Nodal Prices and Transmission Rights: A Critical Appraisal

This article challenges several prevalent claims about the role of nodal prices and transmission rights which underlie Poolco proposals. The application of nodal prices for pricing transmission services in networks with parallel path flows can have perverse consequences due to the interaction of power flows.

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Nodal prices, or locational spot prices, are a key instrument in the restructuring of electricity sectors in Chile and Argentina and they play a central role in the discussion concerning the electricity sector reforms in California, the United Kingdom and New Zealand. The concept of nodal prices originates with the work of Schweppe and his collaborators[1] and has been recently championed by Hogan and others.[2] Nodal prices reflect the differential value of generation and consumption at each location arising from physical characteristics of electricity networks, namely the existence of losses and capacity constraints.

Because nodal prices equal the marginal valuation of net benefits at different locations, they provide the right incentives for consumption and generation decisions, both in the short and in the long run. Since nodal price differences also reflect the existence of transmission constraints, their use for pricing transmission services and to compensate for transmission ownership has received substantial attention in both the academic literature and in policy circles.[3]

The main purpose of this paper is to challenge several claims about the role of nodal prices that are accepted by some practitioners and academicians involved in the discussion on the transition towards a more competitive electricity sector, both in the United States and abroad. In particular, we will demonstrate the pitfalls of using locational spot price differences for pricing transmission services and for compensating for transmission ownership. In simple (i.e., linear or radial) networks, such application of nodal prices may be suitable.[4] In networks with parallel flow paths, such as the Eastern and Western U.S. networks, basing transmission pricing on nodal price differences is inappropriate. Such pricing schemes will not provide the right incentives for transmission investments or expansion, nor will they provide appropriate compensation for ownership of transmission assets or rights in a decentralized ownership network.

We will first show in Section I that the use of nodal prices for pricing of transmission services is based on inappropriate analogies with transportation and arbitrage theory. These analogies have also led to improper assessments of the viability of firm or tradable transmission rights. The article touches on a variety of issues, all of which are related to the improper use of nodal prices as the universal answer to problems arising in implementing direct access in the electric power industry.

In Section II we introduce an example which illustrates some counterintuitive behavior of nodal prices under optimal dispatch, such as: (i) nodal prices may be higher at the sending end of a line than at the receiving end; and (ii) nodal prices at the ends of a line may differ (above and beyond losses) even though that line is not operating at its line-flow limit.[5] Although these are counterintuitive results, they are intrinsic features of meshed electricity networks.

In Section III we use the above example to challenge the claims that an efficiently coordinated system of purely bilateral contracts is equivalent to an optimally dispatched-type pool and that market-making functions and system operations must be integrated to achieve efficient operation. The first proposition has been advance both by Hunt[6] and Hogan.[7] Instead, we show that to replicate optimal dispatch in a decentralized fashion, multilateral trades may be necessary. Thus, there is a natural progression from a bilateral (Opco-based system) to a Poolco-based system. As the size of the multilateral trades required to achieve efficient system operation increases, so does the advantage of a Poolco system. However, if large multilateral trades are systematically involved only in a distinct regional portion of the network, an island-size Poolco will naturally arise to coordinate those multilateral trades in a sea of bilateral trades. Thus, we conclude that there is no need to implement a single institutional solution to a large and varied regional area. Indeed, the approach taken in the U.K. is a mixed institutional system, wherein the Scottish system operates based on bilateral trades with two separate utilities working as system operators, while a pool runs the England & Wales electricity system.[8]

The use of nodal prices for pricing of transmission services is based on inappropriate analogies with transportation and arbitrage theory.

In Section IV we address the issue of transmission rights and discuss three alternative forms of such rights. We first demonstrate that firm transmission rights are inconsistent with the efficient operation of the network, and as such are incompatible with either centralized dispatch or bilateral trading systems.[9] We then show that financial rights to merchandising surplus based on link ownership lead to perverse investment incentives that would call for regulatory intervention. Finally, we show that transmission rights in the form of contract networks are redundant in a decentralized environment with nodal spot and forward markets. Furthermore, they do not provide a satisfactory solution to the problem of how to compensate transmission assets ownership and facilitate long-term efficiency. Therefore, they call for a complex regulatory process to control transmission investments and allocate rights.

I. Nodal Prices and the Transportation Analogy

The notion of pricing transmission across two nodes based on the difference of nodal prices is rooted in the following idea. If the good is priced at level p_A at location A then the price at any other location B cannot exceed p_A plus the cost of transportation from A to B. Otherwise arbitrage would take place and force the price in B to converge to the sum of p_A plus transportation costs. As transportation prices go up, either because of limiting shipping capacity from A to B or because of increased transportation costs, the difference in price between the two locations will also tend to increase.

At first glance this analogy seems valid for a linear or radial electricity network. In such a network, the difference of nodal prices between two nodes A and B measures the sum of marginal transmission losses from A to B and the value of relieving the congestion in the AB link. Marginal transmission losses can be interpreted as the equivalent of a transportation cost. In the absence of such losses, nodal price differences would reflect no physical transmission costs. They reflect, however, the welfare gain from relieving the congestion between A and B.

