Incremental Cost Pricing of Transmission Services

Final Report

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Prepared by:

ICF Resources Incorporated

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MASTER

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EXECUTIVE SUMMARY

INTRODUCTION

A broad debate relating to U.S. electric transmission policy in general, and the pricing of transmission services in particular has been underway for several years. As early as 1988, the Federal Energy Regulatory Commission (FERC) formed a Transmission Task Force to study electric transmission policy issues and report its findings to the FERC. The Transmission Task Force produced a major report, *Electric Transmission: Reality, Theory and Policy Alternatives, October 1989*. In 1992, the Energy Policy Act (EPAct) was signed into law and Title VII of that Act gives the FERC new authority to order the provision of transmission services in the purchase and sale of electric power at wholesale.¹⁾

This report, prepared by ICF Resources, under a sub-contract with IT Corporation, is concerned chiefly with examining the economic concepts underlying an Incremental Cost Pricing Framework (ICPF), which is defined here as a pricing regime that takes into account several factors: economic efficiency in terms of sending the correct long-term price signals to both users and owners of transmission assets; pricing of individual services in relationship to cost causation; full recovery of costs associated with transmission service; and applicability to real-world power systems without extraordinary administrative burdens. In the course of this examination, the report makes assumptions, as necessary, and assesses the extent to which they may or may not comport with real-world conditions. It also assesses the pros and cons of different approaches to pricing various components of transmission service without making a recommendation as to the superiority of one approach over another from a public policy perspective.

Economic concepts presented in this study have been developed in the context of an integrated transmission system. The essential generic features of such an integrated transmission system are as follows:

- The transmission system can be represented by a stylized grid or network consisting of transmission lines and points at which they meet called "buses."
- From a cost accounting perspective, a single entity is responsible for the incurring and recovering of transmission-related costs and the transmission system has no material interactions with other transmission systems.
- The transmission system or its agent is responsible for real time management of the transmission system, although the extent to which this agent functions as a "central dispatcher" can vary from circumstance to circumstance.

¹⁾ On June 30, 1993, the Federal Energy Regulatory Commission (FERC) initiated an inquiry dealing with pricing policy for transmission services. That inquiry culminated with FERC issuing a Policy Statement on transmission pricing on October 26, 1994. Because this report was substantially complete prior to October 26, 1994, the FERC's Policy Statement is not examined here. However, submittals by various parties in the course of that inquiry were analyzed.

- Economically correct bus-specific ex post spot prices based on real power flows can be determined for the transmission system.
- The transmission system is indifferent as to who wins or who loses in the competition among generators.

TRANSMISSION COSTS

The transmission system incurs various types of costs in providing its service. These include electric losses; a range of ancillary services; operation and maintenance on transmission facilities; opportunity costs, to the extent they are experienced; and the carrying charges associated with the capital costs incurred by the system both in terms of already-incurred costs and recurring costs. Table ES-1 provides a summary of the causal factors underlying each cost element and the nature of the cost with respect to the variability (or lack thereof) of the cost.

TABLE ES-1
Major Elements of Transmission Cost

Cost Element	Causal Factors	Fixed vs. Variable Nature of Cost
Electrical Losses	Electrical resistance	Variable
Ancillary Services	Incremental transmission requires: <ul style="list-style-type: none"> • Black Start Capability • VAR Support • Spinning Reserves and Frequency Control 	Variable and Fixed
O&M on Transmission Facilities	<ul style="list-style-type: none"> • Incremental O&M. • Share of system-wide O&M. 	Primarily Fixed
Opportunity Costs	Transmission constraints cause: <ul style="list-style-type: none"> • Non-economic Dispatch • Cost of Lost Transactions 	Primarily Variable but reflective of underlying capacity constraint.
Capital Costs	<ul style="list-style-type: none"> • Allocation of existing system carrying charges • Construction of new facilities required for transaction 	Fixed

ALLOCATION OF TRANSMISSION COST TO TRANSMISSION SERVICES

Definition of Transmission Services

The discussion in this study focuses on transmission as a physical service under which the purchaser of transmission service purchases the right to (a) remain interconnected with the system, subject

to meeting safety and other engineering requirements, and (b) schedule electric output (energy and capacity) in an agreed-upon manner at one or more buses on the transmission system as well as receive such electric energy at one or more buses in amounts commensurate with the output scheduled at the delivery buses.

Critical Characteristics of Transmission-Related Costs

Certain characteristics of transmission-related costs are particularly important in developing an ICPF. They are:

- **Fixed Versus Variable Nature of Costs:** In general, fixed costs do not vary in the short-term with levels of usage (e.g., carrying charges associated with transmission plant, and fixed components of operation and maintenance), while variable costs do vary directly with usage (e.g., losses). Assigning variable costs based on usage is therefore usually straightforward, although to the extent incremental variable costs deviate sharply from average costs, cost allocation becomes more complicated. Allocating fixed costs in accordance with the ICPF principles is generally more complicated.
- **Common Versus Directly Assignable Costs:** Common costs, which are frequently fixed costs, and their allocation represent the major challenge in developing an ICPF. Certain fixed costs are directly assignable to users (or to zones/regions within the transmission system) on the basis that these costs would not have been incurred "but for" the need to serve the users to whom the costs are assigned. A common example is interconnection costs and costs of system enhancements that have to be undertaken in order to accept the electric output of an IPP. Common costs, on the other hand, cannot be assigned logically to specific users. The characteristics of common costs include the following:
 - Although they cannot be assigned logically to specific users, the transmission system would not be able to function if these costs were not incurred. Therefore, these common costs can be considered stranded only if some or all portions of the transmission system with which they are associated can be abandoned without affecting service.
 - Some common costs are recurrent in that they have to be incurred every year. The nature of these common costs is such that even if overall usage decreases, the level of these recurring common costs remains the same. If this were not true, it would have been possible to assign these costs to specific users in the first place.
 - If common costs are not fully recovered, the transmission system, as a whole, will not recover all its costs.

Findings Related to Alternative Pricing Approaches

Based upon an examination of cost causation on transmission systems as well as the basic considerations that are to be satisfied under an Incremental Cost Pricing Framework (ICPF), this study identifies several elements that are applicable to an ICPF:

- Under an ICPF, incremental users of the transmission system pay for their contribution to losses, variable operation and maintenance, and other allocable variable cost. With regard to losses, one approach is to have zone-specific loss factors that are more representative of an incremental treatment of losses.
- Fixed costs that are directly assignable to an incremental user are paid for by that user, under an ICPF. Also, to the extent there are fixed costs assignable to the incremental user's zone, that user pays its share of such zonal costs.
- Much of the controversy over cost allocation centers on how common fixed costs (i.e., common to the entire system) are allocated. Given the nature of common costs, any allocation rule is open to criticism as being arbitrary. Possible cost allocation approaches include the following:
 - A usage-based allocation leads to what is usually termed an "embedded cost." While this approach appears to be equitable across customers, it does not in all circumstances result in the correct, long-term economic signals to users. This criticism applies regardless of the usage measure employed.
 - An alternative is a zone-specific or user-specific allocation of common costs that is designed to send the correct economic signals to users. If the generation market can be considered to be competitive at each location on the system, the transmission system can be given total freedom in carrying out these cost allocations. An alternative is to combine zone-specific knowledge and judgment to derive an allocation that reflects relative cost conditions in different zones (the "relative cost rule"). Other practical constraints can be added to the relative cost rule: all users must pay a common cost component that exceeds zero; the transmission system can offer discounts relative to a cost-derived, zone-specific cap; and so on.

I. INTRODUCTION

A broad debate relating to U.S. electric transmission policy in general, and the pricing of transmission services in particular has been underway for several years. As early as 1988, the Federal Energy Regulatory Commission (FERC) formed a Transmission Task Force to study electric transmission policy issues and report its findings to the FERC. The Transmission Task Force produced a major report, *Electric Transmission: Reality, Theory and Policy Alternatives*, October 1989. In 1992, the Energy Policy Act (EPAct) was signed into law and Title VII of that Act gives the FERC new authority to order the provision of transmission services in the purchase and sale of electric power at wholesale.¹⁾

As part of providing greater transmission access, the FERC is currently conducting a wide-ranging inquiry on transmission pricing issues. While that inquiry may result in generic modifications to its pricing regime, the FERC, at the same time, is making decisions in individual cases involving transmission-related issues (including pricing) that are brought before it.

This report, prepared by ICF Resources, under a sub-contract with IT Corporation, is concerned chiefly with examining the economic concepts underlying an Incremental Cost Pricing Framework (ICPF), which is defined here as a pricing regime that takes into account several factors: economic efficiency in terms of sending the correct long-term price signals to both users and owners of transmission assets; pricing of individual services in relationship to cost causation; full recovery of costs associated with transmission service; and applicability to real-world power systems without extraordinary administrative burdens. In the course of this examination, the report makes assumptions, as necessary, and assesses the extent to which they may or may not comport with real-world conditions. It also assesses the pros and cons of different approaches to pricing various components of transmission service without making a recommendation as to the superiority of one approach over another from a public policy perspective. FERC decisions in certain cases and filings made by various parties in pending cases are used to illustrate some points. While the report explores economic implementation issues (e.g., susceptibility to measurement; availability of data; use of system models; and so on), it does not address institutional and legal implementation issues.

The report consists of five chapters, including this one. The next chapter, Chapter II, deals with a review of the public policy debate over transmission. Chapter III provides a discussion of the elements that contribute to transmission costs; it describes engineering issues without delving deeply into purely engineering considerations. Chapter IV discusses the economic concepts underlying transmission pricing and presents what is termed the Incremental Cost Pricing Framework (ICPF). This chapter evaluates the pros and cons of various concepts, albeit at a conceptual level. Chapter V addresses implementation issues. It draws upon actions taken and cases filed before the FERC to illustrate the extent to which current pricing practices can be changed so as to be consistent with an ICPF. The discussion also points up the extent to which current practices do not meet the criteria set forth for the ICPF.

¹⁾ On June 30, 1993, the Federal Energy Regulatory Commission (FERC) initiated an inquiry dealing with pricing policy for transmission services. That inquiry culminated with FERC issuing a Policy Statement on transmission pricing on October 26, 1994. Because this report was substantially complete prior to October 26, 1994, the FERC's Policy Statement is not examined here. However, submittals by various parties in the course of that inquiry were analyzed.

II. REVIEW OF THE PUBLIC POLICY DEBATE OVER TRANSMISSION PRICING

In conjunction with the rapid changes occurring in the electric power industry, federal regulation of transmission access and pricing is in the process of fundamental review and change. Over the past 5 years, the Federal Energy Regulatory Commission (FERC) has used a series of merger and rate cases to implement a movement towards greater transmission access and incremental pricing of transmission services. With its passage of the Energy Policy Act (EPAct) in 1992, the U.S. Congress affirmed the general direction of these policies and provided FERC with greater authority to order wheeling if necessary. Further development of FERC policy is ongoing—FERC requested comments on its pricing policies in June 1993,¹⁾ and a policy statement on the subject is expected during the summer of 1994.

This chapter will provide background on the development of transmission pricing policy at the Federal Energy Regulatory Commission (FERC), with a focus on recent initiatives of FERC and Congress to develop new pricing principles over the last 5 years. This review will provide the context for the discussion of transmission pricing, cost allocation, and incremental cost pricing discussed in later chapters.

HISTORY OF POLICY DEVELOPMENT

The history of federal transmission pricing policy can be divided into four periods:

- Pre-PURPA
- Post-PURPA
- Between 1988 and the passage of EPAct
- Post EPAct

Although each of these periods will be reviewed, the period following 1988 has the most relevance for the development of future transmission pricing policy and will be examined in greater detail.

Pre-PURPA

Modern regulation of wholesale power sales and exchanges originated with the Federal Power Act, one of two titles of the Public Utility Act of 1935.²⁾ The Federal Power Act (FPA) authorized Federal Power Commission (now FERC) regulation of electric utility rates and practices. Federal authority to direct or order wheeling was limited under the FPA, and wheeling was primarily left to the voluntary actions of electric utilities.

The issue of wheeling and the pricing of transmission services was not a key issue for the next several decades. The electric power industry was growing at a rapid pace during this period. Electric

1) FERC, *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act*, Docket RM93-19-000, Notice of Technical Conference and Request for Comments, June 30, 1993

2) Pub. L. No. 74-333, 49 Stat. 803 (1935)

utilities typically built generation capacity to meet their native load. Except in special cases such as the Pacific Intertie, transmission linkages between electric utilities were developed to either increase system reliability or to take advantage of load and resource diversity between utilities and regions. To further promote reliability and operational and economic efficiency, power pools were developed in several regions (e.g., NEPOOL and PJM) and between affiliated utilities (e.g., Southern Co.).

In addition to the limited authority under FPA, there were two additional potential sources of federal authority to issue wheeling orders. The first source of authority was the use of antitrust law to remedy anti-competitive or monopolistic behavior by electric utilities and/or transmission owners. The use of this authority has been rare, and even a plaintiff with a strong case could expect to take years to negotiate acceptable arrangements. The second source of authority was the licensing power under the Atomic Energy Act. The Nuclear Regulatory Commission and its predecessor, the Atomic Energy Commission, have been a major source for guaranteeing transmission access for requirements customers. Many licenses included wheeling agreements for plant co-owners. These wheeling agreements were particularly important for publicly-owned utilities, who, in many cases, did not own transmission assets.

