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Different Approaches Towards Electricity Transmission Expansion

ABRIL 2003

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Acknowledgements.

The author is grateful to William Hogan and Ingo Vogelsang for very helpful suggestions and discussions. I also thank Tarjei Kristiansen for his comments. The research reported in this paper was supported by the Comisión Reguladora de Energía in a grant to Centro de Investigación y Docencia Económicas (CIDE)

Abstract

There is a growing interest, both in theory and practice, on the variables that determine investments in electricity transmission. The way to resolve short-term congestion is known from the literature on power flows, nodal prices and transmission rights. However, there is an intense debate regarding the way to attract investment to finance the long-term expansion of the transmission network. We study three existing hypotheses that rely on distinct institutional set ups: the long-term financial-transmission-right hypothesis, the incentive-regulation hypothesis, and the market-power hypothesis. The first approach, also known as the "merchant" alternative, tries to derive optimal expansion through the auction of long-term financial transmission rights by an independent system operator. The second one tries to make sure that the transportation company (or Transco) faces the entire social cost of transmission congestion, so that it has incentives to expand the network. The third alternative method defines optimal expansion of the transmission network according to the strategic behavior of generators with market power. This paper surveys the significant contributions made in each of these three areas, and discusses the analytical and practical strengths and weaknesses of each approach.

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Resumen

Existe un creciente interés, tanto en la teoría como en la práctica, respecto a las variables que determinan la inversión en transmisión eléctrica. La forma de resolver los problemas de congestión de corto plazo es concoida en la literatura sobre flujos de potencia, precios nodales, y derechos de transmisión. Sin embargo, existe un intenso debate sobre la forma de atraer inversión para financiar la expansión de largo plazo de la red de transmisión. Estudiamos tres hipótesis existentes que dependen de diferentes marcos institucionales: la hipótesis de derechos financieros de transmisión de largo plazo; la hipótesis de regulación por incentivos, y la hipótesis de poder de mercado. El primer enfoque, también conocido como la alternativa "de mercado", consiste en derivar la expansión óptima a través de la licitación de derechos financieros de transmisión de largo plazo por parte de un operador independiente del sistema. El segundo enfoque consiste en asegurar que la compañía de transmisión (o Transco) enfrente costo social total de la congestión en transmisión, de forma tal que tenga incentivos para expandir la red. El tercer método alternativo define la expansión optima de la red de transmisión de acuerdo al comportamiento estratégico de los generadores con poder de mercado. Este documento

examina las principales contribuciones hechas en estas tres áreas, y discute las fortalezas y debilidades tanto analíticas como prácticas de cada hipótesis.

Introduction

As in other infrastructure industries, the transportation or "transmission" segment of the electricity industry is a vital activity for its development. Transmission capacity shortages hinder the development of other electricity segments (such as generation) resulting in reductions of social welfare due to high final electricity prices paid by consumers. The development of electricity transmission requires adequate incentives to solve short-run congestion problems, recuperation of long-term fixed costs, and investment to intertemporally expand the network.

There is (more or less) a consensus in the economics literature regarding the way to calculate the short-run price of electricity transmission usage and, hence, to resolve short-term congestion. As shown in Hogan (2002b), the difference of electricity prices between two nodes in a Power Flow model (that we present in Section 3) defines such a price. However, there is an intense debate regarding the way to attract investment to finance the long-term expansion of the transmission network, and to solve the dual opposite incentives to congest the network (in the short run) and to expand it (in the long run). In the international practice, there have also been several divergent mechanisms that try to solve this issue. While regulation has been basically applied in England, Wales and Norway to guide the expansion of the transmission network, a mixture of planning and auctions of long-term transmission rights has typically been used in the Northeast of the U.S., while their application to New Zealand's electricity sector is currently under consideration. A combination of regulatory mechanisms and merchant incentives is alternatively used in the Australian market.

Under constant returns to scale, conditions for the optimal capacity expansion of the transportation segment of an infrastructure industry are well known. At the optimum, the per-unit marginal cost of new transportation capacity must be equal to the expected congestion cost of not adding an additional unit of capacity (see Crew, Fernando and Kleindorfer, 1995). Optimal capacity utilization could be achieved through proper pricing (see Wilson 1993), while optimal capacity expansion is achieved in practice through price regulation (see Armstrong, Cowan and Vickers, 1994).

However, different from other industries electricity transmission presents special characteristics --beyond economies of scale and cost subbaditivity-- that complicate the regulatory analysis of proper incentives for transmission network expansion. Such characteristics do not permit to naively apply to electricity transmission the above optimality condition for capacity expansion, proper of transportation models. Externalities in electricity transmission are mainly due to "loop-flow" problems, which arise through interactions in the transmission network. These interactions are governed by Kirchhoff's laws which state that electricity flows follow the path of least transmission line resistance. In a direct current (DC) model (a linear representation of power flows), if an indirect path is twice as long than a direct path, so is the resistance. (For example, in a three-node network this implies that an electricity unit produced at one node will generate a 1/3 flow along the indirect path, and a 2/3 flow along the direct path. See Joskow and Tirole 2000, and Léautier, 2001).

The effects of loop flows imply that it is not possible to define the "available transmission capacity" in a point of time without the existence of complete information about the use of the network at the time. Likewise, transmission opportunity costs and pricing critically depend on the marginal costs of power at each location. Energy costs and transmission costs are not independent since they are determined simultaneously in the dispatch and the spot market. Then, as explained by Bushnell and Stoft (1997), the external benefits of transmission investments are not appropriable and, even more, certain transmission investments in a particular link might have negative externalities on the capacity of other (maybe remote) transmission links. In fact, the addition of new transmission capacity can sometimes paradoxically reduce the total capacity of the network (see Hogan, 2002c).

In this context, standard theory of Public Economics (as in Laffont, 1989) would suggest that one way to proceed with a line expansion would be to make the investor pay for the negative externalities generated. This means that, to restore feasibility, the investor would have to buy back sufficient transmission rights from those who hold them initially (as in Bushnell and Stoft, 1997), or that an independent system operator (or dispatcher) would have to retain some transmission rights in an auction for long-term rights to make sure that the expansion project does not violate the property rights of the original transmission right holders. This is essentially the first proposal that we survey in Section 4.

In Section 5 we analyze a regulatory alternative that seeks to solve the transmission expansion problem in a different institutional framework. Operation and ownership of the transmission company are carried out by a "Transco" that is regulated through benchmark or price regulation so as to provide it with incentives to invest in the development of the grid, while avoiding congestion. The price regulation proposal is basically different from the transmission rights one in that it tries to derive a cost and production function for transmission, while the transmission rights approach avoids dealing with this issue due to the practical impossibility to exactly trace the physical flows of electricity.

In Section 6 we study a last proposal that seeks to derive optimal transmission expansion from the power-market structure of electricity generation. Based on real options analysis, this approach finds the joint probability distribution for both transmission and generation outcomes. This joint probability distribution is subsequently used to calculate the net present value of the transmission expansion projects.

The plan of the paper is as follows. Section 2 surveys the different electricity markets and the basic elements of optional institutional designs for electricity transmission operation, while Section 3 presents the basics of the Power Flow model and of the locational price theory. The concepts developed in these two Sections are fundamental to understand the distinct transmission expansion mechanisms presented in Sections 4 to 6. Such mechanisms build on the institutional settings for the system operator presented in Section 2, and on the management of the short-run spot energy market by a system operator developed in Section 3. Concluding remarks are given in Section 7.

Market Architecture of the Electricity Sector.

Market Architecture is a relatively new discipline of economics that analyzes details of market organization of an industry that affect performance of economic agents. Economists then become “architects” in the sense that they design the features of an economic building (the market) using as instruments a number of theoretical and practical mechanisms. As in an architectural process, the technology available to the architect-economist constrains his design possibilities. Wilson (2002) analyzes these issues for the electricity industry, which is plagued with incomplete and imperfect markets, and identifies a set of issues that complicate efficient market design. Electricity is an economic good that is expensive to store. Its transmission from generation plants to consumption centers is usually carried out in meshed networks that are very complex, and that can also be affected by capacity constraints. Due to the electricity-flow nature, rights in the electricity transmission are difficult to define. Other obstacles for market design are due to the need for energy and transmission provision in order to meet demand at real time as well as for reserves to meet random demand shocks.

Power generation and electricity marketing are nowadays considered as areas where competition might work, while transmission and distribution remain with naturally monopolistic characteristics. Technological advances in thermo electrical generation have recently turned thermal generation into a potentially competitive activity. However, hydro electrical and nuclear generation typically retain huge sunk costs and cost subadditivity. Ideally, all output, throughput, coordination and marketing activities should be vertically separated - in terms of ownership– in a competitive wholesale electricity market structure.

A continuous electricity spot market is typically needed but its operation has to be coordinated with that of the complex transmission system. Since electricity can hardly be stored, a system operator (SO) is thus needed in order to coordinate real-time operations from an engineering technical scope as well as from an economic perspective. According to Hogan (1999a) or Borenstein (2002) the SO must be allowed to offer the economic dispatch (pool) service based on marginal-cost power pricing, and participation in the dispatch should be voluntary. The pool service provides the means by which generation costs are minimized through merit-order bids that selects generators based on their generation price, and establishes as the market uniform price the price-bid of the last dispatched generator. Pay-as-bid auction is an alternative discriminatory-auction mechanism. Wolfram (1999) analyzed the pay-as-bid auction mechanism in the "Programme to Reform the Electricity Trading Arrangements" (RETA) for the British electricity industry. She shows that it may lead to less competition and higher prices than the uniform-price auction.

The SO may operate a sequence of day-ahead and real-time operation as well as longer time frames. The system's stability is also maintained by the SO through the management of a pre-arranged system of reserves. A continuous balance is achieved using the submitted offers and several categories of reserves including regulation capacity, operating reserves (spinning and non-spinning), replacement reserves and reliability-must-run.

