Alternative Business Models for Transmission Investment and Operation

Alternative Business Models for Transmission Investment and Operation

Shmuel Oren
University of California at Berkeley
Berkeley, California

George Gross
University of Illinois at Urbana-Champaign
Everitt Laboratory
Urbana, Illinois

Fernando Alvarado
The University of Wisconsin
Madison, Wisconsin

Introduction

A common theme in restructured electricity systems around the world is the unbundling of generation, transmission, and distribution and the creation of independent transmission entities that link competitive generation to regulated distribution. The transmission sector, which enables wholesale competition in the electricity industry, is viewed as the centerpiece of restructured systems. Consequently, the requirement that all market participants have nondiscriminatory access to the transmission system is the key requirement for facilitating competitive markets. The central question that this paper addresses is what transmission system governance structure and business model can most effectively support the objective of promoting competition through nondiscriminatory access to the grid. Transmission system business models define the relationship among the three basic business functions associated with the provision of transmission service: system operations, market operation, and grid ownership.

The complexity of system operations and the unique physical characteristics of electricity production and distribution necessitate considerable centralization of system operating functions to assure stable, reliable power supply. A debatable issue is the extent to which system operations should be combined with market operation, especially for day-ahead and forward trading; possibilities in this area are reflected in the diversity of market designs in the U.S. and abroad. The Pennsylvania-New Jersey-Maryland (PJM) Independent

System Operator (ISO), for instance, operates a day-ahead energy market and offers economic dispatch and unit commitment services. At the other extreme, the Texas system operator—the Electric Reliability Council of Texas or ERCOT—provides only real-time reliability-related services, including energy balancing, ancillary services procurement, and congestion management.

For the relationship between system operations and grid ownership, most current restructured systems have adopted business models based largely on the ownership of the grid. In the U.S., where a large portion of the grid is owned by investor-owned utilities, formation of nonprofit ISOs that *control* but do *not own* transmission assets has been an expedient approach. This strategy enabled restructuring to proceed without requiring that utilities divest their transmission assets. By contrast, in countries such as England and Wales, New Zealand, and Spain, where the grid was centrally owned by governments or private entities, for-profit Independent Transmission Companies (ITCs) were formed.

The main concern in this paper is the extent to which incentives for operational efficiency and reliability of the grid and for efficient investment in the transmission system are facilitated or hindered by business models that differ in their level of vertical integration of ownership and control, investment financing mechanisms, reward structure and regulation, nature of governance, and degree of financial control.

As we address these issues, some background about transmission needs to be kept in mind. First, transmission asset costs [including fixed and variable costs] constitute a small percentage of the total cost of electricity supply and generally run less than 10 percent of generation cost (Awerbuch, Hyman, and Vesey 1999). Furthermore, transmission costs consist mostly of investment costs.[1]

Another feature of transmission is that, although transmission and generation are complementary in the sense that transmission provides the means of transporting generated power to load, they are also substitutes because generation at a load center can reduce the need for transmission and vice versa. This substitutability was exploited by vertically integrated utilities through "integrated resource planning," whose objective was to optimize the allocation of investment between supply- and demand-side investments for the social good. The vertical separation of transmission and generation makes such coordination of investment much more difficult. In addition, the objective of transmission investment in a market with competitive generation extends beyond the maximization of social welfare.

Mitigation of market power and reduction of transfers between consumers and producers can sometimes be achieved by constructing transmission lines that do not represent socially optimal investments. Often a small investment in transmission may have large financial consequences for market participants. For example, a transmission line connecting two isolated, self-sufficient regions where local suppliers have market power will engender competition and reduce consumer prices although the line may hardly be utilized.

[1]Leonard Hyman, in a private communication (October 2001) offered the following back-of-the-envelope calculation as an illustration of how insignificant the cost of transmission investment is relative to energy cost: We could add $5 billion/year to transmission capital expenditures (which now total $3 billion/year), depreciate the incremental assets over 10 years (vs. 40 years for existing assets), provide 20 percent pretax return on capital (vs. the current 12 percent) , and maintain the new assets in line with existing standards at a cost of about an extra 1 percent per year on the consumer's electricity bill. (Doing this for five years in a row would add approximately a total of five percent to the electricity bill). This calculation assumes no gains from efficiency improvements, trade or mitigation of market power. Any such gains would offset part of the added cost.

The Scope of a Transmission Enterprise

Federal Energy Regulatory Commission (FERC) Order No. 888 mandated open access to the transmission grid; FERC Order No. 2000 encourages and provides ground rules for the formation of Regional Transmission Organizations (RTOs) for providing nondiscriminatory access to transmission service for all market participants. These two orders define the roles and scopes of transmission enterprises. According to these orders, RTOs must, at a minimum, have the following characteristics:

- Be *independent* from market participants,
- Have appropriate scope and geographic configuration,
- Possess operational authority for all the transmission facilities under the RTO's control, and
- Have exclusive authority to maintain short-term reliability.

FERC identifies the seven functions that, at a minimum, an RTO must perform:

- Administer its own tariffs and employ a transmission pricing system aimed at promoting efficient use and expansion of transmission and generation facilities,
- Implement market mechanisms to manage transmission congestion,
- Develop and implement procedures to address parallel path flow issues,
- Serve as a supplier of last resort for all ancillary services required by Order No. 888 and subsequent decisions,
- Operate a single Open Access Same Time Information System (OASIS) site for all transmission facilities under its control with responsibility for independent calculation of Total Transmission Capability (TTC) and Available Transfer Capability (ATC),
- Monitor markets to identify design flaws and detect the exercise of market power, and
- Plan and coordinate necessary transmission additions and upgrades.

Order No. 2000 does not identify a preferred business model for transmission functions or a mechanism for financing transmission investment. It encourages innovative proposals that will meet the characteristics listed above. The remainder of this issue paper addresses candidate models, methods of evaluating them, and relevant international and domestic experience with these issues, as follows:

- The range of options for business models,
- Criteria for analyzing business models,
- International experiences with different transmission business models,
- Recent U.S. developments in for-profit transmission-only companies and the construction of direct current (DC) merchant transmission lines,

- The strengths and weaknesses of two "straw man" proposals that represent alternative business models: the nonprofit ISO and the for-profit ITC,
- Options for policy initiatives toward selecting business models for the U.S. transmission system, and
- Summary of the paper, conclusions, and recommendations.

The Range of Options for Business Models

From the perspective of customers (i.e., generators, loads, distributing entities, and other users of transmission services), transmission service providers (TSPs) in a restructured power industry should provide one-stop shopping for the transmission services needed to execute wholesale transactions. However, from a supply-side perspective, a TSP performs two generic functions: provision (ownership) and control (operation) of transmission assets. As part of its control function, a TSP must procure and deploy appropriate resources to relieve congestion and ensure system reliability. We subscribe to the premise that is widely accepted in the U.S. that, in order to avoid conflicts of interest, the TSP, regardless of its underlying business model, should not own generation assets or have a financial interest in any of its transmission service customers. In keeping with this premise, the TSP procures all the generation services it needs through short-term markets or long-term contracts. The principal criterion by which business models for TSPs are categorized is whether or not ownership and control of the transmission assets are vertically integrated. The two main categories of business models are:

- Separate ownership and control: control functions and interactions with transmission customers are handled by a system operator, and transmission assets are owned by separate entities;
- Joint ownership of transmission assets and control of the grid: both functions of the TSP are combined in a single entity.

Within each of these categories[2] are several options, described below, that are compatible with power industry realities. Some of these options capture the essence of existing U.S. and international structures, but not all are compatible with the FERC RTO guidelines listed above.

Separate Ownership and Control of Transmission Assets

System operator publicly owned; assets owned by utilities, generators, municipalities, and private investors

Under a separate ownership and control situation, the system operator is a public enterprise or government agency issuing instructions to owners of transmission assets regarding asset maintenance, operation and investment. The system operator faces soft incentives (because there are no residual claimants, i.e., no share-

[2]This classification is based on Awerbuch, Crew, and Kleindorfer (2000), pp. 23–40.

holders that would gain from financial incentives or bear the consequences of financial penalties) and is charged to behave fairly and efficiently and to maintain adequate system reliability.

System operator jointly owned by the owners of the transmission assets and operated as a nonprofit organization; assets owned by utilities, generators, municipalities, and private investors

As in the previous situation, the system operator in this case issues instructions to transmission asset owners. However, the owners of the transmission assets might be able to form coalitions and use their voting power to favor their own facilities. A nonprofit orientation amplifies this effect by eliminating potential tradeoffs between profit from efficient utilization of facilities and the motives of system operator owners wishing to favor their own facilities. On the other hand, sharing the profits of a for-profit system operator is more likely to induce owners to opt for efficiency (and higher profits from system operations) rather than pursuing the selfish motives of the party they represent.

System operator jointly owned by the owners of transmission assets and operated for profit; assets owned by utilities, generators, municipalities, and private investors

This case is similar to the previous one, but the potential for profit may moderate the tendency to form coalitions.

System operator established as an independent nonprofit company (ISO); assets owned by utilities, generators, municipalities, and private investors

This structure exists in California, Texas, and PJM. The ISO's independence in this model can make the formation of coalitions difficult, depending on the composition of the governing board. When the governing board is composed of stakeholders, as was the case in California prior to January 2001 and is the case in Texas, coalitions may still be formed.[3]

Joint Ownership and Control of Transmission Assets

Transmission Service Provider owned by a public enterprise

In this configuration, transmission assets are owned by a public entity, so all externalities within the region are internalized. In other words, because a public entity owns all the assets, there is no possibility that the action of one transmission owner may adversely affect another transmission owner. The structure of Western Area Power Administration (WAPA) is similar to this model.

[3]The fundamental shortcoming of this structure was articulated by the CAISO Market Surveillance Committee in the following observation with respect to reserves: "We note that the ISO does not bear the final cost of the reserves that it acquires. These are passed on to the users of the system. However, as a fledgling institution, the ISO has a very strong incentive to avoid serious reliability problems. The thorny problem of providing operators the incentive to both minimize costs and ensure reliability is a long-standing one in the electricity industry." Similar incentive problems exist for transmission system operation (CAISO, "Annual Report on Market Issues and Performance", June 1999).

Transmission Service Provider owned by utilities, generators, and municipalities and operated not for profit

When the TSP is operated not for profit, owners who are also market participants may favor investments in generation assets, which would produce profits, over investments in transmission, which would not when these investments are substitutable.

Transmission Service Provider owned by utilities, generators, and municipalities and operated for profit

This case is similar to the previous one, but the potential for profit from transmission investments weakens the motive of transmission company owners to favor generation investments that would benefit the parent companies over transmission investments that would improve the service provided by the TSP.

Transmission Service Provider owned by a single regulated utility and operated for profit

This case is similar to the previous one except that the ownership is in the hands of a single utility. Competitors and customers served by the transmission company may fear discrimination against them in favor of the utility owner. In other words, the regulated utility operating the transmission grid may favor its own affiliated resources and customers at the expense of other customers and competitors that wish to use the transmission system. The RTO plan proposed by Entergy fits into this category.