During this period, FERC permitted public utilities providing firm transmission service over a transmission grid to charge rates reflecting the rolled-in embedded cost of the grid, including the rolled costs of any new facilities or upgrades which became part of the grid. Under embedded cost rate-making, users paid a share of the fixed costs based on their usage (typically their contributions to non-coincident system peak). The Commission has also historically designed firm (and non-firm) transmission rates on a "postage stamp" basis. "Postage stamp" rates are ones that do not depend on distance transmitted.

Post-PURPA

By the late 1970's, the electric utility was beginning to enter a period of transition from large central station-based power plants to smaller, independent and customer-owned generation sources. Higher fuels costs, and an interest in increasing the efficiency of use of facilities and resources by electric utilities, led the U.S. Congress to enact the Public Utility Regulatory Policy Act (PURPA) of 1978.³⁾ Among other measures, PURPA created a new class of generators, termed qualifying facilities (QFs) and granted FERC limited authority to order wheeling by adding sections 211 and 212 to the FPA. A major intent of these wheeling sections was to ensure that QFs had access to a utility purchaser, even if the local utility was not interested in purchasing power from the facility.

With the passage of PURPA, FERC began implementing policies to promote greater competition in the electric utility industry. However, the ability of FERC to use its enhanced transmission powers was found to be limited. In the period prior to 1988, FERC did not use Sections 211 and 212 to order wheeling. The version of these sections that passed Congress stipulated in Section 211 that FERC could issue a wheeling order if it found that such order: (1) was in the public interest; (2) would conserve energy, promote efficiency, or improve reliability; and met the criteria of section 212. Section 211 also prohibited FERC from issuing an order under that section unless it found that such order would reasonably preserve existing competitive relationships. Section 212 prohibited issuance of a wheeling order if such order: (1) was likely to result in a reasonably ascertainable uncompensated economic loss for any affected utility; (2) would not place an undue burden on any affected utility; (3) would not unreasonably impair the ability of any electric utility affected by the order to render adequate service to

3) Pub. L. No. 95-617, 92 Stat 3117

its customers. These provisions proved to be highly restrictive. When FERC did attempt to order wheeling, federal courts held that "wheeling cannot be ordered solely on the basis of the public interest and the enhancement of competition"⁴⁾ and "the agency is without authority under the FPA to compel wheeling."⁵⁾

1988 to Passage of EPAct

Without authority to order wheeling or open access, FERC found that its ability to promote competition was limited. However, some states did take an active role in encouraging voluntary transmission access. For example, as part of New Jersey's competitive bidding program, which was agreed to by the state's utilities, the utilities agreed to provide transmission to QFs desiring to have their power wheeled out or wheeled in to other New Jersey utilities, subject to reliability considerations and FERC approval of tariffs.

Importantly, FERC began to use its Section 203 authority to condition approval of utility mergers on acceptance by the utility seeking a merger of requirements to provide transmission service that would mitigate potential anti-competitive effects of the merger.

Starting in the mid-1980's, FERC began issuing a series of orders associated with the merger requests it received. The landmark case during this period was the merger of Pacific Power and Light and Utah Power and Light. FERC conditioned approval of this merger on the merged company's acceptance of broad obligations to provide transmission services to third parties, a practice called "open access."⁶⁾ Later merger orders in the Northeast Utilities/Public Service of New Hampshire and Kansas City Power & Light/Kansas Gas & Electric cases further refined FERC's policies associated with providing full access to the transmission assets of the merged companies. Indeed, FERC's Utah Power and Light order imposes an absolute duty to satisfy firm wheeling requests on the utility, and requires the utility to make such capacity available within five years of a request, either by building new transmission capacity or by reducing or altering its system use.

A key issue associated with open access is the impact of such access on the existing, "native" customers from whom the utility's cost-of-service, including the cost of transmission assets is recovered. One concern was that to the extent that a wheeling request pre-empted the purchase of economy energy (and, hence, cost savings), these native customers could, under some circumstances, end up with increased costs relative to a situation without the wheeling transaction. To rectify this problem, FERC revised its pricing policy beginning with the Northeast Utilities (known as NU I) merger case in 1991.⁷⁾

4) See *New York State Elec. and Gas Corp.* 638 F.2d at 402

5) See *Florida Power and Light Co.*, 660 F.2d at 677-79

6) 45 FERC ¶ 61,095 (1988)

7) *Northeast Utilities Service Co.*, 56 FERC ¶ 61,269

Through a series of decisions and rehearings in the Northeast Utilities case, FERC developed and refined a policy that has served the basis for ongoing FERC pricing policy. In NU II⁸⁾ FERC adopted three goals for pricing firm transmission service:

1. Native load customers of the utility providing transmission service should be held harmless;
2. Transmission customers should be charged the lowest reasonable cost-based rate; and
3. Transmission pricing should prevent the collection of monopoly rents by the transmission owner and promote efficient transmission decisions.

The Commission stated that it would balance the three goals on a case-by-case basis in ruling on proposed rates.

To implement these goals, utilities were allowed to charge incremental rates to transmission customers for system upgrade or expansion, if the additional investment cost more than the average for facilities on the system. Furthermore, FERC specified that in order to "hold harmless" native customers, utilities would be able to recover the "opportunity costs" associated with the inability of the utility to buy cheaper power or sell excess electricity. The result of these rulings was a pricing policy that allowed NU to collect the higher of embedded costs or verified opportunity costs, but not both. NU III⁹⁾ extended the ability to recover opportunity costs to the non-firm context.

In a subsequent case associated with Pennsylvania Electric Company's request for approval of a transmission service agreement, this policy was further refined to become the "or" pricing policy currently in practice, i.e.:

- Utility with available transmission capacity can charge embedded costs;
- Utility that adds transmission capacity can charge the higher of embedded costs or incremental costs, but not both; and
- Utility that is constrained in capacity but does not add transmission capacity can charge the higher of embedded costs or opportunity costs, but not both.

From these principles, the Commission has adopted two pricing guidelines: "(1) incremental cost pricing for grid expansion or upgrades that relieve a constraint, and (2) opportunity cost pricing for a change in operations that relieves a grid constraint."¹⁰⁾ This policy was upheld at the U.S. Court of Appeals (D.C. Circuit) in December 1993.

8) 58 FERC ¶ 61,070 (1992)

9) 58 FERC ¶ 61,069 (1992)

10) FERC, *Transmission Pricing Issues*, Staff Discussion Paper, June 1993

Post-EPA Act

Congress gave FERC the statutory authority to order wheeling under some circumstances when it passed the Energy Policy Act of 1992 (known as EPA Act).¹¹⁾ The electricity reform provisions of EPA Act were intended to promote greater competitiveness in bulk power markets in order to lower rates for consumers. The bill's sponsors shared FERC's view that lack of transmission access may be a barrier to enhanced competition in wholesale power markets and removed many of the restrictions on FERC's wheeling authority in Sections 211 and 212 of the FPA, as amended by PURPA.¹²⁾

Within Section 721 of EPA Act, Congress specified that anyone generating electric energy for resale can apply for a FERC order for transmission service if they had previously requested, but not received, transmission services from the transmitting utility at least 60 days before the request is filed at FERC. FERC can issue a transmission order if it finds such an order to be in the public interest, if regional or national reliability is not unreasonably affected, and if the order does not replace energy already being wheeled by a transmitting order under an existing contract or FERC rate schedule. If transmission capacity must be expanded to accommodate FERC's order and a transmitting utility makes a "good faith" effort but fails to obtain necessary government approvals or property rights, FERC must modify or terminate the order.

In Section 722, Congress amended Section 212 of the FPA as follows:

An order under section 211 shall require the transmitting utility ... to provide ... services at rates, terms, and conditions which permit the recovery by such utility of all costs incurred in connection with the transmission services and necessary associated [ancillary] services, including, but not limited to, the 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 and the costs of any enlargement of transmission facilities. Such rates ... shall promote the economically efficient transmission and generation of electricity and shall be just and reasonable. Rates ... shall ensure that, to the maximum extent practicable, costs incurred in providing the wholesale transmission services, and properly allocable to the provision of such services are recoverable from the applicant ... and not from [the] utility's existing wholesale, retail, and transmission customers.

With these changes, Congress articulated the bases under which FERC could establish transmission pricing concepts, applicable over the long term. Indeed, EPA Act removed the goal of lowest reasonable transmission prices from the three goals developed by FERC, and placed the goal of holding native customers harmless as primary.

In light of its new wheeling authority and the new guidelines on transmission pricing, FERC, as noted, is currently conducting an inquiry into its transmission pricing policy.

¹¹⁾ Energy Policy Act of 1992, Pub. L. No. 102-486

¹²⁾ See Joseph T. Kelliher, "Pushing the Envelope: Development of Federal Electric Transmission Access Policy," *The American University Law Review*, Vol. 42, pp. 543-606, 1993 and Joshua Z. Rokach, "Transmission Pricing Under the Federal Power Act: Applying a Market Screen," *Energy Law Journal*, Vol. 14, pp. 95-125, 1993 for good summaries of the history and politics associated with the passage of the wheeling sections of EPA Act.

CONTEXT FOR THIS REPORT

As is evident in the history of the development of FERC's current transmission pricing policy and the number of comments to Docket RM93-19-000, the direction of future electricity transmission policy is of great interest to the electric power industry and policy-makers¹³⁾. As a result of the changes promulgated by Congress in PURPA and EPAct, the industry is profoundly different today than it was 20 years ago. Further change is underway and a restructuring of the industry is certainly possible. An increasing number of industry observers believe that the generation sector can function as a distinct and workably competitive industry. There is consensus, too, that the transmission function is characterized by pervasive scale economies making transmission service one that would have to be provided by a monopolist transmission owner. In this context, the manner in which transmission pricing is regulated becomes particularly important and is the subject of this report. Finally, there appears to be a consensus that physical distribution service will remain a monopoly, although retail access proposals such as those in California may well give retail customers greater choice in structuring service packages.

¹³⁾ As noted earlier, comments made in the FERC transmission pricing inquiry were analyzed as part of this work, although the work itself was substantially complete prior to FERC's issuance of its Policy Statement on October 26, 1994.

III. TRANSMISSION SERVICE AND COST CAUSATION

This section provides a discussion of the major transmission cost causation elements. The allocation of these costs to a particular transaction is discussed in Chapter IV.

As shown in Table III-1, there are five major elements of incremental transmission costs: (1) electric losses; (2) ancillary electric services including VAR support, flow regulation, and the maintenance of spinning reserve; (3) O&M on transmission and distribution facilities; (4) opportunity costs, including non-economic dispatch, and the cost of lost transactions; and (5) capital costs. Each of these five elements is discussed in more detail below.

ELECTRIC LOSSES

Electric losses are a component of the cost of transmitting power. These losses are caused by the dissipation of energy in the form of heat during transmission, and result from the electrical resistance along the lines. The most important determinant of electric losses is the degree of loading on the transmission lines. The higher the line loading, the greater the rate of energy dissipation along the line, and therefore the greater the electric losses. Conversely, the lower the line loading, the lower the losses. The cost of additional electric generation required to cover these losses is an important incremental cost of transmission.

The cost associated with transmission losses is almost entirely a variable (or per kWh) cost. While there may be some small fixed component associated with the need to maintain capacity to compensate for transmission losses, the primary component of the cost is in the generation of power to compensate for electric losses. The amount, and therefore cost, of the "replacement" generation required is determined directly by the magnitude of the electric losses.

ANCILLARY SERVICES

A variety of ancillary services are fundamental to the secure operation of the transmission system. In general, it is possible in some, but not all circumstances, to isolate specific ancillary services and establish a rough casual relationship between those specific services and the provision of an incremental transmission service. Ancillary services that are necessary for the secure operation of the entire network can be viewed as part of general operation and maintenance expenditures. However, certain ancillary services can be seen as distinct functions. They include:

- Black Start Capability: This capability refers to the ability to start up specific plants without relying on external electric supply (i.e., from the grid). In the event of system-wide power failure, it is essential that a number of plants on the system possess the capability to restart without electric supply from the outside. Typically, to maintain such capability, it is necessary to maintain plants such as diesel engines that are capable of starting without external electric supply. There is, of course, a fixed cost associated with maintaining such capability.
- Voltage Control (VAR Support) - Large increases in electricity demand may have an appreciable effect on the reactive power balance on the system and therefore on system-

TABLE III-1
Major Elements of Transmission Cost

Cost Element	Causal Factors	Fixed vs. Variable Nature of Cost
Electrical Losses	Electrical resistance	Variable
Ancillary Services	Incremental transmission requires: <ul style="list-style-type: none"> • Black Start Capability • VAR Support • Spinning Reserves and Frequency Control 	Variable and Fixed
O&M on Transmission Facilities	<ul style="list-style-type: none"> • Incremental O&M. • Share of system-wide O&M. 	Primarily Fixed
Opportunity Costs	Transmission constraints cause: <ul style="list-style-type: none"> • Non-economic Dispatch • Cost of Lost Transactions 	Primarily Variable but reflective of underlying capacity constraint.
Capital Costs	<ul style="list-style-type: none"> • Allocation of existing system carrying charges • Construction of new facilities required for transaction 	Fixed

wide voltages. As one example, if a particular point on the electric system is connected to a distant generating unit and receives electric energy via a long, heavily loaded line, the system will experience voltage reductions at the receiving end of the line, if no compensatory actions are taken. This voltage drop is best corrected by providing special strategically located voltage compensation plant (referred to as "reactive compensation" or VAR support). The impact of a particular transmission transaction, however, will depend on the regional and system operating conditions at the time of the transaction. Certain costs may be incurred by the utility to maintain the reactive power balance on the system as a result of the transaction. Note that under a given set of operating conditions, certain generators on the system may supply VAR support, while others may consume it, based upon their location. There are two ways in which the costs of VAR support can be recovered.

