THE ECONOMICS OF BULK POWER EXCHANGES

Jan Paul Acton, Stanley M. Besen

May 1985

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Prepared for

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A RAND NOTE

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PREFACE

In December 1983 the Federal Energy Regulatory Commission (FERC) authorized an experimental program to analyze the effects of modified regulation of wholesale transactions between electric utilities. Participation by utilities is voluntary, and participating utilities are expected to play a major role in experimental design. The purpose of these experiments is to determine whether it is possible to achieve greater efficiency in these transactions by providing increased pricing flexibility and specifically allowing utilities to retain some of the profits from wholesale power exchanges. FERC will require open and nondiscriminatory access to the transmission system for all utilities that participate in the experiment.

Rand has been retained by FERC to: (1) evaluate the experiments proposed by utilities; (2) assess the usefulness of the data the utilities expect to provide; and (3) analyze the results of the experiments. In an earlier document, Issues in the Design of a Market Experiment for Bulk Electrical Power, N-2029-DOE, Rand analysts discussed the general characteristics to be desired in such a study, identified data needed for quantitative evaluation to take place, and reviewed the proposed Southwest experiment in the light of these criteria.

The present Note develops a general economic analysis of bulk power exchanges among utilities and discusses current institutional and regulatory features of this market. This analysis can be used to assess the likely effects of modified regulation of bulk power exchanges, and can aid in developing analytic models for estimating experimental effects.

The study is supported by the FERC and the U.S. Department of Energy through DOE Contract DE-AC01-80PE70271, Task Assignment 16.
SUMMARY

Utilities exchange electricity with one another in order to increase operating efficiency and system reliability. In the longer term, such bulk power exchanges may permit smaller investment in electricity generating equipment than would otherwise be needed. At present, the Federal Energy Regulatory Commission (FERC) regulates the prices charged by privately owned utilities for the sale or transmission of bulk power. A principal rationale for this regulation is to prevent utilities from charging unreasonably high prices by virtue of possible market power. Such market power might be based on the costliness of searching for alternative sources of supply, high costs of transmission, or systematic differences in costs among utilities.

There is now increased interest in relaxing the regulation of such trades, and permitting market forces to constrain prices. This Note examines the economics of bulk power market exchanges and analyzes the effects of regulation on the incentives to exchange power.

In the very short run—a matter of a few hours—utility operators minimize their operating costs by adjusting the loads on their generating units or by making purchases from other utilities with lower marginal costs. The degree to which such "economy" purchases are realized depends upon the costs of search for trading partners, the prices charged for electricity, and the charges for and availability of transmission capacity to convey the electricity from sellers to purchasers. A number of different institutional arrangements are used for accomplishing the exchange of information and the consummation of trades—ranging from informal search each hour between pairs of utilities to the creation of "tight" power pools with central dispatch of the generating units of participating utilities.

We often observe utilities consciously preferring the less formal arrangements to central dispatch and often exchanging energy at "split the savings" prices rather than seeking to trade on more favorable terms. A variety of explanations have been developed as to why utilities may prefer "split the savings" pricing, but none is totally satisfactory.
The incentive to engage in bulk power exchanges is affected by the existence of several different regulatory authorities employing differing regulatory techniques. Both federal and state regulators have jurisdiction over utility investments that serve both wholesale and retail customers—often leading to different regulatory treatment of the same equipment or operating costs. These include differences in definitions of rate bases, in allowed rates of return, in whether past or anticipated costs are considered, and in whether costs (such as those of purchased fuel) are passed through automatically in prices or affect prices only when rates are formally adjusted in regulatory proceedings.

One significant factor affecting the incentive to engage in bulk power exchanges is the treatment of profits from such transactions. Current FERC treatment requires utilities to estimate the gains from economy transactions and to take them into account in setting other wholesale rates. This effectively allows the utilities to retain, at the margin, 100 percent of the profits under federal jurisdiction that arise from such transactions. Some states allow utilities to retain a specified percentage of the profits above the level that has been estimated in establishing rates for their retail customers, while others flow through all gains to ratepayers. These different policies reflect a desire to have utility ratepayers share in the gains from bulk power transactions while, at the same time, creating incentives for utilities to engage in such transactions by permitting shareholders to retain a portion of the gains.

An incentive to engage in bulk power transactions may also arise if partial requirements utility customers (part of whose demand for electricity is supplied by another utility) can resell purchased energy at a higher price in the bulk power market. Under some circumstances, such transactions may affect only the distribution of gains from trade among utilities, but, because rates to partial requirements customers are regulated, they may affect the efficiency of production as well.

A final issue in the regulation of bulk power exchanges is the "price squeeze" controversy. This situation arises when a purchasing utility is charged so much for its wholesale supply that, when its distribution and other costs are added, it cannot profitably serve its
retail customers at rates that prevail in surrounding utility service territories. Here, it is alleged that the supplying utility is attempting to "squeeze" its wholesale customer in order to displace it as a retail supplier. Regulators often try to limit this phenomenon by constraining the wholesale rate charged, but this may actually lead to less efficient electricity supply.

Several conjectures about the effects of relaxed bulk power market regulation are put forth in the last section of this Note. However, many of the questions raised in this Note cannot be answered unambiguously in the absence of empirical information. It is the purpose of a bulk power market experiment authorized by FERC, involving a number of Southwest utilities, to supply some of these answers. The results of the experiment will be analyzed in a forthcoming Rand Note.
ACKNOWLEDGMENTS

This study would not have been possible without the cooperation of utilities in the Southwest that are participating in the Federal Energy Regulatory Commission experiment, of utilities in the state of Florida, and of the FERC itself. Individuals at the utilities reviewed an earlier draft of the report and offered numerous helpful suggestions. FERC representatives, and especially our project officer Bernard Tenenbaum, also provided helpful comments. Our Rand colleague Scott Cardell read an earlier draft and made several suggestions for improving the presentation and clarifying the analysis. Finally, our editor Will Harriss made many improvements under a tight schedule. We appreciate the assistance of each of the individuals involved.
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I. INTRODUCTION

In the past, two proposals have been put forth for the fundamental reform of the electric utility industry. Under the first, utilities would be encouraged, or required, to form electric power pools.\textsuperscript{1} It was argued that this would increase efficiency both in the construction of generating facilities and in day-to-day utility performance by promoting increased coordination in planning and operations.\textsuperscript{2}

At the other extreme, proposals have been advanced that would reduce formal coordination and regulation of utility operations, by separating utilities into those that generate and those that distribute electricity.\textsuperscript{3} Generators would be largely deregulated and would compete with one another for the patronage of local distribution companies. It was argued that this restructuring of the industry would promote efficiency by substituting competition for regulation in electricity supply.

More recently, a third alternative has been put forth. Under this proposal, more efficient utility behavior would be sought through expanded, and less regulated, wholesale trade.\textsuperscript{4}

\textsuperscript{1}See, for example, Federal Power Commission (1964) and Breyer and MacAvoy (1974). A recent survey of some aspects of power pool economics is found in Gegax and Tschirhart (1984).

\textsuperscript{2}Some of the same benefits might be achieved if utilities were permitted to merge. See Joskow and Schmalensee (1983).

\textsuperscript{3}See Weiss (1975) and Berry (1982). For a sample of critiques of this proposal, see Marshall (1982); Dowd and Burton (1982); Pace and Landon (1982); and Edison Electric Institute (1982). A recent analysis by Schmalensee and Golub (1984) considers the likely degree of competition that would exist in various regional electricity markets. A particular form of the suggestion, by researchers at MIT, would have continuously varying prices set on a spot basis to clear the electricity market. See Bohn et al. (1984).

The basic rationale for each of these proposals is the same: Utilities, and their customers, may benefit when electricity is generated not by the companies that distribute it locally, but by the generators that are most efficient. Generation costs may vary among utilities for several reasons. First, some utility systems are systematically more efficient than others. This can be due to the technical efficiency of the generating equipment, favorable costs of fuel, or general organizational efficiency. All utilities benefit when more efficient systems increase their output and less efficient systems reduce theirs. The resulting gains are available to be divided among the ratepayers and shareholders of both buyers and sellers.

Second, even when two utilities do not differ in their average efficiency, their costs can vary because of changes that occur hourly and by season. Changes in electricity demand, weather, fuel prices, or outages in equipment, each affect marginal cost and may create the potential for gains from reallocating generation among utilities.

Third, utilities may find it profitable to trade energy because of differences in access to subsidized governmental power (e.g., federal hydroelectric projects), allowed rates or rate of return, historical accounting costs for ratemaking purposes, or access to low-cost sources of supply through partial requirements contracts. These differences may make trades attractive on pecuniary grounds.

The first two reasons for trades produce efficiency gains to society and potentially make both utility shareholders and ratepayers better off. By contrast, the third reason for trades may involve only transfers, with no improvement in efficiency, or may actually create inefficiencies. In this Note, we concentrate on factors that affect the efficiency of energy generation rather than on those that involve only pecuniary gains.

This Note explores the possibility that relaxing regulation of wholesale transactions may promote increased efficiency in electricity supply. It discusses the economics of coordination among utilities; examines how current incentives, regulations, and institutions affect trades; and considers how new arrangements, or modified regulation, might cause changes. Its principal objective is to identify the factors
that must be present for the wholesale electricity market to function efficiently. Alternatively, the Note can be viewed as an examination of the barriers to efficient wholesale trade.\(^5\)

Section II below examines the behavior of electric utilities as they determine whether to participate in wholesale power exchanges. It describes the mechanics of determining the prices that will prevail and the methods employed to identify potential trading partners. Here, we develop a general description of utility interaction and draw upon the experiences of the organized brokerage arrangement among utilities in the state of Florida, and a similar broker employed by utilities that are part of the Western States Coordinating Council (WSCC),\(^6\) as well as of various informal wholesale markets that exist. We also describe the role played by the transmission system in facilitating trade. Finally, we consider some special problems that arise where trades extend over periods longer than one hour.

Section III describes FERC and state regulation of coordination transactions. In particular, it focuses on regulation of (a) the prices at which coordination transactions may occur, (b) the retention of profits from wholesale trades, and (c) access to the transmission system.

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\(^5\)It has been known for some time that, if a number of well-defined conditions are met, the outcome achieved through the use of markets will be efficient, in the sense that it will be impossible to reallocate resources to make anyone better off without making someone else worse off. These conditions include: (1) Every buyer and seller is a price-taker, purchasing or selling the amount desired at the existing market price, but unable to influence that price; (2) every buyer and seller is aware of the market price, so that no buyer or seller can exploit an information advantage in making trades; (3) all of those affected by a transaction are parties to it, so that no one can be affected adversely by a trade; and (4) there are no restrictions on the prices at which trades can occur or on the quantities that can be exchanged. These are sufficient conditions for efficiency. Some or all of these conditions may be violated and the outcome might still be efficient. This Note analyzes the extent to which these conditions are fulfilled in the bulk power market.

\(^6\)We understand that the WSCC broker activities were recently stopped.
Section IV analyzes the effects of existing regulation of coordination transactions, particularly at the federal level. Here, we are concerned with analyzing a number of aspects of FERC regulation of these transactions. One question that we address here is whether FERC regulations are binding.

Section V concludes the Note by examining the possible effects of the "deregulation" of coordination transactions. This analysis is divided into two parts. The first explores outcomes in the coordination market itself. Issues such as the competitiveness of these markets and the efficiency of their operation are examined. The second part examines the effects in other markets. In particular, the question of how modified regulation of coordination transactions will affect retail and requirements customers is examined.

