March 15, 2005

PATTERNS OF TRANSMISSION INVESTMENT

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ABSTRACT

This paper examines a number of issues associated with alternative analytical approaches for evaluating investments in electricity transmission infrastructure and alternative institutional arrangements to govern network operation, maintenance and investment. The economic and physical attributes of different types of transmission investments are identified and discussed. Alternative organizational and regulatory structures and their attributes are presented. The relationships between transmission investments driven by opportunities to reduce congestion and loss costs and transmission investment driven by traditional engineering reliability criteria are discussed. Reliability rules play a much more important role in transmission investment decisions today than do economic investment criteria as depicted in standard economic models of transmission networks. These models fail to capture key aspects of transmission operating and investment behavior that are heavily influenced by uncertainty, contingency criteria and associated engineering reliability rules. I illustrate how the wholesale market and transmission investment frameworks have addressed these issues in England and Wales (E&W) since 1990 and in the PJM Regional Transmission Organization (RTO) in the U.S. since 2000. I argue that economic and reliability-based criteria for transmission investment are fundamentally interdependent. Ignoring these interdependencies will have adverse effects on the efficiency of investment in transmission infrastructure and undermine the success of electricity market liberalization.

JEL Classifications: L51, L14, L43, L94

[1] I am grateful for comments on an earlier draft from Ignacio Perez-Arriaga, Jean-Michel Glachant, Yves Smeers, and Richard Green. The Commission de Régulation de l'Énergie (France) and the MIT Center for Energy and Environmental Policy Research have provided research support. Any errors in the theoretical and empirical analyses and all conclusions are my responsibility.

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INTRODUCTION

A transmission network with good performance attributes is essential to support well-functioning competitive wholesale and retail markets for electricity. The transmission network allows decentralized generators, marketers, distributors and large consumers to trade power in competitive markets. It can expand the geographical expanse of competition among power suppliers, giving consumers access to lower cost energy and operating reserves. By expanding the geographic expanse of competition the transmission network can increase the effective number of competitors and reduce market power and thus prices. A well functioning transmission network facilitates the entry of new generators to match demand and supply efficiently at different network locations to achieve economic and reliability goals and supports the development of demand response options for wholesale and retail market participants.

Electricity sector liberalization has not changed the physical constraints or physical laws that govern reliable transmission network operation or its role in supporting economical supplies of electricity. The network must still satisfy the same physical parameters and constraints (frequency, voltage, stability, coordination with interconnected networks) and provide for operating reserves to respond to uncertain realizations of demand and unplanned outages of equipment to maintain these reliability and avoid major losses of load or a widespread network collapse. However, electricity sector liberalization has necessitated changes in the organization of the electric power sector and the tools available to operate the network economically and reliably and to stimulate investment in the network to reduce congestion and maintain the physical integrity of the network.

Implementing effective transmission investment policies has proven to be especially challenging as countries liberalize their electricity markets. In the U.S., transmission congestion has increased and barriers to needed transmission investment are perceived to be a growing problem. Transmission Line Relief orders (TLRs) in the Eastern Interconnection have grown by a factor of 5 since 1998 (Figure 1). Congestion charges in the traditional PJM area grew by a factor of 10 between 1998 and 2003 (Table

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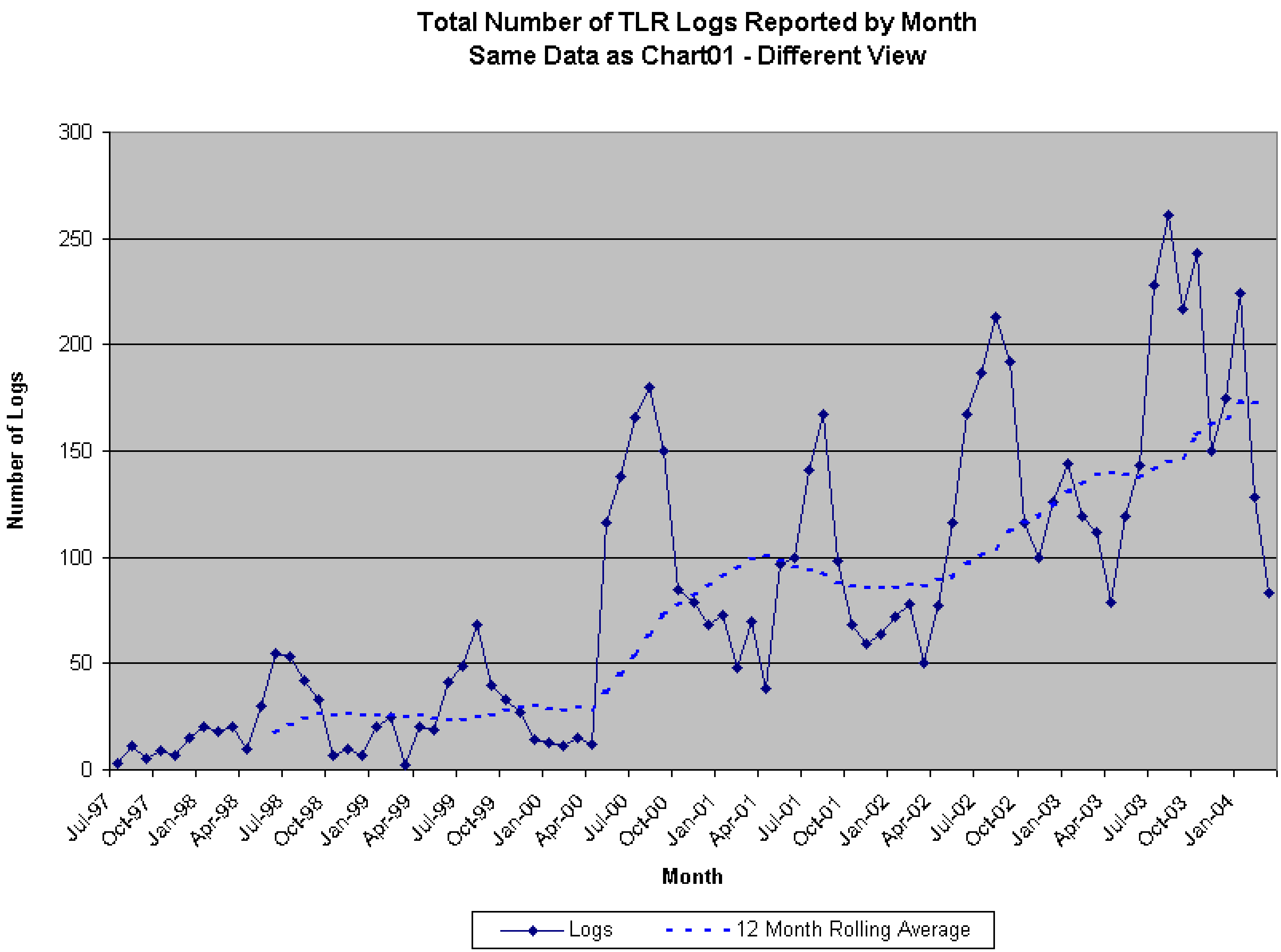
FIGURE 1



Source: NERC

TABLE 1
PJM CONGESTION CHARGES
($ millions)

1999	53
2000	132
2001	271
2002	430
2003	499
Aug 03-Sept 04[1]	1,612

Source: PJM *State of the Market Report 2002 and 2003*

[1]PJM congestion spreadsheet 12/4/04. Data may not be comparable due to expansion of PJM

TABLE 2
CONGESTION CHARGES IN NEW YORK

2001	$310 million
2002	$525 million
2003	$688 million

Source: New York ISO

1). Congestion charges in the New York ISO have more than doubled since 2001 (Table 2). Congestion has grown rapidly in Texas (ERCOT), Southern California and New England as well. At the same time, investment in new transmission capacity has lagged the growth in electricity demand and the growth in new generating capacity (Hirst, 2004). In Europe, as wholesale power trading has grown, transmission congestion limits the geographic expanse of competition, limits opportunities fully to exploit generating capacity with the lowest operating costs, has led to concerns about generator market power within several countries (Newbery, 2004) and has created reliability challenges. As market liberalization proceeds, there has been very little investment in inter-TSO transmission capacity in Europe or the U.S. Intra-TSO congestion is a growing problem in some European countries as well (Serrani, 2004; Figures 2A, 2B, 2C). Policymakers in many countries with competitive power markets are increasingly concerned about reliability problems and reliability considerations are playing an increasingly important role at the interface of wholesale market design, transmission pricing, and transmission investment policies.

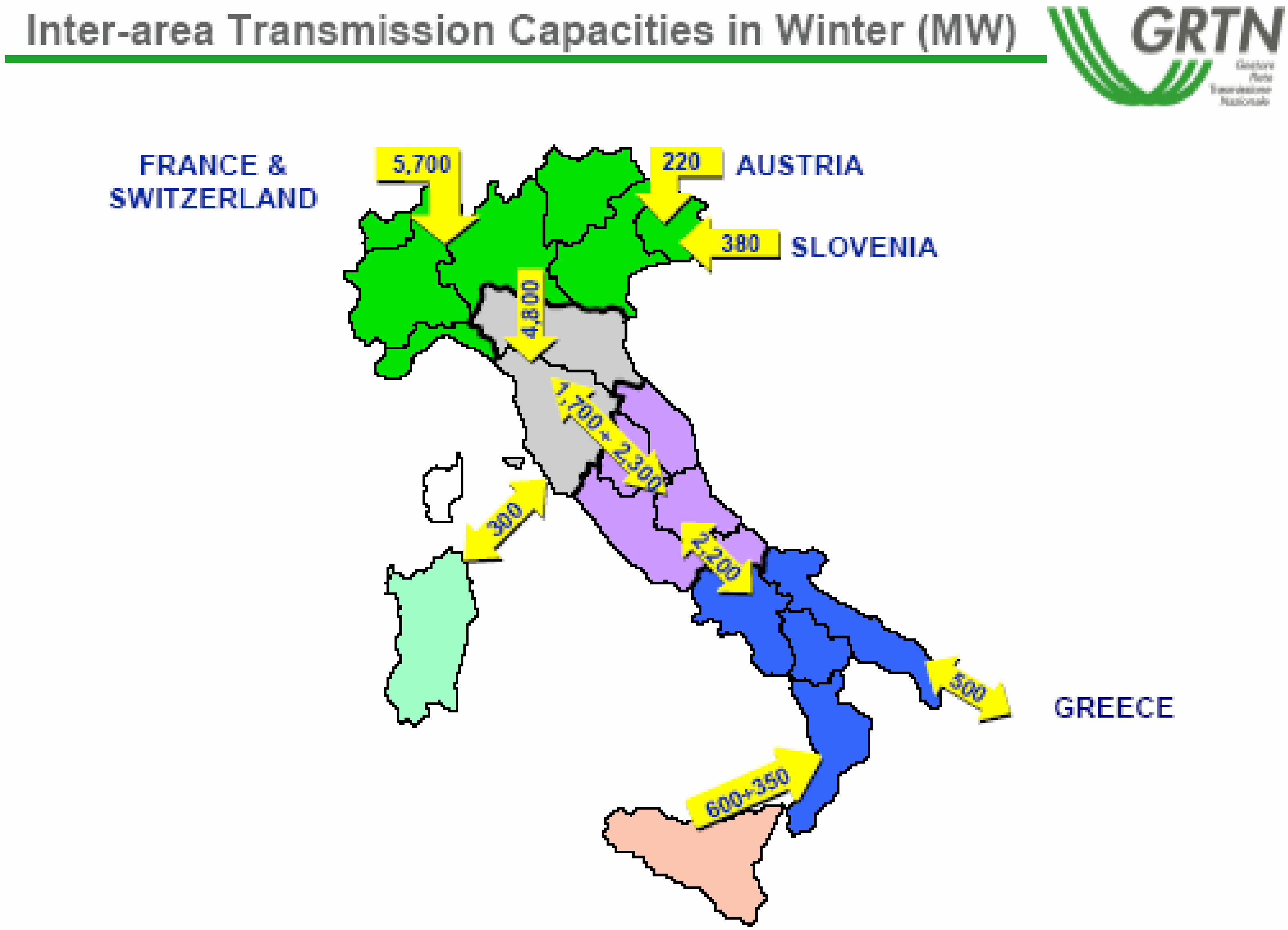
In this paper I discuss a number of issues associated with the creation of an institutional environment that supports the identification of and efficient investment in transmission infrastructure. I illustrate how the wholesale market and transmission investment frameworks have addressed these issues in England and Wales (E&W) since 1990 and in the PJM Regional Transmission Organization (RTO) in the U.S. since 2000 in operation in these areas. I am led to the following conclusions:

1. The simple models of transmission network congestion and investment that are used by economists have little to do with the way transmission investment is actually planned, developed, and the associated transmission services priced within the boundaries of individual TSOs today. Economic models and analysis need to be expanded to better capture the factors that TSOs and regulators consider when they identify transmission investment needs, especially as they relate to the implementation of reliability criteria used for network investment planning and system operations.

2. The application of a set of complex electric power network models, engineering reliability criteria, and simulation studies using these models guide almost all intra-TSO transmission investment that is taking place around the world today. Commonly used economic models of transmission networks and transmission investment opportunities do not capture these reliability criteria or their application adequately, if they do so at all.

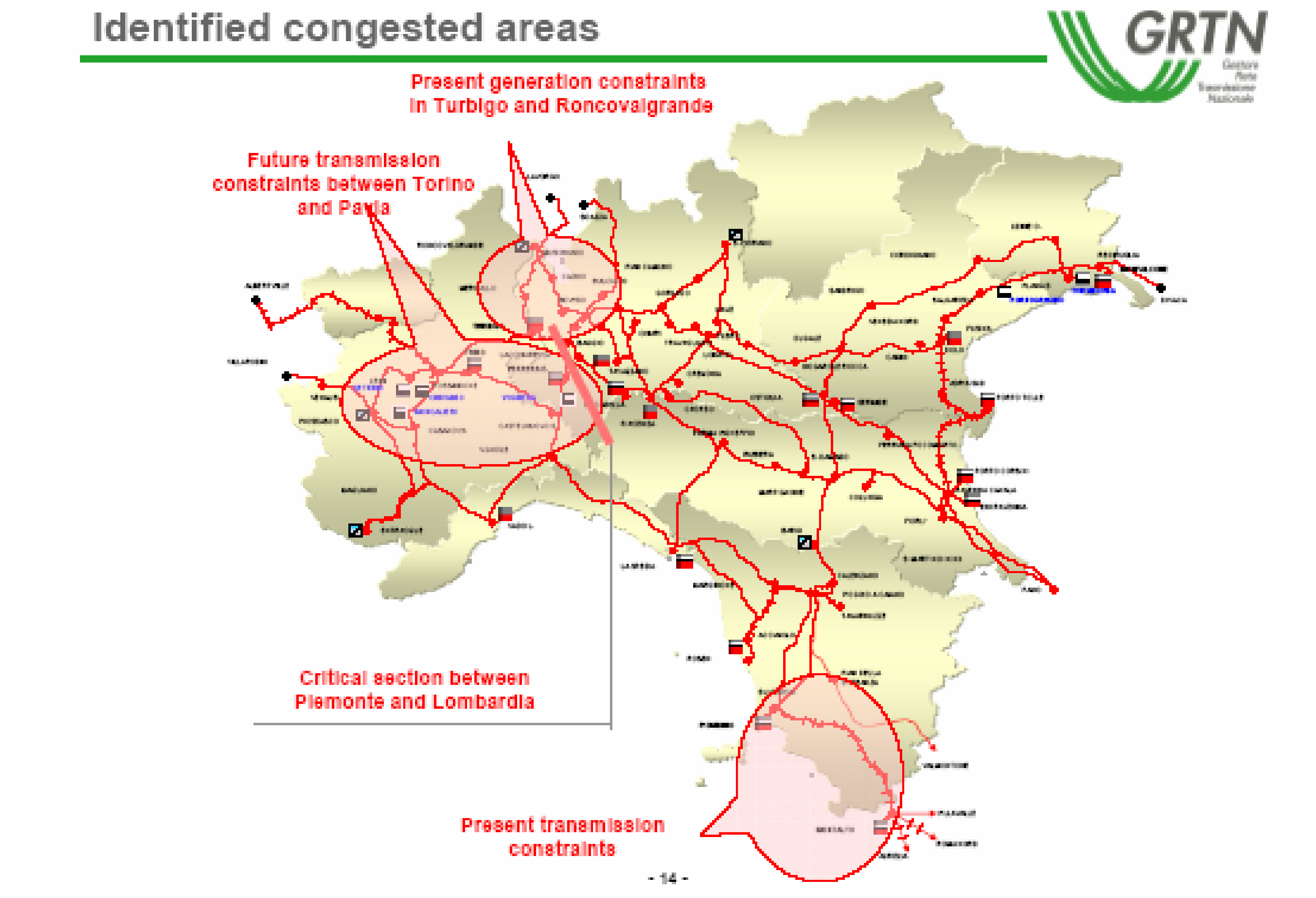
3. Policymakers in a number of countries have sought to distinguish between "reliability" transmission investments and "economic" transmission investments. The former investments are conceptualized as being needed to meet engineering reliability criteria while the latter are conceptualized as being developed to reduce congestion costs (and losses). These two categories of investment are often treated as if they are distinct and independent. This is nonsense. "Reliability" driven transmission investments are not independent of the variables thought to