- In the view of some experts, the economic implications of reactive power flows should be factored in and reflected in spot electricity prices. While conceptually elegant, such an approach may well make the pricing regime extremely complicated.
- One approach to controlling VAR supplies is to install capacitors at various points to increase the supply of VARs. To the extent that a transmission use creates a need for VAR support (e.g., by scheduling energy at specific locations) and to the extent this responsibility for supplying VARs can be met by actions such as installing capacitors at other points or by operating a voltage compensation plant, it is possible to handle VAR support generally as a fixed cost that can be assigned to a specific user. In terms of overall system operation, some portions of VAR support cost may not be assignable to specific users.
- Spinning Reserves and Frequency Control - Because electricity cannot be stored readily, there is a risk that at any given half-hour (or smaller) interval of time, generation will be less than demand. This, in turn, could lead to an unacceptable fall in frequency. Therefore, safe operation requires that there be available a certain amount of "spinning reserves" that can be brought on-line in seconds or minutes. Fuel and variable O&M costs associated with the incremental spinning reserve requirements may be directly attributed to the wheeling transaction. These costs will be primarily variable, recovered on a per kWh basis.

O&M ON TRANSMISSION FACILITIES

Operation and maintenance on transmission facilities consists of supervision & engineering, load dispatching, station expenses, and maintenance of structures, station equipment, and overhead. A full accounting of O&M costs would also include costs associated with the operating of area control centers that are responsible for real-time balancing loads and generation within a control area in coordination with system-wide scheduling of generation on a daily or monthly basis.

OPPORTUNITY COSTS

Heavy utilization of transmission facilities caused by the transmission of wheeled power may impose certain costs on overall electric operations. These costs, broadly characterized here as

"opportunity costs," may be reflected in the cost of transmission as a combination of fixed and variable costs. Included in this definition of opportunity cost is the cost associated with out-of-merit dispatch, and the cost of foregone transactions. In particular:

- Non-Economic Dispatch - Increased utilization of transmission lines may make it impossible for a utility to dispatch its units in a least-cost fashion. That is, a utility may be forced to dispatch a higher cost unit instead of a lower cost unit because transmission constraints prevent power being moved from the low cost unit to the utility's load center. Although seemingly of a variable cost nature, these costs are reflective of long-term constraints requiring capital for alleviation.
- Cost of Lost Transaction - Increased congestion on the transmission system may also force a utility to forgo a profit-generating power sale or cost-saving power purchase opportunity. The opportunity cost of transactions precluded by the presence of wheeled power may be included in the transmission cost.

CAPITAL COSTS

There are two important capital-related costs associated with electric transmission. First, the cost of transmitting electricity may include a component to cover carrying charges associated with the construction of the existing transmission system. The existing system includes transmission lines, switch gear at substations, a range of control devices, and metering devices. Second, the transmission cost may include a component to cover the cost of constructing new transmission facilities needed to support a wheeling transaction. Particularly if the current system is operating at or near full capacity, new transmission facilities may be needed in order to wheel large amounts of additional power. The costs associated with the construction of these facilities will in turn be reflected in the transmission cost. Even if substantial additions to the existing system are not necessary, certain capital expenditures may nonetheless be required, for instance to interconnect the facility with the electric grid (e.g., upgrading the substation; and upgrading of specific circuits). These costs are generally fixed, and have typically been recovered on a per kW basis.

Certain capital costs may be directly related to accommodating a specific user's need. For example, one technological approach to increase power flows and reduce congestion is to use Thyristor-Controlled Series Capacitors (TCSC), which, by changing line impedance, allows increased power flow on selected lines. The National Grid Company of Britain has reported that by siting quadrature boosters in strategic circuits, it is possible to control the flow of electricity on the system, deferring or eliminating the need for future reinforcements. Over the long-term, actions to strengthen the transmission system, as a whole, might be required and the costs associated with such actions may not be directly associated with individual transactions. For example, certain equipment may need to be upgraded to make it possible to increase the voltage of certain operating circuits. Generally, such costs are primarily capital costs (i.e., they are fixed costs).

IV. COST STRUCTURE, COST ALLOCATION, AND INCREMENTAL COST PRICING

This chapter presents and assesses concepts relating to cost structure and cost allocation. These concepts are employed to develop what is termed the Incremental Cost Pricing Framework (ICPF). The ICPF is a regime for the pricing of transmission services on a stylized transmission system that takes into account several factors: economic efficiency in terms of sending the correct long-term price signals to both users and owners of the transmission system; pricing of individual services in relationship to cost causation; full recovery of costs associated with transmission service; and applicability to real-world power systems without extraordinary administrative burdens.

THE CONTEXT: A TRANSMISSION SYSTEM

A key premise underlying the discussion here is that it is possible to define an "integrated transmission system" that, in a cost accounting and management sense, is distinct from the generation aspects of the business. That is, without clarifying how it could be achieved, we assume that a separation of generation and transmission at least for cost accounting purposes can be achieved.

A transmission system of the kind envisioned here could arise in the following plausible circumstances.

1. The member utilities ("Original Utilities") of an existing, tightly dispatched U.S. power pool voluntarily form a Regional Transmission Group (RTG) and, for cost accounting and pricing purposes, consolidate all of the transmission-related cost of service into a single ratemaking unit administered by the RTG. Membership in the RTG is open to any entity that is eligible to apply at FERC to obtain or be subject to an order under Section 211 of the Federal Power Act (FPA) as amended by the Energy Policy Act of 1992.
2. The cost of service associated with the real-time management of the system (including balancing load and generation by control area) can be seen as being caused by activities at the pool level and at the control area level. Both activities are under the control of the RTG. A simple approach might be for the RTG to become responsible for both the human resources and physical assets associated with the transmission function of the Original Utilities.
3. The member companies of the RTG (i.e., former power pool) have very limited transactions with entities outside the RTG. To the extent that these transactions create transmission costs or benefits in the form of loop flow, these costs or benefits are booked by the RTG as a distinct common cost to be borne by all users.
4. Technical and economic committees are set up by the RTG to put in place pricing framework that follows the principles laid out in this section. The planning assumption is that the RTG will recover its cost of service with various transmission services priced in accordance with the Incremental Cost Pricing Framework. These RTG transmission revenues would then flow back, in part, to the Original Utilities. If the RTG is, in fact, responsible for the day-to-day management of the transmission system, it will use the

cost recovery associated with operation and maintenance costs to cover its costs. The revenues associated with the use of the physical assets that belong to the Original Utilities would flow back to them.

While we assume here the existence of a functionally separate transmission system, we do not intend to here suggest that a reorganization of the current industry structure is "problem-free" from a public policy perspective. In fact, we are aware of several practical and regulatory/jurisdictional issues that will have to be addressed in order to reorganize the structure of the industry.

The essential generic features of our integrated transmission system can be stated in the following general terms:

1. The transmission system can be adequately characterized by a stylized grid consisting of transmission lines (generally, high voltage lines) and buses, which are points on the transmission system (or network) at which circuits meet. These points of connection between circuits are frequently electric substations that include switchgear.
2. While generation and demand conditions—and hence line loadings—can vary in real time across the transmission system, it is assumed either that there are no interactions with electric systems outside the transmission system or that such interactions as exist are accounted for (in a cost accounting sense) outside our conceptual framework.
3. Transmission assets, including individual lines within the "transmission system," could be owned singly or jointly by specific utilities. However, for purposes of cost accounting and pricing, it is assumed that all transmission assets can be treated on a consolidated, "one transmission system" basis.
4. Generation on the transmission system is not taken as "given." Rather, it is determined hourly to minimize cost across the system, subject to all applicable constraints. It is not necessary that the transmission system schedule all generation and essentially function as the central dispatcher. Rather, individual generators can be given varying degrees of flexibility in scheduling generation and transfers to users at selected buses, subject to safety and reliability considerations. To achieve this, the transmission system or an affiliate may need to control certain types of generation.
5. For our stylized transmission system, it is possible to calculate economically correct ex post "spot prices" for generation at each bus that reflect least-cost operation of the system (or a variation thereof, as discussed above), subject to all applicable constraints. Note also that forcibly scheduling certain generation during an hour (i.e., treating it as must-run) has an impact on the ex post spot price at all buses. For purposes of analysis and spot price determinations, it is acceptable to deal only with real power flows. Costs associated with reactive power and other network services on the system are recovered from users through a system of charges, not embodied in the spot price. Two points relating to this are particularly important:
 - Whether costs associated with reactive power and other network services can be excluded from "spot prices" and recovered separately is an empirical question.

Theoretically, it would be elegant to allow these factors to be reflected in spot prices¹⁾.

- Some experts believe that attempting to make “spot prices” reflect reactive power costs is both analytically and administratively impossible. Rather, their view is that the functions currently performed by sophisticated network area control centers can continue to be performed by such centers (working with a central entity responsible for daily/monthly scheduling of generation). To be effective, these control centers would effectively control and operate small amounts of generating capability and flow control assets and would have an obligation to provide network services for their control area. Their cost-of-service is likely to be largely fixed costs, which can be shared by all network users²⁾

6. The transmission entity is indifferent as to who wins or who loses in the generation market.

THE CONCEPTUAL FRAMEWORK: ISSUES AND DEFINITIONS

Transmission Service

In the context of our stylized transmission system, “transmission service” can be defined either in terms of a physical service or as a purely economic arrangement that is made between parties in the process of purchasing electric energy at different points on a transmission system.

Transmission as a Physical Service

Under this definition, the purchaser of transmission service purchases the right to (a) remain interconnected with the system, subject to meeting safety and other engineering requirements, and (b) schedule electric output (energy and capacity) in an agreed-upon manner at one or more buses on the transmission system as well as receive such electric energy at one or more buses in amounts commensurate with the output scheduled at the delivery buses.

Within many U.S. power systems, there is no integrated transmission system for purposes of making service arrangements. The common approach is to create the fiction that electricity flows along a contract path on the systems of contiguous utilities from the point of origination to the destination. Transmission arrangements are made with (and charges paid to) each individual utility in the contract path. The definition provided here does away with such a “contract path.” However, under the definition provided here the purchaser does purchase certain physical rights. As part of this definition, it is useful

1) See William W. Hogan, “Markets in Real Electric Networks Require Reactive Prices,” pp. 172-176 in the Energy Journal, Vol. 14, No. 3.

2) See Graves, F., Carpenter, P., Ilic, M., Zobian, A., “Pricing of Electricity Network Services to Preserve Network Security and Quality of Frequency Under Transmission Access,” Response to the Federal Energy Regulatory Commission's Request for Comments in its Notice of Technical Conference, Docket No. RM93-19-000, November 8, 1993.

to distinguish "point-to-point" service from "network service," terms that have been discussed recently by the FERC in decisions on specific matters.

- Point-to-Point Service: Under the transmission regime now evolving at FERC, point-to-point transmission service is defined as service that designates point(s) of entry and exit on the transmission system as well as a designated transfer capability at each point³⁾.
- Network Service: Under FERC's still-evolving standards, network service is service that offers the purchaser greater flexibility with respect to (i) designating points of entry and exit on the transmission system, and (ii) scheduling the level of electric generation and purchases at the designated points. In a recent case, FERC defined network service as a transmission arrangement that would allow a purchaser to distribute a given quantity of transmission network usage among various delivery points, without paying multiple monthly or yearly transmission charges⁴⁾. A common example of network service would be a request by a wholesale, full requirements customer of a franchised utility requesting the utility to provide over the applicable transmission system, a service under which it could schedule say a total of X MWH/hour of electric generation distributed in a flexible manner at three buses and purchase the same amount of generation less losses at two other buses, again with a degree of flexibility as to the purchase level at each bus.

Transmission as a Purely Economic Arrangement

Some experts view the entire concept of transmission as a physical service (including network service) as flawed. The alternative proposed by these experts is that network service should be defined as "access to the grid and the ability to buy and sell power at locational marginal costs⁵⁾." The locational marginal costs referred to here are the same as the "spot prices" referred to under our stylized transmission system.

