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A COOPERATIVE APPROACH TOWARD RESOLVING ELECTRIC TRANSMISSION JURISDICTIONAL DISPUTES

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EXECUTIVE SUMMARY

Title VII of the Energy Policy Act of 1992 (EPAct) divides regulatory jurisdiction over transmission services between the Federal Regulatory Energy Commission (FERC) and state public utility commissions. EPAct explicitly gave the FERC jurisdiction over wholesale customers' *access* to transmission services. FERC already had jurisdiction over transmission service *pricing*. Meanwhile, EPAct gives state public utility commissions explicit jurisdiction over the siting of transmission lines and the associated environmental review. State commissions also have implicit jurisdiction over the recovery of any residual revenue requirements that are associated with the deployment of transmission facilities. Consequently, EPAct prevents the FERC from preempting the state commissions in the areas of transmission siting and environmental review. In sum, state and federal regulators share sovereignty over transmission services, implying that cooperation and coordination among them is necessary to bring about efficient outcomes.

In addition to the shared regulatory jurisdiction over transmission services, a utility's transmission facilities are shared by wholesale and retail customers. Moreover, the network characteristics of transmission services are well-known: it is not possible to accurately predict the particular transmission path that will be followed to bring electricity from its origination point to its destination point. As a result, an entire regional transmission grid can come into play when a wholesale customer transports electricity from point A to point B. Thus wholesale transmission service involves shared transmission facilities. Consequently, transmission service is appropriately termed a *shared good.*

As a shared good, the parties (regulators, transmission-owning utilities (TOUs), retail and wholesale customers) are mutually dependent, implying efficiency depends on coordination which in turn requires cooperation. Cooperation, though, depends on equitable outcomes from the cooperative process. As shown in Figure ES-1, transmission efficiency is inextricably linked to equity.

Fig. ES-1.	A diagram depicting the reenforcing relationship between efficiency and equity through cooperation, made necessary by shared federal/state jurisdiction and shared transmission facilities (Source: Authors' construct).

The authors propose the Network Model, built on cooperation and coordination, as the efficient arrangement to price, allot, and expand transmission services. The Network Model involves the creation of two institutional arrangements.

The first, the Regulatory Alliance, is a voluntary and regional regulatory oversight group made up of state public utility commissions and the FERC, with technical assistance from the appropriate North American Electric Reliability Council (NERC) region. The two goals of a Regulatory Alliance are (1) to fashion a set of state and federal regulatory transmission policies that create net benefits for utilities, wholesale customers, and retail customers, and (2) to equitably share these net benefits among these stakeholders. Because a Regulatory Alliance is a voluntary, cooperative forum, each regulatory body continues to be sovereign in its own jurisdiction as it fashions these policies.

The second group, the Transmission Cooperative, is made up of interdependent TOUs within a region. The Transmission Cooperative would operate a formal market for wholesale power and transmission service, and would jointly plan transmission investments. Figure ES-2 describes the relationship between a Regulatory Alliance and its associated Transmission Cooperative. Generally speaking, Regulatory Alliances oversee Regional Transmission Cooperatives.

Fig. ES-2. A diagram of the Network Model depicting the various groups, their members, processes, and goals (Source: Authors' construct).

The interrelationships in the Network Model between institutional group, their processes, and their goals is illustrated in Figure ES-3. The Regulatory Alliance seeks regulatory efficiency by implementing a cooperative policymaking process to coordinate the policies of state commissions and the FERC. The coordinated policies of the Regulatory Alliance guide the transmission planning, pricing, and allocation decisions of the Transmission Cooperative toward transmission service efficiency. Because transmission efficiency and generation efficiency are inextricably coupled, a formal wholesale power market is used to allot transmission service and direct investment decisionmaking.

Fig. ES-3. A diagram depicting how the Network Model results in electric wholesale market efficiency (Source: Authors' construct).

The formal wholesale power market (each Transmission Cooperative is a formal market) uses the processes of competitive bidding to achieve the goal of generation efficiency. The Transmission Cooperative selects the combination that maximizes net generation savings from among the bids and offers to buy or sell wholesale "power." In the Network Model, the allocation of transmission service is tied directly to the value of wholesale power transactions with the goal of maximizing net generation cost savings.

Next, the Network Model deals with pricing and access issues in a manner that promotes generation and transmission efficiency. The price for transmission service is based on the average cost of transmission investments in a Transmission Cooperative. The price is also tied proportionately to the relative contribution of transmission resources to the creation of net generation cost savings through the competitive process. The TOUs are rewarded according to sharing rules set by the Regulatory Alliance.

The net generation savings that are associated with the substitution of low-cost for high-cost generation are shared among the utilities, wholesale customers, and retail customers according to sharing rules that are devised by members of the Regulatory Alliance. There are three sharing rules. The first sharing rule determines the reward to the wholesale customers for purchasing transmission capacity and substituting less costly generation for more costly generation, as well as the reward (a percentage of net generation savings) to affected TOUs. The second sharing rule deals with the allocation of the latter. In effect, the second rule divides this benefit among the TOUs in the Transmission Cooperative. The third sharing rule deals exclusively with the values of the net generation savings allocated to each utility. Specifically, state public utility commissions determine how the allocated portions are to be shared between the utility's stockholders and the utility's retail customers. The operation of these three equitable sharing rules emphasizes that the efficient use and expansion of transmission should create net benefits for both wholesale and retail customers. Figures ES-4 summarizes the important points of the pricing and access portions of the Network Model and compares them with the more familiar "OR" pricing policy proposal.

Fig. ES-4. A comparison of the "OR" pricing policy and the Network Model (Source: Authors' construct).

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FOREWORD

This report deals with complex legal, economic, and technical issues and, as such, is not written as a primer. It is a follow-on to two previous NRRI reports on transmission access and pricing issues and assumes that the reader may be familiar with them. These are *Some Economic Principles for Pricing Wheeled Power* (1987) and *Non-Technical Impediments to Bulk Power Transfers* (1987). It is also helpful for the reader to have some familiarity with the "club theory," for example, the work contained in the latter chapters of NRRI's *Regional Regulation of Public Utilities: Opportunities and Obstacles* (1992).

The cooperative approach developed in this study is, we believe, a fresh one that has a superior chance of minimizing and relieving jurisdictional disputes that can arise in the new environment of electric power transmission. It focuses on equity's role in achieving efficiency, facilitates prudent transmission investment, and emphasizes the promotion of welfare gain to retail ratepayers. To accomplish this, several new institutional arrangements are introduced--primarily "Voluntary Regulatory Alliances" and "Transmission Cooperatives."

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CHAPTER 1

INTRODUCTION AND BACKGROUND

In May 1992, the Board of Directors of the National Regulatory Research Institute (NRRI) approved a project plan regarding ways of relieving jurisdictional disputes over electricity transmission. This report is the product of that approved project. According to the project plan, the objective of this report is to provide a policy analysis of different proposals to resolve emerging jurisdictional conflicts over electricity transmission. An approach to ease the jurisdictional tension on transmission matters is sought that will also enhance the efficiency of wholesale electricity markets while benefitting retail (sometimes called native-load) customers. It is a fundamental maxim of the authors that in order to maximize the nation's benefits from the operation of the electric industry, there must be efficient use of current and future transmission assets as well as efficient use of generation in the wholesale electricity markets. However, for any approach to be acceptable, state commissions must be able to protect the well-being of their constituents, not just in a static sense of holding native-load customers harmless, but in the dynamic sense of securing their economic welfare over time.[1]

Since the approval of this project plan, Congress enacted the National Energy Policy Act of 1992 (EPAct): Title VIIA contains provisions dealing with the wholesale power market, Title VIIB contains provisions dealing with transmission access and pricing, and Title VIIC contains provisions focusing on siting and environmental authority of state public service commissions. The authors recast the project plan in light of EPAct. The research questions and tasks undertaken are in light of EPAct to increase both the timeliness and usefulness of this report.

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[1] For a classical discussion of the relationship between "well-being" and "economic welfare," see I.M.D. Little, *A Critique of Welfare Economics,* 2nd. ed. (Oxford: Oxford University Press, 1957), chapter 1.

The report contains four chapters and three appendices. The first chapter includes an historical overview of the increasing tension between the Federal Energy Regulatory Commission (FERC) and the states over transmission issues, including recent major FERC and court actions affecting jurisdictional authority over transmission access. The chapter contains a review of the transmission provisions of Title VII of EPAct and explains how the stage may be set for further transmission jurisdictional disputes. Chapter 1 presents a discussion of criteria that should be used to judge proposals for solving the transmission jurisdictional disputes. Most of these criteria are statutorily-based or mandated. One additional criterion is presented that is necessary to fulfill statutorily-mandated federal and state goals. Chapter 1 concludes with a summary of the results of applying our objectives and criteria to the current FERC Staff proposal. Appendix A contains a more detailed examination of the current FERC Staff proposal on transmission access and pricing and shows how the proposal fails to fulfill the objectives and criteria developed in Chapter 1. Chapter 2 and 3 present a better alternative to the FERC Staff proposal, a network pricing approach for easing transmission jurisdictional disputes that also fulfills the criteria. Chapter 2 examines the desirable jurisdictional features of the transmission network, and Chapter 3 examines the economic features of the network approach. In Chapter 4, the authors present conclusions. The two remaining appendices, B and C, are devoted to presenting (1) the current FERC Guidelines on Regional Transmission Groups, and (2) the FERC Staff Discussion Paper on Transmission Pricing Issues.

Historical Overview

Prior to 1927, state public service commissions exercised jurisdiction over most activities of electric utilities, including ratemaking authority over interstate sales of electricity. However, in the landmark case of Public Utilities Commission v. Attleboro Steam & Electric Company,[2] the United States Supreme Court struck down state

[2] Public Utilities Commission v. Attleboro Steam & Electric Company, 273 U.S. 83 (1927).

commission regulation of electric rates for sales across state lines because the regulation imposed a direct burden on interstate commerce. The Court held that, although retail sales of electricity were essentially local in nature, wholesale transactions were national in character and thus were subject only to federal regulation under the Commerce Clause. At the time, however, there was no federal regulation of electricity rates. This created a regulatory gap: interstate transactions of electricity were regulated by neither the states nor the federal government. The pressure to fill this regulatory gap resulted in the enactment of the Federal Power Act of 1935 (FPA).

Although common carriage provisions were first proposed for the FPA, they were not enacted.[3] The FPA contained no provisions concerning the ability of the Federal Power Commission (the predecessor to the FERC) to mandate the wheeling of power. Nevertheless, the FPA provides that federal regulation applies "to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce."[4] But, before the 1960s, wheeling was relatively rare and bulk power sales were, by today's standards, meager.

Since the 1960s there has been tremendous growth in the interstate transmission system and its use both for wheeling transactions and bulk power sales for resale. Then, in response to the energy crisis of the 1970s, Congress enacted a five-part National Energy Act in 1978, which included the Public Utility Regulatory Policies Act of 1978 (PURPA). Title II of PURPA opened entry into the wholesale generation market to a select group of cogeneration and renewable-resource power entities known as "qualifying

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[3] As originally drafted, Part II of the FPA would have imposed common carrier obligations on electric utilities by making it "the duty of every public utility to furnish energy to, exchange energy with, and transmit energy for any person upon reasonable request. . ." S. 1725, 74th Cong. 1st Sess., sec. 202(a); H.R. 5423, 74th Cong., 1st Sess., sec. 202(g).

[4] Federal Power Act, section 201(b), 16 U.S.C. sec. 791 et seq. (1992).

facilities (QFs)." More importantly, PURPA sections 203 and 204 amended the FPA by adding sections 211 and 212. These new FPA sections contain detailed substantive and procedural requirements that must be met before the FERC can mandate wheeling. Taken together these requirements created a series of barriers to wheeling that was virtually insurmountable: only under extremely limited circumstances could the FERC mandate wheeling. For all practical purposes the FERC's authority to order wheeling was ineffectual.[5]

Because the FERC could not effectively order transmission access under the FPA as amended by PURPA, several state public service commissions asserted their authority over transmission access in limited (typically intrastate) power transactions.[6] However, the United States Supreme Court clearly stated that FERC has jurisdiction over "interstate transmission of electric energy" and "interstate wholesale sales of power" with exclusive authority to set rates, terms, and conditions of service even where all the parties to the transaction are located within a *single* state *if* the transmission service or wholesale power sale occurs over lines connected to the interstate grid.[7] Even when transmission service or a wholesale power sale involves parties only in one state, some interstate power and energy would be commingled with intrastate power and energy because of a utility's interconnection to the interstate grid. Therefore, by extension, it is

[5] A detailed analysis of the requirements of PURPA sections 203 and 204 is contained in an earlier NRRI report and is not repeated here. See Robert E. Burns, "Legal Impediments to Power Transfers," *Non-Technical Impediments to Power Transfers,* Kevin Kelly, ed. (Columbus, OH: The National Regulatory Research Institute, 1987).

[6] These states include California, Connecticut, Florida, Maine, New Hampshire, and New York. For a detailed discussion of the legal rationale for limited state public service commission authority to order intrastate transmission access under a pre-EPAct, PURPA environment see, Burns, "Legal Impediments to Power Transfers."

[7] F.P.C. v. Florida Power & Light Co., 404 U.S. 453 (1972).

also clear that the FERC has authority over rates, terms, and conditions of the transmission service if "unbundled," even if offered on an entirely intrastate basis.[8]

Before the enactment of EPAct, the FERC was quite active in setting price, terms, and conditions for both wholesale power sales and transmission service. Although, historically, embedded costs were used as the basis for both wholesale power sales and transmission service, the FERC has recently moved toward abandoning its traditional, cost-based pricing for wholesale power service if certain conditions are met.[9] In particular, the FERC indicated that it is comfortable with two forms of price discipline: cost-of-service regulation and market competition. The FERC intends to use the former when monopoly power is likely and the latter when suppliers must compete with one another.

Market-based rates for wholesale transactions are allowed when (1) the seller lacks market power in generation services, (2) the seller lacks market power in transmission services, and (3) there is no potential for affiliate abuse. By stating that the seller must not have market power in generation services, the authors mean that the seller must not dominate the relevant generation market. All independent power producers (IPPs) would pass this test because they are not utility affiliates and own no transmission facilities. Utility-affiliated power producers (APPs) might also meet this test, if they are selling from and to markets other than those where the utility affiliate has

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[8] FERC has accepted unbundled transmission tariffs from a number of utilities, for example, Utah Power & Light Company et al., Opinion No. 318, 45 FERC para. 61,095 (1988), order on reh'g, Opinion No. 318-A, 47 FERC para. 61,209 (1989), order on reh'g, Opinion No. 318-B, 48 FERC para. 61,035, aff'd in relevant part sub nom., Environmental Action Inc. et al. v. FERC, 939 F.2d 1057 (D.C. Cir. 1991); Entergy Services Inc., 58 FERC para. 61,234 (1992), order on reh'g, 60 FERC para. 61,168 (1992), appeal pending sub nom., Cajun Electric Power Cooperative Inc. et al. v. FERC, Nos. 92-1461 et al. (D.C.Cir. filed Sept. 24,1992). Thus, without a more cooperative relationship than now exists between states and the FERC concerning areas of their existing joint jurisdictions on transmission matters, retail wheeling might be too bitter a pill for state commissions or legislatures to swallow. Later chapters of this report discuss a more cooperative relationship.

[9] This discussion is based on J. Stephen Henderson, "The Commission's Transmission Pricing and Access Policy," *Proceedings of the Eighth NARUC Biennial Regulatory Information Conference*, David Wirick, ed. (Columbus, OH: The National Regulatory Research Institute, 1992), 127-30.

its franchised service area, and away from any "remote generation areas" where the utility also dominates.

By stating that a requestor of market-based rates should have no market power in transmission services, the authors mean that a requestor (for example, an exempt wholesale generator) must not have market power with *the ability to exclude other suppliers* from the market due to its or its affiliate's (utility's) ownership or control of transmission facilities. Here again, IPPs would easily meet this criteria. However, utility-affiliated power producers would need to offer open access transmission service if the power were to be transmitted over transmission lines owned by the utility affiliate. Within a regional power market, the utility would need to offer voluntary open-access transmission service; otherwise the FERC could not assure itself that the transmission-owning utility (TOU) wishing to compete in a regional power market, either directly or indirectly through an affiliate, had not used its transmission grid to block other, possibly lower-cost, suppliers from the market. Alternatively, the utility must show that its own transmission system is not relevant either to the immediate transaction or the regional transmission market. The latter is more easily demonstrated when the APP is producing and selling at a location outside of the region in which the affiliated utility is located.

The third concern about market-based rates for wholesale power sales is that there must be no potential affiliate abuse. Sales from IPPs are not affected by this criteria. For any APP, concerns about cross-subsidies, self-dealing, and daisy-chains and reciprocal dealing typically keep the APP from receiving market-based rates unless it is selling power far from its utility affiliate's grid. Selling to the APP's parent or to a neighboring utility raises these issues, particularly concerning whether the APP's price is preferentially high.[10] Thus, FERC developed a policy to encourage the use of market-based rates in the wholesale market for IPPs and "remote" APPs in situations where there were alternative suppliers. These pricing policies meshed with the new development of state public service commission oversight of competitive bidding for electric

[10] Preferentially low prices could be addressed by requiring the APP to offer to sell to other nonaffiliates at that price.

power supplies.[11]

Transmission Pricing

Indeed, the FERC also recently modified its traditional embedded-cost transmission pricing approach to allow for a more market-based approach. The new pricing model was developed in the NU Merger and Penelec cases.[12] It is based on balancing three principles: (1) holding native-load customers harmless, (2) providing the lowest reasonable cost-based price to third-party transmission customers, (3) preventing the collection of monopoly rents by transmission owners, and (4) promoting efficient transmission decisions. Applying these principles, the FERC adopted an "OR Pricing Policy" option. The "OR Pricing Policy" works as follows. When the transmission grid is expanded, the price of transmission service is set at the higher of either embedded costs (for the system as expanded) or incremental expansion costs, but not the sum of the two. Note that incremental costs can be short-run or long-run. Short-run incremental costs reflect line losses due to the transmission service, as well as any minor, short-term upgrades that are necessary for the transaction to take place. Long-run incremental costs are the costs of expanding or making a major upgrade to the transmission system to accommodate additional transmission service. Here, long-run incremental costs are appropriate because the authors are assuming that the transmission grid is expanded.

When the transmission grid is constrained but the utility chooses not to expand its system,

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[11] For a thorough discussion of state competitive bidding activities and associated regulatory issues, see Kenneth Rose, Robert E. Burns, and Mark Eifert, *Implementing a Competitive Bidding Program for Electric Power Supply* (Columbus, OH: The National Regulatory Research Institute, 1991).

[12] Northeast Utilities Service Company, Opinion No. 364, 58 FERC para. 61,070 (1992), reh'g denied, Opinion No. 364-B, 59 FERC para. 61,042 (1992), order granting motion to vacate and dismissing request for rehearing, 59 FERC para. 61,089 (1992), affirmed in part and remanded in part sub nom., Northeast Utilities Service Company v. FERC, Nos. 92-1165 et al. (1st Cir. May 19, 1993); Pennsylvania Electric Company, 58 FERC para. 61,278 (1992), reh'g denied and pricing policy clarified, 60 FERC para. 61,034 (1992), reh'g rejected, 60 FERC para. 61,244 (1992), appeal pending, No. 92-1408 (D.C. Cir. filed Sept. 11, 1992).

the FERC allows a utility to charge the higher of either embedded costs or legitimate and verifiable opportunity costs, but not the sum of the two. Opportunity costs are the value of foregone opportunities to the transmitting utilities. They tend to occur when third-party transmission access forces the transmitting utility to operate near its system capacity, thereby lowering the amount of economic dispatch and the number of off-system transactions it can engage in. These opportunity costs are, in turn, capped by incremental expansion costs. In no event is transmission pricing set below the embedded cost of transmission service.

Thus, the purpose of the "OR Pricing Policy" is three-fold. First, an embedded cost floor is set to protect native-load customers by preventing their rates from increasing because of a particular transaction. Native-load customers are also protected because if the incremental cost of expansion is greater than embedded costs, then the incremental cost is the price charged for transmission service. Native-load customers are also protected from bearing the differential of the lost opportunity costs over embedded costs. If, due to the transmission service, the transmitting utility lost legitimate and foregone opportunities with a higher value than embedded costs, then the price for the transmission service is the value of foregone opportunities (the opportunity cost). Thus, in all cases the native-load customer is held harmless, at least in the short run, from this single transaction.

Second, in the case of system expansion, the "OR Pricing Policy" does not allow for transmission pricing to be greater than the higher of embedded **or** incremental costs. Where there is no transmission system expansion, the "OR Pricing Policy" provides that transmission service pricing will be at the higher of opportunity costs or embedded costs. By setting the price of transmission service at (1) the higher of embedded or incremental costs, or (2) the higher of embedded or opportunity costs, it is contended that the FERC is setting the transmission price for third-party service at the lowest, reasonable price consistent with holding the native-load customers harmless. This is probably true in the static sense for a particular transaction, that is, when a particular transaction does not cause and will not contribute to transmission system expansion.

Third, by not allowing the utility to charge more than its incremental costs of expansion,[13] whether the transmission system is expanded or not, the TOU is prevented from earning monopoly rents. It may also be presumed, that by capping the TOU's transmission service price at the incremental cost of expanding the system, an incentive is not created to expand the transmission system to provide for efficient transmission investment decisions, because the utility's ability to earn a return on its transmission system is effectively capped by its incremental cost of expansion. Although preventing a TOU from earning more than its incremental costs of expansion mitigates against the utility earning monopoly rents, it does not create an incentive to invest in new facilities that may be needed to promote efficient wholesale power generation and transmission decisions.

The Provisions of EPAct Title VII

Although the PURPA Title II provisions dealing with FERC's authority to wheel were ineffectual, the Title II provisions allowing for market entry of QFs was most effective. By 1988, FERC had approved about 62,000 megawatts (MW) of QF capacity, and by some estimates half of all new capacity is expected to be from nonutility sources. This created further demand for more sources of economical nonutility generation. Even though several state commissions implemented competitive bidding to find the most economical sources of new power (whether from a utility or nonutility source) and the FERC implemented market-based wholesale power rates and revised its transmission pricing rules to promote economic sources of nonutility generation, two major impediments to the development of nonutility generation remain. First, non-QF, nonutility generation could not develop without obtaining an exemption to the Public Utility Holding Company Act of 1935 (PUHCA).[14] Second, nonutility generation "must be able

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[13] Recall that opportunity cost recovery is capped at the incremental cost of expanding the transmission system.

[14] Daniel Duann, Robert E. Burns, and Mark Eifert, *Competitive Bidding for Electric Generating Capacity: Application and Implementation* (Columbus, OH: The National Regulatory Research Institute, 1988), 42-46; Kenneth Rose, Robert E. Burns, and Mark Eifert, *Implementing*

to obtain transmission service at cost-based rates for the wholesale power market to be competitive and robust."[15]

Accordingly, when Congress sought to set out a new national energy strategy by enacting EPAct, it addressed each of these issues in Title VII. Title VII contained three interrelated parts: Subtitles A, B, and C. Subtitle A created a new class of generators called "exempt wholesale generators" (EWGs). Generally Subtitle A provides that any person engaged (directly or indirectly through affiliates) in the business of owning and/or operating one or more facilities used to generate electricity exclusively at wholesale is exempt from the PUHCA. This removes the first barrier to nonutility generation in the wholesale power market for both IPPs and APPs. Nevertheless, utilities are still prohibited from purchasing power from an affiliated EWG, unless every state commission having jurisdiction over the retail rates of the utility makes specific determinations that it has sufficient regulatory authority, resources, and access to books and records, has determined the transaction will benefit consumers, does not violate state law, does not create any unfair competition because of its affiliate nature, and is in the public interest.

Subtitles B and C are of greater relevance to this report. Subtitle B addresses transmission access and pricing. It begins by amending sections 211 and 212 of the FPA, removing the nearly insurmountable barriers of PURPA and providing the FERC with broad, albeit limited, authority to mandate or order wheeling in the wholesale power market. Taken together, EPAct sections 721 and 722 amend sections 211 and 212 of the FPA to provide that any wholesale generator may apply to the FERC for an order requiring a transmitting utility to provide transmission services to the applicant, including any enlargement of transmission capacity necessary for the services. Here is where Title VII, Subtitle C comes into play. Subtitle C is comprised of one section, EPAct section 731, that provides that "nothing in this Title [Title VII] or in any amendment made by this

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a Competitive Bidding Program for Electric Power Supply, 83-90; and Kenneth Costello, Edward Jennings, and Timothy Viezer, *Implications of a New PUHCA for the Electric Industry and Regulators* (Columbus, OH: The National Regulatory Research Institute, 1992).

[15] FERC Staff Transmission Task Force Report, 171; also see, Douglas Houston, "Toward Resolving the Access Issue: User-Ownership of Electric Transmission Grids," Policy Insight No.129 (Santa Monica, CA: The Reason Foundation, August 1991); and "Electric Power Wheeling and Dealing" (Washington, D.C.: Office of Technology Assessment, May 1989).

Title shall be construed as affecting or intending to affect, or in any way to interfere with, the authority of any state or local government relating to environmental protection or the siting of facilities." In other words, any FERC order that provides for enlargement of transmission capacity necessary for transmission service is subject to applicable state commission and local siting and environmental review. This provides the potential for transmission jurisdictional disputes. Although the FERC may order wholesale transmission service and may order that transmission capacity be enlarged, the ordered transmission service may not take place if the transmitting utility fails, after making a good faith effort, to obtain the necessary environmental and siting approvals, or property rights, under applicable federal, state, and local laws. Thus, EPAct specifically allows state and local environmental and siting policies to override a FERC order that would otherwise represent a federal policy that encourages the use of wholesale wheeling to encourage the efficient use of the wholesale generation market.[16]

There are also other restrictions on FERC's ability to order wheeling. For example, an order requiring transmission service may not be issued if, after considering consistently applied regional or national reliability standards, guidelines, or criteria, the FERC finds that the order would unreasonably impair the continued reliability of electric systems affected by the order. Most importantly, any wheeling order issued under section 211 will require the transmitting utility to provide wholesale transmission services at rates, terms, and conditions that meet the somewhat conflicting objectives and criteria found in section 212(a). In the next section, the authors discuss the statutorily-mandated objectives and criteria found in section 212(a) along with other implied objectives and criteria that must necessarily be met in order to fulfill the statutorily-mandated criteria.

Objectives and Criteria

The goals and objectives to be achieved by the FERC's transmission pricing and access policy are (1) to facilitate competition in wholesale power markets, (2) to promote efficient

[16] There is no federal preemption because EPAct explicitly reserves these powers for state and local agencies.

transmission decisions, (3) to provide the lowest reasonable transmission price to third-party customers, (4) to hold native-load customers harmless, and (5) to prevent the collection of monopoly rents by TOUs.[17]

Under FPA section 205, rates for transmission service provided voluntarily must be just and reasonable and not unduly discriminatory or preferential. As noted above, rates for transmission service ordered under FPA section 211 must meet the requirements of amended FPA section 212(a). Such transmission rates must allow the transmitting utility to recover all costs incurred in connection with transmission services and necessary associated services. This includes, but is not limited to, an appropriate share, if any, of legitimate, verifiable, and economic costs, including taking into account any benefits to the transmission system of providing the transmission service, as well as the costs of any enlargement of transmission facilities. The transmission rates must also promote the economically efficient transmission **and** generation of electricity. They must be just and reasonable, and not unduly discriminatory or preferential; and ensure, to the extent practicable, that costs incurred in providing the wholesale transmission services, and properly allocable to the provision of such services, are recovered from the applicant for transmission service and not from a utility's existing wholesale, retail, and transmission customers. Further, they must prevent the collection of monopoly rents by the TOU. In order to achieve the above objectives and criteria, the FERC must seek comity with the state public service commissions who have exclusive jurisdiction over transmission siting and environmental concerns, as well as residual jurisdiction over recovery of capital and other transmission-related costs from native-load, retail customers.

For the FERC to address these objectives and criteria in a systematic fashion, it must be willing to take a comprehensive look at its transmission pricing and access policies to see if they properly foster competition. The principal means of fostering competition in the wholesale generation market is to promote the economically efficient use of the transmission **and** generation of electricity. To achieve the goal of fostering competition in the wholesale generation market, the FERC must be willing to **link up** its wholesale generation pricing policy with its transmission

[17] See "FERC Staff Report on Transmission Pricing and Access."

pricing and access policy in such a way that both currently economic transactions can take place (fulfilling static efficiency) and investments in transmission can be made that will also allow economic transactions to be made in the future (fulfilling dynamic efficiency).[18]

It must be remembered that state public service commissions maintain jurisdiction over transmission siting and environmental concerns, as well as jurisdiction over any residual revenue requirement necessary for full recovery of the cost of transmission lines, whether old, new, or newly expanded. Unless native-load customers of investor-owned utilities are permitted to benefit (or at least be held harmless) from wholesale generation transactions, whether they be customers of a buying, selling, or transmitting investor-owned utility, there is no incentive for the state public service commissions to encourage their investor-owned utilities to be active in the wholesale generation market. Therefore, the FERC must develop its transmission pricing and access policy in such a way that native-load, retail customers are, in all cases, not only held harmless, but benefit from the development of a competitive wholesale market, regardless of whether an investor-owned utility is a seller, a buyer, or a transmitting utility.

[18] Static efficiency deals only with the efficient allocation of existing resources. Dynamic efficiency considers the efficient allocation of resources through time, and therefore, involves investment efficiency; that is, investment that promotes the efficient allocation of future resources.