On further examination, however, the analogy between transmission costs and transportation costs breaks down even for a simple two-node network. The reason is that in electricity networks transmission constraints and their pricing are determined by the action and judgments of grid operators rather than by the decentralized decision making of transportation companies and their clients. In electricity networks there is no active competition among transmission operators to carry electrons over their wires. As a consequence, a better analogy to the differences in nodal prices is an externality tax imposed by a network operator. For any tax, whether or not the tax is set at the optimum level, there is a competitive equilibrium corresponding to the shifted cost functions. Thus, in electric power systems there are many potential market equilibria, each depending on a different set of taxes (congestion charges) distributed over the network. The fact that markets clear, however, does not mean that these taxes (or dispatch) are optimal. Differing from standard transportation networks, these taxes (congestion charges) are set by an operator and not by market forces. For market clearing to reflect optimality, however, the operator has to be forced to set network constraints or nodal prices appropriately.[10]

The analogy to transportation systems breaks down even further when we move to more complex networks (even in a system as simple as a three-node network). The main reason for the breakdown of the transportation analogy is that in more complex networks Kirchoff's laws governing electric power flows imply that congestion is a network rather than a link phenomenon. In these types of networks we may observe several counterintuitive relationships which cannot occur in transportation systems. For example: (i) links which operate below their line-flow capacity limits may still have nodal price differences in excess of marginal losses (true transportation costs) because of congestion in another line; (ii) reinforcing (i.e., decreasing the reactance) of a particular line may in fact reduce the transfer capabilities of the network; (iii) under optimal dispatch, power may flow from higher-price nodes to lower spot-price nodes; (iv) transmission rights in a dynamic setting are not compatible with economically efficient dispatch.[11]

These relationships have implications for the design of competitive electricity systems. First, economically efficient dispatch may not be emulated by purely two-way contracts, as some flows may require more complex transactions involving three agents or more. Second, nodal price differentials are not appropriate for allocating congestion rents across the network, thus an alternative mechanism to allocate network congestion rents has to be designed. Third, physical transmission rights and financial instruments should be separated. Physical transmission rights should not be implemented, as they interfere with optimal dispatch. While financial transmission rights are feasible, it will be argued that they are inferior to nodal forward markets and they do not fully solve the problem of distributing the transmission surplus inherent in the operation of a pool.

II. An Example

Many of the issues raised above can be illustrated with the use of simple three-node examples. In **Box 1** we present a three-node system.[12] We elaborate on this example in this section, and in the following sections we fully discuss its implications. In Box 1 we assume, for simplicity, that the system is lossless and we ignore reactive power considerations.[13] We assume that generation is located at buses 1 and 2, while demand is located at bus 3. See Box 1 for a detailed description of the example. The marginal costs at both nodes 1 and 2 are assumed to be linear and increasing, and the demand at bus 3 is infinitely elastic at a certain price.

The example in Box 1 makes several points. First, the figure provides the outcome from optimal dispatch. We note that marginal cost at node 2 is above marginal cost at node 1, and above marginal valuation at node 3. The reason for such a high output level at node 2 is that line 1-2's line-flow constraint of 8 MW imposes an upper bound on generation at node 1. Second, although flows in line 1-3 do not reach the line's line-flow constraint, prices at nodes 1 and 3 differ by more than losses (in our case losses are zero). Indeed, the line-flow constraint in line 1-2 implies that line 1-3 is also subject to transfer constraints. Third, flows in line 2-3 go against prices: Although prices are higher in node 2 than in node 3, flows are from node 2 to 3, i.e., if nodal price differences are to be used to price transmission, then transmission between nodes 2 and 3 should have a negative price. Thus, transactions from nodes 2 to 3 should be subsidized. We will use this example through the remainder of this paper to highlight the various issues mentioned in the introduction.

III. The Relative Efficiency of Bilateral Transactions

It has been argued that there is no difference between a system of efficient bilateral transactions and a fully integrated pool. It has also been implied by these arguments that efficient operation of the system requires the integration of system operation and market making as in the Poolco proposal. The purpose of this section is to chal-

Notation:

q_i: MW injection at node i (positive for generation, negative for consumption)

q_{ij}: MW power flow from node i to node j

p_i: nodal price at i (¢/kWh)

Marginal Cost at node 1: $MC_1 = .2q_1$ (¢/kWh)

Marginal Cost at node 2: $MC_2 = .335q_2$ (¢/kWh)

Marginal Valuation at node 3: $MV_3 = 3.3$ (¢/kWh)

Line reactance between nodes 1 and 2: $X_{12} = 1$

Line reactance between nodes 2 and 3: $X_{23} = 1/3$

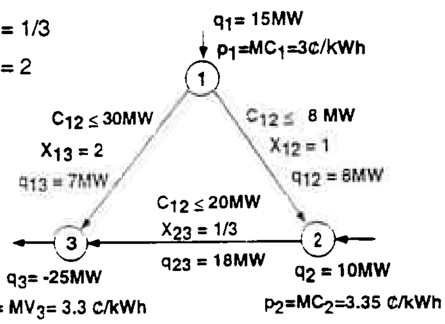
Line reactance between nodes 1 and 3: $X_{13} = 2$

Line flow limit for line 1-2: $C_{12} = 8MW$

Line flow limit for line 2-3: $C_{23} = 20MW$

Line flow limit for line 1-3: $C_{13} = 30MW$

Figure A



Results from optimal dispatch:

Total Merchandising Surplus: $MS = -\Sigma q_i p_i = 25 \cdot 3.3 - 15 \cdot 3.0 - 10 \cdot 3.35 =$ \$40/hour

