MARKET-BASED TRANSMISSION INVESTMENTS AND COMPETITIVE ELECTRICITY MARKETS

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Market-based transmission investments can play a role in competitive electricity markets. A short-term electricity market coordinated by a system operator provides a foundation for a competitive electricity market. In this setting, locational price differences define the opportunity cost of transmission. The potential to arbitrage these same price differences provides a market incentive for transmission investment, if there is a method to capture the benefits of investment. For an integrated grid, transmission congestion contracts are equivalent to perfectly tradeable physical transmission rights. With such contracts to allocate transmission benefits, it would be possible to rely more on market forces, partly if not completely, to drive transmission expansion.

INTRODUCTION

A framework for market-based investments in transmission would extend the scope of competitive electricity markets. Electricity market restructuring emphasizes the potential for competition in generation and retail services, with the operation of transmission and distribution wires as a monopoly. Network interactions and economies of scale both complicate the extension of market incentives to investment in the wires business. Two broad approaches suggest themselves for dealing with these network problems in a manner compatible with a competitive generation market.

There could be monopoly management of transmission operations and investment, with incentive pricing for the monopoly. Transmission would be like a large "black box" run by the monopoly that takes on an obligation to provide unlimited transmission service for everyone. With the appropriate price cap or other incentive regulation, the monopoly would make efficient investments or contract with market participants to remove or manage the real transmission limitations. This approach results in a powerful monopoly with the familiar problems of finding the right level and form of incentive regulation. This approach is found, for example, in the

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market in England and Wales with the National Grid Company.[2] Although some elements of this monopoly approach may be found in any practical framework for transmission investment, it is not the focus here.

An alternative approach would lean more in the direction of market mechanisms. This would allow for market participants to make transmission investments in response to price incentives. The transmission investment would be voluntary, rather than included in mandatory charges. The benefits would be captured through tradeable transmission property rights.[3] A workable system that provides an equivalent to transmission property rights could be used by market participants to guarantee the costs of the actual flow of power or traded in a secondary market. Acquisition of these transmission benefits would provide a market incentive for transmission investment. This approach would be consistent with policy proposals at the Federal Energy Regulatory Commission (FERC)[4] and reflects influences of market restructuring developments around the world.

Market-based transmission investments confront a number of challenges. In practice, the difficulties can lead to a conundrum, a "Catch 22." The typical example of a transmission investment invokes the image of a large new transmission line, which might look to be too difficult to base solely on market decisions. As a result, the implicit assumption often is that only a regulated monopoly could manage the intended investment, and the discussion of market institutions defaults to the design of monopoly mechanisms. Market-based investments may never get a hearing, and would be foreclosed in the market design. However, with some innovation it is possible to envision a least a partial escape from this trap by designing market institutions that could meet some or all of the challenges and support market-based transmission investments. The purpose here is to outline such a framework.[5] In part it is also to extend the consideration of the potential for market-based transmission investments which already have moved from theory to reality.

A central problem is in defining a workable notion of property rights for transmission. In the case of simple physical rights and controllable transmission flows, market-based

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[2] David M. Newbery, "Privatization and Liberalization of Network Utilities," European Economic Review, Vol. 41, 1997, pp. 357-383.

[3] James B. Bushnell and Steven E. Stoft, "Grid Investment: Can a Market Do the Job?", The Electricity Journal, January-February, 1996, pp. 74-79. Eric C. Woychik, "Competition in Transmission: It's Coming Sooner or Later," The Electricity Journal, June 1996, pp. 46-58.

[4] Federal Energy Regulatory Commission, "Capacity Reservation Open Access Transmission Tariffs," Notice of Proposed Rulemaking, RM96-11-000, Washington DC, April 24, 1996. Federal Energy Regulatory Commission, "Regional Transmission Organizations", Notice of Proposed Rulemaking, Docket No. RM99-2-000, Washington DC, May 13, 1999.

[5] This paper extends the earlier discussion in William W. Hogan, "Transmission Investment and Competitive Electricity Markets," Center for Business and Government, Harvard University, April 1998.

investments would be easy to define and a natural approach for transmission expansion. In this case, analogies to other markets would apply. In the real electricity market, physical rights for the full capacity of the grid are difficult to define, and controllable flows are the exception rather than the rule. However, it is still possible to define a workable system of financial transmission rights that could achieve the same outcomes and could support a system of market-based investments.