Under this definition, all users would and should have access to network service. The purchaser of transmission service would purchase the right to collect, with respect to designated buses within the transmission system, "congestion rentals" — i.e., the difference, if any, between the spot prices between the designated buses. The purchaser would purchase no right for the specific movement of power. Such a transmission contract is a necessary part of a market structure that differs significantly from the

3) See Federal Energy Regulatory Commission, "Policy Statement Regarding Good Faith Requests for Transmission Services and Responses by Transmitting Utilities Under Section 211(a) and 213(a) of the Federal Power Act, As Amended and Added by the Energy Policy Act of 1992," Docket No. PL93-3-000, Issued July 14, 1993.

4) Federal Energy Regulatory Commission, "Final Order Under Section 211 and 212 of the Federal Power Act Directing Network Transmission Service and Establishing Rates, Terms, and Conditions," Docket Nos. TX-93-4-000 and EL 93-51-000, Issued May 11, 1994.

5) See Hogan, William, W., "Transmission Pricing in Support of a Competitive Electricity Market", Response to the Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, Docket No. RM93-19-000, November 8, 1993. See also comments by Putnam, Hayes, & Bartlett Inc. in the same inquiry.

structure visible in the market today and, as noted, is discussed in comments submitted to FERC in connection with its transmission pricing inquiry.

Underlying this definition are several premises about how the entire generation and transmission system would operate. In particular, if the purchaser of transmission service were to also be a generator on the transmission system (a likely circumstance), it is assumed that the purchaser would, as a generator, have access to the transmission system and place its physical generating capability under the control of a central dispatcher. Furthermore, the generator would receive payments for its output based upon the hourly (or half hourly) spot price at the bus at which it is located, while consumers of electricity would purchase based upon the spot price at the buses where they are located. Outside of these payments by consumers and receipts by generators, generators and consumers would enter into other contracts to allocate the risks inherent in the hourly movement of the applicable spot prices. The stylized transmission system discussed above can support a structure such as this. However, we believe that the notion of transmission as a physical service is likely to remain for some time. Accordingly, the focus here is on that definition.

Incremental Transmission Service Versus "Base" or "Native Service"

Under the physical service definition of transmission service, it is possible to distinguish "Base" or "Native" Service from "Incremental Service." In general, the transmission system is used mostly, though not entirely, to serve customers of franchised electric utilities. Under cost-of-service regulation, these customers are responsible for all prudently incurred costs associated with the transmission system. These customers, referred to as Native Customers, of franchised utilities include the following types of purchasers: (i) residential, commercial, industrial customers who purchase electricity at retail, and (ii) wholesale customers who purchase either their entire electric needs ("full requirements"- FR - customers) or an agreed-upon level of their needs under a long-term agreement ("partial requirements"- PR - customers). These customers generally purchase electric generation and transmission as a bundled product and their implied current level of transmission service will be referred to as "Native Service." Frequently, this Native Service will be Network Service rather than point-to-point service. Incremental Service is defined as any transmission service placed on the transmission system over and beyond Native Service, including new demands over current levels placed by Native Customers; new service requests from EWGs, electric marketers, or others; and service stemming from agreed-upon modifications to the agreements of FR or PR customers.

Transmission Service: the Provision of Multiple Products

At any given time, the transmission system will be in a position to meet various requests for Network Service as well as Incremental Service. Each such service can be viewed as a distinct product provided by the transmission system operating as one entity. As will be discussed below, there are "common costs" associated with the provision of these different products.

Incremental Cost Pricing Framework

The term Incremental Cost Pricing Framework (ICPF) will be used to refer to a pricing regime for the pricing of Incremental Transmission Services on our stylized Transmission System. The pricing regime will take into account the following: economic efficiency in terms of sending the correct long-term price signals to both users and owners of the transmission system; pricing of individual services in

relationship to cost causation; full recovery of costs associated with transmission service; and applicability to real-world power systems without extraordinary administrative burdens.

In this context, it is worthwhile to reiterate several economic definitions, which are important to developing the ICPF.

Common Costs are essential costs without the incurrence of which a viable transmission system would not exist, but that, on a reasonable engineering-economic basis, cannot be assigned to any one or more specific transmission services (products) provided by the transmission system. Some common costs associated with infrastructure are "sunk" in the sense that capital has already been expended by some parties to create portions of the transmission system. Other common costs are recurring, annual fixed expenditures which are necessary to have a viable transmission system. If the entire transmission system could be abandoned in that all users could carry on their activities without the transmission system, the "sunk" costs would become "stranded" and the recurring annual common costs are "avoidable." But if a viable transmission system is required at least by some users, then the sunk costs are not "stranded" and the annual, recurring costs are not avoidable.

Fully Distributed Cost (FDC) or Fully Allocated Cost (FAC) for a specific Incremental Transmission Service is the increase in costs directly attributable to providing that service (on a per unit basis) plus some share of the common costs associated with providing the service in question along with all the other services (products) provided by the transmission system. In general, all rules that impute a share of the common costs to a specific service or services are arbitrary. With respect to fixed cost elements, the "embedded cost" is one type of FAC. Specifically, embedded costs frequently reflect a distribution of common, fixed cost elements in proportion to the user's estimated contributions to non-coincident system peak.

Incremental Cost is the increase in transmission system total cost (expressed on a per unit basis) that occurs when the level of a specific transmission service provided is increased by a pre-selected amount. If the pre-selected amount is small (i.e., close to a unit increment), the incremental cost and marginal cost will be close.⁶⁾

The Average Incremental Cost of a specific transmission service is the difference in the transmission system's total cost that would result with and without the provision of the entire current level of the transmission service in question. It is important to note that this calculation can be performed on a long-term basis and that avoidable, fixed costs undertaken over the long-term to support the specific transmission service in question would be included in the Average Incremental Cost.

⁶⁾ The definitions presented here are taken from Baumol, W.J. and Sidak, J.G., "Toward Competition in Local Telephony," MIT Press and American Enterprise Institute, 1994. The Incremental Cost, as presented, is in reality a short-term incremental cost. The Average Incremented Cost, on the other hand, is a longer-term concept. Note that some economists offer distinctions between Long-Run Incremental Costs and Long-Run Marginal Costs (see, for instance, Federal Energy Regulatory Commission, "The Transmission Task Force Report to the Commission," October 1989).

Treatment of Fixed Versus Variable Costs

In developing a ICPF, the distinction between fixed and variable costs is an important one. In general, variable costs can be more readily assigned to incremental users based upon usage levels, although the calculation methodology used to estimate "incremental" (as distinct from "average") costs will generate some controversy. The assignment of fixed costs to "incremental users" is clear when such fixed costs would not have been incurred "but for" the needs of the incremental user. The assignment of common fixed costs that cannot be clearly assigned to any user (incremental or otherwise), on the other hand, generates considerable controversy.

Table IV-1 places in perspective the manner in which the assignment of fixed costs relates to current FERC policy. As noted, current FERC policy adopts three principles: hold native customers harmless; provide the lowest reasonable cost-based third party firm transportation rate; and prevent collection of monopoly rents by transmission owners and prevent efficient transmission decisions. Table IV-1 shows several important points:

- If the incremental cost is set (or capped) by the long-term expansion cost, it is possible, under current FERC policy, to charge a rate higher than that incremental cost if, in fact, the embedded cost is higher than the incremental cost.
- Although opportunity costs are frequently experienced in the form of differences between the spot price (or value of generation) at different buses in cents/kWh within the transmission system, they are appropriately viewed as part of the compensation for fixed costs. This is because the underlying reason for the existence of opportunity costs is constraints on the transmission system. And, in principle, these transmission constraints can be remedied by incurring capital costs. In fact, under current FERC policy, the payment of opportunity costs can be seen as part of the compensation for capital cost (see Table IV-1) and actual recovery of opportunity costs is "capped" by the cost of grid expansion to remedy the underlying transmission constraint.

As discussed above—and elaborated on below—opportunity costs are an important aspect of transmission systems. However, it is worthwhile to note that while bus-specific spot prices (from which opportunity costs can be derived) can be reliably calculated on an ex post (or after-the-fact) basis, projections of these opportunity costs over the long-term generally are fraught with more uncertainty than economic forecasts of other power market characteristics. This means that pricing agreements that rely upon using actual opportunity costs (on an ex post basis) translate to an uncertain price. The risk inherent in fluctuating opportunity costs can from a user perspective, in principle, be transferred to others at some cost. But it will likely require more real-world experience with opportunity costs before entities find ways to price and allocate such risks efficiently.

Duration and Quality of Transmission Service

The quality and duration of transmission service are both dimensions that are sometimes ignored in developing a theoretical framework. Each dimension is, however, very important in implementing a transmission pricing regime.

In particular, transmission users, notably generators, might well view long-term transmission arrangements at known prices to be "essential." This has several implications. First, it means that the

Table IV-1
Overview of Current FERC Policy On Fixed Cost Elements

Source: J. Stephen Henderson, "The Commission's Transmission Pricing and Access Policy," Presentation to the Federal Energy Bar Association and the American Bar Association Conference.

transmission entity has to make projections relating to its system characteristics and associated costs and "lock-into" pricing terms based on these projections. Second, it will raise the question of whether, even in a system with excess transmission capacity, the transmission system, by tying up capacity on the system for certain users through long-term agreements, will have to add (or enhance) transmission capacity to meet the needs of growth sooner than it would have to, absent such long-term agreements. Thus, the existence (or lack thereof) of excess transmission capacity is a question of assessing both current and future system conditions. In this sense, Native Customers are long-term users of the transmission system.

In addition to duration, transmission service can also be distinguished by quality. Conceivable quality distinctions include long-term, firm service that gives the purchaser long-term rights to move power without being preempted by other needs on the system; long-term, best efforts service that can be interrupted under certain agreed-upon circumstances; and economy or as-available transmission that can be interrupted with little notice for economic or technical reasons.

Much of the discussion below focuses on the pricing of long-term, firm transmission in an ICPF. However, the concepts discussed provide a basis for pricing other types of transactions as well.

CONCEPTUAL FOUNDATIONS OF AN INCREMENTAL COST PRICING FRAMEWORK

Dealing With Variable Cost Elements

Several cost elements that were identified in Chapter III are "variable" in the sense that the costs that they pose to the transmission system vary directly with the quantity (in kWh) transmitted. They include losses; the variable component of transmission-related operation and maintenance; the variable component of ancillary services. Opportunity costs, in the very near term, can be expressed as a variable cost, but there are special issues with respect to their treatment and they are dealt with separately.

With respect to losses and other variable cost components identified in Section II, it is, in general, appropriate from the perspective of the transmission system to recover them based on the kWh delivered. Several issues related to these variable costs are particularly important:

- First, in order to specify an incremental block, there has to be agreement on the transmission that is part of the "Base" flow. Relative to such a Base, an increment can be defined. This will generally be difficult to define as a practical matter. In the cases of losses, in particular, average losses over all energy transmitted on the system can average between 3 and 6 percent, while incremental losses on a heavily loaded line can be considerably higher—as much as 30 percent or more. Note that if all kilowatthours transmitted are priced based upon the losses caused by the last increment, the transmission system may over-recover for losses significantly.
- Second, while it is possible to estimate incremental losses (using a model-based cost reconstruction), these estimated incremental losses can be expected to change based on system conditions.⁷⁾ For example, for the same incremental transmission transaction,

⁷⁾ Southern California Edison proposed an incremental approach to account for a Capacity Load (continued...)

estimated losses will be different between an hour during the day and an hour at night. Similarly, for the same hour, the estimated losses will be different depending on whether or not certain units are available.

- Third, the complexities of estimating incremental losses increase in instances where the transmission service being provided is “network service” in which the transmission system agrees to receive electric energy at multiple locations and transmit it to multiple delivery points, with some flexibility on the part of the transmission user to schedule electric energy levels at different receipt points.

Because of these complexities, a practical approach, both for losses and for other variable cost elements, may be to divide the transmission system into regions or zones for costing purposes. If specific causal factors can be identified, it may be reasonable to adjust loss factors or variable cost responsibility upwards or downwards. Such an approach, by bringing prices more in line with cost causation could make a contribution towards sending the correct economic signal without imposing an extraordinary administrative burden.

Dealing With Opportunity Costs

As noted in Section II, the broad term “opportunity cost” is used to describe costs that arise, in the first place, because of transmission constraints. The existence of opportunity costs has several interesting implications:

- Even though opportunity costs are experienced as a difference in cent/kWh of the value of generation at different buses, they reflect the existence of a transmission constraint that presumably can be remedied by capital additions. As noted, under current FERC policy, opportunity cost payments can be viewed as a compensation associated with capital (see Table IV-1).
- If the pricing approach called for an incremental transmission user to pay the actual opportunity cost experienced on an “after-the-fact” basis and the transmission system was the only party capable of alleviating (or even eliminating) the constraint by undertaking capital additions, it may be rational (in a profit-maximizing sense) for the transmission entity to not undertake capital additions. Under current FERC policy, however, compensation for opportunity cost is capped at the expansion cost. Generally, opportunity costs are observed for some, but not all, hours on an “after-the-fact” basis. This means that for hourly transactions, it is straightforward to allow transmission prices to reflect opportunity cost.
- If the incremental user requires transmission service between buses where spot prices differ because of opportunity costs, it is correct to assign that cost to the incremental user. However, as in the case of losses, it may not be apparent as to who is the

⁷⁾(...continued)

Adjustment Factor (CLAF) and an estimated Energy Load Adjustment Factor (ELAF) in its competitive solicitation. Also, the National Grid Company of Britain calculates incremental loss factors.