Total Surplus: $TS = -3.3 \cdot q_3 - 1/2[0.2 \cdot q_1{}^2 + 0.335 \cdot q_2{}^2] =$ \$432.5/hour

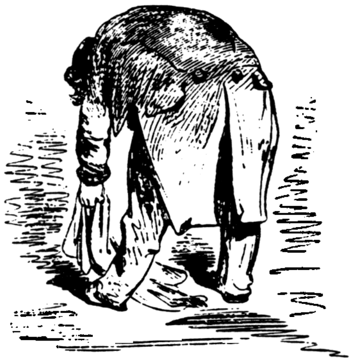
Shadow value of line flow constraint C_{12}: $dTS/dC_{12} =$ \$5/MWh

Box 1: Illustrative Example

lenge these assertions. These arguments have focused only on the method for settling differences between contracted and dispatched quantities.[14] The main reason for the presumed equivalence is that in a pool, like that in the United Kingdom, the entire quantities dispatched are transacted at pool prices, while in a bilateral system (e.g., Norway), pool prices are applied only to the difference between contracted and realized quantities. The proponents of this equivalence argue that the addition of contracts for differences in a pool setting is enough to replicate the workings of an efficient system of bilateral transactions.

This discussion leaves out some important network considerations that limit the capability of simple bilateral transactions to achieve economic efficiency. One particular aspect is that in any congested network with parallel lines, optimal dispatch may require the transmission of power from a high-price to a low-price node. In a pure bilateral framework such transactions will not be commercially viable because the seller's price will be above the buyer's price, so there's no deal. This could be corrected with an *ex ante* subsidy system, but the problems in designing such a system are obvious. Thus, an efficient bilateral system is not equivalent to a pool system with optimal dispatch.

The fact that some transactions will not be commercially viable in a pure bilateral system, does not mean that optimal dispatch is unachievable without a pool. On the contrary, the fact that the bilateral system leaves unexploited trading opportunities implies that there will be incentives for market players to design more complex trading arrangements. For example, brokers may organize feasible trilateral trades which bundle the flows from high- to low-price nodes with other transactions and yield a net profit to the involved traders. Such transactions are implicit in a pool-based bidding system. A fully integrated pool, however, may be overly restrictive and the efficiency gains may be



achieved in a more decentralized fashion. Furthermore, a system operator that has no cost information can still provide the players with technical information needed to balance the system and to design feasible trades that lead to economic efficiency.

To illustrate the potential for such trades, we revisit the example of Box 1. In what follows we assume that transmission charges cover only system losses (the example assumes no losses), while congestion is handled directly by the system operator through quantity controls. Trading starts with generators and buyers entering into bilateral transfer agreements. In the absence of any constraints, given cost and demand configurations, there will be two types of bilateral contracts: Generators at node 1 and customers at node 3 will want to contract for a transfer of 16.5 MW at a price of 3.3¢/kWh, while customers at node 3 and generators at node 2 will want to contract for a transfer of 9.85 MW at 3.3¢/kWh. See **Figure A** in **Box 2.** Those are the quantities at which the respective marginal costs of generation equal the market-clearing price of 3.3¢/kWh.

Contracts have to be cleared with the system operator who checks for feasibility. In this case, however, because both trades are not feasible simultaneously, the system operator could, for example, curtail to 14.975 MW the contract between generators at node 1 and customers at node 3.[15] The resulting flows are illustrated in **Figure B** in Box 2. In addition, an enlightened system operator will also indicate to the traders that injections at nodes 1 and 2 could be increased simultaneously at a rate of one to six without overloading the congested link.[16] This opens up the opportunity for a trilateral trade of the form shown in **Figure C** of Box 2.

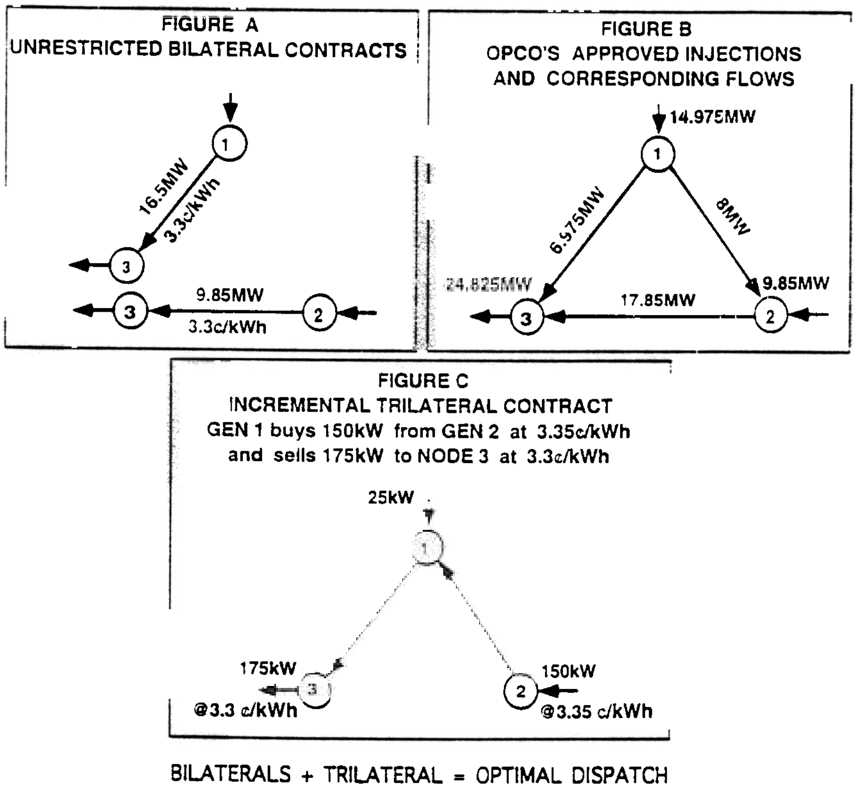
The market then will proportionally scale the quantities in this contract up to the point that there are no more profitable injection increases. In our example, this will result in an incremental trilateral contract involving a 25 kW injection at node 1 at a marginal price of 3¢/kWh, and a 150 kW injection at node 2 at a marginal price of 3.35¢/kWh, and an additional 175 kW ejection at node 3 at a marginal price of 3.3¢/kWh. Note that at these marginal prices, the trilateral contract just breaks even. Furthermore, the contract will be profitable for both generators 1 and 2 as their average costs are below those prices.[17]