Transmission Service Provider organized as for-profit, independent transmission company (ITC)

In this configuration, the ITC has no other facilities of its own that it might differentially favor, and its profit incentive will drive its pricing and investment decisions. Its monopoly status requires regulation to ensure just and reasonable prices.

Criteria for Analysis of Alternative Business Models

Alternative business model for transmission enterprises may be evaluated using several criteria:

- Market efficiency,
- Operational efficiency and system reliability,
- Transmission access and interconnection policy,
- Investment and innovation in the transmission grid,
- Governance and regulatory oversight, and
- Political feasibility.

As noted above, system operators under the separate ownership and control paradigm and TSPs under the joint ownership and control paradigm can come in many forms; a critically important consideration is their roles in market operation and the extent to which they are affiliated with entities that use the transmission system. In any case, the central role that such entities play in the market and their monopoly status will necessitate some form of regulation. We assume that FERC's RTO initiative will move ahead so that any business model for transmission entities will function within the RTO framework. The subsections below discuss the separate ownership and control and joint ownership and control paradigms using the above criteria.

Market Efficiency

Economic efficiency is achieved when the price of goods and services is close to their marginal costs and when the price of scarce resources results in efficient rationing. Because we assume that the TSP would not be affiliated with wholesale or retail market participants, bias or deliberate discriminatory treatment should not be a concern. Nonetheless, it is not clear which of the TSP structures discussed above would be more likely to result in efficient price signals that would facilitate competition, reduce exercise of market power, and encourage efficient investment in generation (in terms of quantity and location). The key questions are whether a system operator under separate ownership and control or a TSP under joint ownership and control would have inherent advantages or disadvantages in managing scarce transmission resources, operating a balancing market, and procuring ancillary services that are essential for system operations. To promote market efficiency, a TSP must manage congestion efficiently and provide appropriate price signals to guide decisions about production, consumption, and location of load and generation and to reduce abuse of market power. It is not clear whether either the separate ownership and control or joint ownership and control approach has inherent advantages or built-in incentives that would help achieve these objectives or whether an incentive system exists under either approach that would induce the TSP to come up with rules and protocols that will achieve the goal of economic efficiency. Most likely, any business model would have to include a specified set of rules and protocols that are consistent with FERC RTO principles and that will foster the desired behavior by the TSP whether operation and ownership of the transmission assets are joint or separate.

Another concern is the extent of transaction costs for rebundling required transmission assets. A system operator must deal with the added complication of negotiating with independent transmission owners (TOs) for increased use, enhancement, and maintenance of their assets. When the TOs are involved in the governance of the system operator, committee decision-making processes involving TOs create an opportunity for transaction costs and organizational inertia.

On the positive side, a separate ownership and control structure, particularly one in which the system operator is nonprofit, would be more amenable to enforcing a set of market protocols that are designed to pursue market efficiency. Adoption of such "socially efficient" protocols is more likely when the system operator operates as an ISO that is not governed by stakeholders. One question is whether the added efficiency achieved by a separate ownership and control structure would cover the added transaction costs and inefficiencies resulting from the separation between ownership and control of assets.

The joint ownership and control models that involve public ownership under nonprofit operation raise concerns about the transparency of motivation for efficient operation and decision-making. In a sector such as electric power where economic drivers are primary, a structure that puts technical groups or committees in charge of key components is highly problematic. Technical committees tend to emphasize technical integrity and often compromise economic principles for political expediency. Such compromises have manifested, for instance, in congestion management protocols that opt for spreading the costs of congestion relief to all users rather than assigning them to those who cause the congestion. Adoption of such rules has, in some systems, resulted in gaming and market disruptions. A related problem is absence of residual claimants (e.g., shareholders who have a claim to gains from efficient operation) in the first two options under the joint ownership and control structure. This absence may create a conservative bias in operating decisions (e.g., derating transmission lines or overprocurement of reserves in order to avoid economically justifiable risk), which may limit trade and foster the exercise of local market power.

In many respects, the ITC option may be viewed as the *gold* standard of the joint ownership and control structure. The only business of the ITC is transmission, so it has no incentive to discriminate against any particular customer.[4] This contrasts with the option of a TSP owned by a single utility, which would have a strong incentive to favor its own customers, generators, and loads. Mitigating these tendencies would require considerable regulatory intervention. The potential to discriminate is attenuated when transmission customers or several companies jointly own the for-profit TSP. Unfortunately, profit incentives are also attenuated under such joint ownership, and the potential for formation of coalitions may present additional problems. Specifically, groups of owners representing diverse interests of transmission users may form voting blocks and trade (among themselves) support of inefficient policies that favor the interests of the various coalition members (e.g., voting against a market-power-mitigation measure in exchange for a vote supporting the spreading of intra zonal congestion costs among all users).

Questions about how horizontal integration of transmission ownership and control affect market efficiency must be framed in the context of the geographical scope and market-making authority of TSPs. The answers depend on whether we assume a highly centralized transmission organization such as PJM, which operates a day-ahead energy market and provides unit commitment services, versus a decentralized organization such as ERCOT. Similarly, when ownership and control of transmission assets are not joined in a single entity, horizontal integration of ownership and control may have advantages or disadvantages for efficient coordination of adjacent markets.

A TSP's objectivity towards the users of transmission services may not completely eliminate the potential for price distortions and economic inefficiency. The substitutability between transmission and generation investment puts a for-profit TSP operating under the joint ownership and control structure in competition with the generators it serves. This TSP may have perverse incentives that may bias its congestion management practices to favor "wire solutions" over "generation solutions" in its investment policy. These concerns must be addressed through incentive regulation that rewards market efficiency and also punishes inefficiency. For instance, the Transmission Services Scheme in England and Wales provides the National Grid Company (NGC) with financial incentives to reduce transmission "uplift" costs, which may be viewed, in part, as a crude proxy for market inefficiency. In that regard, system operators under a separate ownership and control paradigm may be more objective in choosing between wire solutions and generation solutions, which will result in price signals and investment plans that promote economic efficiency.

[4]Of course, the ITC may engage in monopoly pricing and must therefore be regulated.

Operational Efficiency and Reliability

The business structure of a TSP affects its incentives to operate the transmission system efficiently (i.e., at least social cost) and reliably. One of the main concerns about nonprofit TSPs is that they have little to gain from reducing costs of operation through, for example, the judicious procurement of ancillary services. In the absence of a profit motive, TSPs are judged primarily on system reliability performance without any consideration of the economies (efficiency), so they have an incentive to operate conservatively (at increased cost). By the same token, there is a legitimate concern that a for-profit TSP will have the opposite incentive—to sacrifice system reliability in favor of profit. Restraining the natural tendencies of either structure requires the specification of appropriate rules of the road and a well-crafted system of governance and regulation. This requirement shifts the emphasis to determining what form of organization is easier to regulate and how to do so effectively.

Operational efficiency and system reliability can be achieved by alternative means, including short-term operational procedures, which include dispatch of generation resources, maintenance of transmission assets, and investment in innovation. Separation of these functions as under the separate ownership and control approach creates risks that need to be mitigated by means of contracts and risk management, which result in increased costs. An advantage of the separate ownership and control approach, however, is that the system operator is indifferent to the utilization of transmission or generation resources to perform its duties and should thus opt for the most efficient solution to a reliability problem when there is a choice between investment in generation resources (e.g., Reliability Must Run (RMR) contracts) or transmission assets. The analysis of the separated functions option must compare the benefits of separating transmission ownership from operation to the costs involved.

Transmission Access and Interconnection Policy

The premises of FERC Orders Nos. 888 and 2000 and the subsequent decisions concerning the formation of RTOs are that widespread interconnection and direct access to the transmission network will expand the scope of the market and foster market efficiency. Determining which transmission organization business model will best facilitate that vision is difficult because of many political and regional considerations, including the tension between state and federal jurisdictions. More pragmatic questions focus on whether certain organizational structures would expedite implementation of the RTO vision in different parts of the country and whether and how separate ownership and control and joint ownership and control structures can coexist. Considering the option of accommodating diverse organizational structures raises questions about coordination of operations and investment across seams between control areas or more generally RTOs. The principal concern is that decentralized investment and control of transmission facilities can result in loop flows and other network effects; in other words, individual transmission operators and investors may behave in ways that affect interconnected transmission grids. Such externalities may be inconsistent with the overall efficiency of operations and investment. The main advantage of the separate ownership and control paradigm is that separation facilitates the system operations of the grid combining the transmission assets owned by diverse organizations—e.g., utilities, private owners, municipalities—over a large geographic area. To the extent that an organization based on separate ownership and control can enforce its decisions, this integration, which enables one-stop shopping for transmission services over large regions, internalizes many of the externalities inherent in the *transportation* of electricity over meshed transmission networks. However, as the degree of horizontal integration of transmission assets serving adjacent geographic areas increases, the above rationale for vertical separation (i.e., that it is an effective way to consolidate operation of diversely owned resources) becomes less compelling, and the arguments in favor of joint ownership and control become stronger.[5]

If control areas are not horizontally integrated, the issue of seams must be explicitly considered. Efficient coordination among adjacent control areas or, more generally, RTOs depends more on the consistency of the congestion management protocols than on business models. It is difficult to assess the impact of alternative business models on efficient coordination at the seams. Mergers and standardization of protocols among control areas are the ultimate solutions to seams problems; the limited experience with restructuring to date appears to suggest that merging control functions is easier without merging asset ownership.

Investment and Innovation

Creating incentives for transmission system investment and innovation to congestion and expand the scope of the competitive market is a central issue in electricity industry restructuring. According to Paul Joskow[6] (1999), "Transmission investment decisions cannot rely exclusively on market mechanisms. They are lumpy, involve externalities, and are characterized by economies of scale. Restructuring experience to date shows no evidence that market forces will draw significant entrepreneurial investment into transmission capacity." Consequently, transmission expansion requires centralized planning and investment. How are activities hindered or facilitated by separation of control and ownership? To address this question, we have to consider what mechanisms the alternative business models offer for creating appropriate economic signals that provide incentives for efficient investment and innovation with adequate capability to finance these investments and reward ownership of assets.

Under the separate ownership and control paradigm, the system operator plans and evaluates transmission expansion. The market signals for such investments result from: congestion management protocols; locational energy prices; the definition, allocation, and settlement of transmission rights; and the regulation of return on transmission assets. Investments in transmission are made by the owners, who are responsible for the financing and are rewarded with: regulated returns on their investments, transmission rights, and/or direct benefits from the transmission assets, which may complement and enhance the owners' ability to buy or sell energy. Merchant transmission investment is also possible, but, because of externalities (except in the case of DC lines), such investments would need to be approved by the system operator as well as the regulatory authority. The separation of functions under the separate ownership and control structure can, however, lead to different objectives for the system operator and the TOs, as has been seen in California with regard to the California Independent System Operator (CAISO)-proposed expansion of Path 15.[7]

[5]This argument is based on the well articulated discussion in Joskow 1999.
[6]Merchant DC line proposals such as those proposed under the Neptune Project and by TransEnergie are notable exceptions that will be discussed below.
[7]Although the cost of this transmission expansion is only about $300 million, which is relatively small in comparison to the estimated $70 million in annual congestion cost, Pacific Gas and Electric (PG&E) argued against expanding Path 15 on the grounds that generation expansion plans would make this transmission investment unnecessary. The ISO argued that savings to northern California consumers alone justified the transmission expansion, which was eventually approved.