FIGURE 2A



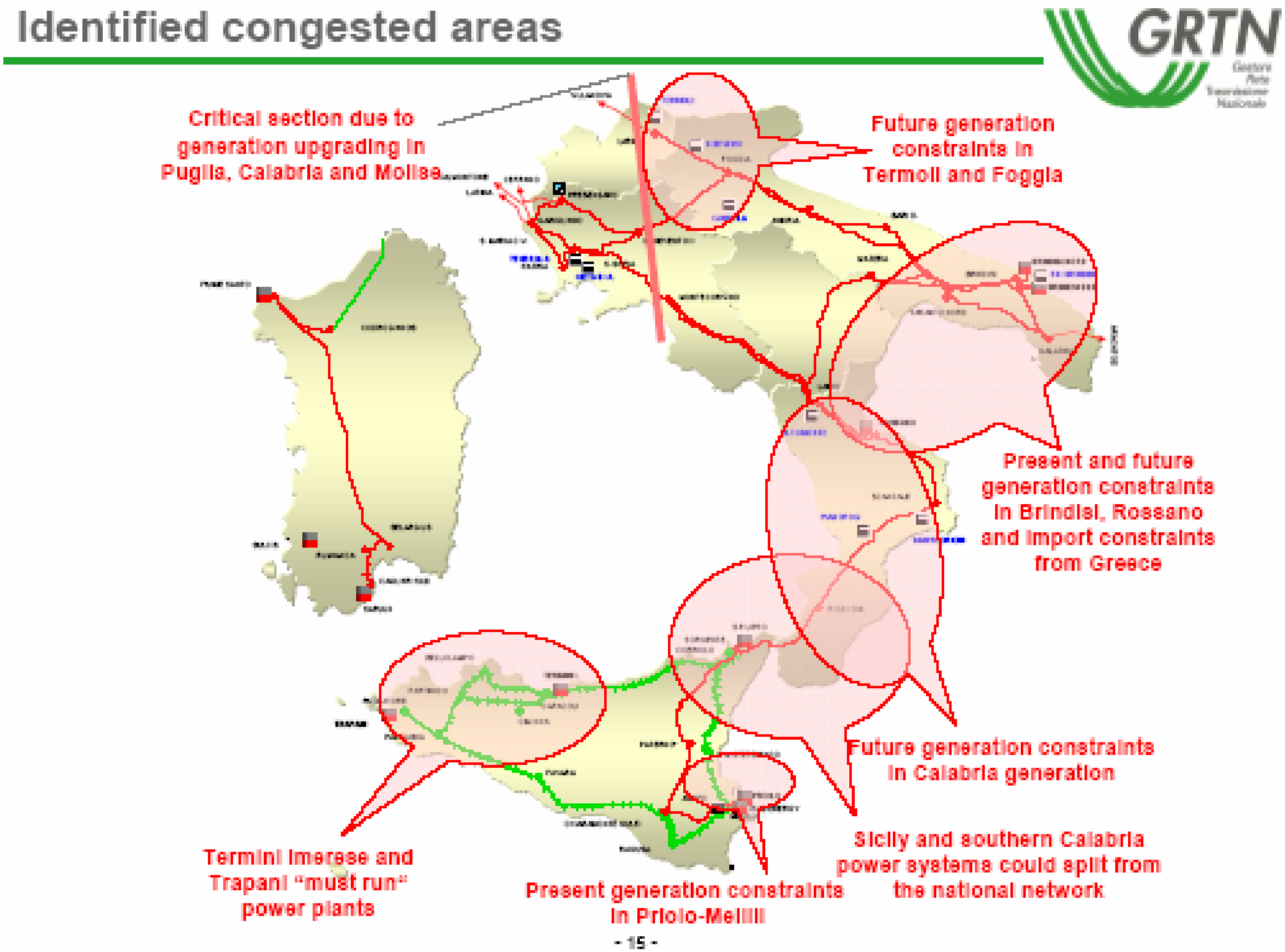
Source: Serrani 2004

FIGURE 2B



Source: Serrani 2004

FIGURE 2C



Source: Serrani 2004

other system balancing costs. It also provides incentives for NGC to maintain the network and spend resources on restoration of outages when these expenditures are valuable because they reduce system balancing costs. As with all incentive regulatory mechanisms, these mechanisms reflect a balancing of the incentives to reduce costs and meet quality standards and capturing the "rents" from cost reductions for consumers (Laffont and Tirole 1993, Chapter 1).

Investments in interconnectors with other networks are not covered directly by NGC's license. The existing interconnector with France is now organized as a separate "merchant" business and the associated capacity is allocated by auctioning physical rights of various durations. In principle, both NGC and third parties are free to propose to add interconnectors between NGC's network and, for example, France or Belgium. The regulatory treatment of such facilities can be negotiated with OFGEM, though the assumption has been that these facilities would be built on a merchant basis. No interconnectors have been added since the CEGB's restructuring in 1990, so how this would play out in practice is unclear. Moreover, the UK's interconnector policies are in the process of being harmonized with the "regulated third party access regulations" specified by recent EU Directives (OFGEM 2003, 2004).[18]

b. Performance metrics

When the new E&W industry structure and market arrangements were implemented in 1990, the system naturally started with a legacy network and configuration of generating capacity. Substantial entry of new generating capacity and retirements of old generating capacity followed, with major changes in power flows over the legacy network. During the initial years of operation there was no incentive regulation mechanism governing system operating costs, including the costs of managing congestion and other network constraints. NGC's SO costs escalated rapidly growing from about $75 million per year in 1990/91 to almost $400 million per year in 1993/94. After the introduction of the SO incentive scheme in 1994, these costs fell to about $25 million in 1999/2000. OFGEM estimates that NGC's system operating costs fell by about £400 million between 1994 and 2001 (OFGEM, April 2004). Overall costs of transmission service, including operating, energy and system balancing, use of system, and connection charges fell by about 50% between 1994 and 2001. (See Figure 4) There is also an incentive mechanism governing the cost of losses. NGC's loss rate has also declined over time. (See Figure5) A new SO incentive scheme was introduced when NETA went into operation in early 2001. The mechanism involves the specification of a target budget for energy and balancing services, upside and downside sharing factors, and a cap and a floor on sharing of variations from the budget target. NGC's SO costs have fallen by nearly 20% over the three year period since the new scheme was introduced (OFGEM, December 2003).

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[18] The Dutch government recently granted permission to TenneT, the manager of the high voltage grid in the Netherlands to finance a regulated transmission interconnection between Norway and the Netherlands, after taking direct economic, reliability, and competition considerations into account. "Decision on the Application of TenneT for permission to Finance the NordNed Cable in Accordance with section 31(6) of the Electricity Act of 1998," 23 December 2004 (English Translation).

create the need for "economic" transmission investments. Reliability investments can have significant effects on current and forecast locational marginal prices (LMPs) for energy and operating reserves, can have significant effects on intra-TSO congestion and losses, and can affect inter-TSO transmission capacity, congestion and losses as well.

4. Changes in network operating practices, TSO discretion in the procedures used to evaluate whether and when reliability criteria will be violated, and TSO discretion in the implementation of reliability criteria in actual operating practices can have significant effects on locational prices for energy and operating reserves, congestion costs and rents, the cost of losses, and incentives to invest in transmission capacity to reduce congestion. System operators need discretion to operate transmission networks reliably. However, discretionary decisions affect the level and locational distribution of wholesale market prices and incentives to invest in both generating and transmission capacity.

5. There are major asymmetries between the way intra-TSO and inter-TSO transmission investment planning, evaluation, and pricing are implemented. Differences in inter-TSO and intra-TSO transmission investment frameworks reflect organizational and political boundaries, as well as the attributes of the legacy networks controlled by incumbent TSOs, rather than the physical attributes of the larger synchronized network, portions of which are controlled by individual TSOs. Inter-TSO investment opportunities can best be addressed through wider area planning using a common set of reliability criteria and evaluation principles and by integrating wholesale power markets and harmonizing the principles for setting transmission service prices across control areas.

6. Horizontal integration of previously independent TSOs can have significant effects on network operations, generator dispatch and locational prices for energy and operating reserves (LMPs), congestion costs and incentives to invest in transmission facilities to meet reliability and economic goals by internalizing inter-TSO inefficiencies under a larger geographic TSO umbrella.

7. Merchant transmission investment has and is likely to make a very small contribution in the overall portfolio of transmission investment projects that will be made in the future. The merchant model that seems to be evolving is one in which regulated entities (and ultimately their customers) take on the risk of entering into a long term performance contracts with a developer of an HVDC transmission link to expand "interconnection" capacity between TSOs with no or limited interconnections and with large sustained differences in prices. Merchant investments supported by arbitraging short term variations in locational spot market prices are unlikely to be attractive to investors.

8. In addition to the problems with relying primarily on a merchant transmission investment model discussed in Joskow and Tirole (2004a), the sensitivity of locational prices for energy and operating reserves and associated congestion

rents and costs to regulated "reliability" transmission investments and discretionary changes in TSO implementation of operating reliability rules create significant additional barriers to intra-TSO merchant transmission investment.

9. The interconnection rules and associated cost responsibilities governing the interconnection of new generators and interconnections of new inter-TSO transmission links to a TSO's internal network have significant effects on locational incentives faced by new generators and on both the economic attractiveness and economic efficiency of merchant transmission investment projects. "Deep" interconnection rules, the associated allocation of cost responsibilities or interconnection service prices provide superior locational incentives in these dimensions to "shallow" interconnection rules and interconnection prices that do not vary by location.

10. Most transmission investment projects are being developed today and will be developed in the future by regulated entities. Accordingly, the creation of a sound, stable and credible regulatory framework to govern regulated transmission investments is very important. The absence of such a framework for the identification of transmission needs, for transmission cost recovery, for mechanisms to align investor incentives with public interest goals, and for efficient pricing of the associated transmission service is a major barrier to the efficient mobilization of transmission investment. An attractive regulatory framework will accommodate but not rely on merchant transmission investment.

11. There exists no single mechanical "silver bullet" incentive regulation mechanism that can be developed to govern transmission investment. A practical regulatory framework will inevitably include a mix of cost-of-service regulation with an overlay of performance based regulatory (PBR) mechanisms based on benchmarking, profit sharing (sliding scale) and "ratchets." The development and application of performance norms, formal investment criteria, as well as considerable regulatory judgment is an inevitable component of a sound regulatory process. One component of such a regulatory framework is a transparent regional transmission investment planning process with clear rules for achieving defined reliability and economic goals.

12. The bifurcation of regulatory responsibilities in the U.S. between the states and the federal government (FERC) creates significant potential disincentives to transmission investment in what is only a partially liberalized sector. Full unbundling of transmission service and the transfer of regulatory responsibility for all transmission service to FERC would be very desirable.

13. In order to implement an effective regulatory process, regulators will need more information about the performance of the transmission network, will have to establish performance norms and criteria, and apply PBR systems that align TSO incentives with public interest performance goals. These incentive mechanisms must satisfy firm viability/participation constraints and reflect rent extraction

goals in the context of information asymmetries between the regulator and the firms it regulates.

14. TSO that are also vertically integrated into generation and marketing activities create additional regulatory challenges because of the conflicts of interest between operating and investment decisions made by the TSO and their impacts on the profitability of generation and marketing businesses that make use of the same transmission network. Regulatory rules requiring "functional" separation eliminate any benefits of vertical integration if they are followed while providing imperfect protection against abusive self-dealing behavior by the TSO. The creation of truly independent TSOs reduces the regulatory burdens and creates entities whose management focuses on the transmission business.

15. Separating SO and TO functions may be a second-best response to vertical integration between transmission, generation and power marketing, but it also is likely to lead to some inefficiencies.

ATTRIBUTES OF TRANSMISSION INVESTMENTS

Transmission investment policies must respond to a number of interdependent questions. What are the societal goals that a transmission investment framework should seek to achieve? What are the respective roles of economic goals, reliability goals and other potential public policy goals? What are the physical and economic attributes of different types of transmission investments? How are transmission investment needs identified? What entities are expected to develop the new facilities? How are the associated costs expected to be recovered through transmission charges or price arbitrage profits resulting from transmitting power from a relatively high wholesale price location to a lower-wholesale price location? Which entities that make use of the network should pay for its various components? Where does "transmission" end and "distribution" begin?

While policymakers talk about "transmission investment" in general, in reality those responsible for identifying investment needs and opportunities typically divide transmission investment into a number of different categories. If we are going to make progress in understanding the transmission investment problem from a theoretical and empirical perspective, we need to better coordinate economic analysis with the conceptual framework that governs the consideration of transmission investment by system operators, transmission owners and policymakers.

Let me note as well that there is no uniform definition of the facilities that make up the high voltage transmission network that is subject to the control of the system operator. In England and Wales (E&W), the transmission network license includes only facilities with voltages of 275kV and 400kV. In the U.S., transmission facilities typically include lines that operate at 66kV and above with various exceptions based on differences in network topology, legacy ownership and regulatory arrangements. In France, RTE's transmission network includes facilities with voltages similar to those in the U.S.[2] Different rules may be applied for defining which "side of the fence" interconnection facilities lie. I will ignore these differences in the definition of the facilities that comprise the transmission network in different countries in what follows. However, we should keep in mind that these differences complicate comparisons of transmission network performance, since performance indicia like congestion costs, losses, network component availability, unserved energy (loss of load), operation and maintenance costs, etc., will depend on which network components are included in the definition of "transmission" and which are not.

a. Categorization of transmission investments

Different TSOs also categorize (and characterize) transmission investments in a variety of different ways, use a wide range of very different methods to assess charges to cover the capital and operating costs of transmission facilities, to cover the costs of congestion and losses, and to assign responsibility for payments to cover the costs of investments in new transmission network facilities. In the discussion that follows, I will make use of the following categorizations which are broadly consistent with those used in the transmission planning and investment frameworks in the U.S. and the UK.

Generator interconnection investments: When new generators are constructed they must have interconnections to the transmission network in order to sell energy and ancillary network support services in the wholesale market. Some minimal level of investment is required merely to connect the generator to the closest point of interconnection to the network and to allow the generator to deliver its maximum generating capacity to the network at this point of interconnection. At a minimum, these investments will include new (or reinforced) transmission lines between the generating plant's switchyard and the first point of interconnection to the high voltage network and investments in transformer capacity at the point of interconnection to the network to accommodate the reliable injection of additional power into the network at the proper voltage. The investments required will vary directly with the generator's maximum capacity, the maximum capacity of proximate generating facilities that share an interconnection point on the network, the voltage at which the power is delivered to the network, and the reliability of the interconnection facilities as measured by their planned (for maintenance) and unplanned forced outage rates under different system conditions.

Interconnection investments alone do not assure the associated generator that there will be adequate transmission capacity to transmit the power from the point of interconnection to the network on to other locations on the network without curtailments or additional charges due to congestion. As a result, as I will discuss in more detail presently, if the generator expects to be able to utilize fully its generating capacity to deliver power to serve demand nodes dispersed around the network without experiencing curtailments of incurring congestion charges, investments "deeper" into the network are likely to be required. Alternatively, the generator or its customers will have to secure transmission rights to utilize the scarce transmission capacity that already exists from others.

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[2] 63kV and above. http://www.rte-france.com/htm/an/qui/qui_reseau_lignes.htm

Distribution network and large retail customer interconnection investments: Distribution networks and large customers who take power directly from the transmission network must also have transmission facilities that interconnect them to the high voltage transmission network. These interconnection investments are the flip side of generator interconnection investments except that distribution networks typically have multiple points of interconnection with the transmission network <u>and</u> individual loads' locational decisions will, in most cases, be insensitive to interconnection costs. At a minimum, these investments will include new (or reinforced) transmission lines between the distribution network's facilities and the first point of interconnection to the high voltage network and investments in transformer capacity at these points of interconnection. The investments required will vary directly with the distribution network's maximum coincident demand, the number and attributes of interconnection points, the voltage at which the power is delivered to the distribution network before being further stepped down by the distributor, and the reliability of the interconnection facilities as measured by their planned (for maintenance) and unplanned forced outage rates under different system conditions. Interconnection investments per se do not assure the distributor that there will be adequate "upstream" transmission capacity to transmit all of the power it needs to meet its end-use customers' demand because there may be congestion between the distributor's point of interconnection and generation nodes on the network under some operating conditions. However, a distribution company will not add interconnection capacity unless it can fill that capacity with energy drawn from the transmission network by securing, in one way or another, the network capacity "deeper" into the network needed to gain access to enough energy to meet the demand of its distribution service customers. Of course, the distributor may also be able to balance supply and demand with generation embedded in the distribution network (distributed generation) and with load reduction programs, including the impacts on consumer demand of real time pricing or priority rationing contracts (Chao and Wilson 1985). As already noted, there is no well accepted firm line between "distribution" and "transmission."

"Intra-TSO" economic transmission network upgrade investments: By intra-TSO, I mean investments made within the footprint of a specific TSO. The TSO may cover only a portion of a larger synchronized AC network as in the U.S. and Europe. Economic models of transmission network operations and investment focus on the effects of transmission capacity (whether in the context of a simple two-node network or a multi-node network with loop flow) on congestion costs and congestion rents. Congestion *rents* are measured by the difference between nodal prices times the flows of power between injection and delivery points on the network. On a simple two-node network this is the difference in nodal prices between the high price and low price node times the capacity of the radial transmission link between them (e.g. Joskow and Tirole 2000). Congestion *costs* are the *difference* between the cost of supplying generation services to meet demand given the scarce transmission capacity actually available on the network and what the cost of generation would be if there were no congestion to limit imports of less costly power (including the dead weight loss associated with reductions in price-sensitive demand due to the higher prices) in the high price "constrained on" zone.

Figure 3 depicts this kind of two-node network situation, assuming that there is perfect competition in the generation supply market. There is relatively inexpensive generation located in the North with an export supply curve S_N. There is relatively expensive generation in the South as well as demand in the South. The residual demand in the South for imports from the North is given by D_sS_s which is defined (roughly) as the difference between the demand in the South and the marginal cost of generation in the South. If there were no transmission capacity constraints Q_N^U would be imported and the market clearing price would be defined by point B where the S_N and D_sS_s cross. However with transmission capacity of $K_0 < Q_N^U$ imports from the North are constrained. The price in the North falls to P_N and the price in the South rises to P_S. The difference between P_S and P_N is the marginal cost or price of congestion η where $\eta = P_S - P_N$. The congestion rent is given by ηK_o and the congestion cost by the hatched triangle ABC in Figure 3. This congestion cost reflects the additional cost of generation in the South required to balance supply and demand given limited transmission capacity from the North plus the dead-weight loss to consumers from the associated higher prices. A small increment in transmission capacity δK has a value equal to η and transmission capacity with marginal cost c_K should be expanded up to the point where (in expectation and properly discounted) $c_k = \eta$. [3]

Economic models of transmission expansion should, in principle, also include the cost of losses (Joskow and Schmalensee 1983, pp. 36-37) in both locational prices and investment planning. And loss cost considerations play a significant role in traditional engineering-economic system planning models.[4] However, perhaps for convenience, many contemporary economic models have ignored losses, although in the wholesale markets operation in New York and New England, LMPs reflect both the marginal costs of congestion and the marginal cost of losses. Indeed, marginal losses lead to significant differences in LMPs in these markets even when there is no congestion. In what follows, when I refer to congestion costs I am using the term to encompass the cost of losses as well.

