Reconciliation: Revenue reconciliation done by modifying the spot prices considering both network and generation related revenues and embedded capital costs.

Revenue reconciliation for the network (Network Only or as part of Generation and Network) can be done in two ways:

Section C.9 Obligation to Serve and Revenue Reconciliation

If revenue reconciliation were not of concern, we could simply substitute the formula of Section C.5 into (C.8.1). However, when revenue reconciliation is required, we have to use buy-sell spot prices as in Section C.7 and it turns out that, in some cases, the revenue reconciliation terms can dominate the ideal wheeling rates. It also turns out that there are various possible revenue reconciliation philosophies and the choice of which to use is tied to the concept of "obligation to serve". Therefore, before discussing actual wheeling rate formulae, we use this section to provide background discussions on revenue reconciliation and the obligation to serve.

Role of Obligation to Serve

Utilities have legally granted monopoly status for most customers within their service territory. That is, the customer must purchase all of its electricity needs from its local utility. In return, the utility promises open-ended availability; the utility has an "obligation to serve" that customer with as much electricity as the customer wants, when the customer wants it. The customer does not need to pre-specify its demands. This type of arrangement can work because there are many customers, and diversity effects reduce the variance of demand. Because customers must buy from the utility, the utility can forecast its demand without worrying about whether some customers will be supplied from other sources.

This obligation to serve is important because wheeling, in effect, reduces the monopoly provider status of a utility. A customer who buys from an external utility, with its local utility wheeling in the energy, will purchase less from its local utility. This implies that the customer should

- o Wheeling rate should be equivalent to the wheeling utility buying energy at one bus and selling the same amount of energy at the other bus.

which leads to

(Wheeling = (Difference Between Spot Prices
Rate) at the Buy and Sell Buses) (C.8.1)

It can be shown that (C.8.1) yields the same result as Eq. 1 of Section 5 of the main text.

When bus to bus wheeling takes place, the utility receives an inflow of power at Bus S. It simultaneously sees an equal outflow at Bus B. This simultaneous inflow and outflow has various effects on the wheeling utility such as

- o It will cause changes in line losses, which may either increase or decrease.
- o If any of the transmission lines were near their line limits, and their flows are increased, the utility will have to re-dispatch some of its own generators to reduce the level of flow in those lines. This will cause increased generation costs.
- o Conversely, if transmission line limits are affected favorably by the flow, this may allow the utility to re-dispatch and achieve lower generating costs.
- o The utility's ability and cost to honor other transmission arrangements may be affected.

These effects are quite complex and situation specific. The same wheeling may have very different effects at different times, depending on what other flows exist. Fortunately, spatial spot prices precisely capture the economic value of the different effects. Therefore they capture the costs of the wheeling.

from (C.10.1) and (C.10.5) is:

$$\tilde{\omega}_{BS} = \eta_B - \eta_S$$

$$\eta_k = \sum_i \xi_i H_{ik} \qquad (C.12.2)$$

$$H_{ik} = \frac{\partial z_i}{\partial d_k}$$

For the example, there is only one line so

$$\eta_B = \xi H_B$$

$$\eta_S = \xi H_S$$

The line flows $z_i(t)$ do not depend on the generation level at the swing bus. Thus $\eta_1 = 0$ and

Forward Flow Wheeling: Bus S is Swing Bus (bus 1)

$$H_S = 0 \qquad H_B = 1$$

$$\tilde{\omega}_{21} = \eta_2 = \eta_B = \xi$$

Reverse Flow Wheeling: Bus B is Swing Bus (bus 1)

$$H_B = 0 \qquad H_S = 1$$

$$\tilde{\omega}_{12} = -\eta_S = -\xi$$

When there are no line constraints, then $g_2 = 0$, $\gamma = \lambda_1$,

$$\xi = \lambda_1 \frac{\partial L[z]}{\partial z}$$

Using the quadratic model for losses

$$\frac{\partial L}{\partial z} = 2Rz$$

so

$$\xi = 2\lambda_1 Rz$$

Thus

Forward Flow Wheeling

$$\tilde{\omega}_{21} = 2\lambda_1 R[d + W]$$

Reverse Flow Wheeling

$$\tilde{\omega}_{12} = -2\lambda_1 R[d - W]$$

with corresponding numerical values

Forward Flow

$$\tilde{\omega}_{21} = 2(5)(5)(10^{-5})(1000 + 200)$$

$$= 0.6 \text{ ¢/kWh}$$

Reverse Flow

$$\tilde{\omega}_{12} = -2(5)(5)(10^{-5})(1000 - 200)$$

$$= -0.4 \text{ ¢/kWh}$$

Class 0 Wheeling Rates

As already discussed, bus 1 is the swing bus, so $\eta_1 = 0$, $\eta_2 = \xi$.