"incremental user." Interestingly, in Britain, according to our research, the costs associated with losses and opportunity costs are recovered on an average basis from all customers by the power pool (which is distinct from the National Grid Company, the transmission system owner) under a charge called "uplift."

- The existence of opportunity costs provides an economic signal for investment in additional transmission facilities to alleviate transmission constraints. While projections of opportunity costs into the future, "with" and "without" a transmission constraint are technically feasible, they are characterized by a greater degree of uncertainty than that normally attached to economic projections. This is because these projections will, in turn, depend upon load, generation, and other system conditions on an hourly basis. Therefore, the use of long-term projections of opportunity costs between buses in a network to set a meaningful, real-world benchmark for transmission pricing purposes must be viewed with a degree of skepticism. Note, however, that actual, after-the-fact opportunity costs may be more amenable to measurement.

Dealing with Fixed Costs

There are several types of essentially fixed costs (i.e., they do not vary in the near term with levels of electric energy transmitted) that the transmission system has to recover. Pricing the transmission benefits that flow from these fixed costs within an "incremental cost pricing" regime raises many issues that are discussed below. For convenience, issues associated with each fixed-cost category are discussed separately.

Fixed Costs Directly Assignable to Incremental Services

Certain fixed costs associated with integrating into the transmission system a new generation source or a new demand can, without much controversy, be assigned to that incremental generation source or new demand. Indeed, qualifying facilities under PURPA (QFs) and IPPs in the U.S. routinely pay "interconnection" charges. Frequently, these interconnection charges include the equipment required to safely connect the facility to the electric substation as well as any system enhancements that need to be undertaken to safely accept the electric output of the facility. Similarly, large industrial customers are routinely assessed charges associated with the equipment and system upgrades that have to be undertaken to serve incremental demands they place on the system.

From an incremental cost perspective, these costs, because they primarily, if not entirely, benefit the incremental user, are appropriately recovered from the user. In some instances, the incremental user may be charged only a portion of the costs associated with a system enhancement based upon a technical judgment as to the extent to which benefits accrue directly to that user. In such instances, the remaining charge would be part of "system" fixed costs and would be recovered from all customers.

A second element of the directly assignable fixed cost can be viewed as those system-related fixed costs that could be avoided, but for incremental demand or generation at specific portions of the transmission system. Underlying this definition is the notion that the transmission system can be divided into zones or regions such that electric conditions within a zone or region do not vary to any material degree. Once the transmission system is divided into electrically meaningful regions or zones, it is possible, in principle, to assess zone-specific costs that would not have been incurred "but for" the need to serve a particular zone. While some fixed costs can be readily assigned to a specific zone, it is quite

likely that there will frequently be grey areas and where such assignment is based on an engineering-economic judgment.

Under the British system, both types of customer-specific or zone-specific charges are recovered under a "Connection Charge." These charges are intended to recover costs incurred in "providing the assets which afford connection to the transmission system for the specific benefit of a customer."

Systemwide Fixed Cost Benefitting All Network Users

Systemwide fixed costs include the following elements:

- The capital-related costs of the original transmission network, including system enhancements undertaken over time, that are not directly assignable to a zone, region, or user.
- The capital-related costs of system enhancements that are (i) undertaken to maintain an ongoing system, and (ii) unassigned costs undertaken to connect new generation or demand sources.
- Fixed operation and maintenance costs that cannot be directly assigned to a zone, region, or user.
- Fixed costs of providing ancillary services that cannot be directly assigned to a zone, region, or user.

Several features of systemwide fixed costs deserve emphasis. First, although these costs cannot be assigned to a single user or zone/region, the network will simply be unable to function without the services associated with these costs. In simple terms, the incremental user would not have been able to transmit any electricity if the lines had not been laid in the first place. Second, these costs are, by and large, fixed (e.g., the annualized cost of capital) and would not vary with increased or decreased levels of transmission. Third, even over the long term, these costs are not avoidable if a viable transmission network has to remain in place. Therefore, they cannot be assigned in any strict, causal sense to specific user(s), zones, or regions. To the extent they are avoidable over the long term, their avoidability will make it possible to assign them to a user, zone, or region. Fourth, if these costs are not recovered, the transmission system will operate at a loss.

Given the characteristics of systemwide fixed costs, it is not surprising that there is controversy over their allocation.⁸⁾ The debate over allocation of these costs centers on two important arguments:

- Because all users benefit from the services associated with these costs, a common refrain is that all users should "pick up their fair share." And a common way to achieve that

⁸⁾ In reply comments filed in connection with FERC's transmission pricing inquiry, the U.S. Department of Energy offered the view that "all customers who enjoy the benefits of transmission service, whether as a wheeling customer or as part of bundled wholesale service, to make some contribution to a transmitting utility's joint and common costs" (see Reply Comments of the U.S. Department of Energy, Docket No. RM93-19-000).

result is to take the annualized level of fixed costs and spread it evenly over each user's contribution to system peak (or other usage measure) to yield a charge in \$/kW/year. This charge (and variations of it) are referred to as "embedded costs."

- A second argument is that the charges associated with transmission services, particularly the charges associated with recovery of these systemwide fixed costs, should send the right economic signal (i.e., they should be designed to promote economically efficient decisions). This argument has at least two ramifications:
 - On the one hand, if the incremental user were assigned no part of the systemwide fixed costs, and these fixed costs were assigned to the "non-incremental" user(s) on a basis that minimized distortions in their decisions on demand and generation, it could be argued that economic efficiency would be served. However, such an approach would make the transmission entity completely indifferent to the addition of incremental users; they would presumably cover only their incremental costs and make no contribution to system fixed cost. Furthermore, it could set off a race among users attempting to get themselves classified as "incremental."
 - A second approach is to allow the transmission entity to set the system wide fixed cost, subject to certain guidelines, in such a manner that (i) economic efficiency is served, and (ii) the incremental user makes a contribution to systemwide fixed costs. Implementation of this approach, in turn, raises many issues.

Usage-Based Pricing

As a general proposition, if costs vary directly with usage, pricing approaches tied to usage send sound economic signals. Variable cost elements that vary directly with kilowatt hours transmitted, for instance, can be priced at an appropriate charge in cents/kWh. Various approaches to extend usage-based pricing to fixed costs and common costs have been proposed and tried. But employing usage-based pricing to allocate fixed costs and common costs has two associated problems. First, a true fixed cost is one that cannot readily be changed with usage levels. For example, if network capacity is increased by 100 MW in anticipation of increased usage, but that usage does not materialize, the ability of the transmission owner to recover the costs associated with the capacity increase are limited to some form of reselling. Note that in the case of variable costs, costs are avoided as usage declines. The issue is even more complicated with respect to common costs because to have a functioning network, these common costs have to be incurred and, once incurred, they do not vary with usage levels. Moreover, even in the long-term, truly common costs cannot be avoided in response to lower usage levels. Second, there are alternative ways of measuring usage and frequently there is disagreement over the applicability of various measures. We now turn to two usage-based approaches.

Embedded Cost Based on System Peak

Fixed and common costs (expressed on an annualized basis in terms of \$/year) can be allocated to zones or users based upon that particular zone or user contribution to non-coincident system peak. Such an allocation will yield a charge in \$/kW/year that is frequently referred to as an "embedded cost." Several aspects related to embedded cost are worth emphasizing:

- It is easy and simple to understand;
- There is an implicit allocation of common costs;
- In a transmission system where transmission conditions (e.g., extent of congestion) do not vary significantly between zones, the resulting long-term economic signals may be acceptable; however, in system with significant differences across zones, the resulting economic signals may not even be directionally correct; and
- It does result in full cost recovery if the planning assumptions are correct.

Embedded Cost Based on MW-Mile

The MW-mile approach is frequently presented as a distinct approach to cost allocation. In fact, it is fair to characterize the MW-mile approach as one in which fixed and common costs are allocated based on a particular usage measure, namely, the MW-mile. It is argued that because this measure is rooted in physical reality, the resulting cost allocations will result in sound economic signals.

Under the MW-mile approach, a Base Case Load Flow Study is first performed assuming all zones and incremental users are included. The Base Case MW-mile calculation consists of multiplying for each transmission line on the system, the MW power flow by the physical length of the line in miles, and summing the MW-miles across the system. In the next step, the change in the system-wide MW-miles associated with a single change can be calculated (e.g., relative to the Base Case, this may be a case without the incremental transaction in question). And this change in MW-miles becomes the basis for calculating the contribution to costs to be made as a result of that single change.

If the MW-mile change associated with an event was a good reflection of overall transmission conditions, this approach could be an attractive way of allocating fixed and common costs. For example, would the MW-mile change associated with locating additional generation in a generation-rich zone always be larger relative to a situation where the same generation were to be located in a generation-poor area? The answer to the question depends upon all the instantaneous changes affecting the transmission system. In particular, the MW-mile impact will vary from hour-to-hour and will depend upon instantaneous load and demand conditions across the system. Second, technically and economically sound actions taken to meet loads in one zone will have an impact on the imputed MW-mile usage in another zone.

As a costing approach, the MW-mile approach has the following features:

- It is a usage-based measure that is considerably more complicated to implement than the traditional embedded cost approach;
- Depending on the actual load, generation, and transmission conditions, it may be an effective way to send long-term economic signals; and
- Changes in one zone or part of the transmission system and technical choices made by unaffected parties with respect to, say voltage of new lines, type of equipment, and so on, may all affect the calculated MW-mile impact.

The Efficient Component Pricing Rule

One potential way to achieve the objectives discussed above is to put into effect what is termed the "efficient-component pricing" rule in economic literature. Discussed in several books and articles dealing with regulatory economics, this rule has been applied for purposes of regulatory ratemaking in several industries.⁹⁾ In general, the efficient-component pricing rule is applicable in the following situation: Two firms, X and Y, compete to provide the same product P. Firm X, in addition to selling product P, produces a component product of P called Q. The focus of the rule is an efficient pricing rule for product Q. Baumol and Sidak (1994) discuss in detail a simple but important example from the railroad industry. In their example, Railroad X (in Figure IV-1), referred to as the landlord, owns and controls the segment A-B as well as a single route between B and C. Railroad Y (the tenant) owns and controls an alternative route between B and C and competes on the B-C route with Railroad X. The question is the appropriate pricing rule for Railroad X to follow in renting trackage rights on A-B to Railroad Y. Assuming that (i) the price of the product delivered at C is determined by a competitive market to be \$10/ton, and (ii) Railroad X's incremental cost of providing service between A and B is \$3/ton and between B and C is also \$3/ton, Baumol and Sidak show that it is economically efficient for Railroad X to charge \$4/ton for trackage rights in A-B.¹⁰⁾

If there is a workably competitive market in generation, the result of which is to set a market price at each bus in our stylized transmission system, both in the near term and in the future, the analogy between the railroad example and our stylized transmission system is meaningful. In other words, if the generation market was deemed to be competitive, the transmission system would be free to set rates that reflected whatever level of systemwide fixed cost contribution it felt was appropriate. Note that a rational, profit-maximizing transmission system would take into account demand conditions at each bus in setting these rates. Thus, it would consciously price-discriminate between transmission users.

In FERC's Transmission Policy Task Force report, this issue is discussed in some detail.¹¹⁾ Although the Task Force Report appeared to agree that a competitive generation market could act as a restraint on transmission pricing and that, in the long-term, the generation market could be deemed competitive, it nevertheless found this approach of restraining transmission pricing unsatisfactory because (a) pervasive market power in transmission was significant in the mid-term due to large differentials between regions in the total cost of generation, and (b) a complete capture of all rents by the transmission owner, even if economically efficient, might affect perceptions of industry participants about the attractiveness of the generation sector.

At the present time, U.S. transmission systems do not routinely publish ex post spot market prices on a location-specific basis. Thus, location-specific spot prices set by a competitive generation market are, at least at the present time, an abstraction in the U.S. context. This practical reality combined with

9) An excellent exposition can be found in Baumol, W.J., and Sidak, G.J., "Toward Competition in Local Telephony," MIT Press and the American Enterprise Institute, 1994.

10) This is the contribution over and above the incremental cost of service that each ton of traffic provides Railroad X (i.e., \$10/ton - \$3/ton - \$3/ton = \$4/ton).

11) Federal Energy Regulatory Commission, "The Transmission Task Force's Report to the Commission," October 1989. See discussion on pp. 73.

Figure IV-1
The Trackage Rights-Pricing Problem

Source: Baumol, W.J. and Sidak, G.J., "Toward
Competition in Local Telephony," MIT Press
and American Enterprise Institute, 1994.

the Transmission Policy Task Force report's finding that in the near term market power in transmission is pervasive, suggests that more empirical evidence about its applicability in the current context will have to be developed before the efficient component pricing rule can be adequately judged.

The Relative Cost Pricing Rule

The relative cost pricing rule attempts to use practical judgment and relative cost information in such a manner as to send, at least directionally, correct economic signals to transmission users.