One advantage of the separate ownership and control structure is that the system operator is indifferent to solving congestion problems by means of either energy generation displacement or through transmission investment. Such indifference may lead to a relatively balanced and socially efficient investment pattern and may also enhance the credibility of the system operator's recommendation for transmission expansion, which would facilitate approval by state commissions of rate increases required to finance such expansion. It is worth noting that the current prevailing separate ownership and control structures in the U.S. have fallen short in producing transmission investment, which suggests that separate ownership and control bias toward "wire solutions" is essentially nonexistent.

Reliance on market-based signals for investment in systems using transmission rights settlements and dispatches of RMR resources to relieve congestion raises concern because the patterns of nodal and zonal prices upon which market-based expansion initiatives must rely are very sensitive to reliability (i.e., security) criteria and are highly volatile. Such uncertainty is likely to discourage market-based transmission investment.

Settlements of transmission rights awarded to investors can, in principle, produce a market-based income stream, but the lumpiness of transmission investments as well as the issues of externalities and economies of scale make it difficult for investors to gauge the precise amount of transmission capacity at which transmission rights income offsets the costs of the investments. Consequently, compensation to TOs cannot be guaranteed from solely transmission rights revenues, which, in most cases, cannot be relied on to provide adequate cost recovery. These revenues would need to be supplemented or replaced by an uplift charge that relies on a regulated-return-on-investment approach. A major weakness of the separate ownership and control structure in this regard is that setting the regulated return on investment in transmission on the basic cost (book value) of transmission assets rather than on the contribution of such assets to the market and to system efficiency (market value).

As noted earlier, transmission costs represent a small fraction of the overall costs of electricity, yet relatively small investments in transmission may have a major impact on economic efficiency and system reliability. Furthermore, in the context of deregulated markets, it is possible that a transmission investment that contributes little to the reduction of social costs may have a significant impact on transfers between consumers and producers due to mitigating market power. For example, a line between two self-sufficient areas may not carry much flow, but its presence creates competition in each of the local markets, thereby mitigating market power exercise and reducing prices to consumers in both markets. In this situation, consumers clearly benefit from the investment, but financing may be difficult. When control and ownership of transmission are separated, a major challenge to investment and innovation is the creation of a financing linkage between those who benefit from the investment and those who make the investment.

Traditional regulated-rate-of-return approaches that compensate investments based on cost and allocate the compensation to users on some pro rata basis are ineffective in this regard. One explanation offered by some speakers at U.S. Department of Energy (DOE) public workshops is that the traditional rates of return approved by public utility commissions for transmission investments are inadequate considering the risks associated with such investments in restructured markets.[8] The proposed solution is to raise that rate of return substantially. Although this approach may work in the short run, "throwing money at the problem" is an overly simplistic and naive solution that may ultimately result in inefficient investment.

[8]This point was raised by two speakers at the public workshop in Phoenix, Arizona.(September 28, 2001).

Under the joint ownership and control approach, it may become possible to separately track the costs associated with operations, assets, maintenance, and investment. However, the key advantage of the joint ownership and control approach is that the impact of investment on operations may be internalized by the TSP and the compensation for asset ownership may be based on value added by the assets rather than their costs. As noted above, it is doubtful that incentives alone can induce a TSP to develop a transmission pricing scheme and congestion management protocol that would result in efficient price signals. The pricing scheme requires regulatory oversight and approval. However, it might be possible to develop a performance-based compensation scheme that would internalize the complementarity between operations and investment in achieving the desired "end product" transmission system.

The main problem lies in defining and measuring that end product. Is it defined by interconnection, transaction volume, absence of congestion, or some degree of economic efficiency and effective competition? Evaluation of the performance of the TSP in the combined ownership and control approach hinges on whether it is nonprofit or for-profit. For a nonprofit TSP, there may be a tendency to use reliability as the primary measure of performance, which would lead to overly conservative operation and therefore overinvestment, the costs of which would be borne by consumers. With a for-profit TSP under combined ownership and control, the challenge is to develop performance-based regulation (PBR) that rewards efficiency and penalizes inefficiency. Such a regulatory scheme would balance incentives for efficient and reliable operation with those for investment and innovation so as to result in a stream of revenues capable of financing requirements for such investments.

Governance and Regulatory Oversight

The key regulatory questions are:

- What is the effect of vertical integration of operation and ownership on the efficacy of regulation?
- Which organizational structure is easier to regulate: a nonprofit TSP, which is typically governed by a board of stakeholders or an independent board, or a corporate, for-profit TSP?

Regulation encompasses issues of governance of the system operator and the determination of appropriate compensation for the TOs. If the system operations are provided for by a for-profit organization, then the regulator would also have to regulate the system operator's profit. In principle, under the separate ownership and control paradigm, the regulator has direct control of the compensation of TOs and consequently can protect consumers while directly influencing investment decisions by authorizing appropriate levels of return on investment incorporating the consideration of attendant risks. This is the prevailing model in the U.S. where all restructured systems to date fall into the ISO category with TOs being compensated under a cost-of-service or rate-of-return (ROR) scheme. ROR regulation provides a prima-facie basis for achieving fairness between shareholders and rate payers by setting the allowed rate of return at a level that justly compensates the owner for investment and risk taking so as to be able to attract capital.

At least in theory, ROR is fully cost based, allowing cost increases or reductions to flow directly to the customers of the regulated firm. The emphasis here is on fairness at the expense of efficiency. ROR has been popular with regulators and utilities because it is well understood and its cash flows and risks are relatively transparent. For transmission, however, ROR may not be the appropriate approach to provide incentives for investment and attract capital. Clear evidence that this approach is inefficient is the lack of investment in transmission since the onset of electricity industry restructuring in the U.S., especially in contrast to the extensive investments in generation during the same period. At the DOE public workshop in Phoenix, Arizona (September 28, 2001) at least one presenter argued that the allowed rate of returns for transmission investments does not properly reflect the risks associated with such investments under deregulation and that higher rates are needed. In any case, the ROR approach puts the regulators in the position of being "penny wise and pound foolish" with regard to transmission investment. By shaving a few points of the cost of transmission, which constitutes a small percentage of the total cost of electricity, the regulator may deter transmission investments that may bring impacts that greatly exceed their costs through efficiency improvements and market power mitigation, which will affect transfers from consumers to producers.

With regard to the system operator function, we focus on the nonprofit ISO model, which is the prevalent structure in the restructured electricity systems in the U.S. The major advantage of this model is that it requires only light-handed regulation. The absence of the profit motive leaves no role for the regulator in setting prices other than trying to influence the allocation of charges among customer groups. The California Public Utility Commission, for instance, takes an active role in protecting residential customers and intervening in CAISO tariff cases before FERC. When the ISO is independent of transmission users and owners, it has no motive to be unfair. The fact that an organization is nonprofit does not mean that it has no incentives to control cost, but the objectives of a nonprofit firm may be different and more complex than those of a for-profit firm in the same business, making it more difficult to monitor the nonprofit's performance. Decisions in a nonprofit organization are driven by personal managerial objectives and compromises with the stakeholders, some of who are profit driven.

No one argues that it is possible to devise a regulation scheme that creates incentives for a transmission organization to develop an operation and settlement protocol that will result in efficient markets. Hence, realistically, whichever organizational form is chosen, the market design will be determined through a regulatory review process, which will include protocols for managing congestion, scheduling and dispatching power, balancing market operation, and procuring ancillary services.

The ISOs in the U.S. are governed by boards of directors that are composed of either stakeholders, as in the case in ERCOT and in California (before January 2001), or independent members, as is the case in the PJM New York and New England ISOs. Governance by a stakeholder board circumvents the nonprofit aspects of the ISO because the stakeholders, some of who represent for-profit companies, will try to influence the ISO rules and procedures to maximize their own profits. The result is an "Ouija board" decision-making process whose outcomes are unpredictable and unlikely to consistently promote efficiency.

In the case of joint ownership and control, there is legitimate concern that the TSP will exercise its monopoly power to the detriment of transmission service customers. To prevent such abuse, a more heavy-handed regulatory scheme may become necessary. The objective of such a scheme should be to reward efficiency and penalize inefficiency. This is easier to do when the TSP operates for profit, such as an ITC, because then a PBR scheme can be designed to induce appropriate risk taking on the part of the TSP and proper balancing among efficient operations, investment in new facilities, and innovation. Such a PBR system has not yet been designed or implemented, however, and none of the proposed approaches has been proven to produce the ideal desired outcome. The U.K. Transmission Services Scheme, which provides the grid operator with financial incentives to reduce transmission "uplift" costs, is a good example of a practical PBR approach and a step in the right direction. The underlying assumption of that scheme is that the TSP's performance can be measured in terms of the uplift charge that the TSP must recover from its customers To some extent, high uplift charges indicate inefficient operations and/or a high level of congestion costs. The uplift charges can be reduced by improving operational efficiency or expanding the transmission system. The main challenge in such a scheme is to determine the proper yardstick for uplift charges.

Price-cap regulation (PCR), which is common in the telecommunications industry and is widely used throughout the world for utility services, may also be appropriate, at least as an initial mechanism for an ITC. This scheme provides incentives for cost minimization by decoupling regulated price levels from the firm's costs. The price levels are generally defined by a price-cap index, but firms are often given flexibility, which, in the case of transmission pricing, would enable the TSP to respond to short-term demand fluctuations. Pure PCR allows the regulated firm to retain the fruits of its successes within the constraints of the price level and the period of the price cap. Other variants would involve some sort of risk sharing that would protect the firm against catastrophic failure but would also limit its potential windfall profits.[9]

Political Feasibility

The attractiveness of the separate ownership and control paradigm and particularly the nonprofit ISO model is that it overcomes ownership barriers in the transmission system and facilitates competitive markets by internalizing externalities and creating "one-stop shopping" for transmission. This relative advantage decreases with the degree of horizontal integration of transmission assets. The combined ownership and control structure can also offer similar services. However, the extent to which such horizontal integration can be achieved is largely a political question. In California, the ISO structure was chosen largely because it was politically infeasible to require the three major investor-owned utilities to divest their transmission assets. Even when the state considered purchasing the transmission assets from the utilities as a way to keep them solvent, the idea of consolidating ownership of these assets in the hands of the ISO was not considered. The divestiture and horizontal integration of transmission assets is a necessary condition for vertical integration of ownership and control with significant geographical scope so that most of the externalities associated with operation and investment can be internalized. However, the authority to force divestiture may involve state and federal jurisdictional disputes as well as other political considerations. For example, a considerable fraction of the transmission assets in the northwest and the southeast are owned and controlled by the Bonneville Power Administration (BPA), Western Area Power Administration (WAPA), and the Tennessee Valley Authority (TVA), so the creation of any new transmission organization requiring the transfer of ownership of these assets would entail new congressional legislation. Similarly, transmission assets owned by public power and municipal entities such as the Transmission Agency of Northern California (TANC), New York Power Authority (NYPA), and Los Angeles Department of Water and Power (LADWP) are difficult to transfer to for-profit enterprises due to "private-use" tax rules, which apply to assets funded through

[9]For a more detailed description of PCR, see Awerbuch, Crew, and Kleindorfer (2000).

tax-exempt bonds. Violation of private-use rules can make tax-exempt bonds retroactively taxable.[10] Such tax restrictions might also prevent public power resources from participating in RTOs without requiring the transfer of ownership. Joining an RTO, even on short-term basis, may prevent a public power entity from issuing tax-exempt bonds to finance new transmission facilities. Thus, seeking a new ruling from the Internal Revenue Service on such issue, might be necessary regardless of the business model selected.