However, linking generation and transmission policies together is a prerequisite for the FERC to achieve both its statutorily-mandated goal of promoting economically efficient transmission and generation, and to facilitate comity and cooperation with the state public service commissions. Only in partnership with the state commissions can the FERC hope to promote both the short- and long-term efficient transmission and generation of electricity. Therefore, promoting a partnership and comity with the state commissions should be an additional goal for the FERC and state commissions--necessary for efficient transmission and generation, as well as for fostering and encouraging the development of a dynamic and competitive wholesale market.

Comments on the FERC Staff "OR" Policy

The "OR" policy is the FERC Staff's proposal, for discussion purposes, on transmission access and pricing. It combines "first-come, first-served" open access for third parties with fixed-price contracts for transmission service. Transmission price would equal embedded cost for surplus transmission capacity and the lesser of opportunity cost or incremental cost otherwise.

Two interesting features of the "OR" policy are (1) the use of "first-come, first-served" rule to allot transmission service and (2) the assigning of common-property status to surplus transmission capacity. Appendix A contains the authors' economic analysis of the "OR" policy with the key points summarized below.

Allocative Efficiency

The Appendix A analysis concludes that the "OR" policy will not allocate generation or transmission resources efficiently. Competition relies upon price changes to ration and reallocate resources. The "first-come, first-served" rule to allot transmission service does not ensure that those obtaining transmission service are those who maximize generation cost savings. If they are not, the "OR" policy would not remedy the problem because contract prices are fixed, stifling intertemporal competition. Under fixed contract prices, reallocation is impossible, allowing inefficient wholesale power transactions to remain on line.

The "OR" policy also results in price discrimination for transmission service by tying prices directly to the incremental cost of service that is likely to rise with usage and the passage of time. In the short run, efforts to upgrade a transmission system toward its theoretical limit meet with diminishing returns. Diminishing returns imply the cost-of-service curve will be upward sloping for transmission service, absent technological improvements. Over time, rising input prices and regulatory costs, more stringent environmental laws, less suitable terrain, and other factors are consistent with the cost-of-service curve to be upward sloping. Under the "OR" policy, the cost-of-service curve becomes the price-of-service curve, implying those who get transmission service first pay a lower price than those coming afterward.[19]

Price discrimination due to the "first-come, first-served" policy in the wholesale transmission market undermines competition in the wholesale power market. Those obtaining transmission service early will have a cost advantage and therefore a competitive advantage in the wholesale power market. They could employ "limit" pricing strategies, that is, they could charge a price for wholesale power that impedes entry, yet still earns a supranormal profit.

The competitive advantage given to those first in queue for service increases with the steepness of the cost-of-service curve. The larger the anticipated increase in transmission costs the more likely wholesale parties will be induced to quickly buy up surplus transmission reserves, since they are priced at embedded costs. The "OR" policy also provokes a "Tragedy of the Commons" in that transmission reserves will go to those making the quickest of power deals and not necessarily to those conserving the most

[19] See Appendix A for a general discussion on the temporal, sequential nature of transmission pricing under the current "OR" pricing policy.

generation resources.[20] Competition in the wholesale power market is hindered because the "OR" policy penalizes search time. Wholesale parties taking time to seek the best power deal are penalized with higher transmission prices.

Investment Efficiency

The "OR" policy, by giving surplus transmission capacity common property status, removes all incentive to build beyond current needs. Neither retail nor wholesale users can plan ahead and build ahead because no one has any residual property right on unused transmission investments. This provokes less efficient, power-voltage transmission investments, implying smaller scale economies and higher transmission costs. This would reinforce the "tragedy of the commons" problem and give those first in queue a larger competitive advantage in the wholesale power market.

The "OR" policy may or may not be implemented with an economic return to TOUs on wholesale transmission investments. Wholesale transmission investments would be priced at incremental cost that may or may not involve an economic rate of return. The issue of an economic return revolves around whether TOUs can finance wholesale transmission investments using equity. However, under the "OR" policy, investment decisions will be inefficient regardless of whether an economic return is or is not allowed.[21]

If no economic return is allowed, the TOU has little incentive to plan ahead on behalf of wholesale customers. Why assume the risk inherent to long-term planning for no economic return? Instead, the TOU would prefer to invest on an as-needed basis according to the needs of individual wholesale customers. Because no one has an incentive to exploit economies of scale, investments will not be efficient, and transaction costs will be higher than necessary.

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[20] The "Tragedy of the Commons" results from a lack of enforceable property rights over the use of a shared good. The absence of property rights causes each individual to overconsume in the present, for fear of being excluded, without adequate investment being made for the future renewal or expansion of the shared good.

[21] See Appendix A.

If an economic return is allowed, the TOUs have an incentive to maximize the capital costs of all levels of wholesale power transmission because this strategy maximizes total profit. The TOU would purposely separate wholesale transactions and handle each one individually because this allows it to avoid the scale economies that would reduce capital outlays and therefore total profits. With or without the profit motive, the "OR" policy would motivate inefficient wholesale transmission investments.

Equity Considerations

The "OR" policy lacks equity and is inconsistent with both economic theory and equity theory. Economic theory states that a resource should be paid the "value" of its marginal product on the margin so it earns at least the value of its total product. The operative term is "value" and value is linked to the net economic surplus created. In other words, the value of transmission service and its price should be directly linked to the net savings in generation costs it helps to create.

Equity theory considers production processes as cooperative processes in which individuals or entities come together to pool their resources. Equity theory adds to the efficiency argument that cooperation (joint production) only occurs as long as the net wealth created is shared equitably. The sharing rule found most equitable overall is called in the literature the "Principle of Proportionality," in which each individual's share of net wealth is made proportional to the relative value of their contribution.[22] Equity theory also concludes that the price paid for transmission service should be linked directly to the savings in net generation costs.

The "OR" policy does not link the price of transmission service to the value of net generation cost savings and the "Principle of Proportionality" it helps to create.

[22] See Charles G. McClintoch et al., "Equity and Social Exchange in Human Relationships," *Advances in Experimental Social Psychology* 17 (1984): 183-227

Therefore, the "OR" policy is inequitable, and in consequence, inefficient. Some may argue that equity and efficiency are not really linked and that efficiency is all that matters. This view is flawed because in a milieu where parties are mutually dependent, equity and efficiency go hand-in-hand or not at all. Efficiency requires cooperation, cooperation requires equity.

The electric power industry is imbued with mutual dependency largely because of the network properties of transmission. The implication is clear: the pricing of transmission service must be equitable for results to be efficient. Transmission prices must be tied to generation cost savings for transmission service to be efficiently provided and for the wholesale power market to be sufficiently competitive. This is the very reason why the authors have developed an alternative proposal called the "Network Model" that binds equity to efficiency in a way that bolsters competition in the wholesale power market and encourages optimal transmission investments. The Network Model employs "regulation by rewards" instead of "regulation by commands" to direct transmission and wholesale power market activities.

Jurisdictional Concerns

Once implemented, the "OR" policy could evoke a flurry of wholesale power transactions for the reasons given above. Transmission systems would be driven toward their system limits, making new transmission investment necessary to accommodate further wholesale transactions. As argued above, investments will most likely be inefficient, allowing a strong argument to be made for FERC intervention. Investment inefficiency could extend FERC oversight to transmission planning.

Under the "OR" policy, states may not willingly site transmission investments particularly when most of the benefit flows to others. This would be especially troublesome for states located between others that are highly involved in the wholesale power market. The refusal to site transmission circuits could also be seen as a restraint on interstate commerce and could provoke further federal involvement in regional transmission-grid planning, including siting and expansion. In Chapters 2 and 3, the authors introduce the "Network Model," which emphasizes jurisdictional cooperation as a regulatory vehicle to promote the efficient use of transmission and generation resources.

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CHAPTER 2

THE TRANSMISSION NETWORK MODEL: JURISDICTIONAL FEATURES

The Network Model is proposed by the authors as a viable way to mitigate jurisdictional disputes, bolster competition in the wholesale power market, allot transmission service efficiently, and promote equity. The Network Model takes a regional view of transmission service by creating two groups to bridge regulatory and industry activities and to bridge the regional gap in regulation. One group, the Regulatory Alliance, joins the state commissions and the FERC, with technical support from the North American Electric Reliability Council (NERC). Its job is to oversee the second group, the Transmission Cooperatives, that joins TOUs. The Transmission Cooperatives' job is to put forth the policies and agreements of its Regulatory Alliance. The Network Model builds upon the distinct but dependent roles of regulators. It supports more competition in wholesale power markets; it does not, however, act as a surrogate for regulatory oversight. In fact, its aim is to make regulation the guardian of competition and competitive markets the conduit for regulatory policies. The regulation versus competition debate is here dismissed as misguided; both regulation and competition are needed, and the Network Model builds on this.

The competitive process is not always smooth and orderly. Left alone, it could impair the industry hallmark of stable service. The challenge for regulators is to organize their forces and improve overall service, both generation and transmission. The Network Model holds cooperation as the best way for regulators to enhance competition in wholesale power markets. Regulatory Alliances are voluntary groups (partnerships) of regulators seeking to bridge regional gaps in regulation, resolve jurisdictional differences, and reach cohesive agreements that align autonomous policies. The goal is to place competition within the regulatory paradigm, not the other way around, and dovetail the fit.

The main reason to open up wholesale transmission service is to make the wholesale power market more competitive. Greater competition would conserve generation resources, both fixed and variable inputs, and narrow the gaps in regional costs. The challenge is how to coordinate regulation and competition in a way that brings about the best use of all resources.

Although the "invisible" hand may drive a competitive market, a market matures as it becomes more formal and standard in operation. To promote this, the Network Model uses competitive bidding as the primary way to allot transmission service. The buyers do not directly bid for transmission service per se; but instead, submit wholesale power contracts, or bids and offers to either buy or sell wholesale power. The job of the Transmission Cooperative is to put together a combination of contracts, given transmission limitations, that produces the highest net generation cost savings, that is, total generation savings net of transmission costs.[1]

The pricing formula for wholesale transmission service is tied to the systemwide, average cost of material investments, such as, poles, transformers, conductors, and everything else needed to transport power and maintain system reliability. To be fair and efficient, a sharing rule is added--the Transmission Cooperatives would receive a share of net generation savings. This ties the reward for Cooperatives to how well they control the cost of service and tally-up savings in generation: the more they save, the more they earn *and* the more society saves. This is consistent with what analysts call "incentive compatibility."

Discussions follow on the main features of the Network Model: Regulatory Alliances, the Transmission Cooperatives, the pricing formula, and the competitive-bid format. The discussions are general in nature, but strung together reveal a framework as to how regulators as a cooperative group can hone the forces of competition to the good of society. Each discussion gives rise to many how-to technical questions.   Although it is

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[1] The Network Model uses competitive bidding to allot both firm and nonfirm transmission services.

true that the acceptance of an idea ultimately rest on settling technical issues, such issues go well beyond the intent of this report and are left for future study.

The discussion on Regulatory Alliances emphasizes the importance of cooperation among regulators, and how without it, efficiency suffers. The need for cooperation comes from the mutual dependency binding together jurisdictions, and the premise that no jurisdiction is sovereign in all matters of industry.

The discussion on the Transmission Cooperatives centers on what they do, how they do it, how they dovetail with the Regulatory Alliances, and how they differ from Regional Transmission Groups (RTGs, the FERC conception of industry cooperation). Their main purpose is to conserve both generation and transmission resources. Their main duties are to run the competitive-bid process and coordinate transmission planning. Their main feature is they include TOUs only.

The discussion of the pricing formula builds on the inseparable linkage between equity and efficiency. It shows how incentives--sharing formulas--can be used to bring about the efficient use of both generation and transmission resources. A part of the discussion concerns the unique feature of transmission systems. Transmission systems are club goods and this affects the pricing of transmission service.[2]

Much of the current debate over transmission is extraneous. The real issue is competition in wholesale power markets; it is here where the real savings to society can be found. The authors' intent is to go beyond the transmission issue per se, and focus directly on competition. The solution is to employ the Transmission Cooperatives as brokers of wholesale power, and to use competitive bidding as the medium to make formal and standard the brokering process. The competitive-bid process becomes the centerpiece to streamline the relationship between regulators and TOUs. Thus, competition becomes the conduit of regulation and regulation the guardian of competition.

The Regulatory Alliances

[2] Club goods are shared by users, implying that the good's value to any one user depends on its usage by others.

The expression "Regulatory Alliance" is meant to differ from regional regulation as normally understood. An alliance is any group joined in purpose for mutual benefit. All profits and losses are to be shared by all members. In the Network Model, a regional alliance (partnership) of regulators would form to open up wholesale transmission service. The mutual gain is the savings in generation resources; however, for cooperation to work and last, the mutual gains from saving generation resources must be shared fairly.

In a recent NRRI report on regional regulation, cooperative clubs were described and detailed.[3] Their purpose is to make the dependency among regulators an asset, a source of mutual benefit. They are defined as voluntary groups with an agreed-upon protocol to form and put forth joint policies. Their design can vary, but members are always autonomous, and participation is always voluntary and selective. Cooperative clubs are *not* regional sovereigns with regulatory powers; they are simply forums to reach and put forth mutual agreements.

The view of regional regulation expressed here differs widely from more well-known versions. Most involve a new layer of regulation: a self-governing entity with regulatory powers. Our form of regional regulation does not; nor would such a new layer of regulation work anyway because neither the states nor the FERC are about to willingly give up any of their autonomy. However, the need for regional oversight exists, and will only grow as competition grows within the wholesale power market and as those markets become more regional.[4] The basic dilemma is clear: the industry does business on a regional level, but regulators operate on the state and federal levels. This lack of balance has already sparked disputes; and a poorly framed transmission policy would only make matters worse. Clearly, to restore balance, regulators must come together, and as a group, form their own regional offshoots.

A club's design, its unity, depends on the extent of mutual dependency. In general, as codependency grows, regulators must cooperate more and align their policies more in order for

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[3] Douglas N. Jones et al., *Regional Regulation of Public Utilities: Opportunities and Obstacles* (Columbus OH: The National Regulatory Research Institute, 1992), Part III.

[4] See Robert Poling et al., *Electricity: A New Regulatory Order?* (Washington, D.C.: U.S. Government Printing Office, 1991), 68-71, on the growth of the wholesale power market.

any one of them to work. In the electric industry, dependency can come from mergers, power pools, joint ventures, new technology, the transmission network, new regulations, as well as from other sources. As the industry becomes more regional, more mutually dependent, more inseparable, so do the jurisdictions. The policies of regulators can spill over and become entangled. The spillovers can evoke policy loop flows because the industry operates on a regional level. Like electrical loop flows the policies of one jurisdiction can spill over to the chagrin of others.

Like any unattended flow, policy flows can become turbulent and disturb regulatory outcomes, making the regulatory process unstable and uncertain until regulators accept their mutual dependence, cooperate, and put forth mutual agreements. Although dependency may work to remove or limit autonomy, cooperation works to regain it. The agreements can be complex and involve joint action, or be simple and involve mutual limits on individual action.[5] Their purpose, however, is not to create dependency nor to remove it, but to mold it to the benefit of all.

As mentioned, the Regulatory Alliances are cooperative clubs, not sovereign bodies. They have no leaders, nor powers beyond their members, nor status to write new laws. They are not legal entities gaining power from and ultimately having power over the states. The Alliances would each have a FERC member, at least one NERC representative, and any given number of state commission members. The members are autonomous, and participation is voluntary and selective. Although, those with an agreement can pursue it without the consensus of others, assuming its lawful, the goal of

[5] Ibid., 221-36. There are three basic types of agreement (episodic, sequential, and coordinated) of varying complexity.

an Alliance is to reach mutual outcomes and turn mutual dependency into a source of mutual benefit so that it does not become a source of mutual opposition.[6]

To do this, regulators must find points of mutual gain and mold them into policies of mutual benefit. The benefit must be shared by all; otherwise, there is no incentive to cooperate. To be workable, cooperation must be incentive compatible. This prompts a healthy respect for equity, putting it on a par with efficiency. It urges continuity by urging regulators to redress ill-fated policies and settle them fairly. It prompts them to use new gains to settle old disputes, and to turn dispute resolution into a search for greater gains through greater levels of cooperation and efficiency.

One source of dependency among jurisdictions comes from the limited authority each has over wholesale transmission service. The FERC has control over the price of wholesale transmission services due to the Energy Policy Act of 1992 and those acts of Congress preceding it. It also controls the terms and conditions of access. The states have control over major transmission investments because of their control over siting and environmental issues. The NERC has control over the technical issues of reliability and system-to-system interconnection. This makes the FERC responsible for allocative efficiency, the states responsible for investment efficiency, and the NERC responsible for technical efficiency.

These sources of efficiency are themselves conditional. Allocative and investment efficiency are moot without technical efficiency. Investment efficiency is unlikely unless the transmission network is used wisely: current usage signals future network needs. Allocative efficiency is impossible unless transmission investments are where they belong most. Total efficiency--the sum of allocative, investment, and technical--is unlikely, if not impossible, unless regulators cooperate and together hone their policies.

A better use of generation resources is the benefit cooperation makes possible. However, this rests on having a coherent transmission policy: one that rewards quality

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[6] The Regulatory Alliance is an information-sharing, consensus-building forum whose product--jurisdictional agreements--need not be collective. The success of an Alliance does not rest on its ability to reach unanimous agreements, but rather on its ability to reach agreements that minimize turbulent policy flows; that is, that relieve jurisdictional disputes.

wholesale service. The FERC's desire for competitive wholesale power markets depends on the willingness of states to site new transmission facilities. Yet, unless rewarded, a state has no incentive to site new facilities particularly when the benefits go to others. On the other hand, the ability of states to serve their populace will depend upon the FERC's willingness to preserve the regulatory bargain. This, in turn, rests on how well the states embrace the goals of the FERC. Acting alone, no jurisdiction can assure a desirable outcome; such assurances can come only from working together with an eye toward mutual benefit.

Regulatory Alliances can only survive as long as the mutual gains are mutually shared. If not, cooperation will fail and the jurisdictions may try to dominate one another. The idea is to induce cooperation, not coercion. Some states, for instance, might become the natural providers of transmission service, others might become sellers of power, and still others might become primarily buyers of power. An equitable process would choose to reward TOUs and transmitting states for their contribution. A voluntary process would have no choice but to reward them.

With fair sharing, transmitting states have every incentive to open up their systems and make wise investments. In the electric industry, regulators need to cooperate and share mutual gains because no jurisdiction has complete sovereignty. No jurisdiction has complete authority over all matters of industry. For regulators, the electric industry is a shared good; so it only makes sense to cooperate. The alternative for regulators is to compete for jurisdiction and to become mutually opposed, but such contests are seldom in the public interest.[7]

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[7] The states, due to their control over retail rates and transmission siting, could form their own Alliances if cooperation with the FERC proves unattainable. Say, for example, low-cost generation utilities in state A require transmission service from TOUs in state B to market their power to buyers in state C. The states could form an Alliance in which TOUs of state B are rewarded for optimally providing and expanding transmission service. Regardless of the wholesale power and transmission rates set by the FERC, the state-only Alliance could divide the net generation cost savings in any manner desired. A state-only Alliance would not be as efficient as the Regulatory Alliance because not all entities involved in the sale and purchase of wholesale power fall under state commission jurisdiction. There exists a free-rider problem making state-only Alliances a second-best outcome.

The authors' proffered solution is to form cooperative clubs, the Alliances, not as a new layer of regulation, but as a new way to layer those already there. Their role is to discern jointly the who, the what, and the how of transmission service, and from this, craft balanced policies. As the main conveyor of policy, they have the Transmission Cooperatives.

The Transmission Cooperatives

Regulatory Alliances, comprised of regulators, oversee Transmission Cooperatives made up of TOUs. The Cooperatives put forth the policies of the Alliance. Their design would come from the system-to-system webbing already lacing together utilities. Transmission systems acting in union, such as, regional holding companies or power pools, would form natural cooperatives, or at least their hubs. Systems related by strong loop flows would form natural cooperatives. However they begin, their design should adapt to the changes taking place around them, changes they help to author.

The groupings are not special in and of themselves; their main purpose is to conserve both industry and regulatory resources. The driving force behind greater conservation is greater competition. Competition is a process of voluntary exchange; it creates new relationships; it creates new dependencies as it replaces old ones. As the web of dependency changes, the Alliances and Cooperatives will both need to evolve. This means that memberships, especially that of state commissions and TOUs, will change in response to changes in regional activities.

Some Regulatory Alliances may merge, others may split up and form smaller ones, some may stay unchanged. Some state commissions may belong to one Alliance, others to more than one. With time, many different groupings can emerge. Some Alliances may have only one Transmission Cooperative, some may have several. Some TOUs, like large regional holding companies, may belong to more than one Cooperative. TOUs within some Cooperatives may be subject to more than one Alliance. The number of combinations is large and it helps to have some overlap. Overlap among alliances will bring continuity to the competitive process and make it easier to coordinate activities across regions. This helps to bridge the regional gaps in regulation and develop industry standards. All of which helps to conserve industry and regulatory resources.[8]

The groupings (Alliances and Cooperatives) will change with time; thus there may be multiple setups, even though some setups would be more efficient than others. What is important is that the groups be driven by a mutual, continual search for greater efficiency. That is why no grouping should become a living fossil, rigid and fixed in design. Instead, they must stay aware of the changes taking place around them including both changes in interutility activities and changes the groupings helped to induce.

Regulatory Alliances and Transmission Cooperatives are mutually dependent both in action and in design. They are conditional and neither can take shape without the other. They are coupled in a closed, circular way that continually shapes and reshapes them with time. The Alliances guide the activities of the Cooperatives, which guide buy-sell activities in the industry. Buy-sell activities cause the web of dependency to be respun and put pressure on the Alliances and Cooperatives to both regroup. This is evolution through feedback and self-design; a process only possible if the jurisdictions keep their autonomy and the right to ally with whom they choose.[9]

This is why neither group should become heavily laden with institutional investments--especially the Alliances. If the goal is to strengthen competitive forces, then the regulatory process that obtains this must likewise be shaped by it. A competitive market, although organized, is driven by independent action. Any attempt to laden down the Alliances or Cooperatives with formal binding procedures will only be wasteful. Competition only works when everyone can spend their currency as they see fit. This is consumer sovereignty--the force that drives competition. In regulation, the currency of each jurisdiction is its autonomy. Any attempt to limit it will only cater to inefficiency and spark efforts to get it back. For regulators,

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[8] The FERC and the NERC, by belonging to each Regulatory Alliance, can become the natural forces to coordinate activities across Alliances.

[9] Consensus building provides a Regulatory Alliance with a dynamic mechanism to use in meeting its goal of creating and maintaining mutually beneficial agreements for its members. Because the outcomes of most agreements are often uncertain, consensus building and dispute resolution would occur within a Regulatory Alliance on an ongoing basis.

formal binding procedures cannot replace their right to refuse and choose their own path. The alliances can survive only if all members can ally with whom they choose. Alliance formation and decisionmaking must be driven by jurisdiction sovereignty--the force that drives cooperation.

The Cooperatives versus the RTGs[10]

Our depiction of industry cooperation is very different from the RTGs, as put forth in the FERC Policy Statement. The RTGs would have a "legislative" format, and to an extent yet unknown, would be self governing. The RTGs would become a new layer of regulation. In fact, they are offered as the remedy to bridge the current regional gap in regulation.

Their members would have to share information and coordinate activities, yet compete with vigor. They are to be broad in membership and include "fair and nondiscriminatory governance and decisionmaking procedures, including voting procedures."[11] They would join together both sellers and buyers of transmission and generation services. They would plan transmission at the regional level and consider the needs of both members and nonmembers alike. They would work with the states, improve state-federal relations, stop monopoly power, promote wholesale competition, and resolve disputes internally. For groups able to meet these "basic components," the FERC offers a degree of deference to their decisions. However, the FERC notes it has no authority to certify RTGs.

The RTGs could be driven by the all too visible hand of "managed competition." Their design could turn competition into a sluggish, centrally-planned affair, driven by inside politics, that puts equity over efficiency and relative gains over total benefits. Once a status quo forms within an RTG, departures could be rare and costly because not everyone might benefit equally or even proportionately. Any idea that threatens the relative position of RTG members may be discouraged; particularly, if it alters political control over decisionmaking. Even the placement of

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[10] Our discussion and analysis of RTGs is based on a policy statement by the FERC. A copy is provided in Appendix B. See, Federal Energy Regulatory Commission, *Policy Statement Regarding Transmission Groups*, FERC Docket no. RM93-0-000 (July, 1993).

[11] Ibid., 18.

a transmission line could become a hotly-contested affair. Those who benefit less, or not at all, or worse, clearly lose, could appeal to the FERC, or other jurisdictions, or threaten to do so as a ploy to redirect benefits.

Instead of cooling down disputes, an RTG could easily set them aboil. Its tendency is to become a litigation morass,[12] because it is difficult to get members to openly share information, cooperate and coordinate activities, and then compete vigorously. These RTG goals are clearly incongruous.

Within RTGs, group decisionmaking could easily lead to the establishment of a status quo of members. A status quo makes the division of gains more important than their creation. It always seeks income maintenance and constancy in relative position, and it seeks to make guarantees. In contrast, a truly competitive process only rewards those most efficient and removes all others. Competition emphasizes wealth creation. However, competition is dynamic, and always involves income effects and changes in relative positions. Competition offers no guarantees. Competition and the status quo do not mix. RTGs are unlikely to promote the high degree of competition in wholesale power markets that some envision. In fact, they may be more apt to fix prices and discourage entry whenever possible. Their tendency may be to maintain the status quo and become a source of constant dispute over matters of equity.

The Cooperatives are less complex and less costly to set up. They lack a formal political process and have no reason for one. The Regulatory Alliances make policy, the Transmission Cooperatives take policy. They do not self-regulate but leave the business of regulation to regulators. They are there mainly for their technical and business expertise. Their members are very similar, mostly IOUs, who are used to regulation and understand its ways. They are built around utilities already working together, for example, regional holding companies and power pools.

They could advance the competitive forces now shaping the industry. They could also help better align ongoing efforts by regulators to promote competition, rather than, erase and replace them. They would be simpler to set up than RTGs and easier to run because their

[12] For a listing of comments about RTGs from many viewpoints see, "What They Said about Regional Transmission Groups," *The Electricity Journal* (March 1993): 30-39.

members are alike. Their similarity and history of working together would aid their efforts to cooperate and coordinate over technical issues, both vital to efficient transmission service and competitive wholesale markets. Lastly, the Cooperatives would be less contentious because, unlike RTGs, they would not force together opposing groups, demand they cooperate, and then demand they compete. Instead, they take TOUs already working in union, those with a mutual history, and have them together open up transmission service and further activate wholesale competition.

Transmission as a Club Good

A Transmission Cooperative groups together TOUs on the basis of mutual dependency, their degree of physical unity, and considers them a single entity. Their joined transmission systems become a "club" good and not a "private" good. This means that all users--both wholesale and retail--share the same system, in its whole, much like members of a country club share the same golf course. A club good cannot be broken up and sold in pieces; just like a golf course is not sold to golfers hole-by-hole. The value of a golf course lies not in any hole; but in its whole. What a golfer buys is not a fairway or a green, but the right to share the golf course, in its entirety, with other golfers. Whether a golfer plays, depends on the price to share the same course and on how many are sharing it already.

What separates a club good from a private good is the need to share usage in order to capture the scale economies in production. Clubs goods must be shared; private goods are not. Lets say two utilities each need a 115-kilovolt (kV) line to move power. They could build separate lines, or pool their needs and build one 138-kV line. A 138-kV line carries twice the power of a 115-kv line, but costs less than the price of two separate 115-kv lines. Now it becomes smart to pool because each utility can lower its cost to transport power. But, just pooling is not enough, they also must agree to share the same line at the same time.

Private goods do not involve joint consumption. For instance, it is sensible for individuals each wanting a slice of apple pie to bake one pie: this is certainly cheaper than baking individual slices. Once baked, the pie can be sliced and served. The value of each slice is within: each has the same mix of ingredients. To slice the pie in no way lessens its value; in fact, it raises it by making it easier to consume. With private goods, the pooling of demand does not restrict usage nor force users to share: private goods are produced and consumed in separate units. But club goods are not: they are inseparable, and cannot be turned into separate units in any meaningful way. For them, the whole has greater value than the sum of the parts; to divide it up is to lose some of that value.

As such, systemwide methods--network methods--should be used for transmission service. Network methods, of which there are several types, set price on how moving power for one changes the cost and quality of service to others.[13] Network methods correctly presume that transmission networks are shared, congestible facilities; that usage is mutually dependent. This goes against the grain of contract-path methods normally used to price transmission service. These methods set price equal to the cost of a particular path, and in doing so, wrongly treat a transmission system as if it were a private good--something to be parceled out. These methods fail to treat system usage as mutually dependent; but instead, wrongly assume that it is independent.

[13] The term "network method" is a generic title for transmission methods that take an interutility, dynamic approach to power flow analysis. For background material see, William W. Hogan, "Electric Transmission: A New Model for Old Principles," *The Electricity Journal* (March 1993); Steven L. Walton, "Establishing Firm Transmission Rights Using a Rated System Path Model," *The Electricity Journal* (October 1993); Ross Baldick and Edward Kahn, "Transmission Planning Issues in a Competitive Economic Environment" (IEEE/PES, 93 WM 194-1 PWRS, 1992).

Contract-Path Methods

Contract-path methods are popular because of their ease in coming up with a cost-based rate for transmission service. Until now, this has worked well because power normally flowed back and forth across transmission systems; benefits and costs tended to even out over time. However, today power flows do matter, and tomorrow, even more so. With growing wholesale activity, power will begin to flow from low-cost areas, to high-cost areas, through those with transmission lines in between. Power flows are becoming more one-way, and greater activity in wholesale power will reinforce this trend.[14]

Under contract-path methods, a transmission system becomes much like a pie: it is to be served in slices. Each path becomes its own little system with its cost the basis of price. Each is treated as a private good: separable, its value within. But, there are at least two flaws to this approach: (1) it ignores loop flows, and (2) it sells the wrong product.