So-called economic transmission investments (whether intra-TSO or inter-TSO) are motivated by the opportunity for such investments to reduce the social costs of congestion. Optimal economic investment involves a tradeoff between investing in additional transmission and the associated reduction in congestion (and loss) costs. That is, the incremental cost of transmission investment should be compared to the incremental reduction in the costs of congestion on the network (e.g. Joskow and Tirole, 2004a). In the absence of "lumpy" investments, and assuming that all nodal prices reflect

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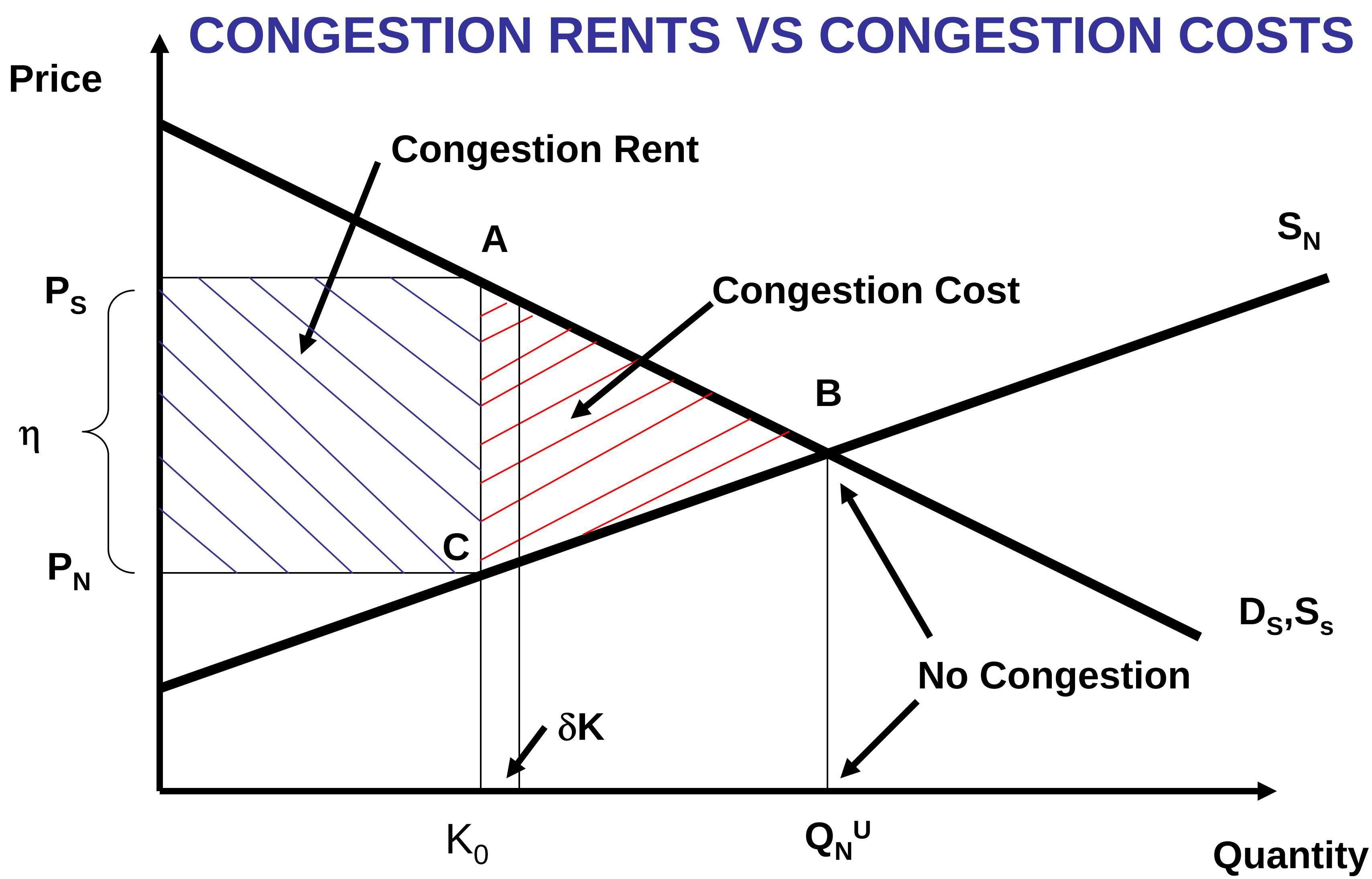
[3] Realized congestion costs and the social cost of congestion will be equal only if the nodal price signals at generation and demand nodes reflect the social marginal cost of generation or the value of lost load at each node (including marginal losses). Differences in marginal losses are often ignored, but the evidence from New England and New York which calculate LMPs that include marginal losses suggest that marginal losses can affect optimal locational prices significantly. Capacity prices must also be accounted for properly in markets that have capacity obligations/capacity prices (Joskow and Tirole 2004b).

[4] I am grateful to Ignacio Perez-Arriaga for reminding me not to forget the costs associated with losses.

FIGURE 3



CONGESTION RENTS VS CONGESTION COSTS
Price
Congestion Rent
A
S_N
P_S
Congestion Cost
B
η
C
P_N
D_S,S_s
No Congestion
δK
K_0
Q_N^U
Quantity

the relevant marginal social opportunity cost at each node, it is optimal to make expenditures on "economic" transmission capacity up to the point where the marginal cost of transmission investment is equal to the (expected) reduction in transmission congestion costs.[5] Since transmission investment is an expenditure today that creates a long-lived asset and congestion is a flow that depends on future supply and demand conditions in both the electricity and input markets (e.g. fuel prices), the benefits of an economic transmission investment are necessarily uncertain at the time they are made and are realized over a period of many future years.

"Inter-TSO" economic investments (interconnectors between TSOs): By "inter-TSO," I am referring to investments that are designed to increase transfer capacity between two (or more) TSOs and to reduce congestion between them. When TSOs operate portions ("control areas") of the same synchronized AC network, the difference between intra- and inter-TSO economic transmission upgrades are primarily institutional, reflecting historical ownership structures, political boundaries and differences in wholesale market design and regulatory mechanisms. The underlying physical attributes of investments at different locations on the larger AC network controlled by multiple TSOs are basically the same as would be the case if there were a single TSO for the entire network. That is, with a single TSO inter-TSO investments would by definition become intra-TSO transmission investments governed by the same market, regulatory and transmission investment frameworks. However, differences in the market designs and transmission investment frameworks of the multiple TSOs controlling portions of the same synchronized network, incompatibilities between the institutions governing interconnected TSOs, and various transactions costs resulting from horizontal separation that affect wholesale market prices and congestion on both network, are likely to affect transmission investment decisions. It is frequently the case that intra-TSO and inter-TSO economic transmission investments are treated --- even conceptualized --- very differently due to these institutional differences rather than due to basic physical and economic realities.

Differences in market design and coordination between interconnected TSOs on the same synchronized AC network can affect the economic attributes and evaluation of opportunities to expand transmission capacity to reduce congestion both between the TSOs' networks and even within their individual networks. This is the case, in part, because differences in market design and network operating practices can affect locational prices and dispatch decisions within both of the individual TSOs' control areas. These effects are exacerbated when multiple TSOs adopt operating protocols that are based on fictional physical characterizations of the interconnected free flowing AC network --- for example, that a large synchronized AC network is really several separate networks connected by radial lines with no loop flow and no congestion within each TSO. Individual TSOs first tend to resolve congestion inside their networks and then facilitate residual economic trades between networks. These policies tend to push congestion out to the borders and reduce economic efficiency. While this is not a necessary result of having multiple TSOs on the same free flowing network, it appears to

[5] As I will discuss further below, there appears to be some confusion about what "lumpiness" means in a transmission ion network context.

be a practical reality of the decentralized operating protocols adopted by individual TSOs. A good example of this is the experience following the integration of PJM West (Allegheny Power Systems) with the incumbent PJM system to the East in April 2002. As reported by PJM's market monitoring unit:

Congestion-Event Hours for the Bedington-Black Oak and APS South Interfaces

The APS extra-high-voltage (EHV) system is the primary conduit for energy transfers from APS and Midwestern generating resources to southwestern PJM and eastern Virginia load, and, to a lesser extent, to central and eastern PJM. The two APS reactive interface constraints of interest, Bedington-Black Oak and APS south, often restrict west-to-east energy transfers across the APS EHV system. Prior to the incorporation of APS into PJM on April 1, 2002, the primary controlling action for these constraints had been for APS to restrict energy transfers through its system, including transfers from western resources to PJM and VAP. This action had the effect of raising the overall PJM dispatch rate higher than it would have been if the transactions had not been curtailed. The result was increased energy prices for the entire PJM Mid-Atlantic Region, regardless of location. There was no impact on measured congestion because the entire PJM system was affected.

After APS was integrated into the PJM Market and the redispatch of PJM generation was used to control APS transmission facilities, a significant change in price impacts occurred. Rather than simply restricting relatively low-cost energy transfers, higher cost generating units were dispatched out of merit order (redispatched) in order to serve load in the transmission-constrained areas. As a result, the price of energy in the constrained areas was higher than elsewhere and congestion occurred. Higher LMPs resulted only at those locations directly limited by a constrained facility while lower LMPs occurred elsewhere. PEPCO was most directly affected by these constrained facilities, followed by BGE. The pattern of zonal LMPs reflected this fact as Figure 6-1 shows.

Source: *PJM State of the Markets Report 2003, Chapter 6.* [6]

This suggests that the horizontal consolidation of TSOs into a single TSO covering the larger geographic footprint of the real physical network could lead to very different evaluations of and incentives for economic transmission investments. By "internalizing" wholesale market and transmission institutions under a single TSO, both the locational price and congestion patterns that drive economic transmission investments are likely to change. Transmission upgrade evaluation policies as they relate to inter-TSO transmission investments are likely to change as well. As we shall see, inter-TSO economic network upgrade opportunities and intra-TSO transmission network opportunities may be evaluated very differently by TSOs on the same AC network. The internalization of transmission investment decisions and the integration of wholesale market institutions are two of the primary motivations in the U.S. for the Federal Energy Regulatory Commission's (FERC) efforts to create large regional transmission organizations (RTOs) that consolidate the multiple control areas that now exist. Consolidating previously separate control areas is expected to transform inter-TSO economic transmission investment opportunities into intra-TSO transmission investment opportunities governed by a single transmission investment framework, a common

[6] The Bedington-Black Oak interface refered to here accounted for over $500 million of gross congestion during the period August 2003 through September 2004 and accounted for about $84 million of (net) congestion costs. The estimated cost of investments to mitigate the congestion is $5-$25 million. PJM monthly congestion spreadsheet, downloaded December 4, 2004; www.pjm.com.

wholesale market design, and wider market area with a set of fully coordinated locational prices.

There are, of course, situations where inter-TSO economic transmission investments involve the creation or expansion of interconnections between truly separate AC networks. For example, by building HVDC inter-connectors between two separate networks, opportunities to increase trades of power from high price to low priced areas can be exploited. The HVDC link between the England and France, the HVDC links between Quebec and New England, the HVDC link being constructed between Tasmania and Victoria, Australia are examples.[7]

Interconnection investments to support Inter-TSO transmission links: Building or expanding an inter-TSO transmission facility (an "interconnector" in European parlance) is only the first step in increasing trade between two TSOs whether they are on the same synchronized network or govern independent networks. The new interconnector will withdraw power under the control of one TSO and deliver it to the network controlled by the other. Facilities need to be constructed to affect the interconnection with each network, just as would be the case for a generator with equivalent capacity located at the point of interconnection at the delivery end or a large load located at the point of interconnection at the withdrawal end of the new inter-TSO link. Moreover, just as in the case of new generators, whether or not the interconnector capacity can be fully utilized to deliver power to serve load depends on network congestion beyond the point of interconnection to each network and how scarce transmission capacity on each network is allocated. Interconnectors may also have reliability implications, especially when they are relatively large and become binding contingencies that affect the evaluation of whether or not the network is meeting established reliability criteria. I will discuss this issue further below. However, unlike a generator seeking to locate on a single network, a proper evaluation of the value of and incentives to invest in an interconnector justified by the cost reductions realized by expanding use of low-cost power to displace the use of higher cost power (plus the change in total net surplus resulting from lower prices and increased demand on the importing network) will depend as well on the compatibility of the interconnection investment policies and the "deeper" network upgrade policies on <u>both</u> networks. Some TSOs "socialize" the costs of these deeper network upgrades into a general "postage stamp" transmission service tariff rather than requiring generators or interconnectors causing the need for additional "deep" network investments to pay for them. This is called a "shallow interconnection" pricing policy. In other TSOs, the costs of deeper network investments required to restore reliability parameters and/or relieve congestion or charged to generators and interconnectors at the locations where power flows cause the need for these deeper network investments. This is called a "deep interconnection" policy. As discussed further below, PJM has a de facto deep interconnection policy while most other TSOs in the U.S. have shallow interconnection policies. In E&W, the use of

[7] These links can also support bi-directional economic power trading opportunities. For example, New England typically imports from Quebec over a DC link during the day and exports power to Quebec at night so that Quebec's hydroelectric dominated system can store water at night when prices are relatively low in New England and sell it back during the day when prices in New England are relatively high.

system charges vary by location and are, effectively, a deep interconnection pricing policy.

Reliability transmission network investments: These are transmission investments that must be made to restore exogenously specified TSO planning reliability criteria that may be violated as a consequence of changes in demand patterns, generation investment and generation retirements. (Planning and operating reliability criteria are not typically the same.) TSO reliability criteria have generally been carried over from the old regime of regulated vertically integrated monopolies. As I will illustrate with several examples below, virtually all of the transmission investment underway today in the U.S. and, effectively, in E&W are either direct interconnection investments as discussed above or some type of "reliability" investment. I am informed that this is the case in many other countries as well. One's first reaction might be that this is a terrible situation. It suggests that current transmission investment frameworks consider only reliability and ignore the economic costs of congestion! However, while "reliability" and "economic" transmission investments are often treated as if they were distinct and independent types of transmission investments, this is a complete fiction. Investments made to restore engineering reliability criteria can have very significant impacts on congestion and locational prices and, accordingly, on the valuation of and incentives for "economic" transmission investments. Similarly, "economic" investments can have impacts on reliability parameters.

Neither reliability transmission investments nor the interrelationship between reliability criteria and economic parameters are given much attention in the literature on competitive electricity markets or transmission investment. Yet so-called reliability investments are playing an increasing role in the overall intra-TSO investment profile and exacerbates incompatibilities between inter and intra-TSO transmission investment. The engineers and the economists interested in transmission investment issues clearly need to be introduced to each other. These issues will be discussed in more detail below after the case studies of E&W and PJM are presented.

b. Physical attributes of transmission network components

The standard metaphor for transmission investment is the construction of a major new transmission line on new rights of way. While major new transmission lines can cost hundreds of millions of dollars, many socially desirable projects are relatively inexpensive and do not require expanding the geographic footprint of the network. These latter investment opportunities are especially important in a world where the construction of major new lines are constrained by "Nimby" ("not in my backyard") constraints. The distribution of project costs for transmission investment projects identified in the latest New England ISO transmission plan is indicative of the patterns of transmission investment opportunities. The 2004 transmission plan includes 245 projects with a total expected cost of $2.1 billion. The five most expenses projects are projected to cost $1.4 billion and the remaining 240 projects a total of about $700 million. (ISO-NE 2004). The full distribution of "reliability" project costs in the New England transmission expansion plan is displayed in Table 3. Of the roughly 50 transmission projects listed in PJM's "economic" transmission investment market window in November 1994 (discussed in more detail below) estimated investment costs vary from $20,000 to $39 million. These investments all seem to be "lumpy" in the sense that they mitigate the congestion identified completely and could not be financed out of the residual congestion rents.

Projects to enhance transmission networks include a wide range of physical components that are to be added to the network or to replace components that are already in the network. They include:

a. new relays and switches
b. new remote monitoring and control equipment
c. transformer upgrades
d. substation facilities
e. capacitor additions
f. reconductoring of existing links[8]
g. increasing the voltage of specific sets of transmission links
h. new transmission lines on existing corridors
i. new transmission lines on new corridors (above or underground)

In addition, the effective capacity of the network may be increased at little of no cost with the adoption of better remedial action schemes or special control schemes that increase the speed with which other transmission links or generating plants can respond to unplanned equipment outages. Changes in operating practices and the way contingencies are evaluated and handled when they occur can also magically increase (or decrease) effective transmission capacity.

The diversity of network components that can be added to or substituted for existing network components reflects in part the factors that limit transmission capacity. On most networks, transmission limitations are driven by reliability criteria and associated assessments of the ability of the network to physically balance supply and demand without shedding load involuntarily or violating network voltage, frequency or stability criteria that would increase the probability of a network collapse. These reliability criteria typically reflect the objective of keeping the probability of involuntary load shedding to a very low level and the probability of a widespread network collapse to zero. The limitations on utilization of the network are frequently one or more sets of "contingency" constraints evaluated under a variety of system conditions ("study conditions") that push the probabilities of load shedding or network collapse to acceptable levels rather than binding pre-contingency thermal limits on particular lines. The binding constraint limiting transmission capacity could be the reliability of a breaker, the speed with which a switch can be pulled, or the ability to monitor line sag in real time. Better or faster communications between system operators controlling portions of the same synchronized AC network can also relax contingency constraints and increase the effective capacity of the network. Accordingly, when we think about expanding

[8] Reconductoring with new conductor technology can also increase effective transmission capacity without adding new transmission corridors or towers. "Reconductoring with gap-type conductors allowed the company [NGC] to increase the capacity of a critical transmission line by 24% without requiring changes to the transmission towers." *Electric Transmission Week*, March 14, 2005, page 14, SNL Energy.

transmission capacity we should have in mind the full range of physical and behavioral options as well as the importance of engineering reliability criteria and associated contingency studies and constraints.

Note that the discussion in this section also implies that measuring transmission "capacity," or changes in transmission capacity, using measures of the length of transmission lines --- e.g. MW miles ---- is not appropriate. Especially in light of the difficulties of siting major new transmission lines, increases in transmission capacity are likely to focus on "deepening" the existing transmission infrastructure and minimizing the expansion of its geographic footprint. When new lines are necessary, siting difficulties will also lead to more underground links and the use of more costly routes to avoid environmentally and politically sensitive areas.

TABLE 3

RELIABILITY UPGRADE PROJECTS
NEW ENGLAND REGIONAL EXPANSION PLAN 2004
($ millions)

Projects	Total Cost	Average Cost
Top 5	$1,388	$277.6
Next 5	322	64.4
Next 15	296	19.7
Remaining 220	132	0.6

Source: New England Regional Transmission Expansion Plan (RTEP04), *RTEP04 Technical Report*, page 310, ISO New England.

c. Legacy infrastructure considerations

It is important to recognize that electricity sector liberalization reforms take place with an existing infrastructure composed of long-lived assets with particular attributes. The attributes of the legacy infrastructure reflect historical institutional arrangements, corporate boundaries, political boundaries, historical patterns of urban and industrial development, and historical economic and technological opportunities. The attributes of this legacy infrastructure will affect the behavior and performance of the system for many years into the future. We can change the institutions but we cannot erase the existing infrastructure in place at the time sector liberalization reforms are implemented but only change it gradually over time.