The relative cost pricing rule is currently being used in Britain. In Britain, the charges associated with recovery of systemwide fixed costs are called "use of system charges." Under the British system, the total amount to be recovered as "use of system charges" is determined as a residual: it is obtained by subtracting directly assignable costs from the total cost of service, which is itself subject to a global cap. Once the total amount to be recovered is known, the allocation of these costs is a function of (a) the zone in which the user is located, and (b) the type of user—generator or source of demand (consumer). In general, using a long-run incremental cost approach and a transport model, the transmission system¹²⁾ calculates the incremental investment in the transmission system that would be required to meet an incremental block of generation in a given zone or an incremental source of demand in a given zone. While the cost of hardware associated with transmission investments (e.g., lines, substations, and so on) does not vary significantly by zone, the relative costs in different zones is a measure of overall conditions in that zone. For example, expansion costs in zones with significant excess transmission capacity will be smaller than those in zones without such excess capacity. The "use of system" costs are then allocated zone-by-zone for generators and for sources of demand in a process that reflects both the relative cost situation in different zones and the transmission system's judgment. On a planning basis, it is expected that full cost recovery of the estimated use-of-system costs will be achieved.

New generators interested in locating generation in a region that has considerable generating capability and which "exports" generation to other zones will, under the relative cost pricing rule, face a high use-of-system charge if accepting the new generation will exacerbate transmission constraints and advance the need date for new transmission capacity. Conversely, if a new generator were to locate in a region that currently "imports" generation and in which the addition of new generation would defer future transmission investments, the generator will face a small use-of-system charge.

We reviewed the most recent "use of system" charges (1994/1995) proposed by Britain's National Grid Company (NGC) (see Table IV-2). Table IV-2 shows that the use-of-system charges vary considerably across the zones. For new sources of demand, the use-of-system charge is positive in all zones and varies by a factor of 3 across zones. It is interesting that new generators in Inner London (a zone with large demand and little generation) face a negative "use of system" charge. At the same time, new demand in Inner London would have to pay a very high "use of system" charge. Note also that although new generators in a region may face a negative use-of-system charge, the total cost of transmission service faced by them is generally not negative. That is, they will have to pay the applicable charges that are directly assignable to them. While the application of the relative cost rules may in some circumstances result in negative use-of-system charges for some zones, it will generally yield a positive charge for most regions. Furthermore, given that the application of the rule involves a degree of judgment in the first place, it is conceivable that, in the real world, regulators may see negative charges

¹²⁾ The transmission system is owned and maintained by the National Grid Company plc.

TABLE IV-2
The National Grid Company, PLC (United Kingdom)

Schedule of Charges for Use of System in 1994/95

Zone Name		National Grid Company 1994/95 Infrastructure Tariff £/kW	
		Generation	Demand
North	Z1	6.490503	5.079785
Yorkshire	Z2	3.952433	8.331480
North Wales & West Lancs	Z3	3.956658	8.622950
East Lancs	Z4	2.493598	9.616614
Notts	Z5	2.885794	8.794433
West Midlands	Z6	1.682215	10.733955
Anglia	Z7	1.056234	11.969242
West & Wales	Z8	0.303684	12.710913
Estuary	Z9	1.867416	10.494041
Outer London	Z10	0.433589	13.949824
Inner London	Z11	-4.063294	17.163837
South Coast	Z12	-0.619093	13.805744
Wessex	Z13	-1.533339	15.365905
Peninsula	Z14	-3.045659	15.373124
<i>Source: Statement of Charges for Use of System and Connection to the System, 1994/95, The National Grid Company plc, United Kingdom, April 1994.</i>			

as impractical. Another variation on the relative cost pricing rule is to provide the transmission system with freedom to set the common cost recovery component at levels below a cost-derived, zone-specific cap. Even if various practical and equity-related constraints are placed on the relative cost pricing rule, it can still be used to send correct economic signals.

As noted, the MW-mile approach is often presented as one that will result in correct economic signals with respect to fixed and common cost allocation. We discussed, however, that because a host of transient factors, including the consideration that decisions made with respect to equipment additions in other parts of the system affect the calculated MW-mile, it is not clear that the approach will yield the correct economic signals. In the relative cost pricing rule, this issues is addressed by incorporating a component of judgment into the determination of how the different zones should be treated. However, the very presence of such a judgment component is also likely to invite criticism.

Practical Implications of the Allocation Rules

The practical implications of the two rules described above can be better understood through the following illustrative example, which is an adaptation of an example provided in the U.S. Department of Energy in its comments on transmission pricing to the FERC.¹³⁾

Consider two power producers P#1 and P#2 that are making bids to sell electric capacity and energy to Utility A in a competitive solicitation. P#1 is located in the service territory of utility B and P#2 is located in the service territory of utility C. In order to make a viable bid, P#1 and P#2 will each require transmission service from the "transmission system," which is the joint owner of the network connecting A, B, and C (see Figure IV-2).

The total cost of P#1's best bid, estimated at the busbar, is 5.0 ¢/kWh (inclusive of all costs and dispatch effects).¹⁴⁾ The total cost of P#2 best bid is 5.3¢/kWh on an identical basis. Because of locational differences between P#1 and P#2, the sum of the directly assignable incremental fixed costs and variable costs of transmission service varies between the two, with P#1's cost being 0.6¢/kWh, and P#2's cost being 0.1¢/kWh. Further, assume that there is a third bidder P#3, who is very advantageously located in the service territory of utility A and has a busbar cost of 5.6¢/kWh and an incremental transmission cost of 0.05¢/kWh.

Now consider several possible scenarios for transmission cost pricing:

Case 1: The transmission system is required to charge producers P#1, 2, and 3 an amount exactly equal to their directly assignable incremental fixed and variable cost. In such an event, P#2 would win on price with a total cost of $(5.3 + 0.1)$ ¢/kWh.

13) See "Comments of the U.S. Department of Energy," submitted to the Federal Energy Regulatory Commission, Docket No. RM93-19-000.

14) In other words, the actual structure of the bid might reflect capacity and energy payments and the impact of such a structure on the unit's dispatch is accounted for in this cost. Such a single number can be derived and has, in fact, been the basis for deriving price points in utility solicitations (see, for example, competitive solicitations conducted by Delmarva Power & Light and Baltimore Gas & Electric).

Figure IV-2
Location of Alternative Power Producers

- Case 2: The transmission system is required to charge, in addition to the directly assignable incremental fixed and variable costs, incremental users P#1 and P#2 an embedded cost amounting to \$2.16/kW/month (or about 0.3¢/kWh) for using the system, while P#3 is assessed no embedded cost payment because it is in the service territory of utility A. Under the current “contract path” fiction P#3 requires no transmission at all and is responsible for losses; if applicable, and direct interconnection and metering charges. In this case, P#3, with a total cost of 5.65¢/kWh will win over P#2 (total cost of $5.3 + 0.1 + 0.3$) and P#1 (total cost of $5 + 0.6 + 0.3$).
- Case 3: The transmission system is required to charge all users the directly assignable incremental fixed and variable costs of service, but is given freedom in setting a charge in \$/kW/month to cover system costs. Further, suppose that the transmission system is aware that if the cost of new generation exceeds 5.75¢/kWh, utility A will simply repower one of its existing plants and, in that event, the transmission system will not be able to recover any more than the directly assignable incremental fixed and variable costs of transmission associated with such a repowering project. In this case, the transmission system has the most to gain by structuring its fixed cost recovery for system costs in such a manner that P#2 would win. This is because the maximum contribution to system fixed costs that the transmission system can hope to obtain is the difference between 5.75¢/kWh and the lowest cost generation option (inclusive of all directly assignable incremental fixed and variable costs of transmission).
- Case 4: The transmission’s system is asked to have in effect for each zone/region statements of charges designed to cover some share of the system fixed cost. These charges are over and above the directly assignable incremental fixed and variable cost(s) of service. The contribution to system fixed charges will, in general, be higher for zones from which it is hard to transmit generation out; they will be low in zones with excess transmission capacity for transmitting out. This is because the relative levels of the long-run incremental cost of putting in place new transmission capacity in each zone will be the basis for setting charges. In our example, P#2 can be expected to see lower system fixed costs than P#1 because P#2’s location is apparently superior in a long-term transmission sense. As an example, P#2 may see system fixed costs of about \$1.50/kW/month (or 0.21¢/kWh), while P#1 may see \$3/kW/month (or 0.42¢/kWh). Therefore, P#2 would win the bid with a full cost of $(5.3 + 0.1 + 0.21)¢/kWh = 5.61¢/kWh$, which is lower than 5.75¢/kWh. P#1 would experience a full cost of $(5.0 + 0.6 + 0.42)¢/kWh$ or 6.02¢/kWh.

Several interesting observations emerge from these cases:

- Case 1 ignores the allocation of system wide fixed costs; Case 2 is based on embedded costs; Cases 3 and 4 reflect other ways of allocating common costs.
- Both Cases 1, 3, and 4 lead to economically efficient generation choices. In Cases 3 and 4, however, unlike Case 1, the new generators make a contribution towards fixed and common costs. In Case 2, which reflects the embedded cost approach, the example was constructed so as to result in an inefficient outcome. Note that even in this case, the outcome does not always have to be an inefficient one.

- In the example discussed, because the competition occurs *ex ante* (i.e., before substantial investments have been undertaken by users), it takes away the prospect of opportunistic behavior to capture potential future rents that might accrue to the power producers (e.g., the producer's revenues remain constant, but fuel costs fall), if the transmission entity is bound by contract to a long-term schedule of charges, especially with regard to system fixed charges.

Dealing with Stranded Generation Costs

The transmission of electricity for a customer (say a wholesale customer) could have the effect of stranding all or portions of the generation assets of a seller. A common example is when a partial or full requirements customer of a large utility that constructed generating capacity to meet that customer's needs changes suppliers of generation and uses the transmission system to move its power. In the process, all or a portion of the former supplier's generation assets may be "stranded." That is, the market value of this asset is substantially lower (or even zero) relative to the period when the wholesale customer was a buyer. Note that this type of "stranding" is not a common cost issue. Rather, it is primarily a question of which parties should bear the consequences when actual events and planning assumptions diverge in the generation sector.

Because the prospect of stranded generation assets increases with increased transmission access, there is a debate in the policy arena about the use of transmission tariffs to recover stranded generation costs from customers. This issue is, we believe, one that is separate and distinct from the ICPF that is the subject of this report.

SUMMARY OF THE ELEMENTS OF AN ICPF

We have discussed above the pros and cons of alternative ways of treating different transmission cost elements. To reiterate, an ICPF is one that takes into accounts considerations of economic efficiency, cost causation, cost recovery, and ease-of-administration.

The basic elements of an ICPF that emerge from our review are as follows:

1. Incremental users of the transmission system pay for their contribution to losses, variable operation and maintenance, and other allocable variable cost. With regard to losses, one approach is to have zone-specific loss factors that are more representative of an incremental treatment of losses.
2. Fixed costs that are directly assignable to an incremental user are paid for by that user. Also, to the extent there are fixed costs assignable to the incremental user's zone, that user pays its share of such costs.
3. Much of the controversy over cost allocation centers on how common fixed costs (i.e., common to the entire system) are allocated. Given the nature of common costs, any allocation rule is open to criticism as being arbitrary. Possible cost allocation approaches include the following:
 - A usage-based allocation leads to what is usually termed an "embedded cost." While this approach appears to be equitable across customers, it does not in all

circumstances result in the correct, long-term economic signals to users. This criticism applies regardless of the usage measure employed.

— An alternative is a zone-specific or user-specific allocation of common costs that is designed to send the correct economic signals to users. If the generation market can be considered to be competitive at each location on the system, the transmission system can be given total freedom in carrying out these cost allocations. An alternative is to combine zone-specific knowledge and judgment to derive allocation that reflect relative cost conditions in different zones (the "relative cost rule"). Other practical constraints can be added to the relative cost rule: all users must pay a common cost component that exceeds zero; the transmission system can offer discounts reactive to a cost-derived, zone-specific cap; and so on.

V. IMPLEMENTATION OF AN INCREMENTAL COST PRICING FRAMEWORK

The purpose of this chapter is to examine, using selected examples, the feasibility of relying upon generally available data to perform calculations that would support an Incremental Cost Pricing Framework discussed in Chapter IV. These selected examples are drawn from several sources including the 1994 Seven Year Plan published by the National Grid Company in Britain; and the actions taken—as well as filings made—in various matters before the Federal Energy Regulatory Commission.