A short-term electricity market coordinated by a system operator provides a foundation for building a system that includes tradeable transmission property rights in the form of transmission congestion contracts. Coordination through the system operator is unavoidable, and spot-market locational prices define the opportunity costs of transmission that would determine the market value of the transmission rights without requiring physical trading and without restricting the actual use of the system. In this setting, these transmission congestion contracts are equivalent to perfectly tradeable physical rights. Hence, this organization of the market defines a context where it would be possible to rely more on market forces, partly if not completely, to drive transmission expansion. Here we review the main ideas and summarize the requirements of a transmission investment approach with maximum reliance on the competitive market.

CONTROLLABLE FLOWS AND TRANSMISSION RIGHTS

If the world were simple, market-based investments in transmission would provide a natural and self-evident approach to transmission expansion. Suppose that an electric transmission network consisted only of transmission lines and valves. In this easy case, the power would flow down the lines from source to sink, and the valves could make the system completely and continuously controllable in the sense that the actual path of power flows could be assured no matter what the pattern of power inputs and outputs in the network. In principle, power flows could be labeled, directed and tracked. We could charge directly for the power flows on each line. If we did not want the power to flow down a particular line, the valve could be closed for those who did not pay. In this world, there would be no network externalities. The convenient contract-path model of electric power transmission would apply. The owner(s) of a line could charge for its use. In competitive equilibrium, the price of that usage would be equal to the difference in the prices of electricity at the source and sink. Equivalently, the owners of the line could buy at the source and sell at the sink, profiting from the difference in locational prices.

Suppose further that investments in transmission lines came in arbitrarily small increments with constant or increasing marginal costs. In other words, investment was not lumpy, and there were no economies of scale. Then the transmission line would be like a bundle of straws, and we would be able to expand the transmission line by adding the cheapest available straw, with anyone allowed to make the investment. The investment would be profitable as long as the difference in locational prices between source and sink exceeded the cost of the incremental straw. In equilibrium, the cost of the last straw added would just equal the resulting expected difference in prices. The profits collected from the purchase and sale of power would be just enough to pay for the market-based investment. Furthermore, in equilibrium all the early investments in cheaper straws would enjoy a capital gain equal to the difference in this market clearing price and the cost of constructing their particular straw.

If the market were out of equilibrium, such as with growing demand or changing cost structures, there would be a dynamic adjustment. For instance, suppose that the price differential between two locations were higher than the marginal cost of investment. Then the owners of the existing straws would enjoy a further capital gain in the form of high profits resulting from scarcity rents. New investors would see the incentive and opportunity. The early movers would add their own straws, capturing some of the scarcity rents, but also adding to capacity and reducing the gap between price and marginal cost. If there were no barriers to entry, the extra profit incentive of the scarcity rent would promote further entry until equilibrium returned, where further expansion would no longer be profitable.

Under these conditions in a competitive market, when equilibrium prices differed at the source and sink there would be three important equations. First, the amount of power purchased and sold at source and sink would equal the capacity created by the transmission investment. Second, the power flowing on the controllable transmission line would be equal to this same capacity. And third, the expected price difference between the locations would be equal to the marginal cost of expansion.

In this simple world with no network externalities or economies of scale, market-based investments alone would be able to achieve the efficient outcome. Investors would follow the price signals and their own profit incentives. The equilibrium difference in locational prices would just cover the cost of the marginal investment. The resulting level of investment in transmission would be just right, given the total costs of investment and the value of additional capacity.[6] The market would work. Nothing would be required of regulators or the law other than enforcement of property rights.

Unfortunately, this simple world has little in common with the more complex reality of the electric transmission system. Just a few of the exceptions have an important impact on the models that can work to support market-based transmission investment. The very nature of interconnected free-flowing transmission networks creates powerful network externalities. Most lines are not controllable, and power flows do not follow the designated contract path. Rather we have the familiar reality that power flows across every parallel path between source and sink. Even with a controllable line as part of a larger system, the impact of the controllable line cannot be fully separated from the pattern of use of the rest of the system. In addition, the services provided by the transmission system go well beyond the model of a straw between two points. For instance, reactive power availability can have a significant impact on the transmission capacity to move real power between many locations. This means that investments such as for

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[6] Here we assume that other externalities, such as environmental effects, have been internalized.

capacitor additions to provide reactive support can increase the capacity of the transmission system without constructing new lines on which the power would flow. Furthermore, it is a commonplace that there can be significant economies of scale in transmission expansion. Hence, the efficient level of investment might come in lumps that change equilibrium prices substantially.