Additionally, contracts for differences provide generators and purchasers freedom to carry out bilateral contracts and ensure that any imbalance in production or consumption is settled though the pool price. In these contracts the parties mutually insure each other covering the difference between the contracted price and the market price. Bilateral contracts may be physical contracts for actual production or financial contracts. According to Wilson (2002), in mature systems the pattern of energy transactions is 80% contracted long term, 20% day-ahead, and less than 10% spot.

a) Electricity Markets and the SO's Institutional Design

According to Wilson (2002), there are four markets that characterize a market for electricity: the forward transmission market, the spot energy market, the forward energy market (or market of bilateral contracts), and the forward market for reserves. Such markets have complex interactions that complicate the analysis of the optimal incentives to expand transmission capacity, and energy supply and reserves. They have an impact on the role of a SO in achieving this task, and they also affect the optimal behavior of a generator in the spot energy market and the forward market for capacity.

The SO has a (natural) monopoly over its functions. However, other design issues arise regarding SO's organization and institutional characteristics such as governance, incentives, regulation, and economic objective function. Regarding congestion of transmission lines, Vogelsang believes that the objective function of a SO should consider the minimization of difference in locational prices (see Vogelsang, 2001).

Wilson (2002), believes there exist three structures for an SO that might be designed in order to reach an equilibrium for the four electricity markets. Each one might determine the way expansion in transmission could be reached. The first structure is an independent system operator (ISO), different from the company that owns the transmission grid, and that is decentralized and aims to intrude the least possible in the four mentioned markets. The second is a centralized ISO that controls and coordinates such four markets, and the third option is an integrated company that combines ownership of the transmission network with system operations or "Transco". Hybrid designs that allow for different degrees of centralization could also possible. For example: central control of transmission and reserves by an ISO together with forward markets for energy.

A centralized ISO imitates vertically integrated functions through an overall optimization of operational decisions and long-term contracting among participants. A centralized system attempts a simultaneous optimization of all four electricity markets. This minimizes the costs of ensuring reliability and coordinating generation, transmission and reserves. Likewise, in a fully centralized system the ISO has full control of the real-time dispatch and reserve options are not voluntary. Additionally, the ISO reduces flows or produces counterflows by directing generators to reduce or expand their production according to a bidding procedures and the use of locational prices.

Wilson (2002) believes that centralization is preferable under the presence of vigorous competition and adequate technical and economic optimization of an electricity industry. However, he argues that centralization does not provide the right incentives for cost minimization since pool bids not always reflect actual costs. On the contrary, a decentralized ISO would manage transmission and reserves with small intrusion into energy markets. A decentralized ISO should permit a sequential optimization of the four electricity markets with voluntary participation of market agents. Wilson believes that decentralization is better when incentives for cost minimization and good scheduling decisions by each participant's pool are more important than coordination in electricity markets. However, Hogan (1995) argues that the dichotomy between centralized and decentralized ISOs is false. He believes that any decentralized market can be centralized through adequate definition of access and pricing.

In practice, the ISO model has been used in Argentina, and most of Australia where system operation is carried out by the ISO, and transmission ownership is carried out by a second independent company, the Gridco. ISOs also exist in the United States (U.S.) in California, New England, New York, Pennsylvania-New Jersey-Maryland (PJM), and Texas. ISO practical experiences and proposals have been centralized. For example, the recent U.S. and Mexican proposals to reform their electricity sectors contain elements of a centralized ISO (see Federal Energy Regulatory Commission, 2002, and Secretaría de Energía, 2002). The recent proposal of the U.S. Federal Energy Regulatory Commission (FERC) establish standard market design measures (SMD) that state that all transmission companies must join a Regional Transmission Organization (RTO) in an effort to promote vertical desintegration between transmission and generation in those regions where such structure still prevails. Regional planning is recognized as an important element for the electrical system expansion. In the Mexican proposal, the ISO would operate a market for large consumers while the existing State utility would keep its vertical integration along the industry (generation, transmission, and generation), and would exclusively provide public service for small consumers. The ISO would consider in a pool the bids of all plants - including those devoted to public service- and would dispatch them according to merit order

The Transco approach is similar to a centralized ISO but with a dispatch controller that also owns the transmission network. Joskow (2000) hints that the decision between the two options is based mainly on institutional conditions. In the case of the United Kingdom, such conditions made possible the implementation of a Transco. In the U.S., however, it is difficult to impose a Transco due to the property structure of the transmission network. In fact, Hogan (1999, a,b) believes that such a measure would end up with small regional Transcos with compatibility problems among them. However, Hunt (2002) favors the Transco approach since it is a profit-making entity that, as opposed to an ISO, is responsible for maintaining and expanding the transmission assets: "A Transco requires a serious board of Directors to see that it meets its financial responsibilities to shareholders (Hunt, 2002, p.213)." Joskow and Tirole (2002) also favor the Transco approach because the separation between transmission operation and system operation can cause coordination costs.

Hunt (2002) believes that the Transco approach should be complemented with FERC's SMD type of policies. In such circumstances, a Transco can therefore better respond to an incentive type of tariff regulation, and better choose between short-run operational and long-term investment decisions.

Notwithstanding, Hunt also recognizes that a Transco should be carefully regulated. If transmission rights created under a central planning transmission process were not to be auctioned, and the Transco kept all the revenues from transmission charges, that could lead it to dispatch the system in a way that causes congestion. Likewise, Hunt believes that either in the ISO form or Transco form, transmission and system operation have to be separated from the generation business to avoid conflicts of interest. In practice, the Transco model has been used in the United Kingdom (National Grid Company (NGC)), Spain and Scandinavia.

The Power Flow Model

There is an extensive literature, both within the economics and electrical engineering fields, on the modeling set up for an equilibrium analysis of the electricity spot energy market (see for example, Hogan, 2002b, Léautier, 2000, Joskow-Tirole, 2000). The typical framework is that of a centralized ISO seeking to maximize social welfare subject to transmission-loss and flow-feasibility constraints in a centralized spot market. In practice, this type of model is applied in several countries such as Argentina, Australia, and several regions in the U.S. (e.g., PJM, New York, Texas, California). FERC's recent SMD and the Mexican reform proposals also foresee the use of such a mechanism (see Federal Energy Regulatory Commission, 2002, and Secretaría de Energía, 2002).

a) The Economic Dispatch Model

Schweppe et al. (1988) make a simplified presentation of the direct current (DC) model. (Other representations are elsewhere available for alternating current (AC) systems and for "DC-load models. See Hogan, 2002b and Schweppe et al., 1988).

Consider a power network with N nodes and L lines. For n = 1,…,N, let:

q_n^s: real power generated (MWh) at node n

q_n^d: real power consumed (MWh) at node n

$q_n = q_n^s - q_n^d$: net real power load (MWh) at node n

$CS_n(q_n^d)$: consumer surplus (MWh) at node n

$C(q_n^s)$: generation cost (MWh) at node n where $CS_n(q_n^d)$ and $C(q_n^s)$ are assumed to be continuously differentiable on R. For, l = 1,…L, let:

z_l: real oriented energy flow (MWh) on line l

K_l: capacity (MW) of line l

In vector notation, let q $\in R^n$ be a vector of net injections, z $\in R^L$ be a vector of real oriented flows, and K $\in R^L$ a vector of capacities. The following technical constraints have to be met in any power network:

Energy balance:

$$\sum_{n=1}^{N} q_n^s = \sum_{n=1}^{N} q_n^d + \widetilde{L}(z)$$

where $L(z)$ are the transmission losses for z $\in R^L$. Since only (N-1) injections are independent, there is a swing node (or "bus") that can arbitrarily be chosen as node N. $\underline{q} \in R^{N-1}$ would then represent the truncated vector of net injections.

Power flow equations:

$$\widetilde{L}(z) = L(\underline{q}) = \underline{q}^t \cdot B \cdot \underline{q}$$

where B $\in R^{N-1} \times R^{N-1}$ is a symmetric matrix.

$$z = H \cdot \underline{q}$$

where H $\in R^L \times R^{N-1}$ is a "transfer admittance" matrix. Under the DC load model, power flows are proportional to line's admittance Y, and the difference of phase angles δ at the extremities of the line, so that $z = Y \cdot \delta$. The line's admittance depends on the physical characteristics of the line, and also determines the transfer admittance matrix (see Schweppe et al., 1988). (In practice, the transfer matrix could have thousands of rows and vectors, and it could be dense and hardly invertible. For such a reason, many practical implementations utilize the functional dependence of flows on phase angles.)

Transmission capacity constraints:

$$|z_l| = \left|\sum_{n=1}^{N-1} H_{\text{ln}} \cdot q_n\right| \leq K_l \quad \forall l = 1,\ldots,L$$

Physical limits on the line arise from thermal, voltage, and stability constraints. There exist operating limits too. In an interconnected grid, power injections at all nodes potentially contribute to congestion.

The economic dispatch maximization problem of the ISO is to find an optimal vector $(\mathrm{q}^{*s}, \mathrm{q}^{*d}, \mu, \lambda)$ that solves:

$$\max_{q_n^s, q_n^d} \sum_{n=1}^{N} \left[CS_n(q_n^d) - C_n(q_n^s)\right]$$

subject to (1)

$$\sum_{n=1}^{N} q_n^s = \sum_{n=1}^{N} q_n^d + \widetilde{L}(\underline{\mathrm{q}})$$

$$|\mathrm{H} \cdot \underline{\mathrm{q}}| \leq \mathrm{K}$$

where μ is the Lagrange multiplier of the energy balance constraint, and λ_l is the Lagrange multiplier of the transmission constraint on line l (in practice, one-day-ahead and real-time markets are typically operated by the ISO).

For $1 \leq n \leq N-1$, the first-order conditions are

$$-C_n^{'}(q_n^s) + \mu\left(1 - \frac{\partial L}{\partial q_n^s}\right) - \sum_{l=1}^{L} \lambda_l H_{\text{ln}} = 0$$

$$-CS_n^{'}(q_n^d) + \mu\left(1 - \frac{\partial L}{\partial q_n^d}\right) - \sum_{l=1}^{L} \lambda_l H_{\text{ln}} = 0$$

At the swing node, the first order conditions are

$$-CS'_N(q_N^d)+\mu=0$$

$$-C'_N(q_N^s)+\mu=0$$

and the complementary slackness conditions are

$$\lambda_l \times \left(\sum_{n=1}^{N-1} H_{\ln} \times q_n - K_l\right)=0 \quad \forall l=1,\ldots,L$$

Locational prices are also obtained from this program and defined as:

$$\rho_n=\mu(1-\frac{\partial L}{\partial q_n})-\sum_{l=1}^{L} H_{\ln}\lambda_l \tag{2}$$

Locational prices are therefore defined in terms of the shadow price of the constraints. A similar result is obtained for the regulatory pricing benchmark formula used in Mexico to regulate the price of natural gas (see Brito and Rosellon, 2002).