The flaws are related and both yield efficiency and equity problems. However, this should come as no surprise: users of a common system are clearly codependent like members of a country club. To physically break apart a transmission system would only ruin its value to everyone, because its value lies within its interconnections. Contract-path methods seemingly break apart a transmission network in just an accounting sense. But, they are not so harmless. They actually give TOUs a reason to break apart and reduce the importance of system-to-system interties.

Ignores Loop Flows

It is well known that power flows where it is least impeded. The actual paths and the contract path can have very little in common; in fact, they seldom do. A contract path is merely a legal fiction for accounting purposes; it has nothing to do with the physics of power flows. This causes the obvious problem: what the seller wants to sell is not what the buyer wants to buy. The

[14] See Appendix C, C-1 to C-4.

seller prefers a costly path, one loaded down with support devices and new equipment.[15] The buyer naturally wants the cheapest path possible. This failure to see eye to eye has nothing to do with efficiency, but has everything to do with equity. As a result, the time and resources used to reach an agreement are wasted. They are wasted because they do not produce any savings nor create any wealth; they merely divide it up. The wastage--a transaction cost--weighs down the competitive process; it slows down its rate of exchange and lowers its overall efficiency. Competition works best when exchange is formal and transaction costs are low.

Use of a contract-path method compounds another problem as well--the loop flow problem. Loop flows occur when the actual flow of power consistently deviates from the contract path. When they spill over and affect outside utilities (those not party to the contract), then problems can arise. Again, there is the obvious equity problem: the TOUs who support loop flows are not compensated. Yet there is an efficiency problem as well--an externality--that occurs because the price of service fails to cover its true cost.

The price only covers the cost of the contract path, not the parallel paths truly carrying the power. Prices will be too low and usage too high. Contract-path methods induce an overuse of transmission resources; they induce allocative inefficiency. They create an incentive problem (a moral hazard) as well; since buyers like low prices, they might agree to certain contract paths simply because most of the power flows off them and onto others. Some TOUs may think this may spare their systems in some way. Such ideas, although seemingly rational, are naive. They are not rational at the group level, and tend to undermine system-to-system relationships.

The material investments in paths taken by loop flows are free goods to wholesale buyers. However, a free good to one is but a tax to another. Someone has to pay, and

[15] There are several reasons why a TOU would charge as high a price as possible: (1) it lowers retail rates by allocating a larger-than-proportional share of costs to wholesale users; and (2) it could give the TOU a competitive advantage in the wholesale power market.

in this case, it is the retail customers of TOUs furnishing the parallel paths. They are the ones who must pay to keep their system reliable and add extra capacity to make up for shortfalls. If the goal is to "hold unharmed" retail customers of TOUs, then contract-path methods are inadequate.

An externality is both an efficiency and equity problem. Absent property rights, the parties harmed always pay. They pay either by being harmed directly or by paying for protection. Protection can be legal as in property rights or mechanical as in devices (for example, Flexible AC Transmission Systems); and, at times, both can substitute or complement the other. Contract-path methods provoke free riding and could very well spur a protective backlash by TOUs. Those harmed might decide to use devices able to protect their systems from loop flows. Such devices are available, including devices that offer some control over the flow of power, devices able to send loop flows elsewhere, and force buyers to bargain on a network basis.

These devices can be costly, both in money terms and in terms of network cohesion; but then, so can loop flows. By treating transmission systems as private goods, TOUs might begin to treat them as private property, as assets worth protecting. This could provoke TOUs to act in private and choose self action over collective action. It could weaken system-to-system interties and induce a "prisoner dilemma" scenario where actions are noncooperative and outcomes inferior. However, seldom are go-it-alone strategies optimal in a dependent world.

In the electric industry, it could lead to a disjointed planning process in transmission and generation, and gradually turn a transmission grid into a semiconnected strip of TOUs. The FERC would have little say in the matter because the states have authority over investments, and these devices have many defendable uses. Yet, this might be seen as a restraint on interstate commerce. This could spark antitrust suits whose outcomes may make matters even less efficient and less certain.[16]

[16] The whole issue of antitrust could fuel a hotbed of controversy on far-reaching issues such as: Do these devices imply a restraint of trade or merely a refusal to trade? Do parties not have the right to refuse trade that would leave them worse off? When does the refusal to trade by one become an illegal restraint on the trade of others? Where do the individual rights end and the rights of others begin? These issues and more could define the legal battles of tomorrow should cooperation fail and efforts to coerce participation arise.

The key point is why bother with contract-path methods? Why pick a method that pits equity against efficiency and one jurisdiction against another? Why pick one that urges TOUs to protect their transmission networks as parcels of private property, and in ways that could impair network reliability and cohesion? Why weaken system-to-system interties just to get buyers to buy on a network basis?

Sells the Wrong Product

Contract-path methods sell to buyers the wrong product. What buyers want is cheap, reliable transmission service, not a transmission path. The two are not the same but contract-path methods hide this. The reliability of service comes from the system as a working whole, and not from the merits of any particular path. It is the presence of multiple paths and the control over system use that makes a reliable system. Service reliability improves with the number of multiple paths able to move power to where it must go.

By selling the wrong product, contract-path methods create another free-rider problem. Like loop flows, the price paid for service does not match its demand on resources. Again, price is too low. It fails to include the multiple paths and other devices that makes service reliable. The reliability received does not reflect its true cost; the difference is a free good to wholesale buyers. Of course, increased reliability is not free to the affected TOUs and their retail customers: they are the ones stuck with the tab.

One way to clear up this problem is to have a standard, "generic" contract path, one that considers all system cost. Yet to be complete, it should include the cost of loop flows and parallel paths. It should include the multiple paths that give service its reliability. In fact, it should include all costs imposed on others, such as, lower system reliability, higher line losses, and foregone options. In other words, it should take a network approach to price transmission service.

In short, there are two basic problems caused by contract-path methods: the loop flow problem and the reliability problem. In both cases, wholesale buyers are given the free use of transmission resources. It results in a two-tier price system that involves a subsidy from the retail sector of TOUs to the retail sector of wholesale customers.

The accounting ease of contract-path methods do not justify their continued, use given the problems they create. They actually create a subsidy. They consider too few resources, distort prices, and cause a misuse of transmission resources. Besides being inefficient, they are unfair to the retail customers of TOUs. It remains to be seen whether their use can, on some ground, be justified.

Summary So Far

The one undeniable feature of the electric industry is that no jurisdiction has sovereignty over all matters. The electric industry is a shared good requiring that regulation be a shared endeavor. No jurisdiction can obtain its goals without the cooperation of others because all are mutually dependent. Mutual dependency makes cooperation necessary. However, for cooperation to work, mutual dependence must be transformed into mutual benefit by finding points of mutual gain. Cooperation does not work in a zero-sum setting. Cooperation only endures when it creates new wealth and shares it fairly among all contributors. The purpose of the Regulatory Alliances is to join together regulators from the FERC and the state commissions with technical staff from the NERC, so they may jointly create wealth.

The following list gives a quick summary of the main features of the Regulatory Alliances and Transmission Cooperatives:

The Regulatory Alliances:

- are voluntary forums of regulators
- made up from the FERC, the NERC, and state commissions that
- have a protocol but no legal regulatory powers

The Transmission Cooperatives:

- are arranged groups of TOUs
- built from current industry ties
- under the guidance of the Regulatory Alliance

The joint goals:

- to pursue efficiency and equity,
- to promote cooperation and coordination,
- to open up transmission service,
- to enhance competition in wholesale power, and
- to conserve generation and transmission resources.

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CHAPTER 3

THE TRANSMISSION NETWORK MODEL: ECONOMIC FEATURES

The basic features of the Network Model are set up to answer the basic issues of transmission service, which are how best to price, allot, and expand wholesale transmission service. The issue of how best to price it begins by accepting that transmission systems are club goods; that they are shared congestible facilities. The formula to set price should consider all material costs of a transmission network and avoid assigning particular paths to set price. It should be fair, not only to retail and wholesale customers, but also to TOUs. It should provide the right incentive to invest wisely and to use the networks efficiently. For this to happen, Transmission Cooperatives must consider congestion costs when planning network expansions.

One solution that meets these criteria is to use a sharing formula. All customers, both wholesale and retail, would pay a price tied to the average of systemwide material costs. However, wholesale customers would also pay a surcharge: a percentage share of the generation savings from wholesale power exchanges.[1] Because costs can vary over time, prices should likewise vary and mirror all moves in material costs, be they from changes in system usage or input prices. No customer, be it wholesale or retail, should be afforded fixed-price contracts. This is especially true of long-term power contracts. Fixed prices are nonresponsive to market conditions and therefore, incapable of driving efficiency. They are incapable of rationing usage, especially that of a transmission network.

The issue of how best to allot transmission service hinges on why it is being opened up in the first place. The answer is to conserve generation resources through greater competition in wholesale power markets. The whole issue of wholesale transmission service revolves around the issue of competition in wholesale generation. If this is the goal, then *competitive bidding* should

[1] Because wholesale customers pay a share of their generation savings, they are called upon to reveal only their expected generation savings. Confidential or proprietary cost information from EWGs or QFs is not required.

become the primary device, but not the only device, to provide wholesale transmission service. A formal bidding process would help to organize competition. It would help to make it a standard fare of low transaction costs. It also would help to resolve the issue of how best to expand transmission service because competitive bidding is a good source of information about future wholesale prospects.

How to Price Transmission Service

It is important to always view transmission networks as club goods whose parts can not be meted out piece-by-piece in any meaningful or nonarbitrary way. Networks should be looked upon as shared, congestible facilities. Methods to set price must respect this feature. To be efficient, prices must match changes in costs and assure full cost recovery. To be fair, they should promote competition in wholesale power markets but not through the use of subsidies. Contract-path methods should be discarded, and network methods adopted. Fairness implies that the approach taken should protect retail customers from wholesale abuses, while it opens up, as cheaply as possible, transmission service to wholesale customers. A good pricing formula would:

- conserve generation and transmission resources
- provide transmission service as cheaply as possible
- open up and wisely expand transmission service, and
- share all gains fairly

To design the right pricing formula, it is important to know how the costs and benefits of service change when users share a common system. The upside for retail customers is that wholesale customers help to pay some of the network's material costs--the cost of poles, conductors, transformers, and so on. The downside is it can lead to new material investments, more network congestion, and less network reliability. The upside for wholesale customers is access to an intact system, one already in place and capable of meeting their needs. The downside is the same as for retail customers.

Both groups share the same upside and downside: the upside comes from the sharing of material costs; the downside comes from having to share the same material investments at the same time. Or put differently, the upside comes from joint production (investment), the downside from joint consumption (congestion).

Congestion is the byproduct of having to share a common good. More precisely, it is the variable cost of joint consumption and has nothing to do with production. It is a feature inherent to club goods and not to private goods: private goods are produced and consumed in separate units. The cost of congestion rises with usage in much the same way that the time it takes to play a round of golf increases when more golfers show up. A good pricing scheme would prompt TOUs to minimize overall costs--the sum of material and congestion costs--and make sure that the net benefits to exchange are always positive; in essence, resources are always conserved.

For private goods, a good pricing scheme is different. Here, variable cost refers to market value of resources used up to make the good. What is meant by marginal cost, is the market value of resources needed to make *one* more unit. This is why setting price equal to marginal cost makes sense for private goods and leads to market efficiency; marginal cost measures best the cost to society of having one more unit. With private goods, this approach works well because they can be made and consumed unit by unit.

The use of marginal cost (or incremental cost) as an efficiency standard does not work well for club goods: it is not efficient nor incentive compatible. Club goods are not made in separate units as are private goods. To expand a transmission system, for instance, is not to create another unit of the same product. The system before and after are two distinct products, not two units of the same product.

To see how this affects the issue of pricing, suppose we used marginal cost to set the fees for a round of golf. There are several versions of marginal cost that could apply. The fee could be set to the marginal cost of building the last hole. Under this version, the first golfer to play a round ends up buying the golf course. Instead, the fee could be set to the marginal cost imposed on the golf course by a golfer. This version would cover maintenance costs but would fail to cover the cost of building the golf course. Then again, the fee could be set to the cost golfers impose on one another when playing a round, yet this too would fail to cover the costs of building and maintaining the golf course.

The treatment of a golf course as a private good and then applying marginal-cost concepts to set price is misguided and inefficient. A golf course is a club good whose usage is shared by all golfers playing a round. The product sold is the right to play a round of golf, and a round of golf consists of eighteen distinct holes. The holes are not separate units of production in themselves, but instead, distinct inputs making up the product. The same analogy holds for transmission networks: the transmission paths are distinct inputs that together make up the product called transmission service.[2]

This is not the approach taken by contract-path methods and by the FERC idea of incremental cost. Both are rooted in the theory of private goods: a theory built on marginal-cost pricing. Both would tie price to specific parts of a transmission system rather than on its wholeness. Because of this, neither method is suitable to price transmission service because neither treats transmission systems as shared, congestible facilities. Neither considers congestion properly (the cost of sharing the same system at the same time). Both lead to inefficiency, both in usage and in planning, and both would lead to equity problems, as well.

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[2] In the apple pie example, mentioned earlier, each slice is a private good. The reason is that: each slice has the same ingredients. They are identical. But each path in a transmission network is distinct and dependent on the others for its properties. To apply contract-path methods would be like selling an apple pie by its ingredients: some get the dough, some the brown sugar, others the apple, and so on. But, if this is done, then no one actually eats apple pie--the product desired.

The Congestion-Investment Tradeoff

As congestion increases along with usage, its costs begin to rise and rise sharply when the system nears its peak. The savings from replacing higher cost generation come to a stop, and the high level of usage challenges system reliability. Yet transmission networks are inherently efficient, and will alleviate congestion and bottlenecks through loop flows. Loop flows reduce system bottlenecks by distributing or spreading congestion costs; they help to manage better the cost of sharing the same system. Nevertheless, congestion is a choice variable. It can be lowered by upgrading a network's carrying capacity.

Whether or not the right amount of congestion is chosen, depends, in part, on the method used to account for costs. Contract-path methods are inherently inefficient:

- Contract-path methods do not compensate for loop flows,
- Loop flows, although seemingly a result of congestion, help to better manage congestion, and
- Contract-path methods do not compensate for helping to manage congestion better.

Another reason why contract-path methods are worth avoiding is that they do not offer the right incentive to efficiently manage loop flows. They will not elicit the right amount nor the right type of material investments. In fact, as argued earlier, they do just the opposite: they induce TOUs to use protective devices that can lead to system separation. So they fail on two counts. Not only do they fail to promote efficiency, they actually reduce it by impeding loop flows.

The network methods, by contrast, compensate TOUs for loop flows. They encourage better investment and usage choices. They induce a greater willingness among TOUs to cooperate and unify their systems. In so doing, they help to lower the start up cost of a Transmission Cooperative. However, to be efficient a Cooperative must decide whether to upgrade the system, to raise material investments but lower congestion costs, or to live with higher levels of congestion and fewer opportunities to supplant higher cost power. The right amount of congestion requires one to compare the net savings in generation resources from expanding the system to the cost of not doing so.

This latter statement is actually quite powerful. It implies that material investments in transmission are very similar to financial investments, so much so, that portfolio analysis applies. The rate of return on material investments becomes the present value of saved generation resources. Because a network cannot be expanded in all directions all at once, and because transmission investments vary in scale, scope, and completion time, the various options must be compared in present value terms. The task of Transmission Cooperatives is to choose the right portfolio of material investments, to choose the right kinds in the right amounts, and to choose the investment package that maximizes the present value of net generation savings.

The Pricing Formula

The pricing formula is not new to regulation. The general set-up is found widely in the literature on incentive regulation. Here, it takes the specific form:

$$P = AC + f\{ AS - AC \} \tag{3-1}$$

The following definitions hold: P is the price of transmission service to wholesale customers; AC is the average cost of all transmission investments, excluding the return to investors, of a Transmission Cooperative; AS is the average savings in generation from wholesale power exchanges; and f is the sharing rule.[3]

The price to retail customers is simply the average cost of material investments, AC.[4] The

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[3] AC is computed by dividing the total dollar value of transmission investments, excluding the return to investors, by total system usage--both retail and wholesale. AS is computed by dividing total generation savings from wholesale power--by both TOUs and third parties--by the amount of transmission capacity used up by wholesale power. AS is also adjusted for the effect of line losses on retail generation. *Infra*, 54.

[4] The price to retail customers could include a prorated surcharge so TOUs could earn a fair rate of return on capacity used for retail service.

price to wholesale customers (Equation 1) is average cost plus the percentage f of net generation savings. Why this formula works is seen when multiplying through by Q, the amount of wholesale service, and looking over the totals. This is shown as:

$$PQ = (AC)Q + f\{ AS - AC \}Q \tag{3-2}$$

$$TR = TC + f\{ TS - TC \} \tag{3-3}$$

Multiplying through by Q transforms the averages into totals: total revenue (TR), total cost (TC), and total saving (TS).[5] Because total revenue minus total cost is profit (PR) by definition, Equation 3 can be rewritten as the economic profit equation given below:[6]

$$(TR - TC) = PR = f\{ TS - TC \} \tag{3-4}$$

As long as the Transmission Cooperative behaves as a profit maximizer, it has the incentive to maximize net generation savings { TS - TC }, because this is the sole source of profit to the utility. Should it upgrade the network to allow more service, both total savings (TS) and total costs (TC) will rise: TC rises because total fixed cost are higher, and TS rises because congestion costs are lower. This is the tradeoff between material investments and congestion costs. To maximize its reward, a Cooperative must find the right portfolio of material investments, which occurs when the marginal savings to generation are offset by the marginal costs to expand the network.

A noteworthy feature of the pricing formula is it promotes efficient behavior even though it is based on the *average* cost of material investments. As stated above, for private goods, price

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[5] The cost of transmission service includes the debt cost of financing transmission investments but not a fair rate of return to investors. The return to TOUs and investors depends on the value of f and the size of net generation savings.

[6] Although Q pertains to wholesale transactions, AC and AS consider all transactions on the network. Higher Q means AC falls because TC is more thinly spread. Higher Q means AS rises but at a diminishing rate due to greater congestion implying higher line losses which is a dissaving. The Cooperative must choose the right amount of new investment (K). More K raises AC because it raises TC and it raises AS by lowering system congestion.

set equal to marginal cost is the rule that leads to efficiency. So why does average-cost pricing work in this instance? The answer is because we are dealing with a club good, not a private good. To give a more complete answer, perhaps an example as to why marginal-cost pricing does not work would be helpful.

Marginal-Cost Versus Average-Cost Pricing:
The Case of Club Goods

Suppose a transmission network is presently underused and congestion is zero. What should be the price to transport one more unit of power? According to the marginal-cost rule, price should be set equal to the marginal cost of variable resources needed to transport that unit of power. However, the cost is zero because no extra resource are needed: the system is assumed to be underused. If this is true of the last unit, it must be true of those units before because congestion costs rises with usage. Hence, under the marginal-cost rule, the efficient price is zero. But at a price of zero, who would be willing to build the transmission system?

It could be posited that the first unit should be charged the full cost of the system. Did it not bring the system into existence? Before the system was built, all resources were variable. Needless to say, no one would want to be the first user under such a pricing scheme. But suppose somebody decides to build a system anyway. Suppose "unit one" decides to build a transmission system for itself. As it is getting ready to do so, it is approached by "unit two." Unit two suggests they pool their demands and build a common system so they can capture the scale economies from pooling. But, how much should each contribute?

Should unit one have to pay the go-it-alone amount with unit two paying just the difference (marginal cost) between this and the total cost of the joint system? Would this be efficient? The answer is clearly no. If unit one pays the same amount regardless, then there is no reason to pool with unit two and share a common system. In fact, it would be unwise given possible congestion problems and their costs. By having its own system, unit one can insulate itself from the habits of unit two. This version of marginal-cost pricing gives no incentive to pool demands and share a common system. The failure to pool and share implies society loses out on the savings from scale economies: the parties will both choose to go-it-alone.

Another option would be to charge unit one and unit two the same marginal-cost price. This could promote pooling and sharing, at least on the part of unit one. However, there is a problem: it fails to cover total cost. Marginal cost is based on the last unit built which, because of scale economies, is less costly then the first unit. Marginal-cost prices will not recover enough revenue to cover the total cost of the joint system. This version of marginal-cost pricing would lead to financial insolvency. Unless subsidized, marginal-cost pricing would dissuade pooling and sharing. Again, the loss to society is the lost scale economies.

So, how should each user contribute? What type of pricing formula gives enough incentive to pool and share, and yet, ensures full cost recovery? The answer is to base price on average cost, not marginal cost. Prices based on average cost ensure that everyone benefits from the savings made possible from pooling and sharing. It also ensures that all cost are fully recovered. Average-cost pricing promotes efficiency because it is incentive compatible: everyone benefits so everyone has a reason to pool and share. It also ensures financial solvency: revenues cover costs. Marginal-cost prices do neither.[7]

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[7] It is easy to get mired in myriad pricing schemes: marginal this, incremental that, average this-and-that, and so on down the line. But what makes a pricing scheme viable is whether it is incentive compatible--is it fair to all contributors? Sooner or later all economic processes revert back to their beginning, that moment when cooperation and the pooling of resources become necessary to create further wealth. For transmission service, the moment reappears whenever the system must be expanded so to conserve greater amounts of generation resources. To know whether a pricing scheme is viable is to know whether it would have been chosen, at the start, by those coming together to pool their resources. If not, then it is inherently unfair. A pricing scheme that fails to incite cooperation cannot possibly maintain it either.

Pricing, Efficiency, and Fairness

A pricing (sharing) formula, based on average, systemwide costs of the Transmission Cooperative, is incentive compatible and conserves transmission resources. Yet it does more: it efficiently and fairly rations transmission service. It is fair because it apportions the material costs of a transmission network proportionately. It is efficient for the same reason, contributions are proportional to usage. Those who use the system most pay the most.

As wholesale usage rises relative to retail, so will its relative contribution toward transmission cost. As the usage of a customer rises relative to others, so will its relative contribution. Average-cost pricing also treats investors fairly in that total revenues will cover total costs. This gives them the solvency protection they need to finance network expansions. However, there is the question as to whether this is fair to retail customers of TOUs. In particular, do they not pay more when wholesale service causes average cost to rise?

The answer is yes. The price to retail customers could indeed rise as a result of wholesale service, given the formula, but the converse is equally true. Every time retail customers replace old, inefficient equipment, or order new capacity for themselves, the wholesale customers contribute because these raise the total material cost to the Cooperative. Wholesale customers would also share the cost of transmission reserves kept for system reliability. Besides, average cost actually drops, not rises, whenever the percentage increase in total usage rises faster then the percentage increase in total material cost. This is an immediate benefit to retail customers of Transmission Cooperatives with excess capacity.

There are two other ways in which retail customers benefit. TOUs also can buy and sell wholesale power; and retail customers share in the reward of TOUs. Open access opens up more ways to buy or sell wholesale power for both TOUs and non-TOUs alike. The Transmission Cooperative's reward must be shared among TOUs, and then again, among its members' investors and retail customers.[8] So, retail customers benefit both directly and indirectly from competition in

[8] The sharing of rewards gives rise to a "sharing tree." The tree and its sharing rules are discussed later in the chapter.

wholesale power markets. These benefits should be considered in judging whether the retail customers of TOUs have been "held unharmed" by open access.[9]

All parties benefit from having a common pricing formula based on systemwide costs and equal access. This makes transmission service a more simple and certain process. It helps to avoid the costly "separation" problems like those plaguing the telecommunication sector. It also gives Transmission Cooperatives the right incentives to make the right choices between congestion cost and material investments.

Yet, the pricing formula alone does not ensure that those receiving transmission service are indeed the ones who save the most in generation resources. Nor does it ensure there will be enough information to make good large-scale investment decisions. These goals need more than just a pricing formula. They also need a formal market for wholesale power: one that brings buyers and sellers together on a regular basis so they can compete for limited transmission resources. To be efficient, the market must be set up to maximize the savings to generation. To be fair, it must guard against monopoly power on the part of TOUs, and against monopsony power on the part of wholesale customers. Competitive bidding can meet these goals if properly designed.

[9] Unfortunately, statements like this one can easily be taken out of context. Some might argue, "If TOUs can buy and sell power like everyone else, then why bother with all this sharing-rule and average-cost stuff?" One reason is because transmission service is scarce and congestible, and its supply curve is upward sloping; so, efficiency matters. Without a sound pricing policy and suitable rewards, there is no incentive to act efficiently. There is another reason as well. Non-TOUs are not burdened by the regulatory bargain as TOUs. They are not obligated to service all needs all the time. They can tailor their service. The TOUs, by contrast, must take the approach "one size fits all." This should give non-TOUs a competitive advantage in certain markets and suggests profit-making is limited for TOUs.

How to Allot Transmission Service

Competitive bidding is the best way to allot transmission service, maximize generation savings, and protect against monopoly and monopsony power. It can make the wholesale power market more formal and standard. It can make transmission service more certain, affordable, and fair.

Competitive bidding can produce the information needed to make wise large-scale investments, the ones that can save the most in future generation resources. It is not just the winning bids that confer value to society; the losing bids do also. They aid transmission planning by showing what could have happened had certain investments been available. They offer direction to the planning process and make planning tools more predictive and useful.

Competitive bidding lends order to the relationship between the Regulatory Alliances and the Transmission Cooperatives; it gives them a centerpiece to organize around. It helps to fill-in the regional gaps in regulation and provide consistency across regions. It helps to make regulation the guardian of competition, and competition the conduit of regulatory policy. What makes competitive bidding such a powerful tool is that it mimics the tatonnement process leading to efficient outcomes. The simple story of the tatonnement process begins with a moderator who quotes a price. Buyers and sellers then make known their quantities. If the amounts offered and requested are equal, the quoted price becomes the equilibrium price and exchange takes place; if not, the process repeats until an equilibrium price is found. The tatonnement process views competition as a static brokering process: transactions take place once the equilibrium price has been found. Outcomes are efficient: only those who value the good more than its price will buy it, only those who value it less will sell it, and no exchange afterward can improve welfare.

The sharing of transmission networks is certainly a more complex ordeal, but competitive bidding does re-create the setting needed for efficiency. It sanctions the bid-offer process that allows all comparisons to be made prior to actual exchange. Yet competitive bidding is essentially an auction. For transmission, what exactly is being auctioned?

In the Network Model, it is *the right to use* a transmission system to put through a wholesale power exchange and *not* the system itself that is being auctioned. The Transmission Cooperatives, under the guidance of the Regulatory Alliances, would be required to make blocks of transmission service available to wholesale customers in a preplanned way. The blocks would be made available through the competitive-bid process.[10] But those interested would not submit bids for transmission space; that is, they would not bid directly for transmission service--this would only confer monopoly power to the Cooperatives. Instead, they submit wholesale power contracts in need of transmission service, or bids and offers to buy and sell wholesale power.

Bidding in this manner has three strengths. One, it enables a Transmission Cooperative to look over all possible ways to allot transmission service before making a final decision. Two, it helps to mitigate monopsony power. It is not just those with a wholesale power contract who can participate; anyone seeking to buy or sell wholesale power can participate as long as they qualify. Three, it controls monopoly power. The reward to TOUs is based solely on net generation savings, not the price of transmission service. This approach to competitive bidding controls monopoly and monopsony power by having bidders compete head on for scarce transmission resources. As a result, there should be a highly competitive market for wholesale power.

The Transmission Cooperative analyzes all bids, offers, and contracts submitted, and then selects the best combination. The best combination is the one that maximizes net generation savings given the interval of firm transmission service available.[11] The task of a Cooperative is to:

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[10] As discussed later, wholesalers can obtain long-term firm and short-term nonfirm transmission service in the Network Model. The formal solicitation applies specifically to long-term firm transmission service for bulk wholesale power transactions. Short-term nonfirm transmission service for coordination transactions can be obtained in the *continuous market*. The continuous market uses surplus transmission capacity set aside specifically to facilitate short-term wholesale power transactions.

[11] The firm transmission service released via competitive bidding can be apportioned over time. For example, 50 percent of the transmission capacity could be for immediate use, 25 percent for power contracts beginning one year later, and 25 percent for power contracts beginning one to three years later. The transmission capacity not used immediately for firm service would be used for short-term nonfirm power transactions. The advantage of allowing deferred transmission

$$\max_{T = \{t_1,...,t_n\}} \{ S(T) - C(T) \} \text{ subject to } [Q^f < Q < Q^c] \qquad (3\text{-}5)$$

The term T is the set of all transactions made possible given the bids sent in. The goal is to find T*, the award set, that maximizes net generation savings. Net savings is defined as the difference between total generation savings S(T), and total transmission costs C(T) of new material investments[12] The phrase "subject to" refers to the interval of transmission service to be released: Q^f the floor amount, Q^c the ceiling amount.

A very relevant question is: How do we know that Transmission Cooperatives will behave properly and maximize net generation savings? To answer this, we simply need to compare the pricing formula [equation (3-1)] to the one above [equation (3-5)]. Except for the sharing rule, the pricing formulas are identical: reward is proportional to net generation savings. The Cooperatives have the incentive needed to make the bidding process highly competitive. They have the incentive needed to choose the right system upgrades and to configure them correctly.[13] They have an incentive to get the word out and attract as many bidders as possible. They also have an incentive to keep transaction costs low, to make the process standard, and to not dawdle over putting together deals. Until the power flows, the rewards do not.