Table 1 summarizes the considerations discussed in this section as they apply to the alternative business model options.

International Experiences

Transmission organizations have taken different forms in various countries. A study of the experience of transmission organizations in Australia, Argentina, Chile, England/ Wales, and Norway indicates that each country is seeking to improve its existing organizations. The experiences with transmission in these countries have varied widely. A key objective of our study was to investigate the nature and ability of incentives to motivate investment in improving/expanding the transmission system. Each system we studied has its own specific incentives whose direct applicability to other jurisdictions' or systems may be limited. Nevertheless, the lessons learned from the various systems may be valuable in designing incentives for transmission organizations in the US. This subsection reviews the key characteristics of the transmission organizations of the five countries mentioned above. For each system, the salient characteristics are analyzed, and the overall experiences are summarized noting features that may be useful in other jurisdictions. Specifically we examine the following aspects of each system:

- Ownership,
- Transmission tariffs,
- Ownership obligations,
- Transmission planning requirements,
- Investment incentives,
- Means of recovery of new investment,
- Role of customers in transmission system expansion, and
- Regulatory body.

Argentina

Argentina was among the first countries to restructure its electricity system. Starting in the early 1990s, Argentina's system restructuring was accompanied by the broad selling off of generation and transmission assets, mostly to foreign entities. The key characteristics of the Argentine transmission system are summarized in Table 2.

[10]This issue was raised by Mr. Gary Schaeff of Large Public Power Council (LPPC) at the DOE Atlanta Workshop (September 26, 2001)

Table 1: Classification of alternative business models

		Market efficiency	Operational efficiency and system reliability	Transmission access and inter-connection policy	Investment and innovation in transmission grid	Governance and regulatory oversight	Political feasibility
Separate ownership and control	**System operator publicly owned; assets owned by market entities**	No motive for inefficiency but weak incentives to facilitate trade	Likely to favor reliability over efficiency (least cost)	Will provide fair and equitable access	Credible with PUCs but may be difficult to attract investment	Light-handed regulation of system operator and ROR for assets	Easy to implement; requires no transfer of assets
	Nonprofit system operator jointly owned by transmission owners; assets owned by market entities	Owners can form coalitions to favor their facilities	Likely to favor reliability over efficiency (least cost)	Owners can form coalitions to favor their facilities	Likely to favor generation solutions	Lack of residual claimants complicates governance of system operator	Requires no transfer of assets but may face objection due to fear of bias
	For-profit system operator jointly owned by TOs; assets owned by market entities	Profit from increased trade moderates selfish interests of TOs	Incentive regulation can improve balance between efficiency and reliability	Profit from increased trade will moderate selfish interests of TOs	Profits from transmission business may offset bias toward generation solutions	PBR of system operator can incentivize efficient operation. ROR for investment	May face objections resulting from fear of bias and fear of monopoly power abuse
	Nonprofit independent system operator (ISO); assets owned by market entities	Neutral toward market participants; Likely to police market power	Likely to favor reliability over efficiency	Neutral toward market participants; Likely to police market power	Credible planning but may be difficult to induce TOs to invest and innovate	Light-handed regulation of system operator but difficult to monitor efficiency	Politically expedient. The currently prevailing solution in U.S.
Joint ownership and control	**Publicly owned TSP**	Externalities internalized but weak incentives to facilitate trade	Likely to favor reliability over efficiency (least cost)	Will favor native constituency over merchant transactions	Acts in the public interest to plan and expand transmission	Light-handed regulation of operation and investment	May require IRS ruling to operate under RTO
	Nonprofit TSP owned by market entities	Owners have incentive to favor their own affiliates	Likely to favor reliability over efficiency	Owners have incentive to favor their own affiliates	Favors generation over transmission investment (no profit from transmission)	Light-handed regulation but market oversight needed	Requires consolidation of assets or coalition of asset owners; Problems with public entities
	For-profit TSP jointly owned by market entities	Owners have incentive to favor their own affiliates	Profit motive shifts scale toward efficiency	Profit motive reduces tenden cy to favor owners assets	Profit from transmission reduces bias toward genera tion investment	PBR can incentivize efficient operation and investment	Requires consolidation of assets or coalition of asset owners. (e.g. Desert Star). May face objections
	For-profit TSP owned by a single regulated utility	Controlling tendency to favor owners assets may lead to a constrained market	Traditional operating mode likely to be efficient and reliable	Tendency to favor affiliates	Follows traditional planning and investment paradigm	PBR can incentivize efficient operation and investment. Oversight needed to prevent bias	Relatively easy to implement but may face opposition from other market entities
	For-profit independ ent TSP (ITC)	Incentives to mitigate market power of genera tors providing ancillary services and offers for congestion relief	PBR provides incen tives for efficiency and reliability balance	PBR provides incentive for increasing access	Interaction between opera tional efficiency and invest ment is internalized, but ITC may favor wire solutions	PBR based on performance simplifies regulation. Independence eliminates need to monitor bias	Frequires consolidation of assets. Publicly owned assets may present legislative challenges

Table 2: Summary of the Salient Characteristics of the Transmission System in Argentina

Ownership	There are seven private transmission grid companies. TRANSENER owns transmission networks across the entire country, and six companies own regional transmission systems. Each company has to obtain the required license from the Argentinean regulator.
Transmission tariff	Charges consist of a fixed component for the recovery of investment costs and a variable component for recovery of operating and maintenance expenses.
Ownership obligations	To provide nondiscriminatory access and service to all customers (independent of their size)
Transmission planning requirements	No systematic planning; expansion plans require regulatory approval. No entity in the country has responsibility for planning transmission.
Investment incentives	There are no incentives to expand the grid by TRANSENER or any of the regional companies. Any expansion has to be entirely paid for by customers.
Means of recovery of new investment	Not applicable
Role of customers in transmission system expansion	Critically important because any expansion of the transmission system has to be requested and financed by the customer
Regulatory body	Ente Nacional Regulador de la Electricidad (ENRE)

Six companies own Argentina's regional grids, and one owns the transmission networks that span the country. Operation/control of the transmission system is separated from ownership. An ISO is in charge of transmission operation/control as well as operation of the electricity markets.

The responsibilities of the Argentine ISO do not include planning. In effect, there is no single entity in Argentina whose charter includes transmission planning. An undesirable aspect of transmission system expansion/improvement in Argentina is its dependence on the willingness of transmission customers to directly bear the burden of any new investment. There are no incentives for the transmission owners to expand/improve the transmission system, and virtually no new major transmission projects have been undertaken since the onset of the restructuring process in Argentina.

Australia

The restructuring of the electricity system has proceeded at different rates in different regions of Australia. Although a single electricity market has been established for the entire country, transmission organizations vary from region to region. Table 3 summarizes the characteristics of Australia's transmission system.

Table 3: Summary of the Salient Characteristics of the Transmission System in Australia

Ownership	Each Australian region has one or more state-owned regional transmission companies that own a transmission grid. In addition, there are non-state-owned companies that own transmission assets across the regions. Transmission-owning companies may be either regulated or nonregulated.
Transmission tariff	For regulated transmission-owning entities, there are regional pricing structures that are determined with regulatory approval by each region. The transmission prices consist of connection fees—so called shallow connection costs, demand charges based on peak and shoulder loading, and energy charges based on usage. Typically, the transmission tariffs are based on (CPI-x) regulation. For unregulated transmission-owning entities, transmission prices are market based and determined from the offers and bids for transmission capacity. In this way, capacity is treated, in effect, as a commodity.
Ownership obligations	All transmission-owning entities must provide nondiscriminatory service to all customers. Most of the state-owned companies have obligations with respect to transmission planning. The nature of additional obligations may vary regionally and depends whether or not the transmission-owning company is regulated.
Transmission plan ning requirements	Each stated-owned transmission company has to prepare an annual statement discussing planning activities. Each region has its own requirements regarding the nature of this statement. Each state-owned transmission company has responsibility for transmission planning. Any entity, including a non-transmission-owning company, is permitted to make investment in transmission assets.
Investment incentives	In the case of regulated assets, there are no clear incentives for expansion of the transmission system. For unregulated assets, the incentives are the future revenue streams for transmission services.
Means of recovery of new investment	The regulated transmission-owning companies may not necessarily be able to recover their investments in additional transmission facilities. The unregulated entities face the usual risks associated with markets and consequently may be able to receive compensation that exceeds their investment.
Role of customers in transmission system expansion	The generators work with the transmission-owning companies to improve the transmission system to avoid or eliminate congestion amd to plan new investments that may be required.
Regulatory body	There are two national regulators: • The National Electricity Code Administrator (NECA), which is in charge of administering and enforcing the Electricity Code, and in that capacity regulates all transmission-owning companies • The Australian Competition and Consumer Commission (ACCC), which handles all aspects related to the market operation, and consequently polices the behavior of the nonregulated transmission-owning companies In addition, each region has its own regulatory body, which determines the policies affecting regulated service.

Australia is unique among the countries we investigated in allowing the ownership of transmission by both regulated and unregulated entities. Regulated companies own most of the transmission, but Australia also allows merchant transmission companies, and at least one such company, TransEnergie Australia, operates in the country. The transmission tariffs of the regulated transmission companies are based on marginal costs. The transmission prices of unregulated companies are market based.

The regulated Australian transmission-owning entities are obligated to undertake planning. In addition, these companies are required to expand/improve the transmission grid, and certain incentives are offered for these activities.

The structure of the Australian transmission system has been in a state of flux and continues to evolve. The experience of TransEnergie Australia is too brief to offer any generalizable experiences. However, the future evolution of the transmission organizations in Australia, particularly the proliferation of merchant transmission lines may provide useful lessons for other jurisdictions.

Chile

Chile led the restructuring of electricity systems as the first country in the world to introduce competition and customer choice in 1982. The salient characteristics of the Chilean transmission system are presented in Table 4.

Table 4: Summary of the Salient Characteristics of the Transmission System in Chile

Ownership	There is a single entity, TRANSELEC, that owns a major part of the transmission system; the rest is the property of generators and large industrial consumers. There are no restrictions on transmission ownership.
Transmission tariff	There are two charges: • Tariff based on the forecasted marginal costs (indexed nodal prices) • An additional charge based on the so-called influence area
Ownership obligations	To provide nondiscriminatory access and service to all customers (independent of their size)
Transmission planning requirements	No systematic planning is done, and no entity in the country has responsibility for planning transmission.
Investment incentives	Nodal price differences and the contributions that the customers make
Means of recovery of new investment	Through the money collected from the tariffs and the contributions that some customers make; the customers' contributions must be repaid over time in some negotiated fashion.
Role of customers in transmission system expansion	Very important because if they are interested in an expansion of the system they can finance it, at least in part.
Regulatory body	Comisión Nacional de Energía (CNE)

In Chile, ownership and operation/control are totally separated. Ownership of the transmission grid is in the hands of a for-profit entity, and operation/control of the system is in the hands of the ISO Centro de despacho económico de carga (CDEC), which also has responsibility for operation of the electricity markets.