Observe that superimposing the modified bilateral contracts approved by the system operator with the trilateral contract leads to the same nodal injections as obtained through optimal dispatch.[18] (See Figure A in Box 1.) Furthermore, observe that the settlement prices arising from the trilateral contract are the same as those obtained through optimal dispatch. Thus, we find that optimal dispatch does not require that all injections at a node carry the same price.

This analysis provides several lessons that counter familiar assertions. *First*, this example illustrates that congestion charges are not necessary to achieve optimal dispatch in a decentralized trading system. Direct imposition of constraints on feasible trades by the system operator together with the working of the market results in the correct "nodal" prices on the marginal transactions that "internalize" the congestion costs. *Second*, efficient dispatch does not require that all transactions be cleared at the same price. *Third*, optimal dispatch is achievable without the system operator having any information about cost or demand. Thus, market making can be separated from the system operation function, and at least in this simple example, market making does not have to be centralized within a pool. *Finally*, optimal dispatch may not be achievable with simple bilateral contracts and may require the development of complex trading instruments, such as multilateral contracts with generation at different nodes adhering to fixed proportions. The development of such trading instruments may require supporting institutions. There is no need, however, for these institutions to merge with the system operation. On the other hand, in areas where the network is heavily congested and the network topology provides for profitable complex multilateral contract opportunities, such mergers may take place. Such a market-driven evolutionary system may be fragmented into pockets of tightly coordinated pools.[19]

IV. Transmission Ownership and Rights

Several proposals for transmission access are couched in terms of transmission capacity rights. Their objective is to grant owners and users of transmission assets entitlement to the usage of, or revenues from, the joint operation of the grid. At one extreme is the concept of firm transmission rights which originates from the implementation of wheeling in the wholesale market. Firm transmission rights provide transmission-right owners the right to



Box 2: Achieving Optimal Dispatch Through Multilateral Transactions

wheel power from one location to another.[20] The allocation of such rights, however, constrains the dispatch by the grid operator, and may impede efficient operation. In **Box 3** we present a three-node network where each line can carry 100 MW. The initial allocation of transmission rights provides generators at node 1 with 150 MW transfer rights to node 3, which may be consistent with initial loads (as shown in Figure A in Box 3). Such rights, however, will prevent efficient dispatch under different demands. For example, if under optimal dispatch the load at node 3 increases to say, 200 MW, and the new optimal dispatch is as illustrated in Figure B in Box 3, that dispatch would be prevented by the initial allocation of firm transmission rights.

To prevent the inefficiencies associated with firm transmission rights, weaker forms of transmission rights can be designed which entitle the holder either to physical performance or to financial remuneration based on nodal price differences. Since the holder of such rights is not permitted to choose between physical performance and financial compensation, the physical performance part of this weaker transmission right can essentially be disregarded, and we can consider these transmission rights as purely financial entitlements.

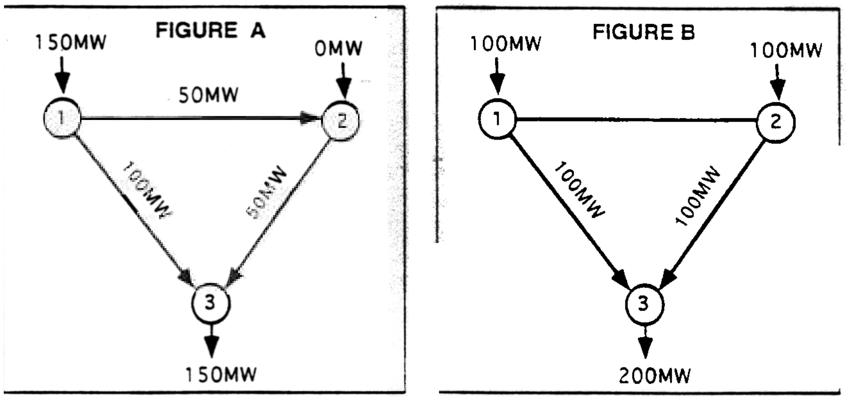
There are two basic approaches to define these weaker transmission rights. On the one hand, transmission grid owners can be given the right to collect the merchandising surplus associated with links under their ownership, i.e., the difference in nodal prices times the flow across the link minus losses. This approach has been used in Chile since 1980 and a variant of it has been recently implemented in Argentina.