The Network Model turns the question of transmission service into one of how to broker wholesale power competitively. After all, why open up transmission access? Is it not to enhance competition in wholesale power markets? If competition is the goal, then why waste time tripping over issues of transmission; why not just create a competitive milieu up-front that is fair and that

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service is that EWGs can obtain a wholesale power contract with guaranteed transmission service before financing their project. Deferred transmission service enhances competition in the wholesale power market.

[12] The costs refer to small-scale system investments needed to ease congestion and support system reliability. They do not refer to large-scale investments, such as adding new transmission lines or building new substations.

[13] More information is presented later about the sizing of the service block and how this affects the transmission planning process.

rewards all contributors including TOUs and their retail customers?[14]

Assigning transmission space on the basis of generation savings will promote competition and overall savings because it ensures the best use of transmission resources. Competitive bidding provides the milieu needed to build a mature market in wholesale power, one that is formal and standard yet under regulatory oversight. The sharing formula gives Transmission Cooperatives the correct incentive to streamline the brokering process, to willingly open up their transmission systems, and to push forward rather than hold back the move toward greater competition.

Competitive bidding has another very important advantage: it is increasingly familiar to regulators and utilities. It becomes the natural centerpiece able to streamline the relationship between the Regulatory Alliances and the Transmission Cooperatives. In recent years, IOUs and others have used competitive bidding to secure power supplies and other inputs as well.[15] For years, regional holding companies and power pools used it to coordinate future planning. Competitive bidding, as a vehicle, has already travelled far up the learning curve: many of its "bugs" have been solved. It only makes sense to expand its usage to transmission, particularly since the transmission issue is at its heart one of electric generation and power.

The Sharing of Generation Savings

So far, only one sharing formula has been discussed: the division of net generation savings between wholesalers and the Transmission Cooperative. Yet the rewards to the Cooperatives must somehow be shared among its TOUs. The reward to a TOU must ultimately be shared among its retail customers and investors. Together, the sharing rules form a sharing tree: its main

[14] Again, this pertains to the issue of fairness; why should it be only the retail customers of those buying and selling wholesale power who should be allowed to benefit? Because the benefits would certainly be smaller (and perhaps nonexistent) without the contribution of the TOUs' transmission resources, equity norms require TOUs to receive some of the benefit, when they contribute their valuable resources.

[15] For a summary of competitive-bidding practices across states, see Kenneth Rose, Robert E. Burns, and Mark E. Eifert, *Implementing a Competitive Bidding Program for Electric Power Supply* (Columbus, OH: The National Regulatory Research Institute, 1991).

trunk, the f-rule; its main limbs, the c-rule; and its main branches, the s-rule.

The f-rule

The f-rule is the sharing rule between wholesalers and the Transmission Cooperatives. The "f" in the f-rule stands for the FERC because it controls the pricing of wholesale transmission service. The FERC has the authority to set the sharing rule, the percentage of net generation savings kept by the Transmission Cooperative.

But what should its value be? How should it be set? The authors discussed concepts of equity in Chapter 2, and how Social Exchange Theory examines "fair sharing" within a social setting. The sharing rule of greatest support is given by the Principle of Proportionality: the sharing of joint benefits should be proportional to relative contributions.

Although neatly stated, the Principle gives very little insight on how "relative contributions" can be ascertained. Equity comes down to knowing the relative importance of each contributor, which can be highly subjective. The authors propose the use of capital ratios as a possible benchmark. In particular, the f-rule could be set equal to the ratio of transmission investments to total capital investments (generation + transmission + distribution). If done on an industrywide basis, the f-rule would be around 7 percent.[16] This means that 93 percent of generation savings from the competitive-bid process would go to the wholesale parties with 7 percent going to the Transmission Cooperative.

The FERC could expand the f-rule into an f-formula that considers the characteristics of the wholesale power transaction to set sharing percentages. The sharing percentage could vary by the location of buyers and sellers, by generation technology, by the amounts transacted and the firmness of the transaction, and from other factors as well. A formula enables regulation by reward. Should, for example, the FERC want to promote innovative generation technologies (IGTs), it could make the sharing percentage larger for transactions involving IGTs than for conventional technologies (CTs). All else equal, a sharing percentage of 8 percent for IGTs and 6

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[16] Robert D. Poling et al., *Electricity: A New Regulatory Order?* (Washington, D.C.: Congressional Research Service, 1991), 302.

percent for CTs would enable wholesale power transactions involving IGTs to obtain transmission service even though they may save up to 25 percent less in generation resources.

The c-rule

The reward earned by a Transmission Cooperative must be shared among its TOUs. This sharing rule is denoted the "c-rule," where the "c" stands for Cooperative.

Like the f-rule, the c-rule is a set weights that sum to one. Unlike the f-rule, each TOU receives a particular weight. But how should they be set? And by whom?

It is best to allow the Transmission Cooperatives to devise their own c-rule when possible, according to their own norms and standards. Yet, with the proviso they reach a consensual agreement; otherwise, the Regulatory Alliance will set them. There are several good reasons for allowing the Cooperatives an opportunity to devise their own c-rule.

For one, the TOUs must learn how to cooperate effectively in order to effectively coordinate all activities. The need for effective coordination shows up both in competitive bidding and in transmission planning. Cooperation will be driven, at least in part, by the equity of outcomes. The c-rule must relate somehow to the value of relative contributions, values best judged by those involved. As relative values change, there needs to be an agreeable process to make such changes.

To have the Regulatory Alliance, or the FERC, set the c-rule could lead to unintended and unwanted results. The stumbling block for outsiders is not knowing what constitutes a contribution in the eyes of TOUs. The wrong choice could undermine cooperation and invoke a prisoner dilemma mentality--self action over joint action. To see how activities could easily go awry, and in ways costly to society, suppose the c-rule was set according to the size of each TOU's transmission system. This would favor large TOUs and could lead to uncooperative outcomes and a loss to total efficiency. It could undermine joint planning and induce a go-it-alone outcome.

Say, for example, that it would be wise for the Transmission Cooperative to build a 345-kV line to meet wholesale power needs. A 345-kV line carries nine times the power of a 115-kV line and at only three times the cost. Yet, some TOUs might decide to build their own lines instead and do so unannounced. Their reason: to increase their weights in order to increase their share of total reward. This is the prisoner dilemma problem and would lead to overinvestment and overly expensive transmission service. By behaving selfishly and seeking a larger share for themselves, the TOUs as a group cause total rewards to shrink. This loss is a deadweight loss for society.

Competitive strategies among TOUs tend to undermine efficient transmission planning and operation. It can be naive to impose a c-rule on a Cooperative without knowing the history and particulars of those involved. The Transmission Cooperative is better equipped than outsiders to develop the norms, the checks and balances, needed to assure equity and efficiency. They are in the best position to judge what is a "contribution" and how to value it correctly.

A part of what a Cooperative must do is to learn how best to combine joint decisionmaking with joint sharing. In part, the solution goes back to the Principle of

Proportionality: tie rewards to relative contributions. One way to dissuade go-it-alone strategies is to consider them valueless to the Transmission Cooperative. The merits of such a stance would depend on the general planning process. Another part of the solution is to allow voluntary participation in planning to preserve autonomy. A TOU should have the option as to whether it contributes to a particular investment plan. However, to promote action, there should be the proviso that the Regulatory Alliance will intervene should the TOUs fail to reconcile a c-rule.

This example shows the importance of the FERC, the NERC, and state commissions forming the Regulatory Alliances: together they have the expertise and legal authority to impose outcomes when necessary. The Cooperatives need some flexibility to the set the c-rule according to their own norms and standards. By imposing a set of weights, regulators could undercut the ability of TOUs to work together and efficiently plan transmission investments and run the competitive-bid process.

This does not mean the Alliances should refrain entirely from directing some of a Cooperative's profit toward particular ends. For instance, the Alliances could instruct each Cooperative to maintain a joint interest-bearing account to aid member TOUs distressed by stranded investments. Also, a Cooperative could be instructed to allocate some profit toward the development of newer technologies capable of improving transmission service and conserving generation resources. Yet, the Alliances should not become overly zealous in earmarking profits because without sufficient discretionary profit the TOUs may lose interest in being efficient.

The s-rule

The "s" in the s-rule stands for the state commission. The s-rule governs how the reward to TOUs is divided among investors and retail customers. Naturally, each state commission can set the s-rule as it sees fit, given the laws of its state, with one exception. The exception pertains to multistate TOUs. In this case, the state commissions involved will need to find innovative and new mutual ways to share the reward.

How best to deal with multistate utilities is an important issue for state commissions. As the electric industry becomes more dynamic, competition may force IOUs to merge across state lines at a growing rate. An increase in multistate utilities will increase the degree of mutual dependency among state commissions. This puts greater pressure on them to cooperate while making it more costly should they fail. This is the whole purpose behind the Alliances: to turn mutual dependency into mutual benefit by finding points of mutual gain.

The key is to find points of mutual gain. The rewards could be used by state commissions to do more than just lower rates across-the-board and raise profits to investors. It could be earmarked for special state projects. It might be used to support demand-side management initiatives, or subsidize low-income households, or promote economic development, as well as a host of other programs important to the states. Some of the rewards may be needed to pay the cost of joining a Regulatory Alliance.

Some of the rewards could sponsor a multistate agency to streamline the regulatory process to site new transmission lines that cross state lines. State commissions of a common Regulatory Alliance might use some of the reward to devise a common database to better oversee the activities of TOUs. Although it is vital to reward TOUs, it is also vital to improve and streamline regulation. Some of the savings from a more competitive wholesale power market could be earmarked with this purpose in mind. A diagram of the sharing tree is given in Figure 3-1 along with a numerical example.

How to Expand Transmission Service

Good transmission planning requires good clues. Good clues come from markets that function well, markets that are allocatively efficient. Efficiency in investment depends on efficiency in usage, implying good planning depends on good usage. Competitive bidding improves the usage of transmission and generation resources by allotting it on the basis of generation savings. The allotment is rank-order perfect: those who save the most are served first, and those who save the least are served last. Competitive bidding can become a source of good clues as long as it is designed correctly, in ways allocatively efficient.

Fig. 3-1. The sharing tree and a numerical example (Source: Authors' construct).

So far, we have discussed how those awarded firm transmission service benefit society: they conserve generation resources. Those not awarded service offer value by being suggestive: losing bids show planners what could have happened had more transmission service been available.[17] They give them an accurate account of excess demand and the extent of potential generation savings. They enhance the art of network modeling by revealing the locations of potential buyers and sellers.

As clues, their value tapers off with time. Losing bids offer only a snapshot of possible opportunities that can easily dwindle unless transmission service becomes available soon. This puts extra pressure on Transmission Cooperatives to bunch together competitive bids and speed up the planning and expansion process. This has its drawbacks: it encourages smaller additions to the transmission network rather than larger ones. Large expansions require more time to plan, to build, and to risk becoming ill-suited when finished. Yet large additions capture scale economies. A piecemeal strategy is less risky, but fails to capture all scale economies.

What handicaps competitive bidding as a planning tool is its inherent lumpiness. Competitive bids are blockish and lack continuity. Although bunching them together can help, this strategy is not highly efficient: it raises transactions costs, forgoes scale economies, and raises prices. The goal is to get a more clear picture of future transmission needs and generation savings. The clearer the picture the better the plans of today will fit the needs of tomorrow. The issue boils down to one of design. How can we design the competitive-bid process to be forward looking? How can we design it to keep current the information received? The solution lies in having a forward-contract market for wholesale power along with a continuous-contract market. The solution requires that the competitive-bid process meet three functions: (1) satisfy the current transmission needs of firm wholesale power customers, (2) reserve transmission service for nonfirm wholesale power customers, and (3) take orders from future firm wholesale power customers.

In the first function lies the lumpiness of the competitive-bid process. In the second function lies its continuity and in the third function lies its ability to look forward. The problem

[17] These parties could still get service through the nonfirm, continuous market discussed later.

faced by a Transmission Cooperative, and its Regulatory Alliance, can be described as follows: the Cooperative has, at any one point in time, only so much transmission service capacity it can make available to the wholesale market. Somehow, it must be decided how much will be auctioned as long-term firm transmission service and how much will be held back to run a short-term nonfirm market for transmission service. Meanwhile, the Cooperative takes orders for future transmission service.

The forward market assists the planning process by giving commitments to the Transmission Cooperatives. However, the commitments are not guarantees to take transmission service; instead, they are guarantees by wholesale customers to bid for long-term firm transmission service in the next auction. Guarantees are impossible because the price and cost for service are unknowable until the auction actually takes place: recall, to have a competitive milieu, transmission contracts cannot offer fixed prices. This is particularly true of forward contracts because costs are as yet unknown.[18] The guarantees can come from both buyers and sellers or from an EWG looking to secure future transmission service to make final a power contract. Although the Transmission Cooperative cannot guarantee a price to an EWG, for example, and although the EWG does not guarantee to take transmission service but just to bid for it, both parties have a better idea of what tomorrow holds. It adds some certainty to the planning process.

The continuous nonfirm market assists planning by giving planners up-to-date information on the regional wholesale market. It gives them a way to separate out trends in supply and demand patterns from short-term aberrations. This allows planners to continually adjust the initial transmission plan so that the investments made and those needed more closely converge.

There is actually quite a bit more to the story. There are other ways that transmission planning benefits from having both a forward-contract and continuous-contract market. This has to do with allocative efficiency: the interaction between the three contract markets (long-term firm, forward, short-term nonfirm) will improve allocative efficiency. As stated before, allocative efficiency and investment efficiency are inseparable; you cannot have one without the other. The

[18] Transmission is a club good whereby the cost of service depends on total usage (congestion) as well as on construction costs.

improvement to allocative efficiency comes from two sources: better risk allocation and lower transaction costs.

Planning and Market Efficiency

A continuous market creates a more competitive wholesale power process because it offers wholesalers not awarded long-term service an outlet to buy and sell power. It offers them an outlet to earn profit and reduce system cost, and lowers their risk and cost to participate in the competitive-bid process.

The continuous market also lowers the risk and cost to those awarded long-term-firm transmission service. Long-term-firm service implies a long-term-firm wholesale power contract that may or may not stand the test of time. The buyer and seller may need the flexibility to breach the power contract during its lifetime should it become uneconomical. A continuous market lowers transaction costs for those breaching long-term contracts because they could still buy and sell short-term nonfirm service.

By having a continuous market, the Transmission Cooperative has a ready supply of suppliers and purchasers to fill the void. Those ending a long-term contract can be replaced quickly by those buying and selling short-term power. Then again, those ending their long-term service would have access to the continuous short-term power market.[19] This helps to maintain competitiveness.

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[19] According to the economic theory of optimal breach, the long-term wholesale party would need to reimburse the Cooperative for lost profits. But the amount could be paid, at least in part, from generation savings or profits earned in the continuous short-term market.

The added mobility helps to reduce overall risk to both the wholesalers and the Transmission Cooperatives and to better manage it across parties. It does so by offering everyone a larger set of options to work from and a standard process to make changes; the more standard the process, the lower the transaction costs; the lower the transaction costs the more competitive the process, and the better the competitive process allocates risk and conserves resources.

Continuity makes for a more flexible wholesale power market. It improves allocative efficiency, which in turn improves transmission planning. Having a forward-contract market also improves allocative efficiency in the planning process. A forward market helps to make the competitive process more contestable. It offers future buyers and sellers a way to signal their expected needs to a Cooperative ahead of time so it can have enough transmission service on hand.

A forward market lowers the risk to new generation projects, making them more likely, albeit not certain. It helps EWGs and others to get the financial capital they need to begin their projects. It reassures investors that the Transmission Cooperative is considering the needs of new projects in their planning process. They also know that should an EWG, for instance, not obtain long-term-firm service at first, it can, in the meantime, participate in the continuous power market and earn revenues to cover costs. Together, the forward and continuous contract markets offer greater revenue assurance to new projects and their sponsors, by lowering capital costs and the cost to enter the wholesale power market. Easier entry enhances competition and its ability to conserve generation resources.

The more competitive the wholesale power market, the greater are the savings to generation. The greater the savings to generation, the larger are the rewards to society as a whole and to TOUs. The larger the reward to TOUs, the more willingly states become to site new transmission investments. More transmission service attracts new sources of supply, causing the wholesale power market to become even more competitive.

Price Assurance in the Continuous Market

The average savings in generation could change often in the continuous market. This suggests that the price of transmission service could change often given the pricing formula. This could cause a lot of confusion among users and the Cooperatives. Unless price information is available in real time, no one would know what the price was until after the fact.

This problem becomes even more acute within the continuous vintage market; that is, offer a range of contracts with various lengths. Some contracts might run as long as a year, others half a year, others for a month, and some might last just a day or even a few hours. The continuous market is wide open, but this openness makes pricing more complex.

There are perhaps many ways to offer price assurance to wholesale users in the continuous market. One way amounts to a simple extension of the pricing formula. The formula could be amended as follows:

$$P_i = AC + f\{ AS_i - AC \}$$

The term P_i stands for the price to wholesale party **i**; with AS_i the average savings in generation cost expected from the contract. One means for price assurance, therefore, is to tie the price of transmission service to the particulars of the wholesale power contract and to allow the price stay as is until the contract ends.

This solution, though good for contracts one month or longer in length, might still be too cumbersome for transmission contracts of shorter length such as a day. Here, price could be set by the average savings in generation of the previous day; or, perhaps the average of the same day of the previous week. Regardless of how price assurances are made, the continuous market needs them to work efficiently.

Service Assurance in the Long-Term Market

An important issue is what happens to those who have acquired a contract for long-term transmission service. Must they continually compete with newcomers who want long-term service? Can their contracts be called back and given to another? What service assurance do long-term wholesale customers have?

Depending on the activity in the continuous and forward markets and the needs of TOUs and newcomers, the Transmission Cooperative must plan and expand the transmission network. Of course the Regulatory Alliance, and in particular the state commissions and the NERC, play a vital role in network expansions. The state commissions help with environmental and siting issues. The NERC helps to judge the technical efficiency of the expansion plan. After the Regulatory Alliance has played its role, the network expansion can commence along with the competitive bid to make available the new service. As before, the bids, offers, and wholesale power contracts come in and the Transmission Cooperative selects an award group based on net generation savings.

For competition to work in the wholesale power market, there must be some assurance that long-term transmission service will not be taken away. Those with long-term contracts from a previous competitive bid should not fear losing it to newcomers. They should have the right to keep long-term service, assuming they are willing to pay the price increase for transmission service that might result from follow-on competitive bids.

Expansion plans can affect the average cost of transmission service and its price. The average cost can go up or down depending on how well any scale economies might offset, for instance, any increase in material costs due to higher input prices. Besides changes in systemwide average cost, the price of transmission service might also change because of changes in the expected level of average generation savings.

Although long-term transmission service should be assured, prices should always be flexible, and always respond to current supply and demand conditions. The choice to keep service, or abandon it and enter the continuous market, or simply drop off the system should be left up to the long-term wholesale user.

Preserving the Regulatory Bargain

The responsibility of the Regulatory Alliances, that is, of the state commissions, the FERC, and the NERC,[20] is to insure the integrity of the bidding process. They should play an active role and help TOUs to develop standard contracts and rules, and methods to measure power flows along networks. They should insure that loop flows are adequately dealt with--although each Transmission Cooperative has the incentive to wisely use its own transmission network, it also has an incentive to free-ride off others.

Competition in wholesale power markets is good for retail customers, and certainly should play a larger role in the electric industry; but if it compromises the regulatory bargain then it comes at too high a price. To keep price low, the TOUs must always keep the right to buy and sell power, and use their transmission system on behalf of their retail customers. This is the only way to protect the integrity of the regulatory bargain that has been, and remains, a mainstay of state regulation.

One way to preserve the regulatory bargain is to allow the TOUs of a Transmission Cooperative to buy and sell power in the same competitive bid process they run. But, how can the Regulatory Alliances control the self-serving tendencies of TOUs? How can they balance the needs of TOUs with the those of wholesale customers? The very idea of allowing the TOUs to participate in the competitive bidding process smacks of self-dealing and invites mischief.

What is not wanted is a scheme that merely transforms market power over transmission into market power over generation. To prevent this, the Regulatory Alliances need to develop rules and standards to judge the integrity of outcomes from the competitive-bid process. This is all part of the compromise that must take place between the state commissions and the FERC. For cooperation to work, the FERC

[20] The NERC regions do not here take on the status of regulators. Rather, the NERC regions provide technical assistance to the regulators, assuring that the bidding process provides for generation adequacy and transmission reliability.

must be willing to preserve the regulatory bargain and the state commissions must be willing to embrace wholesale power competition (the FERC goal).

As stated up-front, competition, although useful, should not become a surrogate for regulatory oversight. Rather, it should become the conduit of regulatory policy. The Network Model builds on the premise that the electric industry needs to be regulated and it is the job of both state and federal regulators to regulate it. At the same time, the industry operates on the regional level and so must regulation if there is to be balance and effective oversight.

The problem of self-serving behavior by TOUs can be overcome partly by having a sufficient number of TOUs in each Transmission Cooperative. Because the size of individual rewards are tied to the amount of total reward, each TOU has a self-serving incentive to hold in check the self-serving behavior of others. For instance, suppose a particular TOU wants to sell power in a competitive bid it helps to run. Naturally, the TOU wants to sell to the buyer willing to pay the most. Yet this may not maximize social gains because other bidders may have lower cost supplies. Lower net generation savings means a smaller reward to the other TOUs, and this gives them the self-serving incentive to stop the transaction and replace it with a more valuable one.

Section Summary

The transmission issue is at its heart the issue of competition in wholesale power. It is here where the savings to society lie. Competition works best when markets are organized: this adds certainty and lowers transactions cost, and helps to streamline regulation. The authors propose competitive bidding as the vehicle to conserve generation, transmission, and regulatory resources. It can make the competitive process for wholesale power cheaper and more efficient. It unites the decisionmaking process: the benefits from competition help determine the right amount of transmission service; and the cost of transmission service helps to determine the right level of wholesale competition.

The authors' design extends the principles of economic dispatch to the allocation of transmission service. All uses for transmission service are compared before any is assigned, making the allocative process one of optimizing instead of maximizing. The goal is to use all resources (both transmission and generation) in the best way possible, not simply to attain the greatest number of transactions possible given transmission resources. The greatest number may not maximize net generation savings, which is the measure of success.

The bidding process forces wholesale parties to compete for transmission service. The pricing formula rewards TOUs for allotting and expanding transmission service. Combined, they promote total resource efficiency, as do flexible prices along with the continuous and forward markets for transmission service. They aid transmission planning and strengthen competition by allocating risk efficiently. They provide the sinew to link today to tomorrow.

The use of competitive bidding has many redeeming aspects. It is familiar to both TOUs and regulators. It takes advantage of TOUs who have the greatest amount of technical expertise and experience with transmission systems. This makes them the industry's natural brokers of wholesale power. By rewarding them, the idea of competition and power brokering becomes more acceptable because it becomes more equitable. The authors' version of transmission pricing and access builds upon the history between regulators and TOUs. The parties are familiar with one another and this may facilitate change to a more competitive milieu. This could help make it easier for regulators to regulate. Competitive bidding offers the natural centerpiece to coordinate regulation and competition.

The material covered in this chapter and the previous one provides an alternative basic framework to wholesale transmission service. Yet, there is probably a litany of unasked and unanswered questions that need to be asked and answered before the Regulatory Alliances, Transmission Cooperatives, and the competitive bidding process can legitimately get started.

Should a competitive bid result in a common price for wholesale power or should it differ by transaction? How can we be sure that the information revealed in a competitive bid is true? Should the bid process be made standard or should it vary across the Cooperatives and regions? How are such decision to be made and by whom? How are grievances to be resolved? Should those in the forward market pay a security deposit?

These questions are but the tip of what could be a very long list--but a list, given the potential benefits for all parties, worth pursuing.

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CHAPTER 4

SUMMARY AND CONCLUSIONS

This report discusses ways of relieving jurisdictional disputes over electricity transmission in light of the recently enacted EPAct. EPAct redefined the jurisdiction of both the FERC and state public service commissions. Under EPAct Title VII, the FERC has complete jurisdiction over transmission pricing unless that transmission service is "bundled" as part of the retail service provided by a vertically integrated utility to its retail customers. FERC also has complete jurisdiction over access to and other terms and conditions of wholesale transmission services.

Recall, EPAct Title VIIA creates a new class of generators called EWGs that can generate and sell electricity exclusively at wholesale while being exempt from the provisions of the Public Utility Holding Company Act of 1935. However, for EWGs to successfully enter and have access to the wholesale generation market, they need access to transmission service at reasonable rates. Accordingly, EPAct Title VIIB addresses transmission access and pricing.

The FERC has certain goals and objectives that they are seeking to achieve through their transmission pricing and access policy. The key to meeting these objectives and criteria is to take a comprehensive look at FERC's transmission access and pricing policies to determine whether they foster competition. The point of FERC and state commission regulation should not be to emulate what a competitive result would have been, but instead to enable competitive forces to operate, wherever feasible.

For the FERC to meet its objectives and achieve comity with the state commissions requires a comprehensive approach to transmission pricing and access. First, one must realize that the main reason to open up wholesale transmission service is to make the wholesale power market more competitive. Greater competition conserves both capital and variable generation resources, narrowing the differences in costs within and between regions. In order to foster competition in the wholesale generation market it is necessary to promote the economically efficient use of the transmission **and** generation of electricity. The FERC must recognize that transmission and generation is a "shared" good and link-up its wholesale generation pricing policy with its transmission pricing and access policy to promote dynamic competitive wholesale markets.

A first step toward this end is to realize that regulation can be supportive of competition and may be necessary for competitive markets to thrive. To support competition that links-up transmission service and wholesale generation, regulators could form Regulatory Alliances comprised of the FERC, NERC, and state commissions. These Regulatory Alliances would be voluntary forums of regulators with protocol but with no independent or sovereign legal regulatory powers. Regulatory Alliances would build upon the need for cooperation among regulators because no jurisdiction is sovereign in all transmission matters. The need for cooperation comes from the mutual dependency that binds together different jurisdictions for the purpose of maximizing net generation cost savings.

The job of the Regulatory Alliance would be to oversee Transmission Cooperatives, voluntary groups of TOUs, whose principal job would be to put together the best combination of wholesale generation contracts given transmission limitations. The best combination would, of course, be the one with the highest net generation savings, that is, total generation savings net of transmission costs. For the Regulatory Alliance and Transmission Cooperative cooperation to work and last, the mutual gains from saving generation resources must be shared fairly. The benefit of net generation savings must be shared by all. Otherwise, there is no incentive to cooperate. To be workable, cooperation must be incentive compatible, prompting a healthy respect for equity, in order to serve efficiency. In other words, dispute resolution must be turned into a search for greater mutual gains to be shared by all.

The challenge is to transform mutual jurisdictional dependence into a cooperative search for mutual gains by finding how mutual cooperation will lead to such gains. A source of mutual jurisdictional dependence is the limited authority that each jurisdiction has over wholesale transmission service. The FERC has control over the price of wholesale service, as well as controlling issues of access to wholesale transmission service. The state commissions have control over major transmission investments because of their control over siting and environmental issues and their regulation of residual revenue requirements needed to support transmission investments. The NERC has control over technical issue of transmission reliability and system-to-system interconnection. In other words, the FERC is responsible for allocative efficiency, state commissions are responsible for investment efficiency, and the NERC is responsible for technical efficiency. Total efficiency, the mutual goal of the FERC and state commissions, is the sum of allocative, investment, and technical efficiency. Total efficiency is unlikely, if not impossible, unless regulators cooperate and hone their policies toward creating mutual gains by encouraging better use of generation resources.

For there to be a coherent transmission policy that encourages a better use of generation resources there must be mutual shared benefits from generation cost savings. The FERC's desire for more competitive wholesale markets depends on the willingness of the states to site new transmission lines. Unless rewarded, a state has no incentive to site new transmission facilities, particularly when the benefits go to others and costs are borne by the TOU and its native-load customers. An equitable process would choose to reward TOUs and their native-load customers for their proportional contribution to wholesale generation transactions. A voluntary cooperative process would have no choice but to equitably reward them.

Transmission Cooperatives, as previously mentioned, are voluntary groups of TOUs that because of their mutual dependence and physical unity should be considered a single entity for purposes of maximizing net generation savings. They operate, under the guidance of the Regulatory Alliances, as a shared network, recognizing that a transmission network is a "shared" or "club" good that cannot be parceled out. Network pricing is needed because contract-path pricing ignores loop flows and sells the wrong product, a transmission contract path instead of reliable transmission service. By ignoring loop flows, contract-path pricing methods fail to account properly for congestion. This could lead to TOUs implementing protective devices that can lead to network system separation and possibly lead to lower reliability and higher costs. These flaws lead to efficiency and equity problems.

The joint goals of Regulatory Alliances and the Transmission Cooperatives they oversee are (1) to pursue efficiency and equity, (2) to promote cooperation and coordination, (3) to open up wholesale transmission service, (4) to enhance competition in the wholesale power market, and (5) to conserve generation and transmission resources by producing net generation cost savings.

The key issues then become how best to price transmission service, how best to allot it, and how best to expand it. To come to the correct answer, one must accept that transmission systems are club goods, that is, they are shared congestible facilities. Congestion is the byproduct of sharing a common good, a variable cost of joint consumption that has nothing to do with production. A common or club good is not made into separate units. As such, the pricing of transmission service must reflect the network costs of the transaction, not the cost of some fictional contract-path. Contract paths are not separate, severable units of transmission; rather, transmission paths combined together make up transmission service.