The CDEC transmission tariff embodies some economic efficiency properties because the rates are based on marginal costs. However, these costs are forecasted values and do not necessarily represent actual operating conditions. There are no economic signals in the Chilean system that provide incentives to expand/improve the transmission grid. Therefore, the Chilean experience seems to be of limited value and applicability for other jurisdictions.

England and Wales

The privatization of the Central Electricity Generating Board in 1990 brought about widespread restructuring of the electricity sector in England and Wales. A salient characteristic of restructuring was the establishment of the Power Pool. The introduction of the New Electricity Trading Agreement (NETA) in March 2001 effectively replaced the Power Pool and introduced major reforms to the transmission sector.

The National Grid Company (NGC) was established as a regulated, for-profit entity with responsibility for ownership and operation/control of the transmission grid and the Power Pool. Transmission system characteristics in England & Wales are summarized in Table 5.

NETA introduced specific new incentives for NGC to invest in new transmission. NGC is subject to PBR under the so-called RPI-x scheme. Included in the NGC's responsibilities is the acquisition and supply of the uplift service, which includes ancillary services, loss compensation, and congestion management. NGC acquires these services from the connected generators and pays for them out of the revenues it receives from its customers. Under the current regulatory scheme, these uplift charges are controlled. NGC has full responsibility for planning of transmission and, as part of this responsibility, issues an annual Seven Year Statement, which describes in detail the most up-to-date plans. NGC is also responsible for all investment in expanding/improving the transmission system. The investments made by NGC may be recovered through savings in uplift costs. Under the price cap regulation regulation, NGC may keep part of its uplift cost savings as additional profits. Consequently, savings in short-term operational expenses that reduce uplift costs provide incentives for long-term investment in transmission. This incentive scheme is a very important model to study for possible adoption in other jurisdictions.

The NGC incentive scheme for reducing transmission service uplift went through several revisions, reflecting accumulated experience with forecasting and controlling uplift costs. In the latest round of revisions prior to the establishment of NETA, NGC argued that the risk profile for transmission service uplift overruns was asymmetric because the likelihood that transmission service uplift costs would increase was greater than the likelihood that they would decrease. NGC also claimed that progressively tightening the targets did not allow the company to realize in successive years the reward for efforts made in earlier years, which reduced the incentives for measures (i.e., investment) that have multi-year paybacks. The regulator saw some merit in these arguments and also agreed that as transmission services uplift is reduced, a saturation effort sets in and it becomes progressively harder to achieve further reductions. On the other hand, because NGC is acquiring greater experience in securing reductions, the regulator determined that the company should be less vulnerable to risks of higher uplift. Consequently, an incentive scheme was adopted that allows NGC to retain 50 per-

Table 5: Summary of the Salient Characteristics of the Transmission System in England & Wales

Ownership	The National Grid Company (NGC) owns most of the grid in England and Wales. In addition, NGC is the operator of the entire grid, including parts not owned by NGC. Each transmission owner must obtain a license.
Transmission tariff	The transmission pricing used by NGC is based on average zonal marginal costs in the 14 zones of the grid. In addition, there is a fixed charge that is paidby all users of the grid. The regulatory body imposes a price cap for the tariff charged by NGC (performance-based regulation).
Ownership obligations	To operate, maintain, develop, and provide an effective electricity transmission service
Transmission planning requirements	The national grid has to publish annually the Seven Year Statement, which provides a forecast of the generation, demand, and transmissions plans. This document is subject to regulatory approval. NGC is in charge of the planning and expansion of the transmission system.
Investment incentives	NGC receives incentives through capped uplift charges; because expansion/improvement of the transmission system may reduce some uplift costs, NGC may use part of the realized savings as additional profits but must also absorb part of cost overruns.
Means of recovery of new investment	Through the money collected from the transmission system rates and the money collected from uplift charges
Role of customers in transmission system expansion	The transmission customers pay for the expansion through the modified transmission rates.
Regulatory body	The Office of Gas and Electricity Markets (OFGEM)

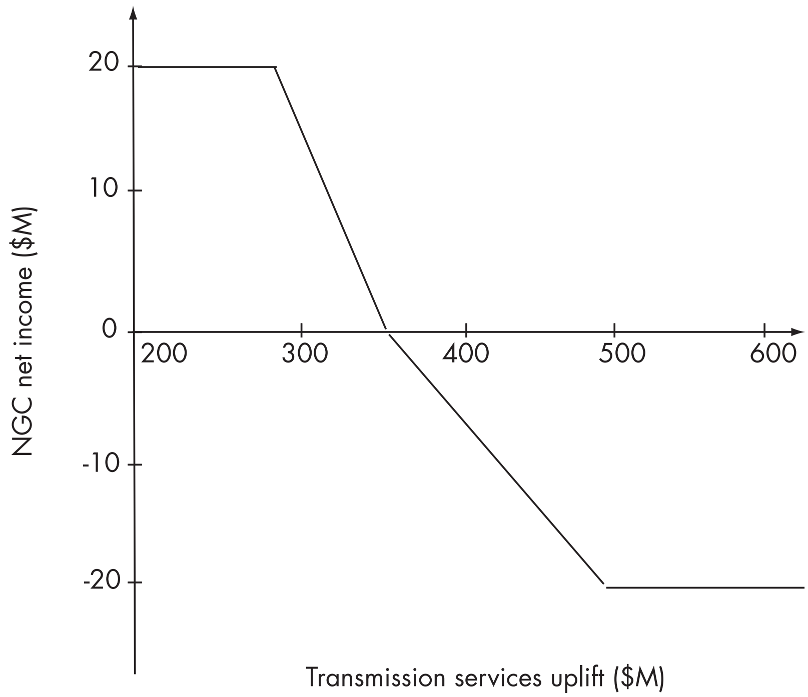
cent of uplift savings relative to the target and requires it to absorb 25 percent of any increase in uplift above the target. Furthermore, "caps and collars" were superimposed on these sharing factors, which limited NGC's risk to large variances from the target but also removed its incentive to reduce the uplift outside that range.

This transmission service uplift scheme was employed in 1998/99 with a target of $355 million and for 1999/00 with a target of $350 million. Both profits and losses were subject to a limit of $32.9 million in 1998/99 and to $34.2 million in 1999/00.[11] For the year 2000/01, the target was lowered to $322 million whereas the "cap and collar" were set to $34 million. The structure of this incentive scheme is illustrated in Figure 1.[12]

[11] In addition, NGC received extra income of about $1.5 million in 1998/99 and $0.75 million in 1999/00 to cover certain operating and capital costs.

[12] Hanney, Alex. EEE Limited (London, UK) Private communications. (November, 2001)

Figure 1: The NGC Transmission service uplift incentive scheme for 1998/99 and 1999/00



The target transmission service uplift was charged to the Power Pool[13] on a prorated daily basis (i.e., the annual quantity was divided by 365). During the year, as cumulative performance against the target became apparent, the daily amount was adjusted according to the sharing factors and the "caps and collars." The daily amounts were allocated among the settlement periods and charged to retailers on a load-share basis. Similar incentive schemes were applied to reactive power uplift and transmission losses. The success of this incentive scheme is evident Table 6, which shows a continuous decline in uplift charges (NGC 1999).

Table 6: NGC uplift charges and incentives from 1993 to 1998 in $ millions

	1993	1994	1995	1996	1997	1998
Transmission service uplift	813	633	422	412	360	337
Reactive power uplift	94	88	87	87	87	71
Transmission losses	-	-	-	229	211	212
Incentive payment to NGC	0	45	41	16	17	16

Norway

The development of a competitive commodity market in electricity in Norway has been accompanied by a deliberate and detailed regulation of the market framework by Norwegian regulatory authorities. There is strong regulation of the rights and the duties of the TSP, which is the state-owned company Statnett. Norway has chosen the TSP model, combining transmission ownership with execution of the operation/control function. The salient characteristics of Norway's transmission system are summarized in Table 7.

So far the Norwegian regulator has not prescribed any specific reliability security standard such as the loss-

[13]This description, which is given as an example of PBR, reflects the situation in the UK prior to NETA, which came into effect in mid 2001.

Table 7: Summary of the Salient Characteristics of the Transmission System in Norway

Ownership	Statnett, a state-owned company, owns about 85 percent of the national grid; 15 percent is owned by about 20 other entities.
Transmission tariff	Every user has to pay a charge, the so-called point tariff, which consists of three components: • An energy charge reflecting the value of marginal losses, • Another energy charge reflecting the costs of constraints, and • A residual element for cost recovery.
Ownership obligations	To provide nondiscriminatory access and service to all customers (independent of their size)
Transmission planning requirements	Stattnet makes a five-year forecast of all projects, and the regulatory body has to approve the projects that will be executed. Statnett and the regional grid company are in charge of planning the expansion of the transmission system
Investment incentives	The existing tariff and, for the case of radial expansion, the contribution made by the future user of the expansion
Means of recovery of new investment	Through the money collected from the tariff and through the contributions that some customers make
Role of customers in transmission system expansion	They can make contributions to financing the expansion of the system (radial lines only).
Regulatory body	Norwegian Water Resource and Energy Administration (NVE)

of-load-probability threshold, which is specified, for instance, in England and Wales. Instead Statnett has been given the responsibility to ensure "satisfactory" reliability of electricity supply and to promote a smoothly functioning electricity market with transport capability adequate for meeting market needs. More recently, Statnett was also given the responsibility for the generation/demand balance for the short and long term. The Norwegian regulator penalizes any supply interruption.

Although Statnett is not the only transmission owner in Norway—there are more than 20 owners—Statnett owns about 85 percent of the transmission grid and is interested in becoming the sole owner. The transmission grid is already operated as an integrated system with a system-wide tariff.

Statnett has responsibility for the planning necessary to ensure a sound and reliable system. Although Statnett does not have a monopoly on the construction of new lines, it is expected to take care of any needed reinforcements if regional transmission owners are not willing to expand their systems. Statnett is spearheading efforts to increase utilization of the existing system and is investigating various means to increase transfer capabilities in order to avoid or postpone major investments in new facilities. The regulatory rules require Statnett to operate, utilize, and expand the system in a way that is consistent with the needs of society.

Loss factors in the transmission tariff give incentives affecting the operation and location of generation development. Congestion management methods partly give financial incentives for increased utilization or reinforcement (counterflow trading) and partly reveal the costs to society of transmission congestion (market splitting with different area prices). The Norwegian regulator implemented revenue-cap regulation in 1997 by defining the maximum income level for grid owners. This level is reduced annually based on the regulatory assessment of grid owners' efficiency improvements. The level is also increased annually by a percentage equal to half the energy-transport growth rate. Any reductions in costs are profits to the transmission owners. Unfortunately, this scheme provides poor incentives for investment in new transmission. Nevertheless, the transmission system in Norway has operated smoothly and facilitated highly competitive electricity markets in Norway and in the interconnected NoodPool countries (Norway, Sweden, and Finland).