For example, in the U.S. the electric power sector evolved with a large number of vertically integrated utilities serving geographic areas that varied widely in size. This structure was significantly influenced by federal and state laws passed during the 1930s that sharply restricted mergers of proximate utilities, especially when they served more than one state. Infrastructure development focused most intensively on the geographic areas served by individual utilities with transmission networks developed to link generators owned by the utility with the load centers within the utility's geographic franchise area. The strengthening of the transmission infrastructure connecting vertically integrated utility control areas proceeded later and more slowly. In many cases it was motivated primarily by reliability considerations rather than with the goal of importing large amounts of power from neighboring vertically integrated utilities (Joskow and Schmalensee 1983). So, for example, New England has only limited transmission interconnections with New York State (about 1500 Mw connecting two networks with peak loads of about 25,000 Mw and 35,000 Mw respectively). This reflects much more the ownership structure of utilities in this area of the U.S. during the last half of the 20th century (there was no common ownership between utilities serving areas in both New York and New England while some utilities in New England had operating companies and generating facilities in two or more New England states) and historical political boundaries (the New England states joined together to form the New England Power Pool in 1969 while New York created its own power pool at about the same time) than it does any natural economic and technological attributes. Similarly, large integrated utility holding companies like AEP and Southern developed strong transmission networks covering several states in which they had operating companies while small independent vertically integrated utilities in other areas of the country have weak interconnections with their neighboring utilities and, as a result, enter the liberalization with weak regional networks.[9]

[9] There were a few major interregional transmission facilities developed in the U.S. to allow high generation cost areas to access less costly power in remote areas. The Pacific Interie projects (AC and DC) linking the Pacific Northwest and British Columbia with California began to be developed in the 1960s with support from the Federal government, federal and municipal power entities (Bonneville and Los Angeles Department of Water and Power) and cooperative agreements with the three vertically integrated investor-owned utilities in California. Two HVDC interties were developed in the 1980s to link Quebec with New England. These projects were promoted by Hydro-Quebec (the low-cost power supplier) and were supported by a cooperative agreement involving all of the major vertically integrated utilities in New England (the high cost power buyers). When vertically integrated utilities took ownership interests in generating facilities outside of their traditional service areas they developed transmission facilities to allow

In Europe, where several countries relied on one or a small number of vertically integrated utilities, or as in Spain, consolidated responsibility for a "shared" high voltage transmission network, there tend to be much stronger "intra-country" transmission networks than "inter-country" transmission networks. This has led European transmission policy to focus on expanding "interconnectors" between countries rather than on intra-country wholesale market design, locational pricing and transmission policies, sometimes using the argument (almost certainly wrong) that the national networks are so strong that there is no internal congestion. Within Italy, for example, there are several congested interfaces, in addition to the congested transmission interfaces with France, Switzerland, Austria and Slovenia (Serrani 2004). . Clearly the attributes of the legacy infrastructure are likely to have significant implications for the need for additional transmission investment to support competitive wholesale power markets.

d. Dimensions of transmission network performance

While I am focusing here on transmission investment, transmission networks have multiple and interrelated performance dimensions. The design of supporting organizational, regulatory and market institutions and judgments about the overall performance of the transmission network should take them all into account. These performance attributes include:

- Costs of congestion, losses, and ancillary network support services.
- Network operating and maintenance costs.
- Availability of network components and efficiency of outage restoration in response to congestion and loss costs.
- Reliability of the network – involuntary losses of load and network collapse.
- Costs of market power and other market inefficiencies affected by the operation of and investment in the network.
- Efficiency with which the investment framework mobilizes investment to expand the "intra-SO" network to meet reliability and economic goals.
- Efficiency with which the investment framework mobilizes capital to expand "inter-TSO" transmission capacity to meeting reliability and economic goals.
- Efficiency with which innovation in "software" and "hardware" technologies are adopted for improving network all aspects of network performance.

them to gain access to the power generated by these facilities. Most of the transmission infrastructure linking Southern California with Arizona, Nevada and New Mexico was developed in this way, as was the very high voltage network in PJM.

TRANSMISSION NETWORK ORGANIZATION

Transmission network organizations have both vertical and horizontal dimensions and we see a variety of different vertical and horizontal structures across countries. These organizational differences are likely to affect the incentives to make transmission investments as well as how transmission opportunities are evaluated. These include:

a. *Full Vertical Integration*: This model is characterized by vertical integration between system operation, transmission ownership and maintenance, generation, retail and wholesale marketing. In these situations, regulations governing non-discriminatory access to the network, non-discriminatory transmission pricing, and non-discriminatory evaluation of and investment in transmission facilities are extremely important but very difficult to implement satisfactorily. The fully integrated TSO has an inherent conflict of interest because its transmission network operating, maintenance and investment decisions affect the value of its generation portfolios and marketing businesses. Moreover, in such companies, the transmission business is likely to represent a small fraction of the income of the enterprise as a whole, and, as a result, transmission is less likely to be primary focus of management attention.

b. *Independent Transco*: This model is characterized by the separation of transmission network functions (SO and TO functions) from generation and power marketing functions. This is the independent Transco model that has been adopted in England and Wales, Spain, New Zealand, Italy (soon) and France (if we ignore the EdF holding company affiliation). System operation, network maintenance, and network investment are vertically integrated and can be managed in a coordinated manner by the Transco. The conflict of interest inherent in an organization where the TSO is not independent of market participants no longer exists and the firm's management is now focused on the provision of transmission services.

c. *Independent System Operator* (ISO): This model is characterized by the separation of system operations from transmission facility ownership, investment and maintenance, as well as from ownership of generation and marketing businesses. The Independent System Operator (ISO) does not own or maintain transmission assets, but is responsible for scheduling and dispatching generation and load in coordination with operating reliability criteria and market rules, managing and enforcing procedures and rules for allocating scarce transmission capacity, interconnection arrangements, administers tariffs governing transmission service prices, and working with TOs and other stakeholders on the coordination of maintenance schedules and planning for new transmission investments to support changes in the demand for and supply of generation services. This is the model that has been or is being adopted in large portions of the U.S., Alberta, Argentina, Norway and other countries.

There are several rationales for creating a separate independent system operator rather than an independent Transco. It may not be politically feasible to force the separation of transmission ownership from generation ownership and marketing activities. An ISO is created to sit on top of the vertically integrated utilities to provide an independent network manager and tariff administrator to govern relationships between market participants and the vertically integrated owners of the transmission network's facilities. There may be geographically balkanized ownership of transmission assets (either regulated or unregulated) and the horizontal integration of transmission assets is deemed to be politically infeasible or undesirable, especially if merchant investment is expected to play an important role in the system. The ISO can then manage a larger physical network with multiple transmission owners more efficiently than would be the case if each TSO operated its own control area. Finally, it is sometimes argued that generation and transmission "compete" (that is they are horizontally and well as vertically related) with one another, that even a transmission owner with no generating assets cannot be truly independent and will have incentives to discriminate against generators on the network. In this case, an ISO that has no direct interest in the financial performance of the owners of any of the assets that comprise or utilize the transmission network will be "unbiased." This naturally leads to the question of what the ISO's objectives are and what incentives influence the monopoly ISO's behavior and performance.

Other things equal I would expect different organizational arrangements to have different performance attributes and to create different regulatory challenges. I offer the following hypotheses:

a. Vertical integration between transmission, generation and marketing creates significant regulatory challenges to mitigate incentives to disadvantage generation and marketing rivals. Moreover, since the regulatory response to vertical integration is typically to require functional separation of the SO/TO functions from generation and marketing and to apply regulations that are designed to force the firm to operate as if it's SO/TO functions are not affiliated with generation and marketing businesses, there are no social benefits to vertical integration between SO/TO functions and generation, marketing and other unregulated lines of business that make use of the affiliated transmission network. What is the point of continuing common ownership of entities regulators are trying to ensure behave completely independently?

b. Vertical separation of system operations from ownership and maintenance of transmission facilities is likely to make coordination between system operations, network maintenance and outage restoration, and investment more costly than if the TO/SO functions were combined. Moreover, to the extent that transmission owners also own generation and are engaged in power marketing activities, it will be difficult for the SO and the regulator to assure that TO behavior, especially related to maintenance, interconnection investment, and investment to reduce congestion, will not be affected by their impacts on affiliated generation and marketing companies. Both the SO and the regulator will have imperfect information about the TOs' cost opportunities, efforts, and incentives. For example, one of the easiest things to accomplish is to fail to get a permit to build a new transmission link that will reduce congestion into an area where an affiliate owns generating capacity. Indeed, I suspect that PJM's hostility toward regulated "economic" transmission investment (more below) is not unrelated to the fact that all of the transmission owners under the PJM umbrella are also vertically integrated into generation and marketing.

c. Limited horizontal expanse of SO functions is likely to create inefficiencies. The more control area operators there are on the network, the more conservative will reliability criteria be, reducing the availability of inter-TSO transmission capacity, and the more difficult it will be for separate market areas efficiently to coordinate wholesale trading of power and the allocation of scarce transmission capacity. As I will discuss presently, there are significant asymmetries between the framework governing intra-TSO transmission investment and inter-TSO investment. Internalizing inter-TSO links through horizontal integration is likely to lead to less congestion and more transmission investment.

These are, of course, only hypotheses that should be verified through empirical analysis.

PRINCIPLES TO GUIDE TRANSMISSION INVESTMENT REGULATORY FRAMEWORKS

A sound transmission investment regulatory framework must address several interrelated issues. The following discussion reflects my view that the bulk of intra-TSO transmission investment will be mediated through a regulatory process of some type and that so-called merchant investment will play a limited role. Merchant investment of one type or another may play a larger role in mobilizing investment for expansion of inter-TSO transmission facilities (interconnectors) as a result of various institutional and political constraints. Merchant opportunities may emerge as well if incumbent TOs are permitted to develop unregulated merchant projects on their own networks, exploiting the market power that they possess. I will also assume that all of the TSO's revenues come from entities that use the network; there are no government subsidies, and a viable TSO, SO or TO must balance its budget.

a. *Objectives and performance norms:* The regulatory framework must specify clearly what the regulator's objectives are for the TSO (or SO and TOs if they are separated) --- that is, what the TSO is expected to accomplish ---, how the TSOs performance will be measured, what norms and benchmarks will be applied to evaluate its performance, and what instruments the TSO may use to achieve these performance objectives. In the case of on organizational structure that separates SO and TO functions, the division of responsibilities and mechanisms for coordinating relationships between the SO and the TOs under it must be clearly defined. As I will illustrate presently, integrating so-called reliability goals and criteria with economic goals and performance norms is especially important.

b. *TSO participation or viability constraints:* The regulatory framework must recognize that there is a firm viability or participation constraint that any regulatory mechanism must adhere to (Laffont and Tirole, 1993, Schmalensee 1989). This "budget balance" constraint can be defined simply as the requirement that any acceptable regulatory mechanism must have the property that expected revenues from the provision of transmission services must at least cover the costs that the regulated firm incurs to provide these services. Private firms cannot be expected to offer to supply services if they do not expected to be compensated for the associated costs. State-owned firms cannot satisfy hard budget constraints (no government subsidies) unless they can recover the cost of providing transmission services from transmission service revenues. If transmission service costs have non-convexities (e.g. scale economies), actual prices for transmission service must depart from efficient prices. We are in the world of second-best.

c. *Rent extraction goals*: The flip side of the firm viability or participation constraint is the impact of higher prices on consumers. The higher are the prices charged by the regulated firm the lower is the surplus left to consumers and, where prices exceed their efficient levels, the lower is aggregate welfare. In a world with asymmetric information, where the regulator has less information than does the regulated firm about its costs, it is well known that there is a tradeoff between providing the firm with incentives to supply efficiently (cost and quality dimensions) and rents left to the regulated firm from charges to consumers that exceed the firm's costs of production (Laffont and Tirole, 1993). Over time, we would like to see the benefits of lower costs flowing through to consumers as lower prices.

d. *Incentive alignment:* Regulators have imperfect information about a regulated firm's cost opportunities, service quality, managerial effort, consumer demand and other factors that influence the cost and quality of services provided by the regulated firm. Regulatory mechanisms should be designed to reflect the asymmetry of information available to the regulated firm and the regulator while making efficient use of the information that is available to the regulator. The goal of effective regulatory mechanisms is to align the incentives faced by the regulated firm with the performance goals established by the regulator. This can be accomplished by (partially) tying the regulated firm's profits to its ability to meet or beat performance goals established by the regulator. The power of such incentive schemes is necessarily limited by the information that the regulator has about the basic cost and demand conditions faced by the regulated firm as well as by firm viability constraints and rent extraction goals. Under all realistic situations, the second-best regulatory mechanism will partially tie a regulated firm's revenues to the actual costs that it incurs and partially place the regulated firm's profits at risk for variations in performance (Schmalensee 1989). This can be accomplished with a sliding-scale mechanism (profit sharing formula), and/or with periodic "ratchet" mechanisms that realign the firm's revenues with its costs from time to time.

e. *Incomplete contract considerations:* Regulatory frameworks can be viewed from a contractual perspective in which regulatory rules define the terms and conditions of an incomplete contract between the regulator and the regulated firm. The regulatory contract also defines a renegotiation framework that allows the terms and conditions of this contract to be adjusted over time as supply and demand conditions change (Joskow and Schmalensee 1986). Investments in transmission facilities are long lived assets that provide services for many years into the future. While the costs of investments are incurred up front, the revenues that the firm will receive from these assets will be realized from transmission service revenues extending over the life of the asset. On the one hand, once the investment is made, the regulated firm must be concerned that it may by subject to a "regulatory holdup" aimed at confiscating the ex post quasi rents created by the investments. Investors in regulated assets will seek a credible commitment that such hold-ups will not occur. A credible full-contingent claim contract negotiated ex ante would be ideal from this perspective. On the other hand, the regulator is not in a position to define an efficient full contingent claim contract ex ante that also satisfies a budget balance constraint. Over the life of regulated transmission investments supply and demand conditions are likely to change considerably, affecting both the profitability of the regulated firm's investment and the rents extracted from consumers. Moreover, the regulator will learn more about the attributes of the regulated firm, its costs, revenues and the quality of service over time as well. An effective regulatory process is like a good incomplete contract (Joskow 1988). It defines that initial terms and conditions, performance norms, formula adjustments to reflect changing economic conditions, and an adjustment process that provides an efficient framework for adjusting these terms and conditions when they fall outside of a "self-enforcing range."

f. *Transmission service price structures:* It is convenient to think about the components of the regulatory framework above as establishing the aggregate revenues (or profits) that the regulated firm can earn under various contingencies. These "allowed revenues" reflect firm viability, rent extraction and incentive alignment considerations Or, to oversimplify, the regulated TSO's current budget constraint is determined first. Prices must then be established for the various services that the TSO provides. These prices should provide efficient signals to transmission system users so that their behavior can adjust to reflect the (marginal) costs of the services provided to them in the short run and the long run. They must also be set at levels that produce the aggregate revenues (or profits) that the regulated firm is allowed to earn based on the terms and conditions of the regulatory arrangements discussed above.

g. *Other terms and conditions of network access*: In addition to the specification of the prices for using the transmission network, other terms and conditions of service must also be defined. This is especially important when the TSO or the TO is not independent of market participants. These terms and conditions include the rules governing the process through which interconnection requests by generators or merchant transmission projects will be processed, specification of cost responsibility for interconnection and network reinforcements, the application of reliability criteria to evaluate the availability and cost of providing transmission service, the specification of and allocation of physical or financial transmission rights, and the mechanisms for allocating scarce transmission capacity in the short run and the long run. Some of these terms and conditions are ultimately linked to the attributes of the wholesale markets that are supported by the transmission network.

h. *Relationships between transmission and wholesale market institutions:* In the early years of electricity sector liberalization in the United States, Europe, Japan, Australia and other countries it was often argued by policymakers that there was a natural and fairly simple "separation" between competitive power markets and the transmission network that is necessary to support these markets. It is quite clear today that no such simple separation exists. Organizing power market and transmission institutions as if a clear separation exists inevitably leads to serious problems. Efficient power markets, efficient transmission operation and investment behavior, and the satisfaction of reliability goals at the lowest reasonable cost are all fundamentally interdependent. Competitive market prices for power (spot and forward) are signals of the value of both energy and transmission capacity at different locations. These price signals can be used to allocate scarce (congested) transmission capacity to highest valued (lowest cost) users, can consumers to express their willingness to pay for "reliability" and express their risk preferences regarding price volatility, can allow generators to factor locational and time series differences in power prices into operation and investment decisions, can allow transmission networks to incorporate the costs of congestion, the value of reliability and other factors into maintenance and investment decisions, etc.

However, the social value of these price signals and the costs and benefits of agents responding to them are only as good as the efficiency of the markets that produce them. Moreover, some of the attributes of electric power networks --- e.g., the possibility of network collapses --- can make investments in "reliability" a public good (Joskow and Tirole, 2004b). Other market imperfections (e.g. generator market power, lumpiness in investments, imperfectly defined property rights) and regulatory interventions (e.g. price caps, SO procurement behavior, non-price rationing --- Joskow and Tirole 2004b, 2004c) affect the prices for generation and the value of scarce transmission capacity in the short run and the long run and can distort rather than improve transmission operating and investments decisions. Accordingly, a well functioning transmission network depends on the design and implementation of sound wholesale market institutions as well as a sound regulatory framework (economic, reliability, network planning) for transmission network owners.

i. *Transmission planning:* Transmission networks do not and will not evolve through the workings of the invisible hand of competitive markets. Even if one were to believe that all transmission investments should be "market driven" and developed by merchant investors, the impacts of proposals for new transmission links on the network must, at the very least, be evaluated by the SO to define the attributes of the incremental network capacity that a merchant project creates and the combinations of any incremental transmission rights that are consistent with the changes in the feasible set of power flows anticipated to be created by the investment, whether the operation of the new facilities would lead to conflicts with existing transmission rights, and the specific allocation of transmission rights that will be conveyed to the transmission developer (Joskow and Tirole, 2004a). As I will discuss presently, in the real world, entry (and exit) of generating plants and changes in demand patterns affect both network congestion as reflected in simple economic models of transmission networks (Joskow and Tirole 2000) as well as reliability constraints as defined by system planners and operators. Investment opportunities driven by economic criteria and investment needs driven by reliability criteria are highly interdependent. At least in the current state of play, a transmission planning process is required to evaluate at least some aspects of regulated reliability driven transmission investments, regulated congestion cost driven transmission investments, merchant transmission investments, and generator interconnection investments. Transmission planning processes should be transparent, provide for stakeholder input, and reflect the objectives and norms defined by regulators for the transmission network.

j. Merchant transmission investment: The regulatory framework, including the transmission planning process, should accommodate proposals for "merchant" transmission investments. Merchant transmission investment was initially conceived as unregulated transmission investment projects that would be developed on an entrepreneurial basis in response to congestion (differences in locational prices) between points on the same network or to differences in electricity prices on different networks that the merchant project connects. Basically, merchant investors would recover their costs by buying power at one end of a link where it is cheap and reselling it at the other end where it is expensive; or selling the rights to use the merchant link to third parties to engage in this type of trading behavior. That, is the merchant investor makes money by arbitraging price differences between the locations to which the merchant investment creates new transmission rights to buy and sell wholesale power.