The Note addresses three basic questions:

- Do utilities have the incentive to purchase electricity at least cost, or will they favor their own facilities even if doing so is more expensive than purchasing electricity?
- Does the way in which access is made available to the transmission system permit efficient trades to occur, or is ownership of transmission facilities employed to prevent such transactions from being consummated?
- Does federal or state regulation, either of bulk power or retail transactions, encourage utilities to engage in mutually beneficial trades, or does it blunt utility incentives to acquire electricity in the least costly manner?
II. UTILITY BEHAVIOR IN THE BULK POWER MARKET

In order to understand how wholesale electricity markets function, and how regulation affects their behavior, it is important to have some understanding of how utilities plan their operations and how they search for trading partners in the bulk power market. Our focus is initially on hour-to-hour operations, ignoring questions of unit commitment, maintenance scheduling, and construction. Next, we discuss the critical role played by the transmission system in the functioning of the wholesale electricity market. The final part of this section discusses transactions that extend over periods longer than one hour.

We also simplify this initial discussion by abstracting from regulatory considerations and institutional impediments. These are introduced in subsequent sections after the basic economics of utility bulk power exchanges are described.

UTILITY OPERATIONS AND PLANNING FOR TRADES

At any given time, a utility will have committed a number of its generating units to operation. This commitment involves "firing up" the units so that, either automatically or under the direction of an operator, increases in the load that are placed on the utility's system can be met by increased generation from these units.¹ Given the load that the utility expects to meet during the ensuing "hour," it will plan to operate its units so as to minimize its production costs. This generally means that it will equalize the marginal cost of all of its operating plants.² In so doing, it will minimize the total cost of meeting its expected demand. If the utility's load differs from what

¹In our discussion we concentrate on meeting the demand, or load, imposed on the utility system. We omit discussion of other important aspects of power system operations, such as frequency and voltage regulation, many of which are handled through automatic equipment in a modern system. See Joskow and Schmalensee (1983) for a general discussion of these other functions.

²The qualification "generally" is meant to indicate that there is a minimum rate at which units may be operated, some units may effectively be at their capacity, and/or that in physically dispersed systems,
was expected, or if some units that the utility expected to operate have experienced unexpected failures, the rates of operation of its committed units will be adjusted in order to continue to minimize production costs.

Utilities need not generate exactly the amounts of electricity demanded by their customers. A utility may be able to reduce its costs by making purchases from other utilities instead of generating the electricity itself. Alternatively, it may find that it can reduce the rates to its customers or increase its own return by selling electricity to utilities that have higher costs than its own. In the former case, the utility will reduce the level of operation of its units to reflect the less costly market alternative. If it is minimizing its costs, the utility's own units will be operated at levels at which marginal costs are equal to the most expensive of its purchased electricity.\(^3\) Similarly, a selling utility will operate its units so that their marginal cost is equal to the price at which electricity can be sold.

For utilities that participate in wholesale electricity transactions of this type, trading is conducted by employees in a dispatching center, where the operations of the utilities' own units are directed and monitored. In the more sophisticated of these operations, the marginal cost of the system--the change in cost for a small change in load--at its actual load, known as system lambda, is available on a real time basis. Since the calculation of marginal cost is based upon the units that are already committed to operation, the change in costs consists primarily of additional outlays for fuel and incremental operation and maintenance expense.\(^4\) System lambda can be compared with generating units may be operated at unequal marginal costs because of transmission constraints. Furthermore, in a spatially dispersed utility system, nominal marginal costs of units may differ because of transmission costs; thus the equality of marginal costs is for delivered energy (net of losses and transmission costs).

\(^3\)The question of whether a utility will purchase electricity when other utilities have lower costs is, of course, the focus of this Note. M. Cohen (1979, pp. 1520-1521) argues that "Both state commissions and the FERC employ a system of rate regulation that arguably discourages coordination initiatives. . . . A regulated monopolist feels less pressure than firms in competitive industries to minimize capital outlays and to pursue cost-cutting innovations."

\(^4\)If operating units are at capacity, their marginal cost will be less than the price of purchased electricity and the marginal cost of
the prices being quoted by other utilities, and electricity either purchased or sold, as appropriate. The process can continue until system lambda is equal to the prices of prevailing market alternatives.\(^5\)

In less sophisticated operations, the utility will prepare estimates of its incremental and decremental costs in advance, based on the units that it plans to have in operation.\(^6\) Usually, there will be estimates for several levels of generation, to reflect the fact that incremental and decremental cost vary with unit loading.

The utility may prepare a table in which, for a number of different levels of planned generation, the changes in costs that accompany a number of possible changes in output are presented. If the utility is attempting to minimize its costs, it will determine from the table its estimated incremental and decremental costs at its native load. Using this information, it will purchase electricity if its estimated decremental cost is greater than the price at which it can purchase energy, and it will sell electricity if the selling price exceeds its estimated incremental costs. Whether a utility is a purchaser or a seller, and the amount that it will buy or sell, will depend on the available market alternatives compared with its own costs. A utility may discover that its estimated decremental cost is greater than the price at which it can purchase electricity for, say, two "blocks" of 100 Mw, but that it cannot find a seller quoting a price that makes it attractive to purchase a third block.

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units that are not operating will exceed the price at which electricity can be purchased. In economy transactions, buyers must retain reserves sufficient to meet their loads in the event that a purchase is interrupted, so that, while they can adjust the rate of output of units that are on line, they may not be able to shut down these units unless other spinning reserves are available.

\(^5\)In practice, utilities tend to compare the prices at which they can purchase or sell electricity with the incremental cost of a large change in output, rather than with system lambda which, in principle, represents the marginal cost of an infinitesimally small change.

\(^6\)Decremental cost is the reduction in total cost divided by the reduction in output for a given change in generation. Incremental cost is the increase in cost divided by the increase in output for a given change. The changes in output are larger than those involved in the calculation of system lambda.
If the availability of units differs from those in the plan, perhaps because of an unexpected equipment failure, the incremental and decremental costs employed will be based not on the estimated unit loading but on a larger amount. For example, if the actual load is 1500 Mw but a unit with a capacity of 200 Mw is unavailable, the utility will employ the marginal cost for 1700 Mw in determining whether to exchange electricity. It will, thus, estimate incremental and decremental costs that are higher than those at 1500. This procedure is clearly only an approximation, since the effect of an outage will depend not only on the capacity of the units that are unavailable but also on their particular operating characteristics.

SEARCHING FOR TRADING PARTNERS

Utilities that wish to buy or sell electricity may do so in one of several ways. Many simply inquire about trading possibilities with a small number of other utilities with which they are interconnected and have existing contracts that detail the terms to be employed in making transactions. If a utility finds a potential trading partner, that is, a utility with incremental costs different from its own, and if access to the transmission system can be obtained at a price smaller than the gains from the trade, the transaction may be consummated at a price based on provisions in the contract between the utilities. Often, although not always, the price is determined under a "split-the-savings" formula, with the price midway between the decremental and incremental costs of the buyer and seller, respectively.

Of course, a utility will not necessarily execute a transaction with the first potential trading partner it finds. Even under split-the-savings, a utility may be able to obtain better terms by finding another partner. A seller will obtain a higher price if it can find a utility with higher decremental costs and a buyer can obtain a lower price if it finds a seller with lower incremental costs. If no costs were incurred in searching for better trades, and if there were many other utilities with whom contracts and transmission paths exist, the prices of all trades would tend toward equality. If search is costly, or if the number of potential trading partners is small, there may be
price variations among transactions occurring at the same time. Not much is known at present about the extent of search that utilities undertake.

Some utilities are members of organized markets, such as the brokerage arrangement that exists among utilities in Florida under the auspices of the Florida Electric Power Coordinating Group (FCG).\(^7\) In Florida, buyers and sellers of economy energy—purchases and sales for the forthcoming hour—are matched and prices are determined under a "high-low matching/split the savings" rule. Under this arrangement, using a computer algorithm, the utility with the highest decremental cost is matched with the utility with the lowest incremental cost, with the price set midway between these costs. The utility with the second highest decremental cost is then matched with the utility with the second lowest incremental cost, and the matching process continues until a minimum spread between incremental and decremental cost is reached, at which point no further matches take place. The matching process takes into account whether or not there is a transmission path between the utilities, the costs of transmission, transmission losses, and whether or not there is a contract between the utilities. Note that this process does not guarantee that the prices of all trades will be equal.

In the Florida economy broker, a utility may submit quotes at which it will both buy and sell, its decremental and incremental costs, respectively. It may also submit multiple buy and sell quotes, reflecting the fact that incremental and decremental costs are different at different levels of output. If multiple quotes are made, a utility may be matched with more than one trading partner, or in more than one transaction.\(^8\)

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\(^7\)See L. Cohen (1982), for a description and analysis of the Florida broker. The Western States Coordinating Council (WSCC) also operated a broker that was organized along the same lines as the one in Florida. However, where Florida utilities consummate almost all of their economy transactions through the FCG broker, many of the transactions among members of the WSCC apparently occurred on an ad hoc basis.

\(^8\)Even if it makes only a single quote, a utility may be matched with more than one partner. Suppose that the utility with the highest decremental cost indicates a willingness to purchase 100 Mw but that the utility with the lowest incremental cost is willing to sell only 50 Mw. The utility with the second lowest incremental cost may also be matched with the highest bidder, although at a different price, and the highest-cost utility will continue to be matched with others until either trades
There are significant differences between this brokerage arrangement and the operation of formal power pools. In "tight" pools, a manager is given control over the operation of all units of each member, permitting them to be operated as if they were a single system. Operations are conducted to minimize the cost of meeting the combined loads of all members. Once operating authority has been ceded to the manager, utilities do not control the trades in which they are engaged. Indeed, it is somewhat awkward to describe the transactions in which pool members are engaged as "trades." Utilities that are "buying" electricity are those that generate less electricity than their customers demand and "sellers" are those for which the reverse is true. Periodically, the pool either presents bills or writes checks to members, depending on whether or not the value of electricity they "bought" exceeds the amount that they "sold."

By contrast, utilities in the Florida broker do not give up control over their generating operations. Instead, coordination is achieved through the market created by the broker. Utilities retain the right to decline transactions that have been recommended by the broker, and, although this is rarely done, utilities apparently place a value on the right to refuse a trade. Indeed, in Florida, utilities actually confirm trades with the utilities with which they have been matched, rather than leaving that function to the broker. Nor does the broker participate in the "settling up" process. Thus, if there are n utilities, instead of n checks being written, with the broker functioning as a clearinghouse, if every utility trades with every other there will be \(n(n-1)/2\) such payments.\(^{16}\) Thus, unlike pool arrangements, which involve multilateral trades among members, the broker exists to facilitate bilateral transactions.

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100 Mw are recommended or there are no sellers with sufficiently low incremental costs for mutually beneficial trades to exist.

They can perhaps be described as trades with the pool.

With 18 participating utilities, the number using the Florida broker, \(n(n-1)/2\) equals 153.
It should be observed that the quantity \((n(n-1))/2\) is also the number of price inquiries that would have to be made each hour if every utility were to be in contact with every other utility. The Florida broker, although it does not reduce the costs of billing and payment, clearly reduces the costs of search. Moreover, since all price quotations are available simultaneously, the problem of whether to accept a bid or continue to search does not exist.

**SOME FURTHER THOUGHTS ONUTILITY SEARCH**

In the preceding discussion, we implicitly assumed that utilities would always search for the lowest-cost seller or the highest-cost purchaser, with the extent of search limited only by its costs. Or, to say the same thing, faced with sellers offering different prices, a buyer would always choose to trade with the one quoting the lowest price. There are, however, observations of the behavior of utilities in wholesale markets that call this assumption into question.