In this real world, a fully efficient transmission investment could destroy at least two of the important equations above. The amount of power purchased and sold at the source and sink could still equal the expanded transmission capacity, properly defined. However, the power actually flowing over the "line" need not be the same. Furthermore, with substantial economies of scale, we might eliminate the important linkage between expected price differences and the marginal cost of investment; the expected price difference between the locations need not be equal to the marginal cost of expansion.

In this real world, power flows across individual lines would not be equal to the increments in capacity, and the simple model of charging for the flows on the line would not support efficient investments. In the extreme case, with economies of scale and the efficient investment eliminating the price difference between locations, there might be no investment at all.

The response to these well-known facts has been largely in the spectrum between denial and acceptance, but with some important innovations. Here we set aside denial and acknowledge that these problems are real, important, and won't go away.[7] The strategy of acceptance can take the form of assuming that these problems are so pronounced that the only solution is to turn away from market-based investments altogether and rely solely on a regulated monopoly. Given the economies of scale and scope, and the large network externalities, the assumption is that only a monopoly could solve the problem of transmission investment. The monopoly, of course, would not need to rely on the voluntary investment choices of market participants. The monopoly could make the investment, under regulatory supervision, and then send the bill to the market participants. Here we look beyond acceptance to examine the needed innovations and consider the role of market-based investments in transmission expansion.

A ROLE FOR MARKET-BASED TRANSMISSION INVESTMENTS

While there are circumstances where the monopoly solution may be the only practical alternative, innovations in market design and policy can address some of the most important special characteristics of the transmission grid. This requires a different approach and perspective, but the innovation would allow for some, perhaps substantial, reliance on market-based transmission investments. Here we outline the most prominent of these issues, first for the treatment of economies of scale. Then we turn to innovations to deal with the problems of

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[7] William W. Hogan, "Getting the Prices Right in PJM. Analysis and Summary: April 1998 through March 1999, The First Anniversary of Full Locational Pricing," April 2, 1999, available through the author's web page.

network externalities, parallel flows and economies of scope.

First ignore the effect of network interactions and focus only on the case where these problems are avoided and a workable system of transmission rights is in place. In the simplest case, these transmission rights would arise from controllable lines. Or the network equivalent may be assumed. Then market-based investments would cover many situations. Locational differences in prices would provide the market incentive for transmission expansion. In the case of relatively small, modular expansions of transmission capacity, the incremental transmission rights could provide the essential ingredient to complete the investment. These small investments would not have a material effect on prices. Hence, the equilibrium prices expected after the investment could be sufficient to pay for the investment. Then there would be no need to look beyond the obvious, and the market could handle this form of transmission investment, given the opportunity.

Even in circumstances where the transmission expansion might have a material impact on prices, there could be situations where the market investment would go forward. To the extent that the transmission component was part of a larger package that involved generation and contracts with customers, the cost of transmission would not dominate the investment decisions. Here the combined acquisition of transmission rights to a location and a purchase power contract at the location could support a market-based investment, given the opportunity.

In the case of larger investments, the problem of economies of scale would appear. The efficient investment might have such an impact on equilibrium prices that there would be no opportunity to pay for the investment once made. The option of contracting might not be available, because even though the investment is efficient, everyone prefers to avoid payment and free-ride on the investment of others. This is the typical case that supports the judgement that market-based transmission investment would be inadequate.

A practical compromise in this latter case would be to limit access to the new capacity, for at least long enough to justify the investment. An ability to control use of the incremental capacity could preserve sufficient margins in the locational price differences to justify the transmission investment as a stand-alone business. This would make the transmission investment like market-based investments in other industries where there are economies of scale. Furthermore, the investment could provide other benefits through relief of contingency constraints or provision of voltage support to include expansions of transmission capacity in cases other than the construction of new transmission lines. Although this would not be the "first best" efficient investment, we would be better off in the aggregate compared to the case where the investment was not forthcoming.

The argument for each example of market-based investments, including with economies of scale, is expanded below. However, to envision this in the general case we need a framework that goes beyond the case of controllable lines to investments in the real network that may create substantial network externalities. The approach is to create a set of market institutions that can support transmission rights with the key economic properties of controllable lines, but for situations which deal with the real network. This framework depends on a description of the basics of a competitive electricity market and the design on innovative market structures. An outline of the structure of the spot market coordinated by the system operator and supported by a system of transmission congestion contracts sets the stage. With the proper market institutions, there could be substantial opportunities for market-based transmission investments. The basic market elements include a coordinated spot market implemented by the system operator through a bid-based, security-constrained economic dispatch. This model would include locational prices which provide the essentials tools to create point-to-point financial transmission rights in the form of transmission congestion contacts. These contracts would serve in the place of physical rights as the mechanism for capturing the major benefits that would flow from transmission investment. This framework could expand the reach of market-based investments in transmission.