Optimal dispatch is then characterized in Schweppe et al (1988) as

$$\rho_n=C'_n(q_n^{s*})=CS'(q_n^{d*})$$

The economic dispatch model can be understood in the context of a static competitive equilibrium model. The producing entity would be an ISO that provides transmission services, receives and delivers power, and coordinates the spot market through solving program 1. Its objective is to maximize the value of power flows. The ISO is then a price taker who chooses q^{*s} and q^{*d} that are feasible and that maximize profits. The ISO has of course a monopoly over provision of transmission services, which means that it must be regulated. Hogan (2002b) argues that the competitive market definition could provide a benchmark for the service standard of the ISO.

On the consumer side, each market agent has a utility function for electricity Ui(qi) which is concave and continuously differentiable. Consumers inject power into the grid at some points and draw power out of the grid at other points. Likewise, consumer i is assumed to have an initial endowment $\widetilde{w}_i$ of the numeraire good that represents the rest of the economy. Additionally, each consumer has an ownership share si ($\sum_i s_i = 1$) of the profits π of the ISO. Consumers are also assumed to be price takers so that given market electricity prices, p, consumers choose the level of consumption of the aggregate good, ci, and electric energy and transmission services according to

$$\underset{q_i, c_i}{Max} U_i(q_i) + c_i$$

subject to

$$p^t q_i + c_i \leq \widetilde{w}_i + s_i \pi \tag{3}$$

Given an initial endowment $\widetilde{w}_i$ and ownership shares si, a competitive equilibrium is defined as a vector of prices, p, profits, π, and a set of net loads, qi, for all i that simultaneously solve (3) and a similar program to (1) but with the value of power flows (or profits) as objective function. (Hogan (2002b, p. 18) shows that a solution that maximizes profits π would also maximize welfare $\sum_{n=1}^{N}\left[CS_n(q_n^d) - C_n(q_n^s)\right]$; however the converse is not always true when the feasible set is not convex). At the optimum, locational prices are such that consumers pay a marginal unit of power, plus their marginal contribution to losses and their contribution to congestion of all lines in the network. Generators are paid their marginal unit of power, minus their contribution to losses and their contribution to congestion of all lines.

b) Nodal Prices and Financial Transmission Rights

The difference in locational prices (2) defines the price for transmission usage for bilateral schedules. Hogan (1999a) makes emphasis on the "nodal" nature of locational prices. There is not really a sound reason to average congestion costs over large zones, and pricing by nodes is not complex under competitive markets. Hogan further argues that nodal prices provide the principles for economic dispatch and "are self policing and self auditing" (Hogan, 1999a, p. 40), while zonal pricing imply deviations from reliable dispatch. For example, generators that have a lower bid price than the zonal price ("constrained off" generators), and that are located in nodes within the zone, have an incentive to self-schedule in bilateral contracts, compromising congestion management by the ISO.

Difference in nodal prices and congestion transmission charges as well as network congestion can widely vary over time. Demand and supply availability can also vary over time. Variation in prices then creates a demand by risk-averse agents for instruments to hedge against price fluctuations. A financial transmission right (FTR) is a type of such instruments. According to Hogan (2002a), transmission congestion rents are redistributed by the ISO to market agents through FTRs.

Physical transmission rights are also discussed in the literature. However, attempts to define physical right in terms of physical flows have not succeeded. The main reason is that tracing the physical flow through a transmission network has proven to be an impossible task in practice(see Hogan, 2002a, p. 116, and Hogan, 2002b). Besides, superiority of FTRs over physical rights has been analytically shown as well (see, for example, Joskow and Tirole, 2000). However, Joskow an Tirole also find in their model that the absence of either financial or physical rights does as well or better than either type of transmission system (in terms of effects of transmission rights on market power and production efficiency). A transmission right market would then be only required so as to define adequate property rights for investors.

Under a centralized structure of an ISO, an FTR gives the holder a share of the congestion-payment surplus that is received by the ISO, when a transmission constraint is binding. Joskow and Tirole (2002) explain that the quantity of FTRs is fixed ex ante and allocated to holders to reflect estimates of the capacity of the network. The difference between actual transmission capacity and allocated FTRs results in congestion revenues for the ISO. For example, in the PJM system the revenues from FTRs are returned to owners of the transmission capacity so as to defray capital and operation and maintenance costs. The ISO defines the quantity of FTR to be auctioned and also defines the auction rules. FTRs are defined in terms of the market clearing prices of the competitive equilibrium.

Hogan (2002b) studies several types of financial transmission instruments such as rights, obligations and options. He argues that "point-to-point" (PTP) forward obligations have demonstrated to be the most feasible instrument in practice, which is not the case for PTP options and flowgate rights (flowgate rights are defined in terms of the selling of capacity constraint limits). Given a vector of inputs and outputs by location, the kth PTP forward obligation is defined by

$$PTP_k = p^t \begin{pmatrix} 0 \\ -q_i^s \\ 0 \\ q_j^d \\ 0 \end{pmatrix}$$

Given the market clearing prices, the FTR is a contract to receive

$$p^t PTP_k = p^t \begin{pmatrix} 0 \\ -q_i^s \\ 0 \\ q_j^d \\ 0 \end{pmatrix} = p_j q_j^d - p_i q_i^s$$

A “balanced” forward obligation is defined as:

$$\tau_k^f = \begin{pmatrix} 0 \\ -x \\ 0 \\ x \\ 0 \end{pmatrix}$$

while an unbalanced obligation is defined as

$$\overline{g}_k^f = \begin{pmatrix} 0 \\ 0 \\ g \\ 0 \\ 0 \end{pmatrix}$$

An agent that has a balanced FTR between two locations and carries out a bilateral transaction with same inputs and outputs (x) would be charged (pj - pi)x, which is exactly the payment received under the FTR. Then a perfect hedge is achieved through a balanced FTR. Under an unbalanced obligation FTR, there is an obligation to make a payment equal to the value of the energy at the pertinent location. Hence, the unbalanced PTP-FTR obligation can be seen as a forward sale of energy.

Hogan (2002b) explains that the FTR market can be operated by the ISO in parallel to the operation of the spot market, as long as a simultaneous flow feasibility condition is met. A set of FTRs is simultaneously feasible if the associated set of net loads q satisfies the energy balance and transmission capacity constraints, as well as the power flow equations. With many transmission lines and several possible contingencies, the number of constraints to be met in order to reach simultaneous feasibility can be as high as hundred of thousands of constraints. However, the practice of electricity markets as the ones in New York and PJM shows that the adequate software to solve this problem can be designed.

Likewise, Hogan (1992) shows that under a spot market equilibrium price p* and equilibrium load q*, the "revenue adequacy" condition $p^*(q^* - q) \geq 0$ is met by a set of PTP-FTR forward obligations that are simultaneously feasible. Since under simultaneous feasibility it is true that $q = \sum_k \tau_k^f - \sum_k \overline{g}_k^f$, net equilibrium payments collected by the ISO through economic dispatch (p*, q*) will be greater than or equal than payments required under the PTP-FTR forward obligations (p*, q) (revenue adequacy is the financial counterpart of the physical concept of availability of transmission capacity; see Hogan, 2002c).

PTP-FTR forward obligations are usually allocated through auctions. In an auction, the ISO would seek to maximize a concave and differentiable bid function $\beta_k(t_k^f, \rho_k^f)$ subject to simultaneous feasibility (where t_k^f and ρ_k^f are the scalar amounts of balanced and unbalanced FTR obligations, respectively). A solution to this problem would determine the award of FTRs and the associated market clearing prices for awards, and it will also provide opportunities to reconfigure the pattern of FTRs. FTRs can then be traded in liquid secondary markets.

In practice, FTRs are used in countries such as Argentina, and the U.S. North East pools. Both the FERC and the Mexican proposals have recently proposed the use of locational marginal pricing as well as congestion revenue contracts and tradable financial rights (see Federal Energy Regulatory Commission, *2002*, pp.116 through 148, and Secretaría de Energía, 2002, pp. 28-31). The PJM implementation of FTRs employs a DC-Load dispatch model where locational prices differ due to the effects of congestion. The PTP-FTRs are then defined for congestion-cost payments. In New York losses are included in the dispatch model, and only balanced PTP-FTRs are defined to provide payments for congestion costs but not for losses. An AC formulation is used to define the FTR auction.

c) Market Power, Market Volatility, and the Power Flow Model

The power flow model presented is mainly based on perfect competition assumptions such as no market power in production or consumption, as well as in the FTR market. It is also typically necessary that a generator does not have a predominant position in the FTR market. Under these assumptions, the FTR solution allows investment in transmission to compete with investment in generation, and solves the natural monopoly regulatory problem (see Joskow and Tirole (2002), p. 15). However, when such assumptions are lifted, the nice results of the model are no longer valid and FTRs does not fully provide enough incentives to avoid transmission congestion. For example, under a pay-as-bid pool rule Léautier (2000) shows that even under FTR payments, monopoly generators have incentives to reduce transmission capacity in order to preserve local market power. Bushnell (1999), and Joskow and Tirole (2000) reach a similar conclusion for physical transmission rights since physical rights can be withheld reducing transmission capacity.

Borenstein (2002) argues that market power and volatility are inherent to electricity markets since demand is difficult to forecast and inelastic. Likewise, supply faces binding constraints at peak times, and it is inelastic and very costly to store. This implies that short-term prices are extremely volatile so that small changes in demand or supply conditions lead to price bursts, and even small-share generators can exercise market power. Borenstein believes that the best way that regulators can handle market power in the electricity industrial market is through long-term forward contracts between power buyers and sellers together with real-time pricing. Forward contracts help to lower the average price paid in both spot and forward markets, while real-time pricing also makes the demand curve flatter

Market power in generation can also be enhanced by vertical integration between generation and transmission, or by generators that posses a predominant position in the FTR market (as shown by Joskow and Tirole, 2000). Likewise, market power in generation can be increased due to geographical isolation. Lack of transmission connectivity and availability of supply options and fuel inputs may allow that the exercise of market power be widespread. Borenstein (2002) provides a concise explanation for the Californian case, while Comisión Federal de Electricidad (2000) provides a thorough market power analysis for Mexico.