In a long series of discussions with utilities that participate in the Florida broker, we inquired as to why they employed and accepted the split-the-savings formula for pricing transactions. Why, in other words, did buyers not seek transactions at prices lower than those recommended by the broker and why did sellers not search for higher prices? One possibility—that the utilities behaved this way because the FERC approved only split-the-savings pricing—could be eliminated for several reasons. First, FERC was apparently willing to consider alternative pricing rules, so the utilities did not appear to be constrained to use the formula. Indeed, it had approved such alternatives in a few cases.\(^\text{11}\) Second, even under split-the-savings, a purchasing utility can still lower its price by matching itself with a lower-cost seller. Finally, the utilities adamantly rebuffed a suggestion that the brokerage arrangement be modified so that the same price would prevail on all transactions.\(^\text{12}\) If we reject the hypothesis


\(^{12}\) This would have involved using the same matching algorithm that is currently employed, but with all trades occurring at the price of the marginal transaction, the one matching the highest-cost seller and the lowest-cost buyer.
that the utilities behaved in this fashion solely as a result of inertia, some explanation for their behavior is required.

The explanation, we believe, stems from three critical factors. The first is that utilities involved in wholesale electricity exchanges frequently are also linked by other arrangements, an especially important one being that they rely upon one another for emergency assistance. This assistance involves the provision of electricity during periods lasting up to several hours during which the buyer is firing up units that are needed because of the unexpected outages of others.

At the times at which emergency assistance is provided, there may be a considerable opportunity for the seller to behave opportunistically, i.e., to exploit a temporary monopoly position to exact a price far in excess of its costs. However, agreements between utilities usually call for emergency power to be provided at or near the costs of the seller. Since these agreements are typically reciprocal, each utility effectively agrees not to take advantage of the difficulties of another, in return for a similar promise from others. Such arrangements make utilities better off, since they permit them to hold smaller reserves. As a result, utilities may be loath to do anything that disturbs these relationships. Thus, even if a utility that is purchasing electricity knows that another buyer is obtaining a lower price, either because the other buyer has lower decremental costs or is matched with a seller with lower incremental costs, the buyer paying the higher price may not attempt to negotiate a better deal. Instead, it will accept the trade that results from the "high-low matching/split-the-savings" formula. A reputation for "sharp trading" in the wholesale power market may threaten other dealings, so that the parties may limit how competitively they act. It may be difficult, in other words, for the parties to behave cooperatively in one setting while being rivals in another. Thus, rules for "acceptable" behavior in the wholesale market are adopted in order to assure cooperative behavior elsewhere.

\footnote{The terminology is due to Williamson. See, e.g., Williamson (1975).}
The second factor is that, in organized wholesale electricity markets, utilities trade with one another in a continuing series of market "periods." Suppose that, in one period, a buyer and a seller find an alternative match that is better for both than the one proposed by the broker, and engage in the alternative transaction.\textsuperscript{14} The question now is what happens in the next period. In response to the violation of the "rules of the game" by some participants, others may decide to search outside the broker in the next period as well. In principle, given enough time to search, a single market-clearing price would emerge, and the joint gain would be maximized, i.e., efficiency would be achieved. But there may not be enough time, and search is expensive, so that some gains may be lost if a decentralized market replaces a centralized one. Recognizing, therefore, that their attempt to strike a better deal may threaten the viability of the entire institution, or at least to reduce the welfare gain that it produces, all participants may forbear from "competing."

If there were only a single market period, no utility would be concerned about the effect of its actions on the viability of the trading mechanism, so that we might expect "harder" bargaining to ensue.\textsuperscript{15} The preceding argument does not explain, of course, why the utilities do not employ a market mechanism that produces a single price at which all transactions occur. However, in the broker arrangement, prices serve only to distribute the gains from trade, not to promote efficiency, since the high-low matching algorithm exploits all of the potential gains from trade among participants in the broker. Therefore, there are no additional efficiency gains from changing the pricing rule. It should also be noted in this connection that the pricing mechanisms employed in power pools generally do not produce a single price at which all transactions occur. As in the Florida broker, in power pools the pricing arrangements serve only to distribute the gains from trade, with

\textsuperscript{14} Of course this can occur only if the participants in the thwarted transaction cannot make new bids. If they could, and if there were enough time, a single market-clearing price would emerge.

\textsuperscript{15} See Luce and Raiffa (1957), pp. 98-99, for a discussion of why cheating is more likely where the number of "plays" is finite.
efficient operation of the generation system being assured by the pool manager.

Finally, there is the fact that the Florida broker involves trade among a stable set of market participants. Maintaining the discipline required to prevent one utility from "undercutting" another is more difficult if, from time to time, other utilities enter the market and compete with the incumbents. These "outsiders," being less concerned with the long-term viability of the market than with immediate profits, are more likely to be the source of undercutting than are the "regulars," so that the law of one price is more likely to prevail. Only if participants in the broker reject better alternatives provided by the outsiders can the broker's pricing mechanism survive. A market with fluid membership may thus be more likely to exhibit uniform prices than one in which participation is stable. The ability of the Florida utilities to maintain their pricing arrangement may thus be tested by the recent construction of a transmission line from Georgia, which facilitates trades with outsiders.\(^{16}\)

Although these explanations are based on close observation of only a single organized market, if they are correct they may also be applicable to trades within markets where buyers and sellers are matched through informal search. Thus, one utility may be willing to sell to another even where a better trade may be available, if the two utilities rely upon one another for emergency reserves. Moreover, a utility may be content to trade with only a limited number of partners in order to limit the cost of search if its partners similarly limit the scope of their search. Finally, the behavior of markets in which there is a stable group of traders may be different from one in which membership is more fluid, even where the market is not an organized one.

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\(^{16}\)In this connection, it should be observed that if the members of the broker reject trades involving outsiders in favor of less advantageous trades with other members, some potential efficiency gains may be lost. However, it may be rational behavior for the members to agree collectively to reject such transactions, in order to continue to achieve the benefits of lower costs of search. Preventing "cheating" on such agreements may, however, be a difficult matter.
Having made these observations, however, we should hasten to state that the maintenance of a market among a stable group of traders is likely to be strained as additional trading opportunities become available outside the market and the costs of consummating transactions with outsiders decline. We conjecture that the limited role played by the WSCC broker, compared with the one in Florida, may have resulted from the fact that WSCC member utilities could also trade outside the WSCC broker, whereas FCG utilities make virtually all of their trades through the broker. As the gains from non-broker trade (or trades with outsiders) increase, the mutual self-denial of searching becomes more costly, and is, thus, less likely to survive. However, with a large increase in the number of potential trading partners, the costs of using informal search will increase, possibly leading to pressures to develop more organized methods of exchange.

By themselves, the above arguments explain only why a "high-low matching/split-the-savings" formula can be maintained. That is, they provide a rationale for why such a system may survive even if it is in place although, at any time, some market participants may be trading on terms that are less favorable than those available to others. They do not, however, explain why the system will be preferred to one in which all trades occur at the same price. In discussions with utility analysts, the argument for preserving the present pricing arrangement often focused on stability of the resulting prices.

One argument that has been made to us for preferring the high-low matching/split-the-savings arrangement is that the price at which a utility can buy or sell electricity may be substantially insulated from changes in the circumstances of other utilities where such a system is used. Under this arrangement, as long as the trading partner with which it is matched and the quote of that partner are unchanged, so will be the price a utility receives or pays for electricity. In contrast, it is argued, under a system in which all trades occur at the market clearing price, a change in the circumstances of the marginal buyer or seller will affect the price at which all infra-marginal trades occur.
On the other hand, the reverse argument can also be made. A change in the circumstances of a single utility or its trading partner will alter the price at which the utility trades if a high-low matching/split-the-savings rule is in effect. But if the same change leaves the market clearing price unaffected, the price at which the two utilities trade will not change. Here, the split-the-savings rule results in prices that are more sensitive than those where only a single price prevails in the market.

It should also be noted that both the split-the-savings and market-clearing price rules are vulnerable to misrepresentation by traders of their costs, which can lead both to redistribution of the gains to trade and to inefficient trade. For example, under the high-low matching/split-the-savings procedure, a buyer who knows the quotes of all other utilities may be able to obtain a lower price than if it quotes its true decremental costs. Either by quoting a lower decremental cost, so that it is matched with a seller with a higher incremental cost at a lower price, or by quoting a higher decremental cost, so that it is matched with a seller with a lower incremental cost at a lower price, or by quoting a lower decremental cost and being matched with the same seller at a lower price, it may be able to improve its position at the expense of other utilities.

Moreover, if this utility buys more electricity than it would if it were accurately representing its costs, the result is not only to redistribute the gains to trade in its favor but also to reduce the overall magnitude of those gains. A utility that knows the costs of all other utilities can offer to buy some blocks at a price in excess of its true decremental cost where it knows that the price it will actually pay is less than its true cost. The result is to displace other buyers whose decremental costs are higher than its own.17

17A similar strategy is available to a seller, who can offer to sell some blocks at a price below its incremental cost, secure in the knowledge that it will actually receive a price in excess of its incremental cost. L. Cohen (1982) shows how a utility can increase its share of the gains from trade by misrepresenting its costs if it knows the costs of others. She does not consider how such behavior might affect the aggregate gains, but she does consider how the aggregate gains might be adversely affected if several utilities misrepresent their costs.
Where a single price prevails in the market, a seller who knows the bids of all other utilities can raise the price for all trades by offering to sell somewhat less electricity than it would if it were accurately revealing its costs. The result is to raise the price, and hence the profits, on all sales it continues to make and to eliminate the profits on those amounts that are withdrawn from the market. If the amount of electricity that continues to be sold and the increase in the price of electricity are large, this is likely to be a profitable strategy.\textsuperscript{18}

The upshot of this is that one cannot tell, on a \textit{a priori} grounds alone, whether a market with a single price or one in which prices are determined by a high-low matching/split-the-savings algorithm will seem more attractive to potential participants. Each exposes utilities to instability in prices in some situations while insulating them from such instability in others. And each is vulnerable to misrepresentation of costs by utilities, which can affect both the distribution of the gains from trade and their aggregate amount.

\textbf{ACCESS TO THE TRANSMISSION SYSTEM}

Electric utilities maintain physical interconnections with one another for two basic reasons. First, when utilities are interconnected, they are able to call upon one another in emergency situations when a unit that had been expected to be used to generate electricity must be taken out of service. On these occasions, other utilities increase their generation by the amount that would have been provided by the displaced unit. The second reason that utilities are interconnected is to permit them to purchase and sell electricity in situations when differences exist in the marginal costs of generation.

A prerequisite for trade of electricity between two utilities is that they be interconnected. But two other conditions must also be met for trade to occur. Two utilities can trade only if they can contract to use a transmission path between them in consummating their trade.

\textsuperscript{18}A similar strategy is available to potential buyers, who would offer to buy somewhat less in order to reduce the price for the electricity they continue to buy.
That is, using the physical transmission system to which both are connected, it must be possible to piece together, and contract for, access to a series of links that connect the two utilities. The second condition is that the capacity of the transmission system must be sufficient to handle the increased flow caused by the trade.

Note that there may be little or no relationship between the contract path and the actual flow of electricity, since trade of electricity between utilities does not involve the physical delivery of particular units of output from seller to buyer. After arranging for a contract path, the purchaser reduces its generation and the seller increases its generation by equal amounts, in order to maintain the physical equilibrium of the generation and load in the interconnected system.\footnote{Since there are transmission losses associated with the transfer of power, utilities agree in advance whether the buyer or seller is responsible for covering any loss. In many instances, the transmission agreement, which may involve a third utility, has specific provisions for losses—requiring financial or in-kind payment.} The actual path taken by the traded electricity, i.e., the portion of the transmission grid over which the flow is increased, may be very different from the contract path, depending on the relative impedances in various portions of the transmission system. Utilities are unlikely to be able to contract to use the actual path since the flows of electricity resulting from a given trade will be affected by all simultaneous uses of the transmission system. For trade to take place, the actual path must have sufficient capacity for the additional flow to occur.\footnote{Where the flow of electricity is increased over a portion of the system other than the contract path, several problems are created. The utility over whose lines the flow takes place will naturally be unhappy that it has not received compensation for the service it has provided. Even worse from its viewpoint is when the capacity of its transmission system is strained to the point where it cannot employ it for its own purposes. Groups of interconnected utilities frequently undertake studies to determine whether there are physical bottlenecks in the system that links them.}

This brief discussion has identified three possible reasons why two utilities that wish to consummate a trade may, nonetheless, have the transactions thwarted. First, the utilities may not be part of the same transmission system, i.e., they may not be interconnected. Second,
there may exist no contract path between them. Finally, there may be no excess capacity in the portion of the transmission system over which the electricity actually flows. Below, we address a fourth possibility, that the utility that controls the transmission system denies access to it.