The Class 0 equation (C.10.8) for $\gamma = \lambda$, is

$$\omega_{BS} = \tilde{\omega}_{BS} + m\, 2\lambda_1 + m\, [\eta_B + \eta_S]$$

Thus

Forward Flow Wheeling (S = bus 1, B = bus 2, $\eta_S = 0$)

Since $\tilde{\omega}_{21} = \eta_2$

$$\omega_{21} = \tilde{\omega}_{21}\,(1 + m) + 2m\lambda_1$$

Reverse Flow Wheeling (S = bus 2, B = bus 1, $\eta_S = \xi$)

Since $\omega_{12} = -\xi = -\eta_S$

$$\omega_{12} = \tilde{\omega}_{12}(1 - m) + 2m\lambda_1$$

Two possible values for the total revenue reconciliation multiplier

- o $m = 0.2$ Utility is under-recovering its embedded costs without reconciliation
- o $m = -0.2$ Utility is over-recovering without reconciliation

Substituting for $m = 0.2$ and Forward Flow yields

$$\omega_{21} = (1 + 0.2)(0.6) + 2(0.2)\ 5 = 2.72\ ¢/kWh$$

Evaluating all four cases in a similar fashion yields

	m = 0.2	m = -0.2	Ideal (m = 0)
Forward Flow	ω_{BS} = 2.72 ¢/kWh	-1.52	0.6
Reverse Flow	1.68	-2.48	-0.4

The impact of revenue reconciliation is dramatic as these Class O rates have little relationship to the Ideal rates.

Class N Wheeling Rates

Equation (C.10.7) for Class N wheeling is

$$\omega_{BS} = \tilde{\omega}_{BS} + m|\tilde{\omega}_{BS}|$$

Substituting numerical values for Class N rates yields for $m = 0.2$ and Forward Flow

$$\omega_{12} = 0.6 + (0.2)(0.6) = 0.72\ ¢/kWh$$

Doing similar calculation for all four cases yields

	m = 0.2	m = -0.2	Ideal
Forward Flow	ω_{BS} = 0.72 ¢/kWh	0.48	0.6
Reverse Flow	-0.32	-0.48	-0.4

These Class N rates are much closer in character to the Ideal rates of 0.6 and -0.4 than to the Class O rates.

Net Utility Benefit

The net benefit the utility receives from wheeling is defined as the additional operating costs the utility incurs because of wheeling plus the revenue it receives from wheeling. That is

B_W = Net benefit to wheeler

$B_W = \Delta C + \tilde{\omega}_{BS} W_{BS}$ (\$)

ΔC = [Change in Operating Costs]

For the example, $\lambda(t) = \lambda$ for all generation levels so when $g_2 = 0$

Operating Cost = $\lambda_1 g_1$

In the following, we note that λ_1 = 5 ¢/kWh = 50 \$/MWh. Substituting yields

Forward Flow Wheeling

$$\text{Cost} = \lambda \; [d + R \; (d + W_{21})^2]$$

$$\text{Cost}(W = 200) = 50 \; (1072) = 53{,}600 \; (\$)$$

$$\text{Cost}(W = 0) = 50 \; (1050) = 52{,}500 \; (\$)$$

$$\Delta C = -1100 \; (\$)$$

Reverse Flow Wheeling

$$\text{Cost} = \lambda \ [d + R \ (d - W_{21})^2]$$

$$\text{Cost}(W = 200) = 50 \ (1032) = 51{,}600 \ (\$)$$

$$\text{Cost}(W = 0) = 50 \ (1050) = 52{,}500 \ (\$)$$

$$\Delta C = 900 \ (\$)$$

For Ideal Reconciliation (remembering that 0.6 ¢/kWh = 6 \$/MWh), the net benefit B_W becomes

Forward Flow

$$B_W = -1100 + (6)(200)$$
$$= 100 \ (\$)$$

Reverse Flow, net benefits are the same

$$B_W = 900 - (4)(200)$$
$$= 100 \ (\$)$$

For Class O, and m = 0.2, Forward Flow benefits are

$$B_W = -1100 + (27.2)(200) = 4340 \ (\$)$$

Performing similar calculation for all four cases yields

	m = 0.2	m = -0.2	Ideal
Forward Flow	B_W = 4340 (\$)	-4140	100
Reverse Flow	4260	-4060	100

For Class N, the numerical results become

	m = 0.2	m = -0.2	Ideal
Forward Flow	B_W = 340 (\$)	-140	100
Reverse Flow	260	-60	100

Effect of Line Flow Constraint

In all the preceding cases there were no constraints on the allowable line flow. We now consider a case where the line flow is limited by

$$|z| \leq 600 \text{ MWh}$$

If $g_2 = 0$, the line limit is exceeded for both Forward and Reverse Flow. Thus a solution with $g_2 = 0$ no longer exists. The utility must redispatch g_1 and g_2.