AN INCREMENTAL COST PRICING FRAMEWORK RELATIVE TO THE STATUS QUO

Relative to the current U.S. transmission regime, which itself is still evolving, implementation of the ICPF would have several implications for key users of the transmission system. In understanding these implications it is useful to think of an example where a number of former power pool members (“Original Utilities”) have formed an RTG, as described earlier, and effectively turned over control of the transmission system to a distinct entity.¹⁾ The key impacts as seen from the perspective of different players are illustrated by the following examples:

1. In selling electric capacity and generation to one of the Original Utilities, an EWG that is on the transmission system would face transmission charges that would depend upon its location on the transmission system, not upon which of the Original Utilities is the purchaser of the EWG's output. In particular:
 - Even if the EWG was located in the franchised service territory of the purchasing utility, it would have to pay a share of the transmission system's common costs. Today, such an EWG would, in general, only pay for the directly assignable costs of interconnection. In fact, a very significant proportion of non-utility generation in the U.S. is located within the service territory of the purchasing utility and is not “wheeled” in a contractual sense. Assuming that location-specific (i.e., zone-specific) transmission charges were set so as to send the correct economic signals, such a structure would work effectively. As noted in Chapter IV, to the extent the EWG were to locate in a zone that was characterized by high loads and relatively little generation, it would face low transmission charges with respect to the common costs. Depending on the degree of flexibility actually provided, the component cost charge could conceivably be negative.
 - Furthermore, the transmission charges for which the EWG would be responsible would not depend upon its contract path. That is, if the contract path crossed the transmission lines owned by several of the Original Utilities, that fact would, by itself, have no effect on its total transmission charge. The New England Power Pool (NEPOOL) has had such a transmission rate in effect for certain generating units designated as Pool Planned Units (PPUs). That is, any pool member that

¹⁾ As noted in Chapter IV, the purpose of such an example is not to suggest that a reorganization of the current industry structure along these lines is “problem-free” from a public policy perspective.

has an ownership share in a PPU pays a transmission rate in order to gain access in a contractual sense to the generation from the PPU. However, the rate charge is not dependent on the number of intervening utility systems that might own all or portions of the transmission system.

2. If a full requirements municipal customer of a utility system were to impose incremental loads (over and beyond) the levels deemed as "Native Load," it would face a transmission charge based upon its location relative to load and generation conditions on the transmission system. If the customer's load was located in a zone characterized by a rapidly growing urban population with very little local generation, it would be logical to expect that the customer would be responsible for relatively high transmission charges, particularly with respect to the division of common costs. In terms of long-term economic incentives, this has several implications.

- First, individuals and firms making decisions to locate in that zone likely would have to take into account that it is a zone characterized by a relatively high cost of providing service. Of course, the actual rates seen by individuals or firms would depend upon how cost are recovered at the retail level.
- Second, the municipal customer could partially mitigate its high cost of serving incremental loads by procuring (either through a power purchase agreement with an EWG or by building its own resources) generation resources located in the same zone. These generation sources would, as discussed, experience relatively low transmission charges, particularly with respect to the division of common costs. Thus, if generation costs were not different across zones, the customer and the generator could both benefit by locating generation in the same zone, which is the correct economic signal to send in this circumstance. In reality, of course, the same factors that historically made the zone an unattractive location for generation in the first place (e.g., inhospitable permitting regime; inadequate infrastructure to move fuels) might continue to prevail.

PRACTICAL ISSUES RELATED TO IMPLEMENTATION

The discussion below reviews basic issues relating to performing the calculations to support the ICPF laid out in Chapter IV. The discussion is based upon an assortment of materials that are in the public domain, including cases before FERC and documents from the National Grid Company in Britain.

Treatment of Variable Costs

Losses

As noted in Chapter IV, it is possible to bring the accounting of losses closer to an incremental cost framework, although it introduces greater analytic complexity than average loss calculations. Also, even in circumstances where the determination of the incremental transaction for loss calculation purposes is judged to be analytically intractable, it might well be possible to calculate zone-specific loss factors that represent superior economic signals.

Approach Used by Britain's National Grid Company

In its 1994 Seven Year Statement, the National Grid Company (NGC) in Britain presents zone-specific loss factors that reflect important differences between the zones. The methodology employed by the NGC is as follows. System wide losses are first assessed from a network model of the transmission system under a "Base Case." Such a system-wide loss level can be measured as the difference between the total generation for the system (or Net Energy for Load in U.S. terminology) and the sum of demands at each bus on the transmission system that is met by this generation. (Note that the reference here is to demand at the busbar level, not at the end-use level, which generally will reflect distribution lines as well.) Then, in successive runs, a 100 MW of additional generation is modelled in each zone, one zone at a time. The change in system wide losses is then estimated for each run. Results provided by NGC from their modeling reveal several interesting points:

- If the additional generation is placed in a zone that in the Base Case has little generation relative to its load and receives substantial amounts of generation from other regions, the change in system losses can actually be negative.
- Based on the change in system losses, the NGC calculates a zone-specific "effective generation" estimate for a 100 MW increment in generation. By comparing the effective generation estimate to the 100 MW level, a zone-specific incremental loss factor can be worked out. For example, in the generation-poor zone, effective generation by adding 100 MW may turn out to be 107 MW (because of the ability to reduce imports), implying a loss factor of -7 percent. In the generation-rich zone, on the other hand, effective generation may turn out to be 91 MW, implying a loss factor of +9 percent.

U.S. Utilities Generally Use Average Losses

By and large, losses are currently handled in the U.S. on an average basis. For example:

- General Public Utilities provides the following general statement on transmission losses: "The system losses cost component reflects compensation to the System Company for the average actual cost of (a) replacement energy supplied owing to the additional energy losses caused by the wheeling services, and (b) the installed generating capacity required to supply the replacement energy. This component is a function of the actual amount of energy wheeled, the cost of replacement energy and a fixed loss rate of 3 percent. Currently, this component is approximately 1.5 mills/kWh."²⁾
- Texas Utilities Electric Company in a recent case presented an average loss ratio 3.05 percent at the transmission level based upon known or reasonably predictable kWh sales and system input by voltage level.³⁾

2) See "Transmission Services Agreements: An Introduction to Concepts and Costs," GPU System Companies, Effective September 1, 1992.

3) Attachment to letter from Texas Utilities Electric Company to Tex-La Electric Cooperative of Texas, Inc., in connection with negotiations relating to Tex-La application in Docket No. TX-94-4-000 before the Federal Energy Regulatory Commission.

Opportunity Cost

Under FERC's "or" policy, utilities can currently charge the higher of embedded cost or opportunity cost, with the opportunity cost being capped by the costs associated with transmission system enhancements to cure the underlying transmission constraints. As discussed, transmission systems in the U.S. currently do not routinely estimate bus-specific spot prices either ex post or ex ante. On centrally dispatched systems and power pools, it generally will be possible to reconstruct spot prices that are location-specific, if not bus-specific. As a practical matter, for instance, the spot price on a poolwide basis will be the poolwide system lambda for hours with no transmission constraint. For hours with transmission constraints, information available at the pool level will generally be adequate to estimate spot price differentials across the pool's major interfaces, where transmission constraints exist.

Although bus-specific prices are not routinely made public, utilities are, at a minimum, incorporating language about opportunity costs into transmission agreements. It also appears that many are putting in place implementation mechanisms, as examples below show.

General Public Utilities

General Public Utilities in a 1992 statement on transmission charges⁴⁾ states as follows with respect to an "increased energy charge:"

"This cost component reflects compensation to the System Companies for that portion of the limiting transmission capability which is used by the project, thereby preempting deliveries of lower-cost energy to the System Companies' native load customers. This component is based on actual transmission system conditions and actual energy cost differentials, but will be limited by a cost ceiling which represents the project's proportionate share of the System Companies' actual or estimated carrying charges on the incremental investment cost to install transmission system upgrades, improvements and reinforcements necessary to avoid the increased energy cost charge over the term of the Transmission Services Agreement.

The increased energy cost component is expected to have a range up to five (5) mills/kWh over the intermediate to long-term. However, in the short-term, this component is likely to range up to two (2) mills/kWh.

Kansas City Power & Light

Kansas City Power & Light (KCPL) in a recent FERC filing offering firm and non-firm transmission service has set forth the following terms in a proposed Transmission Service Agreement:

- a. Purchaser Responsibility — Whenever system impact studies performed by the Company identify capacity constraints that may produce Opportunity Costs in connection with the

⁴⁾ Note that this statement reflects the policy that FERC had laid down in a widely-discussed case involving Pennsylvania Electric Company, one of the GPU System Companies. (See Federal Energy Regulatory Commission, "Order Conditionally Accepting Proposed Transmission Service Agreement," Docket No. ER 91-313-000, Issued March 10, 1992.

provision of firm Transmission Service, and the Company determines not to undertake Network Upgrades to eliminate such constraints, the Purchaser shall be charged a rate that does not exceed the higher of (a) the embedded cost-based rate set forth in FTS-1, or (b) the sum of Opportunity Costs computed over the term of the Service Agreement, determined in accordance with Commission rules and policies governing recovery of such costs.

- b. **Cap on Opportunity Costs Charged to Purchaser** — Any Opportunity Costs charged to Purchaser will be subject to a maximum payment based on the projected costs to alleviate the capacity constraints that give rise to the Opportunity Costs. This cap shall not apply to (i) transactions with a term of one (1) year or less or (ii) that portion of the term of the transaction during which the Company is diligently pursuing efforts to design and construct incremental facilities identified in the Service Agreement as necessary to alleviate the relevant capacity constraints. The Service Agreement negotiated with the Purchaser also shall include provisions for the calculation and verification of such Opportunity Costs. The Company will provide an Eligible Utility with an estimate of these costs prior to initiating service. In the event the Company decides not to construct facilities to alleviate the transmission constraint, then the non-binding estimated cost of expansion in the System Impact Study will become a binding cost of expansion for purposes of determining an Opportunity Cost cap.

As can be seen, these terms reflect FERC's current policy. However, the Agreement does not spell out the manner in which the user can verify KCPL's Opportunity Costs on an ex post basis.

Thus, while the principle of reflecting opportunity costs in actual, after-the-fact payments for transmission service is not novel any longer, there remain many practical implementation issues. In particular:

- Information on bus-specific or location-specific spot prices on an after-the-fact basis is not routinely published by U.S. utilities or power pools.
- At the present time, it appears that entities (other than utilities) willing to consider making contracts and bearing risks associated with spot price differentials (or congestion rentals) will find that they will have to act more on judgement than on a sound empirical understanding. Furthermore, EWGs that rely upon project financing may prefer to pay a premium for essentially freeing transmission pricing from the uncertainties of movements in opportunity costs. Certain firm transmission service agreements do exactly this. That is, no part of the payments for transmission service under such agreements is tied to opportunity costs.

Treatment of Fixed Costs

As discussed, the allocation of fixed common costs that cannot be clearly attributed to a single user or zone frequently generates considerable controversy. Provided below is a discussion of how fixed costs in general have been treated in selected cases.

Characterization of Fixed Cost Elements

A primary question is whether or not a utility (or utilities within a transmission system) can isolate their transmission related cost-of-service, particularly with respect to the fixed cost elements. A major component of fixed cost is the cost associated with the transmission lines, switch gear, and other electric equipment that make up the transmission system.

At the present time, utilities are generally in a position to classify their cost-of-service by function (i.e., by transmission, generation, distribution, and so on). Indeed, it is based on such a cost-of-service that embedded cost rates are derived. Once a transmission system is divided into appropriate zones, it should be feasible to further categorize transmission-related costs into (i) zone-specific system costs, and (ii) system-wide common costs. It should also be feasible to estimate fixed costs directly assignable to incremental users.

Recall that zone-specific system costs are those that would not be incurred "but for" the need to serve the particular zone in question. For example, the need for safety-related equipment as well as meters at a substation that is located at the interface between two zones may be allocable to one of the two zones. Frequently, however, it may not be possible to reasonably further allocate these zone-specific costs to individual customers.

Table V-1 provides an illustration of the type of cost allocation matrix that would be necessary to support an ICPF. Our research shows that the development of such a matrix for the transmission system should be possible based upon current accounting categories, although there likely will be questions of judgment on the issue of assigning costs to zones (or users) as opposed to listing them as common costs.

While the development of a matrix such as the one shown in Table V-1 is feasible, a review of firm transmission service arrangements (and associated cost-of-service filings) in effect today shows that few systems use zones for cost allocation and ratemaking purposes. Furthermore, a limited subset of the transmission cost of service is directly assigned to specific users. Examples of such assignment include the construction of radial lines to inter-connect with a specific customer, or, the addition of capacitor banks necessitated by the addition of new load in certain parts of the system.

Allocation of Common Costs

The notion that "common costs" exist is recognized, at least implicitly. But because zone-specific allocations are not typically performed, all of the fixed costs elements are treated as "common costs" except for radial lines and some other special costs. As requests for FERC Orders under Section 211 and 212 of the Federal Power Act (FPA), as amended by the Energy Policy Act of 1992 (EPAct) grow, it is logical to expect that there will be a more sophisticated distinction between common costs and other costs. The next step will be whether, as discussed under the ICPF of Chapter IV, the allocation of these common costs can be made in such a manner as to send the correct economic signals. The manner in which current FERC policies recognize and deal with common costs is illustrated by FERC statements in a recent Order.