A second approach, coined "contract networks" in Hogan's seminal article,[21] tries to solve some of the shortcomings associated with the "link-based" approach. The contract network approach allocates rights for injecting and ejecting of a predetermined amount of power at specific nodes. Thus, a 100 MW transmission capacity right from node A to B entitles the owner to a 100 MW injection at A and a 100 MW ejection at B, or to receive the nodal price differential between B and A for 100 MW (minus losses), regardless of actual flows. We will discuss first the implications and merits of the link-based approach and later those of Hogan's contract network.

A. Link-Based Transmission Rights

Assigning link-based merchandising surplus to transmission owners (or investors) has several shortcomings. First, because a higher difference in nodal prices will usually translate to a higher link-specific merchandising surplus, owners of the link will have perverse investment incentives. In particular, they will have an incentive to degrade the link. This is not different from the problem created by the monopolist's incentive to restrict supply, and it was so recognized in both Chile and Argentina. Thus, in both countries, third parties can expand or request an expansion of a particular link.

Second, economic anomalies and perverse incentives occur in meshed networks (that is, networks characterized by parallel flows), with behaviors that seem counterintuitive from an eco-

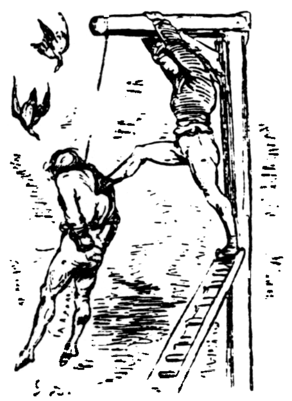


Box 3: Firm Transmission Rights are Incompatible with Efficient Dispatch

nomic perspective. The general point we want to make here is that optimal dispatch by a neutral entity, e.g., Poolco, is not of itself enough to assure long-term efficiency. Transmission pricing and ownership of transmission links have a strong impact on the expansion and long-run performance of the system. In particular, we find that granting link-specific merchandising surplus to link owners can create perverse incentives. Overcoming the distortions inherent in such an approach will require strong regulatory oversight and it is, therefore, an unsound basis for compensation of transmission ownership and investment.

The perverse incentives mentioned above can be best illustrated in the context of the example of Box 1. As noted earlier, power flows in link 2-3 from a high- to a low-price node. As a consequence, link 2-3 has a negative merchandising surplus, for which the owners of link 2-3 are liable. The existence of a negative merchandising surplus has several implications.[22] At first, one may wonder whether the fact that line 2-3 has a negative price gradient does not imply that the network would be better off by eliminating line 2-3. This, however, is clearly not the case here. Although line 2-3 could be needed for reliability considerations, even if we ignore that aspect, the reader can compute that line 2-3 provides a net social surplus gain. Indeed, if line 2-3 were eliminated, consumption at node 3 would fall, total merchandising surplus would increase, but total social surplus would fall. Thus, if transmission investment is controlled by a single operator who collects the merchandising surplus, the operator has an incentive to eliminate the link 2-3, reducing social surplus.

Assume that eliminating link 2-3 is not an option, and that owners of transmission links get assigned the merchandising surplus (whether positive or negative) associated with their links. Thus, the owner of the claims on the merchandising surplus associated with line 2-3 will be liable for the



negative merchandising surplus associated with it ($9/hour). This liability creates a perverse incentive as the liability can be reduced by further *strengthening* the line 2-3 (i.e., reducing its reactance) to the detriment of the system as a whole. If, for example, the reactance of line 2-3 is reduced from 1/3 to 1/12, then optimal dispatch will reduce the merchandising surplus liability of line 2-3 from $9/hour to $5.56/hour. This is accomplished because the reduced reactance of line 2-3 reduces the injection capabilities of generator 1, thus reducing the flows on line 2-3 and the negative price difference between nodes 2 and 3.

This illustrates a well-known but counterintuitive result that strengthening a line may reduce the transfer capability between two buses (not directly linked by that line) under optimal dispatch. In this particular case, the transfer capability from node 1 to node 3 has been reduced by over 15 percent and consequently the expansion reduced total surplus by approximately four percent. This result raises questions about the adequacy of using a direct allocation of individual links' merchandising surplus as a scheme for compensating transmission expansion.

One restructuring proposal[23] advocates relinquishing operational control to a Poolco but retaining ownership over the grid by generators. In the example of Figure A in Box 1, generator 2 is the primary beneficiary of the existence of line 2-3. Generator 2, then, will have a strong incentive to build the line even if it has to pay the negative merchandising surplus of $9/hour associated with link 2-3.[24] The combined ownership of generation and transmission lines together with the imputation of link-specific merchandising surplus to link owners creates a perverse incentive for transmission expansion. In this case, generator 2 will have an incentive to strengthen line 2-3 beyond the optimal point. Indeed, lowering the reactance of line 2-3 from 1/3 to 1/12 increases the combined profit (plus the associated merchandising surplus) of generator 2.

B. Contract Networks

Hogan characterizes contract network rights in the following terms:

(1) "A transmission capacity right is defined as the right to put power in one bus and take out the same amount of power at another bus."