With an active line limit, (C.5.2) yields

$$\xi = \lambda \frac{\partial L(z)}{\partial z} + \mu_{QS,\eta}$$

where $\mu_{QS,\eta}$ is the Lagrange multiplier for the line limit. At this point we could proceed to evaluate the value of $\mu_{QS,\eta}$. However, it is easier to go back to the basic equation

$$\tilde{\omega}_{BS} = \tilde{\rho}_B - \tilde{\rho}_S$$

and note that when the line limit is active, both generators have a positive output. Thus, prices at each bus must equal the marginal operating cost of generation of the respective generators. Thus,

$$\tilde{\rho}_1 = \lambda_1 = 5 \quad ¢/\text{kWh}$$

$$\tilde{\rho}_2 = \lambda_2 = 10 \quad ¢/\text{kWh}$$

and wheeling rates obtained as the difference of spot prices are

Forward Flow (Bus 1 = Bus S, Bus 2 = Bus B)

$$\tilde{\omega}_{21} = 5 \ ¢/\text{kWh}$$

Reverse Flow (Bus 1 = Bus B, Bus 2 = Bus S)

$$\tilde{\omega}_{21} = -5 \ ¢/\text{kWh}$$

This illustrates the major impact that line flow constraints can have.

Wheeling Between Independent Islands

The two bus case is analogous to wheeling between two electrical islands, connected by a single transmission line. As long as that transmission line is not fully loaded, the two islands will generate in a coordinated way, using the cheapest sources (after allowing for losses in the transmission line).

However, when the transmission line limit is exceeded, the two islands become in effect independent, except for a fixed flow over the tie line. In the above line flow constraint example, the spot price at bus 1 is determined by the cost of generation at bus 1, and the spot price at bus 2 is determined by the cost of generation at bus 2. The tie line flow of 600 MW can be considered a constant sale from island 1 to island 2.

Section C.13 Decomposed Network Revenue Reconciliation

The discussion so far has concentrated on the difference between Class O and Class N wheeling; i.e., the impact of the obligation to serve. Both Class O and N rates include the effect of embedded network costs. We now discuss several ways in which these can be handled.

Separate Generation-Network Reconciliation

Consider the Class N rate of (C.10.7)

$$\omega_{BS}(t) = \tilde{\omega}_{BS}(t) + m|\tilde{\omega}_{BS}(t)| \qquad (C.13.1)$$

The associated discussion tacitly assumed that the multiplier is computed to try to achieve a revenue target based on both generation and network operating and capital costs. One alternative approach is to use an apparently similar equation

$$\omega_{BS}(t) = \tilde{\omega}_{BS}(t) + m_\eta |\tilde{\omega}_{BS}(t)| \tag{C.13.2}$$

which uses a constant m_η computed to try to achieve a revenue target that is based only on network operating and capital costs. This difference could have a significant impact as m in (C.13.1), and m_η in (C.13.2) can have different signs. For example the utility may have a strong new generation system (so $m > 0$; under-recovery) but an old and weak transmission system ($m_\eta < 0$).

<u>Decomposed Line-by-Line Network</u>

The ideas of separate reconciliation of generation and network can be extended to do revenue reconciliation on an individual line by line basis.

Using (C.10.6) it is possible to rewrite $\tilde{\omega}_{BS}(t)$ as

$$\tilde{\omega}_{BS}(t) = \sum_i \tilde{\omega}_{BS,i}(t)$$

$\tilde{\omega}_{BS,i}(t)$: Rate arising from ith line

$$= \xi_i(t) \; [H_{iB} - H_{iS}]$$

Thus for Class N rates, a logical extension of (C.13.2) is

$$\omega_{BS}(t) = \tilde{\omega}_{BS}(t) + \sum_i m_{\eta,i} |\tilde{\omega}_{BS,i}(t)| \tag{C.13.3}$$

where the $m_{\eta,i}$ are determined on a line by line basis. For example, an old transmission line (with capital costs mostly written off) that is heavily loaded (high losses) would have a negative $m_{\eta,i}$ as the utility would over-recover using Ideal Reconciliation. Similarly a new line that is not yet heavily loaded would have a positive $m_{\eta,i}$.