Summary Remarks Regarding International Experience

Among the systems examined, Norway's appears most successful to date. The combined ownership and operation/control vested in Statnett has resulted in reliable operation of Norway's transmission grid.

The applicability of the Norway model to other jurisdictions may be limited, however, for historical reasons and the unique manner in which the market in Norway has evolved. Although there are certain incentives for improvement/expansion of the Norway transmission system, they seem to be insufficient for driving new investment; instead, the large penalties that may be assessed against Statnett in case of supply interruption are far more potent than these incentives in driving the grid owners to invest in expansion/improvement. Unfortunately, the command-and-control approach of the Norway regulator is not consonant with the competition in its electricity markets. There is a markedly insufficient economic signal from the compensation scheme for new transmission investments. As a result, the need to adopt a more market-oriented scheme for transmission in Norway persists. It is expected that the transmission framework will be revised when it is reevaluated in 2002.

The incentive scheme in England and Wales may be the most appropriate paradigm for adoption by other jurisdictions. The existence of economic signals such as those given by the uplift charges collected by NGC may be useful models for creating effective incentives for expanding/improving the transmission grid. Such incentives coupled with effective PBR are worthy of further study.

The restructuring of the U.S. electricity industry has been accompanied by the advent of new players in the

For-Profit Transmission Companies and Merchant Transmission Projects in the U.S.

transmission arena—for-profit, transmission-only companies and merchant transmission projects. These new investment vehicles have been launched to showcase the critical role of transmission in the electric power business. This section briefly describes the American Transmission Company (ATC), which started operations on January 1, 2001, as an example of a for-profit, transmission-only company, and the Neptune Project of the Neptune Regional Transmission System LLC as an example of a major merchant transmission project.

ATC was created as the result of legislation enacted by the state of Wisconsin. The company owns transmission facilities in Wisconsin, Michigan, and Illinois with book value in excess of $500 million and is the first for-profit, transmission-only company to operate in more than one state. ATC was formed through the transfer of assets primarily from investor-owned utilities and capital contributions by public-power entities. The latter have fractional ownership of the company. As electric transmission is ATC's only business, its only profits are through its earnings on transmission assets.

The company became a member of the Midwest ISO (MISO), the not-for-profit RTO in the region where ATC operates. It expects to make money by providing transmission for its customers using its existing and planned facilities. ATC can make money only by saying "yes" to customer requests for transmission capacity. Its expected construction budget of more than $100 million per year for four years is quite large for a company of its size. The company wishes to take advantage of the fact that a transmission-only company can spread the costs of new construction over a greater portion of the area that will benefit from the new construction. The company expects to develop and receive FERC approval for new products for its customers. It remains to be seen whether the incentives established by the regulators will allow the company to meet its goals of ensuring cost-effective reliable transmission to all its customers with appropriate earnings for its investors.

The past two years have witnessed the proposal of several new independent speculative (merchant) transmission projects. The three most prominent are: the TransEnergie U.S. Ltd. 26-mile DC underwater cable joining Connecticut and Long Island; the 4,800-MW high-voltage direct current (HVDC) Neptune Project connecting Atlantic Canada with New England, New York, and PJM; and the expansive TransAmerica Grid project to link mine-mouth coal-fired plants in Wyoming to load centers in the Chicago and Los Angeles regions through DC lines. The Neptune Project is probably at the most advanced stage and will be used below to illustrate the key aspects of a merchant transmission project.

The basic thrust of Neptune is to connect generators in areas with plentiful supplies to loads in large metropolitan areas. The project aims to exploit the resource and load diversity of the interconnected regions and to strengthen the interconnections between the New York, New England, and PJM grids. In effect, the Neptune Project would become an integral part of the emerging Northeast RTO envisioned by FERC. The Neptune Project's May 23, 2001 filing with FERC detailed the four-phase staging of this ambitious DC submarine-cable-based grid network. The filing requested FERC's approval for the proposed open-access tariff at negotiated rates following an open-season approach to capacity reservation (FERC Docket No. ER01-2099-000). The July 27, 2001 FERC Order accepted the tariff subject to certain conditions. FERC required all Neptune Project capacity to be subject to the open-season approach to capacity reservation and thereby put an end to the project's proposed set-aside of 30 percent of capacity for bilateral negotiations. The project was mandated to join an RTO and use the RTO's tariff. FERC's Order directs the project to work with the future Northeast RTO in the design of a tariff to integrate the project's financing needs. This is a two-sided directive because the FERC July 12 Order detailing its vision for the Northeast RTO stated unequivocally that its "long-term competitive goals are better served by RTO expansion plans that allow for third-party participation as well as merchant projects outside the plan." FERC directed PJM to develop revised procedures so that "third parties may participate in constructing and owning new transmission facilities." The FERC directive clearly puts out a welcome mat for merchant transmission projects.

The July 27, 2001 FERC Order dealt a death blow to the project's request to include compensation in the tariff for system benefits on the existing transmission system. However, negotiations with the future Northeast RTO may result in compensation for the increase in available transfer capability in the existing network resulting from the new facilities if the parties can design the RTO tariff to explicitly or implicitly accommodate this compensation. The project will know the stream of revenues it may expect once the open season for capacity reservation is completed.

The FERC open-door policy for merchant transmission may considerably change the nature and structure of the transmission grid in the U.S. Unless carefully crafted initiatives/policies are formulated, the grid may face the threat of Balkanization. This threat could result in opportunistic expansion along the profitable paths while neglecting the reliability of the remaining grid. Such "cherry picking" reduces the investment incentives for investors willing to undertake a more comprehensive regional expansion plan. Steps will be required to ensure that commensurate improvements of the other parts of the grid are undertaken so no grid customers are disadvantaged.

"Straw Man" Business Models

Two of the business model variations described in the section "The Range of Options of Business Models," on page C-4, represent the main advantages of the separate ownership and control and joint ownership and control approaches. The nonprofit ISO that controls assets owned by regulated TOs represents the business model that currently prevails with separate control and ownership of transmission assets. At the other extreme is the for-profit ITC. These two models have been at the center of the national debate concerning the preferred business model for RTOs. Much of that debate has not been specific about the key weak points of each model:

- The nonprofit ISO model implemented in several systems in the U.S. lacks a market-based mechanism to attract transmission investment. In fact, the California ISO has just issued a contract for the development of methodology for market-based evaluation of transmission investment proposals.
- Most characterizations of ITCs allude to PBR schemes but do not specify details.

The subsections below present "straw man" versions of these two business models for the purpose of fleshing out the possibilities inherent in the separate ownership and control and combined ownership and control organizational structures.

Nonprofit ISO Controlling Transmission Assets Owned by Regulated TOs

This section describes two variants of a business model in which a nonprofit ISO operates and controls the transmission assets owned by TOs and manages congestion in real time by dispatching balancing energy resources using a security-constrained, bid-based economic procedure. These variants roughly represent the designs implemented at PJM and ERCOT, with the addition of a mechanism for fostering market-based transmission investment. Under these models, users of scarce transmission resources who schedule energy transactions through the ISO are charged a real-time congestion fee that represents a "scarcity rent" for the use of these resources. That scarcity rent also reflects the incremental cost of relieving congestion through counterflow, which results from dispatch of generation resources out of merit (i.e., dispatching more expensive energy ahead of less expensive energy). In principle, any congestion problem has a "generation solution," which amounts to creating counterflow on the congested interface, and a "wires solution," which requires investment in transmission assets. From an economic perspective, the optimal amount of transmission capacity is achieved when the marginal cost of the generation solution and that of the wire solution are equal. This equality represents the optimum solution from a social perspective, i.e., the total of consumer and producer surplus is maximized; however, there is no guarantee that the consumer surplus increases at this solution. Transmission capacity mitigates market power, so it is possible that additional capacity may benefit consumers by facilitating trading and reducing energy prices although such investment need not be optimal from a total welfare perspective. It is also possible that a transmission expansion that is socially desirable may disadvantage some consumers by increasing their energy costs.[14]

In current nonprofit ISO structures, the ISO has responsibility and authority for transmission planning, but the investments are made by the TOs. The ISO can order a TO to build transmission facilities and has the authority to evaluate and authorize construction of facilities proposed by investors. These planning and evaluation activities are predominantly driven by reliability considerations. Investments in new transmission assets that are approved by the ISO are transferred to ISO control and receive compensation on a regulated-rate-of-return or cost-of-service basis in the same way as is true for existing facilities. The funds required for compensating TOs are collected by the ISO through the sale of transmission rights, congestion charges, connection charges, and energy-based uplift charges.

We explore next the options for economics-based transmission investment in the context of a nonprofit ISO. The basic idea in an economics-based transmission investment paradigm is that efficient investment in capacity[15] is aimed at reducing scarcity of capacity resources up to the point at which the socially optimal capacity level is achieved and such investments can still be financed by scarcity rents. Hence, all we need is to establish a system of property rights to the transmission system and a mechanism that will allow investors in new capacity to collect the appropriate scarcity rent for that capacity. Then, investors will have the incentive to put up the capital for capacity expansion and the scarcity rents that they will collect will be sufficient to finance that investment as long as the wires solution is more economical than the generation solution.

Consider a simplified world with no externalities where a transmission line connecting two locations could be expanded in small increments by adding individual fibers to the line. If the capacity of the line is scarce, users will be charged a congestion fee. By adding fibers to the line, the investment results in increasing the flow and would be entitled to collect the congestion fee for the additional flow. As long as that revenue exceeds the financing cost of the capacity expansion, investors are motivated to add more capacity. However, as more capacity is added, scarcity rents may drop until the rent for shipping another MW of power across the transmission line exactly covers the financing cost for adding one more MW of transmission capacity. Because the scarcity rent reflects the marginal cost of dispatching energy out of merit in order to relieve congestion on the line, the level of capacity at which the congestion rent exactly covers the financing costs is also

[14]An example of this possibility is described in the Issue Paper, *Transmission System Operations and Interconnection,* by F. Alvarado and S. Oren.
[15]We use the word "capacity" loosely; capacity refers to an increase in the transfer capability of the transmission system.

the socially optimal capacity level at which the marginal cost of a wires solution equals the marginal cost of a generation solution. Clearly, under this scheme it is never socially optimal to add transmission capacity to the extent that it will eliminate congestion completely even though that might be desirable from the perspective of facilitating trade and mitigating market power.

In the next subsections, we apply the above principles of economics-driven capacity expansion in the context of two variants of nonprofit ISO operation.

The nodal pricing/forward financial transmission right approach (the PJM model)

In this variant, the ISO operates an energy spot market where locational marginal energy prices are based on a security-constrained, bid-based, optimal dispatch. Congestion charges for a point-to-point transaction are priced at the opportunity costs given by the locational price difference between the two points. Point-to-point forward financial transmission rights (FTRs) take the form of financial instruments that entitle their holders to the locational price difference times the number of rights (in MW units) over the specified time interval. This instrument is *equivalent* to a physical right because it enables its holder to execute a point-to-point transaction and offset the congestion charges with the FTR revenues. FTRs are auctioned off by the ISO periodically for different time horizons. The FTRs that are issued must satisfy simultaneous feasibility conditions, which require that if all FTR holders were to use their rights by scheduling corresponding transactions, these transactions would be feasible without impacting the security of the system. This simultaneous feasibility condition guarantees that the congestion revenue collected by the ISO can cover the FTR settlements.