Only in the case of substantial economies of scale and scope, with strong network interactions, would there be a presumption that market-based transmission incentives would be inadequate. In this case the regulated alternative would be available to use a monopoly institutional framework to make the investment and collect the cost through mandatory access charges. However, the existence of the market alternative and financial transmission rights would reinforce both the ability to make such regulated investments and simplify the oversight of the investment process.

Those working to design market institutions should ensure that the market-based transmission investment option is included, not foreclosed from an unexamined judgment that only regulated monopoly solutions would work. In theory, market-based transmission investments have a lot to offer. In practice, they have already begun. Given the opportunity, market-based transmission investments can play an important, if not exclusive, role in transmission expansion.

ECONOMICS OF A COMPETITIVE ELECTRICITY MARKET

A general framework that encompassed the essential economics of electricity markets provides a point of reference for evaluating market design elements.[8] Here we focus on the implications for competition in generation, and the rules for the wholesale market. The treatment of competition for other contestable elements, such as retail services, is important but need not affect the design of the wholesale market. This framework provides a background for evaluating the prescriptions for independent system operators (ISO) and related market institutions that could support market-based transmission investments.

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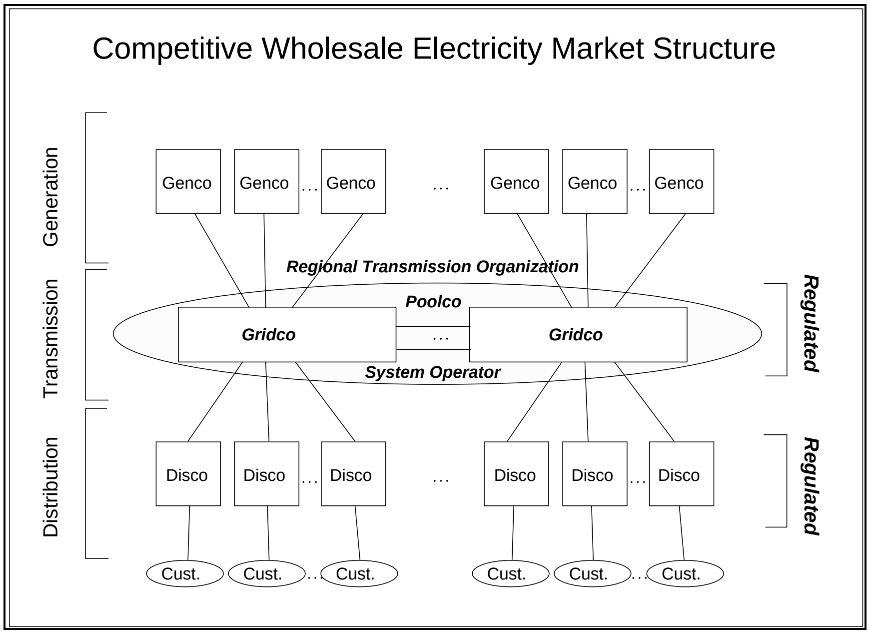
[8] This summary comes primarily from William W. Hogan, "Transmission Investment and Competitive Electricity Markets," Center for Business and Government, Harvard University, April 1998. The issues are developed further there, but summarized here for completeness given the central importance of the basic economics in the case of electricity. See also, William W. Hogan, "Competitive Electricity Markets: A Wholesale Primer," Center for Business and Government, Harvard University, December 1998.

Competitive Market Design

Reliable operation is a central requirement and constraint for any electricity system. Given the strong and complex interactions in electric networks, current technology with a free-flowing transmission grid dictates the need for a system operator that coordinates use of the transmission system. Control of transmission usage means control of dispatch, which is the principal or only means of adjusting the use of the network. Hence, open access to the transmission grid means open access to the dispatch as well. In the analysis of electricity markets, therefore, a key focus is the design of the interaction between transmission and dispatch, both procedures and pricing, to support a competitive market.



To provide an overview of the operation of an efficient, competitive wholesale electricity market, it is natural to distinguish between the short-run operations coordinated by the system operator and long-run decisions that include investment and contracting. Market participants are price takers and include the generators and eligible customers. For this discussion, distributors are included as customers in the wholesale market, operating at arm's length from generators. The system is much simpler in the very short run when it is possible to give meaningful definition to concepts such as opportunity cost. Once the short-run economics are established, the long-run requirements become more transparent. Close attention to the connection between short- and long-run decisions isolates the special features of the electricity market.