The existence of market power in electricity markets is recognized by the FTR literature. Since electricity markets are volatile in nature, the existence of a general market equilibrium for programs (1) and (3) and the revenue adequacy condition for FTRs cannot be guaranteed (see Hogan, 2002b, p.28). Joskow and Tirole (2000) also conclude that the implementation of a transmission right structure must consider measures to investigate market power in buying-seller nodes, since FTRs can be used to enhance profits and market power in generation and consumption.

Long Term Financial Rights for Transmission Expansion

We now turn our analysis to the forward transmission market. We would like to explore how to reach an equilibrium in this market building on an equilibrium of the spot market, as illustrated by the economic dispatch model. More specifically, we are interested in studying optimal mechanisms to attract investment to finance the long-term expansion of the electricity transmission network. There are in the literature at least three approaches that --building on equilibrium in the spot market— use long-term regulatory mechanisms such as FTR auctions, price caps, and planning in order to provide investment incentives. We analyze in this Section the use of FTRs to solve the transmission investment problem, while in the remaining Sections we study the other alternative approaches.

a) Long-Term FTRs and Transmission Expansion

As seen in the previous Section, the power flow model provides nodal prices through the shadow prices of the model's constraints. FTRs are defined from these shadow prices. However, short-term FTRs cannot resolve alone the problem of incentives for long term transmission expansion.

The approach of using FTRs to address the problem of long-term (LT) transmission expansion relies on a centralized ISO that allocates through an auction the necessary LT FTRs to protect the holders from future contingent changes in congestion costs. LT transmission rights should work in parallel with LT generation contracts (see Hogan 2002a, p. 19). The LT concept is an important one for expansion projects. As argued by Gribik et al (2002), most auctions allocate FTRs with durations of one month through five years. However, since a transmission project has a useful life of approximately 30 years, the owner of the project would like to receive LT FTRs. The LT FTR allocation mechanism typically relies on the operation by the ISO of a short-run spot market for energy and ancillary services, and on a bid-based, security-constrained, economic dispatch with nodal pricing.

Authors in this area (as Hogan, 2002c) view the LT FTR alternative as "merchant transmission investment" since incremental FTRs can provide market-based transmission pricing that attracts investors to pay for transmission expansion. However, even the FTR literature believes that certain type of central planning should accompany this type of "merchant investment" due to the economies of scale, and the free riding and congestion incentives, present in a transmission expansion investment process. As Joskow and Tirole (2002) argue, "the merchant transmission model cannot operate as by an invisible hand" since that model requires a centralized ISO. This view is supported by the recent FERC's SMD that promotes the use of a regional planning process to guide investments in transmission infrastructure (see Federal Energy Regulatory Commission (2002), pp. 193-201). However, a question remains on how a central planned system would accommodate transmission investments of unplanned expansion projects, considering their impact on social welfare.

b) General Criteria to Define Long Term FTRs

Bushnell and Stoft (1997) argue that market failures in electricity transmission might be due to several factors: a) the market power of a single owner of the transmission capabilities in a certain region; b) the external benefits of transmission investments are not appropriable, and c) there negative externalities caused by investment in a certain transmission link on the transmission capacity of other links. Building on this last externality, Bushnell and Stoft carry out the study of the effects of transmission expansion in a three-node network. They show that the expansion investment might violate some of the existing property rights, and propose to require the agent willing to make the expansion investment to "pay back" for the possible loss of property rights.

Bushnell and Stoft use a simple example of a network with loop flow. Given an initially radial three-node configuration with two links, they consider the effects of adding a third line. The new link creates a new feasible set that requires a redispatch of the net loads at each node. Loads (and associated FTRs) that were not previously feasible (pre-investment) become feasible (post-investment), while pairs of loads (and associated FTRs) that were feasible, become infeasible. In particular, the initial optimal dispatch is no longer feasible and the expansion link reduces social welfare because it is a binding constraint on low-cost generation schedules. (Implicitly, Bushnell and Stoft's model relies on the assumption of agents that operate in a spot market but without holding LT FTRs, so that the externalities are due to lack of hedging by spot market participants). The new link is therefore inefficient and should not be built. However, according to standard theory of Public Economics (as in Laffont, 1989), one way to proceed with the line expansion would be to make the investor pay for the negative externalities that he generates. This means that, to restore feasibility, the investor would have to buy back sufficient rights from those who hold them initially.

Bushnell and Stoft (1997) further show that the value of new allocated FTRs dispatched according to the feasibility rule will be less than or equal to the change in social welfare. In particular, if social welfare is decreased by a transmission expansion, the investor will have to take FTRs with a negative value (while if social welfare is increased there will be free riding). They argue that some agents might still benefit from investments that reduce social welfare, whenever their own commercial interest improves more than offsets the negative value of the new FTRs. This problem can be solved if it is required that FTRs are used by each agent as a perfect hedge for their net load. In such a case, FTRs allocated under the feasibility rule will ensure that anyone can benefit from an expansion that reduces welfare.

Hogan (2002c) generalizes Bushnell and Stoft analysis and makes a preliminary attempt to analytically provide some general axioms to properly define LT FTRs. Hogan's model relies on an institutional structure where there are various established agents (generators, Gridcos, marketers, etc.) interested in the transmission grid expansion, as opposed to a single owner of the grid. Under an initial condition of non-fully allocation of FTRs in the grid, the awarding of incremental LT FTRs (say 20-year) should satisfy some basic criteria. A first criterion would be that an FTR increment keeps being simultaneously feasible (feasibility rule) (recall that a set of FTRs is simultaneously feasible if the associated net power flows are also simultaneously feasible).

A second is that such an increment remains simultaneously feasible given that certain currently unallocated rights (or proxy awards) $\hat{T}$ are preserved. In other words, that the transmission energy balance and capacity constraints, as well as the power flow equations, are satisfied for $\hat{T}$ + T + δ, where T are existing rights, and δ are incremental rights. The third criterion is that investors maximize their objective function (maximum value), and a fourth one implies that the awarding process apply both for decreases and increases in the grid capacity (symmetry).

As shown by Bushnell and Stoft (1996) and Bushnell and Stoft (1997), under these conditions allocation of new PTP-FTR obligations will not reduce social welfare. Hogan explains however that defining proxy awards is a difficult task. One possibility would be to define every possible use of the current grid as a proxy award. This rule would really not be a good idea in practice since it would preclude any investment beyond a radial line (a network with only two nodes and one transmission line). Any incremental award of FTRs might require adding capacity to every link on every path of a meshed network.

Hogan then believes that a better possibility would be to define as a proxy award the best use of the current grid along the same direction that the (positive or negative) incremental FTR was awarded. The main problem then of course is how to define "best use." There are two possibilities. One is to define "best" in terms of preset proxy references so that proxy awards maximize the value of such references, that is:

$$\hat{T} \in \arg\max_{T} \{Tp\delta \,/\, T + T\delta \, is \; simultaneously \, feasible\}$$

Another possibility would be to define "best" in terms of the maximum value $\beta(\theta\delta)$ of investors' preferences. Proxy awards would then minimize such maximum value, that is:

$$\hat{T} \in \arg\min_{T} \left\{ Tp\delta \,/\, \max_{\theta \geq 0} \{\beta(\theta\delta) \,/\, T + T\delta + \theta\delta \, is \; simultaneously \; feasible\} \right\}$$

Given a proxy rule, an auction could be carried out in order to attract investment for transmission expansion. In case the investors' preference criterion is chosen, the auction model would maximize $\beta(\theta\delta)$ to award "θ" MWs of FTRs in direction δ subject to the simultaneously feasibility conditions and the "best" rule. However, Hogan argues that practical implementation of such an auction has to consider incentives for merchant transmission investment as well as the needed software to solve such a problem. But, most importantly, the main question is if such an auction mechanism could produce in practice acceptable proxy awards and acceptable incremental FTR awards.

Hogan (2002c) presents various examples that show how simple expansions in a 3-node network might have complex implications in the grid. Assuming LT rights that do not use the full capacity of the grid, and proxy awards that use the rest of the capacity, an investment that introduces a different link in the network will change impedances (resistances) and flows to the network, both expanding and contracting the set of feasible FTRs (Hogan 2002c, p. 19).

c) Some More Practical Proposals

Pope (2002) makes a more detailed attempt to implement an LT FTR mechanism. She designs an auction process for incremental FTRs --or TCCs (Transmission Congestion Contracts) as denoted by the New York ISO-- associated with transmission expansion that provides a hedge against congestion costs, both in the short and long terms. The ISO awards incremental FTRs to the parties that fund the expansion, only if the new FTRs are made possible by such an expansion. FTR awards are mainly based on choices made by investors although the ISO could in certain cases identify incremental FTRs.

When investors choose an increment in FTRs for transmission expansion simultaneous feasibility of both the already existing FTRs (including "grandfathered" FTRs, and FTRs purchased in auctions) and the new FTRs must be checked, since the amount of power that could be transferred between many different pairs of nodes (or buses) could be affected by the expansion. The auction process should also control investors' nominations to preserve simultaneous feasibility, and should exclude granting already existing FTRs that were not made possible by the expansion. When defining expansion FTRs, the ISO will also temporarily reserve some feasible FTRs prior to the expansion.

Pope's bidding process consists of various steps. Given pre-existing FTRs, in the first step investors are offered the choice between long-term and short-term (ST) expansion FTRs (LT FTR awards are one-time awards for a 20-year period, while ST FTR awards occur every six months).

In a second step, allocation of new expansion LT FTRs takes place in either an auctioned period or an unauctioned period. In the auctioned periods, the FTR auction model is used to sequentially determine incremental expansion awards. Investors nominate expansion FTRs (either in winter or summer) and assign to each one a certain positive valued weight that indicates preference for each FTR. (Differentiation of "winter" FTRs from "summer" FTRs is not trivial since an incremental FTR that is feasible in one period might not be feasible in another). This auction model would maximize investors' preferences and would be simultaneously feasible along with all pre-expansion FTRs. "Mitigating" counterflow FTRs with negative expected value and weights, are also assigned to preserve feasibility of pre-expansion

FTRs as well as to give rise to more valuable FTRs. In the unactioned periods, a mechanism is designed in order to reserve capacity for sales in later auctions, rather than leave all the available capacity for expansion awards. In the third step, the auction and allocation of ST FTRs takes place.