An idealized market-based approach to transmission investment can be implemented within the above framework by simply awarding transmission investors an appropriate number of FTRs that will reflect the enhancement provided by their investment.[16] These awards can capture all the external effects of the expansion. Awarding the investor a portfolio of FTRs that reflects the incremental transfer capabilities between the different nodes can accomplish this goal. If the transfer capability between some pairs of nodes has been reduced by the expansion, the corresponding FTRs must be taken off the market and the market value of those FTRs debited from the investor's award. If the investment is socially efficient (i.e., it costs less than a generation solution to the congestion problem it solves), the settlement income of the awarded FTRs should provide sufficient funds to finance the investment. The portfolio of FTRs that represents the increase in transfer capabilities of the grid from expansion of even a single line is not unique. Hence investors may be allowed to choose the FTR portfolio that provides them appropriate compensation for their investment.[17]

The above approach may work for relatively small incremental investments that will not have a major impact on the market value of the FTRs. Its major shortcoming is that is does not correspond to the reality of transmission investments, which are lumpy. The incremental addition of fibers, while a useful metaphor to explain the concepts involved, is unrealistic. The addition of capacity will likely eliminate the congestion as well as the congestion rents that are supposed to provide the income stream to finance the investment. The effect of lumpiness and the perceived risk associated with a cash flow resulting from FTR settlements may discourage investors from accepting FTRs in lieu of a stable income stream. Thus, major investments in transmission will

[16]This description follows the work of Hogan (1999), who articulates this approach and the resolution of some obvious shortcomings in detail.

[17]The details of such a procedure are described by Bushnell and Stoft 1996.

still require regulatory approval and some form of cost-based rate-of-return regulation. Nevertheless, even if FTRs cannot serve as an investment compensation, FTR market prices provide important market signals for transmission investment and should be taken into consideration in transmission planning activities.

An interesting, although potentially controversial, resolution to the lumpiness problem has been proposed by Hogan (1999), patterned after the treatment of patents and intellectual property. This scheme would allow investors in transmission to withhold a portion of the capacity they install for a limited time period to maintain an "optimal" level of congestion that will sustain the market value of the FTR they obtain and thus allow them to recover their investment costs. This scheme is similar to the approach used in awarding patents on drugs, which allows drug companies to collect monopoly profits during a limited time period in order to recover R&D costs. Implementing such a scheme would be relatively easy. The investor would instruct the ISO about the capacity the investor wishes to release to the ISO, and the ISO would adjust the constraint it uses in its economic dispatch algorithm accordingly (effectively derating the line). The investor would get FTRs only for the capacity released. The investor would not have an incentive to abuse the system and withhold more capacity than needed to recover the investment cost because such excessive withholding might result in higher FTR values that may attract additional investment, and that would undermine the investor's objective of maximizing profits. At least in theory, an investor would be motivated to release to the ISO what would have been the optimal amount of capacity expansion absent the lumpiness issue.

The zonal pricing/flowgate approach (the ERCOT model)

The wide variation in real-time nodal prices resulting from security-constrained, bid-based economic dispatch can often be traced to a small number of constrained elements in the transmission system, referred to as flowgates.[18] Although the above observation may be true at any point in time, it is debatable to what extent flowgates are persistent and predictable. The congestion management system adopted in California and by ERCOT and under consideration in some emerging RTOs is based on the premise that most congestion occurs at a limited number of predictable bottlenecks. If this premise is reasonable, then it is possible to design a pricing system based directly on the marginal value of the individual congested facilities and a corresponding system of property rights with respect to these facilities. This approach, sometimes called the "flowgate" rights (FGR) approach, is dependent, however, on knowledge of the Power Transfer Distribution Factors (or PTDFs).[19] Under this scheme, transmission users schedule transactions with the ISO, and the ISO employs incremental and decremental energy bids to relieve congestion and meet security constraints at least cost. Transmission users are charged a congestion fee based on the fraction of their scheduled transaction that flows on the designated commercially significant constraints (CSCs). The charge per MW flow on a CSC is set to the shadow prices (i.e., marginal value) on capacity of the CSCs ,which reflects a scarcity rent. These shadow prices are also equal to the marginal cost of relieving congestion on the CSC through deployment of balancing energy to produce counterflow. For the case of radially connected flowgates, this model leads naturally to a zonal pricing structure. For other cases, it is equivalent to a nodal pricing system unless a zonal approximation is created for the resulting prices.

---

[18]Even one congested element may result in different prices at every node in the system.
[19]For a detailed discussion of the flowgate approach to congestion management, see Chao, Peck, Oren, and Wilson (2000).

Transmission rights take the form of flowgate rights which are rights, denominated in MW, that entitle the holder to a payoff equal to the shadow price on the corresponding CSC. In most cases, it is quite simple to define these rights as directional rights (i.e., they have value only if transmission capacity is scarce in the designated direction of the right). A user of the transmission system can fully hedge the congestion fee for a transaction by holding a portfolio of FGRs that reflects the distribution of flow on the CSCs induced by the transaction. It that case, the FGR settlement revenue exactly offsets the congestion fee.

Capacity expansion in this variant of the nonprofit ISO business model (implemented in Texas and California) is based on a planning and approval process run by the ISO and driven by considerations of reliability. The ISO can order capacity expansion and has the authority to approve investments proposed by TOs. Approved investments are compensated through a cost-based, regulated rate of return.

Applying the market-based transmission investment paradigm in the FGR is context would be simpler than in the nodal pricing case because for the FGR approach the externalities have been priced out. The shadow price on a CSC reflects exactly the marginal value of adding one MW to the flow limit on that CSC. Consequently adding one MW of capacity to a CSC can be directly rewarded with a one-MW FGR on that CSC, and the income from that FGR covers the financing of the incremental investment as long as the investment is socially efficient. An investment is deemed inefficient when the shadow price reflecting the marginal value of the incremental capacity or equivalently the marginal cost of producing counterflow through procurement of balancing energy exceeds the amortized investment cost for expanding the capacity of a CSC. Incidentally, because the FTR (full nodal) pricing system is fundamentally equivalent in its valuation structure to the FGR approach, a corresponding analysis can be performed for the FTR case.

As in previous examples, a major obstacle to market-based investment is the lumpiness of capacity expansion projects, which prevents investors from being able to exactly gauge the appropriate amount of transmission expansion so that the FGR revenues pay off the financing costs of the project. The FGR prices provide a useful market signal for capacity expansion that should be taken into consideration in planning and evaluating investments; however, regulatory intervention is needed to guarantee an appropriate return on investment. The alternative of allowing withholding of the capacity for a limited time horizon so that investors can recover their investments through FGR settlement revenues applies here just as in the FTR case.

It is worth noting that FTR and FGR become identical in the case of a radial AC system or a controllable DC transmission link between two nodes. In both cases, the entire flow resulting from a point-to-point transaction moves through the line. One may interpret FGR as an attempt to treat the expansion of a transmission interface as if it were a merchant DC expansion for the portions of the flow that go through that line. However, unlike the case of controllable DC merchant lines, there is no one-to-one correspondence between the added capacity and the increased point-to point transfer capability. A trader would need to acquire FGRs on multiple lines impacted by the trader's transaction in order to be hedged against congestion charges. Therefore, a merchant investor in a nonradial AC interface cannot finance investments by directly selling capacity on its merchant line as is the case for the Neptune and TransEnergy projects described on page C-25.

The For-Profit ITC

Although no for-profit ITCs exist in the U.S. to date, several proposals have been developed in response to FERC Order No. 2000. In this model, we envision a company of sufficient regional scope to internalize many of the externalities associated with its transmission operations. The ITC owns or leases and operates most of its transmission resources.[20] The ITC is independent (as spelled out in the FERC Order No. 2000) of any generator, wholesale energy trader, or distribution company, and it operates as a regulated monopoly responsible for transmission operations, maintenance, and investment. Such an ITC would typically be created by divestiture of facilities from one or more vertically integrated utilities to form an independent company. If a single company divests all its transmission assets, the process of setting up the ITC is conceptually simple, akin to any divestiture except that the value of the assets will be determined by existing and anticipated regulation, and the divestiture itself will require regulatory approval. In the U.S., the more likely scenario is that several utilities would divest their transmission assets to form an ITC.[21]

Whether the assets of an ITC are divested from a single company or from multiple owners, their valuation depends on the regulatory rules regarding rates, profits, and any operational constraints imposed on the ITC. The key issue here is that the vertical integration of ownership and control internalizes some of the externality between investment and operation. This enables the regulator to devise a reward scheme that appropriately reflects the output of the ITC, i.e., the transmission service it provides, rather than the costs of its assets. As indicated earlier, it is unlikely that an incentive scheme can be devised that induces the ITC to selfishly produce a set of operating rules that are consistent with FERC's open-access orders and with social efficiency objectives. The regulatory regime imposed on the ITC determines the constraints it faces and its profitability. ITC regulation must be compatible with FERC's Orders Nos. 888 and 2000 and provide incentives and constraints that will induce the ITC to operate the transmission network to foster efficient short-term energy markets. It should also be compatible with the financial viability of the ITC and with long-term incentives for the ITC to invest in and maintain the transmission network.

The goal should be to move ITC regulation toward a performance-based approach; this goal can be approached in an evolutionary manner, starting with an ROR strategy that will evolve into PBR. The ROR phase can provide a training ground for the subsequent PCR phase in which price caps can be benchmarked against the immediately preceding ROR regime. Initially, the PCR might include constraints on the allowed rate of return in the form of profit-sharing bands. Over time, as the ITC and the regulator develop a better understanding of the risks involved, these profit-sharing bands can be relaxed until they disappear altogether, leaving the price cap to assure proper incentives and reasonable consumer dividends.

Whether under ROR or PCR, the ITC can offer more than one service, and each service may have a complicated cost structure. Thus, the ITC needs flexibility to change individual prices to accommodate changing customer needs, subject to an overall profit or price constraint. For this straw man business model a price

[20]This model follows closely the ITC vision articulated in Awerbuch, Hyman, and Vesey (1999) and Awerbuch, Crew, and Kleindorfer (2000).
[21]In California, for instance, the recent electricity crisis provided a golden opportunity for the formation of an ITC. There was discussion about the state purchasing the transmission assets of PG&E and Southern California Edison to provide these companies cash that would enable them to pay off their debts.

structure that consists of a three-part tariff, as described by Awerbuch, Crew, and Kleindorfer (2000) has the components:

- A fixed access charge, levied on loads. This charge depends on the system's ability to offer access (capacity) to customers. Such a charge gives the company an incentive to add customers or capacity in the most economical manner because these factors increase access charge revenues and are not a return on rate base.

- A MW-based priority injection rights fee or congestion charge, levied on generators. The revenues from this charge can be used to help manage congestion. These fees do not go to the ITC but are used as offsets against access charges, which eliminates a potentially perverse incentive for the ITC to perpetuate congestion in order to collect more congestion fees.[22]

- A MWh throughput charge levied on loads for each MWh delivered. This reflection of system usage provides the ITC with incentives to use its assets more efficiently. This charge may be varied by node, zone, time of day, etc. to better reflect the marginal costs of transmission.