TRANSACTIONS OVER PERIODS LONGER THAN ONE HOUR

Although most coordination transactions among electric utilities involve economy energy, to an increasing degree utilities are engaging in transactions that extend over periods longer than a single hour. In economy transactions, the savings to be divided between the buying and selling utility take the form of reduced operating costs, primarily the cost of fuel. For transactions that cover longer periods, additional cost savings are possible. For example, if a utility can find a seller willing to supply it with firm electricity for a week, it may be able to avoid the costs of starting up a unit to meet an expected increase in its load. Similarly, if a utility can arrange to purchase electricity during a period when one of its units is being maintained, it may be able to avoid the costs of starting up and operating one of its own less efficient units. Thus, in deciding whether or not to make a purchase, a utility must compare the purchase price with the combined startup and operating costs incurred in generating the electricity itself.

Transactions involving commitments for periods longer than one hour are, for that reason, more complex than those involving economy energy. Recently, the utilities in Florida have begun experimenting with an Expanded Broker, in which trades extending over more than a single hour are consummated.\textsuperscript{21} One of the reasons that the "high-low" matching employed in the economy broker cannot simply be extended to the Expanded Broker can be illustrated by means of a simple example.

Suppose that a prospective seller can make available 100 Mw of electricity at an incremental cost of $50/Mwh for each of two weeks (168 hours). One prospective purchaser of 100 Mw has decremental costs of $80/Mwh for the two weeks while another, which wishes to purchase only during the second week, has decremental costs of $90/Mwh. If the first

\textsuperscript{21}For details about the operation of the Expanded Broker, see Florida Electric Power Coordinating Group, Inc. (1983).
purchaser is matched with the seller for both weeks, the combined cost saving of buyer and seller is $1,008,000 = [100(80 - 50)(168 + 168)]. However, the gain will be $1,176,000 = [(100(80 - 50)168) + (100(90 - 50)168)] if the second purchaser provides the match during the second week. More generally, efficient matching requires an algorithm that takes into account the effect of each transaction on the ability to undertake every other possible transaction. The fact that the economy transactions occur simultaneously, and all are for what is apparently the minimum or "standard" transaction period, makes matching straightforward.\footnote{If utilities were willing to make transactions for periods as short as, say, one-half hour, a similar matching problem would arise in the market for economy energy.}

If transactions must be at least two weeks in length, it may pay to forgo entirely some transactions that would promote efficiency. Suppose that a seller can supply 100 Mw per week for three weeks, that one buyer is willing to purchase 100 Mw for up to $80/MWh during the first and second week, and that a second buyer is willing to purchase them for up to $90/MWh during the second and third weeks.\footnote{It is assumed that the seller's incremental costs are lower than $80.} In these circumstances, efficiency requires that a transaction with the first buyer be rejected, although it would produce an efficiency gain. By waiting for the second buyer, a saving of $336,000 = [100(90 - 80)(168 + 168)] can be achieved.\footnote{An alternative is, of course, for the first buyer to agree to a transaction for only the first week, but the seller will have to recognize such a possibility when approached by the first buyer.} It should be noted here that the problems we are discussing are not the result of uncertainty about the price offered by the second buyer. Even where all present and future offers are known, the market clearing process is complex. A matching algorithm would have to consider all possible combinations of transactions if it is to maximize efficiency. With a large number of traders and many overlapping trading periods, the number of such combinations is likely to be very large.\footnote{The development of a matching algorithm is apparently planned for the Expanded Broker. See Florida Electric Power Coordinating Group (1983), pp. 16-18.} The problems involved in developing a matching algorithm also suggest
that it will be difficult to achieve efficient matching when informal search, rather than a broker, is employed.
III. FERC AND STATE REGULATION OF COORDINATION TRANSACTIONS

This section describes the Federal Energy Regulatory Commission and some of the states regulate coordination transactions among utilities that are under their jurisdiction.¹ The issues to be addressed involve regulation of: (a) transaction prices; (b) profit retention; (c) transmission pricing; and (d) access to the transmission system.

PRICE REGULATION

The prices paid to all investor-owned utilities for coordination transactions are subject to FERC approval. Moreover, these prices are to be "cost-based." Thus, FERC's stated policy is that, "unless strong policy interests demand otherwise, energy charges and adders should do no more than recover the incremental variable costs of the seller in providing coordination services."²

It is common for coordination transactions to be priced at the seller's incremental costs plus an "adder," which may be either a fixed number of mills per kwh, or a percentage that is added to the seller's incremental cost. The theory is that this allows the seller "to recover any unquantifiable or difficult-to-quantify incremental variable costs and to protect the seller from any error in estimating incremental variable costs."³ However, it is also common for the FERC to approve contracts that call for prices of coordination transactions to take place at prices midway between the incremental costs of the buying and selling utility. These prices will, therefore, often take place at prices that exceed the seller's incremental cost, sometimes by a substantial amount.⁴ FERC has approved such prices to encourage

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¹It should be noted that FERC jurisdiction does not extend to publicly owned or cooperative utilities.
³Ibid.
⁴Ibid., pp. 62-63. Edison Electric Institute (1982), p. 21, also notes that "... regulators have shown a willingness to allow rates for short-term power that substantially exceed the incremental cost of such sales to the seller." Earley (1984) summarizes FERC pricing and access policy with respect to several types of coordination services among utilities.
coordination transactions "because they lower the cost of providing electricity, give sellers an incentive to make economy energy available, and are equitable in that no party gets a disproportionate share of the benefits of the transaction."

FERC has apparently also approved split-the-savings arrangements in which the split is not 50/50. In addition, FERC permits some utilities in the Pacific Northwest to sell certain types of non-firm energy "at a price that recovers the incremental variable cost plus up to one hundred percent of the allocable fixed costs of the generating units providing the energy [with] the percentage . . . negotiated to reflect market conditions," and permits two utilities in Florida to exchange short-term firm service "at a price that recovers variable cost plus a capacity charge not to exceed the levelized fixed cost of the seller's thermal fossil-fueled production capacity."

Although all of these arrangements are "cost based," in the sense that the seller's, and at times the buyer's, cost enters the pricing formula, the wide variation in the way these costs are used raises questions concerning whether the prices at which transactions occur are effectively constrained by regulation. If any of a number of formulae that take cost into account may be approved by FERC, there may be substantial discretion in setting prices. Indeed, two of the formulae previously referred to permit prices to be set within a very wide range. And in justifying the establishment of a wide zone of acceptability for prices in its wholesale power market experiment, the FERC could point to the fact that some prices that had previously been approved were approximately twice the fully distributed costs of the selling utility.

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6Private conversations with FERC staff.
8Ibid., p. 73.
PROFIT RETENTION

Although FERC regulates the prices of bulk power sales by private electric utilities, the ability of these utilities to retain profits from these transactions is affected by regulation at both the federal and the state levels. In both cases, the objective of regulation is to encourage efficient generation of electricity while, at the same time, limiting the prices that utilities can charge to their customers. Both federal and state regulators limit the rate of return that utilities under their jurisdiction may earn.

In order to understand how regulation of the rate of return of utilities can affect the incentive to engage in wholesale electricity transactions, it is necessary to discuss three facets of the regulatory process. The first is the jurisdictional separation between the Federal Energy Regulatory Commission and the states. The second involves the distinction between setting retail rates, and rates for requirements customers, on the basis of a test year and the use of automatic adjustment clauses in the rate-setting process. Finally, there is the question of the extent to which the costs and revenues resulting from participating in the wholesale electricity market are "flowed through" to utility customers.

JURISDICTIONAL SEPARATION

Electric utilities have two types of customers that, under law, they are required to serve. The first are the residential, commercial, and industrial customers located within the service territory that has been assigned to the utility--its native customers. Since these customers generally have no alternative sources of electricity, the rates they can be charged are regulated by state public utility or public service commissions. Moreover, utilities are required to meet the entire demand of these customers. Indeed, one of the primary obligations imposed on these utilities is that they expand their generating capacity to anticipate the demands that their local customers may impose in the future. A utility that fails to anticipate demand and, therefore, finds itself unable to serve the customers that have been assigned to it, is likely to be severely criticized by the regulatory commission in its state.
A second class of customers that a utility must serve are so-called requirements customers. These generally consist of small municipal or cooperative electric companies that have either little or no generating capacity of their own. Utilities that have no generating capacity, "full requirements customers," and are solely in the distribution business, clearly must purchase all of the electricity needed to meet the demands of the residential and commercial customers in their service areas. In some cases, these utilities receive part of their electricity supply from federally constructed hydroelectric generators, but they usually receive at least part of their supply from private generators. Historically, these utilities, proceeding either through the courts or the regulatory process, have been able to force nearby privately owned utilities to serve their needs. Since only a single utility is obligated to serve a requirements customer, and since requirements customers were believed to have few alternative sources, rates for these transactions are regulated by the Federal Energy Regulatory Commission (and, previously, by its predecessor, the Federal Power Commission). In this, and in other respects, the obligations that a privately owned utility has toward its requirements customers are similar to those toward its retail customers, but the locus of regulation is different.

Partial requirements customers differ from full requirements customers in that they own some generation facilities. Nonetheless, where these facilities are thought to be inadequate to serve the utility's customers, a larger privately owned utility may incur an obligation to meet the "requirements" of a municipal or cooperative utility over and above that utility's own capacity. Rates charged to partial requirements customers are also regulated by the FERC.

If, for the moment, we ignore wholesale transactions other than those involving requirements customers, and if we assume that utility costs can be perfectly forecast, the effect of jurisdictional separation can be seen most clearly. Since a utility's generating facilities can be used to serve both its native and requirements customers, some procedure must be found for dividing its costs between them in order to set both wholesale and retail rates. Although, in principle, if the costs of serving these two classes of customers were the same, the rates
charged to them need not differ, differences may arise because rates for retail and requirements customers are regulated by different entities. This requires a separation of a utility's capital between state and federal jurisdictions, two determinations of the rate-of-return the utility will be permitted to earn on its rate base, and separate treatments of factors such as cost recovery and depreciation. The fact that there are two rate-setting processes means that rates are unlikely to be the same, even if the costs of serving the two customers classes are identical. Significantly, the two jurisdictions may treat the revenues and costs from other wholesale transactions differently in setting rates, and this will affect the incentives to engage in these transactions differentially.

TEST YEAR VERSUS AUTOMATIC ADJUSTMENTS IN THE RATE-SETTING PROCESS

To the extent that the revenues from coordination transactions exceed their incremental costs, either prices paid by utility customers can be reduced, or the earnings of shareholders can be increased, or both. Similarly, if a utility can purchase electricity for less than its decremental costs, it can either reduce rates or increase shareholder profits.

Historically, utilities have established rates by estimating the cost of serving their estimated demand and setting prices so as to recover these costs, including the cost of capital. Under this procedure, the test year, the period used for making the estimates, may be based either on historical experience or on a projection of the future. In either case, however, there is no "trueing up," that is, if rates fail to yield revenues that cover a utility's costs, including the allowed rate of return, the shortfall is borne by shareholders. Only when rates are recalculated, in a subsequent regulatory proceeding, can

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9 The rates could differ by such factors as time-of-day, of course, but this would not require differences among customers. Moreover, optimal pricing may require differential prices based on differences in demand elasticities among classes of customers. On the latter, see Baumol and Bradford (1970).