Transmission pricing should be fair not only to the buyers and sellers of wholesale power, but also to the TOUs and its native-load customers. Further, it should provide the right incentive to invest wisely and to use the networks efficiently. A solution to the transmission pricing question is to require that all customers pay one price tied to the average of systemwide transmission service cost, without fixed-price contracts. Fixed-prices lead to inefficient usage and inefficient expansion of the transmission network. In addition, a percentage of the net generation cost savings resulting from wholesale transaction is shared.

Proper pricing not only promotes efficiency, it promotes fairness. The net generation cost savings that result from wholesale power transactions must be shared, not only between the buyers and sellers of wholesale power, but among the TOUs, and among the TOUs' investors and retail customers. This is important. Not only must net generation savings be equitably divided between wholesale sellers, buyers, and the Transmission Cooperatives, there also must be an equitable sharing of the savings among the TOUs. The reward to each TOU must ultimately be shared among the TOU's investors and retail customers. Such an equitable sharing of mutual gains is necessary to foster cooperation that allows the Regulatory Alliance and the Transmission Cooperatives to jointly function: to pursue efficiency and equity, to promote cooperation and coordination, to open up wholesale transmission service, to enhance competition in the wholesale power market, and to conserve generation and transmission resources by producing net generation savings. A mutual sharing of gains can also allow the FERC and state commissions to effectively and efficiently deal with the problem of recovering the transition costs of moving from a static regulatory to a dynamic competitive environment. The shared gains from net generation savings could mitigate stranded investment and other transitional costs without hindering the development of a competitive wholesale generation market. Mutual sharing of gains turns mutual dependency into a mutual benefit by making it possible and beneficial to find points of mutual gain.

Competitive bidding is the best way to allot transmission service, because it maximizes net generation savings and protects against both monopoly and monopsony power. As previously shown, the FERC first-come, first-served policy tends to merely convert monopoly power to monopsony power, leading to lower net generation savings than would otherwise be the case.

Competitive bidding in this context is an auctioning off of the right to use the transmission system for a wholesale power exchange, not the auctioning off of the transmission system itself. The objective of competitive bidding must be to maximize net generation savings. Through competitive bidding a Transmission Cooperative can look over all possible ways to allot transmission service and select the best possible combination: the combination that maximizes the net generation cost savings given the interval of transmission service available.

Further, competitive bidding is already familiar to state regulators and utilities. Competitive bidding lends focus and leads to an orderly relationship between Regulatory Alliances and Transmission Cooperatives. Competitive bidding makes regulation the guardian of competition.

Competitive bidding also produces good clues about future transmission needs. Good transmission planning requires such good clues about the future. Competitive bidding improves the current transmission and generation resource use by allotting transmission service on the basis of net generation resource savings with those who save the most served first, and those who save the least served last. Thus, competitive bidding not only benefits society by conserving net generation resources, but it is suggestive by providing information showing planners what could have happen had more transmission service been available.

Competitive bidding of transmission service (requiring periodic blocks of transmission service to be offered) as a planning tool is handicapped by its inherent lumpiness and lack of continuity. To get a clear picture of future generation savings and transmission needs in order to better plan transmission expansion, competitive bidding should be designed to satisfy the current transmission needs of firm wholesale power customers, reserve transmission service for nonfirm wholesale power customers, and take orders from future firm wholesale power customers. To accomplish this, the Transmission Cooperative and its Regulatory Alliance must first decide how much transmission service capacity to make available to the wholesale market as long-term firm transmission service and how much to hold back for a short-term nonfirm market for transmission service.[1]

The losing wholesale customers make up a forward market, providing guarantees to bid for long-term firm transmission service in the next auction, which in turn assists the planning process. Being able to identify the size and location of potential buyers and sellers of wholesale power allows the Transmission Cooperative to better plan the expansion of transmission service. It allows for the expansion of a congestible, shared resource--a club good--in a competitive milieu.

Losing bidders and some nonbidders make up the continuous nonfirm market. The nonfirm market provides planners up-to-date information on the regional wholesale market and allows planners to make continual adjustments to ongoing investments, allowing a more optimal configuration of the transmission network.

Further, transmission planning and the competitiveness of the wholesale generation market benefit from interaction between the three contract markets (long-term, forward, and short-term or continuous nonfirm). Allocative efficiency is improved because of better risk allocation and lower transaction costs. A continuous nonfirm market offers wholesalers not awarded long-term service an outlet to buy and sell power, lowering their risk and transaction costs. The risk and transaction costs of long-term firm service is lowered: the continuous market provides the flexibility necessary should a power contract become uneconomical during its lifetime. Finally, the forward-contract market helps to keep the competitive process contestable, offering future

[1] This is one of the important technical issues to be decided in the future.

buyers and sellers a way to signal the Cooperative ahead of time on the need for expansion. The forward-contract market also lowers the entry costs of EWGs and their sponsors by lowering the capital cost and risk of entering the market.

Thus, the authors have sought to provide the FERC and the state public utility commissions with a more comprehensive approach to transmission pricing and access policy. The current FERC Staff proposal which centers around first-come, first-served access, a contract path, and an "OR" pricing policy with fixed-price contracts fails on all counts to meet the objectives of the Federal Energy Regulatory Commission and the statutory objectives of the Energy Policy Act. Instead, it seems geared toward maximizing the number of transmission transactions in the short-term, loading up the transmission lines with low value transactions, while uneconomically increasing line congestion. Certainly such a policy will aggravate state-to-state and state-federal transmission conflicts over the need for and siting of new transmission lines. It is the unfortunate result of a piecemeal approach to transmission pricing and access.

State public utility commissions must speak with a single strong voice on transmission pricing and access policy. Otherwise, it seems likely that the FERC will implement a policy that not only fails to meet its own, and EPAct's statutory objective, but will aggravate transmission jurisdictional disputes. State commissions should indicate that they strongly prefer network-based, flexible pricing policies that are designed to maximize net generation gains in a dynamic, competitive wholesale power market, with an equitable sharing of those gains between all parties of the wholesale power transaction. Such a policy emphasizes cooperation instead of conflict, with the FERC, state commissions, and NERC as equal and sovereign partners overseeing TOUs that are providing transmission service so as to maximize mutual gains.

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APPENDIX A

AN ECONOMIC ANALYSIS OF THE FERC STAFF "OR" TRANSMISSION POLICY

The FERC recognizes that transmission access and pricing issues comprise only one part of a complete policy to bolster competition in wholesale power markets. There are nonprice issues as well, and the FERC has addressed some of them. The list includes: the FERC's final rule on certifying EWGs; the FERC's final rule on transmission information requirements of section 212(b); the FERC's guidelines on RTGs; and, the FERC's policy statement on good faith requests for transmission services. The FERC policies all follow a common theme: competition in wholesale power requires freeing up transmission service.

The purpose of this appendix is to examine in some detail the "OR" policy, the FERC Staff proposal, for discussion purposes, on transmission access and pricing. The authors consider its efficiency and equity features, including how it could affect transmission investments, competition in the wholesale power markets, and the relations among regulatory jurisdictions. The authors examine whether it is effective, efficient, fair, and conducive to competition, and importantly, whether it builds collegial relations among jurisdictions.

The "OR" policy combines two ideas: open access and fixed prices. Under the "OR" policy, access to the system would be awarded on a first-come, first-served basis. Price would be tied to the cost of service, and once set, fixed for the life of the transmission contract. The price would equal embedded cost for surplus transmission capacity, and the lesser of opportunity cost or incremental cost for constrained transmission systems.

The key issue is whether the FERC Staff's proposal will meet its own goals; that is, will the "OR" policy:

(1) bolster "competition" for wholesale power,

(2) prevent "monopoly" profits,

(3) give the "lowest reasonable" cost of service, and

(4) hold retail customers "unharmed".

The operative terms are all in quotes. The vital question is what do they all mean, and, do they mean the same thing to the FERC Staff as to the state commissions? For instance, are retail customers "unharmed" if the "OR" policy promotes wholesale competition but inadvertently "shuts-in" retail generation? Are all transmission profits monopoly profits? Should a reasonable cost-of-service price include future adjustments? Should the wholesale power market be subsidized? These questions and others are addressed in this appendix whose format is organized around the goals of the FERC Staff.

To Bolster Competition

The FERC Staff argues correctly that freeing up transmission service is necessary to promote competition and to narrow regional gaps in generation costs. Yet, can the "OR" policy, a transmission policy of open access with fixed contract prices, produce a highly competitive wholesale power market that conserves generation and transmission resources? The authors conclude otherwise; instead, the "OR" pricing policy tends to subsidize competition in the wholesale power market, keep generation cost savings below efficient levels, both discourage optimal transmission planning.

The main problem is fixed transmission prices. Once set, those with transmission service need not compete with future wholesale power transactions of greater economic value. Fixed prices, by their very nature, cannot readjust to efficiently allocate scarce transmission service. Inefficiency in the transmission market flows downstream to the wholesale power market and hinders competition in the wholesale power market.

Transmission Cost and Strategic Behavior

The fixed-price rule is especially troublesome when transmission costs are rising, and there are reasons to believe that costs will rise over time. For instance, efforts to upgrade a transmission system become more expensive as it nears its theoretical limit. Sooner or later diminishing returns set in and each new installment adds less and less to a system's ability to carry power reliably. In the short run, both average and marginal costs rise, making the short-run cost-of-service curve upward sloping.

In the long run, the cost of transmission service depends upon the tradeoffs between scale economies and construction costs. Scale economies come from building high-voltage transmission circuits that keep transmission costs down, whereas rising construction costs due to rising input prices and regulatory costs, stiffer environmental standards and less suitable terrain, raise transmission costs. As argued below, the "OR" policy discourages long-term transmission planning and the pursuit of scale economies by reducing the economic return on large investments. The long-run cost of transmission service will depend mostly on construction costs that tend to rise over time. Hence, the long-run cost-of-service curve, as a function of time, will also most likely slope upward.

Rising transmission costs lead to rising transmission prices, causing price discrimination in the market for transmission service. Those who obtain service early can "lock in" lower prices putting those to follow at a competitive disadvantage in the wholesale power market. Instead of a single price for transmission service, one that is flexible and driven by the economic value of wholesale power contracts, the "OR" policy ties transmission price to position in the first-come, first-served sequence.

The steeper the slope of the cost-of-service curve, the greater the price advantage in the wholesale power market to those first serviced. By evoking price discrimination, the "OR" policy enables wholesale power contracts of lesser economic value to beat out more valuable ones in the wholesale power market. As a result, everyone has an incentive to demand service quickly, lock in low prices, and get as much service as possible, particularly if the capacity is idle and priced at depreciated embedded costs.[1] It also means that no one can linger over wholesale power deals because those who search for better deals are penalized with higher transmission prices. Surplus

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[1] Embedded costs are based on the past prices of transmission inputs not on current prices. Input prices tend to rise with time implying embedded-cost prices would make transmission a bargain. A bargain locked in by those first in line.

transmission capacity goes to the quickest of deals and not necessarily to best of deals, implying the "OR" policy does not ensure the efficient allocation of transmission resources nor does it maximize generation cost savings in either the short or long run.[2]

To Prevent Monopoly Profits

The FERC Staff argues that the benefits of a more competitive wholesale power market are that it conserves generation resources, promotes efficiency, rewards innovation, and lowers electricity prices. Yet, the FERC Staff is reluctant to extend the virtues of competition to transmission service because it has concluded that transmission networks are natural monopolies and that TOUs would exploit users. This is probably true, but the "OR" policy is unlikely to outperform the unregulated monopoly outcome; in fact, based on its merits, its performance would likely be worse.

Monopoly power results in too few power exchanges taking place meaning monopolist are allocatively inefficient; but they are technically efficient because technical efficiency increases profits. The economic loss from allocative inefficiency is an opportunity cost to society because the monopolist, to raise profits, would deny transmission service to wholesale power transactions of positive economic value. Yet, the economic loss is bounded because the monopolist will always service the higher-value wholesale power transactions first since they raise profits the most. In other words, the allocation of transmission resources by a monopolist, going first to wholesale transactions of highest economic value, would be rank-order perfect as in a competitive market.

The same holds over time: the monopolists has every incentive to replace lesser-value wholesale power transactions with more valuable ones. In fact, a monopolist has a profit incentive to bolster competition in the wholesale power market because it increases the demand for transmission service.

As a result, a monopolist would want to be technically efficient in configuring its

[2] As discussed more fully below, the "OR" policy, by not using market forces to reassign transmission service, leads to allocative inefficiency that accumulates over time.

transmission system, thereby minimizing its cost-of-service, yet it would behave allocatively inefficiently by restricting the supply of transmission service. The economic cost to society, however, is bounded because only the transactions of lesser economic value are denied transmission service by the monopolist. Also, the monopolist has every incentive to bolster competition in the wholesale power market and reassign transmission service in ways beneficial to itself and society.

Efficiency and the "OR" Policy

The "OR" policy is also allocatively inefficient; in part, because it fails to create a formal wholesale power market that drives the efficient use of transmission and generation resources. Efficiency requires that transmission service be allotted first to those saving the most in generation resources and last to those saving the least. The results should mimic the supply-and-demand diagram in Figure A-1, the diagram normally used to depict competition.

As Figure A-1 shows, the competitive process is rank-order perfect in that the demand curve (generation savings curve) begins with the most valuable transaction and descends to the least, and the supply curve (the cost-of-service curve) begins with the lowest-cost unit of transmission service and proceeds to the most expensive. Because supply and demand are both well ordered, net generation savings (shaded area) reach their peak under competition. The competitive market is both allocatively efficient (using all resources optimally) and incentive compatible. It rewards most those who save the most in generation resources and offer the lowest-cost transmission service.[3]

The "OR" policy lacks this feature owing to its first-come, first-served rule in which speed determines ordering and not the level of generation cost savings. Under the

[3] Profits to wholesale parties are measured by the vertical difference, at each point, between the generation savings curve and the equilibrium price line **P*** in Figure A-1. The profit to TOUs is measured by the vertical difference between the equilibrium price line and the cost-of-service curve.

Fig. A-1. Supply and demand curve illustration of competitive model (Source: Authors' construct).

"OR" policy, the generation savings curve is unlikely to be rank-order perfect resulting in wholesale transactions of lesser economic value being serviced first. In Figure A-2, the downward dashed line is the generation savings curve under perfect ordering whereas the upward dashed curve depicts complete rank-order imperfection. It begins with the wholesale power transactions of lowest economic value and ends with the highest.

Because transactions of higher economic value are last in line and can afford to pay more for transmission service, too much transmission service is provided. The optimal amount is S* in Figure A-2, but the larger amount S' occurs. The shaded area underneath the cost-of-service curve depicts the loss to society from overusing transmission resources. Whereas a monopolist would inefficiently undersupply transmission service, the "OR" policy results in an inefficient oversupply. The inefficiency

Fig. A-2. The effect of perfect versus imperfect ordering on efficiency (Source: Authors' construct).

from the oversupply increases with the degree of imperfection in the ordering of wholesale power transactions.

The "OR" policy lacks incentive compatibility because power contracts of higher economic value can earn a smaller economic return than those less efficient. In Figure A-2, the vertical difference at every point between the cost curve and the imperfectly ranked generation savings curve measures a wholesale transaction's profitability. The wholesale transaction **S'**, for instance, results in no net economic gain even though its economic value is higher than those serviced which do earn a positive economic return.

Net generation cost savings, by definition, is the difference between gross generation cost savings (the area underneath the generation savings curve) and the total cost of transmission service. The area {AB} in Figure A-2 is the optimal level of net cost savings under competition;

but the smaller area {BC} is what occurs under the "OR" policy. The first-come, first-served process runs the risk of leaving the more valuable wholesale power transactions without transmission service even though more total transmission service is provided.

It is unlikely that the ordering of wholesale power transactions will be completely imperfect under the first-come, first-served process. Still, it is equally unlikely it will be rank-order perfect. Its tendency, though, is to be imperfect because search time is made costly under the "OR" policy. Those who choose to wait and find a better power deal may find their profits eaten up by higher transmission prices, some of which could be the opportunity cost of waiting on new transmission investment.

The absence of a formal wholesale power market forces both buyers and sellers of wholesale power to search out a power deal. The search process offers the highest economic return to low-cost power suppliers and high-cost power buyers implying their search process would be longer in duration than for higher-cost suppliers and lower-cost buyers. The "OR" policy penalizes the search process because transmission cost (price) rises with time and usage. This lowers the economic return to search, particularly to low-cost suppliers and high-cost buyers, and reduces the probability they will be paired. The ordering of wholesale power transaction will be less perfect and savings in generation costs less than optimal.

Whereas a monopolist discriminates against wholesale power transactions of lesser economic value, the "OR" policy does the contrary and discriminates against transactions of higher economic value. In fact, the degree of discrimination increases with the importance of the search process to competition, which is likely to be very important since the "OR" policy offers no formal market for wholesale power.

The "OR" policy might evoke a flurry of wholesale activity as everyone goes after cheap surplus transmission capacity; yet, once it is gone, competition would dwindle, in part, because transmission service cannot be reassigned to more efficient entrants offering greater generation cost savings. The "OR" policy enables those with transmission service to keep it regardless if its alternative value. The monopolist, as stated above, is driven by profit and the economic value of alternatives and would raise price to reassign transmission service to wholesale power contracts of higher economic value.

Monopsony Power and Equity

To prevent TOUs from earning a monopoly profit, the "OR" policy assigns the entire gains from wholesale transmission service to the buyers. In other words, the "OR" policy uses monopsony power to curb monopoly power. The cost-of-service curve in Figure A-1 becomes the price-of-service curve with all economic surplus (shaded area) going to the wholesale buyers. Yet, economic surplus would be shared in a competitive market as shown in Figure A-1 by the areas above and below the equilibrium price line **P***. The bottom portion would go to the TOU with the top portion going to the buyers of wholesale transmission service.

In a competitive market, the features of supply and demand determine how the economic surplus is shared among buyers and sellers. For example, the more competitive the wholesale power market, the larger the share of net gains received by the TOUs. This is shown in Figure A-3 by the flatter generation savings curve $\{GS\}_2$.[4] The TOU's share is larger under $\{GS\}_2$ than $\{GS\}_1$ in which competition is less.[5]

Then again, the cheaper it is to expand transmission service the larger the share kept by wholesale buyers. This is shown by the cost-of-service curves $\{CS\}_1$ and $\{CS\}_2$ in Figure A-4. The share of net generation savings kept by wholesale buyers is larger under $\{CS\}_1$ where transmission service is cheaper to expand.[6]

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[4] A flat curve implies that power exchanges are of nearly equal generation cost savings. This tends to bid up the price for transmission service and increase the amount supplied. A steep savings curve implies the opposite.

[5] The change in relative shares can be ascertained by comparing areas above and below the respective price line. Under $\{GS\}_1$, the area above its price line P_1 is much larger than below. But for $\{GS\}_2$ in which generation savings are larger, the area above and below P_2 are nearly equal.

[6] Again, the relative change in shares comes down to comparing areas above and below the price lines.

Fig. A-3. Effect of wholesale power competition on the sharing of generation savings (Source: Authors' construct).

Fig. A-4. Effect of transmission cost on competitive sharing of gains (Source: Authors' construct).

The "OR" policy lacks equity and goes against the basic tenets of both economic theory and equity theory. Economic theory shows that a resource must be paid the value of its marginal product to elicit its efficient supply. This suggests the price for transmission service should be tied to its economic value, that is, to the generation savings it helps to create. It suggests that transmission revenues should be tied directly to net generation savings.

In competitive markets, suppliers earn an economic rent in the short run when supply costs are increasing, which is necessary to elicit supply and encourage future investments. The same logic holds for transmission service: TOUs need an economic reward to invest voluntarily and optimally; otherwise, competition in the wholesale power market could quickly dissipate. Transmission service is an input to the wholesale power market, implying efficiency in the wholesale power market depends on efficiency in the transmission market. Without adequate rewards, TOUs have no incentive to supply transmission service efficiently.

Research in equity theory reaches the same conclusion.[7] It views production as a cooperative process in which contributors come together to pool their resources. The wealth created must somehow be shared fairly or cooperation will fail and everyone losses. Equity theory gives credence to the maxim that efficiency and equity go hand-in-hand or not at all. The sharing rule found most widely accepted is the "Principle of Proportionality." It states that a contributor's share of the created wealth should be proportional to the relative value of its contribution. Those who contribute the most get the most; those who contribute the least get the least.

Again, equity theory suggests the TOUs should be rewarded in amounts tied to the relative importance of transmission toward net generation cost savings. The only way the "OR" policy could be deemed "fair" is if the relative value of transmission resources are zero. Yet, this is impossible because transmission resources are necessary to the flow

[7] See Charles G. McClintoch et al., "Equity and Social Exchange in Human Relationships," *Advances in Experimental Social Psychology*, 17 (1984): 183-227.

of electric power. Without an adequate supply, there is no competitive wholesale power market.

The Role of Resale Markets

Resale markets help maintain allocative efficiency by enabling buyers of a good or service to resell it to those valuing it more. Yet, to limit monopoly profits by wholesale users, the "OR" policy limits resale markets by relying on contract paths as the vehicle to market transmission service. Contract paths are legal fictions invented for cost accounting purposes, with no relation to actual power flows. They invoke point-to-point service in that power must enter and exit the transmission system at specific points.

Contract paths make it more difficult to resell wholesale transmission service because not every path would be useful to everyone. A particular path would only attract a limited number of buyers, thereby containing but not eliminating the market power of the path's holder. Recall that wholesale buyers pay a fixed price for transmission service, one tied to the cost-of-service at the time of the contract. As transmission costs rose, the holder could resell the contract path for a profit at least equal to the cost increase, and more should the prospective buyer have to wait for the TOU to expand the transmission system.[8]

The "OR" policy, in consequence, does not necessarily prevent monopoly power nor above normal profits, it just prevents the TOU from becoming the recipient. The operation of an unregulated resale market could evoke speculation as some buyers buy with the intent of profiting from cost increases. Meanwhile, the transmission system would be used inefficiently because those buying wholesale transmission service for speculative reasons are not the ones saving the most generation resources. If they were, then their speculation would be pointless.

[8] Because the prospective buyer loses profits from having to wait on transmission service, he might willingly offer a premium to obtain it immediately.

Lowest Reasonable Cost

To avoid overpaying for transmission service, the "OR" policy uses the criteria of lowest-reasonable-cost to establish transmission prices. A TOU must set the price of transmission service equal to embedded cost for surplus transmission capacity, or the lesser of opportunity cost or incremental cost, otherwise. Yet, the lowest-reasonable-cost criterion will unlikely be the minimum-efficient-cost to provide transmission service. The minimum-efficient-cost requires the TOU to plan transmission expansions efficiently, which is unlikely under the "OR" policy.

Transmission Planning

The "OR" policy does not guarantee that TOUs will earn an economic return on wholesale transmission investments; this depends on state commissions. A TOU only earns a positive economic return if the state commission allows it to issue equity capital to finance the cost of wholesale transmission investments. Yet, as it turns out, the presence or absence of an economic return has only a secondary effect on investment efficiency. The primary influence is the common property status given by the "OR" policy to surplus transmission capacity.

Common property status means the complete absence of any residual property right over the use of surplus transmission capacity. As common property, surplus capacity becomes an unsecured investment that can be appropriated by third parties at any time. This discourages long-term planning and high-voltage transmission investments because both involve surplus transmission capacity. Since it causes shorter planning horizons and smaller-scale investments, the average cost of transmission service would tend to rise under the "OR" policy. This is depicted in Figure A-4 as the movement from the cost-of-service curve $\{CS\}_1$ to the less efficient $\{CS\}_2$. The area in between the curves measures the economic loss to society from inefficient transmission planning.

Allowing TOUs to earn an economic return on wholesale transmission capital would not alleviate the adverse effect common property has on transmission planning. In fact, just the opposite would occur. Allowing an economic return would make it profitable to TOUs to purposely separate wholesale transactions and service them individually. This would enable TOUs to make small-scale investments, avoid scale economies, raise the total capital cost of service, and thereby raise total profit.[9] Ironically, the "OR" policy would actually become an enabler of such a strategy because of its first-come, first-served rule to allot transmission service.

Similarly, denying an economic return would only remove the incentive to preplan on the behalf of wholesale customers--why accept the risk inherent in long-term planning for no economic return--and would only serve to reinforce investment inefficiency. By conferring common property status to surplus transmission capacity, the "OR" policy provokes inefficient transmission planning that cannot be overcome by offering TOUs an economic return on wholesale transmission investments.

RTGs, Investment Efficiency, and Competition

One way to recapture lost scale economies and lower transmission costs is to form groups to pool demand. In part, this is the rationale behind the formation of RTGs. Their aim is to encourage optimal transmission planning at the regional level; but, as discussed in Chapter 2, RTGs are unlikely agents of efficiency.

Assuming RTGs form and somehow function, the disincentive to build beyond current needs still remains. Because the RTGs are open-ended groups, nonmembers could appropriate surplus transmission capacity at any time. Although a group can spread the risk more thinly, the risk remains because the absence of property rights still remains even in the group setting. In fact, common property makes forming groups more difficult because it empowers nonmembers.

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[9] This argument does not imply that TOUs should not be rewarded; earlier the authors argued they should. The argument is that rewards in the context of the "OR" policy will not overcome its deleterious effect on transmission planning.

Group formation can cause another problem as well, one that lessens competition in the wholesale power market. Instead of permanent groups such as RTGs, spurious groups could form, pool their demands, capture scale economies, and lower their average cost of transmission service. On its face this seems like a good idea, but it tends to make the wholesale power market less contestable and competitive over time.

The groups first to form have a first-mover advantage. Not only can they lock in lower transmission prices,[10] they can take advantage of the large regional gaps in generation costs. Plentiful profits make cooperation simpler, aiding group formation. Yet, in time, profitable sites will become more scattered making future group formation a less viable option. This forces later potential entrants to enter singularly and not be privy to the same low transmission prices.[11]

Because first-comers have a cost advantage in wholesale power, all else equal, they may invoke limit pricing to impede entry in the wholesale power market; that is, first-comers may charge a price for wholesale power that is profitable but just low enough to preclude entry. As transmission prices rose, limit pricing would become even a more viable strategy; incumbents could earn an above-normal profit without significantly provoking entry.

Congestion and Opportunity Costs

By discouraging long-term planning and large-scale investments, transmission systems are more likely to be congested and operate continuously near their system limit. Greater levels of congestion mean higher line losses, a greater wastage of generation resources, lower profits to wholesalers, all of which hinders activity in the wholesale power market. Yet, the purpose of the "OR" policy is to conserve generation resources. By inducing greater congestion, the "OR" policy compromises achievement of its own goals.

The "OR" policy also increases opportunity costs, but not the type of opportunity costs

[10] Those first to secure transmission service would buy up the idle capacity at depreciated embedded-cost prices.

[11] They lose out on scale economies and must face higher prices for transmission inputs.

discussed by the FERC Staff: the value of foregone opportunities a TOU might experience when servicing wholesale power transactions. Instead, here, opportunity cost denotes the economic cost to society from having wholesale power transactions wait on transmission service. The average waiting for transmission service would increase under the "OR" policy because of the disincentive to overbuild.

To Hold Retail Customers Unharmed

The "OR" policy can be summed up as a policy that treats surplus transmission capacity as common property; allots service on a first-come, first-served basis; and fixes contract prices to the cost-of-service at the time of the contract. What is important to state commissions, though, is the effect the "OR" policy has on retail customers. Does the "OR" policy hold retail customers "unharmed"? Our analysis suggest it harms retail customers and challenges the regulatory bargain that defines the relationship between retail customers and TOUs.

One source of harm again comes from the effect of common property has on transmission planning. For example, suppose the current need of retail customers only warrants adding a 115-kV transmission line to the transmission system; yet, the TOU realizes that a 345-kV transmission line would be in their best long-term interest even though it costs them three times more in the short term. Building the 345-kV line would likely involve surplus transmission capacity, which is risky due to the absence of property rights on its future use. Wholesale users at any time could commandeer any surplus capacity and misappropriate its benefits. As a result, the TOU may build the 115-kV transmission line even though over time it means higher retail rates for electricity.

The "OR" policy also lowers the social value of the regulatory bargain by compromising long-term retail planning. Long-term planning requires combining generation and transmission investments plans. The "OR" policy, however, discourages joint planning by discouraging TOUs from planning large generation investments that involve surplus transmission capacity.

There are strategies at the TOU's disposal to mitigate common property but they are not costless. A TOU, for instance, could go ahead and build a large generation facility and then gradually update its transmission investment as retail demand warrant. Under this strategy, retail customers forego scale economies in transmission in hopes of preserving scope economies in the generation-transmission configuration that finally emerges. This strategy, though, is not risk free since unexpected wholesale loadings could radically alter the transmission system and make the original plan obsolete.

The "OR" policy also introduces new sources of risk to the retail planning process because all investment plans are now conditional on unknowable wholesale demand. As a result, the retail planning process becomes less tailored to retail customers. Yet, the problem is not with opening up the transmission planning process; but rather, with the shifting of all risks to TOUs and their retail customers. Wholesale users are protected from future risks because they can lock in a fixed price for transmission service whereas retail customers cannot. Because the prices paid for transmission service do not incorporate a risk premium, retail customers subsidize wholesale users, and therefore, the wholesale power market under the "OR" policy.

Besides scale and scope economies, the other reason to plan ahead and overbuild is to lock in current cost. Surplus transmission capacity offers a hedge against rising capital costs, material costs, regulatory costs, and so on, and the more likely cost are to increase the more valuable the hedge. Yet, under the "OR" policy, the hedge can be appropriated from retail customers at any time; so in addition to scale and scope economies, retail customers lose their protection against future cost as well.