By properly adjusting the weights between the access and energy charges in the price cap formula and accounting for regulatory lag between adjustments, it is possible to provide incentives to the ITC to make the investments necessary to relieve congestion. This classic PBR approach has been employed in the telecommunications industry. The basic principle is that it is more profitable for the firm to meet its price cap through usage revenues than through access revenues. This creates an incentive for the firm to relieve congestion in order to increase transaction volume on the transmission network.

Options

In the preceding sections, we examined a variety of alternative business models for transmission and issues associated with these models. One important message that emerges from this examination is that there is no perfect business model for transmission. The "best" model in any given situation depends on the ownership structure and regulatory environment that form the context for the creation of the transmission entity. Therefore, rather than prescribing particular models, we define ultimate goals that could be selected to guide short-term actions and set an agenda for change in transmission business models. The options we outline below are not mutually exclusive but are intended to emphasize different key points.

Option 1

Move toward regional consolidation of transmission assets under the control of for-profit regulated independent transmission companies that will be subject to PBR and will have the authority and responsibilities

[22]The details of this scheme are described in Deng and Oren (2001).

of an RTO, including the planning and financing of new transmission investment. This option may require legislative initiatives to empower FERC to order divestiture of privately owned transmission assets and enable the divestiture of transmission assets owned by public power entities, including federal power authorities and municipal utilities. It would also require modifications to the existing statues to exempt transmission assets funded through tax-free bonds from private-use rules.

Option 2

Initiate congressional legislation and tax reform that will enable publicly owned transmission assets including those owned by federal power authorities and municipalities to be put under the full operational control of RTOs for unrestricted commercial use. Empower the RTOs to plan, authorize, and order transmission expansion and finance this expansion through a federally mandated, energy-based surcharge.

Option 3

Initiate organic growth of independent transmission companies by spinning off transmission assets owned by federal power authorities (e.g., TVA) to form the core of a voluntary transmission-owners consortium that would operate as a for-profit ITC, subject to PBR and with the authority and responsibilities of an RTO. The profit share resulting from the federally owned transmission assets can be channeled into the federal power authority. This option would still require congressional legislation altering the mandate of the federal power authorities and relevant tax reforms.

Option 4

Have nonprofit RTOs operate transmission assets that have multiple owners. Investment and innovation would be left opportunistic, with merchant DC and AC transmission-expansion initiatives subject to approval by the RTO. Merchant investment would be financed through transmission rights issued by the RTO as entitlements to congestion rents or to physical capacity. Additional investment for expansion needs identified by the RTO could be solicited and financed on a cost basis through rate increases, subject to state regulation. A federal energy surcharge (similar to a gasoline tax for financing highway construction) can provide an alternative financing mechanism for RTO-initiated transmission expansion subject to FERC approval. (This option is closest to the current situation in the U.S.)

Summary and Conclusions

This paper describes the issues that must be considered in adopting a business model for a transmission service provider. Many dimensions must be accounted for, and there is an ongoing debate, in the context of FERC's RTO initiatives, over the merits of competing models. The key issues that distinguish the models are whether or not control and ownership of transmission assets are vertically integrated and whether the TSP operates as a for-profit or nonprofit enterprise. The two extremes that have been the focus of the ongoing debate are the nonprofit ISO that operates transmission assets owned by regulated transmission assets owners and the for-profit regulated ITC that owns and operates transmission assets. With few exceptions, most of the material previously written on this topic advocates one model or another. This paper delineates the issues involved in the variations on these two general models, describes a broad range of options, and presents the pros and cons of the alternatives based on positions expressed by experts on both sides of the debate. The paper also reviews approaches that have been adopted in other countries and the resulting experiences. The fundamental question remains: what is the best way to provide incentives and finance investment in the transmission system, which has not kept up with the generation sector and the increased demands for transmission services resulting from restructuring of the electricity industry in recent years.

Of the various options for business models described in the previous section, Option 4 is the closest to the current state of affairs. Unfortunately, reliance on merchant expansion alone is unlikely to produce sufficient investment in transmission, and cost-based remuneration of new investment fails to adequately recognize the risks perceived by investors.

The fact that even a relatively large increase in transmission investment would result in modest increases in customers' electricity bills while having great potential benefits for efficiency, reliability, commerce, and mitigation of market power suggests that we should err on the side of overinvestment in transmission to enhance trade and increase system reliability. Such investment should therefore be encouraged through PBR that offers incentives for additional capacity by allowing the investor to share in the value added by such capacity to the system in terms of improved reliability and increased trading. Such an approach can only be implemented when operation and investment are controlled by the same entity, which can profit from the added value. A scheme like that found in the UK, which allows the transmission company to share in the gain from reducing congestion uplift cost. This type of scheme could not be implemented when congestion management is under the control of a nonprofit RTO that passes congestion costs through to consumers and neither bears any of the cost of capacity expansion nor shares in any benefits from congestion reduction.

It is the authors' opinion that Option 1 presents the most promising business model to serve the transmission sector in the long term since it is amenable to performance based regulation and enables compensation of transmission assets based on their value rather than cost. Option 2 is a partial but necessary step toward achieving the goals of Option 1, and Option 3 is less desirable because of its limited scope but could represent a pragmatic starting point that would enable us to experiment gradually and on a limited scale with the

References

notion of a regional, for-profit ITC.

Awerbuch, S., M.A. Crew, and P.R. Kleindorfer. 2000. "Transmission—Enabler of Wholesale Competition" in *Expanding Competition in Regulated Industries,* ed. Michael Crew. Boston MA: Kluwer Academic Publishers, May, pp. 23-40.

Awerbuch, S., L.S. Hyman, and A. Vesey. 1999. *Unlocking the Benefits of Restructuring: A Blueprint for Transmission.* Vienna VA: Public Utilities Reports, Inc.

Bushnell, J.B. and S.E. Stoft. 1996. "Electric Grid Investment under a Contract Network Regime." *Journal of Regulatory Economics,* Vol. 10: 61-79.

CAISO. 1999. "Annual Report on Market Issues and Performance", June.

Chao, H., S. Peck, S. Oren, and R. Wilson. 2000. "Flow-based Transmission Rights and Congestion Management." *Electricity Journal,* October.

Deng, S. and S.S. Oren. 2001. "Priority Network Access Pricing for Electric Power." *Journal of Regulatory Economics,* Vol 19, No. 3: 239-270.

FERC. 2001. Docket No. ER01-2099-000.

Hanney, A. 2001. EEE Limited (London, UK). Private communications. November.

Hogan, W.W. 1999. "Market-based transmission investments and competitive electricity markets." Harvard University: Center for Business and Government, August.

Hyman, L.S. 2001. Personal communication, October.

Joskow, P.L. 1999. "Comments before the Federal Energy Regulatory Commission." FERC Docket No. RM99-2-000, August 16.

NGC. 1999. *Transmission Services Uplift and Reactive Power Uplift Schemes: Initial Proposals: A Consultation Document.* London UK: Office of Electricity Regulation Publications. August.

Supplemental Bibliography[21]

Abdala, M. and A. Chambouleyron. 1999. "Transmission Investment in Competitive Power Systems. Decentralizing Decisions in Argentina". *Public Policy for the Private Sector.* Note 192.

Boyce, J.R. and A. Hollis. 2001. "Governance of Electricity Transmission Systems," University of Calgary, Department of Economics. August.

Christie, R. and I. Wangensteen. 1998. "The Energy Market in Norway and Sweden: Introduction". *Power Engineering Review*.

Cook, A.S. and R. Coxe. "A Review of Commercial Frameworks for Networks Investment in Competitive Power Markets."

Cura, E. 1998. "Tarificación de Sistemas de Transmisión Eléctrica: Evaluación de Metodologías de Asignación de Cargos Complementarios". Master Thesis. *Pontificia Universidad Católica de Chile*.

Gómez, T. "The Regulation of the Argentine Power Sector. Case Study." *Instituto de Investigación Tecnológica. Universidad Pontificia Comillas.*

Hogan, W.W. 2000. "Regional Transmission Organizations: Millennium Order on Designing Market Institutions for Electric Network Systems"(May).

---

[21]These references were reviewed in preparing this document but no specific citation is given in the text

Hogan, W.W. 2001. "Interregional Coordination of Electricity Markets," FERC Technical Conference on Interregional Coordination, Washington DC (June 19).

Hyman L., S. 2000. "Without It, The Lights Go Out." Report to Salomon Smith Barney (October).

The Keystone Center. 2000. "The Keystone Dialog on Regional Transmission Organizations," Washington DC (July).

Kleindorfer, P.R. 1998. "Ownership Structure, Contracting, and Regulation of Transmission Servics Providers," In *Designing Competitive Electricity Markets,* Chao and Huntington eds.Boston: Kluwer Academic Publishers. pp. 63-78.

Michael, R.J. "Can Nonprofit Transmission Be Independent?", *Regulation,* Vol 23, No. 3, pp 61-66.

Michael, R.J. 1999. "The Governance of Transmission Operators," *Energy Law Journal,* Vol. 20, No. 2.

Ministerio de Minería. Chile. 1982. DFL 1/82.

Ministerio de Minería. Chile. 1998. DS 327.

NERA. 1988. "Current Network Arrangements". A report for National Electricity Code Administrator. Australia.

NERA. 1988. "Principles of Efficient Pricing for Transmission and Distribution." A report for National Electricity Code Administrator. Australia.

Oren, S.S. 1998. "Authority and Responsibility of the ISO: Objectives, Options and Tradeoffs," pp. 79-98. In *Designing Competitive Electricity Markets,* Chao and Huntington eds., Boston: Kluwer Academic Publishers.

Palmer, R. 1997. "Transmission Network Privatization-Pricing, Investment and Access." *Power Engineering Journal*.

Palmer, R. "Network Pricing, Investment and Access. Experience—The England and Wales Network." The National Company Plc.

Rudnick, H. and J. Zolezzi "Expansión de los Sistemas de Transmisión en Mercados Competitivos de Generación." Departamento de Ingeniería Eléctrica. Pontificia Universidad Católica de Chile.

Rudnick, H. "Transmission Open Access in Chile." Departamento de Ingeniería Eléctrica. Pontificia Universidad Católica de Chile.

Rudnick, H. "Planificación y Expansión de los Sistemas de Transmisión en Mercados Eléctricos Competitivos." Departamento de Ingeniería Eléctrica. Pontificia Universidad Católica de Chile.

Tabors, R. 1996 "Lessons from the UK and Norway." *IEEE Spectrum*.

TransGrid. 2000. "New South Wales Annual Planning Statement."

http://www.neca.com.au

http://www.nemmco.com.au

http://www.transenergie.com.au

http://www.tg.nsw.gov.au/

http://www.gov.enre.ar

http://www.cammesa.com.ar

http://www.cne.cl

http://www.cdec-sic.cl

http://www.cdec-sing.cl

http://webben.nve.no/english/

http://www.nationalgrid.com/uk/activities/mn_transmission.html