The volume of talk about merchant investment far exceeds the investments activity of merchant investors, despite the fact that the transmission frameworks in Australia, New England, New York, and PJM were designed to accommodate "market driven" investments for "economic" transmission investment opportunities. Two small merchant links have been developed in Australia which intended to earn revenues and profits by arbitraging spot price differences between the networks in adjacent states. Both projects have now applied for regulated transmission status. A merchant underwater HVDC transmission link is being constructed between Tasmania and Victoria. However, the project is being developed in response to an RFP from the state-owned electric power company in Tasmania and will be supported by a long-term contract (whose costs can be recovered from the sponsor's customers) between the sponsor and the developer. A competitive RFP process initiated by the municipally-owned Long Island Power Authority (LIPA) supported by a 20-year long term contract governs the completed Long Island Sound HVDC link between Connecticut and Long Island, New York. A similar 20-year contractual arrangement is supporting a proposed HVDC project between PJM and Long Island. HVDC projects linking PJM with New York City and between Upstate New York and New York City (recently cancelled due to the failure to obtain financing) have been discussed for several years. That's about it.

The merchant model that seems to be evolving is one in which regulated entities (and ultimately their customers) take on the risk of entering into a long term performance contract with an HVDC transmission link developer to expand "interconnection" capacity between networks with no or limited interconnections and large sustained differences in prices that are not affected significantly by the addition of the link.[10] Perhaps a better term for this model is "private initiative" transmission investments. It should be recognized as well, that the financing costs for a merchant project are significantly higher

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[10] Merchant opportunities may emerge as well for incumbent TOs seeking to exploit their market power if the regulatory framework permits it.

than those for an equivalent regulated project. A recent analysis of the financing costs for a $100 million merchant transmission project[11] indicated that the cash flow required to finance a regulated project developed by a utility and subject to traditional cost of service regulation would be $9.4 million per year. The annual cash flow for the same merchant project with a long term contract (taking on construction cost and performance risk but not market price risk) using project financing was estimated to be $13.9 million per year. The annual cash flow for the same merchant project without a long term contract (taking on, in addition, market price risk) using project financing was estimated to be $16.5 million per year. Thus, the financing costs for a traditional merchant project that relies on variations in spot market prices would be about 70% higher than a regulated utility financed project. This capital cost variation suggests that the efficiency benefits of merchant vs. regulated projects would have to be quite large to justify relying on merchant investment.

Joskow and Tirole (2004a) identify "lumpiness" as <u>one</u> barrier to efficient investment under a merchant transmission investment model. "Lumpiness" is a relative not an absolute size concept. That is, whether an investment project is lumpy or not must be measured relative to the impact of the most efficiently sized project on the congestion rents that it would reduce. The post-investment congestion rents are the source of the revenue that a merchant investor would count on to support the investment. Regardless of the absolute cost of the project, if an efficient (benefits greater than costs) project of optimal scale would eliminate congestion completely, for example, there would be no way for it to be financed under a merchant investment framework. Similarly, a large project of optimal size (e.g. a 1000 MW HVDC link to New York City) may not have such a large effect on price differences as to make the investment uneconomical. Some commentators have suggested that the "lumpiness" problem can be addressed by treating very large projects differently from small projects. This policy prescription reflects a misunderstanding of what "lumpiness" means in this context. Indeed, this policy advice is likely to get it backwards. As we shall see in the discussion of PJM's transmission investment policies below, there are many small projects that completely mitigate congestion and, accordingly, would not be financed on a merchant basis. At the same time, the merchant projects that are attracting the most attention are large projects that link market areas with demands that are much larger than the scale of the projects and have significant sustained congestion and the associated locational price differences. These large projects are small relative to the size of the markets that are being linked and, as a result, their completion is not expected to have a large effect on differences in locational prices.

While I view the opportunities for merchant transmission projects as being limited primarily to inter-TSO investments that fall outside of TSO regional planning procedures, where there exist large sustained price differences and where a regulated entity is willing to provide long-term contract support for the project, there is no reason why such projects should not be accommodated in the regulatory and planning process. A practical model for doing so has emerged in PJM and I will discuss it further below.

[11]Presentation of Gary Krellenstein, JP Morgan, December 16, 2004, CMU Transmission Conference.

TRANSMISSION REGULATION AND INVESTMENT FRAMEWORK IN ENGLAND AND WALES

In 1990, the electricity sector in England and Wales (E&W) was privatized and restructured to create competitive wholesale and retail markets for power. The state-owned generation and transmission company (CEGB) that historically had provided wholesale power to distribution entities (Area Boards) and large industrial customers in England and Wales (E&W) was broken into three generating companies and a single regulated transmission company (NGC). NGC owns the E&W high voltage transmission network (400kV and 275kV facilities), maintains the network and is responsible for making investments in it to meet its obligations specified by various license conditions. It also is a joint owner with RTE (the French transmission operator) of a 2000 MW HVDC transmission link between France and E&W.[12]

There has been much written about the design and performance of the wholesale power markets in England and Wales (e.g. Henney, Wolfram, Sweeting). Accordingly, I will provide only a brief description of these wholesale market arrangements. From 1990 until March 2001, the wholesale market for power was built upon a mandatory bid-based pool which determined the economic dispatch and associated uniform market clearing price for energy (and where applicable capacity payments) for each of 48 thirty-minute periods each day. Generators were effectively provided with firm transmission service in the sense that if NGC had to dispatch generators out of bid merit order to deal with congestion and other network operating constraints it had to pay generators either to reduce their scheduled generation or to increase it. In March 2001, the New Electricity Trading Arrangements (NETA) was introduced. NETA replaced the mandatory pool with a new wholesale market design that was structured to encourage generators and load to enter into bilateral contracts and to minimize the amount of trade going through a "centralized pool." NETA requires generators and loads to submit generation and demand schedules up to a short period before actual dispatch. These schedules became financial commitments on the part of generators and loads. NGC is then responsible for balancing the system using offers to buy and sell increases and decreases in real time generation supplies mediated through in a pay-as-bid "balancing market." NGC's balancing responsibility includes real time balancing of demand and supply for energy and management of network congestion and other network operating constraints. Generators or load that voluntarily deviates from their schedules must (effectively) buy or sell energy in the balancing market. As before, generators paying interconnection and use of system charges (below) are effectively buying firm transmission service and must

[12] There is also a six-circuit AC interconnector between Scotland and England. The costs of this interconnector and associated facilities are included in the TOs' use of system charges (except that there is a separate charge for use of non-firm capacity above the 850Mw of firm capacity that existed in 1990). The interconnector's capacity is presently allocated using an administrative procedure that involves pro-rate allocations when requests for capacity reservations exceed capacity. When BETTA goes into effect the assets forming the Scotland-England interconnector will be subsumed into the Great Britain transmission system. The regulator is developing new mechanisms to allocate scarce capacity across this interface once BETTA goes into effect. (OFGEM, December 2003)

be compensated if NGC needs to increase or decrease their output from the pre-scheduled levels to manage congestion and other network constraints.

Among other things, NGC's license conditions and associated codes and standards specify the operating procedures and principles governing NGC's relationships with all users of the transmission system (generators, distributors and retail electricity suppliers). Under it's transmission license NGC must operate the network in an efficient, economical and coordinated manner and offer its services based on non-discriminatory terms and conditions. Transmission System Security and Quality of Service Standards have been developed to govern NGC's responsibilities. These codes and standards define reliability criteria that are to be used by NGC to plan needed enhancements to the transmission system and to identify transmission investment requirements. NGC evaluates transmission investment needs and alternatives to meet these obligations on an ongoing basis. It publishes an annual Seven-Year Forward Statement[13] which provides forecasts of demand, supply, approved transmission enhancements and expected transmission enhancements that would be needed to accommodate additional generation at various locations on the E&W grid. The Seven-Year Statement is made available to provide information to new generators regarding the capabilities of the network to accommodate new generating capacity at various future dates and the network enhancements that NGC has identified as being required to accommodate new generating capacity of various amounts at different locations on the network. The Connection and Use of System Code (CUSC) specifies a contractual framework for interconnection to and use of the network. NGC is also the system operator for E&W and thus is vertically integrated into all aspects of transmission operation, maintenance and investment.[14]

NGC is subject to regulation by the Office of Gas and Electricity Markets (OFGEM). Separate but compatible incentive regulation mechanisms are applied to the transmission owner (TO) and system operating functions (SO).[15] These regulatory mechanisms effectively yield values for the revenues NGC is permitted to earn from charges for transmission service and system operations. Transmission customers (generators and retail suppliers) pay NGC for transmission service pursuant to a regulated tariff. The tariff has two basic components. The first is a "shallow" connection charge that allows NGC to recover the capital (depreciation, return on investment, taxes, etc) and operating costs associated with the facilities that support each specific interconnection (now using the "Plugs" methodology). The second component of the transmission tariff is composed of the Transmission Network Use of System Charges (TNUoS).

The general level of charges are set to allow NGC to recover its cost-of-service based "revenue requirement" or budget constraint as adjusted through the incentive regulation mechanism that I will discuss presently. The structure of the TNUoS charges

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[13] http://www.nationalgrid.com/uk/library/documents/sys_04/default.asp?action=&sNode=SYS&Exp=Y

[14] Under the recently enacted reforms, NGC's system operating functions will be expanded to cover Scotland as well (British Trading and Transmission Arrangements --- BETTA). However, in Scotland the incumbent vertically integrated companies will remain the transmission owners.

[15] http://www.nationalgrid.com/uk/ click "charging".

provides for price variation by location on the network based upon (scaled) differences in the incremental costs of injecting or receiving electricity at different locations as specified in the Investment Cost Related Pricing Methodology. So, for example, generators pay significantly higher transmission service costs in the North of England than in the South (where the prices may be negative) because there is congestion from North to South and "deep" transmission network reinforcements are more likely to be required to accommodate new generation added at various locations in the North but not in the South. Similarly, load in the South pays more than load in the North because transmission enhancements to increase capacity from constrained generation export areas benefits customer in the South more than those in the North. The current locational TNUoS charges for generation and demand are displayed in Tables 4 and 5. The objective of this pricing mechanism is stated to be:

> "… efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore charges should reflect the impact that Users of the transmission system at different locations would have on National Grid's costs, if they are to increase or decrease their use of the system. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy." (NGC, 2004)

Finally, in its role as system operator, NGC has an obligation to balance the supply and demand for energy in the system in real time (energy balancing) and to meet operating reliability criteria (system balancing). These costs include the net costs NGC incurs to buy and sell power in the balancing market (or through short-term bilateral forward contracts) to balance supply and demand at each location, including to manage congestion, provide ancillary services, and other actions it must take to meet the network's operating reliability standards. These costs are recovered from system users through an "uplift" charge based (mediated through an incentive regulatory mechanism discussed further below) on the quantities of energy supplied to or taken from the network.

The regulatory framework for determining the revenues that NGC can recover through the Use of System charges and the energy and system balancing charges is based on a set of incentive regulation mechanisms. These mechanism have a cost-of-service base, a performance-based incentive, and a ratchet that resets prices from time to time to reflect NGC's realized or forecast costs. A base annual aggregate "revenue requirement" for use of system charges is established at the beginning of each five year "price review" period (though the latest period is being extended to seven years). The starting revenue requirement is determined based on fairly standard cost of service principles. A rate base (regulatory assets value or RAV) is defined that is composed of the carrying value for the existing assets that make up the transmission system plus the forecast cost of incremental capital expenditures budgeted for next five years to meet NGC's interconnection and system security criteria described above. The final investment budget is determined by OFGEM through a public consultation process. Depreciation rates and a cost of capital (allowed rate of return) are defined and applied to the RAV to yield allowed capital

TABLE 4

Schedule of Transmission Network Use of System Generation Charges (£/kW) in 2004/2005

Generation Zone	Zone Area	Generation Tariff (£/kW)	Short Term Generation Tariff (£/kW)		
			STTEC Period = 28 days	STTEC Period = 35 days	STTEC Period = 42 days
1	Northern	9.009237	1.891940	2.364925	2.837910
2	Humberside	5.767201	1.211112	1.513890	1.816668
3	North West	6.222266	1.306676	1.633345	1.960014
4	Pennines & North Wales	4.121912	0.865602	1.082002	1.298402
5	Dinorwig	10.715347	2.250223	2.812779	3.375334
6	Anglesey	7.011370	1.472388	1.840485	2.208582
7	East Anglia	2.889748	0.606847	0.758559	0.910271
8	West Midlands	2.032089	0.426739	0.533423	0.640108
9	South Wales & Gloucs	-2.150590	0.000000	0.000000	0.000000
10	Oxon & Bucks	0.004330	0.000909	0.001137	0.001364
11	Estuary	1.733641	0.364065	0.455081	0.546097
12	Central & SW London	-6.604821	0.000000	0.000000	0.000000
13	South Coast	-1.507146	0.000000	0.000000	0.000000
14	Wessex	-3.829097	0.000000	0.000000	0.000000
15	Peninsula	-6.836065	0.000000	0.000000	0.000000

Source: NGC 2004

TABLE 5

Schedule of Transmission Network Use of System Demand Charges (£/kW) and Energy Consumption Charges (p/kWh) for 2004/2005

Demand Zone	Zone area	Demand Tariff (£/kW)	Energy Consumption Tariff (p/kWh)
1	Northern	4.940866	0.656585
2	North West	8.325173	1.100254
3	Yorkshire	8.455923	1.171611
4	North Wales and Mersey	8.709914	1.107068
5	East Midlands	10.771600	1.479424
6	Midlands	12.600874	1.733413
7	Eastern	11.007104	1.394934
8	South Wales	16.130442	2.228075
9	South East	14.321101	1.773924
10	London	16.761568	2.430277
11	Southern	15.679987	2.076489
12	South Western	17.798154	2.198679

Source: NGC 2004

charges for the starting year**.** Current allowable O&M expenditures are defined and added to the year one capital charges. A target rate of productivity improvement in O&M charges --- the "X" factor --- is then defined. The value of X is determined through a regulatory consultation process based on NGCs forecasts of O&M requirements, wage escalation, and various benchmarking studies performed for OFGEM by independent consultants. The starting value for allowed capital charges is then adjusted each year for budgeted incremental capital additions and changes in an inflation index while O&M costs are escalated based on a general price index minus "X." Unbudgeted capital expenditures during the price review period can be considered in the next price review, though NGC may be at risk for amortization charges during the period between reviews. Underspending on capital may also be considered in next price review and adjustments made going forward. After a five year (or longer) period another price review is commenced, the starting price is resent to reflect then-prevailing costs, and new adjustment parameters defined for the next review period.[16]

The regulatory mechanism is often contrasted with characterizations of cost-of-service or "cost plus" regulation that developed in the U.S. during the 20th century. There is less difference than may first meet the eye. The transmission regulatory framework applied to NGC is best characterized as a combination of cost-of-service regulation, the application of a high powered incentive scheme for O&M and investment costs for a fixed period of time, followed by a price ratchet to establish a new starting value. The inter-review period is similar to "regulatory lag" in the U.S. (Joskow 1974, Joskow and Schmalensee 1986) except it is structured around a specific RPI-X formula that employs forward looking productivity assessments, allows for automatic adjustments for inflation and has a fixed duration. However, a considerable amount of regulatory judgment is still required by OFGEM. The regulator must agree to an appropriate level of the starting value for "allowable" O&M as well as a reasonable target for improvements in O&M productivity during the inter-review period. The regulator must also review and approve investment plans ex ante and make judgments about their reasonableness ex post, though investment programs that fall within budgeted values are less likely to be subject to ex post review. An allowed rate of return must be determined as well as compatible valuations of the rate base (capital stock) and depreciation rates. Thus, there are many similarities here with the way cost-of-service regulation works in practice in the U.S. Indeed, perhaps the greatest difference is philosophical. OFGEM takes a view which recognizes that by providing performance-based incentives for regulated utilities to reduce costs consumers benefit in the long run. It has generally (though not always) been willing to allow the regulated firms to earn significantly higher returns than their cost of capital when these returns are achieved from cost savings beyond the benchmark, knowing that the next "ratchet" will convey these benefits to consumers.[17] Under U.S. regulation, the provision of incentives through regulatory lag is more a consequence of

[16] There is also an incentive regulation mechanism that governs network losses that involves annual adjustments in the benchmark.

[17] There is an least one problem with the fixed ratchet period. A dollar (or Pound Sterling) of cost savings in year 1 is worth much more to the firm than a dollar of cost savings in year 5. OFGEM recently adopted policies to equalize the returns from cost saving during the inter-review period.

the impracticality of frequent price reviews and changing economic conditions than by design.

In its role as the E&W system operator, NGC is also subject to a set of incentive regulation mechanisms. Each year forward targets are established for the costs of energy and system balancing services. A sharing or sliding scale formula is specified which places NGC at risk for a fraction (e.g. 30%) of deviations from this benchmark (up or down) with caps on profits and losses. Table 6 displays the attributes of the SO incentive mechanism in effect since NETA went into operation. OFGEM is in the process of developing a new incentive regulation mechanism that would apply to network outages that lead to variations in the fraction of "lost energy" resulting from transmission network outages (OFGEM, 2004).

This brings us finally to the transmission investment framework. NGC has the obligation to identify transmission investments required to meet its obligations under the Grid Code, the Transmission System Security and Quality of Service Standards, and the Interconnection and Use of System Code. The Transmission System Security and Quality of Service standards are engineering reliability criteria used for planning purposes that have largely been carried over from the pre-restructuring era. The Transmission System Security and Quality of Service Standards are of fundamental importance for transmission investment planning purposes. The transmission planning process is built around a set of reliability criteria designed to meet these security and quality of service standards.