Short-Run Market

The short run is a long time on the electrical scale, but short on human scale – say, half an hour. The short-run market is relatively simple. In the short run, locational investment decisions have been made. Power plants, the transmission grid, and distribution lines are all in place. Customers and generators are connected and the work of buyers, sellers, brokers and other service entities is largely complete. The only decisions that remain are for delivery of power, which in the short-run is truly a commodity product.

On the electrical scale, much can happen in half an hour and the services provided by the system include many details of dynamic frequency control and emergency response to contingencies. Due to transaction costs, if nothing else, it would be inefficient to unbundle all of these services, and many are covered as average costs in the overhead of the system. How far unbundling and choice should go is an empirical question. For example, real power should be identified and its marginal cost recognized, but should this extend to reactive power and voltage control as well? Or to spinning reserve required for emergency supplies? For the sake of the present discussion, focus on real power and assume that further unbundling would go beyond the point of diminishing returns in the short-run market.

Over the half hour, the market operates competitively to move real power from generators to customers. Generators have a marginal cost of generating real power from each plant, and customers have different quantities of demand depending on the price at that half hour. The collection of generator costs stacks up to define the generation "merit order," from least to most expensive. This merit order defines the short-run marginal-cost curve for the market, which governs power supply. Similarly, customers have demands that are sensitive to price, and higher prices produce lower demands. Generators and customers do not act unilaterally; they provide information to the dispatcher to be used in a decision process that will determine which plants will run at any given half hour. Power pools provide the model for achieving the most efficient dispatch given the short-run marginal costs of power supply. Although dispatchable demand is not always included, there is nothing conceptually or technically difficult about this extension. The system operator controls operation of the system to achieve the efficient match of supply and demand.

This efficient central dispatch can be made compatible with the market outcome. The fundamental principle is that for the same load, the least-cost dispatch and the competitive-market dispatch are the same. The principal difference between the traditional power pool and the market solution is the price charged to the customer. In the traditional regulated power pool model, customers pay and generators receive average cost, at least on average. Marginal cost implicitly determines the least-cost dispatch, and marginal cost is the standard determinant of competitive market pricing.

An important distinction between the traditional central dispatch and the decentralized market view is found in the source of the marginal-cost information for the generator supply curve. Traditionally the cost data come from engineering estimates of the energy cost of generating power from a given plant at a given time. However, relying on these engineering estimates is problematic in the market model since the true opportunity costs may include other features, such as the different levels of maintenance, that would not be captured in the fuel cost. Replacement of the generator’s engineering estimates (that report only incremental fuel cost) with the generator’s market bids is the natural alternative. Each bid defines the minimum acceptable price that the generator would accept to run the plant in the given half hour. And these bids serve as the guide for the dispatch.

As long as the generator receives the market clearing price, and there are enough competitors so that each generator assumes that it will not be providing the marginal plant, then the optimal bid for each generator is the true marginal cost: To bid more would only lessen the chance of being dispatched, but not change the price received. To bid less would create the risk of running and being paid less than the cost of generation for that plant. Hence, with enough competitors and no collusion, the short-run economic dispatch market model can elicit bids from buyers and sellers. The system operator can treat these bids as the supply and demand and determine the balance that maximizes benefits for producers and consumers at the market equilibrium price. Hence, in the short run electricity is a commodity, freely flowing into the transmission grid from selected generators and out of the grid to the willing customers. Every half hour, customers pay and generators receive the short-run marginal-cost (SRMC) price for the total quantity of energy supplied in that half hour. Everyone pays or receives the true opportunity cost in the short run. Payments follow in a simple settlement process.

Transmission Congestion

This overview of the short-run market model is by now familiar and found in operation in many countries. However, this introductory overview conceals a critical detail that would be relevant for transmission pricing. Not all power is generated and consumed at the same location. In reality, generating plants and customers are connected through a largely free-flowing grid of transmission and distribution lines.

In the short-run, transmission too is relatively simple. The grid has been built and everyone is connected with no more than certain engineering requirements to meet minimum technical standards. In this short-run world, transmission reduces to nothing more than putting power into one part of the grid and taking it out at another. Power flow is determined by physical laws, but a focus on the flows – whether on a fictional contract path or on more elaborate allocation methods – is a distraction. The simpler model of input somewhere and output somewhere else captures the necessary reality. In this simple model, transmission complicates the short-run market through the introduction of losses and possible congestion costs.