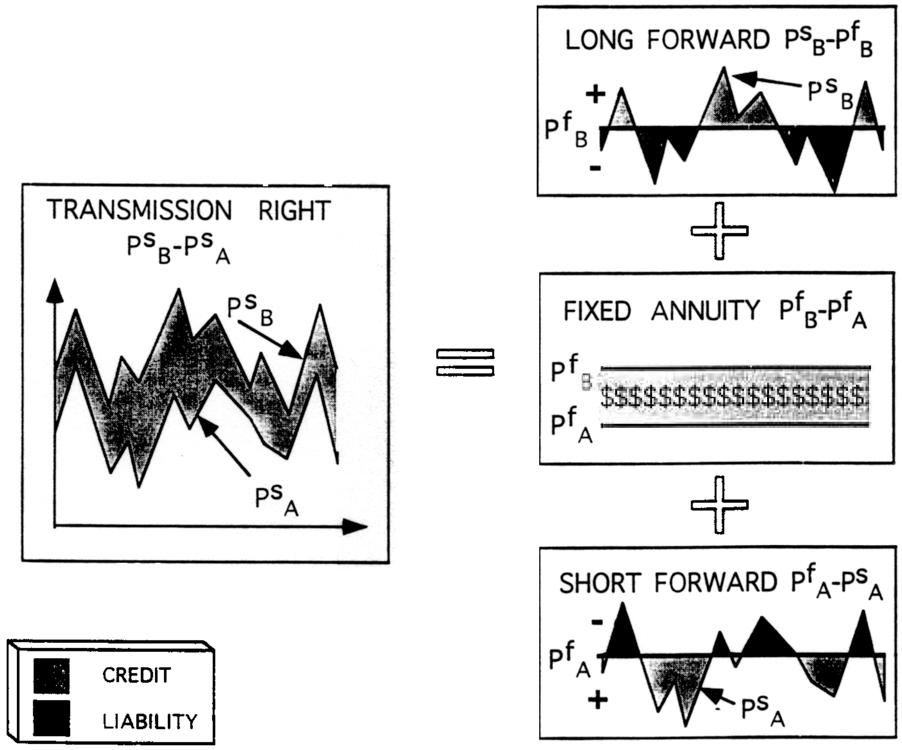
(2) "However, in the contract network, we amend the definition of capacity right to allow for either specific performance or receipt of an equivalent rental payment."

(3) "We assume that the simultaneous use of all allocated rights is feasible."[25]

In public presentations and private communications since the publication of his 1992 article, Hogan has recognized that the specific performance option is irrelevant. Thus, the right in a contract network is defined as a financial entitlement to the actual difference in nodal prices (minus losses) between a specific pair of nodes times a predetermined fixed quantity. The third condition restricts the quantity of allocated rights to meet feasibility conditions.

The contract network approach has two main purposes: First, it is a way to compensate transmission owners for the joint use of their transmission assets; second, it provides users of the grid a mechanism to hedge against congestion by purchasing transmission rights. To analyze the implications and merits of the contract network approach, let us start by analyzing what it really is. A contract network right for 1 MW from node A to node B entitles the holder to a stream of payments equal to the price difference between nodes B and A. This payment is a volatile payment, and will vary from period to period, as nodal prices change. As illustrated in **Box 4** this stream of payments can be viewed as a composite financial instrument consisting of three parts: (i) a short forward at node A; (ii) a long forward at node B; and (iii) a fixed annuity equal to the difference in the forward prices of B and A at the issuing time.[26]

In a network with N nodes, there are as many as N(N-1) different contract network rights corresponding to each possible directional pair of nodes. But all these contracts can be derived in a simpler way with the development of N forward nodal contracts and supplemental annuities. Reducing the number of needed financial instruments increases their liquidity, and facilitates the creation and development of those markets. Forward contracts serve the dual purpose of providing hedging against volatile spot nodal prices *and* against congestion. Furthermore, the creation and development of nodal forward markets will enable both speculators and users of the grid to hedge against both spot prices *and* spot price differences. By entering into a pair of long and short forwards at different nodes, anybody can own *virtual* transmission rights. Thus, from a hedging consideration, contract network rights are redundant. Furthermore, for valuation and trading of contract network rights, nodal forward prices are re-



Box 4: Synthesis of a Contract Network Right From Nodal Forward Contracts

quired; otherwise contract network rights will be illiquid. But if nodal forward prices exist, then contract networks are unnecessary.[27] Thus, by creating nodal forward markets we can do anything that contract network rights can do, and furthermore, nodal forward prices provide more flexibility in the allocation and distribution of the merchandising surplus.

As with other tradable commodities, it is reasonable to expect that the number of contracts traded will exceed the actual physical deliveries. This suggests that the feasibility condition (3) in Hogan's 1992 formulation[28] is unnecessary and meaningless.

Because the contract network rights are purely financial instruments and have no operational or physical implication, the feasibility condition (3) is only intended to serve as a solvency condition for the market maker. Hogan shows that condition (3) assures that if dispatch is optimal and all contract network rights are jointly feasible, the merchandising surplus exceeds the market maker's obligations to the holders of contract network rights.[29] This result, however, should be interpreted with caution. Consider the example in Box 1. Here a feasible allocation of transmission rights consists of 15 MW from node 1 to node 3 and 10 MW from node 2 to node 3. Assuming that those are the expected future loads, the right from 2 to 3 has a negative value. Hogan's 1992 solvency result—i.e., that the merchandise surplus is enough to cover the market maker's liability to the transmission-right holders—hinges on the assumption that transmission rights with negative values have been allocated.[30] In principle, it could be possible to force those negatively valued transmission rights to those who want positively valued transmission rights. This, however, will require some supplemental regulatory rules.[31]

On the other hand, the solvency condition implies that the merchandising surplus may exceed the market maker's liability, re-

quiring another regulatory rule to dispose of the excess merchandising surplus. Lastly, Hogan's contract networks approach leaves unspecified the initial allocation of the contract network rights among grid owners and users. Hence, a regulatory procedure will be needed for that allocation as well.