The Standards specify criteria (to oversimplify) for defining a set of "boundary circuits" and associated power flows over which the generating capacity on one side of the boundary must be able to flow reliably (thermal, voltage and stability) over the boundary to serve demand there if any two circuits are out of service. NGC performs power flow studies based on forecasts of demand and generating capacity at various locations to identify boundaries (individually or collectively) where reliability criteria may violated during the forecast period. Transmission investment projects are then identified which will restore the relevant reliability criteria when and if they are expected to be violated. Depending on the nature and magnitude of the transmission investments identified, various "siting" approvals must be obtained for proceeding with actual investments. NGC will also seek to include these projects in the investment case for the subsequent price review. These planning criteria do not take the economic cost of congestion directly into account. However, the reliability criteria effectively provide firm transmission service to system users under the study conditions used for transmission planning purposes and necessarily mitigate congestion under the study conditions in the process of meeting reliability criteria. However, variations in supply and demand conditions, as well as outages of transmission facilities, can lead to congestion in real time operations. Through the balancing incentive mechanisms, NGC must pay for a share of the costs of balancing the system in the face of congestion that may arise in real time operations. This provides additional incentives to NGC to make transmission investments with short paybacks that were not included in the plan upon which the price control was based or to advance investments in the base plan to reduce congestion and

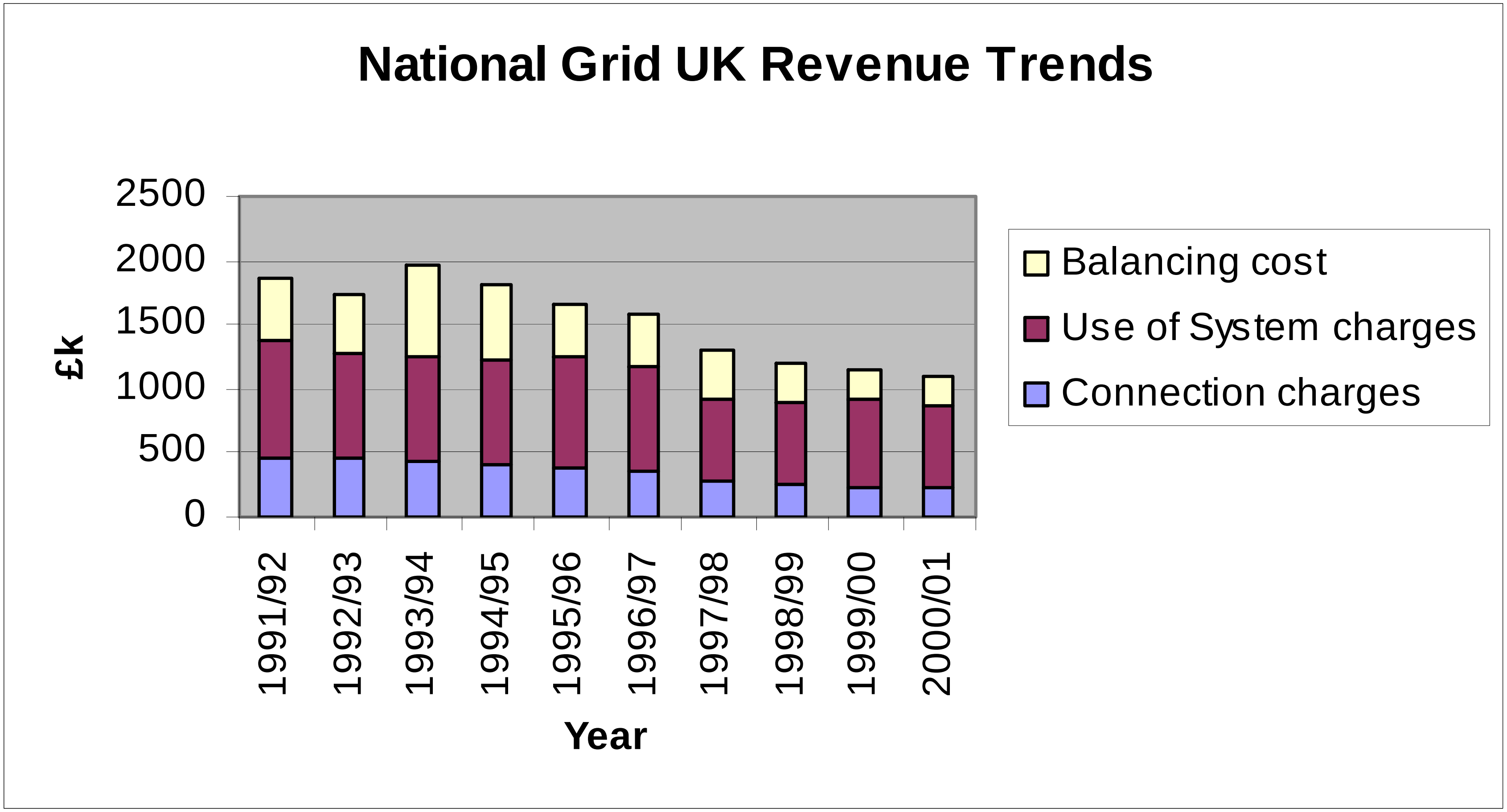
TABLE 6

England & Wales System Operator Incentive Mechanism Under NETA

Parameter	First Year	Second Year	Third Year
Target Expense	£484.6 million - £514.4 million	£460 million	£416 million
Upside Sharing	40%	60%	50%
Downside Sharing	12%	50%	50%
Cap	£46.3 million	£60 million	£40 million
Floor	- £15.4 million	- £45 million	- £40 million

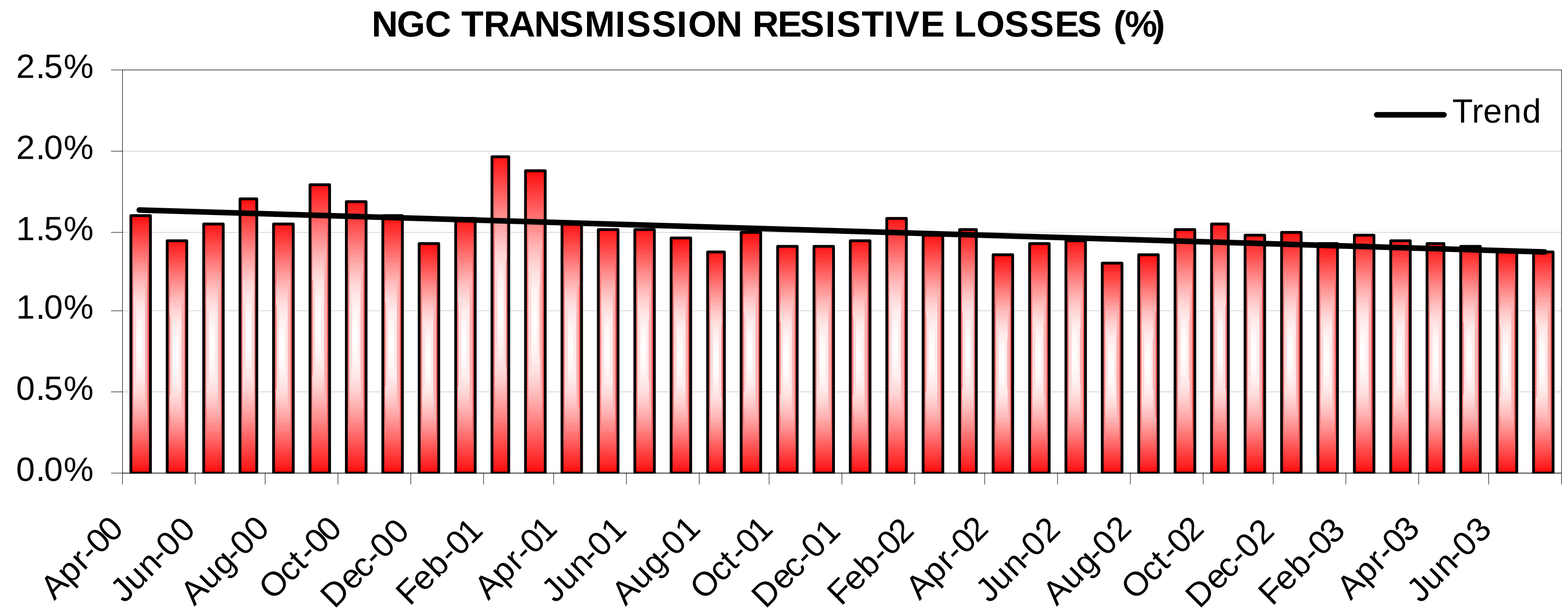
Source: OFGEM, December 2003

FIGURE 4



Source: NGC

FIGURE 5



Source: NGC

The organizational and regulatory arrangements that characterize the system in England and Wales are generally viewed to have been quite successful in supporting competitive wholesale and retail power markets with a transmission system that has attractive operating and investment results. During the period, demand grew, about 25,000 Mw of new generating capacity entered the system, and almost an equal amount was retired. Power flows changed significantly on the network. While network investment is cyclical, following cycles of generation additions and retirements, intra-control area investment post-restructuring has increased significantly compared to intra-control area investment pre-restructuring (Figure 6), while congestion costs have declined significantly since 1994. Network losses have also declined. As noted above, however, there has been no new investment in inter-connector capacity between E&W and other European countries.

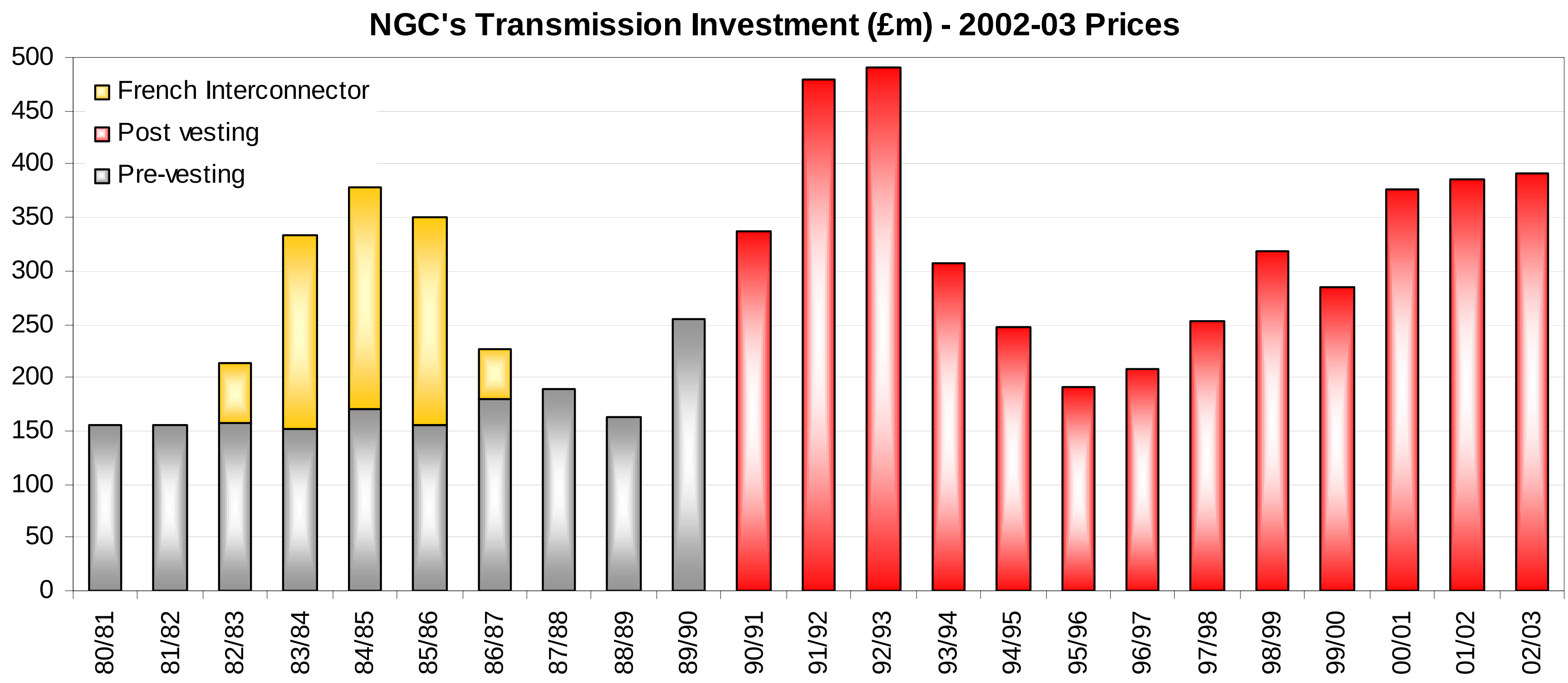
MARKET, REGULATORY AND TRANSMISSION POLICIES IN PJM

It is difficult to describe or evaluate transmission investment policies in the U.S. in a simple way. This is the case for several reasons. First, transmission policy in the U.S. has been in a constant state of change for the last decade. Second, the regulatory responsibility for important aspects of transmission policy is split between the federal government and the states and reflects the legacy of vertically integrated utilities regulated primarily by the states. Third, different states have taken very different approaches to liberalization of the electricity sector (Joskow, 2005 forthcoming). No federal laws have been enacted clearly to promote wholesale and retail competition or the changes in supporting institutions required to help to make these competitive initiatives achieve their goal of providing long-term benefits to consumers. Fourth, the availability of consistent data on transmission prices, investment, and network performance is extremely limited (U.S. Energy Information Administration, 2004). Accordingly, I will focus here on transmission pricing and investment policies in PJM where the Federal Energy Regulatory Commission's (FERC) vision for the ideal model for wholesale market design and transmission institutions (the so-called "Standard Market Design" or SMD) has been implemented and for which we now have several years of experience. A more detailed discussion of U.S. transmission pricing and investment policies can be found in Joskow (2005, forthcoming).

a. Industrial Organization of PJM and Wholesale Market Design

PJM entered the electricity liberalization era as a multi-state power pool ("tight pool") which centrally dispatched the generating facilities for vertically integrated utilities in Pennsylvania, New Jersey, Maryland, Delaware and Washington D.C. based on the marginal costs of the generating units owned by PJM's member utilities. PJM's origins and experience in economic generator dispatch, management of network reliability, and system planning can be traced back to the 1920s when it began to be created by the private vertically integrated electric utilities in this area. In 1998, the PJM

FIGURE 6



Source: NGC

agreement was restructured to turn the cost-based power pool into a set of bid-based wholesale spot power markets and supporting institutions, including transmission pricing and investment protocols.

PJM is now an Independent System Operator (ISO) and has been qualified as an RTO by FERC pursuant to Order 2000. It is structured as a for-profit limited liability company with an independent board of directors, though it presently operates de facto as a non-profit organization. PJM is not a market participant, does not own generation, transmission and distribution assets and is not engaged in wholesale or retail marketing.[19] PJM is responsible for system operating reliability and for applying reliability rules and criteria developed by regional reliability councils (MAAC in the case of the original PJM footprint). PJM's geographic footprint has expanded in the last couple of years to include transmission owners in portions of Pennsylvania that were not previously in PJM, and utilities covering portions of West Virginia, Ohio, Kentucky, Indiana and Illinois.[20] (The Midwest ISO --- MISO --- includes the transmission owners covering the rest of these Midwestern states).

The transmission owners in PJM are all vertically integrated utilities that also own generating capacity, distribution companies, and have unregulated wholesale and retail marketing affiliates. They continue to have transmission operating functions, including transmission maintenance, outage restoration, and investment responsibilities, subject to various agreements between the transmission owners and PJM and supporting FERC regulations. The prices for "unbundled" transmission service made available by these transmission owners to third parties (generators, retail and wholesale marketers, and unaffiliated distribution companies) is regulated by FERC. The prices for "bundled" transmission service that the vertically integrated transmission owners make available to their own retail customers (those who have not agreed to be supplied by competitive retail suppliers in those states with retail competition) are effectively regulated by each state as part of the overall regulation of the prices for bundled retail service. Thus, the same transmission facilities are compensated through two regulated revenue streams, one (unbundled) governed by FERC regulation and one (bundled) governed by state regulation. The prices for transmission services are set based on traditional cost-of-service or rate of return principles (as discussed in more detail in Joskow (2005, forthcoming) and below) applied to each transmission owner's facilities. Although FERC Order 2000 encourages it, there are no formal incentive regulation mechanisms applicable to costs or quality of service that is applied by FERC or the state regulators to either the TOs in the PJM area or to PJM itself.

PJM operates (voluntary) day-ahead and real time (adjustment or balancing) bid-based markets for energy and ancillary services. Market participants submit bids and

[19]In theory an independent Transco could qualify as an independent system operator RTO as well, but this would require substantial ownership restructuring in the U.S. context.

[20] The APS network (PJM-West) was integrated into PJM in April 2002. The Commonwealth Edison network was integrated into PJM in May 2004. The AEP network was integrated into PJM in October 2004. Virginia Electric Power (Dominion) is expected to become part of PJM in 2005.

offers to the day-ahead and real time markets. Locational Marginal Prices (LMP) that balance supply and demand at each location on the network and the allocation of scarce transmission capacity are performed together using a least cost bid-based security constrained dispatch (state-estimator) model that incorporates the physical topology of the network and reliability constraints. The LMPs reflect equilibrium marginal energy costs and the marginal cost of congestion at each location (marginal losses will be included soon, as in the LMP systems in New York and New England). Participation in day-ahead and real time markets is voluntary in the sense that generators, loads, and marketing intermediaries may submit their own day-ahead schedules for energy and ancillary services to the RTO and can (try) use bilateral arrangements to stay in balance in real time. However, bilateral schedules are still liable for congestion and loss charges and any residual imbalances are settled at the real time prices. Congestion is priced based on the difference in LMPs between the designated delivery and receipt points of generation supplies chosen by a transmission service customer.

Load Serving Entities (LSEs --- distribution companies or competitive retail suppliers which have responsibility for supplying retail consumers) in PJM have forward generation "capacity obligations" based on their expected peak loads in each month and must contract forward for capacity or pay penalties. PJM operates capacity markets, but it appears that bilateral arrangements govern the allocation of qualifying generating capacity. Generators must meet certain transmission "deliverability" requirements to qualify as capacity resources. As discussed further below, these deliverability requirements play an important role in the transmission investment process and in providing locational incentives to generators.

b. Transmission Pricing and Related Policies

PJM administers an open access transmission tariff that requires the transmission owners in PJM to offer transmission services at non-discriminatory cost-based prices. This tariff (along with the PJM Operating Agreement and the PJM Reliability Assurance Agreement which are interdependent) establishes prices for various categories of transmission service available to third party transmission users;[21] defines how the associated revenues are distributed to transmission owners (TO); specifies interconnection rules and obligations for generators, merchant transmission owners (none yet) and regulated TOs; specifies the definition, allocation mechanisms, accounting and settlements for financial transmission rights (FTRs); and a establishes a process for identifying and approving regulated transmission expansion projects and the allocation of the associated costs and financial transmission rights.