10 Of course, there would also likely be differences in rates even if rate-setting occurred under a single jurisdiction, since the costs of serving the two types of customers are likely to differ.
this deficiency be remedied. By the same token, if a utility earns more than its allowed rate of return, it can retain the excess until rates are revised in the next rate case. If the period between rate revisions is substantial, a utility can actually earn considerably more or less than the rate of return it has been "allowed." Thus, although the theory of federal regulation holds that profits from wholesale transactions flow through to requirements customers, in practice this occurs only on an ex ante basis. Ex post, a utility's profits may exceed those granted by the FERC if earnings from coordination sales, or cost savings from coordination purchases, exceed those that were estimated in setting rates for requirements customers; or the utility may earn less than its allowed rate of return, if these earnings or savings are smaller than estimated.

When state regulators employ the test-year method, errors in estimating the gains from coordination transactions have effects on a utility's profits that are subject to state regulation similar to those on the portion of its rate base that is subject to FERC regulation. And since the proportion of a utility's rate base that is allocated to the intrastate jurisdiction is generally far greater than that under federal jurisdiction, the quantitative effects are far more important.

Regulation with rates based on a test year was the norm for many years in the electric utility industry for two basic reasons. First, the real costs of generation declined over time (in some cases, nominal costs declined as well) as technological change permitted the construction of larger and more efficient plants. Under such circumstances, there were few, if any, risks that unforeseen developments would reduce utility profits below those estimated at the time of the filing of a rate case. During the periods between rate cases, if costs fell faster than expected, the utility would obtain additional profits.

Second, as long as fuel prices remained relatively constant, a utility was likely to be able to forecast its costs with a high degree of accuracy. This, too, meant that the downside risks to a utility involved in establishing rates for a considerable period of time were small.
With the rapid and erratic increases in fuel prices during the 1970's, combined with an apparent decline in the rate of technological change in the generation of electricity, the strains on the existing regulatory system became great. A utility faced with the possibility of large and unanticipated increases in fuel costs and long delays in obtaining a rate increase found itself subject to considerable risks under traditional rate-setting methods. It was during this period that utilities began to ask for, and receive, permission from regulators to adjust rates regularly and automatically in response to changes in fuel costs. Although the permitted adjustment varied among jurisdictions, most utilities were able to shift at least a part of the risk of changes in fuel prices from their shareholders to their ratepayers.

TRANSMISSION REGULATION AND WHOLESALE TRADE

The pricing of transmission services is regulated by the FERC. Generally, utilities provide both firm and interruptible transmission service. Rates for firm service are typically quoted on a per Mw basis, with the objective of recovering the fully distributed cost of providing the service, regardless of how much electricity is actually taken. Rates for interruptible service are usually quoted on a per Mwh basis, with the rates designed to recover fully distributed costs, if the assumed load factor is achieved. Utilities may also impose adders, to recover unquantifiable or unquantified costs of providing transmission services, but current FERC regulation limits these adders to one mill per kwh.

FERC regulation pertains only to the prices that can be charged by those utilities that have offered to provide a transmission service. Such transmission is often called "wheeling," as the electricity sold by one utility to another requires the transmission facilities of the third utility. Generally speaking, utilities are not required to provide such services. Although there have been instances in which the provision of wheeling services has been required, FERC cannot require a utility to

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11This discussion is based on Holmes (1982a).
12The most prominent example is the requirement that Otter Tail Power Company wheel for two municipally owned electric utilities. This
wheel. Two commentators have recently described the situation as follows: "Except for section 203 of [the Public Utility Regulatory Policies Act of 1978], which has extremely limited practical application, there are no well-defined methods of securing involuntary wheeling. There are, however, available theories--notably, monopolization under the Sherman Act, and to a lesser extent, discrimination under the Federal Power Act--that although undeveloped in the context of compulsory wheeling, merit examination by industrial customers seeking to secure such wheeling."\textsuperscript{13}

\textsuperscript{13}Fels and Heap (1983). Although this article is directed at the question of whether utility customers can obtain wheeling services, the analysis also applies to the utilities themselves. In another recent article, the author contends, citing PURPA, that "The Federal Energy Regulatory Commission (FERC) may now order an electric utility to provide transmission services." See Lopatka (1984), p. 567, footnote 26. Although this statement is literally correct, the conditions under which FERC may order wheeling are so stringent that they will be satisfied only rarely. A recent article argues that "the wheeling provisions [of PURPA] have been so encumbered with caveats and conditions as to render them virtually meaningless." See "FERC Limits PURPA Transmission Authority," \textit{Legal Times}, January 30, 1984, p. 18.
IV. REGULATION AND THE EFFICIENCY OF WHOLESALE ELECTRICITY TRADE

This section explores how several types of regulation affect the efficiency of wholesale electricity trade. It begins with a discussion of the effect of rate-of-return regulation on the incentives for efficient utility operation.\(^1\) The next two subsections discuss the effects of specific types of regulatory treatments—profit retention and cost and revenue "flow throughs"—on utility behavior. The final subsection considers regulation of access to and pricing of transmission services. It concludes with discussion of two particular regulatory issues, price squeezes and resale of average-cost electricity.

UTILITY INCENTIVES TO MINIMIZE COST

The assumption in economic theory that firms will choose the cost-minimizing mix of inputs, does not necessarily hold for regulated utilities. For example, it has been known for two decades that a firm subject only to the constraint that it earn no more than a prescribed "fair rate of return" on its invested capital will employ more capital and less of other inputs than it would if its output were being produced in the least costly manner.\(^2\) Whether this result applies to any particular set of utilities depends on a number of factors that include how quickly rates are adjusted downward when the allowed rate of return is exceeded, and how quickly rates can be increased when earnings are inadequate to produce that return. If rates are slow to change, even a regulated firm may have a considerable incentive to minimize its costs. This can occur either where it is earning more than its cost of capital, and additional profits accrue until rates are adjusted downward, or where it is earning less than its cost of capital, so that losses are minimized while waiting for rates to be raised.

\(^1\)Utilities that are not under FERC regulation will, of course, have different incentives.

\(^2\)Averch and Johnson (1962). This result requires that the allowed rate of return exceed the firm’s cost of capital.
Not only may the speed with which its rates are adjusted affect a regulated utility's costs, but so also may other facets of its treatment by regulators. For example, if regulators treat the returns to an investment asymmetrically, requiring rates to be reduced if the investment is successful but not permitting them to be raised if it is not, some investments that can be expected to reduce costs may not be made. By the same token, however, if rates can be raised to compensate utilities for all investments that turn out to be unsuccessful, they may be encouraged to undertake some activities that have a low probability of success—especially if they are permitted to retain some of the proceeds when an investment succeeds. Similarly, if the costs of unsuccessful investments can be shifted to users that they were not originally intended to serve, regulated utilities may be encouraged to undertake such investments even where the likelihood of success is small.

These considerations suggest that one cannot be certain whether regulated firms will minimize their costs without detailed knowledge of the regulatory regime in which they operate. A corollary is that, in designing regulatory procedures, attention must be paid to their effects on utility costs.

REGULATORY TREATMENT OF PROFIT RETENTION AND EFFICIENCY IN BULK POWER MARKET

The test-year procedure for regulating utility rates has one obvious advantage and one obvious shortcoming. Its advantage is that it creates a powerful incentive for a utility to reduce its costs below the estimate employed in the rate-setting process and to increase its revenues above their estimate. A utility that can lower its costs by purchasing electricity from another utility rather than generating the electricity using its own facilities has a strong incentive to do so, since it can retain the entire difference in costs. Similarly, a

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3 The other side of this is, of course, is that it has an incentive to overestimate its costs and underestimate its revenues, if regulators cannot easily assess the validity of these estimates.

4 Note that this is the case regardless of the cost estimates that were employed in setting rates.
utility that can sell electricity in the wholesale market at a price that exceeds the additional cost of producing it will find it profitable to do so, regardless of the estimate of the profits from such transactions that were employed in setting rates.⁵

Although the test-year procedure creates a powerful incentive for efficient operation after rates have been set, it has an important shortcoming. It gives utility shareholders all of the gains from unexpected improvements in external circumstances, e.g., a fall in fuel prices, while making them bear all of the costs of adverse developments that were unforeseen when rates were set. In other words, all of the risks of unforeseen developments are borne by utility shareholders and none are borne by ratepayers. If rate cases occur infrequently, and, thus, long periods elapse before rates can be raised or lowered in the face of changed circumstances, these risks can be substantial.

Although a regulatory regime involving automatic rate adjustments in response to changes in costs does succeed in reducing shareholder risks, it has another possible impact. In shielding utilities from the risks of changes in external circumstances, it also reduces the costs they incur as a result of mistakes in judgment. Moreover, it reduces their incentives to lower costs, since some or all of the benefits from the reduction accrue to ratepayers.⁶ The effect of replacing a regulatory system based entirely on estimates of costs and revenues with one based partially on actual costs is to reduce somewhat the incentives for efficient operation.⁷

⁵A utility will, under this regime, wish to estimate as few gains from wholesale trades as regulators will allow.
⁶Edison Electric Institute (1982), p. 11, argues that "... the growing predilection of state agencies to flow-through any and all savings from intersystem transactions to ratepayers is probably a much more significant factor than regulation by the FERC in management decisions relating to intersystem coordination."
⁷Under many types of fuel adjustment procedures, utilities use monthly estimates rather than actual fuel costs in setting rates, with adjustments made subsequently if there are errors in these estimates. Presumably these estimates are more accurate than those made at the time base rates are determined and, in any event, there are often procedures for adjusting rates quickly when errors occur so that a utility recovers all of its costs.
It is an empirical question whether the movement to a regulatory system in which some changes in costs are automatically passed on to ratepayers actually makes utility operations less efficient. To the extent that regulatory bodies increase their surveillance of utilities in order to offset any adverse incentives created by the form of regulation, the change in efficiency may be small. But regulators must be concerned about the fact that, when rate-setting involves automatic adjustments, incentives for efficient operation may be reduced.

In this Note, we are especially concerned with the effect of rate regulation on the incentives to engage in efficient wholesale electricity trades. What this analysis suggests is that the incentives for trade are greater where all of the gains from trade are passed through to shareholders, as they are under the test-period approach, than they are under a system of automatic rate adjustments. Under the latter approach, a utility that must reduce its rates dollar-for-dollar when it purchases electricity at a price lower than its own incremental generating costs may have limited incentive to engage in such a trade. Similarly, if a utility must reduce its rates by the entire difference between its selling price and its incremental cost, it, too, may have only weak incentives to sell electricity to other utilities.

THE EXTENT OF COST AND REVENUE "FLOW-THROUGHS"

The previous discussion, comparing regulation involving prospective rate-setting using test-year data with that employing automatic rate adjustments, implicitly assumed that all purchase costs could be flowed through to ratepayers and that all "profits" from the sale of electricity had to be credited to revenue requirements. However, in practice, even where a flow-through exists, it is not always the case that the costs of all purchases are immediately flowed through to ratepayers. Depending on the purpose of the trade, and on the jurisdiction regulating the rates, a utility may be unable immediately to add all of the costs of a purchase to its rates. Similarly, under some regulatory arrangements, a selling utility may be required to use only a portion of the profits from the sale of bulk power to reduce its

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8Indeed, these incentives are maximized under the former.
retail and/or requirements rates and thus be able to retain a portion of
the profits for its shareholders.

The effect of a less-than-complete pass-through of the gains from
trade on the incentives to engage in wholesale electricity transactions
is to encourage purchases and sales. We argued above that, where a
purchasing utility was required to pass through all of the gains from
trade to its ratepayers, it had little incentive to engage in such
purchases even where the selling utility's incremental costs were lower
than its own. In California, in order to encourage such purchases,
utilities are permitted to retain 2 percent of any gains that exceed an
estimate of the gains from purchases.