Transmission of power over wires encounters resistance, and resistance creates losses. Hence the marginal cost of delivering power to different locations differs at least by the marginal effect on losses in the system. Incorporating these losses does not require a major change in the theory or practice of competitive market implementation. Economic dispatch would take account of losses, and the market equilibrium price could be adjusted accordingly. Technically this would yield different marginal costs and different prices, depending on location, but the basic market model and its operation in the short-run would be preserved.

Transmission congestion has a related effect. Limitations in the transmission grid in the short run may constrain long-distance movement of power and thereby impose a higher marginal cost in certain locations. Power will flow over the transmission line from the low cost to the high cost location. If this line has a limit, then in periods of high demand not all the power that could be generated in the low cost region could be used, and some of the cheap plants would be "constrained off." In this case, the demand would be met by higher cost plants that absent the constraint would not run, but due to transmission congestion would be then "constrained on." The marginal cost in the two locations differs because of transmission congestion. The marginal cost of power at the low cost location is no greater than the cost of the cheapest constrained-off plant; otherwise the plant would run. Similarly, the marginal cost at the high cost location is no less than the cost of the most expensive constrained-on plant; otherwise the plant would not be in use. The difference between these two costs, net of marginal losses, is the congestion rental.

This congested-induced marginal-cost difference can be as large as the cost of the generation in the unconstrained case. If a cheap coal plant is constrained off and an oil plant, which costs more than twice as much to run, is constrained on, the difference in marginal costs by region is greater than the cost of energy at the coal plant. This result does not depend in any way on the use of a simple case with a single line and two locations. In a real network the interactions are more complicated – with loop flow and multiple contingencies confronting thermal limits on lines or voltage limits on buses – but the result is the same. It is easy to construct examples where congestion in the transmission grid leads to marginal costs that differ by more than 100% across different locations.

If there is transmission congestion, therefore, the short-run market model and determination of marginal costs must include the effects of the constraints. This extension presents no difficulty in principle. The only impact is that the market now includes a set of prices, one for each location. Economic dispatch would still be the least-cost equilibrium subject to the security constraints. Generators would still bid as before, with the bid understood to be the minimum acceptable price at their location. Customers would bid also, with dispatchable demand and the bid setting the maximum price that would be paid at the customer's location. The security-constrained economic dispatch process would produce the corresponding prices at each location, incorporating the combined effect of generation, losses and congestion. In terms of their own supply and demand, everyone would see a single price, which is the SRMC price of power at their location. If a transmission price is necessary, the natural definition of transmission is supplying power at one location and using it at another. The corresponding transmission price would be the difference between the prices at the two locations.

This same framework lends itself easily to accounting extensions to explicitly include bilateral transactions. Here market participants prefer to schedule point-to-point transmission rather than explicitly buy and sell through the spot market. The bilateral schedules would be provided to the system operator. Those not scheduled would bid into the pool-based spot market. This is often described as the "residual pool" or "net pool" approach. For market participants who wish to schedule transmission between two locations, the opportunity cost of the transmission is just this transmission price of the difference between spot prices at the two locations. This short-run transmission usage pricing, therefore, is efficient and non-discriminatory. In addition, the same principles could apply in a multi-settlement framework, with day-ahead scheduling and real-time dispatch. These extensions could be important in practice, but would not fundamentally change the outline of the structure of electricity markets.

This short-run competitive market with bidding and centralized dispatch is consistent with economic dispatch. The locational prices define the true and full opportunity cost in the short run. Each generator and each customer sees a single price for the half hour, and the prices vary over half hours to reflect changing supply and demand conditions. All the complexities of the power supply grid and network interactions are subsumed under the economic dispatch and calculation of the locational SRMC prices. These are the only prices needed, and payments for short-term energy are the only payments operating in the short run, with administrative overhead covered by rents on losses or, if necessary, a negligible markup applied to all power. The system operator coordinates the dispatch and provides the information for settlement payments, with regulatory oversight to guarantee comparable service through open access to the spot market run by the system operator through a bid-based economic dispatch.

With efficient pricing, users have the incentive to respond to the requirements of reliable operation. Absent such price incentives, choice would need to be curtailed and the market limited, in order to give the system operator enough control to counteract the perverse incentives that would be created by prices that did not reflect the marginal costs of dispatch. A competitive market with choice and customer flexibility depends on getting the usage pricing right.