[21] The incumbent regulated transmission owners, all of whom were previously (and most of whom still are) vertically integrated utilities providing generation, distribution and transmission services to retail customers ("native load") do not actually purchase transmission service under the PJM open access transmission tariff to use their own transmission networks to serve their retail customers. Instead they provide the transmission service "internally" and the associated costs are included (recovered) in the regulated bundled prices they charge to their retail customers. However, they subject to all of the other terms and conditions of the PJM Tariff, PJM Operating Agreement and the PJM Reliability Assurance Agreement.

The PJM transmission tariff provides for various types of transmission service using the transmission facilities owned by the TO participants in PJM.

Firm Network Integration Service: This service was designed to replicate the cost of the "internal" transmission service available to the regulated vertically integrated utilities that made up PJM at the time the new wholesale market arrangements were created in 1998. This service is designed to make it possible for any Load Serving Entity (LSE) to integrate flexibly any generating plants it owns and power supply arrangements it makes with third parties with its retails loads. The closest analogy to the system in England and Wales are the TUoS charges applicable to demand areas. Each LSE purchasing network integration service pays a transmission access charge based on their proportionate peak demand on the network in each "transmission zone" in which power is delivered to a distribution network to serve their load. A transmission zone is effectively the geographic area served by each incumbent regulated TO. The transmission access charge is FERC regulated and equal to the average total cost of capital investments (depreciation, interest, return on equity investment and taxes) plus the operating costs of the existing transmission assets included on the network. Additional charges may be assessed to cover network enhancements necessary to provide the service consistent with PJM/MAAC reliability rules. The charges are remitted to existing transmission owners to cover their regulated cost of service. The price for this service is more or less equivalent to the transmission component of the incumbent utilities' state-regulated bundled retail prices. Depending on the delivery zone on the PJM network, prices for network integration service are in the range of \$15 - \$25/kw-year. The service is available on a yearly basis and prices can be adjusted over time based on regulatory cost-of-service formulas. This service is analogous to the use of system charges assessed to "demand" in the E&W system.

By paying these access charges LSEs also receive financial transmission rights (FTRs) or Auction Revenue Rights (ARR) which they can/must put up for auction in annual and monthly auctions operated by PJM. There are no firm physical transmission rights in the PJM system in the sense that the SO has no obligation to compensate generators if they are curtailed. However, since the LMP framework is designed to use markets to allocate scarce transmission capacity, involuntary physical curtailments should not occur in the ordinary course of events. FTRs give their holders the right to a proportionate share of the annual congestion charges (difference in LMPs between delivery and receipt points times the associated Mw of transfers) associated with the points of receipt and delivery designated in their network integration transmission service agreements (or the equivalent for incumbent vertically integrated utilities). The FTRs were designed to make it possible for LSEs to hedge the annual congestion costs associated with the sources and sinks designated in the Network Integration Service agreements.

When the new market system was initially established, FTRs were allocated to the incumbent TOs with native load obligations. They could sell their rights but had no obligation to do so. In 2003, the PJM tariff was changed to require that all FTRs (subject to a number of limitations that are too complicated to discuss here) be put up for auction in an annual and monthly auction process administered by PJM. Instead of FTRs, firm transmission service customers are allocated Auction Revenue Rights (ARRs) which entitles them to the revenues received when their FTRs are auctioned. Thus, firm transmission customers have a choice between hedging congestion costs forward by selling their FTRs in the annual and monthly auctions or (effectively) selling and then buying back the FTRs at in the PJM auction so that they can hedge congestion costs as they are realized. FTRs were originally "obligations" which could carry either a positive or negative value at a particular point in time depending on the sign of the difference in LMPs between delivery and receipt points. In 2003 PJM introduced FTR "option" rights which can take on only positive values as well as peak and off-peak FTRs.

Firm-Point-To Point Transmission Service: This service is designed to support imports in, exports out, intra-PJM transactions, and transit through the PJM system between interconnected control areas to support transactions that are not otherwise covered by Network Integration Service agreements. Short-term firm point-to point service is available on a daily (peak and off peak), weekly or monthly basis. Long-term point-to-point service is available on an annual and (by agreement with the TO) longer basis. The pricing arrangements (average total cost of the transmission network per Mw of peak demand on the network) are similar to those for network integration service except confer rights to a designated set of receipt and delivery points. Firm transmission customers are subject to congestion charges and charges for losses. They are allocated FTRs/ARRs to match the firm point-to- point transmission service they have purchased. There is no comparable service in the E&W transmission pricing scheme.

Non-firm point-to-point transmission service. This service is a "non-firm" variant of firm point-to-point transmission service. It is availably only on a monthly, weekly, daily or hourly (peak and off-peak) basis. When there is congestion indicated on the network based on day-ahead schedules, non-firm customers' schedules are curtailed first to try to relieve the expected congestion <u>before adjusting locational prices</u> to allocation scarce transmission capacity. Accordingly, if congestion can be relieved by such curtailments then congestion charges are not created. Non-firm customers have the option of responding to the curtailment requests by reducing their schedules or paying any congestion charges that are realized. Pricing arrangements are otherwise similar to those for firm service, except there would be no network enhancement charges. Non-firm transmission service customers are not allocated any FTR/ARRs in return for paying for this service. There is no analogy to this in the E&W system where both generators and loads pay for firm network service.

As noted above, the price for each type of transmission service offered by PJM is based on traditional regulatory cost-of-service/rate-of-return formulas applied to one of more TOs in the transmission zones where delivery points are designated. In addition, the probability of and costs of congestion depend, in part, on the availability of transmission facilities. But while PJM coordinates transmission maintenance schedules, it is each of the TOs that is responsible for physically operating and maintaining the transmission facilities it owns. PJM does not own any transmission facilities, does not have maintenance personnel and equipment and cannot penalize or reward TOs for variations in the availability of their facilities. Capital, operating and maintenance costs for transmission service must be recovered by the TOs through a convoluted mix of FERC and state cost-of-service regulation. In Order 2000, FERC encouraged RTOs to develop and propose performance-based-regulation (PBR) mechanisms that would apply to owners and operators of regulated transmission assets. None of the Northeastern RTO/ISOs has developed or applied PBR mechanisms to date and no formal regulatory mechanisms are in place to encourage TOs to cut operating costs, to improve the availability of transmission equipment, or to respond quickly to especially costly unplanned equipment outages.

Transmission prices charged to generators: Generators (or merchant transmission projects interconnecting with the PJM network) are not required to pay a separate transmission service charge to use the PJM network. Thus, technically generators are not required to pay a fee equivalent to the generation component of the TUoS charges in E&W. However, as discussed below, they must pay for the costs of interconnection facilities, network upgrades required to restore PJM/MAAC reliability criteria if their interconnection leads to violations of these criteria, and any costs of meeting MAAC generator "deliverability" criteria if the generators want to be certified as "capacity resources," as almost all generators do. As discussed further below, about 65% of the regulated transmission investments identified in PJM's latest Regional Transmission Expansion Plan update (July 2004) fall in one of these last two categories and are paid for by new generators (or merchant transmission links) seeking to connect to the network.

As far as PJM is concerned, generators deliver power at their point of interconnection with the network and are paid/billed based on the associated LMP. Accordingly, they are not assessed congestion charges directly. However, whether or not generators pay network congestion charges de facto depends on their agreements with buyers of power and whether it is the buyer or the seller that is providing the supporting transmission service to get the power from the point of delivery to the point of receipt.

c. Transmission Investment Framework

Transmission investments in PJM are grouped into several categories:

Direct interconnection investments: When a new generating unit or merchant transmission projects seeks to connect to the PJM network, the TO in whose transmission zone the project will be located performs a study of the direct capital and operating costs associated with the new transmission facilities require to make the direct connection to the network. The proposed generating project is responsible for 100% of these direct interconnection costs. About $304 million of investments that appear in PJM's July 2004 Regional Transmission Expansion Plan (RTEP) update fall in this category, out of a total approved projects of about $785 million.[22] Direct interconnection costs are therefore treated similarly in PJM and E&W.

[22] The $785 million figure covers projects completed since 2000 as well as future projects that are scheduled for completion over the next few years. The rate of investment is significantly lower than in E&W from 1990 - 2001, though the systems have similar peak loads.

Interconnection Network Reliability Investments: PJM and the TO in whose transmission zone the facility is located also evaluate the impact of the proposed project on network reliability. A series of engineering studies are performed to assess whether the proposed project, as an increment to the existing facilities on the network, will lead to any violations of PJM/MAAC reliability criteria. These criteria are much more complex than the simple N-1 operating reliability criterion that is often discussed in the literature. The reliability assessments involve a set of assumed study conditions under various contingencies: when all facilities are operating; N-1; N-2; multiple contingencies; and delivery to load criteria. These criteria and their application have not changed significantly since before the new PJM markets were created and take no account of the LMP mechanisms or of the associated market mechanisms for allocating scarce transmission capacity. If the engineering studies indicate that reliability criteria are violated, the expected costs of network investments required to restore the reliability parameters are identified. The proposed generator will be required to pay for these costs, though they may be shared with other generators in the construction pipeline that benefit from these network enhancements (the cost allocation mechanism is fairly complicated). The generator will receive its proportionate share of any new FTR/ARRs created as a consequence of the network facility enhancements it is required to pay for.

It is important to note that these reliability assessments are based on a set of engineering assumptions and study conditions that may be little relationship with the way the network would actually operate if the network enhancements where not made and increased congestion were realized. That is, if the generators were built and these "deep" network enhancements were not made, the network would not necessarily suffer a violation of its operating reliability criteria. Instead, redispatch would have to be used to balance the network.

Generator Deliverability Investments: If a generator or HVDC merchant transmission project wants to qualify as a "capacity resource" under PJM's Reliability Assurance Agreement and wholesale market Operating Agreement, as is typically the case since there is significant "capacity value" in the PJM market, they must meet a final "reliability" criterion called "generator deliverability." Engineering studies are performed to determine whether (oversimplifying a complex process) the full power that the proposed generator can produce can be reliably delivered outside of its transmission zone under a set of engineering study conditions that assume all existing generators are dispatched first to meet load.[23] If the generator deliverability condition is not satisfied the generator must either pay for any necessary network enhancements (and receive any incremental FTR/ARRs) or purchase firm transmission service that supports deliverability from a third party. Interconnection network enhancements and deliverability network reliability enhancements together account for about $207 million of investments in PJM's latest RTEP update (July 2004). These obligations are conceptually most similar to the generator component of the locational TUoS charges in E&W. Thus, generators are obligated to pay for about $511 ($304 million direct interconnection + $207 million "deep" network upgrade investments) of the roughly $785

[23] New generator deliverability criteria were recently proposed.

million of transmission investments approved through the PJM planning process or about 75%. Thus, PJM effectively has a "deep" interconnection pricing policy.

It should be noted that interconnection network investments and deliverability network investments provide potentially powerful locational incentives to new generating projects. The network upgrade costs at some locations may be zero (or even negative) and at other locations these costs may be substantial (as are the generator TUoS charges in E&W). New generators can reduce their investment costs by selecting a location where these network upgrade obligations are low rather than high. It is likely that these interconnection network upgrade cost obligations play a more important role in generator location decisions than do variations in LMPs.

Other network reliability investments: The PJM RTEP process may indicate that one or more PJM/MAAC reliability criterion is expected to be violated for other reasons e.g. load growth or generator retirements at specific locations. PJM can direct TOs to make the necessary investments required to restore the reliability parameters. The associated costs are then recovered from charges to the load that benefits from the investments. These costs amount to about $274 million in the 2004 RTEP. This appears to be the fastest growing category in the RTEP planning process and would include network upgrades required as a consequence of retirements of existing generating facilities.

Merchant transmission investments: The original design of the PJM system was predicated on the assumption that any "economic" transmission investments that were not required for "reliability" would be made on a merchant basis. The costs of merchant transmission projects would be borne by the developer and the developer in turn would receive the financial transmission rights created by the investment. The incentive for merchant investment would then be the market value of the transmission rights created by the project. The associated expected value of the transmission rights created is then the expected difference between the LMPs between the affected delivery and receipt points times the incremental transmission capacity between these ponts created by the investment (Joskow and Tirole 2004a). In the case of AC facilities, a merchant investor would receive any incremental FTR/ARRs resulting from the investment. HVDC merchant transmission facilities are treated like generators and effectively create physical import or export rights to the AC network.

Merchant transmission projects must also pay for direct interconnection and "deep" network upgrade costs in essentially the same way as do new generators. Table 7 illustrates the results of the PJM interconnection study process and the estimated costs of direct interconnection and "reliability" network upgrade costs for a proposed merchant HVDC project under Lake Erie connecting Ontario with Pennsylvania (now cancelled). The total interconnection costs for this project were estimated to be $102 million of which 10% were direct interconnection charges and 90% "deep" network upgrades to restore a long list of reliability problems expected to be created by the project.

TABLE 7
PJM INTER-CONNECTION CHARGES
PROPOSED ERIE-WEST HVDC

Transmission Interconnection Queue #G00_MTX3 is a TransEnergie U.S. Ltd. request to connect the southern terminal, of the Erie West to Nanticoke HVDC intertie, to the Erie West 345 kV substation. TransEnergie proposes to construct a HVDC converter station in the vicinity of Erie West, and a double circuit 345 kV line to connect Erie West to the converter station. The northern terminal of the intertie will be connected to Nanticoke substation in the Ontario Hydro system. The interconnection request is nominally rated at 1000 MW net of losses on the HVDC system. The developer has requested Firm (Capacity) Transmission Injection Rights in the amount of 1000 MW and Firm Transmission Withdrawal Rights in the amount of 1060 MW at the HVDC terminal in PJM. Project #G00_MTX3 is scheduled for commercial operation in 2004.

Direct Connection Facilities: $9.5 million

"Deep" Network Upgrades: $91.5 million

- Single contingency
- Second contingency
- Multiple facility contingency
- Generator Deliverability
- Other

Total Cost interconnection cost : $102 million
3.5 year construction time

Source: PJM

PJM's "deep" interconnection pricing policies for new generators and merchant investment projects are not typical of the pricing of interconnection and transmission use of system services elsewhere in the U.S. A "shallow" interconnection policy is more typical in the U.S. Generators pay direct interconnection charges as in PJM. The costs of network upgrades deeper in the network are then typically rolled in with the legacy network costs to create use of system charges that are identical at all interconnection points on an individual TO's network. FERC's most recent interconnection rule provides for shallow rather than deep interconnection charges.[24] As RTOs have grown, FERC has endeavored to (effectively) reallocate these costs to eliminate "pancaking" and to shift network use charges to load from generators (Joskow 2005, forthcoming). These reallocations of transmission costs have been quite controversial.

Several merchant transmission projects have been proposed through the PJM interconnection and regional transmission planning process, primarily DC interconnectors with neighboring control areas. Two transformer upgrades have been made by a TO in PJM as merchant projects in return for FTRs. None of the proposed DC interconnectors have yet gone into construction and several have been cancelled. The most active projects are HVDC interconnections between PJM and New York City and Long Island. The farthest along is a project that has been awarded a long term contract for transmission between PJM and Long Island by the Long Island Power Authority (LIPA), a municipal utility which can pass the associated costs on to its regulated customers without approval of a state or federal regulatory agency. LIPA already has a long term contract for all of the 330 Mw capacity of the Cross Sound Cable connecting New England with Long Island, the only "merchant" project completed so far in the U.S.

HVDC links to New York City and Long Island are especially attractive for a number of reasons. The LMPs in NYC and Long Island are consistently significantly higher than those in neighboring areas --- about $20/Mwh on an annualized basis. In addition, these are both very difficult places to find sites for new power plants and have extremely high construction costs. In addition, HVDC links from PJM and New England can be brought in under water where NIMBY issues should be less of a problem (though this did not mute the controversy over the Cross Sound Cable process). Finally, on Long Island there is a municipal distribution utility that is willing and able to sign long term contracts for the transmission capacity developed in this way. This means that the developer does not have to rely on differences in spot market LMPs to produce the revenues for the project, reducing financing costs and opportunism problems.

Economic Planned Transmission Facilities: PJM resisted doing any analysis of "economic" transmission investment opportunities or including such potential investments in its regional transmission plan and requiring TOs to proceed with them if merchant investors did not show any interest in them. As before, by "economic transmission" investment opportunities I refer to transmission investments whose expected economic benefits arise from reducing congestion (and losses). When the

[24] FERC Order 2003, "Standardized Generator Interconnection Procedures," July 23, 2003.

expected incremental reduction in congestion and loss costs exceeds the incremental cost of the network enhancement then the investment is "economical."

PJM's dream that the invisible hand would lead merchant investors to come forward to make intra-TSO investments in response to congestion rents has not been matched by reality. After a contentious regulatory proceeding, in 2003 FERC issued an order that required FERC to include potential "economic" transmission investments in its planning process. PJM has now developed a process to identify transmission constraints that create "unhedgeable congestion" and to assess the benefits and costs of potential network enhancement projects that would mitigate this congestion. When projects that mitigate unhedgeable congestion are identified and pass certain cost/benefit thresholds they are included on a "market window" list. The projects on this list are then open for one year to proposals from merchant investors. If satisfactory proposals are not forthcoming, PJM may direct incumbent TOs to build the projects as regulated projects and include them in the PJM tariff for cost recovery. The process is complex, still evolving, and the phrase "unhedgeable congestion" somewhat misleading.

This process is complex and still evolving. Moreover, the phrase "unhedgeable congestion" is somewhat misleading. The process for identifying so-called unhedgable congestion actually yields an estimate of the <u>costs</u> of congestion after netting out congestion <u>rents</u>. To oversimplify,[25] PJM defines unhedgeable congestion as congestion which cannot be hedged with the existing portfolio of FTRs. The easiest way to think about the "unhedgeable" congestion concept is in a two-node network (see Figure 3). There is an elastic supply of cheap generation in the North with marginal cost c_N. There is expensive generation in the South with constant marginal cost $c_S > c_N$. There is a transmission link between North and South with capacity K. There is demand in the South of D > K (demand is assumed to be completely inelastic). The competitive equilibrium involves the supply of K Mw of generation from the North, D-K Mw of generation from the South and locational prices in the North and the South of c_N and c_S respectively. The transmission congestion <u>rents</u> produced by the scarce transmission capacity is $(c_S - c_N)K$ and the social cost of congestion is $(c_S - c_N)(D-K)$. If PJM has K Mw of FTRs available for allocation to users of the transmission link then the transmission congestion rents associated with the interconnector capacity K are "hedgeable." The value $(c_S - c_N)(D-K)$ would be defined as "unhedgeable" congestion according to PJM's definitions which, in this simple example, is the social cost of congestion. Indeed, the best way to think of PJM's unhedgeable congestion concept is as an approximation to the social cost of congestion. And this appears to be the number that one actually would want to use in order properly to evaluate potential "economic" transmission investment opportunities. For the 14-month period August 2003-September 2004 there was \$1.6 billion of "gross" congestion in PJM (including congestion rents), of which \$336 million was defined as "unhedgeable". [26]

[25] For a detailed discussion of the procedures that were recently adopted by PJM see PJM FERC Filing in Docket Number RT-01-2-01, dated April 21, 2004. http://www.pjm.com , accessed June 15, 2004.