Blocking Strategies

Blocking transactions are another strategy to protect surplus transmission capacity and the hedge against future cost increases. They involve a commitment by TOUs to move power back-and-forth solely to load up their transmission systems. The transactions might save little, if any, generation resources, but would force wholesale users to expand the transmission system and pay incremental cost. Blocking transactions create a quasi-property right over surplus transmission investments and could make self-dealing, usually viewed suspiciously, a means to protect retail customers.

The strategy is particularly useful to power pools and regional holding companies who already rely heavily on interutility power transactions and is useful as long as the short-term loss from inefficient exchange are outweighed by the future benefit having transmission capacity on demand. Blocking transactions enable TOUs to lengthen their planning horizon and protect economies of scale and scope. They also help TOUs avoid having their generation capacity "shut in."

Because transmission prices are fixed at the time of the service contract, they do not consider future effects on the TOU and its retail customers. A TOU can only charge embedded-cost rates for surplus capacity unless an immediate cost from servicing the wholesale power transaction can be demonstrated. There may be none at the time of the contract, even though with time, the TOU might be force to forego profitable off-system power sales or opportunities to dispatch generation facilities and lower system cost.

As surplus transmission capacity dwindles away, a TOU's control over its generation resources could become constrained to the point of being shut in. Unless profitable opportunities are long lasting, new transmission investments might not be economical; and even if they are, net economic gains are smaller because new investments would be priced at incremental cost. Either way, retail customers are harmed because the "OR" policy keeps wholesale prices fixed even though system costs and usage are constantly changing.

The "OR" policy, by treating wholesale customers preferentially, subsidies the wholesale power market. Yet, most wholesale transactions are for retail customers located somewhere. Therefore, it is unclear as to why retail customers of TOUs should subsidize retail consumption elsewhere.

Summary

The FERC Staff has proposed, for discussion, an "OR" pricing policy that combines two ideas: open access and fixed prices. Transmission access would be awarded on a first-come, first-served basis. The price would be tied to the cost of transmission service, fixed for the life of the transmission contract. The price would equal embedded cost for unused transmission capacity, and the lesser of opportunity cost or incremental cost for a constrained transmission system. However, the FERC Staff's proposed transmission policy does not meet its own goals. The policy does not bolster competition for wholesale power, does not prevent monopoly profits, does not in the long-run provide transmission service at the lowest reasonable cost of service, and does not hold native-load customers harmless.

The primary goal of the FERC is to bolster competition in the wholesale power market. Yet, the FERC Staff's proposed policy does the opposite by creating an unlevel playing field, favoring transactions based on a first-come, first-served basis, without regard to the generation cost savings that they generate. This in turn discourages the optimal use and expansion of the transmission system. The problem is compounded by the use of fixed prices. Fixed-price contracts lead to an overuse of transmission resources, with service contracts of less value remaining on-line even if better contracts come along. Indeed, instead of bolstering competition, which leads to efficiency, fixed-price contracts impair competition and lead to inefficiency. The "OR" policy promotes the misuse of both generation and transmission resources, by loading the transmission lines with lesser value transactions, and discourages long-term transmission planning. The "OR" policy yields outcomes that are less efficient than those of a monopolist-controlled transmission service in the absence of regulatory oversight.

Although it can be argued that the proposed "OR" pricing policy prevents monopoly rents to TOUs, it has the effect of turning all unused transmission investment into common property. TOU monopoly is converted into wholesale users' monopsony power. The FERC gives the entire gains from wholesale competition (all the net generation savings) to the buyers of transmission service, who pay only the cost of transmission service. No reward beyond the cost of service (which includes normal profits) is given to TOUs for expanding or enlarging their transmission service. The "OR" policy provides no economic incentive to use or plan transmission system wisely.

The proposed "OR" policy does not provide transmission service at the lowest reasonable cost because it tends to raise both material congestion and opportunity costs. Service on demand coupled with fixed-price contracts turns transmission systems into a form of common property where no one has an incentive to build beyond present needs because there are no residual private property rights in the unused capacity. Because these are bottleneck facilities, this is a severe shortcoming. Pricing should encourage service on demand. Anyone can claim it. Long-term transmission planning is undermined and economies of scale are lost, thus raising the material costs of transmission. Less investment means the transmission system will operate frequently at close to its system limit. As congestion increases, line losses increase, and generation resources are wasted. Retail rates are then higher and wholesale transactions must wait longer for service, increasing opportunity cost.

Nor does the proposed "OR" pricing policy truly hold retail customers harmless. The problem again is that it treats existing transmission investments as common property. Any TOU with unused transmission capacity is required to offer it upon demand to wholesale users, leading to the "tragedy of the commons." Everyone seeks to overuse the system now and get as much as possible transmission capacity on a first-come, first-served basis. Retail customers lose, without compensation, the unused transmission capacity that serves as their hedge against increasing transmission costs. Wholesale users obtain a valuable, but underpriced hedge because unused capacity is priced at embedded cost, not current or expected future costs. The wholesale users can lock-in embedded-cost prices with fixed contract prices. This shifts the risk of rising transmission costs to the retail customers.

In short, the proposed "OR" pricing policy fails to meet FERC's prescribed goals of bolstering competition for wholesale power, preventing monopoly profits, providing transmission service at the lowest reasonable costs, and holding retail customers unharmed. Further, the proposed "OR" pricing, if implemented, would increase the likelihood for transmission jurisdictional disputes between the FERC and the state public utility commissions, particularly when there are FERC orders to enlarge the transmission facilities of TOUs. Because retail customers are not truly held harmless and there is no equitable sharing of the net generation gains from wholesale power transactions that are made possible by the TOU's transmission facilities, state commissions will tend to be disinclined to site or provide environmental approval for transmission lines. Under the proposed "OR" policy, native load customers are, in the long-run, burdened only with costs without offsetting benefits.

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APPENDIX B

THE FERC POLICY STATEMENT REGARDING REGIONAL TRANSMISSION GROUPS

UNITED STATES OF AMERICA 64 FERC ¶61,138
FEDERAL ENERGY REGULATORY COMMISSION

[Docket No. RM93-3-000]

POLICY STATEMENT REGARDING REGIONAL TRANSMISSION GROUPS

POLICY STATEMENT

(Issued July 30, 1993)

AGENCY: Federal Energy Regulatory Commission

ACTION: Policy Statement

SUMMARY: The Federal Energy Regulatory Commission is announcing a general policy of encouraging the development of Regional Transmission Groups (RTGs), and providing guidance regarding the basic components that should be included in RTG agreements filed with the Commission.

DATES: This Policy Statement is effective on July 30, 1993.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION: In addition to publishing the full text of this document in the *Federal Register*, the Commission also provides all interested persons an opportunity to inspect or copy the contents of this document during normal business hours in Room 3104, 941 North Capitol Street, N.E., Washington, D.C. 20426.

The Commission Issuance Posting System (CIPS), an electronic bulletin board service, provides access to the texts of formal documents issued by the Commission. CIPS is available at no charge to the user and may be accessed using a personal computer with a modem by dialing (202) 208-1397. To access CIPS, set your communications software to use 300, 1200, or 2400 bps, full duplex, no parity, 8 data bits, and 1 stop bit. CIPS can also be accessed at 9600 bps by dialing (202) 208-1781. The full text of this rule will be available on CIPS for 30 days from the date of issuance. The complete text on diskette in WordPerfect format may also be purchased from the Commission's copy contractor, LaDorn Systems Corporation, also located in Room 3104, 941 North Capitol Street, N.E., Washington, D.C. 20426.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Elizabeth Anne Moler, Chair;
Vicky A. Bailey, James J. Hoecker,
William L. Massey, and Donald F. Santa, Jr.

Policy Statement Regarding Regional Transmission Groups	))	Docket No. RM93-3-000

POLICY STATEMENT REGARDING
REGIONAL TRANSMISSION GROUPS

(Issued July 30, 1993)

I. BACKGROUND

When Congress enacted the Federal Power Act (FPA) in 1935, it declared in FPA section 201(a) that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest and that Federal regulation of matters relating, *inter alia*, to the transmission of electric energy in interstate commerce is necessary in the public interest. 16 U.S.C. § 824(a). Congress in FPA sections 205 and 206 gave the Federal Power Commission, and later the Federal Energy Regulatory Commission (Commission), 1/ the responsibility for regulating the rates, terms and conditions of transmission of electric energy in interstate commerce by public utilities. 16 U.S.C. §§ 824d and e. However, with the exception of certain authority to address war and emergency conditions (now the responsibility of the Department of

1/ See Department of Energy Organization Act, 42 U.S.C. § 7171.

Energy), 16 U.S.C. §§ 824a(c) and (d), Congress did not give the Commission the explicit authority to order transmission.

This changed in 1978 when Congress, as part of the Public Utility Regulatory Policies Act (PURPA), added section 211 to the FPA, which gave the Commission general authority to order electric utilities to provide transmission to, *inter alia,* other electric utilities. 2/ However, section 211 of the FPA, as enacted in PURPA, was largely unused because the Commission could only order transmission if the Commission determined that the order "would reasonably preserve existing competitive relationships."

The Energy Policy Act of 1992 (Energy Policy Act) has significantly expanded the Commission's authority to order transmission services under section 211. 3/ As amended by the Energy Policy Act, section 211 now gives the Commission authority, upon application, to order transmitting utilities, as defined in section 3(23) of the FPA, to provide transmission to electric utilities, Federal power marketing agencies, or any other person generating electric energy for sale for resale, if such action will not unreasonably impair reliability and will be

2/ All public utilities, as defined in the FPA, are electric utilities as defined in the FPA. However, electric utilities include entities that are not public utilities, such as cooperative and municipal utilities.

3/ Pub. L. No. 102-486, 106 Stat. 2776 (1992).

in the public interest. Section 211 allows the Commission to order entities that are not subject to section 205 jurisdiction to provide transmission, and the Commission has authority to review the rate charged by such an entity pursuant to a section 211 order under the standards of section 212.

During the final stages of Congress' consideration of the Energy Policy Act, which, as noted above, significantly expanded the Commission's authority to order transmission upon application, representatives of the electric utility industry and other interest groups presented "consensus" Regional Transmission Group (RTG) 4/ legislation for consideration. The consensus proposal would have explicitly required the Commission to "certify" RTGs meeting certain statutory criteria. Included among the criteria were requirements for: broad membership; an obligation for a member transmission-owning utility to wheel power for others, including an obligation to upgrade its system or build new facilities; coordinated regional transmission planning and information sharing; and fair procedures for decision-making and for dispute resolution. Under the proposal, an RTG that met these (and other) standards for Commission certification would have been entitled to have its decisions

4/ The Commission defines an RTG as a voluntary organization of transmission owners, transmission users, and other entities interested in coordinating transmission planning (and expansion), operation and use on a regional (and inter-regional) basis.

receive some degree of deference from the Commission (consistent with the FPA). Moreover, the Commission would have been required to afford some degree of deference to the decisions reached through dispute resolution procedures contained in an RTG agreement. The rates charged for transmission by non-public utilities (*i.e.*, entities not otherwise subject to Commission rate jurisdiction) would have had to meet the substantive FPA rate-making standards and would have been subject to suspension and refund as if they were subject to sections 205 and 206 of the FPA. The consensus proposal set forth procedures for the Commission to impose conditions on certification of RTGs, if necessary, and to exercise continuing oversight. Certification was to be denied if all the affected state commissions unanimously objected to certification. The consensus proposal was presented after the conferees had voted on the provisions of the H.R. 776 Conference Report affecting electric power regulation and was not included in the bill. 5/

On November 10, 1992, the Commission issued a Request for Public Comments on the consensus proposal and solicited comments on how the consensus proposal could be adapted into a proposed rulemaking that would address Commission consideration of RTG agreements affecting matters subject to Commission jurisdiction.

5/ See 138 Cong. Rec. S.17,616 and S.17,620-22 (daily ed. Oct. 8, 1992).

6/ We received 100 comments from a wide variety of commenters. Most of the commenters supported the concept of RTGs. However, the comments presented differing views of exactly what an RTG should be and do. 7/

The Commission believes that RTGs can be alternative vehicles for attaining the same goals inherent in the new section 211: promoting competition in generation, improving efficiency in both short-term and long-term trading in bulk power markets, and reducing the cost of electricity to consumers. RTGs can provide mechanisms for encouraging negotiated agreements and resolving transmission issues without resorting to the procedures under sections 211 and 213 of the FPA. 8/ As such, RTGs should reduce the need for potentially time-consuming and expensive

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6/ 61 FERC ¶ 61,232 (1992).

7/ As discussed infra, the Commission is adopting a general statement of policy rather than a detailed rule. The comments submitted in this docket have provided a very thorough discussion of the issues. However, we discuss below only those comments that are relevant to this Policy Statement.

8/ As the Commission stated in its recent Policy Statement regarding good faith requests for transmission services and responses by transmitting utilities under sections 211 and 213: "we believe that as a policy matter sections 211(a) and 213(a) should be implemented in a manner which encourages negotiation." The Commission also stated that its "guidelines are broad enough to encourage individual initiative and negotiation within a flexible framework, leading to accommodations that will encourage optimum access to this country's transmission system." 58 FR 38964, 38965-66 (July 21, 1993).

litigation before the Commission. To that end, the Commission is announcing a general policy of encouraging the development of RTGs, and providing guidance regarding the basic components that should be included in RTG agreements filed with the Commission.

II. DISCUSSION

A. <u>The Expected Benefits of RTGs</u>

A primary purpose of RTGs is to facilitate the provision of transmission services to potential users and voluntarily to resolve disputes over the provision of such services. We believe that RTGs can address disputes over transmission issues in a manner that satisfies the statutory standards of the FPA, and can minimize applications seeking Commission orders for mandatory transmission services under section 211.

Properly functioning RTGs will serve the public interest by enabling the market for electric power to operate in a more competitive, and thus more efficient manner, and by providing coordinated regional planning of the transmission system to assure that system capabilities are adequate to meet system demands. They will decrease the delays that are inherent in the regulatory process, resulting in a more market-responsive industry. RTGs may also significantly enhance regional transmission planning by providing a mechanism for cooperation among state commissions and the utilities they regulate.

Regional transmission needs will change as the generation sector becomes more competitive, thereby affecting many more companies than in the past. Since RTGs bring together both transmitting utilities and their customers (and potential customers) in a region, they can provide a means for companies to coordinate their transmission planning more effectively, avoid costly duplication of facilities, and, in conjunction with their respective state commissions, find more efficient solutions to region-wide problems. This is critical because the transmission network is highly interconnected; thus, the actions of one party often affect many others.

Many transmission issues (*e.g.*, loop flow) are highly technical. As far as possible, those with technical expertise should resolve such issues directly. RTGs can bring together the technical experts from all interested parties to address technical issues directly. This promises to be more productive than using traditional regulatory approaches, which tend to force parties to polarize their positions, as the primary mechanisms for resolving disputes.

As the generation sector continues to become more competitive, the industry will have many new opportunities to trade power. RTGs can provide a forum in which planning data and other useful information can be compiled and exchanged. 9/ They can also provide a forum for parties to find workable ways to conduct business with each other. RTGs can develop procedures that make transactions efficient for all -- for example, through region-wide trading systems based on electronic bulletin boards. In short, RTGs promise efficient and expeditious solutions to problems that may stem from expanded transmission access.

B. Recent Developments - Why the time is ripe for Commission action

During the time since the Commission issued the request for public comment on the consensus RTG proposal, there has been considerable activity in various regions of the country concerning the development of RTGs. For example, utilities in New England, California, the upper Midwest, and the Southwest and Northwest regions of the United States have been actively negotiating RTG agreements. 10/ Utilities in other regions also

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9/ As the Commission noted in its Notice of Proposed Rulemaking proposing to implement the information-collection requirement in section 213, making more information available will improve efficiency, expedite negotiations, and reduce the number of section 211 applications. New Reporting Requirements Under the Federal Power Act and Changes to Form No. FERC-714, Proposed Rulemaking, IV FERC Stats. & Regs. ¶ 32,493 (1993), 58 FR 17,544 (April 5, 1993).

10/ For example, the Southwest Power Pool is considering RTG-like reforms in its Vision Statement of November, 1992. The Western Association for Transmission Systems Coordination and the New England Power Pool are also attempting to form RTGs.

may be considering such agreements. All of these regions differ with regard to generating resource mix, transmission system integration, and existing institutional frameworks. 11/ These factors, among others, can affect the resolution of planning, access, and operational issues important to RTG agreements. Differences in important regional characteristics support the view, expressed by many in written comments on the consensus proposal, that considerable flexibility is needed in forming RTGs.

Although considerable activity is already under way in various parts of the country toward creating regional transmission organizations, recent events in some of the more advanced negotiations indicate difficulties in reaching final agreements. Recent public reports from both California and New England indicate that negotiations in both of these regions have failed to come to closure. The impasse may be due, in part, to parties' decisions to delay commitment to the RTG process pending action by the Commission. The issuance of this Policy Statement is intended to provide assurance that the Commission encourages these collaborative efforts and to provide guidance as to the

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11/ For example, in New England, NEPOOL, a centrally dispatched pool, and in the upper Midwest, MAPP, a non-centrally-dispatched but highly coordinated pool, both already provide for significant sharing of installed and operating reserves of generation resources. Any RTG in these regions may develop as a complement to these power pools.

basic components that should be included in jurisdictional RTG agreements.

In issuing this Policy Statement, the Commission emphasizes that it intends to use its new transmission authority to ensure that electric generation markets can become fully competitive. However, there are several reasons why we believe that RTGs, as opposed to case-by-case determinations by this Commission, offer the potential to be more effective and efficient in dealing with the complex issues that arise as a result of expanded transmission access. First, by including and addressing the needs of all transmission users in a region, RTGs can use the technical expertise of the industry to the benefit of all parties. RTGs can provide a forum for resolving difficult technical issues relating to transmission system operation and planning in a fair and non-discriminatory manner that will benefit all participants. Second, RTGs can provide a practical means for collaboration between the industry and its regulators at both the state and Federal levels. As discussed below, consultation and cooperation with state regulatory authorities are critical to the timely and efficient provision of transmission services. Third, consensual resolution of issues involving transmission in interstate commerce, consistent with the FPA, can lead to enhanced efficiency in both transmission and generation and can reduce expensive and time-consuming litigation before the Commission and possibly state regulatory authorities.

It is important to recognize the Commission's limited authority in the development and success of RTGs. RTGs are purely voluntary associations of transmission owners, users, and others with differing interests. Therefore, the formation of an RTG, by itself, does not insulate its transmitting utility members from proceedings under FPA section 211. However, RTGs that succeed in accommodating all parties' interests, so that members do not feel the need to resort to section 211, will meet the goals intended by the Commission in issuing this Policy Statement. In addition, the Commission will afford an appropriate degree of deference to decisions under an RTG, depending on the degree to which an RTG agreement mitigates the market power of transmission owners and provides for fair decision-making. The success of RTGs will be determined less by the Commission's approval of RTG agreements than by the consensual resolutions negotiated by the members.

C. Minimum Components for RTG Agreements

The Commission does not have authority to "certify" RTGs. However, under section 205(c) of the FPA, public utilities must file with the Commission the classifications, practices, and regulations affecting rates and charges for any transmission or sale subject to the Commission's jurisdiction, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services. Thus, a governing agreement or other RTG-related agreement that in any manner affects or relates to jurisdictional transmission rates or services must be approved or accepted by this Commission as just, reasonable, and not unduly discriminatory or preferential under the FPA. 12/ Accordingly, in addition to adopting a general policy of encouraging the development of RTGs, we believe it is also important to provide guidance regarding the basic components that should be included in RTG agreements in order to satisfy FPA requirements.

The experience drawn from the RTGs developing in various areas of the country indicates that there is a need for flexibility in forming these voluntary associations and the agreements that govern them, in order to reflect specific geographic, operational, historical, or other circumstances of the parties. RTG governing agreements may differ substantially both substantively and in terms of the level of detail. For example, an RTG governing agreement may contain only general criteria for determining the rates that will be charged for transmission services, detailed rate formulations, or no price

12/ Any jurisdictional entity seeking to invoke any other basis for jurisdiction over an RTG should set forth its arguments that such other basis exists.

provisions at all. 13/ Likewise, a governing agreement may contain only general criteria regarding terms and conditions of service, or it may specify detailed terms and conditions. We believe it is crucial to RTG development to permit considerable flexibility regarding the formation of RTGs and RTG agreements, particularly at this early stage and in light of the desire to encourage voluntary participation in RTGs. Therefore, parties may file any RTG agreement that they believe satisfies their contractual needs and complies with the substantive standards of the FPA. Still, the Commission believes that RTG agreements should, at a minimum, contain the following basic components:

13/ The Commission recently issued an inquiry on transmission pricing. Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, Notice of Technical Conference and Request for Comments, 64 FERC ¶ 61,109 (1993), 58 FR 36400 (July 7, 1993). Since the FPA does not mandate the use of a particular method in setting rates, the Commission may decide, for example, that in certain circumstances either "postage stamp" rates or distance-sensitive rates would be just and reasonable. The Commission envisions that an RTG may propose a particular pricing method for its region, which the Commission will accept if it finds the method is just, reasonable, and not unduly discriminatory or preferential. Ultimately, however, the Commission must ensure that any rate developed using the method is just, reasonable, and not unduly discriminatory or preferential. If RTG participants are able to reach agreement with regard to specific rates, the RTG agreement should specify the type of rate (e.g., tariff, individual rate schedules, formula), the underlying pricing method, and any necessary cost support.

1. (§ 2.21(b)(1)) An RTG agreement should provide for broad membership and, at a minimum, allow any entity that is subject to, or eligible to apply for, an order under section 211 of the FPA to be a member. An RTG agreement should encompass an area of sufficient size and contiguity to enable members to provide transmission services in a reliable, efficient, and competitive manner.

Component No. 1 allows for the broadest possible membership for RTGs, including foreign utilities that are interconnected with the national grid. 14/ Numerous commenters emphasized the importance of the broadest possible membership. 15/ Broad membership will extend the benefits of RTGs to the greatest number of market participants, thereby leading to greater efficiency.

In regard to participation by foreign utilities, such entities currently participate in existing reliability councils and power pools. Domestic and foreign utilities' current participation in reliability councils, power pools and commercial transactions over the existing international boundary facilities should be taken as models to draw from in order to structure

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14/ The term "foreign utilities," as used in this document, means electric utilities that are not located in the United States but are interconnected with the United States transmission grid.

15/ See, e.g., Comments of Ohio Edison Company at 3, Edison Electric Institute at 3, the National Independent Energy Producers at 4, Electric Consumers at 15-16, the Electric Generation Association at 5.

continuing, viable working relationships in newly forming RTGs. Furthermore, the history of international cooperation on transmission issues (such as resolution of the Lake Erie loop flow problem) 16/ provides evidence that inclusion of foreign utilities in RTG associations will be beneficial.

Component No. 1 also provides that the geographic area covered by an RTG agreement should be sufficiently large and contiguous. It is implicit in section 202(a) (which concerns "regional districts" for voluntary coordination and interconnection) that there should be coordinated operation in areas large enough and contiguous enough for economic efficiency. 17/ Many commenters also made this point. 18/

2. (§ 2.21(b)(2)) An RTG agreement should provide a means of adequate consultation and coordination with relevant state regulatory, siting, and other authorities.

Component No. 2 provides for adequate consultation and coordination with states. Many commenters, 19/ representing

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16/ See The Transmission Task Force's Report to the Commission, October, 1989 at 62-66.

17/ FPA section 202(a) was transferred to the Department of Energy in the DOE Organization Act. See 42 U.S.C. §§ 7151, 7172.

18/ See, e.g., Comments of Utilicorp United, Inc. at 4-5, American Public Power Association at 13, Cajun Electric Power Cooperative, Inc. at 11, and Department of Energy at 8-9.

19/ See, e.g., Comments of National Association of Regulatory Utility Commissioners (joint comments with, among others,
(continued...)

transmission-owning utilities and transmission-dependent entities as well as the states themselves, pointed out the need for involvement of the states in RTGs. We agree that consultation and coordination with the states are critical to the successful implementation of RTGs, especially in view of the fact that states have authority over retail rates which recover transmission costs, integrated resource planning, and siting of transmission facilities. In addition, state involvement in RTGs can allow state agencies to improve communications with utilities and with each other in dealing with transmission concerns, and can facilitate coordinated treatment of siting issues among the states.

It will be our policy to encourage RTGs to involve the states in whatever way is most effective. State participation is important particularly in the formative stages of RTGs. RTGs are encouraged to seek state participation during formation to ensure that the RTG's governing agreement recognizes that actions taken by RTG members under an RTG agreement must be consistent with state and local law.

3. (§ 2.21(c)(1)) An RTG agreement should impose on member transmitting utilities an

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19/(...continued)
Electricity Consumers) at 6-7, The National Regulatory Research Institute at 1, Municipal Electric Utilities of Wisconsin at 2-6, Missouri Public Service Commission at 1-3, and the Large Public Power Council at 18-19.

> **obligation to provide transmission services for other members, including the obligation to enlarge facilities, on a basis that is consistent with sections 205, 206, 211, 212 and 213 of the FPA. To the extent practicable and known, the RTG agreement should specify the terms and conditions under which transmission services will be offered.**

Component No. 3 provides for an affirmative obligation to provide transmission services. Many commenters 20/ argued that this is essential to an RTG. An inability to obtain service on reasonable terms and conditions will likely result in filings with the Commission under sections 211 and 212 of the FPA. Section 211 does not place a limit on the meaning of the term "transmission services" and provides that the Commission can order facilities to be enlarged, if needed, to provide requested service. Accordingly, the service obligation of RTG members should extend to all types of transmission services and should include a commitment to expand or upgrade facilities when needed to meet service requirements. Such a commitment by RTG transmitting utilities will assure members that they can obtain transmission services similar to those that the Commission could order upon application under sections 211 and 212. RTGs thus may help to secure the benefits of expanded transmission access, such

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20/ See, e.g., Comments of Edison Electric Institute at 3, 16-17, National Independent Energy Producers at 3, Electricity Consumers at 17-19, and Cajun Electric Power Cooperative at 11-12.

as facilitating competitive generation markets, without the additional costs of lengthy regulatory proceedings.

4. (§ 2.21(c)(2)) An RTG agreement should require, at a minimum, the development of a coordinated transmission plan on a regional basis and the sharing of transmission planning information, with the goal of efficient use, expansion, and coordination of the interconnected electric system on a grid-wide basis. An RTG agreement should provide mechanisms to incorporate the transmission needs of non-members into regional plans. An RTG agreement should include as much detail as possible with regard to operational and planning procedures.

Component No. 4 provides for coordinated transmission planning and sharing of transmission planning information. 21/ The coordinated planning process should be open to participation by all members and should address the transmission needs of members as well as non-members. The term "coordinated planning" is a broad term that should encompass the goal of efficient use and expansion of the nation's transmission system. The term "efficient expansion" goes beyond planning needed for reliability purposes. It also includes planning to make expansions that are economically justified from a regional perspective. This component assures that the economic trade-offs between generation and transmission expansion will be weighed appropriately.

21/ Several commenters supported a coordination role for RTGs. See, e.g., comments of American Public Power Association at 11-13, Electrical Generation Association at 4-5, Iowa Association of Municipal Utilities at 5-6.

Another key aspect of coordinated planning, in our view, is that it addresses the needs not only of the region encompassed by the RTG, but also of the surrounding areas that have transmission assets that interact with those of the RTG. Transmission upgrades in one part of a regional network can affect the operations in another part because power flows freely within the larger grid. RTGs should not only plan for efficient expansion within their own boundaries, but also should coordinate with one another to assure that bottlenecks do not develop on the boundaries between RTGs and that existing bottlenecks are appropriately eliminated. We believe that the development of coordinated plans can assist in removing impediments to power transfers within and among the RTGs that share a larger grid.

5. (§ 2.21(b)(3)) An RTG agreement should include fair and non-discriminatory governance and decisionmaking procedures, including voting procedures.

Component No. 5 provides for fair and non-discriminatory governance and decisionmaking procedures. No commenter opposed such a standard, and transmission-dependent entities expressed particular concern that they not be powerless within an RTG. The Commission will not specify in this Policy Statement what specific governance rules or features would be acceptable. In general, we think an RTG should have rules or procedures to protect the rights of entities that are more susceptible to the exercise of market power, such as transmission dependent utilities (TDUs). If the voting rules permit transmission owners to dominate the RTG, for example, this would disadvantage weaker users and would be unfair. 22/ An RTG may wish to strive for consensus when dealing with regional grid issues that affect most members. Accordingly, super-majority voting rules may be appropriate in some circumstances. Different regions and organizations may wish to address these issues in their own manner. The Commission believes that RTGs must have substantial flexibility in designing governance procedures to deal with the difficulties that will be encountered. The procedures must be fair and non-discriminatory if an RTG is to meet the objectives discussed above.

6. (§ 2.21(c)(3)) An RTG agreement should include voluntary dispute resolution procedures that provide a fair alternative to resorting in the first instance to section 206 complaints or section 211 proceedings.

Component No. 6 provides for voluntary dispute resolution procedures. The Commission particularly encourages RTGs to develop high quality alternative dispute resolution procedures

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22/ See, e.g., Comments of the Electricity Consumers Resource Council at 21-22, American Public Power Association at 14, Missouri Basin Municipal Power Agency at 26-27, and Northeast Texas Electric Cooperative at 3.

23/ for resolving technical and reliability issues. As discussed in detail *infra*, we encourage proposals under which we would afford substantial deference to outcomes resulting from appropriate alternative dispute resolution (ADR) procedures that are specified in the RTG agreement.

7. (§ 2.21(c)(4)) An RTG agreement should include an exit provision for RTG members that leave the RTG, specifying the obligations of a departing member.