Harvey (2002) provides a preliminary analysis of incremental-expansion LT FTR awards for controllable lines (such as DC lines). For a controllable line, he analyzes the pricing of energy, the method for representing the line in FTR feasibility tests, and the way to determine the quantity of supportable (and feasible) FTRs. He shows that such analysis depends on whether a controllable line is proposed by a market agent or by the ISO. For example, if a market participant schedules the line, pricing of the line might differ from locational marginal pricing when the outage of the controllable line is a binding constraint. Meanwhile, if the ISO controls and schedules the lines locational marginal pricing would operate.

Another alternative effort for defining LT rights for transmission expansion is provided by Gribik et al (2002). They look to base their method on the physical characteristics of the transmission network -namely capacity and admittance-- in contrast to the definition of incremental PTP FTRs that, as shown by Hogan (2002c), Pope (2002) and Harvey (2002), can give rise to numerous inconsistencies. The Gibrik et al novel idea is to pay explicitly for admittance (as opposed to implicitly). However, these admittance payments are really a transfer of rents among transmission owners, which brings about questions about strategic behavior of investors.

Gribik et al confirm that allocation of PTP FTRs associated with transmission expansion would mainly depend on PTP FTRs allocated prior to the expansion. They also show that flowgate rights allocated to owners of a transmission expansion might not reflect the value of the additional transmission capacity. Hence, they propose a method to allocate flowgate rights for the new capacity added by the owner of an expansion, as well as admittance rights to collect the marginal value of access to the added facility.

As in all LT FTR model, Gribik et al's DC power flow model assumes a centralized ISO that auctions PTP FTRs and that collects revenues from the sales of FTRs in the auction. Revenues are used to make payments to owners of transmission facilities. The ISO calculates in the auction two main components of the LT fixed costs associated with transmission expansion: the shadow price (or marginal value) of the capacity of the line, and the shadow price of the admittance to the line. The ISO then makes payments to the owners according to a two-part tariff: a capacity payment (shadow price of capacity times the capacity of the line), and an admittance payment (shadow price of admittance times the admittance of the line).

The model assumes that some previous PTP FTRs were allocated. As in Pope (2002), with the new FTRs associated with transmission expansion, the resulting power flows should remain simultaneously feasible. Gibrik et al define the power flow equations, energy balance and transmission capacity constraints for both before and after a new line is added. When the new line is added, it might be possible that the original set of FTRs is no longer simultaneously feasible. In that case, the owner of the expansion is required to add (or buy back) enough FTRs so that the resulting set of FTRs satisfies the simultaneous feasibility test.

In the FTR auction for the expanded system, the ISO maximizes the value of FTRs subject to the ex post (after the new line is added) power flow, energy balance and transmission capacity constraints. Let λ and μ be the dual variables for the energy balance and the transmission capacity constraints of this program, respectively. Also let R* and $\Delta\delta^*$ be the optimal values for the set of FTRs and changes in voltage angles. Gibrik et al find the standard result that a PTP FTR obligation from node i to node j will be charged $\lambda_j - \lambda_i$ for each MW.

Let transmission line k connect nodes i and j, with positive flow direction defined as i to j. Let the marginal value of capacity on transmission line k in the positive direction be $\mu_k^{\max *}$, while the marginal value of capacity in the negative direction be $\mu_k^{\min *}$. Gribik et al find that the capacity payment to the owner of line k is:

$$z_k(\mu_k^{\max *} - \mu_k^{\min *})(\Delta\delta_i^* - \Delta\delta_j^*) \tag{4}$$

while the admittance payment is:

$$-(\lambda_i^* - \lambda_j^* + \mu_k^{\max *} - \mu_k^{\min *})(\Delta\delta_i^* - \Delta\delta_j^*)z_k \tag{5}$$

Adding (4) and (5), the total payment to the owner of line k is obtained:

$$z_k(\Delta\delta_i^* - \Delta\delta_j^*)(\lambda_i^* - \lambda_j^*) \tag{6}$$

This amount would of course be paid by the ISO from the FTR proceeds. In fact, Gribik et al also check revenue adequacy of their mechanism (see Gribik et al, 2002, appendix A). If the change in flow on line k from node i to node j as a result of the auction is denoted by Δs_{ijk}^{*}, the total payment to the owner of line k can be finally written as:

$$-(\Delta s_{ijk}^{*})(\lambda_i^{*} - \lambda_j^{*}) \qquad (7)$$

It can be observed that the revenue-balance problem is then solved by Gibrik et al by payment of all admittance costs but for only part of the capacity defined as incremental. This solution might fall short from supporting efficient expansion whenever revenues are not able to justify total capacity costs. Additionally, Gribik et al show with an example that it is possible to have negative payments (a negative value of (7)) when the direction of the change in power flow is from a node with higher nodal price to a node with lower price. These negative payments indicate the need for equipment (such as phase shifters) to control power flows and, hence, to eliminate negative payments.

d) Implementation Issues

Practical implementation of any of the above-described LT FTR mechanisms requires more than analytical and computational developments. Various authors coincide in the need to mitigate market power for any FTR auction to work. As shown in an extensive body of literature (Joskow and Tirole, 2000, Léautier, 2001, and Gilbert, Neuhoff, and Newbery, 2002) ownership of FTRs can exacerbate market power in generation. Joskow and Tirole (2000) study a two-node export-import network under several scenarios of market structure both in the generation market and the FTR market. They show that market power in the FTR market by a producer in the importing region (or a consumer in the exporting region) aggravates their monopoly (monopsony) power, since dominance in the FTR market provides an incentive to curtail ouput (demand) to make FTRs more valuable.

Generators' behavior in the FTR market should then be regulated. In fact, Hogan (2002c) believes that transmission companies (or Gridcos) should be the principal buyers and sellers of LT FTRs. In particular, Gridcos could have the primary responsibility of making a regulated investment under market failure conditions. But this would also require strict enforcement for open access to transmission networks.

Additionally, Joskow and Tirole (2002) make a more extensive critique of the FTR model and its ability to deal with proper incentives for transmission investment. They argue that the FTR model relies on strong assumptions of perfect competition that permits efficiency results (such strong assumptions include: no increasing returns to scales, no sunk costs, nodal prices are able to fully reflect consumers' willingness to pay, the network externalities are internalized by nodal prices, there is no uncertainty over congestion rents, there is no market power so that markets are always cleared by prices, there exists a full set of future markets, and the ISO has no internal intertemporal preferences regarding effective transmission capacity). In fact, they argue that no restructured electricity sector in the world has adopted a pure merchant approach towards transmission expansion (the most close case is Australia where a mixture of regulated and merchant approaches has been recently implemented). They then carry out an extensive analysis on the implications of lifting these strong assumptions.

First, Joskow and Tirole (2002) argue that due to market power in constrained regions, prices will not reflect the marginal cost of production. The generators in constrained regions will tend to withdraw capacity to bring their generation price up and this will overestimate the cost-saving gains from investments in transmission. Second, lumpiness in transmission investment implies that the total value paid to investors through FTRs understates the social surplus created by such an investment (pp. 21, 22). The large and lumpy nature of major transmission upgrades then calls for the need of LT contracts before making the transmission investment, or of property rights (or "patents") to exclusively use the incremental investment for a certain period of time.

Third, since transmission investment is not static in reality, there is no perfect coordination of interdependent investments in generation and transmission. In fact, the stochastic changes in supply and demand conditions imply uncertain nodal prices (p. 25). Fourth, equal access to investment opportunities is not a good assumption because deepening investments of the incumbent's network can only be efficiently implemented by the incumbent. Fifth, existing transmission capacity and incremental capacity are not well defined and are of a stochastic nature. Even in the two-node case, realized capacity could be less than expected capacity so that the revenue-adequacy condition is not met (p. 29). Sixth, the separation of transmission ownership and system operation creates a moral-hazard "in teams" problem. For example, an outage can be claimed to result from poor line maintenance (by the transmission owner) or from imprudent dispatch (by the SO). Seventh, as shown by Bushnell and Stoft for a network with loop flow, an addition in transmission capacity might have a negative social value. Additionally, the initially feasible FTR set can depend on random exogenous variables.

Harvard Electricity Policy Group, 2002b then recognizes that workable rules are needed to avoid free riding under considerable economies of scale and scope of the transmission grid investments. Demand and generation side solution that reduce congestion, should also be taken into account. But maybe, the main consensus in the FTR literature is the unavoidable (and paradoxical) coexistance of central planning and merchant investment in order for the LT forward transmission market to work, so as to attract the necessary investment for expanding the system. These then calls for a careful definition of the role of the ISO in planning opportunities, timing, and degree of participation in transmission expansion. However, this last task seems to be very complex since the effects that a new transmission line might have on the value of existing lines depend on the specific future uses of the network. This means that such effects depend on the probabilities of all states of the world over a entire investment horizon. Since this probabilities are of no common knowledge, the actual probabilities chosen by the ISO could be rather subjective. Likewise, markets for such contingencies could hardly be implemented in practice since that would presuppose that the owners of the existing network would not be neutral with respect to new investments. Hogan (2002b, pp. 13-15) argues that contingencies in the short-run FTR model can be addressed through security-constrained economic dispatch. However --besides to the computational difficulties for the ISO to calculate probabilities of contingencies-- it remains to be seen if the LT FTR/merchant approach can really solve the loop flow problem.

Finally, another interesting feature of the LT FTR model is that it does not consider the electricity transmission activity as an output (or throughput) process. The reason being the impossibility to follow any physical trace of the physical volume transmitted through the electricity wires. Although this is of course true in practice, there is at least the analytical question on the way cost and production functions in electricity transmission behave. If, as in other infrastructure industries (such as the gas industry), electricity transmission presents large sunk costs and cost subbaditivity, then why not think about a way to regulate the long-term monopolistic behavior of a Gridco through some type of incentive regulation? We address this issue in the next Section.