Section C.14 Reactive Energy and Voltage Magnitudes

The preceding discussions have considered only real energy. Reactive energy flows can also be important as they affect both real line losses and voltage magnitudes. In practice, it would sometimes be desirable to include a wheeling rate on reactive energy flows as well as a constraint on the allowable voltage magnitude at each bus. The preceding equations can be generalized by viewing the energy and prices as complex numbers whose real and imaginary parts correspond to real and reactive energy respectively.

Section C.15 Wheeling Transactions

The hourly spot wheeling rate $\omega_{BS}(t)$ is the basis for all wheeling transactions. However, there is no single set of transactions that are best for all situations. The three basic types of transactions to be discussed are:

Price-Only: Wheeling parties can have all the electrical energy wheeled they desire at a quoted price (\$/kwh).

Price-Quantity: Wheeling parties agree to "adapt" the amount to be wheeled to the utility's needs under prespecified conditions.

Long Term Contract: Wheeling parties engage in long term, fixed price, fixed quantity contracts with the utility. Any amount wheeled which is less than or greater than the contracted amount is at a different price.

An ideal criterion to be considered when choosing a set of transactions is

- o Choose those transactions that yield the best possible cost-benefit tradeoffs for the utility and the wheeling parties.

Therefore elaborate transactions (e.g. hourly spot wheeling rates) should only be used when their efficiency and other gains outweigh their transactions costs. Of course such a criterion cannot be used until the costs of transactions and benefits are understood.

Wheeling transactions result in costs such as

- o Costs of Computation (rates, etc.)
- o Costs of Communication (rates, flows, etc.)
- o Costs of Metering (flows)

A transition from the present system to the wheeling rates of this appendix would also cause costs associated with training utility personnel and educating wheeling parties to deal with new types of transactions.

Transactions costs can be quantified reasonably well by engineering analysis. Benefits, however, are much more complex and depend on how well wheeling transactions satisfy criteria such as

Economic Efficiency: Wheeling parties should see wheeling rates which motivate them to behave in a socially desirable fashion; e.g. ideally their wheeling levels should be as if they were "seeing" the Ideal spot wheeling price.

Equity: The wheeling utility's own customers should not subsidize the wheeling.

Freedom of Choice: Wheeling parties should have a high degree of freedom to choose their own patterns.

Acceptance and Understanding: Wheeling parties should be able to understand the nature of the transactions and believe that they are fair.

Utility Control, Operation, and Planning: The wheeling utility's job of running the power system should not be compromised.

Wheeling Parties' Control, Operation, and Planning: The wheeling parties reaction to transactions should not have to be unwieldy or unnecessarily complex.

The benefits of different types of transactions are measured in terms of how well they satisfy the above criteria. Unfortunately the criteria are often conflicting. For example, a flat wheeling rate (no variation over time) satisfies the last criterion but not the criteria of economic efficiency or utility control and operation.

Price-Only Transactions

For a price-only wheeling rate, the utility quotes, in advance, a fixed price for wheeled energy (\$/kwh) where the quote is valid for some specified period of time. The wheeling parties can buy any amount of wheeling at the quoted price.

There are many possible price-only transactions. The four discussed here are:

- One Hour Update: An energy rate valid for the next hour is quoted at the beginning of the hour.
- 24 Hour Update: On the afternoon of the present day (say at 4 pm), the 24 rates that will hold each hour for a period starting early the next morning and lasting until the same time the subsequent morning are quoted (say from 6 am to 6 am).
- Billing Period Update Flat: A flat energy rate (i.e. constant in time) valid for the subsequent billing period is quoted at the beginning of the billing period.
- Billing Period Update TOU: A time of use (TOU) type energy rate (i.e. varies at prespecified times of day and days of week) is quoted at the beginning of the billing period, e.g. once each month.

Yearly update flat and TOU rates could be defined analogously to the above.

These four examples illustrate two of the general characteristics of price only transactions:

- Update Cycle Length: The length of time a quoted rate or set of rates is valid.
- Period Definition: The number of separate rates that are quoted within the update cycle.

For example, a 24 hour update has an update cycle length of 24 hours and period definition of 24 periods (one for each hour). A billing period TOU update has a period definition that depends on the definition of peak, off peak and shoulder times.