Component No. 7 provides for an exit provision for RTG members who wish to leave the RTG. If a party has accepted a responsibility under an RTG agreement and then decides to leave the RTG, the obligation of such departing party to comply with its prior commitments should be set forth in the RTG agreement. 24/

D. Other Issues

(1) Adoption of policy statement rather than rule

In the comments on the consensus legislative proposal, EEI and many others, including several TDUs, argued that the Commission should issue a general statement of policy rather than a rule with specific requirements. These commenters argued that the Commission should review RTG agreements on a case-by-case

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23/ See Comments of the Electric Generation Association at 6, Southern Maryland Electric Cooperative at 11-12.

24/ For example, under Article II of the Mid-Continent Area Power Pool Agreement, any participant may withdraw by giving four years' written notice.

basis as they are filed. Several reliability councils and power pools, as well as others, are concerned that a rule would stifle the developing RTGs by imposing uniform, detailed requirements. A policy statement would allow flexibility for individual RTGs to form in ways that are suited to accommodate unique circumstances in different regions of the country.

Many other commenters, particularly certain TDUs, supported issuance of a rule that would adopt the "consensus proposal;" some suggested various changes, and others argued that it should be adopted unchanged to preserve the consensus of support.

We have decided to adopt a policy statement rather than a rule because, as discussed above, the ongoing development of RTGs clearly indicates a need for flexibility to adapt to specific geographic, operational, historical or other circumstances. A rule with specific, detailed requirements might stifle the development that is already taking place and discourage the evolution of different types of RTGs that respond to the needs of particular regions of the country. This Policy Statement is designed to allow sufficient flexibility for various creative solutions, while at the same time ensuring that RTG agreements are just, reasonable, and not unduly discriminatory or preferential.

(2) <u>State Issues</u>

A general concern was raised in the comments on the consensus proposal concerning Federal preemption of state rights and authorities as a result of the Energy Policy Act. These concerns stem in large part from the provisions in the Energy Policy Act which expand the Commission's authority to order transmission services upon application, including any enlargement of transmission capacity necessary to provide such services, and the possible adverse impacts on retail customers that may result from such orders.

In reference to concerns regarding enlargement of facilities, Congress was clear in its intention to preserve state authorities. 25/ RTGs that deal with enlargement of capacity must obtain necessary state approvals for the construction of transmission facilities.

The ultimate resolution of concerns regarding the impact of RTGs on retail customers will be largely driven by any changes in transmission pricing that result from the implementation of the Energy Policy Act. However, the creation of RTGs may also substantially influence these concerns.

25/ Under section 211(d)(1)(C) of the FPA, added by the Energy Policy Act, the Commission must modify or terminate an order requiring enlargement of transmission facilities if it finds, upon application and after notice and opportunity for hearing, that the transmitting utility after making a good faith effort, failed to obtain necessary approvals or property rights under applicable Federal, State, and local laws.

Some see a need to improve collaboration between state and Federal authorities as a result of the Energy Policy Act provisions. The creation of RTGs pursuant to this Policy Statement could help to meet this perceived need. RTGs by their very nature are collaborative mechanisms. In order for an RTG to reach successful outcomes, it must simultaneously satisfy not only the needs of the transacting parties but the requirements of state and Federal regulatory authorities as well. This collaborative effect would also reach to possible conflicts between the various state interests involved. In sum, properly designed and functioning RTGs will inherently provide effective, close collaboration among all parties necessary to assure an efficient transmission system. The extent of collaboration and coordination with states would be one factor influencing the degree of deference the Commission would give to consensual resolutions reached under an RTG.

3. Deference to RTG alternative dispute resolutions

Some commenters argued that the Commission cannot afford any deference to an alternative dispute resolution technique such as arbitration. Several referred to the Commission's lack of authority to "delegate" its authority to private organizations. Others argued that while parties to contracts may agree to arbitration, states must be able to challenge these contracts before the Commission without being hampered by a deference standard.

On the other hand, many commenters argued that alternative dispute resolution proceedings, with some degree of Commission deference, are critical to RTGs. These commenters argued that the Commission has authority to allow parties to a contract to bind themselves to reasonable arbitration procedures with limited Commission review; in other words, a party may contract away its statutory right to Commission review under the normal "just and reasonable" standard.

Another argument raised is that the RTGs' alternative dispute resolution procedures should be used only for technical issues, such as reliability and the adequacy of existing transmission; RTG members could go directly to the Commission with disputes over policy matters (such as cost allocation or the terms and conditions of access).

Whether consensual resolutions are reached by direct negotiation among the parties or by various methods of ADR, 26/ the Commission has the authority and is willing to give appropriate deference to outcomes produced by agreement of the parties. In either case, the Commission must ensure that the

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26/ ADR can include, but is not limited to, conciliation, facilitation, mediation, early neutral evaluation, fact-finding, mini-trials, and non-binding or binding arbitration. See Administrative Dispute Resolution, Notice of Inquiry, IV FERC Stats. & Regs. ¶ 35,823.

resolution is not unjust, unreasonable, or unduly discriminatory or preferential, as required by the FPA, which we are bound to enforce, and that it does not result from the exercise of market power by one party over another.

Voluntary resolution of disputes is consistent with the statutory scheme under the FPA that relies on contracts between the parties in the first instance. 27/ It is also consistent with the Alternative Dispute Resolution Act. 28/ We believe that an RTG agreement that assures that transmission owners cannot exert significant market power or control over non-owners can provide the Commission the assurance it needs to give appropriate deference to voluntary resolutions or resolutions reached as a result of ADR. While the Commission cannot "delegate" its authority, it can give deference to resolutions which meet the standards of the FPA.

One type of ADR is arbitration. We note that arbitration of certain FPA-related matters is not a new concept at the Commission. 29/ We have long recognized the value of parties

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27/ United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332, 337-9 (1956); FPC v. Sierra Pacific Power Co., 350 U.S. 348 (1956).

28/ 5 U.S.C. § 581-593.

29/ The Commission has accepted arbitration provisions for non-rate matters such as determining what is a reasonable amount of time for new transmission facilities to be built. Public Service Co. of Indiana, Opinion No. 349, 51 FERC ¶ 61,387, (continued...)

agreeing to attempt to resolve matters through other means before coming to the Commission. We have pointed out that it is "desirable and appropriate, if otherwise consistent with the public interest, to attempt to adhere to the results of a binding arbitration award" because arbitration is a valuable way to avoid time-consuming and expensive administrative proceedings. 30/ Moreover, where parties have agreed to submit disputes to fair arbitration procedures before resorting to the Commission, the Commission will insist that they do so. 31/ There are a variety of other ADR procedures, in addition to arbitration, that RTGs could use.

The Commission encourages RTGs to develop alternative dispute resolution procedures for resolving transmission issues, particularly those involving technical and reliability issues. We are also willing to entertain proposals for the Commission to give some degree of deference to decisions rendered pursuant to

29/(...continued)
dismissed No. 90-1528 (D.C. Cir. January 21, 1992). The Commission has also allowed arbitration of rate disputes. Kansas Gas and Electric Co., 28 FERC ¶ 61,112 (1984).

30/ Kansas Gas and Electric Co., 28 FERC ¶ 61,112 at 61,195 (1984); accord, Madison Gas and Electric Co., 56 FERC ¶ 61,447 at 62,579 (1991); North Carolina Eastern Municipal Power Agency v. Carolina Power and Light Co., 45 FERC ¶ 61,487 at 62,518 (1988), rehearing denied, 46 FERC ¶ 61,181 (1989); Pacific Gas and Electric Co., 43 FERC ¶ 61,403 at 62,035-6 (1988).

31/ Pacific Gas and Electric Co., 44 FERC ¶ 61,010 at 61,053 (1988).

an ADR process, pursuant to procedures that are specified in the RTG agreement and that assure due process for all participants.

We will not attempt to decide in this Policy Statement exactly what degree of deference we will be willing to afford. This may depend on a number of factors including, but not limited to, the type of issue to be resolved, the degree of specificity in the RTG agreement, the ability of any party to exercise market power, and the type of ADR being used. We will make that decision based on the particular facts of the proposals presented to us.

For example, it may be appropriate to give considerable deference to an arbitrator's finding on a purely factual issue, such as how much an improvement to the system will cost. This is somewhat analogous to factual decisions of administrative law judges, to which we afford considerable deference. However, just as we would not defer to an administrative law judge's decision that is directly contrary to Commission policy, we would not defer to an arbitrator's decision that is directly contrary to Commission policy. Other factors that might influence the degree of deference we would afford to the outcome of a dispute resolution process include, for example, whether a party can or does object to the decision, the degree to which the decision was reached under procedures that maximize fairness, and the degree to which the decision is based on a well-developed record.

4. Antitrust concerns

Several commenters expressed concern that RTGs may raise antitrust concerns. Some argued that the Commission cannot guarantee immunity from antitrust proceedings. 32/ While the Commission can provide no guarantees, we agree with other commenters 33/ that RTGs need not violate the antitrust laws. As the Department of Justice pointed out in its comments, 34/ the purpose of RTGs is to *encourage* competition in generation, not to discourage it, by making transmission more easily available to a wider spectrum of generating entities and by increasing the efficiency of the transmission system. More easily available wheeling should make the market work better and should lead to greater economic efficiency.

In this regard, we note that RTGs are in many ways analogous to power pools, which have been found not to violate the antitrust laws. In Central Iowa Power Cooperative v. FERC, 35/ the court rejected arguments that the Mid-Continent Area Power Pool (MAPP) violated the antitrust laws or policies. The

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32/ See Comments of American Public Power Association at 9, Old Dominion Electric Cooperative at 1, Central Power and Light Company at 10.

33/ See, e.g., Comments of Edison Electric Institute at 31-32, Public Generating Pool at 10, Southern California Edison Co. at 5.

34/ DOJ Comments at 1-7.

35/ 606 F.2d 1156 (D.C. Cir. 1979).

court pointed out that FPA section 202 expresses Congress' view that coordination is in the public interest. It specifically rejected arguments that MAPP constituted price fixing under the Sherman Act because of the pool's service schedules, which set forth rates.

5. Filing Procedures

The Commission expects that most RTGs will contain public utilities. As such, RTG agreements must, at a minimum, be filed under section 205(c) as contracts affecting or relating to transmission services provided by public utilities. We anticipate that most such filings will be made by one or more public utility members, on behalf of all public utilities in the RTG. 36/ If the filing entity believes that the filing will become effective automatically if the Commission does not act on the filing within 60 days, 37/ it should so state in the first paragraph of the cover letter in bold-faced type and should explain the arguments on which that view is based.

List of subjects in 18 CFR Part 2

36/ See Western Systems Power Pool, 55 FERC ¶ 61,099, 61,301 (1991), reh'g den'd, 55 FERC ¶ 61,495 (1991), aff'd sub nom. Environmental Action, et al. v. FERC, No. 91-1404 (D.C. Cir. July 2, 1993).

37/ As with all section 205 filings, the Commission intends to notice RTG filings in the Federal Register and to provide an opportunity for comment prior to Commission action on the filing.

Administrative practice and procedure, electric power, natural gas, pipelines, reporting and recordkeeping requirements.

In consideration of the foregoing, the Commission amends Part 2, Chapter I, Title 18 of the Code of Federal Regulations as set forth below.

By the Commission.

(S E A L)

Lois D. Cashell,
Secretary.

PART 2 - GENERAL POLICY AND INTERPRETATIONS

1. The authority citation for Part 2 continues to read as follows:

AUTHORITY: 15 U.S.C. 717-717w, 3301-3432; 16 U.S.C. 792-825y, 2601-2645; 42 U.S.C. 4321-4361, 7101-7352.

2. Part 2 is amended by adding § 2.21, to read as follows:

§ 2.21 Regional Transmission Groups.

(a) General Policy. The Commission encourages Regional Transmission Groups (RTGs) as a means of enabling the market for electric power to operate in a more competitive and efficient way. The Commission believes that RTGs can provide a means of coordinating regional planning of the transmission system and assuring that system capabilities are always adequate to meet system demands. RTG agreements that contain components that satisfy paragraphs (b) and (c) of this section generally will be considered to be just, reasonable, and not unduly discriminatory or preferential under the Federal Power Act (FPA). The Commission encourages RTG agreements that contain as much detail as possible in all of the components listed, particularly if the RTG participants will be seeking Commission deference to decisions reached under an RTG agreement.

(b) Organizational Components.

(1) An RTG agreement should provide for broad membership and, at a minimum, allow any entity that is subject to, or

eligible to apply for, an order under section 211 of the FPA to be a member. An RTG agreement should encompass an area of sufficient size and contiguity to enable members to provide transmission services in a reliable, efficient, and competitive manner.

(2) An RTG agreement should provide a means of adequate consultation and coordination with relevant state regulatory, siting, and other authorities.

(3) An RTG agreement should include fair and non-discriminatory governance and decisionmaking procedures, including voting procedures.

(c) Other Components.

(1) An RTG agreement should impose on member transmitting utilities an obligation to provide transmission services for other members, including the obligation to enlarge facilities, on a basis that is consistent with sections 205, 206, 211, 212 and 213 of the FPA. To the extent practicable and known, the RTG agreement should specify the terms and conditions under which transmission services will be offered.

(2) An RTG agreement should require, at a minimum, the development of a coordinated transmission plan on a regional basis and the sharing of transmission planning information, with the goal of efficient use, expansion, and coordination of the interconnected electric system on a grid-wide basis. An RTG

agreement should provide mechanisms to incorporate the transmission needs of non-members into regional plans. An RTG agreement should include as much detail as possible with regard to operational and planning procedures.

(3) An RTG agreement should include voluntary dispute resolution procedures that provide a fair alternative to resorting in the first instance to section 206 complaints or section 211 proceedings.

(4) An RTG agreement should include an exit provision for RTG members that leave the RTG, specifying the obligations of a departing member.

(d) Filing Procedures. Any proposed RTG agreement that in any manner affects or relates to the transmission of electric energy in interstate commerce by a public utility, or rates or charges for such transmission, must be filed with the Commission. Any public utility member of a proposed RTG may file the RTG agreement with the Commission on behalf of the other public utility members under section 205 of the FPA.

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APPENDIX C

THE FERC STAFF DISCUSSION PAPER ON TRANSMISSION PRICING ISSUES

NOTE: THIS PAPER WILL NOT BE PUBLISHED IN THE <u>FEDERAL REGISTER</u>

STAFF DISCUSSION PAPER
Transmission Pricing Issues

The Commission is interested in engaging in a broad discussion of transmission pricing reform. This paper sets out major pricing issues that confront the electricity industry. The discussion here reflects the dialogue that has begun within the industry. The Mid-Continent Area Power Pool (MAPP) has recently initiated a re-examination of transmission pricing, including alternatives that would explicitly account for distance in developing transmission rates. The General Agreement on Parallel Paths (GAPP), which is a committee of the Interregional Transmission Coordination Forum, is engaged in a discussion of parallel-path/distance-sensitive pricing concepts. The New England Power Pool has examined transmission pricing issues as part of its Regional Transmission Association discussions. In addition, advanced models of spot transmission pricing, as discussed below, have been developed to the point where serious consideration is warranted. Thus, it is appropriate for the Commission to engage in this inquiry at this time.

Transmission pricing has multiple policy dimensions which will involve important tradeoffs. For example, it is important to provide transmission price signals that accommodate the efficient operation of existing generating plants while also encouraging least cost investment in new plants. At the same time, any pricing reform must also be fair and equitable to existing and new users of the grid. More precise cost measurement is a reasonable goal, but the result should not be overly complex to implement. The Commission must weigh these competing considerations and decide whether reform is appropriate and, if so, how extensive any reform should be. Reform, however, should not be sought for its own sake. Pricing policy changes are appropriate only if they enable the industry to improve its performance at a reasonable cost of implementation. The threshold issue, then, is whether the benefits of changing our existing transmission pricing policy outweigh the costs.

This paper first reviews the Commission's traditional approach to transmission pricing and recent developments that have led to this inquiry. This is followed by a short discussion of the scope of the inquiry in order to focus comments on certain major issues. Included in this discussion is a short list of suggested criteria for evaluating alternative pricing options. The next three sections discuss specific pricing issues that have triggered proposals for reform.

I. BACKGROUND

A. The Commission's Traditional Approach to Transmission Pricing

Historically, the Commission has based its approach to transmission pricing on the rolled-in, average historic costs of the transmitting utility (including those of any affiliates, in the case of holding companies). This precedent was largely developed for requirements service where the wholesale customer's load is dispersed throughout the utility's service territory and integrated generation and transmission facilities are used. The result has been a "postage stamp" rate, *i.e.*, a unit charge for moving a unit of electricity over the transmitter's grid that does not recognize whether the electricity is transmitted 10 miles or 200 miles. 1/

The Commission has supported the postage stamp method for cost recovery on the grounds that a transmitter's grid is an integrated whole. That is, the Commission has approved single, rolled-in transmission rates because a corporate entity, the transmitting utility, operates its grid in a single, unified way. Such integrated operation complicates the issue of establishing cost responsibility. In addition, the benefits of reliable operation are difficult to separate and quantify in such an integrated system. By averaging system transmission costs and recovering them from all uses of the system, postage stamp rates have the practical virtue of administrative simplicity.

However, postage stamp rates may have important limitations, particularly in providing price signals to transmission users. Such rates may not reflect the cost of scarcity when there is a bottleneck on the grid, the costs of expanding capacity to remove such a bottleneck, or the cost of transmitting power over long distances. Because of the recent enactment of the Energy Policy Act of 1992 (EPAct) and the emerging competition in wholesale power markets, it is now appropriate to reevaluate postage stamp ratemaking.

Utilities transact with one another based on a so-called contract path concept. Under the contract path concept, all parties assume, for pricing purposes, that power flows are confined to a specified sequence of interconnected utilities that are located on a designated contract path. In reality, however, power flows are rarely confined to a designated contract path. Instead, power flows over multiple parallel paths that may be owned by several utilities that are not on the contract path. The actual power flow is controlled by the laws of physics which cause power being wheeled (or transmitted) from one utility to another to travel along multiple parallel paths and divide itself among those paths along the lines of least resistance. This parallel path flow is sometimes called loop flow.

The industry's contract path approach has been incorporated into the Commission's traditional transmission ratemaking. In effect, the industry has adopted and the Commission has accepted a convenient fiction that power travels along a contract path that differs from the real physical paths. The result is that some utilities whose transmission facilities are used to carry the power in reality, but who are not part of the contract path, may not be adequately compensated

1/ The term "grid" is used in this paper to mean the interconnected network of high-voltage transmission lines. Facilities that provide no system-wide benefit, *e.g.*, radial lines to remote load or facilities connecting generation facilities to the grid, are not considered part of the grid. Under certain limited circumstances, the Commission has allowed transmitting utilities to assign the capital costs of radial lines directly to specific customers. Where appropriate, such costs can be added to the charge for use of the grid. Central Maine Power Company, 54 FERC ¶ 61,206 at 61,611-12 (1991).

unless they seek compensation in a rate case before the Commission. Under Section 205 of the Federal Power Act, if a utility can demonstrate that others are imposing costs on its transmission system, it can file a separate rate to recover the costs imposed. However, this issue is complex and could require a fairly elaborate evidentiary showing.

The current contract path approach to pricing may or may not continue to be appropriate; however, it is clearly an issue which the Commission wishes to explore. In the past, the mismatch between compensation and actual flows was widely accepted, mostly because the industry believed that the overall costs and benefits were roughly balanced--others carried your power as much as you carried their power. In addition, utilities' planning efforts contributed to this balance by sharing the cost of new facilities or by taking turns in building. However, the mismatch has become more difficult to manage or ignore as power flows have become more unidirectional.

In the past 20 years, for example, the divergence between actual and assumed contract path flows has led utilities to install mechanical devices known as phase shifters in both the Eastern and Western Interconnections. A phase shifter is a device that redirects electrical current on an alternating current (AC) transmission grid. In addition, Western utilities experimented with various compensation mechanisms. Insulated from the other interconnections, utilities in the Electric Reliability Council of Texas (ERCOT), under the leadership of the Public Utility Commission of Texas, have been able to fashion wheeling rates that take account of loop flow. ERCOT's ability to deal with actual, as opposed to contracted, power flows has been successful, in part, because of the limited number of utilities involved.

Even with its limitations, the contract path approach to transmission pricing has served the Nation well. It has accommodated substantial amounts of efficient trading in the industry, all at a reasonable administrative cost. Nonetheless, the drawbacks in that approach are creating increasing stress. The expansion of the grid, regional imbalances in available generation resources and the emergence of competitive power markets are helping to create more transactions with benefits and costs that may not balance out among utilities as they have in the past. For example, bundled transactions involving both generation and transmission were prevalent in the past. Such transactions allow the parties to share the benefits associated with the sale of a bundled generation and transmission service. In contrast, a utility providing unbundled transmission service may be fully compensated for its transmission costs, but it does not receive any share of the possibly much larger benefits associated with the power sale. Accordingly, as the trend toward more unbundled transmission service continues, 2/ greater pressure will be placed on the Commission to adopt

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2/ The Commission has accepted unbundled transmission tariffs from a number of utilities, *e.g.*, Utah Power & Light Company, *et al.*, Opinion No. 318, 45 FERC ¶ 61,095 (1988), *order on reh'g*, Opinion No. 318-A, 47 FERC ¶ 61,209 (1989), *order on reh'g*, Opinion No. 318-B, 48 FERC ¶ 61,035 (1989), *aff'd in relevant part sub nom.* Environmental Action Inc. *et al.* v. FERC, 939 F.2nd 1057 (D.C. Cir. 1991); Entergy Services, Inc., 58 FERC ¶ 61,234 (1992), *order on reh'g*, 60 FERC ¶ 61,168 (1992), *appeal pending sub*
(continued...)

pricing policies that identify transmission costs more accurately, to allocate those costs appropriately, to develop rates that convey good price signals to users, and to develop approaches that fairly distribute benefits.

B. Recent Changes to the Traditional Approach

In the last two years, the Commission has attempted to address the industry's changing needs by modifying its transmission pricing policy in some respects. Incremental cost pricing is an example. Under traditional ratemaking, the addition of new, expensive transmission assets can cause average rolled-in rates to go up. If the Commission were to require a utility to provide transmission service (*e.g.*, as a condition for a merger or market-based pricing) for which an expensive upgrade would be needed, native load rates could increase under rolled-in pricing. As a result, native load customers would pay some part of the wheeling costs caused by the third-party service. The Commission has sought to avoid such an outcome.

The Commission recently revised its pricing policy to address this possibility. The revised pricing model was developed in the *NU* merger case 3/ and in the *Penelec* case. 4/ The model is based on a balancing of three principles:

- Hold native load customers harmless
- Provide the lowest reasonable cost-based price to third-party transmission customers
- Prevent the collection of monopoly rents by transmission owners and promote efficient transmission decisions.

From these principles, the Commission has adopted two pricing modifications: (1) incremental cost pricing for grid expansion or upgrades that relieve a constraint, and (2)

2/(...continued)
nom., Cajun Electric Power Cooperative, Inc. *et al.* v. FERC, Nos. 92-1461, *et al.* (D.C. Cir. filed Sept. 24, 1992).

3/ Northeast Utilities Service Company, Opinion No. 364, 58 FERC ¶ 61,070 (1992) (hereinafter cited as *NU*), *reh'g denied*, Opinion No. 364-B, 59 FERC ¶ 61,042 (1992), *order granting motion to vacate and dismissing request for rehearing*, 59 FERC ¶ 61,089 (1992), *affirmed in part and remanded in part sub nom.* Northeast Utilities Service Company v. FERC, Nos. 92-1165, *et al*. (1st Cir. May 19, 1993).

4/ Pennsylvania Electric Company, 58 FERC ¶ 61,278(1992) (hereinafter cited as *Penelec*), *reh'g denied and pricing policy clarified*, 60 FERC ¶ 61,034 (1992), *reh'g rejected*, 60 FERC ¶ 61,244 (1992), *appeal pending*, No. 92-1408 (D.C. Cir. filed Sept. 11, 1992).

opportunity cost pricing for a change in operations that relieves a grid constraint. A change in operations might require the transmitting utility to run uneconomical generation units (called re-dispatching) or to forego off-system sales or purchases (by curtailing scheduled power transfers). Either operational change could free up transmission capacity for use by a third party, without building new capacity.

In implementing these pricing modifications, the Commission has concluded that third-party rates should be high enough to hold native load harmless. As a result, when the grid is expanded, the Commission's current policy allows a utility to charge third party transmission customers the higher of embedded costs (for the system as expanded) *or* incremental expansion costs, but not the sum of the two. When the grid is constrained but the utility chooses to not expand its system, the Commission allows a utility to charge the higher of embedded costs *or* legitimate and verifiable opportunity costs, but not the sum of the two. The opportunity costs, in turn, are capped by incremental expansion costs. These pricing policies are collectively referred to as the "or" option.

Implementing these policies has been controversial. The Commission's "higher of" policy (i.e., the "or" option) has been opposed by some transmission owners who urge the Commission to allow them to charge third party transmission customers the existing embedded cost rate (without the expansion) *and* to specifically assign any additional incremental costs associated with the transaction to the third party requesting service (i.e., the "and" option). This is now known as the "and/or" pricing issue. 5/

The "or" policy is also opposed by some representatives of the parties that the Commission had intended to protect--the native load. Further, some state regulators believe that the "or" pricing policy is not fully compensatory. 6/ At its core, the and/or issue is whether holding native load customers harmless is enough or whether some additional compensation for transmitters is appropriate. In effect, the Commission's benchmark for "hold harmless" is economic neutrality (prevent native load rates from going up), while some transmission owners and state commissions would prefer the benchmark to be some form of fair compensation for the use of existing facilities plus any expansion or opportunity cost. This argument is raised below as part of the discussion of incentives to provide service under the current pricing approach.

5/ The controversy was discussed in the Congressional Record accompanying the passage of the EPAct. *See, e.g.*, 138 Cong. Rec. H.11412-13 (daily ed. Oct. 5, 1992); 138 Cong. Rec. S.17612-623 (daily ed. Oct 8, 1992).

6/ As an example, see the resolution passed by the Executive Committee of the National Association of Regulatory Utility Commissioners, *Resolution Encouraging State Regulatory Commissions to Consider Reforming Transmission Pricing Policies for Retail Electric Services*, adopted March 1993. The resolution encouraged state commissions to consider alternative ways of regulating the transmission function as part of retail service in light of the increasing federal role.

The "or" policy has been criticized on other grounds. The "or" policy allows a transmitting utility to charge an embedded cost price, which it will presumably choose to do, when the incremental cost is lower than the embedded cost. This provision is objectionable to some transmission customers who feel that if they must pay incremental cost when it is higher, they should also receive the benefits of paying the incremental cost when it is lower. Assuming that incremental expansion cost is lower than an embedded cost rate, it can be argued in response that such a policy would allow third parties to pay lower rates when service is constrained than when it is not. In addition, it raises questions about equity to native load customers since third-party rates would be lower than native load rates in such circumstances.

II. SCOPE OF THE INQUIRY

Staff believes that, although the Commission's pricing inquiry should be broad ranging, it must be focused in order to be manageable. To help focus the dialogue, Staff particularly encourages comments on the questions raised in this paper. This is not intended to preclude comments on any other transmission pricing issue that commenters believe warrants the Commission's attention. At a minimum, comments should be identified under one of the following three categories:

- Revisions to the Current Pricing Policy
- Reform of Traditional Ratemaking: Firm Service Pricing Issues
- Reform of Traditional Ratemaking: Non-Firm Service Pricing Issues

Within these categories, we ask specific questions that are designated by number later in this paper. Responses to these questions should be identified by reference to the question number.

The scope of this pricing inquiry is limited in two ways. First, this inquiry is limited to wholesale transmission service. Retail wheeling issues will not be addressed. Second, Staff recognizes that State regulatory commissions have substantial jurisdiction over transmission facilities. Indeed, transmission facilities are used to provide service to retail consumers and these facilities are included in the retail rate base. Furthermore, most states have siting authority with regard to transmission construction. While this inquiry is not focused on State-Federal issues relating to transmission pricing, commenters are invited to address such issues to the extent that particular reforms are affected by jurisdictional matters.

As a general matter, Staff notes that many of the issues discussed in this paper also are appropriate subjects for discussions within regional transmission groups. 7/ In many instances, regions would not be expected to adopt a uniform national approach in addressing a particular issue, *e.g.*, loop flow.

7/ *See*, Notice of Request for Public Comments on Regional Transmission Group Proposal, Docket No. RM93-3-000, November 1992.

Staff believes that, to the extent practicable, the criteria to be used to assess alternative transmission pricing options should be explicit. Among the possible criteria that could be used to evaluate any transmission pricing reform are the following:

- Promote efficient use of and investment in the transmission grid and provide appropriate price signals to transmission customers. To the extent practicable, prices should accurately:
    - account for transmission constraints
    - reflect any prudent costs incurred as a result of transmission service
    - reflect the actual power flows of the transmission service
    - reflect the distance- and location-sensitive costs of the transmission service
    - reflect the prevailing direction of the flow, distinguishing between "with the flow" and "counter flow"
- Address any transition problems arising from the reform
    - Balance equity considerations associated with any reform with the potential efficiency improvements
    - Mitigate the hardships arising from any reform
- Allow customers an option to have stable prices over time
- Be simple to implement and to administer.

QUESTION 1. Comment on these proposed criteria for assessing transmission pricing reform.

Staff recognizes that trade-offs between these objectives are unavoidable. It may not be possible to achieve efficiency, precision and administrative simplicity simultaneously. For example, the Commission will need to assess how complicated the administration of new transmission pricing policies might become in meeting these various criteria. The administrative costs may be higher for some criteria than others. In addition, the economic disruptions accompanying any departure from the status quo must be mitigated, if possible. Any remaining equity concerns then would be weighed against possible efficiencies. Reform is not sought for its own sake, but only as appropriate to support in an equitable manner the industry's evolution towards greater efficiency through competitive power markets.