It should also be noted that there are cases in which the
incentives to purchase electricity are even weaker than where all of the
gains are passed on to ratepayers. This occurs where all of the costs
of a purchase cannot immediately be recovered from ratepayers, while
fuel costs incurred in generating electricity are immediately recovered
through an adjustment clause. In some states, where utilities are not
permitted immediately to pass through all purchased power costs, they
are permitted to include any unrecovered costs in base rates in
subsequent rate proceedings. If an appropriate interest payment is also
included, this amounts to a complete flow-through. However, of the ten
state regulatory commissions surveyed by Odisio, only one includes any
allowance for interest when adjustments are made. The result is to
discourage the purchase of electricity even where doing so could reduce
rates charged to native customers, since the utility's shareholders are
made worse off as a result of the trade.

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Joskow (1974) has argued that, where costs are rising, a utility
will still wish to purchase electricity if doing so lowers its rates,
even where there is no increase in profit from doing so, because
limiting rate-increases reduces criticism from regulators.

Odisio, pp. 26-27.

A similar incentive to engage in inefficient behavior occurs
where all of the costs of some types of electricity purchases may be
passed through immediately, while some of the costs of other types are
borne by shareholders. For example, under some regulatory regimes,
demand charges cannot be passed on to ratepayers while energy charges
can be. Thus, a utility may purchase economy energy, which does not
involve a demand charge, rather than buy cheaper firm power, where a
demand charge is imposed.
Where an incomplete pass-through of costs reduces, if not eliminates, the incentive to *purchase* electricity in the wholesale market, a utility will have an increased incentive to *sell* electricity where it need not credit all of the profits from sales to its ratepayers.\textsuperscript{12} Thus, one would expect utilities to attempt to make additional sales if they are permitted to retain a portion of the profits from such sales rather than being required immediately to credit their ratepayers for any profits earned.\textsuperscript{13}

Figure 1 can be used to illustrate the various ways in which profits from coordination sales are treated by different regulatory bodies. Note that, in all cases, we are considering the treatment of revenues from coordination sales minus variable costs incurred in making these sales.

As a point of reference, consider the 45-degree line labeled "100% Retention." This line represents a regulatory arrangement under which a utility retains all of the profits from coordination sales. Presumably, this creates the maximum incentive to engage in such transactions (short of receiving a bonus above 100 percent of the profits, of course). An alternative arrangement, which reflects present FERC regulation, is depicted by the 45-degree line labeled "Current FERC Policy." Here, the utility must make an estimate of the profits from coordination sales, $E^*$ in this case. This amount is taken into account in setting base rates by subtracting it from revenue requirements for the utility's other customers. If the utility earns more than $E^*$ from coordination sales, its shareholders benefit from coordination sales. However, as in the

\textsuperscript{12}Note that the comparison is with a complete pass-through of profits. The incentives to sell under any automatic adjustment clause will generally be smaller than under a test-year method of rate-setting, for the reasons discussed above.

\textsuperscript{13}In some states, utilities must pass through to their ratepayers revenues equal to the fuel costs of their coordination sales, but can retain any excess for their shareholders. In others, it is expected that the excess will be taken into account in setting base rates. In New York, utilities are permitted to retain a portion of any excess above an amount specified at the time that base rates are determined. Odisio, p. 52. This amount reflects an estimate of the *minimum* amount of coordination sales that can be expected. The remainder must be flowed through to ratepayers.
Fig. 1 -- Illustration of effects on retained profits of alternative regulatory rules

"100% Retention," the utility's profits increase dollar-for-dollar with every additional transaction that it makes. Thus, at the margin, the incentives to trade are the same regardless of the value of $E^*$. The curve labeled "New York" represents the treatment of profits from coordination sales by the New York State Public Utility Commission. In New York, a utility must estimate its minimum profits from coordination sales, $E_m$. If the utility earns a profit in excess of $E_m$, 20 percent is retained by utility for its shareholders and 80 percent is passed on to ratepayers. Up to $E_m$, the profit retention rate is 100 percent, the same as under "100% Retention" and "Current FERC Policy," so that the curve "New York" is kinked at $E_m$. 

The curve labeled "FERC Experiment" represents the treatment of profits from sales in the Southwest experiment. It goes through the origin since the treatment applies to all revenues. It is slightly steeper than the one labeled "New York" beyond Em, because the profit retention rate in the FERC experiment in the Southwest is 25 percent instead of 20 percent as in New York. Below Em, it is, of course, less steep. And it is less steep everywhere than either the curve "100% Retention" or the curve "Current FERC Policy."

What all of these arrangements reveal is that the maximum incentives for sales occur when the utility retains at the margin all of the profits from trade. This occurs whether or not the utility is required to estimate the profits from sales in determining its base rates. Any other type of arrangement necessarily reduces the utility's incentive to sell electricity. However, for various reasons, a 100 percent retention arrangement may be impossible to implement.

If a utility is not required to make an estimate of expected profit, so that shareholders retain all of the gains, ratepayers and public utility commissioners may regard the distribution of the gains as unfair. This can be rectified by requiring utilities to estimate their profits from sales, but this shifts risks to shareholders, since if the utility earns less than the amount expected it will fail to earn the allowed rate of return. For this reason, the utility can be expected to try to make its estimate as low as possible, which increases the required surveillance by regulators.

The risk to the utility can be reduced, the need to estimate revenues can be avoided, and ratepayers can share in the gains from sales, by dividing by formula all realized profits between ratepayers and shareholders, as in the FERC experiment or the New York State revenue treatment.\textsuperscript{14} However, while such arrangements produce all these

\textsuperscript{14} Recently, the Oklahoma Corporation Commission replaced a system under which Oklahoma Gas and Electric deducted profits from off-system sales during the test year in computing its base rates with one in which 90 percent of the profits from "opportunity" sales are credited to ratepayers through the fuel adjustment clause, with the company keeping 10 percent. \textit{Electric Utility Week}, December 19, 1983, p. 5. A company official was quoted as saying that "the new method reduces the downside risk."
benefits, they cannot be expected to create as large an incentive to trade as those that permit utilities to retain all additional profits from coordination sales. Or, in other words, one cannot simultaneously have ratepayers share in the gains, limit the risks borne by utility shareholders, and maximize the incentive to trade. The optimal policy must involve a trade-off among these goals.

It should be noted here that if all utility costs are included in measuring the gains from trade, there should be no difference in the incentive effects whether the utility retains 25 percent or 100 percent of the gains. The gain to a utility is \( pG \), where \( p \) is the proportion of the total gain retained by the utility and \( G \) is the total gain. If \( p \) is a constant, the quantity \( pG \) is maximized where \( G \) is maximized. We would, however, expect the value of \( p \) to affect the incentive to trade if all costs are not included in determining \( G \). Among the costs that are not likely to be included are those involved in consummating trades. Profit maximization implies that trades will take place to the point where incremental profits before trading costs just equal the marginal cost of trading. This will occur at a higher volume of trade, the larger is \( p \).

TRANSMISSION REGULATION AND WHOLESALE TRADE

Although utilities are not required to wheel electricity for one another, it could be in their interest to do so. Indeed, since utilities that are not connected directly must contract for transmission capacity equal to the amount of electricity they wish to trade, an unregulated utility that controlled the only transmission path available to other utilities would maximize its profits by setting a monopoly price for transmission service, selling electricity only when it is the lowest-cost supplier, and purchasing electricity only when it is the highest-cost buyer.\(^{15}\) It would have no incentive to use its control of the grid to defeat more efficient transactions among other utilities and, indeed, would sacrifice profits from doing so.\(^{16}\) An example illustrates the point.

\(^{15}\)If generation could be substituted for transmission, a utility that controlled the transmission system could increase its profits by selling both electricity and transmission services in the efficient proportions. See Vernon and Graham (1971).

\(^{16}\)We recognize that electricity need not follow the contract path
Suppose that utility A is willing to pay up to $100 per Mwh, its decremental cost for electricity, and that utility C is willing to sell electricity if it receives at least $80 per Mwh, its incremental cost. Utility B, which controls the transmission system, has incremental costs of $90 per Mwh.

If utility B attempts to thwart a transaction between A and C by denying access to the grid, its maximum gain is $10 per Mwh, since its incremental cost is $90 and A is willing to pay at most $100. Utility B can increase its profit by allowing A to trade with C and charging a price in excess of $10 per Mwh for transmission service. Since the difference between A's costs and C's costs is $20 per Mwh, they should be willing to pay up to that amount for access to the grid. Precisely where in the range between $10 and $20 the actual price of transmission service will lie is less important than the fact that it is in the interests of all parties for A and C to trade if the price B can charge for transmission services is unregulated. Alternatively, if B can purchase electricity from C and resell it to A, electricity will be produced efficiently, although a significant portion of the gains from trade will still accrue to B. Thus, in our example, if B pays C $84 and sells to A for $96, both A and C benefit from the exchanges, but B obtains $12 of the total gain of $20 per Mwh.

However, unless B can obtain at least $10 per Mwh from its "middleman" function, either by charging more than that amount for its transmission services or by simultaneously purchasing and selling electricity at prices that differ by more than that amount, it will frustrate the transaction between A and C. If the price of transmission is restricted to less than $10 per Mwh, B will either purchase

but, from the point of view of the exercise of monopoly power, it is the contract path that is relevant. A monopoly over the contract path may permit the exercise of market power even if the electricity actually flows over another portion of the transmission grid.

17Alternatively, if it purchases from C, the maximum gain is also $10.

18This assumes that there is no alternative transmission path that can be used at a price less than $10 per Mwh.

19If B's incremental cost is $81, it is still be more efficient for A to trade with C, although they will have to pay at least $19 for transmission service.
electricity for its own use from C, or sell electricity that it produces to A, both of which are inefficient. Or, to put it slightly differently, C will be unable to compete with B in selling electricity to A.20

Regulators may succeed in preventing B from exploiting its monopoly by regulating its transmission rates, but in doing so, they run the risk that rates will be set so low that the provision of transmission services is discouraged completely. If either transmission rates are regulated, placing a limit on the amount that B can charge for these services, or there are restrictions on the prices that B can pay and charge when it purchases and resells electricity, inefficient transactions may occur.21 In effect, B will vertically integrate into both generation and transmission in order to evade the effects of regulation.22 Thus, the regulation of transmission rates or the prices at which utilities can purchase and resell electricity, combined with the inability to compel wheeling, can lead to less efficient transactions displacing more efficient ones. If either price regulation were eliminated, or utilities were compelled to provide wheeling services, including a requirement that they construct transmission capacity as needed, this inefficiency might be eliminated. But, as long as both elements of the regulatory system are present, one cannot be certain that the gains from trade will be maximized.23

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20Reiter (1983), p. 62, argues that "Where those in possession of bottleneck monopolies are vertically integrated, the potential for anticompetitive mischief is ever present." He does not discuss, however, how this "potential" is affected by regulation of transmission charges.

21M. Cohen (1979), p. 1522, argues that "... vertically integrated systems use their control over the regional transmission network to isolate competing distributors from potential pooling partners or outside vendors of bulk power."

22For a brief discussion of price regulation as an incentive for vertical integration see Stigler (1983), pp. 136-137.

23The FERC bulk power market experiments, by making it more difficult for a utility to refuse to wheel, may encourage more efficient transactions.
Holmes (1982a) argues for imposing a requirement on utilities to wheel, including a requirement that transmission capacity be expanded to meet demand. He does not recommend any particular form of regulation for charges for transmission services, assuming that if rates are regulated they will be sufficient to cover the cost of building and operating the transmission system.²⁴ However, if rates are regulated, not only will regulators be required to prevent utilities from establishing monopoly prices for their transmission services, but also they will be forced to monitor their investment decisions. As long as rates for transmission services or wholesale electricity are regulated, utilities may have an incentive to thwart the transactions of others in order to obtain gains for themselves. This might be prevented by establishing priorities for the use of the transmission system when there is excess demand, but this would impose additional problems for the regulators.²⁵ The general point is, however, that, under regulation, utilities that control the transmission system may deny access to others to increase their own profits, with a resulting loss in efficiency.²⁶

SOURCES OF MARKET POWER IN THE BULK POWER MARKET

FERC regulation of bulk power transactions is predicated, at least in part, on a belief that, in the absence of regulation, some utilities would be able to exercise market power in making wholesale trades.²⁷ That is, it is felt that some utilities could, by limiting their

²⁴Schwartz (1976), p. 62, expresses the concern that even if utilities are required to wheel, they would "attempt to exact an unreasonable rate for the wheeling of power."