Two other general characteristics of price-only transactions are

- o Advance Warning: Length of time before the start of an update cycle that the rates are quoted.
- o Number of Rate Levels: Rates may be constrained so that they can be set only at prespecified levels.

A one hour update might have an advance warning time of 5 or 10 minutes while a 24 hour update quoted at 4 pm to start at 6 am the next morning would have an advance warning time of 14 hours.

Price-Quantity Transactions

Wheeling can be "controlled" through the use of prices or the use of quantity control. In theory the desired wheeling parties' behavior could be obtained by the use of pure quantity control wherein the utility directly controls all wheeling using wheeling parties' provided information on how they value the services. In practice we believe the use of prices is far superior to a pure quantity control with respect to both reducing transactions costs and increasing benefits. There is, however, a potential role for certain combined price-quantity wheeling transactions.

Combined price-quantity transactions can sometimes be used to reduce transactions costs. For example a 24 hour update price-only transaction has lower transactions costs than a one hour update but is vulnerable to unexpected line or plant outages. The use of a 24 hour update wheeling rate combined with an interruptible contract (i.e. a type of quantity contract) enables corrections to be made for unexpected line outages but with transactions costs that might be lower than those of a one hour update price.

The basic idea of a price-quantity transaction is for wheeling parties to contract an "amount of wheeled energy" which the utility can "control" under certain circumstances. Such contracts can involve:

- o Fixed amount of energy reduction over some time interval, or
- o Fixed amount of power level reduction, or
- o All energy above a prespecified level is not wheeled, or
- o Reduction of power to a prespecified level

In addition to the above, there are the characteristics which are analogous to price-only transactions such as update cycle length, number of levels, advance warning time, etc.

Long Term Contract

One desirable property of wheeling transactions is that they facilitate the wheeling parties' operating decisions. It might be very important for certain wheeling parties to know what their wheeling costs are going to be a day to multiple years in advance or alternatively to purchase the right to wheel at some future time. This desire could be accomplished by offering them transactions with extremely long update cycle times but this would result in a major reduction in production efficiency. The same loss of production efficiency can result if the utility sells a fixed amount of "wheeling capacity" for some period of time. Fortunately there is a mechanism which enables future wheeling rights to be purchased at a fixed price (e.g. to buy an insurance policy) while still maintaining the efficiency of short update cycle lengths.

The basic approach is to offer fixed price, fixed quantity contracts for specific future time intervals. Consider a pair of wheeling parties who have bought such a contract. When the future time finally arrives, they can definitely have the agreed amount of energy wheeled at the specified price independent of the actual spot wheeling rate at that time. However, if the hourly spot wheeling rate turns out to be above the value in the wheeling parties' contract, the wheeling parties might choose to have less wheeled than in the contract and effectively sell back their rights to the utility at a profit. If the hourly wheeling rate turns out to be much lower than that specified in the contract, the wheeling parties have paid a "penalty" for having replaced uncertainty with certainty.

As an example, assume that on January 1, two wheeling parties purchase for 0.5 ¢/kWh the right to wheel 1 MWh of energy between 10 and 11 am on July 1. Assume that when July 1st finally comes, $\omega_{BS}(t)$ between 10 and 11 am is either 0.4 ¢/kwh or 5 ¢/kwh. The actual cash flow depends on the actual wheeling level on July 1st and is given in Table C.15.1.

Long term contracts could lead to the evolution of a futures market, with continual trading of future rights. For example, wheeling parties who on January 1st bought 1 MWh to be wheeled on July 1st at 0.5 ¢/kwh might decide on April 1st that their needs for electric energy in July have changed and therefore, may try to sell off their futures rights.

Assume Wheeling Parties Have a Long Term Contract for 1 MWh at 0.5 ¢/kWh.

Amount Wheeled Is	If $\omega_{BS}(t)$ = 0.4 ¢/kWh the wheeling parties	If $\omega_{BS}(t)$ = 5 ¢/kWh, the wheeling parties
1 MWh	Pay $5	Pay $5
2 MWh	Pay $9	Pay $55
0 MWh	Pay $1	Receive $45

Table C.15.1

Example of Cash Flow with Long Term Contracts

ABOUT THE AUTHORS

Alvin Kaufman is a consulting economist whose specialty is public utility regulation. He recently completed ten years of service as expert on regulated utilities with the Congressional Research Service (CRS) of the Library of Congress. There he advised the Congress about the basic characteristics of energy utility institutions and about legislation that could alter these institutions. His most recently published CRS report is Wheeling in the Electric Utility Industry.