Table V-1

ILLUSTRATIVE FIXED COST ALLOCATION FOR TRANSMISSION SERVICES

<u>COST ITEM</u>	<u>ZONE-SPECIFIC COSTS</u>			<u>SPECIFIC INCREMENTAL USERS</u>			<u>COMMON COSTS</u>
	<u>Zone 1</u>	<u>Zone 2</u>	<u>Zone 3</u>	<u>New Loads In Zone 1</u>	<u>New EWGs in Zone 2</u>	<u>New Plant in Zone 3</u>	
<u>Capital-Related Carrying Charges</u>							
Transmission Plant							
General Plant							
Enhancements for Zone 1 Service							
Enhancements for Zone 2 EWGs							
Enhancements to Connect New Plant in Zone 3							
<u>Operations & Maintenance</u>							
Transmission O&M							
Customer Expense							
Administrative & General							
Taxes							

Florida Power & Light Versus Florida Municipal Power Agency

Even if "common costs" are not labelled as such in rate cases, the traditional cost-of-service approach recognizes that such costs exist. For example, a recent FERC decision in a matter involving Florida Power & Light and the Florida Municipal Power Agency is significant in that it (i) recognizes that common fixed costs have to be shared, (ii) approves a sharing of these costs based on usage (i.e., an embedded cost formulation), and (iii) does not address the issue of whether and how the cost of upgrades can be divided into directly assignable costs and common costs.

One portion of the Order recognizes the existence of common costs:⁵⁾

The FP&L proposal recognizes that a transmission system is designed to meet the needs of native load and that the needs of native load are defined primarily by the size of the load to be served. It incorporates FMPA's load as though that load were part of Florida Power's native load. Because the transmission system to support this hypothetical melding of customers must be designed and operated — and fixed costs must be incurred — to meet the combined loads of Florida Power and FMPA, it makes sense that each would pay based on its contribution to the system loads to be served by the transmission network.

It is worth re-emphasizing that this portion of FERC's Order recognizes the principle that there are fixed costs that the system incurs that have to be shared. The Order also embraces the sharing of these fixed costs based on contribution to system loads (i.e., usage) which is the embedded cost or rolled-in cost approach. A later part of the same Order raises interesting issues relating to cost allocation of future upgrades, which FERC felt it did not have to address in that Order. The relevant portion is presented below (footnotes omitted):

Florida Power proposes that it and FMPA each bear the incremental costs of new transmission facilities that must be built because of the decisions each makes about where to locate new generation facilities. It argues that this direct assignment approach, rather than rolling in the costs, is necessary in order to hold its native load customers harmless. Florida Power states that, if the incremental costs of network upgrades that would not have been incurred but for the addition of a new FMPA resource are rolled into the embedded costs pot, Florida Power's customers will end up paying for 97% (Florida Power's current load ratio responsibility) of the costs, and that this would be a subsidy. Its proposal is economically sound because it gives FMPA the correct price signal in making siting decisions, Florida Power says. It states that its proposal is evenhanded because it will apply to Florida Power as well because FMPA will not be required to pay as part of its embedded costs rate the incremental network costs associated with Florida Power's new resources.

FMPA argues that the costs of improvements should be rolled into the transmission rate base. It says that this is how Florida Power treats the cost of improvements that are

⁵⁾ Federal Energy Regulatory Commission, "Final Order Under Section 211 and 212 of the Federal Power Act Directing Network Transmission Service and Establishing Rates, Terms, and Conditions," Docket Nos. TX-93-4-000 and EL 93-51-000, Issued May 11, 1994.

needed to serve Florida Power's native customers. It also argues that Florida Power's proposal will be difficult to administer because of disagreements about the extent to which an improvement is needed to serve FMPA's or Florida Power's load. Moreover, FMPA says that the license conditions on Florida Power's St. Lucie nuclear license provided that all transmission upgrades must be considered to benefit Florida Power. Finally, FMPA argues that Florida Power must eliminate from the rolled-in rate the costs of already-built facilities that were built to serve Florida Power's native load.

We do not believe it appropriate to resolve this issue now. The driving force behind FMPA's request for transmission service is its desire to integrate its existing load located within Florida Power's service area with its existing resources both within and without that area, and neither party suggests that either FMPA's or Florida Power's load will require transmission upgrades in the near future. Thus, the issue of how to price such upgrades is not pressing. Moreover, we are presently considering transmission pricing issues in a generic proceeding. We will defer deciding this pricing issue until Florida Power actually proposes a specific upgrade necessary to accommodate the transmission service requested in this docket or to meet its own needs. At that time, Florida Power should file a petition for a rate order in a new subdocket in Docket No. TX93-4.

The issues raised in this portion of the Order are similar to those discussed generically in Chapter IV. As noted there, certain portions of the costs of network upgrades will not be reliably attributable to any user or zone. As discussed, a useful first step is to recognize these costs as "common costs." The next step is to address how they should be allocated.

Treatment of Common Costs Under the Embedded Cost Approach

The embedded cost approach to dealing with common cost is simple to implement and, for reasons discussed earlier, not necessarily consistent with sending the correct economic signals. Quite simply, under the embedded cost approach, some measure of usage is used to allocate common costs. One commonly used measure of usage is the contribution to system peak, which, as discussed above, was applied in the Florida Power & Light matter. Under a usage-based formulation, in a two-zone system, if one zone contributes 2,500 MW out of a total (non-coincident) system peak of 10,000 MW and the other contributes 7,500 MW, the first zone is allocated 25 percent of the common costs, while the other zone is allocated 75 percent.

Under the ICPF, if the second zone is in fact generation-poor and has considerable loads, new loads in that zone might well be allocated a disproportionate share of the common costs. The merit of this approach, if implemented properly, is that it sends the correct economic signal to new users.

A simple example will help illustrate these points. Assume that total common costs for a two-zone transmission system amount to \$100 million per year in carrying charges. The tables below derive a common cost component of the transmission ratio under the embedded cost approach and the ICPF.

Embedded Cost Approach

Zone	Common Cost Allocation for New Loads (\$ Million/Year)	Contribution to System Peak (MW)	Common Cost Component (\$/KW/Year)
1	25	2,500	10
2	75	7,500	10

Under the ICPF, we would a priori expect Zone 2 to have a higher transmission change in order to send the correct economic signals. Assume, based upon an allocation rule similar to the relative cost pricing rule of Chapter IV⁶⁾, 90 percent of the common costs are allocated to Zone 2.

Incremental Cost Pricing Approach

Zone	Common Cost Allocation for New Loads (\$ Million/Year)	Contribution to System Peak (MW)	Common Cost Component (\$/KW/Year)
1	10	2,500	4
2	90	7,500	12

The derived rates pertain only to the common cost component. By design, Zone 2 has a high rate for new loads under the Incremental Cost Pricing Approach, providing a correct economic signal. The above example shows that common costs are shared under the embedded cost approach in a simple manner that even directionally (as distinct from magnitude) may not send the correct economic signal. It is worthwhile noting that users make a contribution to common costs under both approaches discussed above, although under the ICPF approach that contribution would be set (by design) to be low for certain types of users and high for others.

⁶⁾ Recall that the efficient component pricing rule could also provide a basis.

APPENDIX A
OVERVIEW OF THE POWER
MARKET STRUCTURE IN
BRITAIN

APPENDIX A

OVERVIEW OF THE POWER MARKET STRUCTURE IN BRITAIN

As part of a program of deregulation, Britain undertook major steps in the 1980s to create the current market structure.

In the generation sector, the British government created private generating companies by the sale of generating assets that were previously state-owned. At the present time, there are two major generating companies: National Power and Power Gen. Under a recent agreement with regulators, these two companies have agreed to divest themselves of 6,000 MW of generating capacity which they currently own. This action is expected to reduce the ability of these firms to restrict output and drive up prices. In addition, several independent power projects, unaffiliated with either company, will be on-line by 1995. Nuclear generating assets are owned by Nuclear Electric, which is not a private company.

The National Grid Company (NGC) is the holder of the transmission license for the power system (England and Wales). Under its license, NGC is required "to develop and maintain an efficient, coordinated and economical system of electricity transmission and to facilitate competition in the generation and supply of electricity." NGC has developed its pricing of transmission service keeping in mind its obligation to "facilitate competition in generation and supply of electricity." NGC is the operator of the transmission system and schedules and dispatches generating units, subject to technical and reliability requirements. Ancillary services associated with reliable operation of the transmission system are procured by NGC under agreements with service providers. Generators and end-users pay NGC for transmission-related services. These include payments for connection to the grid; use-of-system; and ancillary services.

Individual end-users are allowed to make their arrangements for the purchase of electricity from generators. Typically, large industrial users make their own arrangements. The Regional Electric Companies (RECs) or the distribution companies also purchase from generators, essentially acting as agents for their retail customers.

The Power Pool ("Pool") in Britain refers to a pooling and settlement system that facilitates trading between buyers and sellers. All trading must take place through the Pool. Virtually all generators (with the exception of small ones) are subject to central dispatch by NGC. Based upon offers submitted by generators and estimated demand, NGC uses a production scheduling model (GOALPOST) to project generation schedules for individual units. System marginal price forecasts (for the next 24 hours) are also calculated by the Pool. The operational scheduling program is re-run several times a day to "fine-tune" the System Marginal Price to account for changes in generation offers, load conditions, unit availability and so on. The Pool determines final half-hourly prices called the Pool Purchase Price (PPP) and the Pool Selling Price (PSP), which are the marginal costs used for settlements. For every half-hour, each generator on the Pool is paid the PPP and each purchaser (user) pays the PSP. The difference between PSP and PPP covers costs related to electric losses, and out-of-merit dispatch, if any. Thus, the pool makes no money from these transactions; it simply collects the applicable amounts from users and pays the amounts to generators. Contracts between generators and users are bilateral transactions negotiated outside the Pool settlement system. They are simply financial arrangements to allocate the risks associated with Pool prices that fluctuate on a half-hourly basis. The transmission service that generators pay for and obtain also has no physical meaning. It represents their share of the costs of keeping an ongoing transmission system, without which there would be no trades at all.

APPENDIX B
THE TRANSMISSION SYSTEM:
AN ILLUSTRATION

APPENDIX B

THE TRANSMISSION SYSTEM: AN ILLUSTRATION

Several aspects of a simple transmission system are highlighted in the example discussed below. Notably, the notion of having available a spot price at each bus is discussed in this example, taken from Hogan.¹⁾

Figure B-1 shows a simple 3 bus system, in which a utility has generating units at buses 1 and 2 and a load center at bus 3. In this example, the cost of generation at bus 1 is \$40/MWH and the cost of generation at bus 2 is \$44/MWH. The transmission line between bus 1 and 3 is assumed to have a maximum thermal capacity of 600 MW, and losses between buses 1 and 3 are a flat 7.5%. That is, losses are not calculated on an incremental basis.

Example A shows the optimal way to dispatch the system when the load at bus 3 is 900 MW. In this case, all of the generation is provided from bus 1 (the least cost source), and the spot price of electricity at bus 3 is \$43/MWH (\$40/MWH for generation * 1.075 loss factor).

Suppose, however, that the load at bus 3 rises to 1,800 MW. It might seem that the most economic way to dispatch the system would simply be to increase generation at bus 1 to 1,800 MW. Such a dispatch, however, would attempt to force 1,200 MW to flow over the transmission line from bus 1 to bus 3, melting the line (which we assumed has a maximum thermal capacity of 600 MW). This dispatch pattern is clearly not feasible. As Example B shows, the only feasible way to meet the load at bus 3 is to generate all of the required energy at bus 2 (the more expensive generation source). In this case, the spot price of energy is \$57/MWH at bus 3, significantly more than when the load was only 900 MW. This is a direct consequence of the non-economic dispatch caused by the transmission constraint. To better understand this, consider the change in costs that would result if the load at bus 3 in Example B was reduced by 1 MW. Such a reduction would mean a least-cost re-dispatch with the following generation levels at the different buses: bus 1—1MW; bus 2—1798 MW. The combination of (i) lower dispatch costs arising from the shift in generation from bus 2 to bus 1, and (ii) lower overall losses, including the impact of the fact that generation at bus 2 experiences two times the loss experienced by generation at bus 1, leads to the result that decline in costs associated with a 1 MW reduction in load at bus 3 is \$57/MWH.²⁾ Had there been no constraint, all of the power would have been generated at bus 1 and the spot price at bus 3 would have been \$43/MWH.

Examples A and B illustrate two important cost components on a transmission system: electrical losses caused by resistance in the transmission lines and non-economic (out-of-merit-order) dispatching of generating units caused by transmission constraints.

While the examples illustrate the effects of an increase in load on the system, a similar effect could occur if a third party requested wheeling services. Suppose, for example, that the system was being dispatched as shown in Example A. If a third party requested wheeling of 9 MW from bus 1 to 3, note that the wheeling request would simply state that the transmission system would have to receive 9 MW at bus 1 and deliver 9 MW at bus 3. To accommodate the receipt of 9 MW at bus 1, the system would

1) William W. Hogan, "Markets in Real Electric Networks Require Reactive Prices," pp. 172-176 in *The Energy Journal*, Vol. 14, No. 3.

2) See Hogan, *ibid.*

Figure B-1
Spot Pricing in a Transmission Constrained Network

Example A

Example B

Source: Hogan, W.W., "Markets in Real Electric Networks Require Reactive Prices," The Energy Journal, Vol. 14, No. 3, 1993.

have to be re-dispatched to avoid melting the line between bus 1 and bus 3. In particular, generation at bus 1 would have to be backed down and generation at bus 2 would have to be increased. The effect of such a re-dispatch ~~would be to~~ drive up the spot price at bus 3. Thus, such a wheeling request would create an "opportunity cost."