[26] PJM congestion spreadsheet downloaded from www.pjm.com on December 4, 2004.

Where unhedgeable congestion is identified, a set of simple cost benefit assessments are then performed by PJM. The actual unhedgeable congestion values attributed to each constraint over the previous 12-month period is divided by the estimated cost of a transmission upgrade that would mitigate the congestion costs identified.[27] This is defined as the "benefit/cost ratio," though it is actually a measure of the simple payback period for each identified investment opportunity assuming that congestion rents do not change in the future. When these assessments yield benefit/cost ratios that exceed certain specified thresholds a project is put on a list of potential regulated "economic" transmission projects. Market participants are then given a year to propose alternative "market solutions" to the identified projects. If market solutions are not forthcoming the projects are added to the PJM Regional Transmission Expansion Plan and the incumbent TOs in whose transmission zones the projects are located are directed to make the investments. The resulting costs, net of revenues from the auctioning of ARRs created by the investments, are then recoverable through the PJM Open Access Tariff from the customers of the LSEs who are expected benefit from the investments. The responses to the first "market window" open for proposals to resolve this economic congestion are due in early 2005.

Roughly 50 potential "economic" transmission investment projects have been identified since this evaluation process was implemented in March 2004 and "market windows" are now open for merchant projects to fill these needs before regulated transmission projects are added to the Regional Transmission Expansion Plan (RTEP).[28] The cost-benefit analysis indicates that seven of the identified projects have simple paybacks of three months or less (again, assuming that unhedgeable congestion does not change in the future). Another 12 have simple paybacks of less than four years (see Table 8). If FERC had not forced PJM to examine "economic" transmission investment projects, all of these would have been left on the table in the hope that merchant investment would eventually come forward. It should also be noted, that in several cases, fairly small investments completely eradicate the congestion so that they are not conducive to being supported by merchant investments.

Inter-TSO (interconnector) investments: The expansion of interconnections with neighboring control areas is not included in the PJM planning process, though procedures are in place that govern the rules governing pricing of the costs of interconnecting inter-TSO facilities to the PJM network. Accordingly, by default, inter-TSO transmission investments are left to merchant developers. As already discussed, a few merchant HVDC links with New York City and Long Island have been proposed and at least one is likely to move forward, supported by a 20-year contract with the Long Island Power Authority (LIPA). There is little if any additional merchant investment activity on the

[27] Unlike the New England ISO, PJM has refused to include congestion forecasts in its planning process.

[28] PJM FERC Filing in Docket Number RT-01-2-01, Appendix 1, dated April 21, 2004 and PJM "market window" spreadsheet downloaded December 4, 2004. Available on the PJM web site www.pjm.com.

horizon. However, by incorporating neighboring TSOs into PJM, it is effectively internalizing inter-TSO transmission investment opportunities (as well as integrating generator scheduling, wholesale market, and congestion management mechanisms) into the intra-TSO transmission investment planning process. As these additional TSOs are integrated into PJM, the PJM generator interconnection, reliability, and economic investment protocols will apply to what were previously inter-TSO opportunities that have largely been ignored due to the balkanization of transmission ownership and system operations. Just as a fairly large number of "economic" transmission investment opportunities popped up once PJM actually looked for them, I expect that many more "reliability" and "economic" projects will emerge as PJM's transmission planning footprint grows to incorporate what were previously separate TSOs.

Despite the investment in new intra-TSO facilities in PJM, congestion charges in PJM continue to grow. See Table 1. Moreover, the prospect of a growing number of generation retirements is also leading to a need for network reliability investments. Since there are no exit fees, these charges are likely to be paid for by the TOs in the areas where the retiring generators are located (PJM, 2004).

TABLE 8
MARKET WINDOW PROJECTS IN PJM
As of November 2004

MONITORED FACILITY	* Unhedgeable Congestion $	Limit	Cost to Relieve Limit	Cost / Benefit
LINE 230 KV ADA-BRUX	$1,091,588	Circuit Switcher	$200,000	< 0.25
LINE 500 KV BED-BLA	$1,607,237	Wavetrap	$75,000	< 0.25
BED-BLA	$83,999,705	Voltage	$5 - $25 Million	< 0.25
LINE 230 KV ADA-BENX	$4,146,221	Circuit Switcher	$200,000	< 0.25
LINE 138 KV BRU-EDI	$1,134,130	Circuit Switcher	$200,000	< 0.25
LINE 69 KV SHI-VIN	$3,397,773	Conductor	$500,000	< 0.25
LINE 500 KV FTM-PRU	$307,337	Disconnect Switch	$45,000	< 0.25
PJMW500	$3,284,457	Voltage	$5 - $25 Million	0.25 - 4
LINE 230 KV NWA-WHI	$2,739,456	Conductor	$1,000,000	0.25 - 4
EAST	$2,264,606	Voltage	$5 - $25 Million	0.25 - 4
JACK ME 230 KV 4 BA-P	$2,454,986	Transformer	$2,500,000	0.25 - 4
YORKANA 230 KV 1A BANK	$1,647,801	Transformer	$2,500,000	0.25 - 4
LINE 230 KV CED-CLIK	$709,851	Disconnect Switch	$50,000	0.25 - 4
LINE 230 KV BER-HOB	$654,222	Cable	$2 Million	0.25 - 4
LINE 138 KV EDI-MEAR	$499,774	Circuit Switcher	$200,000	0.25 - 4
LINE 500 KV ELR-HOS	$112,364	Wave Trap	$300,000	0.25 - 4
LINE 69 KV EDG-NSA	$47,120	Disconnect Switch	$20,000	0.25 - 4
LINE 230 KV BRA-FLA	$200,355	Wave Trap	$200,000	0.25 - 4
JACK ME 115 KV 5 BA-S	$9,272,381	Transformer	$2,500,000	0.25 - 4

* previous 12 months
Source: PJM Market Window spreadsheet downloaded, December 4, 2004. www.pjm.com.

"RELIABILITY" VS. "ECONOMIC" TRANSMISSION INVESTMENT

All economic models of transmission investment that I am aware of focus on transmission investment as a mechanism to reduce the costs of congestion (e.g. Joskow and Tirole 2000, 2004a). Some (properly) include the cost of losses as well. When transmission capacity is congested, high cost generation must be substituted for low cost generation to balance supply and demand. The incremental cost of the high cost generation that must be dispatched due to transmission capacity constraints plus any dead weight loss associated with reduced demand resulting from higher locational prices is the cost of congestion. Transmission investment should then optimally be made (ignoring lumpiness, market power and other market imperfections) up to the point where the incremental cost of transmission capacity is equal to the incremental reduction in the expected present discounted value of congestion and loss costs. These models bear little if any relationship to the way intra-TSO transmission investments are actually evaluated by TSOs in the U.S. and E&W.

As we have seen, in E&W and PJM, virtually all of the transmission investments that have been approved have been justified either by direct interconnection costs or by "reliability" considerations.[29] The E&W system does not even appear to have a transmission investment concept akin to economic transmission investments that are justified by savings in congestion costs aside from the incentives to reduce congestion costs embodied in the SO incentive mechanism. In New England, with a similar market design to PJM's, the New England ISO manages a very detailed regional transmission expansion planning process that examines needs and opportunities for both "reliability" transmission investments and "economic" transmission investments. This process includes models that forecast congestion. The latest update to the New England ISO's regional transmission expansion plan identified $2 billion ($1.5 to $3.0 billion) of transmission investment projects and essentially all of them are justified as "reliability" investments (ISO-NE, 2004). Not a single project was identified which could be supported by congestion cost savings alone.

In fact, many network upgrade investments that are justified on "reliability" grounds could just as well be categorized as "economic" transmission investment opportunities. In many cases, if the investments were not made, the network could still be operated "reliably," but there would be more congestion, more controlled load shedding, and much higher prices in some areas. Moreover, many reliability investments affect the future trajectory of LMPs and incentives for generation and transmission investments. On the other hand, "economic" transmission investments can also often confer "reliability" benefits as well. Thus, in my view, at the very least, reliability and economic transmission investments are interdependent. At worst, the distinction between them is analytically flawed. Moreover, the distinctions between reliability driven and congestion cost driven transmission investments creates a very significant asymmetry between the treatment of intra-TSO network investments and inter-TSO network

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[29] In E&W an unknown portion of additional transmission investments or planned reliability investments that were moved forward to an earlier date were driven by the annual SO incentive scheme. As previously discussed, PJM has adopted a new framework for regulated economic investments.

investments. The former are evaluated and priced as reliability investments while the latter must be justified and paid for based on congestion cost savings alone, by default on a merchant basis.

It is fairly clear that transmission investments driven by reliability criteria have significant effects on LMPs and network congestion. In addition, discretionary changes in system operating practices, including changes in the ways that operating reliability criteria are applied or evaluated, can have a dramatic effects on the "capacity" of portions of the network and on the resulting congestion rents and congestion costs.

In the studies underlying the New England ISO's 2004 regional expansion plan it is quite evident that reliability investments get triggered well before locational prices or congestion are allowed to rise anywhere close to the value of lost load (ISO-NE, 2004b). In PJM, the data that have been made public regarding "economic" transmission opportunities also make it clear that reliability investments can have a very significant impact on transmission congestion and the incentives for transmission investment to reduce congestion costs. Of the roughly 50 projects initially listed in the "market window" for potential regulated "economic" transmission investment, 16 projects subsequently were tagged with the notation "reliability upgrade expected to mitigate congestion." One of these projects had 12-month unhedgeable congestion (congestion cost) of $192 million. The full list is contained in Table9. Two additional projects were designated as benefiting from changes in operating practices. One of these projects has 12-month unhedgeable congestion costs of $90 million. These example are, of course, only indicative of the more general observation that so-called reliability transmission investments, as well as discretionary changes in operating practices and study assumptions, can mitigate a lot of congestion that would otherwise emerge on the network well before it is actually revealed. This in turn has implications for the consideration of economic transmission investment models that are driven by the tradeoff between transmission investment and the costs of congestion. In particular, for a potential merchant investor, the possibility that reliability driven transmission upgrades and discretionary changes in operating practices and the implementation of operating reliability criteria will significantly reduce or eliminate congestion, is likely to be a significant deterrent to investment that must be supported from congestion rents.

This discussion should not be read as implying either that reliability criteria are unnecessary (in Joskow and Tirole 2004b we explain why operating reliability criteria are necessary due to the threat of network collapses that make reliability a public good) or that they have been set incorrectly. It does imply two things (a) we need to better understand the economic justification (costs and benefits) for these reliability criteria and (b) economic models of transmission investment need to take into account the factors that create a need for reliability criteria and the impacts of reliability criteria that are applied in practice.

TABLE 9
Examples of Transmission Congestion Mitigated by Reliability Investments in PJM

MONITORED FACILITY	* Unhedgeable Congestion $	Limit	
LINE 230 KV GRE-POR	$268,024	Line Trap	RTEP Reliability Upgrade Expected to Mitigate Congestion
WYLIERID500 KV TRAN 5	$6,797,499	Transformer	RTEP Reliability Upgrade Expected to Mitigate Congestion
CEDAR	$5,480,787	Voltage	RTEP Reliability Upgrade Expected to Mitigate Congestion
BRANCHBU500 KV 500-1	$192,863,356	Transformer	RTEP Reliability Upgrade Expected to Mitigate Congestion
BRANCHBU500 KV 500-2	$3,556,256	Transformer	RTEP Reliability Upgrade Expected to Mitigate Congestion
NORTH PE	$1,841,999	Voltage	RTEP Reliability Upgrade Expected to Mitigate Congestion
LINE 138 KV LAN-MIN	$383,541	Line Trap	RTEP Reliability Upgrade Expected to Mitigate Congestion
LINE 69 KV LEW-MOT2	$180,726	Stranded Bus	RTEP Reliability Upgrade Expected to Mitigate Congestion
LINE 230 KV MAR-MRP	$61,392	Wavetrap	RTEP Reliability Upgrade prior to spring of 2004
LINE 138 KV GLA-MTP	$1,738,983	Conductor	RTEP Reliability Upgrade Expected to Mitigate Congestion
LINE 69 KV BEC-PAU	$536,976	Conductor	RTEP Reliability Upgrade Expected to Mitigate Congestion
HUDSON 230 KV HUDSON2	$138,865	Transformer	RTEP Reliability Upgrade Expected to Mitigate Congestion
WYEMILLS138 KV AT-2	$316,952	Transformer	RTEP Reliability Upgrade Expected to Mitigate Congestion
SICKLER 230 KV SICK #1	$592,446	Transformer	RTEP Reliability Upgrade Expected to Mitigate Congestion
LINE 69 KV CED-SAN	$209,335		RTEP Reliability Upgrade Expected to Mitigate Congestion
LINE 69 KV TAL-TRA	$30,141	Conductor	RTEP Reliability Upgrade Expected to Mitigate Congestion

*Previous 12 months

CONCLUDING THOUGHTS

Major questions have been raised about whether and how efficient levels of transmission investment can be mobilized in liberalized electricity sectors. Significant barriers to efficient transmission investment continue to exist in many countries with liberalized electricity sectors. These barriers are primarily institutional rather than fundamental. The experience in England and Wales demonstrates, however, that liberalization does not necessarily lead to depressed levels of transmission investment. The experience in PJM illustrates that regional planning mechanisms and transmission investment criteria can be used effectively to identify transmission investment needs and to price transmission services to provide good locational incentives. The PJM experience also illustrates some of the problems of separating SO and TO functions, vertical integration of TOs with generation, and the bifurcation of regulatory responsibilities between incompatible state and federal regulatory processes. Let me supplement the summary of my conclusions contained in the Introduction to this paper with the following observations.

Industrial structure: Many countries have failed to fully restructure their electricity sectors to support competition. The creation of independent regulated TSOs with system operations, transmission network ownership, maintenance and investment responsibilities with adequate geographic scope is the foundation of efficient operations and investment programs. The full unbundling of transmission service prices subject to a single regulatory regime is a natural complement to the creation of such TSOs. The structure adopted in England and Wales is superior to the RTO structure being promoted in the U.S. However, both are superior to structures with no ISO at all.

Geographic scope: TSOs typically span only portions of larger synchronized AC networks. The mobilization of investment for intra-TSO transmission enhancements is much better developed than is the mobilization of inter-TSO transmission investments. This was a problem (perhaps not perceived) before liberalization and it is a continuing problem today. In the U.S., the effort to consolidate control areas under larger RTOs provides one path to reducing the "seams" problems at the boundaries between TSOs. The creation of a single TSO for Great Britain that covers Scotland, as well as England and Wales, reflects a similar motivation. However, there are practical and political limits on the consolidation of TSOs in many countries. This implies that new cooperative mechanisms need to be developed to harmonize reliability criteria, economic criteria, transmission pricing and investment policies, and wholesale market mechanisms to better integrate inter-TSO behavior so as to smooth out the seams as much as is feasible.

Regulatory framework: Most of the transmission infrastructure that is in place and future investments in it are likely to be governed by some regulatory framework. A clear, credible and transparent regulatory framework that specifies the TSO's responsibilities, performance norms, and regulatory mechanisms consistent with these objectives and performance norms is essential. All regulatory frameworks are imperfect. However, there is no choice but to draw on available experience and regulatory tools to develop and to apply the best feasible regulatory frameworks. A practical regulatory framework will inevitably include a mix of cost-of-service regulation with an overlay of performance based regulatory (PBR) mechanisms based on benchmarking, profit sharing (sliding scale) and "ratchets." The development and application of performance norms, formal investment criteria, as well as considerable regulatory judgment is an inevitable component of a sound regulatory process. One component of such a regulatory framework is a transparent regional transmission investment planning process with clear rules for achieving defined reliability and economic goals. The regulatory framework in E&W has many attractive properties. The bifurcation of regulatory responsibilities in the U.S. and the failure to fully unbundled transmission service prices create significant disincentives to efficient transmission investment.

Reliability vs. economic investments: The liberalization programs in most countries carried along with them the planning and reliability rules and evaluation criteria from the era of regulated vertically integrated monopolies. Transmission investment activity today is driven almost entirely by reliability criteria. Where did these criteria come from? Why are they the right criteria? Little effort has been made to review these rules and criteria in light of the development of markets that both provide information that can be used to evaluate the costs and benefits of these reliability standards and provide market mechanisms that can be used to achieve reliability criteria more effectively. Intra-TSO reliability driven transmission investments and intra-TSO congestion cost driven investments are, at the very least, interdependent. At worst the distinctions between them are not particularly useful. Clearly, economic and reliability criteria need to be better integrated into the transmission investment planning and regulatory arenas. Modest steps to do so are now taking place in the RTOs in the Northeastern and Midwestern U.S.

Investment characteristics: Transmission investment opportunities involve much more than the construction of major new transmission links. Because many transmission limitations reflect contingency limits and associated reliability rules (which should be re-evaluated as noted above), there are often investment opportunities of modest cost that can increase significantly transmission capacity. The institutions and regulatory mechanisms to identify and undertake these opportunities need more attention. This is especially important in an era when it is difficult to obtain permission to build new transmission corridors.

Merchant transmission investment: Market driven transmission investment may be a complement to regulated transmission investment but it is not a substitute. Merchant transmission investment has and is likely to make a very small contribution in the overall portfolio of transmission investment projects that will be made in the future. The efforts to debate its role have been a distraction from more productive initiatives.

Wholesale market design: Efficient transmission network operation and investment decisions are necessarily interdependent with the design, operation, incentives and price signals generated by the wholesale markets for power and ancillary services. Good wholesale market design, the efficient allocation of scarce transmission capacity, and efficient investment programs go hand in hand and cannot be easily separated.

Economic models of transmission investment: The simple models of transmission network congestion and investment that are used by economists have little to do with the way transmission investment is actually planned, developed, and the associated transmission services priced within the boundaries of individual TSOs today. Economic models and analysis need to be expanded to better capture the factors that TSOs and regulators consider when they identify transmission investment needs, especially as they relate to the implementation of reliability criteria used for planning and system operations. Economists and network engineers need to develop better ways to work together.

We have made a lot of progress in understanding the challenges associated with stimulating efficient levels of transmission investment in liberalized electricity markets but there is still a lot of work to do.

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