²⁵However, Meeks (1972), p. 87, argues that a "practical solution might be to treat transmission facilities as common carriers available, at least so long as there is unused capacity, to all potential 'shippers'. The rates and conditions for such carriage would have to be controlled, and, to assure adequate capacity, some form of mandatory regional transmission planning would seem essential."

²⁶Note that in the example presented above, the overall gain from trade was maximized despite the control exercised over access to the transmission system. Thus, a requirement to wheel would affect only the distribution of the gains from trade, not the amount of such gains.

²⁷The Edison Electric Institute (1982), p. 29, observes that "the potential problem of monopoly pricing under deregulation cannot be considered insignificant."
purchases or sales, affect the prices at which transactions occur. A seller of electricity with market power could, by restricting its output, increase prices and its profits, as well.\footnote{Alternatively, it could reduce the rates to its customers.} A buyer with market power could lower prices by limiting its purchases. To prevent such behavior, FERC places restrictions on the prices at which wholesale transactions can occur.

Market power can exist in the bulk power market even if there is no monopoly over access to the transmission system. There are several possible sources of such power. First, because utilities may not search among all other utilities to find trading partners, the cost of doing so being too great,\footnote{A substantial portion of this cost is the time of the operator.} the limited number of utilities with whom trade occurs may have some degree of market power. That is, sellers may be able to raise their prices above their incremental costs without losing all of their customers to other utilities. By the same token, purchasing utilities may be able to quote prices that are less than their decremental costs and still purchase electricity. Both situations may arise even though there are other buyers and sellers who would offer better trades but whose existence is unknown, or too costly to discover. The situation described here is the familiar one of local market power that is based on incomplete information about alternatives because search is costly. Market power based on this factor will depend on, among other things, the actual number of utilities over which search occurs. The greater the number, other things equal, the smaller will be any single utility's market power. If buyers search over a large number of potential sellers, the market power of any individual seller will be slight.

Second, some utilities may possess market power because high transmission costs of limited transmission capacity constrain the number of utilities that can profitably serve a given area. Utilities that would sell electricity to the utilities in an area if transmission costs were low, may be unable to do so because, at prevailing prices, they cannot cover both their own incremental generation costs and the costs of transmission. The result is that those utilities that are in close
geographic proximity to their trading partners may be able to set their prices above their costs, if they are sellers, or below their costs, if they are buyers. To put the point slightly differently, because of transmission costs, the geographic scope of the bulk power market is smaller than the entire country, so that some utilities may have market power in some regional markets.\footnote{Transmission costs here play the same role as do transportation costs in markets for manufactured commodities.} Whether such market power exists will depend on many factors, of course, one of which is the number of utilities for which transmission costs do not present an entry barrier.

Finally, some utilities may have market power if they are more efficient than others in generating electricity and if they have the capacity to serve a substantial portion of the market. These utilities can set their prices above their costs without losing all of their sales, since other utilities cannot profitably sell enough electricity at these prices to constrain their market power. The more efficient utilities will, if unregulated, set their prices so as to maximize their profits, taking into account their rivals' ability or inability to sell electricity profitably at those prices. The extent to which the more efficient utilities can set their prices above their costs will depend, in part, on their rivals' elasticity of supply. The less elastic that supply, the greater the market power they will have.\footnote{On this point see Landes and Posner (1981).}

The monopoly profits earned by firms with superior efficiency are to be distinguished from rents earned by more efficient firms. A firm may be a more efficient supplier of electricity than others but be unable to affect its price, perhaps because of its limited capacity. In such circumstances, the firm's revenues will exceed its costs, reflecting its superior efficiency, but it will have no market power.

**IMPLICATIONS OF THE EXISTENCE OF MARKET POWER**

Several observations are in order about the market power that may exist in the bulk power market. First, its significance partly depends on the costs of searching for trading partners and of transmitting electricity. If institutional, technological, or regulatory changes reduce these costs, the degree of market power that individual utilities
possess will be correspondingly smaller. The creation of energy brokers, as in Florida, reduces the cost incurred by utilities in obtaining price quotations from a large number of trading partners. Technological advances in telecommunications and microelectronics can be expected to reduce further the costs that utilities incur in searching for other utilities with which they can trade. Similarly, the substantial technological improvements in transmitting electricity over long distances that have occurred over the last two decades have increased the geographic scope of bulk power markets and reduced the extent of market power based on the high costs of electricity transmission.

Second, the market power possessed by local monopolies may not result in monopoly profits. If utilities are free to expand or contract the area over which they search, one utility, observing another earning large profits from coordination transactions, can attempt to enter its market, with the effect that the price in that market is reduced and supranormal profits are eliminated. Significantly, this can occur even where the price of electricity exceeds the marginal cost of producing it. There is, in other words, a distinction between possessing market power and earning monopoly profits. Local monopolies may have one without the other.

Third, if a small number of utilities trade with one another because they find wider search too costly or transmission costs too high, although each may have market power, the market outcome may be characterized as bilateral monopoly, rather than monopoly or monopsony. Suppose, for example, that there are only two utilities that trade with one another. Although the buyer has no alternatives, giving the seller market power, the seller is also without alternatives. This market structure, although it is not perfect competition because each participant possesses some market power, is also neither monopoly nor monopsony. Indeed, under some circumstances, the price that arises from the bargaining process may approximate that of competition.

Fourth, reaching judgments about the existence of market power in markets with a small number of trading utilities is complicated by the fact that the identities of buyers and sellers change over time, and indeed, that buyers can become sellers at sufficiently high prices.
From the point of view of the exercise of monopoly power, what is required is that a small and stable group of sellers faces a larger and stable group of buyers. In these circumstances, the sellers may be able to coordinate their actions and raise prices above their costs.\textsuperscript{32} If, however, the group of selling firms continually changes, they will have more difficulty in coordinating their actions, and the exercise of market power will be less likely.\textsuperscript{33}

Finally, even if market power exists, regulation will not necessarily improve the allocation of resources. If, for example, a price ceiling is imposed on a monopoly utility, but it is set too low, the outcome can be less efficient than if the monopolist were left unregulated. That is, the deadweight loss associated with an unregulated monopoly can be smaller than that created if it is regulated. This suggests, as a corollary, that regulation of bulk power markets may appropriate only if there exists a large degree of market power, since in those circumstances it is less likely that the ceiling price will be set inefficiently low.

**COGENERATORS AND SMALL POWER PRODUCERS IN THE BULK POWER MARKET**

A major difficulty in carrying out a market test of the economic viability of alternative electricity generation methods, such as cogeneration and the production of electricity in small units, is the fact that firms using these technologies can sell only to their local distribution company. In order to prevent local utilities from exercising monopsony power in these transactions, therefore, local utilities have been required to purchase electricity generated by qualifying facilities at the utilities' "avoided costs." This has led to considerable controversy about how avoided costs should be calculated and to disputes about whether local utilities have been treating cogenerators\textsuperscript{34} fairly.

\textsuperscript{32} Of course, no problems of coordination arise if there is a single seller.

\textsuperscript{33} There are, of course, equivalent conditions with regard to the exercise of monopsony power.

\textsuperscript{34} From this point on, we take the term "cogenerators" to include small power producers.
One possible way to avoid these controversies, however, would be to permit cogenerators to sell not only to their local utility but to any other utility that is connected to the same transmission system. In this way, it could be argued, the question of the appropriate price to be paid for electricity would not be the subject of negotiation but, instead, would be determined in the bulk power market.\textsuperscript{35} With competition for electricity, the monopsony power of the local utility need not be a matter of concern.\textsuperscript{36}

Several problems are raised, however, by the participation of cogenerators in this market. First, utilities have expressed the concern that the reliability of supply of cogenerators may not be equivalent to that of utilities, so that a purchasing utility might be unwilling to pay the same price to a cogenerator as it would to another utility.\textsuperscript{37} Indeed, in some circumstances it may be unwilling to purchase from a cogenerator at all. One solution to this problem would be to require that cogenerators contract for reserves with other utilities, so that buyers are assured of the same degree of reliability as that provided by utilities. Equivalently, buyers can maintain their own reserves.\textsuperscript{38} No special problem is created, on this account, by the participation of cogenerators in the bulk power market. All parties must recognize, however, that cogenerators cannot expect to obtain the same prices as do utilities, if they are less reliable suppliers. They must either contract for reserves, to provide equivalent reliability, or they must accept a lower price for their electricity.

\textsuperscript{35}To give some idea of the range of prices offered by utilities to cogenerators, the highest price offered in the six New England States in 1983 was 9 cents and the lowest was 3.85 cents per kwh. Even within these states, the range was sometimes considerable. For example, the highest price offered in Vermont was 9 cents while the lowest was 6.6 cents per kwh. See Electric Utility Week, June 27, 1983, p. 9.
\textsuperscript{36}This assumes that the bulk power market is competitive.
\textsuperscript{37}This is likely to be especially significant for transactions extending over several hours, where buyers are not generally required to maintain reserves equal to their purchased electricity.
\textsuperscript{38}In such circumstances, buyers will, of course, pay less for electricity than if reserves are provided by the seller.
A more significant problem arises from the fact that cogenerators generally are also purchasers of electricity at regulated rates from their local utilities. A cogenerator will find it profitable to purchase electricity from its local utility and resell it if the market price exceeds the price at which it can purchase electricity.\footnote{This can also occur where a contract permits a utility to purchase electricity at a rate that does not reflect its marginal cost.} But if the marginal cost of the local utility exceeds the market price, such a transaction will be inefficient.\footnote{This should be distinguished from a situation in which both the price at which the cogenerator can purchase electricity and the local utility's marginal cost are less than the wholesale market price. In such cases, there is no loss of efficiency, but the cogenerator obtains profits that would otherwise have accrued to its local utility and its ratepayers. Some of the concerns expressed by utilities about the effects of the simultaneous purchase and sale of electricity by cogenerators, although couched in terms of potential inefficiencies, are likely also to reflect this transfer.} One way to prevent such inefficiencies would be to ban the sale of electricity by cogenerators during periods in which they are also purchasing electricity.

**PRICE SQUEEZES**

An important issue that arises in evaluating the efficiency of wholesale electricity markets is what has come to be called a "price squeeze."\footnote{For a discussion of FERC treatment of price squeezes, see Holmes (1982).} A price squeeze is supposed to work as follows: An investor-owned utility (IOU) with a large generating capacity, in setting the rates at which it will serve a municipal utility sets them at a level that makes it impossible for the municipal utility to cover its costs through sales to residential, commercial, and industrial customers. The objective of this tactic, it is alleged, is to force the municipal to permit the IOU to serve its retail customers directly. Where the municipal utility is a more efficient distributor of electricity than is the IOU, retail rates in the municipal's market are higher than necessary. An example will illustrate the phenomenon.
Suppose that an IOU has a wholesale rate of $50 per Mwh, can generate electricity at $15 per Mwh, and has local distribution costs of $30 per Mwh. A municipal that it serves has assumed distribution costs of $10 per Mwh. Suppose, further, that the municipal's customers are willing to pay only up to $55 per Mwh for the fixed amount of electricity that they require.\textsuperscript{42}

Clearly, if this is the only IOU from which it can purchase electricity, the municipal cannot continue to operate since it cannot cover its costs of $60 per Mwh, even though it can distribute electricity more efficiently than the IOU.