Incentives for Transmission Expansion through Regulatory Mechanisms

A totally different approach towards transmission expansion is provided by a body of literature on the design of economic regulatory mechanisms for Transcos (see Léautier, 2000, Grande and Wangesteen 2000, Vogelsang, 2001, and Joskow and Tirole, 2002). A regulatory mechanism for a Transco must provide incentives to the regulated firm to make efficient investment decisions, and must also satisfy that the regulated firm earns enough revenues to cover capital and operating costs; all this in an imperfect information environment about cost and demand functions faced by the Transco.

a) Regulation of a Transco

Building on a power flow model, Léautier (2000), Grande and Wangesteen (2000), and Harvard Electricity Policy Group (2002b, pp.27-32) propose mechanisms that compare the Transco performance with a measure of welfare loss due to its activities. The Transco is then penalized by increasing congestion costs in the network. In Léautier (2000), the regulator offers the regulated firm a menu of contracts that, according to the "revelation principle" (as in Laffont, 1994, and Laffont and Tirole, 1993), induces the firm to efficiently operate and build transmission lines while permitting it to recover its costs. Under the mechanism, the firm is responsible for all the congestion costs it creates and the needed investment to relieve it, so that the Transco has an incentive to minimize congestion. A separate mechanism is designed to provide incentives to the firm to invest in the optimal amount of transmission investment.

More specifically, Léautier (2000) shows that a marginal increase in transmission capacity has two effects: a direct effect so that cheap power substitutes expensive power, and an indirect effect that reflects the effects created by the expansion on other transmission lines. The author then defines the cost of congestion as the difference between the price actually paid to generators and the price that would have been paid absent congestion. Such a difference is called the "out-turn." Additionally to the Laffont-Tirole menu of revenue sharing rules, Léautier defines and "uplift management rule" that makes the Transco responsible for the full cost of the out-turn, plus any transmission losses. This mechanism has been applied in England and Wales, where transmission pricing is typically separated from energy pricing.

Joskow and Tirole (2002) propose a simple surplus-based mechanism to provide the Transco enough incentives to expand the transmission network (Brito and Rosellon (2003) carry out a similar analysis for natural-gas pipeline capacity expansion, based on welfare loss minimization). The idea is to reward the Transco according to the redispatch costs avoided by the expansion, so that the Transco faces the entire social cost of transmission congestion. These authors believe that such a mechanism would eliminate the problems associated with lumpiness and loop flows in transmission investment. FTR specification and allocation would neither be a problem, and there would not be any problem in joining operation and ownership of the transmission network because the moral hazard in teams problem is eliminated. However, Joskow and Tirole recognize that their scheme might not work whenever the Transco is vertically integrated with generation so that the integrated company manipulates bids in the energy market. Even under no vertical integration, generators might invest not more than what is needed to match existing transmission capacity.

As an alternative, Vogelsang (2001) proposes to explicitly study the nature of the cost and production functions for electricity transmission. Since electricity transmission generally preserves its technological characteristics of natural monopoly, this approach tries to isolate the monopolistic nature of a for-profit Transco that owns the complete transmission network, and designs an incentive regulatory scheme to regulate it. Although Vogelsang's mechanism is designed to be implemented under the Transco institutional framework, it could also be combined with a (centralized) ISO that takes care of the short-run market, and an independent transmission company that deals with investment issues.

Probably, the main virtue of Vogelsang's approach is that it tries to deepen into the analysis of the cost and demand functions for transmission services, which are very poorly understood by the current economics literature. The costs of a Transco are generally sunk and, therefore, its main problem is short-run utilization of capacity. Main variable costs are associated to congestion. In the long run, however, the Transco has to find an optimum between network expansion and investment-cost minimization.

Regulation of transmission must then solve a duality on incentives for the transmission firm in the short term and the long term since, under a non-adequate tariff scheme, the firm could find profitable not to solve congestion problems or investing in network expansion. Conditions for optimal capacity expansion have been studied by the peak-load pricing literature (Crew, Fernando and Kleindorfer, 1995): the per-unit marginal cost of new capacity must be equal to the expected congestion cost of not adding and additional unit of capacity. However, the question is how regulation can provide incentives to the Transco to reach this point

b) Price Level and Price Structure Regulation

Applied regulatory mechanisms can be analyzed from two perspectives: regulation of "price level" and regulation of "price structure" (see Brown, Einhorn, and Vogelsang, 1991). Price level regulation refers to the long-run distribution of rents and risks between consumers and the regulated firm. Price structure regulation refers to the short-run allocation of costs and benefits among distinct types of consumers. There are several options to regulate for price level (such as cost-of-service, price-cap, and yardstick regulations) as well as for price structure (such as price bands or flexible price structures)(see Vogelsang 1999).

On one hand, Vogelsang (1999) believes that price cap regulation (together with typical inflation (RPI) and efficiency factors (X), and cost of service every five years) is the best price-level regulatory option for electricity transmission tariffs. Since transmission costs are so dependent on geographic localization, the construction of an adequate cost or price benchmark would not be feasible, and pure cost of service would be too cumbersome to implement.

On the other hand, price structure regulation can be used to solve congestion problems of transmission lines, in the short run, as well as capital costs and investment issues, in the long run. Vogelsang (2001) proposes a two-part tariff regulatory model with variable (or usage) charges, and fixed (or capacity) charges (Hunt, 2002, p. 196-201, discusses the practical hurdles to properly define such charges). The variable charge can also be understood as a nodal price in the sense of the FTR literature (see Vogelsang (2001), p. 143). The Transco is a profit-maximizing monopolist that makes investment and pricing decisions subject to a regulation of its two-part tariff. The solution of this problem solves congestion problems through the variable charges. Recuperation of long-term capital costs is achieved through the fixed charge, while incentives for investment in expansion of the network are reached by a rebalancing of the fixed charge and the variable charge. Transmitted volumes for each type of service are used as weights for the corresponding different prices so that Transco's profits increase as capacity utilization and network expansion increases. In equilibrium, rebalancing of fixed and variable charges depends on the ratio between the output weight and the number of consumers.

c) Two-Part Tariffs for a Radial Line

For example, in the simple case of N consumers and a single fix charge and a single variable charge, the problem of a firm that maximize profits subject to the restriction on price structure suggested by Vogelsang (2001) is:

$$\max \Pi^t = p^t q^t + F^t N - c(q^t, K^t)$$

subject to (8)

$$F^t \leq F^{t-1} + (p^{t-1} - p^t) q^w / N$$

$$q^t \leq K^t$$

where:

F_t = fixed charge in period t.
p_t = variable charge in period t.
q_t = quantity of electricity transmitted in period t (in kWh).
K_t = available capacity in period t.
w = type of weight.

A cost function that reflects the sunk and long-run nature of electricity transmission has the following form:

$$C(q^t, K^{t-1}) = C(q^{t-1}, K^{t-1}),\ \forall\ q^t, q^{t-1} \le K^{t-1}$$

$$C(q^t, K^t) = C(q^t, K^{t-1}) + f(K^{t-1}, I^t)\ for\ q^t > K^{t-1}$$

where

$$I^t = K^t - K^{t-1}$$

Assuming binding constraints, and that ¤t is the Lagrange multiplier of the capacity constraint, the optimal conditions of problem (8) with respect to pt are given according to the Ramsey rule:

$$\left(\frac{\partial q^t}{\partial p^t}\right)\left(p^t - \frac{\partial C}{\partial q^t}\right) = q^w - q^t$$

and

$$L^t = -[1 - \frac{q^w}{q^t}] / \varepsilon^t \qquad (9)$$

where ε^{t} is the price elasticity of demand, and Lt is the Lerner index for q in period t.

Incentives for investment in Vogelsang's model crucially depend on the type of weights used. For each service, a Laspeyres index uses the quantity of the previous period as weight for the price. When this type of weight is used, the Transco will not immediately invest the total difference between current capacity and optimal capacity since the Transco faces a tension between gains from congestion or increases in the capacity charge. The Transco does not immediately equate the marginal income from investing (given by consumers' willingness to pay) with the marginal cost of investment. However, investment will continue through time until it converges to the optimal level, and transmission tariffs in turn will converge to Ramsey prices (see equation (9)). This is because profit will increase over time less than welfare over time (using previous period outputs "forces" decreases in prices and, therefore, increases welfare) (see Vogelsang, 2001, p. 148). These results are true only if it is assumed that cost and demand functions are stable, and that the Transco does not have a strategic conduct in setting its prices (see Vogelsang, 1999, pp. 28-31). In the case of changing cost and demand functions, or non myopic profit maximization, convergence to Ramsey prices under the Laspeyres index cannot be guaranteed (see Fraser, 1995, Neu 1993, and Ramirez and Rosellón, 2002).

Broadly speaking, Vogelsang's mechanism works as follows. In times of excess capacity, the variable charge of the two-part tariff decreases causing an increase in consumption. The fix charge, in turn, augments so that total income increases in spite of the diminishment of the variable charge. As a consequence, the Transco does not invest more in capacity expansion and net profits grow since costs do not augment. On the contrary, when there is congestion in capacity the variable charge will be a pure congestion charge and, if congestion charges are in the margin greater than the marginal costs of expanding capacity, the Transco will have incentives to invest in new capacity. This regulatory mechanism is shown to be superior (in welfare terms) to a linear price cap (Vogelsang, 2001, p. 147), and to an average-revenue constraint as the ones dicussed by Sappington and Sibley (1992).

d) Analysis under Multiple Nodes and Fluctuating Demands

When there are multiple nodes in the transmission grid, a multiple interaction among transmission lines takes place. Any injection or extraction of electricity flows in one node will affect the entire grid. Likewise, investment in a new line between two nodes technically and economically affects all the other nodes. Given the existing interaction among all nodes in the network, the marginal cost of expanding transmission capacity between two nodes cannot be defined in isolation since it would have to include the implied cots and benefits for other nodes. To avoid these problems, Vogelsang (2001) assumes that the Transco is always on its long-term cost function.

As seen, the Vogelsang's mechanism has the theoretical disadvantage that under the use of Laspeyres weights the firm does not instantaneously invest the optimum amount to expand the grid. To overcome such a problem, Vogelsang proposes the use of the mean of Laspeyres and Paasche (current quantity) indexes. He shows that in a two-period framework, and under a concave behavior of demand, this option falls short of marginal cost pricing but performs better (in terms of welfare) than Laspeyres weights. However, in a multiperiod framework the mechanism may diverge from marginal cost since it could be subject to strategic behavior of the Transco. This last result is very similar as the ones in Sappington and Sibley (1992), and Ramírez and Rosellón (2002).