Before joining the CRS, Mr. Kaufman served for six years as Director of Economic Research with the New York Public Service Commission. Before this, he was Chief, Office of Economic Analysis, Bureau of Mines in the U.S. Department of Interior, where he served for sixteen years. Since 1979, he has lectured annually at the NARUC Regulatory Studies Program at Michigan State, served on the Board of Editors of the IAEE Energy Journal, and co-authored several NRRI publications. Mr. Kaufman resides in Annandale, Virginia.

Robert Burns is a senior research associate and the regulatory attorney at the National Regulatory Research Institute. In his seven years at NRRI, Mr. Burns has co-authored over a dozen reports in energy utility regulation, many with an emphasis on regulatory law, including "Access to the Bottleneck: Legal Issues Regarding Electric Transmission and Natural Gas Transportation," Regulating Electric Utilities with Subsidiaries, The Prudent Investment Test in the 1980s, and Commission Preapproval of Utility Investment.

Before joining NRRI, Mr. Burns held a position with the Ohio State University's Program for Energy Research, Education, and Public Service. Since 1981, he has been the NRRI liasion with the NARUC Staff Subcommittees on Law and on Administrative Law Judges. Mr. Burns resides in Columbus, Ohio.

Pfeffer, Lindsay & Associates is a utility industry consulting firm. Its paper was written by a team consisting of William Lindsay, Jerry

Pfeffer, Robert Cackowski, and Howard Stone. Mr. Lindsay, who headed the team, is a Ph.D. economist who, for the last five years, has been a consultant to electric utilities, cogenerators and small power producers, major end-use customers, and federal and state agencies. Previously, he was with the Federal Energy Regulatory Commission (FERC, formerly the Federal Power Commission) for eighteen years, serving as Director of the Office of Electric Power Regulation during the last five of those years. Pfeffer, Cackowski, and Stone previously held numerous positions each, including positions with (respectively) the Economic Regulatory Administration of the U.S. Department of Energy (DOE), the Office of Electric Power Regulation of the FERC, and the Resource Consulting Group.

The firm did four major transmission-related studies for the Edison Electric Institute, two on the types and terms of existing transmission services and two on current and alternative approaches to transmission rate design. Pfeffer, Lindsay & Associates is located in Washington, D.C.

Fred C. Schweppe, assisted by Richard D. Tabors, wrote the paper by Meta Systems, Inc., a Cambridge, Massachusetts consulting firm. Mr. Schweppe is a professor of Electrical Engineering at the Massachusetts Institute of Technology (MIT), and a member of the MIT Laboratory for Electromagnetic and Electronic Systems (LEES), and a consultant to Meta Systems. He has over 25 years of experience in electric power systems technology and planning, having been employed both by electric utilities and by universities. Mr. Tabors is a Ph.D. economist, Assistant Director of LEES, and a Principal of Meta Systems. As scientist and economist, he has over 15 years experience in energy planning and pricing.

Schweppe and Tabors are two of the key principals in the recent development of the innovative spot-pricing concept for transmission and wheeling rate design. This concept was developed in a four-year effort, completed in 1985 with the release of the U.S. DOE-funded report, <u>Wheeling Rates: An Economic-Engineering Foundation</u>. Meta Systems presently has a major project, funded jointly by U.S. DOE and the New York State Energy Research and Development Administration, to test this concept with New York State regional utilities. This one-year project, scheduled to be completed in November 1987, involves the development and use of computer software for determining what types of efficient wheeling rates are implementable in specific cases.

Casazza, Schultz & Associates is an electric utility industry consulting firm with an excellent working knowledge of transmission systems. Its case studies paper was written by a team consisting of John A. Casazza, Herbert D. Limmer, Martin E. Gordon, and Steven R. Cumbow. Mr. Casazza, who headed the team, has over 40 years experience as an engineer and executive, both with a major utility and with major consulting firms. He and the other team members hold degrees in electrical engineering and have extensive experience in transmission system operation, planning, and policy analysis.

The firm has exceptional experience and contacts throughout the industry, which helped to provide the avenues of access to the various parties in each case study. Team members have been associated with some 34 separate efforts since 1980 that involve some form of institutional, legal, regulatory, or economic impediment to power transfers. The firm's past clients have included large and small investor-owned utilities, municipal and cooperative utilities, cogenerators, large industrial consumers of electricity, FERC, and state regulatory commissions. Casazza, Schultz & Associates is located in Arlington, Virginia.