Long-Run Market Contracts

With changing supply and demand conditions, generators and customers will see fluctuations in short-run prices. When demand is high, more expensive generation will be employed, raising the equilibrium market prices. When transmission constraints bind, congestion costs will change prices at different locations.

Even without transmission congestion constraints, the spot market price can be volatile. This volatility in prices presents its own risks for both generators and customers, and there will be a natural interest in long-term mechanisms to mitigate or share this risk. The choice in a market is for long-term contracts.

Traditionally, and in many other markets, the notion of a long-term contract carries with it the assumption that customers and generators can make an agreement to trade a certain amount of power at a certain price. The implicit assumption is that a specific generator will run to satisfy the demand of a specific customer. To the extent that the customer's needs change, the customer might sell the contract in a secondary market, and so too for the generator. Efficient operation of the secondary market would guarantee equilibrium and everyone would face the true opportunity cost at the margin.

However, this notion of specific performance stands at odds with the operation of the short-run market for electricity. To achieve an efficient economic dispatch in the short-run, the dispatcher must have freedom in responding to the bids to decide which plants run and which are idle, independent of the provisions of long-term contracts. And with the complex network interactions, it is impossible to identify which generator is serving which customer. All generation is providing power into the grid, and all customers are taking power out of the grid. In a competitive market, it is not even in the interest of the generators or the customers to restrict their dispatch and forego the benefits of the most economic use of the available generation. The short-term dispatch decisions by the system operator are made independent of and without any recognition of any long-term contracts. In this way, electricity is not like other commodities.

This dictate of the physical laws governing power flow on the transmission grid does not preclude long-term contracts, but it does change the essential character of the contracts. Rather than controlling the dispatch and the short-run market, long-term contracts focus on the problem of price volatility and provide a price hedge not by managing the flow of power but by managing the flow of money. The short-run prices provide the right incentives for generation and consumption, but create a need to hedge the price changes. Recognizing the operation of the short-run market, there is an economic equivalent of the long-run contract for power that does not require any specific plant to run for any specific customer.

Consider the case first of no transmission congestion. In this circumstance, except for the small effect of losses, it is possible to treat all production and consumption as at the same location. Here the natural arrangement is to contract for differences against the equilibrium price in the market. A customer and a generator agree on an average price for a fixed quantity, say 100 MW at five cents. On the half hour, if the spot price is six cents, the customer buys power from the coordinated spot market at six cents and the generators sells power for six cents. Under the contract, the generator owes the customer one cent for each of the 100 MW over the half hour. In the reverse case, with the spot price at three cents, the customer pays three cents to the system operator, which in turn pays three cents to the generator, but now the customer owes the generator two cents for each of the 100 MW over the half hour.

In effect, the generator and the customer have a long-term contract for 100 MW at five cents. The contract requires no direct interaction with the system operator other than for the continuing short-run market transactions. But through the interaction with system operator, the situation is even better than with a long-run contract between a specific generator and a specific customer. For now if the customer demand is above or below 100 MW, there is a ready and an automatic secondary market, namely the coordinated spot market, where extra power is purchased or sold at the spot price. Similarly for the generator, there is an automatic market for surplus power or backup supplies without the cost and problems of a large number of repeated short-run bilateral negotiations with other generators. And if the customer really consumes 100 MW, and the generator really produces the 100 MW, the arithmetic guarantees that the average price is still five cents. Furthermore, with the contract fixed at 100 MW, rather than the amount actually produced or consumed, the long-run average price is guaranteed without disturbing any of the short-run incentives at the margin. Hence the long-run contract is compatible with the short-run market.

The price of the generation contract would depend on the agreed reference price and other terms and conditions. Generators and customers might agree on dead zones, different up-side and down-side price commitments, or anything else that could be negotiated in a free market to reflect the circumstances and risk preferences of the parties. Whether generators pay customers, or the reverse, depends on the terms. However, the system operator need take no notice of the contracts, and have no knowledge of the terms.

In the presence of transmission congestion, the generation contract is necessary but not sufficient to provide the necessary long-term price hedge. A bilateral arrangement between a customer and a generator can capture the effect of aggregate movements in the market, when the single market price is up or the single market price is down. However, transmission congestion can produce significant movements in price that are different depending on location. If the customer is located far from the generator, transmission congestion might confront the customer with a high locational price and leave the generator with a low locational price. Now the generator alone cannot provide the natural back-to-back hedge on fluctuations of the short-run market price. Something more would be needed.