III. REVISIONS TO THE CURRENT PRICING POLICY

In this section, commenters are invited to suggest changes to the Commission's current transmission pricing model. In Sections IV and V, we suggest possible alternative pricing models.

A. Incentives to Provide Service

As discussed above, some parties believe that the Commission's current implementation of its "or" policy does not provide sufficient incentives for transmission owners to provide service. 8/ They argue that if third parties pay only for the incremental cost of expansion (when this is higher than embedded cost), native load customers will receive no benefit. Those who support the "and" option contend that additional incentives are needed. For example, if third parties were required to pay embedded costs in addition to incremental costs, native load rates would decrease, thereby simultaneously providing a native load benefit and an expansion benefit.

> **QUESTION 2.** Comment on whether the Commission's current "or" pricing policy provides appropriate and sufficient incentives to transmission owners and transmission customers. Explain when benefits to native load customers above those that would be obtained under the "or" policy would be appropriate and when they would not. Further, explain how the Commission could distinguish between appropriate and inappropriate native load benefits in the context of postage stamp ratemaking in which a utility's grid is viewed as an integrated single system. Should the possibility of an additional financial incentive depend, in part, upon whether the transmission service is offered voluntarily or is mandated? How could the Commission monitor and ensure that "incentives" are not a mechanism for recovering monopoly profits?

The Commission's pricing policy is designed, in part, to hold native load customers harmless. Implicit in that objective is that transmission rates compensate the transmitting utility for all costs incurred in providing the service.

> **QUESTION 3.** Does the Commission's current pricing policy compensate the transmitter for all incurred costs? If not, what elements or cost factors are missing?

As previously discussed, a basic difficulty appears to be that unbundling transmission service will separate its pricing from the benefit sharing associated with power trades. With the exception of a few shared-savings transmission rates, transmission providers receive a cost-based price while power buyers and sellers receive possibly larger trade benefits. This is likely to be the case whether or not the Commission decides to reform its postage stamp ratemaking.

8/ The incentive for the transmission owner to provide service can be distinguished from the incentive to promote good decision making on the part of transmission customers. The latter incentive is discussed *infra*.

QUESTION 4. How does the unbundling of transmission service affect incentives?

Revenues from transmission service are frequently credited, one way or another, to native load customers by state regulators and the FERC. As a result, if the Commission were to allow higher prices for transmission services, most of the additional revenues would flow through to customers rather than shareholders of the transmitting utility.

QUESTION 5. What incentive to provide service remains if native load receives the benefit of incentives to provide transmission service and shareholders do not? Does the time lag in native load crediting affect this and, if so, how? Should the Commission consider revenue crediting less than 100 percent of third-party transmission revenues in developing rates for wholesale requirements service? How effective would this be given the fact that most "native load" rates are established at the state level?

The Commission has also accepted the concept of opportunity cost pricing, which Staff expects will be developed further in individual cases where specific fact patterns will be important in informing the Commission.

QUESTION 6. Does the Commission's opportunity cost pricing policy as articulated in *NU* and *Penelec* provide adequate incentives to the provider of the wheeling service?

QUESTION 7. Should the provision of third-party wheeling service be entitled to a different rate of return--higher or lower--to reflect the risks inherent in such transactions?

B. Incremental Pricing: Contract Vs. Average Incremental Costs

The Commission currently allows incremental cost pricing for grid expansion needed to fulfill a third-party transmission request. There appear to be two general ways to implement incremental cost pricing. One is to charge separate incremental prices in each transmission contract (contract pricing). The other is to charge a uniform price in all transmission contracts based on an average of current incremental costs (average incremental cost pricing). The Commission has begun to implement the first approach in its current pricing policy, although the full implications of that approach have not yet been raised in a case.

Under the contract pricing approach, a transmission customer pays for particular assets--those system upgrades associated with the customer's service. In exchange for paying for specific investments, the customer presumably would receive certain capacity rights. These rights would be specified in the customer's contract. Contract pricing would allow a transmission owner to enter into a contract, fixed as to capital recovery and with less risk for other costs, that gives customers substantial price certainty over the term of the contract. This can be especially important for non-traditional power producers that need project financing and may have little room to tolerate fluctuations in future transmission prices. The contract itself might contain provisions for renewal at the end of the contract term depending on the customer's needs and the utility's plans. In addition, the contract might fix certain pricing components, use inflation adjustments for some components, and allow others to be redetermined according to traditional regulatory procedures. The customer could not expect to have rights outside the contract, however. 9/

> **QUESTION 8.** Under contract pricing, would it be appropriate to develop a separate rate base for each customer? Or should native-load ratepayers remain responsible for a single ratebase with appropriate revenue crediting of all third-party wheeling revenues?

Under the average incremental pricing approach, all customers could be charged some average of the current incremental cost of the grid. This might involve replacement cost pricing or estimates of future expansion costs appropriately averaged over the next few years or some other approach. In contrast to the contract pricing approach, average incremental cost pricing applied uniformly could increase (or decrease) the rates of some third parties because of an expansion caused by others. In addition, some mechanism would have to be developed to ensure that all transmission costs are recovered since this form of incremental cost pricing may not necessarily cover the revenue requirement. Also, the issue of how such pricing for third-party transmission customers should compare to that for native load customers would have to be addressed.

> **QUESTION 9.** What pricing approaches or rate design policies are needed to ensure an opportunity for recovery of total revenue requirements?

Several comparisons can be drawn between the two approaches, as a general matter. For example, under contract pricing, a customer would not pay for his vintage of incremental cost if the resulting service is not worthwhile to him. This provides a private check using the customer's own perception of value on whether an expensive upgrade is worthwhile. Average incremental cost pricing, by comparison, runs the risk that an expensive upgrade which incremental users would not be willing to finance will be built anyway because its costs are averaged into all third-party rates. In this case, the risk is checked by traditional regulatory oversight. Consequently, over-building risk is dealt with differently under the two approaches.

> **QUESTION 10.** Is there a risk of over-building associated with average incremental cost pricing and, if so, how should such risk be handled?

Average incremental cost pricing for all customers is usually supported by noting that all customers are equally at the margin on any grid. That is, the system needs expansion for one customer only in the context of the aggregate demand of all customers. If any one customer were to reduce its demand, this could accommodate a demand expansion on the part of any other

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9/ Under this theory, native-load customers could be considered to have an open-ended, implicit contract with the transmission owner that does not terminate and in which all pricing components are redetermined periodically.

customer, assuming the same facilities would be used by both. Consequently, some would argue, all customers need to face the same incremental price signal at the same time for any particular point on the grid.

Price signaling is different under contract pricing. At any given time, the same price signal is given to all customers that cause expansion, but not otherwise. This succeeds in signaling customers about the financial consequences of future increases in their usage. With respect to decreases in usage, the customer is given a correct price signal to the extent that resale markets work well. That is, if transmission customers can resell existing capacity rights, current customers will be able to reduce their usage. The two approaches, then, depend on different mechanisms to transmit price signals--one uses regulated prices solely, while the other relies on regulation combined with an active resale market.

> **QUESTION 11.** Is it important that all customers face the same incremental price signal and how effective will each approach to pricing be in achieving a single incremental price?

Uniform implementation of incremental cost pricing treats old and new customers the same, *i.e.*, in a non-discriminatory manner, and typically does not require establishing cost responsibility on a customer-by-customer basis. 10/ In contrast, old and new customers will pay different prices under contract pricing. Whether this difference is due or undue discrimination is a separate question.

> **QUESTION 12.** Would the fact that old and new customers might pay different prices under a contract pricing regime constitute undue price discrimination?

Incremental cost pricing charged uniformly for all customers has the advantage that it would be simpler to administer. Contract pricing requires keeping track of investment vintages and associating these with particular customers. The accounting would become increasingly complex over time.

> **QUESTION 13.** Please comment on whether contract pricing is appropriate for wholesale transmission service and whether it can be administered over the long term at reasonable cost. Are the administrative costs large when compared to the risk of poor investment decisions? Would such pricing give good overall price signals with so many different prices for similar services? In competitive markets, reselling works to eliminate such price differentials. Would reselling be effective in creating a single transmission price

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10/ The British National Grid Company charges the same, non-vintaged prices to all users located within the same geographic zones. The Company concluded that it could not fulfill its legal obligation to provide non-discriminatory service if it charged different prices to different users at similar locations with similar characteristics. *See* National Grid Company, *Transmission Use of System Charges Review, Investment Cost Related Pricing--Response to Comments*, Coventry, England, October 30, 1992.

signal, say between a specific pair of points on the grid? Is there likely to be a significant resale market for anything other than major corridor service?

QUESTION 14. Should the Commission allow a different rate of return on transmission investment to reflect different riskiness depending on whether a contract pricing or average incremental cost pricing approach is adopted? If so, how would the different riskiness be assessed?

C. Other Issues Relevant to the Current Pricing Policy

Pricing for Grid Expansions. Although the Commission has accepted the concept of incremental cost pricing for transmission service requiring a grid upgrade, it has not specified any particular method for calculating such costs. A method will have to be identified when a utility proposes incremental cost pricing in a specific case.

QUESTION 15. What is the appropriate way to price transmission services that require grid upgrades? Is the approach of computing the revenue requirement with and without the third-party transaction an appropriate incremental pricing approach for grid expansion? What would be a reasonable time period to forecast costs and loads for such calculations?

Calculation of Line Losses. A transmission customer may pay for transmission losses either through an in-kind payment (replacement of the energy losses) or as part of the basic transmission rate. The payment typically is based on average line losses, as opposed to marginal line losses which would be higher in most cases. 11/

QUESTION 16. Is the current practice appropriate and, if not, what changes should be made?

Direction of Power Flows. Some transmission transactions may have beneficial effects on transmission systems, *i.e.*, relieve constraints, if they involve new power flows that would go against the prevailing flow.

QUESTION 17. Should transmission pricing take account of the direction of power flows? If so, should a customer be entitled to some form of credit if a particular transaction helps to alleviate a constraint?

Network Service vs. Point-to-Point Service. Commenters are invited to discuss pricing issues pertaining to either point-to-point service or more flexible services such as so-called network service. While there is no universally accepted definition of network service, Staff

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11/ *See* Northern States Power, 59 FERC ¶ 61,100 (1992), for a discussion of the Commission's current policy on the use of average and marginal line losses in ratemaking.

understands the term to mean transmission service that allows the user to vary its schedule and points of delivery and receipt on the grid without paying an additional charge for each change.

QUESTION 18. Is staff's definition of network service reasonable? Provide recommendations on how network service should be priced.

Ancillary Transmission Services. Commenters are invited to address the pricing of ancillary services, such as voltage support or reactive power service, load following services, scheduling and dispatch service, and operating reserves. Such services are automatically provided as part of bundled power service, such as requirements service or retail service. As more unbundled transmission service is provided, such services can be expected to become increasingly important. Staff recognizes that an important issue for the Commission to deal with is whether the Commission can order the provision of ancillary services and, if so, which ones. This inquiry will focus on the pricing issues and defer the provision question for later consideration.

QUESTION 19. Can commenters suggest other ancillary services, in addition to those listed above? Provide recommendations on how such ancillary services should be priced.

IV. REFORM OF THE CURRENT PRICING POLICY: FIRM SERVICE PRICING ISSUES

It is possible to reform various dimensions of the current model. For example, postage stamp ratemaking could be replaced with distance sensitive pricing. Likewise, the contract path model could be changed to account for parallel flows. Importantly, reform of these dimensions could be combined in various ways. For instance, a postage stamp, parallel path approach is at least theoretically possible. Staff has no preconceived model of pricing. Commenters are invited to suggest any alternatives they believe are appropriate. The following discussion is intended to illustrate the kinds of issues and trade-offs that the Commission is likely to face in evaluating such models.

A. Distance-Sensitive versus Postage Stamp Rates

A postage stamp rate entitles a user to transmit power over any portion of a utility's grid, whether for 10 or 200 miles, for the same rate. Under postage stamps rates, the cost of providing short-distance transmission or transfer service is implicitly averaged with that of long-distance transfer service. This may create a bias in favor of long transfers and against shorter ones.

QUESTION 20. Does the failure of postage-stamp rates to recognize distance create important cross subsidies between long-distance and short-distance transfers?

Several alternatives to postage stamp rates exist that would make the price paid sensitive to the distance involved. One form of distance-related pricing is the MW-mile method, which could be implemented in numerous ways. It could be used to price power flow within a single utility (as in the case of some New Jersey utilities) or among several utilities, as in the ERCOT experience in Texas. 12/

Another way to incorporate distance into transmission rates would be to develop rate zones within a single utility's grid. This might involve dividing the grid into parts for ratemaking purposes. Power moving across each zone would be identified in load flow analyses, which would help to sort out whether the zones and utilities have a parallel relationship (where only a portion of the total power flow burden is physically carried by a particular utility or zone) or a serial relationship (where *all* of the power flow burden is carried by each of the utilities or zones). Some observers have even suggested facility-by-facility pricing, which would charge users a load-ratio price for each facility used. In the extreme, each facility, *e.g.*, a line or a substation, would effectively become its own rate zone. Further, the concepts of zones and MW-miles could be combined in principle. That is, MW-miles could be used to allocate costs within zones.

> **QUESTION 21.** How much do transmission costs vary with distance and can such costs be easily quantified? Comment on distance-sensitive pricing in general and on MW-mile methods and zonal methods in particular. Comment on the importance of distance-related rates in providing correct incentives. Would distance-sensitive pricing proposals apply to point-to-point service, or network service, or both?

In addition to incorporating distance correctly, it is also important that transmission prices promote good decisions regarding where to locate new generation facilities. The long-term expected congestion at certain critical grid locations may not be adequately incorporated into distance-sensitive prices. Prices may have to be sensitive to location as well.

> **QUESTION 22.** Do postage-stamp or distance-sensitive rates provide adequate price signals about the location of new generators? If not, how can transmission prices help promote good location decisions?

B. Contract Path versus Parallel Path Pricing

As discussed in Section I, the contract path approach currently used by the industry may no longer fit its planning and operating needs. Some utilities whose transmission facilities actually carry the power, but who are not part of the contract path, are not likely to be adequately compensated under the contract path approach. This mismatch between compensation and actual flows was widely accepted in the past because of the industry's belief that the overall costs and benefits were roughly balanced and sometimes an explicit effort was made to achieve a balance by sharing the cost of new facilities or by taking turns in building. However, it is staff's impression

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12/ An example of the MW-mile method has been proposed by Alfred F. Mistr, Jr. and Everard Munsey, "It's Time for Fundamental Reform of Transmission Pricing," *Public Utility Fortnightly*, July 1, 1992, pp. 13-16.

that the mismatch is growing in magnitude and *ad hoc* efforts to achieve a balancing of costs will no longer work.

Contract path pricing may also create inefficient incentives. For example, it may dilute the incentive of transmission owners to build new transmission assets since others may be able to use the new facilities without charge. Contract path pricing could also complicate coordinated building activity among transmission owners. Regional grid upgrades may need to be made sequentially by several utilities over several years. The utility that first upgrades runs the risk that other utilities may not be able to complete the promised investments that would have provided the expected reciprocal benefits. The other utilities would then get to use the first utility's new capacity for free. No one would want to build first if such a risk were large.

Alternatively, contract path pricing may create an incentive for a utility without significant transmission facilities to build an inefficiently small (low voltage) line in the midst of a high voltage grid in order to create a contract path, assuming that it could meet appropriate reliability criteria. Even with the new line, the utility's power will still flow over the higher voltage lines if, as is likely, there is less resistance on those lines. The result would be that an inefficient investment would be made in order to gain access to a neighboring high voltage grid for free. Such a strategy can benefit the utility if the expected savings in procuring power exceed the investment cost of the needed (token) transmission facilities. In contrast, the more appropriate calculation would examine whether such a low voltage line has any place in the regional transmission plan. Such a line, for example, may make an ineffective contribution to regional reliability or perhaps even detract from reliability if it cannot withstand first contingency power surges when elements of the neighboring high voltage grid fail. 13/

If the industry changes its contract path contracting approach, corresponding pricing changes would be needed. An alternative to contract path ratemaking would be some form of parallel path pricing. Parallel path pricing would compensate transmission owners for use of their grids based on the fraction of the total flow carried by each owner. The fraction of flow carried would be determined by an engineering analysis of the load flow. Each transmission owner's price would recover a contribution to capital.

Another alternative would be to establish capacity rights to the *regional* grid, either on a point-to-point or network-wide basis. Such rights are not systematically defined under the current contract path approach, although the utilities in the Western Systems Coordinating Council have begun to address this issue in their process for rating the simultaneous incremental transfer

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13/ A grid that is built to withstand so-called "first contingencies" is one that can continue to operate within the established safety criteria after it has lost the services of the single, largest and most critical element in the grid, perhaps a critical transmission line or a large generator.

capability of grid additions. 14/ Payment for the capacity right would constitute the capital contribution under this approach.

> **QUESTION 23.** Assess the benefits and problems of specific alternatives to the contract path approach and the need for such alternatives.

Parallel path pricing or some other mechanism such as the establishment of capacity rights might neutralize the incentive for transmission owners to not build when they should, and for non-owners to build inefficient facilities. The poor incentives of contract path pricing, however, might be replaced by other poor incentives under parallel path pricing. For instance, parallel path pricing might create an incentive for a utility to build lines at voltage levels much higher than those of its neighbors in order to attract large amounts of parallel flow from neighboring utilities and thus be compensated for them.

> **QUESTION 24.** Does the current approach to contract-path pricing provide appropriate incentives for transmission construction? Would some other approach, parallel path pricing or better defined capacity rights, provide better incentives for such construction?

This phenomenon apparently exists now even in the absence of parallel flow pricing. Some neighboring utilities trade amounts of power that are smaller than the rating of their direct interconnections and yet a substantial fraction of the flow is carried on higher voltage neighboring systems. These utilities are understandably concerned that parallel path pricing could cause them to pay a third party for transmission service even though their jointly owned interconnection could carry their trade in the absence of the neighbor's lines. This situation needs to be considered in any reform involving parallel path pricing.

> **QUESTION 25.** Comment on how the Commission should address situations where utilities are required to pay third parties even though their interconnection would appear to be adequate.

One way might be to exempt directly interconnected neighbors from parallel path pricing. As mentioned, another solution might be to establish firm transfer rights that entitle a holder to use the system at no additional charge (except for line loss payments) up to the amount of the firm rights. Usage in excess of the rights could be subject to parallel path pricing. The rights could be established in advance according to ownership shares, demand charge payments, or other financial considerations.

14/ The WSCC process tries to produce line ratings which recognize that individual transmission lines are embedded within a larger network. The rating of any line depends on the operation and configuration of the larger network. Once a line's capacity rating is established through an open "peer review" process, the rating sets limits on the amount of power that can be transmitted over the line.

QUESTION 26. If you would propose to establish capacity rights, comment on the consequences of such exemptions on your proposal.

In questioning the incentives under both pricing regimes--contract and parallel flow--Staff understands that good decisions are frequently made. The industry norm is that high voltage lines do get built now and inappropriate low voltage lines, while possible, are seldom built. Nonetheless, we believe that a pricing regime based on good incentives will improve performance.

QUESTION 27. Comment on the relative effects of contract path and parallel pricing on the incentives for cost-effective construction of transmission facilities.

Staff believes that parallel path pricing could improve decision making about the use and expansion of the grid. It can more accurately match usage with cost causation by identifying where the power is flowing. In so doing, the parallel portions and serial portions of the flow can be identified. Transmission assets arrayed in a parallel position to carry the power of a particular transaction will share the burden of the flow and accordingly could be allocated an appropriate fraction of the price. Assets arrayed in a serial position will each carry the same power burden and accordingly their costs could be appropriately added. Parallel path pricing could produce dramatic changes from contract path rates. This not only could help to sort out how the power flow burden is shared among parallel path owners, but also could clarify how much of a burden is imposed on serial path owners.

Parallel path pricing would require power flow studies to identify which parallel paths are used in particular transactions. Incorporating load flow information in its pricing practices would be a clear departure for the Commission. The Commission's recent Notice of Proposed Rulemaking on transmission information in Docket RM93-10-000 is relevant here. Staff expects that the information needed to conduct power flow analyses would be assured as a result of this proceeding. Power flow studies would complicate ratemaking considerably. Such a complication may be largely unavoidable, however, since it appears that most proposed pricing reforms would involve such analyses.

QUESTION 28. Provide suggestions for reforms that would not require power flow studies, as well as suggestions for procedures to resolve technical disputes about such studies.

Staff sees important comparisons between contract pricing of capacity rights, discussed in the previous section, and parallel path pricing. For instance, payment for the capacity rights associated with contract pricing, perhaps through a reservation charge, would be the means for recovering capital costs. Most proposals to create capacity rights have small usage charges that recover only variable costs, such as line losses. In contrast, parallel path pricing recovers a capital cost contribution in rates for usage, not reserved capacity.

QUESTION 29. Can these two concepts be combined or are they mutually exclusive?

In addition, trading (reselling) is contemplated in most capacity rights proposals. If two parties both own capacity rights between points A and B on the grid, they presumably could compete to resell those rights to a third party. This would be a version of contract path competition. Such competition would appear to be ruled out in a parallel path pricing model since all the utilities on the parallel path would jointly determine which portion of a transaction is carried on each utility's system. Presumably, no utility would charge for or compete to provide service determined to be carried on someone else's system. The utilities on the parallel path are those that jointly possess parallel capacity rights, in effect. Consequently, reselling in a capacity rights model could involve competition among parallel rights holders to provide service between points of receipt and delivery, while reselling in the parallel path model only would involve returning the capacity to the joint service providers with no competition among them.

QUESTION 30. Is this an important difference between the two models and, if so, which is more appropriate?

C. Equity and Fairness Considerations

The current pricing policy, based on the postage stamp, contract path approach, has prevailed for many years and provides the basis for most trade today. Any change is likely to be disruptive and to affect participants in different ways. Dealing with the equity and fairness ramifications of any pricing reform is important.

QUESTION 31. Comment not only on the efficiency consequences of possible reform, but also on its fairness and equity implications. Provide specific suggestions on how the Commission would manage any transition to a new pricing system, how it would mitigate hardships associated with the transition and how any change would be coordinated among all affected utilities.

QUESTION 32. A possible approach to mitigation would be to apply pricing reform prospectively only, *i.e.*, for new transactions, but not existing ones. If the Commission believed that some version of parallel pricing was appropriate, for example, how should the need for mitigation be weighed against the need to coordinate parallel path pricing among all affected transmitting utilities?

V. REFORM OF THE CURRENT PRICING POLICY: NON-FIRM SERVICE PRICING ISSUES

A. Capital Recovery in Non-Firm Transmission Rates

Non-firm transmission service can be interrupted by the transmitting utility more easily than firm transmission service. A fundamental issue of non-firm transmission pricing is how much of a contribution to fixed costs is appropriate and, further, whether any "demand charge" is appropriate. Such a charge is common practice in the industry today. Despite current practice, many observers believe that recovery of capital costs in non-firm wheeling rates can interfere with short-term efficiency. They argue that the Commission's acceptance of non-firm rates with a capital cost adder discourages economy transactions that could lower generation production costs.

The short-run marginal costs (or variable costs) of transmission consist only of line losses and so-called congestion costs. Congestion costs are the short-term opportunity costs of using constrained facilities, such as the cost of redispatching generation units in order to free up transmission capacity. 15/ Congestion costs could be addressed by using spot pricing, as discussed *infra*. From this perspective, many economists conclude that non-firm service prices should recover only variable costs. The reasoning is that users of non-firm service should not pay for capacity costs, *per se*, since capacity is not built for them--their service can always be interrupted when the capacity becomes tight.

The Mid-Continent Area Power Pool (MAPP) has used a variant of short-run marginal cost pricing to pay for the transmission service that allows for short-term coordination transactions within the pool for years. Critics of this pricing system argue that non-firm transmission users are "free riders" if the grid has adequate capacity. That is, if grid capacity is unconstrained, congestion costs are zero and non-firm users pay only for line losses. Transmission users can avoid making any contribution to capital by subscribing only to non-firm service. Under current rate base treatment, a utility's native load would not be compensated by such users.

In practice, this problem can be and sometimes is addressed by a requirement that all users make some contribution to capital, perhaps through ownership requirements or capacity deficiency payments or some other contribution mechanism. This approach has been adopted by MAPP, for example. In effect, the transmission owners develop rules that ensure that all users pay a fair share of the capital costs and then pay only for line losses on a transaction-by-transaction basis.

Under one theory, another answer to this dilemma is not to install excess capacity. If capacity is optimal, in this view, it would be occasionally short and so non-firm users would have to pay substantial congestion costs in order to avoid interruption during peak loading periods. Many would then desire firm service. These new firm service users would make capital contributions that adequately compensate native load. In effect, the free rider problem would disappear if firm and non-firm service could be made equally attractive by proper adjustment of capacity, according to this theory.

15/ Congestion charges can be viewed as contributions to capital. *See* William W. Hogan, "Electric Transmission: A New Model for Old Principles," *Electricity Journal*, March, 1993.

It is not clear, however, that the optimal level of capacity is one that necessarily makes firm and non-firm service equally attractive over the long run. There are several reasons to believe that some reasonable amount of excess transmission capacity might be optimal. Lumpy investment combined with uneven demand expansion can create long periods of "excess capacity" even if capacity planning is optimal. Some have also argued that, given the relative importance of generation in comparison to transmission, some excess transmission capacity above that needed for reliability purposes should be tolerated in order to have the infrastructure needed to facilitate a competitive generation sector. 16/ In addition, excess transmission capacity would be needed in theory in the absence of very short-term pricing mechanisms that signal the need for end users to curtail during peak transmission loading episodes. The excess in such circumstances would be required to handle short-term needs that cannot be rationed by price. If utilities install excess transmission capacity, for one of these or any other good reason, it could be freely exploited by non-firm users if they paid no capital-contribution charge.

> **QUESTION 33.** Comment on this dilemma: how to give good short-term price signals through non-firm transmission pricing, while avoiding the possibility that non-firm users would make no contribution to capital costs. Is the dilemma important in practice?

B. Spot Pricing for Non-Firm Transmission

Spot transmission pricing refers to very short-term pricing that would reflect hour-to-hour conditions on the grid. Spot prices consist of marginal line losses plus congestion charges. 17/ A spot transmission rate has no demand charge and makes no contribution to capital, except through the highly volatile congestion charge. Such a concept clearly has no place in the Commission's regulation unless the Commission first makes the threshold determination that non-firm demand charges are inappropriate, as discussed above. If the Commission reaches such a determination, Staff is interested in understanding how to implement spot pricing and whether it would improve efficient operation. Note that the issue of how to recover capital costs could be addressed separately, in which case the issues raised in the previous section are relevant.

The theory of spot pricing for transmission is closely related to spot power markets. In the existing literature, *e.g.*, *infra* note 17, well functioning spot markets for power are assumed to

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16/ Charles G. Stalon, "Pricing Transmission Network Services," Presentation to American Bar Association, Denver, Colorado, February 1993, at 8. Generation costs typically constitute about 60 to 75 percent of the price that final customers pay for electricity. Therefore, it is argued that some overinvestment in transmission is desirable if it produces a competitive generation market that lowers generation costs.

17/ For an introductory discussion of spot pricing, *see* K. Kelly, J.S. Henderson, and P. Nagler, *Some Economic Principles for Pricing Wheeled Power*, National Regulatory Research Institute (Columbus, Ohio, August 1987).

exist at multiple locations (buses) around the grid. 18/ These would be multi-lateral trading institutions, perhaps organized like a stock exchange or commodities market. The theory of spot transmission pricing is usually based on the assumption that these dispersed spot markets for power are workably competitive. The literature does not address the question of how well spot transmission pricing would perform if the corresponding spot power markets are not competitive. Regardless, such spot markets for power do not exist today and would represent a substantial departure from the quite active bilateral arrangements for trading power today. Some of the benefits of spot transmission pricing may not be achievable without reform of the institutions for trading short-term power. Accordingly, spot transmission pricing might require more than reform of the Commission's regulation of transmission pricing. The needed institutional reform may be more ambitious than the other pricing reforms discussed in this paper.

QUESTION 34. Comment on the observation that spot transmission pricing might require more than reform of the Commission's regulation of transmission pricing and might involve reform of the underlying market institutions for trading power.

Spot pricing proposals have been developed by several analysts. 19/ Staff is interested in understanding how such pricing could be implemented by the industry to improve coordinated operations.

QUESTION 35. Would spot pricing be intended to improve *ex ante* price signals or be the basis of an *ex post* financial settlements system?

QUESTION 36. Is there a need for spot pricing of inadvertent, unscheduled power flows and, if so, how would this interact with the spot pricing of scheduled transfers?

18/ A bus is a point on the grid where power is either injected by a generator or taken off by a customer's load. Buses are connected by transmission lines.

19/ *See* F.C. Schweppe, M.C. Caramanis, R.D. Tabors, and R.E. Bohn, *Spot Pricing of Electricity* (Norwell MA: Kluwer Academic Publishers, 1988); W.W. Hogan, "Contract Networks for Electric Power Transmission," Working Paper E-90-17, John F. Kennedy School of Government, Harvard University, Cambridge MA, September 1990; M.L. Baughman, S. Siddiqi and J. Zarnikau, "Advanced Pricing in Electrical Systems," University of Texas Working Paper, October 1992; and, M.B. Lively, "Tie-riding Freeloaders--The True Impediment to Transmission Access," *Public Utilities Fortnightly*, December 21, 1989.