Under fluctuating and inelastic demand, Vogelsang argues that transmission pricing could exacerbate that revenues have no relation to the capital cost of capacity. Vogelsang extends the two-part tariff price-cap approach to permit time-fluctuating prices. Under a radial transmission line, and assuming a long-run cost function, Vogelsang proposes defining variable fees to cover short run congestion charges, power losses and ancillary services. The Transco would establish variable charges ex ante and fixed fees are determined afterwards so that the price structure could be changed on short notice to accommodate changes in demand and supply conditions. The price cap would also have to include last period quantities or services as weights. In the extreme, variable charges may be the actual spot prices so that they change almost instantaneously and differ by geographic area, zones, or even nodes. Under this assumption, fixed fees would have to be determined at the end of each period to provide premiums and penalties for variations in the variable fees. So, for example, when there is too much congestion in a period the variable fee will adjust upwards and the fixed fee will have to be adjusted downwards.

Weights would be assigned to each spot price according to time-specific or location-specific services that are repeated each period. There would be many small subperiods which share the same capacity constraint so that in off-peak subperiods marginal cost is zero, while in peak subperiods marginal cost is positive and equal to partial derivative of the cost function with respect to the capacity constraint. Under Laspeyres weights, profit maximization subject to the price-cap constraint implies that prices will converge to the values of marginal cost in both peak and off-peak periods.

Under averaged Laspeyres/Paasche weights, the off-peak price and markup are equal to zero.

There are, however, implementation complications because the Transco will want to trade until immediately before the transaction takes place (due to the spot pricing nature of the mechanism). Moreover weights cannot be precisely defined since it is impossible to identify periods of last year with periods of the current year. Therefore, all subperiods have to be assigned to a single common weight, which imply an average-revenue constraint as described by Ramirez and Rosellón (2002). The use of this constraint produces first-order conditions different from the optimal conditions since the average revenue constraint is softer than the Laspeyres one (see Bradley and Price, 1991, and Sappington and Sibley, 1992). Vogelsang therefore proposes additional constraints to the price cap, including market rules that assure competitive spot prices (market rules imply setting the spot price equal to zero for off-peak subperiods and according to inverse demand in peak subperiods) and weights restricted to peak quantities. These additional conditions assure lower prices and more investment over time.

Since under the fluctuating demand case, investment incentives remain suboptimal under Laspeyres weights, Vogelsang (2001) finally proposes to define fixed fees heterogeneously so that the fixed fee really pays for a service (called access or capacity) demanded along with usage so that the two-part tariff may actually consist of two linear prices for two services. There are three alternatives for the unit of consumption of the now "variable" fixed fee. First, fixed fees might pay for total capacity provided by the Transco. Second, the quantity used to calculate the fixed fee could be individualized and defined by the capacity demanded at the peak. Third, the fixed fee could be allowed to grow according to a predicted rate. The first option leads to overinvestment, the second to underinvestment, and the third one depends on the growth prediction.

e) Implementation Issues

The main criticism to the price-cap approach for transmission expansion is that it is based on very simplifying assumptions that make doubtful the possibility of its application. Firstly, in order to develop a proof of convergence to the Ramsey optimal outcome, Vogelsang (2001) has to assume that the transmission demand functions are differentiable and downward slopping, and that transmission marginal costs curves cut demands only once. As shown in Hogan (2002 c), this assumption is not in general valid since, under loop flows, an expansion in a certain transmission link can derive in a total decrease of the network capacity. Secondly, in order to study the cost and production characteristics of a Transco, Vogelsang finds it useful to define the Transco's output (or throughput). As argued in the FTR literature (Bushnell and Stoft (1997), Hogan, 2002a, Hogan, 2002b), this task is very difficult since the physical flow through a meshed transmission network cannot be exactly traced. Thirdly, Vogelsang abstracts from the existing substitution relationship between transmission and generation projects (while the FTR model folds transmission price to generation bids).

The above, however, do not necessarily mean that the Vogelsang's mechanism totally fails in the presence of loop flows. Its behavior under loop flows has simply not been analyzed in the literature. Likewise, under a network with loop flows, outputs under the price-cap approach could be thought as bilateral trades between pair of nodes that aggregate to net injections at all nodes. Additionally, as argued by Hunt (2002), since transmission investment in the long run is subject to uncertainty, the regulated Transco approach seems to have an advantage over the FTR/merchant approach because the Transco has to make all externality calculations (and associated probability assessments) by itself. In other words, the Transco would solve the loop flow problem by itself, and its regulation through a price-cap scheme could provide a cost-minimizing outcome.

Rosellón and Nevárez (2001) attempt a preliminary application of the Vogelsang mechanism to the electricity transmission system of Mexico, for the case of a stable demand growth for electricity. They analyze three scenarios: (i) a single Transco that offers the transmission service in all the national territory and that applies postage-stamp tariffs to all consumers; (ii) several regional companies that independently operate in each of the nine areas of the national transmission system, and that charge in each of their areas different tariffs to the ones applied by other companies; and (iii) a single Transco that operates in all the areas of the national transmission system but that differentiate the prices applied in each of the regions.

Achieved investment and profits are shown to be the highest under the scenario that allows for a single firm and price discrimination (scenario iii). This confirms the theoretical result that the Transco will have greater incentives to invest in the grid expansion if it is allowed to charge discriminatory tariffs (see Bertoletti and Poletti, 1997). A further step would be to try to do more detailed empirical research to understand the problems of trying to implement a price-cap approach towards transmission expansion. In fact, such problems could explain why in other developed electricity industries, a revenue-cap approach is used as opposed to a price cap one (see Jordanger J, and H Grønli, 2000, for the case of Norway). A revenue approach might evade having to exactly define the nature of the output produced by a Transco.

Vogelsang (2001) believes that the price-cap mechanism could be applied under the (centralized) ISO approach. He argues that an ISO is important in order to coordinate a competitive market for congestion pricing. The ISO would run the short-term utilization of the transmission system (through a bid-based, security constrained market, together with locational marginal pricing), while the Transco would own and physically operate the transmission network, and collect congestion charges and fixed fees. However, Vogelsang also points out that the ISO needs a well-defined objective function and that the variables that might influence this objective function could be the total amount traded over the transmission system and the average nodal price difference.

A crucial issue in an electricity transmission grid relies on the comparison of the congestion gains, and the gains for the expansion of the network. The PTP-FTR model provides efficient results whenever congestion gains are not larger than the benefits from expansion. In such a case, there would be incentives to expand the grid. The difference in nodal prices would be big enough to provide incentives for long run investment. In the opposite case, when it is more profitable for the transmission company to keep a congested network than to expand it, then a small expansion of the transmission grid will have such an impact on tariffs that there would be no incentive to expand the grid.

For example, the Mexican transmission grid must be expanded at a 14.2% growth rate per annum in the next ten years in order to meet an annual growth rate of 6% in demand, assuming that generation capacity also grows at the rate of 6%. This transmission-grid growth rate is extremely high compared to the historic annual average growth rate of 3.9%. Such a difference hints that there could exist incentives for the transmission company for maintaining the transmission lines congested. Theoretically, a grid like the Mexican one might then need to implement some type of regulation to mitigate transmission market power so as to enjoy the benefits from locational marginal pricing and FTRs.

The relationship between market power and transmission expansion seems then to be very much interesting. Under what conditions does transmission expansion mitigate or exacerbate market power? How does the market structure in the generation market determines the transmission expansion projects? How does market power in the FTR market affect market power in power generation or electricity consumption? We study the literature that addresses these types of matters in the next Section.

Transmission Expansion and Market Power

Léautier (2001) studies the effects of an increase in transmission capacity in a three-node network model of two periods. In the first period transmission expansion takes place, so that the owner of the transmission assets receives revenues. In the second period the SO carries on dispatch in order to maximize consumer surplus and according to a pay-as-bid function. The model allows for loop flows. He finds two main effects. First, a substitution effect: transmission expansion permits that cheaper power substitutes the use of more expensive power. Second, a strategic effect: competition in generation increases. The substitution effect is always welfare improving, while the net welfare outcome of the strategic effect depends on the weight of generators' profits relative to the consumers' weight. The higher the generators' weight the lower the positive effect on welfare.

Therefore, Léautier argues that generators are not the best economic agents to carry out transmission expansion projects. Although transmission expansions allow generators to enhance their revenues due to improved access to new markets and increased transmission charges and FTRs, such gains are overcome by the loss of their local market power. Thus, in general, generators might like to congest transmission lines (see Léautier, 2001, pp. 44-47). The regulator should then take measures to vertically separate the electricity industry, and permit that transmission expansion projects might be carried out by any interested economic agent.

a) Market Power and Transmission Investment in the FTR Literature

The FTR literature shows that the expansion of the transmission network has an impact on the market power of other electricity industry agents, such as generators and consumers. As shown in an extensive body of literature, generators can better exert local power when the transmission network is congested (see Bushnell, 1999, Bushnell and Stoft, 1997, Joskow and Tirole, 2000, Oren,1997, Joskow and Schmalensee, 1983, Chao and Peck, 1997, Gilbert, Neuhoff, and Newbury, 2002, Cardell, Hitt, and Hogan, 1997, Borenstein, Bushnell, and Stoft, 1997, Wolfram, 1998, and Bushnell and Wolack, 1999). Specifically, Bushnell and Stoft (1997) show that in a three-node network a single generator might benefit from a welfare-inefficient expansion while Joskow and Tirole (2000) study several scenarios of market structure both in the generation market and the FTR market. They find that a predominant position in the FTR market by a monopoly generator increases its monopoly power, since dominance in the FTR market provides incentives to cut power generation to make FTRs more valuable.