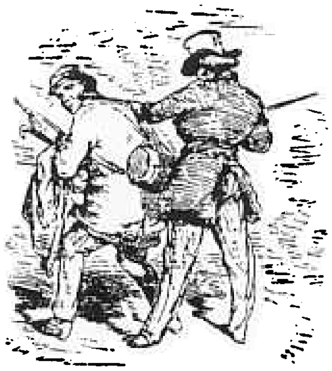
Finally, as a compensation to transmission owners, contract network rights have implications that are not altogether different from those discussed for link-based transmission rights. Although, in principle, contract network rights do not require that the pair of nodes be directly connected by a single link, many will be. In those instances the perverse incentives noted above will remain in effect. Furthermore, even for those nodal pairs that are not directly connected, the topology of the network may be such that perverse investment incentives re main. Thus, contract network rights necessarily have to be supplemented with a regulatory mechanism that determines which transmission investments are appropriate (i.e., maximize social welfare) and which are not. Again it is difficult to design a regulatory process that will bring about efficient outcomes.

To summarize, we find that the objectives of contract network rights can be accomplished in a simpler manner by al locating merchandising surplus shares, or equivalent riskless annuities, to grid owners as part of the compensation for the use of their wires. Users, grid owners and other players can then assume any level of risk they wish by hedging the risk associated with volatile nodal spot prices in nodal forward markets. Second, for contract network rights to be traded in a liquid fashion, nodal forward markets have to develop But given the need for nodal forward markets, contract network rights become redundant. Third, contract network rights do not provide a solution to the transmis sion pricing and expansion problem, as regulatory rules have to b designed for the allocation of the initial rights, for the allocation of rights with negative valuation, fo the allocation of the excess merchandising surplus, and to ensure that transmission investments are socially efficient. Fourth, by forcing trading in a financial composite instrument, rather than in the underlying nodal forward contracts, the initial creation of contract network rights will limit the liquidity of the nodal forward markets, limiting their potential success, and hence the potential for the efficient long-term operation of the wholesale electricity market.

V. Conclusions

This paper shows that even in very simple networks complex coordination problems arise. *First*, transmission investment incentives are not correlated with each link's associated transmission rent. *Second*, individual generators will have incentives to expand the grid even if such action may reduce total welfare. *Third*, if there is a single grid owner who collects all the merchandising surplus, it will have an incentive to degrade the network. *Fourth*, links that are not congested nevertheless may accrue transmission rents. *Fifth*, a transmission link may be beneficial from a network point of view even if it generates a negative transmission rent. *Sixth*, firm transmission rights are incompatible with efficient dispatch. *Seventh*, contract network rights are found to be composite financial instruments consisting of a combination of short and long nodal forward contracts plus a fixed annuity payment. We find that such a composite instrument is redundant as nodal forward markets can do all (and more) that contract network rights are supposed to do. Furthermore, contract network rights do not provide a solution to the allocation of the merchandise surplus among grid owners, and will have to be complemented with complex regulatory procedures for controlling investments in transmission assets.

Nodal prices are likely to become an important component in the economic landscape of a reconstructed electricity system, but they are insufficient by themselves to support all the economic arrangements that the reconstructed system should permit. The proposals for transmission rights discussed seem to be unsatisfactory and needlessly complex. New methods to deal with transmission ownership compensation and expansion are needed if the move towards a competitive wholesale electricity market is not to be bogged down in an increasing regulatory quagmire. ■



Endnotes:

1. R.E Bohn, M. Caramanis and F.C. Schweppe, *Optimal Pricing in Electrical Networks Over Space and Time*, vol. 18, no. 3, RAND J. ECON. (1984); F.C. SCHWEPPE, M. CARAMANIS, R.D. TABORS AND R.E. BOHN, SPOT PRICING OF ELECTRICITY (Kluwer Academic Publishers, 1988).

2. W.W. Hogan, *Contract Networks for Electric Power Transmission*, J. REG. ECON., at 211-42 (1992) ("Hogan I"); W.W. Hogan, An Efficient Bilateral Market Needs a Pool (Aug. 4, 1994)(presentation at CPUC Hearing, San Francisco)("Hogan II"); L. Ruff, *Stop Wheeling and Start Dealing: Resolving the Transmission Dilemma*, ELEC. J., June 1994, at 24-43 (1994).

3. The use of nodal price differences to price transmission services was initially advocated by Bohn *et al.* and Schweppe *et al.*, both *supra* note 1, and has recently been advocated by Hogan also as a way to compensate for transmission ownership. Chile in 1980 and Argentina in 1993 implemented transmission-pricing schemes partially based on nodal price differences.

4. The networks in Chile, Norway and New Zealand may fit that characterization.

5. Line-flow limits could reflect thermal constraints or stability considerations.

6. Sally Streiter Hunt, Bilateral Markets and Pooling (Aug. 4, 1994)(presentation at CPUC Hearing, San Francisco).

7. Hogan II, *supra* note 2, and Hunt, *id.*

8. While the arrangement in the U.K. serves as an interesting example of a system combining the Poolco and Opco concepts, the main motivation for that arrangement was the system's structure prior to privatization.