The problem with this "analysis" is that it is incomplete. Given the municipal's greater efficiency in distributing electricity, an unregulated IOU could increase its profits from a maximum of $10 per Mwh [$55 - 15 - 30], when it serves the municipal's customers directly, by lowering its wholesale price to the municipal to, say, $35. Here, the IOU's profits rise to $20 per Mwh [$35 - 15], because it benefits from the municipal's superior efficiency in distribution.\textsuperscript{43} There may, however, be regulatory impediments to this behavior. First, the IOU may be unable selectively to reduce rates to the municipal if it must provide wholesale electricity on a nondiscriminatory basis. If this is the case, rather than forgo profits on other sales of wholesale electricity, the IOU may choose to maintain its price to the municipal at $50. The result is that the municipal is unable to cover the costs of wholesale electricity and local distribution and, therefore, is "squeezed." It is important to note that the harm caused to the municipal is not offset by a gain to the IOU. In fact, both would be better off if wholesale rates could be reduced selectively.

A second possible disincentive to reducing wholesale electricity rates to a municipal on a selective basis, even where the limitation on the overall return that the IOU may earn. In our example, the effect of reducing the wholesale rate to the municipal was to raise the IOU's

\textsuperscript{42} The assumption that the demand of the municipal's customers is completely inelastic is made only for convenience of exposition.

\textsuperscript{43} An analogy is that a manufacturer can increase its profits by employing independent retailers if they are more efficient in marketing.
profit by $10 per MWh sold to the municipal. However, if the IOU's earnings are constrained by regulation, it may be forced to reduce its prices for other wholesale transactions, or to reduce its retail rates, in order to keep from earning more than its allowed return. The result is to blunt the IOU's incentive to sell to the municipal. Indeed, the IOU may even have an incentive to offer retail service to the municipal's customers at less than its marginal cost of $45 [$15 + 30], making up the shortfall by increasing its rates on other services, since it can expand its rate base by doing so.44

Seen in this light, the incentive that an IOU may have to squeeze a municipal, or a squeeze that may result inadvertently, results from the regulation of the IOU. Freed from the constraint on its overall return, and able to charge different prices to different wholesale customers, an IOU will not wish to squeeze a more efficient municipal distribution company any more than a manufacturer will wish to squeeze an efficient retailer of its products.45

RESALE OF AVERAGE-COST POWER

A controversial issue confronting the operation of wholesale power markets is the terms on which utilities that are requirements customers of other utilities may sell electricity.46 Briefly stated, the issue is this: Requirements customers purchase electricity under long-term contracts that permit them to purchase an amount sufficient to satisfy their requirements at rates that are determined by regulation. Generally speaking, these rates are based on the average historical cost of the selling utility. As a result, it may be in the interest of a requirements customer to purchase electricity at the regulated rate and to resell it at the wholesale market price even where the marginal cost of generating the electricity exceeds the market price. In other words,

44 The additional rate base takes the form of the distribution plant in the municipal's service territory.
45 This is not to say that the IOU is indifferent to the price at which it sells to the municipal, but only that it will not wish to displace a more efficient local distributor.
46 The same issue also arises in connection with the possible participation in wholesale markets by cogenerators, although that participation raises additional questions.
the ability of requirements customers to purchase electricity at regulated rates may result in inefficient generation.  

The resale of partial requirements energy has presented a real-world problem in some instances, including the early operations of the Florida Power Broker. Utilities participating in the Florida Broker addressed this problem by agreeing that municipal utilities would not resell energy under provisions of the broker to the utility that was supplying requirements energy. The municipal may, however, resell the energy to a third utility.  

However, this does not eliminate the potential inefficiency.

Note that, the ability of the requirements customer to purchase electricity at average cost is not always inefficient, although it does always shift profits to the municipal. For example, if the municipal can purchase electricity at a price below the wholesale market price but where the wholesale price exceeds the seller's marginal cost, generation is efficient. The seller shares in the gains, however, only if the price at which the municipal purchases electricity exceeds marginal cost. Indeed, even if the transaction is efficient, in the sense that the electricity that is purchased and resold is less costly than the alternatives that are displaced, the generating utility will be worse off if its marginal cost exceeds the price that it receives. The following table indicates the three possible outcomes where electricity purchased at prices that do not reflect marginal cost can be resold:

| Case 1: Marginal cost > market price > regulated price. Generation is inefficient, generator loses, reseller gains. |

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47 The same inefficiency would arise if an IOU had a claim on the output of a generating unit at a contractual rate that did not vary with actual generating costs. Indeed, some municipals argue that they should be permitted to engage in the resale of electricity because they have paid demand charges that entitle them to the electricity that they resell.


49 Pace and Landon (1982), p. 61, argue that "Public policy aimed at promoting widespread wheeling by electric utilities or converting utilities into common carriers is inappropriate as long as the possibility of shopping for average cost-based wholesale power exists."
Case II: Market price > marginal cost > regulated price.
Generation is efficient, generator loses, reseller gains.

Case III: Market price > regulated price > marginal cost.
Generation is efficient, generator gains, reseller gains.

For generation to be efficient, the generator's marginal cost must be less than the market price, which reflects the marginal cost of all trading utilities in a competitive market. For generators to gain, the market price must exceed their marginal cost of generation. A necessary, but not sufficient, condition for this to occur is that generation is efficient. For resellers to gain, however, it must only be true that the regulated price is less than the market price. This clearly can occur, as in case I, even where generation is inefficient.
V. SUMMARY AND CONCLUSIONS

This section summarizes the major implications of our analysis and provides conjectures about how relaxed regulation of bulk power exchanges may affect the supply and pricing of these transactions. The ongoing FERC experiment in the Southwest will provide an opportunity to test many of the conjectures put forth in this Note. Others will not be formally tested by the experiment, although the experiment may improve understanding of them.

Although modified regulation of wholesale power exchanges may produce important short-run savings in operating and maintenance costs, many observers believe that the greatest benefit of "deregulation" in electricity supply will occur in the long run, as a more appropriate amount and type of investment occurs. It is unlikely that the Southwest experiment, scheduled to run for a maximum of two years, will provide much specific evidence on long-term investment effects. On the other hand, a well-functioning market for coordination sales is probably a necessary condition for realizing long-term gains. Should the experiment provide evidence that increased reliance on market forces can serve short-run efficiency objectives, the case will be strengthened for considering other forms of modified regulation.

The principal conjectures resulting from our analysis to date are the following:

Short-Run Effects

1. Relaxed regulation of wholesale power exchanges will lead to increased efficiency in the operation of participating utilities.

2. Unless transmission capacity is already used to full capacity at all times, the volume of energy exchanged will increase.

3. The effects of relaxed regulation will vary importantly by region of the country, because of historical differences in capital and operating costs.
4. Less regulated wholesale electricity markets will tend to produce prices for energy in each trading period (e.g., one hour) that converge to a single price, net of delivery costs. ¹

5. The smaller the number of trading partners, the larger the variance of prices around the market-clearing price in any trading period.

6. The more divergent the operating costs of the participants, the wider the range over which equilibrium prices may be observed. That is, the dispersion of prices within a given trading period will be wider the greater is the variation in operating costs.

Long-Term Effects

7. In the longer term, modified regulation will lead to investment in generating capacity smaller than would otherwise have taken place. By permitting an increased volume of coordination transactions, changes in regulation will provide a better "match" between distribution and generation for all utilities combined.

8. In the longer term, a greater investment in transmission capacity will occur than would otherwise have taken place, in order to facilitate the increased volume of trade that will occur.

9. In the longer term, less regulated wholesale markets will permit the integration of nontraditional generators, e.g., cogenerators, into the electricity supply system. A market-determined price for wholesale electricity solves the problem of what is the appropriate price to pay to such generators.² Furthermore, a competitive wholesale market will permit market

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¹We do not expect precise equality of price for all commodities in a given hour, because "errors" occur in any process that involves random fluctuations. We do, however, expect smaller dispersions in price than presently exist.

²Currently, the prices must reflect the avoided cost of the local purchasing utility, in accordance with provisions of Public Utilities Regulatory Policy Act.
forces to determine the amount of generating capacity from
these sources. New arrangements will arise for reserve sharing
to allow nontraditional generators to participate in the bulk
electricity market.

10. Long-term capital investments would be facilitated by the
development of a "futures" market for energy delivery.³ Some
form of a "futures" market is likely to develop if utilities
significantly expand their energy exchanges.

Institutional and Regulatory Considerations

11. An expansion of bulk power exchanges will strain the
relationships between private utilities and their requirements
customers. Partial-requirements customers, which frequently
are municipal utilities, can buy electricity from a privately
owned generator at a contract price that reflects historical
average costs and then, if electricity is not needed at that
moment, sell it at a higher spot wholesale price. In these
circumstances, the (private) generating utility may be selling
electricity to the (municipal) partial-requirements customer
at, e.g., 5 cents/kwh and repurchasing it at, e.g., 8
cents/kwh.⁴ Such arbitrage, which would be entirely normal,
and indeed beneficial, if the long-term contract price were
determined in the market, can create inefficiencies when these
prices are regulated. Moreover, even when there are no
inefficiencies, the resale of electricity by requirements
customers results in a transfer of earnings from the generating
utility or a transfer of income from the generating utility's
ratepayers.

³Some observers--e.g., Stelzer (1982)--suggest that power plants
will not be built in the absence of take-or-pay contracts. Others
question this view, observing that many capital-intensive industries
such as steel, chemicals, and the like function without guaranteed long-

⁴Cohen (1982) reports that this was a problem in Florida in the
early days of the Florida Energy Broker. It was solved by an agreement
that a partial-requirements customer could not sell back to its
supplying utility, although it could (and often does) resell to a third
utility under some circumstances.
12. Increased bulk power exchanges will increase the tendency of regulators to take the profits from wholesale transactions into account in setting retail rates. In principle, jurisdictional separation implies that retail rate setting should not be affected by the profitability of wholesale power exchanges. In fact, utilities often assert that state regulators take into account their profits from (FERC-regulated) wholesale exchanges when setting retail rates. Such regulatory "reachback" in retail rate setting may offset part or all of the efficiency gains that could accompany less regulation in the wholesale supply.

13. The coexistence of unregulated wholesale exchange prices and regulated retail prices may create incentives for inefficient trades. For example, utilities that are allowed to recover only historical average costs on the electricity they generate for their own retail customers, but which can obtain a market clearing price for electricity they sell in an unregulated wholesale market, may find it profitable to divert electricity they generate into the wholesale market while serving their retail demands with electricity bought on the wholesale market from other generators. In some circumstances, this may lead to less efficient supply of electricity.

14. The significance of regulatory lag on supplier incentives to participate in wholesale power arrangements will increase. For instance, if retail rates are quickly adjusted to limit earnings to a fair rate of return on invested capital, utilities may have little incentive to purchase wholesale electricity, even from more efficient suppliers. The benefits from deregulating wholesale exchanges may depend, therefore, on other actions taken with respect to retail rates. On the other hand, if present retail rates do not allow utilities to recover their true costs, but do automatically flow-through the costs of purchased energy to retail customers, and there is regulatory lag, utilities may have an incentive to purchase electricity in the wholesale market even if they must purchase from less efficient suppliers.
Comment on the Time of Transition

15. Deregulating wholesale power exchanges will not serve as a "quick fix" for the electric utility industry. Many of the benefits—if they arrive—will take several years to come into being. Any responsible official will want to know who gains and who loses, and how much, before undertaking such an exchange. It should be noted that deregulation of the airline industry was preceded by some twenty years of analysis and discussion in the academic, business, regulatory, and Congressional communities. In telecommunications, the recent settlement of the antitrust case against AT&T came after twenty years of litigation, temporary compromise, and study. One should not expect overnight changes in the electric utility industry; at the same time, additional analysis—and, importantly, the practical experience of a limited demonstration of the kind being conducted in the Southwest—may illuminate the potential benefits and costs of the undertaking.
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