As Joskow and Tirole (2000) show, the precise allocation of FTRs under a monopoly generator depends on the (micro)structure of the FTR market. When all FTRs are initially held by a single owner who is neither a generator nor a consumer, the monopoly generator will want to acquire all FTRs. When the initial ownership of FTRs is dispersed among economic agents without market power, the generator will buy no FTR, while when the FTRs are auctioned to the highest bidders, the generator will purchase a random number of FTRs (but between the other two cases). Building on this analysis, Gilbert, Neuhoff, and Newbury (2002) study ways to cancel perverse incentives by finding conditions where different allocation processes of FTRs can mitigate generation market power when the transmission capacity is constrained. For example, in an arbitraged uniform price auction generators will purchase FTRs that mitigate their market power, but in a "pay-as-bid" auction FTRs might enhance the generator's market power. When the generator is not allowed to own FTRs not related to delivery of its own energy, market power might be mitigated in a two-node case. However, in the three (or more) node case, mitigation of market power implies defining FTRs according to the reference node with the price least influenced by the generator's output decision.

In practice, market power mitigation mechanisms are generally considered with any electricity reform proposal based on the FTR model. In Mexico, the reform proposal foresees that the Mexican Energy Regulatory Commission will establish the necessary regulations for generators with market power (see Secretaría de Energía, 2002, Section 5.4). This due to the fact that Comisión Federal de Electricidad (2000) proves that the isolated Peninsular and Northwest regions are more susceptible for market power abuse than central regions. In the U.S., FERC's recent reform proposal contains specific Sections on "market power mitigation" (see Federal Energy Regulatory Commission, 2002, pp. 224-259). FERC's SMD identifies lack of sufficient demand-side response and the existence of transmission constraints as the two principal causes for the presence of market power in electricity markets. FERC also differentiates high prices due to scarcity and high prices resulting from exercising market power. Building on a merit-order spot market mechanism, a bid cap is used for generators with market power in a "load pocket," while a "safety net" (similar to the $1,000 per MWH bid cap of the Northeast and Texas electricity markets) is proposed for demand-side responses. Regulated generators are also subject to a resource adequacy requirement. Chandley and Hogan (2002) believe that this last mechanism is inefficient since the use of penalties for undercontracting (with respect to the resource adequacy requirement) would not allow prices to clear the energy and reserve markets. Additionally, according to these authors long-term contracting should not be mandatory and should not be based on capacity requirements but on financial hedging.

b) Optimal transmission investment and market power

A basic question is then naturally raised on how to design a mechanism that defines optimal transmission expansion depending on the market-power structure of the generation sector. Sheffrin and Wolak (2001) attempt such a task by deriving the optimal expansion of the transmission network according to the strategic behavior of generators. They use a network model and California generators' bidding data to estimate the generators' bidding behavior before and after a transmission upgrade. Before the upgrade, the bid curves are classified into several peak and off peak types, either weekday or weekend/holiday so that the set of bids of each market participant are classified for each hour of the year. These data are then plugged into the SO's dispatch model so as to obtain the market profit outcomes. The same exercise is carried out after the upgrade, and the expected profit outcomes are calculated. This involves modeling expected profit-maximizing bidding strategies of generators due to the system expansion. In a related work, Wolak (2000) analyzes the optimal bidding strategy under transmission congestion of a generator that owns various generation plants.

London Economics International (2002) (LEI) also discusses a conjectural model with multiple bidders and two (exporting and importing) regions. This approach assumes a centralized SO that is basically interested in mitigating market power in generation through an adequate definition of transmission expansion projects. Considering uncertainty as well as strategic behavior of generation firms, the SO seeks to maximize social welfare as defined by the weighted sum of producer surplus and consumer surplus. Each generator makes a conjecture of the other generator's marginal cost due to the expansion. Each bidder then maximizes its profits in its residual demand function, and given the predicted other bidder's supply functions. The procedure is iterated to set each generator bid function, and to obtain stable market clearing prices. Supply functions in each region for each participant are estimated, as well as changes in consumer surplus and producer surplus due to transmission upgrades. Likewise, the sensitivity of the model is checked with respect to market structure, demand, costs, and elasticities.

The results of LEI's model show that the benefits of transmission expansion are small until added capacity surpasses a certain upper limit that, in turn, is determined by the possibility of induced congestion by the strategic behavior of generators with market power. That is, market structure of the industry plays a decisive role on the impact of a transmission upgrade. Hence, and increase of the number of generators or a redistribution of capacity of the network may reduce bid prices; while hedging contracts also lower bid mark-ups and prices, and high-cost bidding is very sensitive to demand elasticity (for demand levels sensitive to an individual generator's strategy). This means that a transmission expansion will only yield benefits until it is large enough with respect to a given generation market structure. The addition of cost uncertainty to the model (due to environmental factors and local opposition to transmission projects) implies that many small upgrades are preferable to large greenfield projects.

LEI's model is further extended to include uncertainty arising from the interdependence of demand for electricity transmission and the pattern of power generation investment. Transmission and generation can be substitutes when electricity supply is needed at a certain location, but they can also be complements since the building of a transmission line might permit to increase the volume of power that a generator can sell. Under vertical integration of generation and transmission, the integrated firm would select the minimum-cost form of supply trading off costs of transmission and generation investment. When generation and transmission are not integrated, the SO needs to forecast possible investments in generation due to new transmission investment so as to optimize transmission investment.

LEI then use a real options approach to analyze how a transmission investment process is affected by uncertain conditions on demand, costs and possible reaction of investors in generation. This analysis relies on the fact that a transmission investment might be delayed one or several periods. LEI's real options model also builds on a multi-scenario modeling and on Monte Carlo simulations so as to find the joint probability distribution (for both transmission and generation) of the outcomes of transmission expansion given such uncertain conditions, and of the outcomes of a generation project with and without the transmission expansion (outcomes include prices, patterns of generation, profits, loss of load probability, and transmission losses). The joint probability distribution is subsequently used to calculate the net present value of the transmission and generation projects. The interaction between the transmission planner (the SO) and the generation investor is modeled in a game theory set up where each player has two strategies, namely "invest immediately" or "delay investment." Each investor chooses the investment strategy with the highest payoff given by the expected net present value and the net value of the options associated with the project. (This last analysis resembles the one made by Brito and Rosellón, 2003, to calculate the welfare loss associated with delaying the building of a new natural-gas pipeline).

c) Implementation Issues

The Sheffrin and Wolak (2001) and London Economics International (2002) analyses represent an effort to model the welfare loss associated with generators' price gaming under the building of a new transmission line. This approach explicitly addresses the existing substitution relationship between transmission and generation projects. It also implicitly assumes the strategic behaviors of generators will somehow self manage congestion. However, this approach relies on a transportation model with no network loop flows. As argued before (Hogan, 2002 a), the use of a transportation model in the electricity sector presents serious problems in practice since an expansion in a certain transmission link can imply a decrease of the total transmission network capacity

Conclusions

This paper has surveyed the contributions made to the literature on incentives for the long-term expansion of the transmission network. This area has an incipient development. As Joskow and Tirole (2002) argue, the economic analysis of electricity markets has focused on short-term issues (such as spot markets for energy, short-run congestion management, nodal pricing, and day ahead auction rules) and has typically considered the transmission network capacity as given, fixed, and of common knowledge. However, transmission capacity is stochastic and its development mutually depends on the evolution of generation investment.

We studied the three main existing approaches and described its analytical properties and implementation characteristics. The first one, the "merchant" option, relies on the auction of long-term financial transmission rights by an ISO. This approach seems to be promising because it directly faces the problems implied by loop flows. However, we analyzed the technical difficulties in defining an operational LT FTR auction since loop flows could give rise to the opposite result to the one sought by transmission investment. Additionally, this analysis is a static one which seems to be at odds with the dynamic nature of transmission investment. Likewise, the difficulties associated with contingencies in the long-run transmission question the real capacity of the LT FTR/merchant approach to really solve the loop flow problem. Even more, the existence of market power and vertical integration might jeopardize the success of this method. "Financial Transmission rights can support merchant investment, but are inadequate to address the problems associated with large economies of scale and free riding (Harvard Electricity Policy Group, 2002a, p. 32)."

The second alternative is provided by regulatory mechanisms for Transcos. The basic idea is that the Transco faces the entire social cost of transmission congestion. One alternative is a two-part tariff cap that solves the opposite incentives to congest the existing transmission grid and to expand it in the long run. This approach tries to deepen into the analysis of the cost and demand functions for transmission services, which are not very well understood in the literature. However, in order to carry out this task, it has to assume a monotonic increasing behavior of the transmission cost function. As shown by Hogan (2002c), this assumption is not in general valid since an expansion in a certain transmission link can derive in a total decrease of the network capacity.

In fact, there is a debate in the literature regarding the use of a regulated Transco approach for transmission expansion. On one hand, Hunt (2002) and Joskow and Tirole (2002) believe that a Transco regime avoids the moral hazard in teams problem of an ISO regime. In that sense, the regulated

Transco approach would seem to have an advantage over the FTR/merchant approach because the Transco carries out all externality calculations (and associated probability assessments) by itself, and would properly respond to incentive regulation (as in Vogelsang (2002)) even under loop flows. On the other hand, the Transco approach faces several implementation hurdles. As argued by Hogan (1999a), a Transco needs first of an institutional set up that permits a single owner of the entire grid (such institutional conditions do not exist in the U.S., but do exist in the United Kingdom). Additionally, as explained by Wolfram (1999), the Transco system like the one currently used in the United Kingdom, relies on discriminatory treatment to transmission uses. Such a practice would not be politically possible in other countries such as the U.S. Finally, an incentive type of regulation can hardly be implemented because of the impossibility of correctly defining the Transco's output.

The third alternative method for transmission expansion defines optimal expansion of the transmission network according to the strategic behavior of generators, and considers conjectures made by each generator on other generators' marginal costs due to the expansion. It also uses a real-option analysis to calculate the net present value of both transmission and generation projects. The main contribution of this approach is that it explicitly models the existing interdependence of generation investment and transmission investment. However, this approach also relies on a transportation model with no network loop flows.

As seen, there is neither in theory or practice a single mechanism that guarantees an optimal expansion of the electricity transmission network. However, the distinct study efforts surveyed in this paper suggest a second-best standard that could combine the merchant and the regulated transmission models, so that small" transmission expansion projects rely on the merchant approach while "large" and lumpy projects are developed through incentive regulation. This approach could also be complemented with public planning: "To bring coalitions together; to verify and approve the cost effectiveness of projects; and to ensure that transmission gets built in time (Hunt, 2002, p. 206)".

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