9. For a rigorous treatment of this topic, *see* F. Wu, P. Varaiya, P. Spiller, and S. Oren, Folk Theorems on Transmission Open Access: Proofs and Counterexamples (POWER report PWP-23, U of Calif. Energy Inst., 1994).

10. Some writers—*e.g.*, Hogan I, *supra* note 2—use the term "competitive equilibrium" to characterize what is commonly known as economic dispatch. This is justified on the grounds that if transmission is a competitive

sector, then the resulting equilibrium would coincide with economic dispatch. The use of the term, however, suggests the existence of a competitive process independent of the centralized action of a dispatcher. In the context of electric power this independent process does not exist. As a consequence, market equilibrium may differ from economic dispatch. It all depends on the protocols used by the grid operator to implicitly determine transmission constraints. In vertically integrated utilities, the presumption is that the dispatch operator attempts to minimize costs. But in a decentralized environment such an assumption may not be valid. Furthermore, whether the dispatch operator minimizes total costs cannot be verified by the existence of excess demand or supply, as for any dispatch algorithm there will be a corresponding market equilibrium where supply and demand clear at the nodal prices resulting from the operator's actions. The distinction between market equilibrium and economic dispatch in the electric power context highlights the need for some sort of regulatory oversight to insure that the market equilibrium corresponds to the optimal dispatch. The history of regulation teaches us that such oversight is difficult and its success cannot be taken for granted.

11. *See* Wu *et al.*, *supra* note 9, for a more formal treatment of these results.

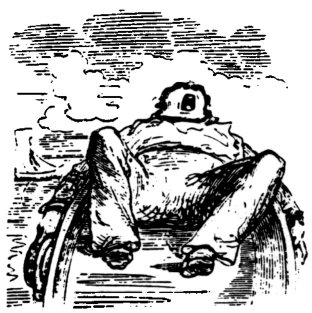
12. Note: The *reactance* of a line is the line's *inductance* times the frequency.

13. That is, we are assuming that all buses are PV, meaning that reactive power is automatically adjusted at each bus so that voltage magnitude is constant, and thus bus behavior is completely specified by giving its voltage phase angle and real power injection. We further assume that all the lines are "strong," meaning that their admittance (reciprocal of impedance) is large relative to the power flows. As a consequence, we can linearize the power flow equations. This is often known as a DC approximation.

14. Hunt, and Hogan II, both *supra* note 7.

15. Since there is no unique way of ensuring feasibility, curtailment protocols will have to be established. The rationale for curtailing the 1-3 contract in this example is that the 2-3 contract by itself is feasible, while the 1-3 contract by itself is not feasible.

16. The ratio of feasible injection increases of one to six is based on the relative reactance of lines 1-3 and 2-3, such that any joint increase in injections will not increase the flow on the congested line 1-2. In real nonlinear power flow models the calculation is more involved and the feasible incremental injections ratio would be determined on the basis of a linear approximation. In any case, no information on marginal costs or willingness to pay is required for the calculation.



17. Nothing in this discussion requires that the trilateral contract be organized by generator 1. Generator 2 could do a purchase from 1 and sell the extra to 3, or a broker could implement the transaction.

18. A general procedure for generating efficiency-improving multilateral contracts that approach economic dispatch is available from the authors.

19. As mentioned, the U.K. has two systems: a bilateral trading system with two operators in Scotland and a tight pool in England and Wales.

20. While we are addressing point-to-point service here, we recognize that network service is now being provided in the industry, beginning with the Federal Energy Regulatory Commission's decision in a case involving Florida Power & Light Co. *See, e.g.*, Florida Municipal Power Agency 67 FERC 61,167 (May 11, 1994).

21. Hogan I, *supra* note 2.

22. Wu et al., *supra* note 9, show mathematically that this is a generic problem in constrained networks with parallel flows.

23. *See* Southern California Edison's August 4, 1994 submission to the CPUC.

24. As the reader may compute, without line 2-3, generator 2's profits will be $107.2/hour, compared to $167.5/hour as in Box 1.

25. Hogan I, *supra* note 2, at 234).

26. A short forward at a node is a contract for differences that entitles the holder to a stream of income (positive or negative) equal to the difference between the forward price at the node and the nodal spot price. A nodal long forward, on the other hand, entitles the holder to a stream of income equal to the spot price at the node minus the nodal forward price. Thus, a contract network right from A to B equals $(P^f{}_A - P^s{}_A) + (P^s{}_B - P^f{}_B) + (P^f{}_B - P^f{}_A) = P^s{}_B - P^s{}_A$.

27. On this point, *see* H. Outhred, Resolving Network Issues in Implementing a Bulk Electricity Market in the Western United States (University of New South Wales, Australia, 1994).

28. Hogan I, *supra* note 2.

29. *Id.*

30. *Id.*

31. It can be seen that if only rights with positive value are given, then the amount of feasible contract network rights is substantially limited. If in the example of Box 1 rights to 2-3 are not given out, the market maker will be able to give only 13.3 MW of 1-3 rights, as those rights will exhaust the $40 merchandise surplus. Thus, by not granting the negatively valued transmission rights, it will have to limit the amount of positively valued transmission rights, limiting the potential for hedging.