Transmission congestion in the short-run market raises another related and significant matter for the system operator. In the presence of congestion, revenues collected from customers will substantially exceed the payments to generators. The difference is the congestion rent that accrues because of constraints in the transmission grid. At a minimum, this congestion rent revenue itself will be a highly volatile source of payment to the system operator. At worse, if the system operator keeps the congestion revenue, incentives arise to manipulate dispatch and prevent grid expansion in order to generate even greater congestion rentals. System operation is a natural monopoly and the operator could distort both dispatch and expansion. If the system operator retains the benefits from congestion rentals, this incentive would work contrary to the goal of an efficient, competitive electricity market.

A convenient solution to both problems – providing a price hedge against locational congestion differentials and removing the adverse incentive for system operator – is to re-distribute the congestion revenue through a system of long-run transmission congestion contracts operating in parallel with the long-run generation contracts. Just as with generation, it is not possible to operate an efficient short-run market that includes transmission of specific power to specific customers. However, just as with generation, it is possible to arrange a transmission congestion contract that provides compensation for differences in prices, in this case for differences in the congestion costs between different locations across the network.

The transmission congestion contract for compensation would exist for a particular quantity between two locations. The generator in the example above might obtain a transmission congestion contract for 100 MW between the generator's location and the customer's location. The right provided by the contract would not be for specific movement of power but rather for payment of the congestion rental. Hence, if a transmission constraint caused prices to rise to six cents at the customer's location, but remain at five cents at the generator's location, the one cent difference would be the congestion rental. The customer would pay the system operator six cents for the power. The system operator would in turn pay the generator five cents for the power supplied in the short-run market. As the holder of the transmission congestion contract, the generator would receive one cent for each of the 100 MW covered under the transmission congestion contract. This revenue would allow the generator to pay the difference under the generation contract so that the net cost to the customer is five cents as agreed in the bilateral power contract. Without the transmission congestion contract, the generator would have no revenue to compensate the customer for the difference in the prices at their two locations. The transmission congestion contract completes the package.[9]

When only the single generator and customer are involved, this sequence of exchanges under the two types of contracts may seem unnecessary. However, in a real network with many participants, the process is far less obvious. There will be many possible transmission combinations between different locations. There is no single definition of transmission grid capacity, and it is only meaningful to ask if the configuration of aggregated transmission flows is feasible. However, the net result would be the same. Short-run incentives at the margin would follow the incentives of short-run opportunity costs, and long-run contracts would operate to provide price hedges against specific quantities. The system operator coordinates the short-run market to provide economic dispatch. The system operator collects and pays according to the short-run marginal price at each location, and the system operator distributes the congestion rentals to the holders of transmission congestion contracts. Generators and customers make separate bilateral arrangements for generation contracts. Unlike with the generation contracts, the system operator's participation in coordinating administration of the transmission congestion contracts is necessary because of the network interactions, which make it impossible to link specific customers paying congestion costs with specific customer receiving congestion compensation. If a simple feasibility test is imposed on the transmission congestion contracts awarded to customers, the aggregate congestion payments received by the system operator will fund the congestion payment obligations under the transmission congestion contracts.[10] Still, the congestion prices paid and received will be highly variable and load dependent. Only the system operator will have the necessary information to determine these changing prices, but the information will be readily available embedded in all the spot market locational prices. The transmission congestion contracts define payment obligations that guarantee protection from changes in the congestion rentals.

The transmission congestion contract can be recognized as equivalent to an advantageous form with controllable lines and the associated point-to-point “physical” transmission rights. With controllable lines the system would be simpler, and the flows across the line would come closer to the expansion of capacity. However, even with controllable line the full increase in capacity in the larger system might be more than the power that flowed across

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9 The description here ignores the effect of losses, but this simplification is not important to the argument.

10 The feasibility test is simple when the transmission congestion contracts are defined as forward contract obligations. If the transmission congestion contracts are defined as options, the feasibility test is well defined but can be more complicated. This difference between obligations and options applies equally to physical and financial transmission rights. For a further discussion, see Scott M. Harvey, William W. Hogan, and Susan L. Pope, “Transmission Capacity Reservations and Transmission Congestion Contracts,” Center for Business and Government, Harvard University, June 6, 1996, (Revised March 8, 1997).

the line. The ability to respond in emergencies or provide voltage support might relieve other constraints and provide additional transmission congestion contracts beyond the strict flows across the line. The transmission congestion contract provides a more general solution, with or without the benefits of a controllable line.

Were it possible to define usage of the transmission system in terms of physical rights, it would be desirable that these rights have two features. First, they could not be withheld from the market to prevent others from using the existing transmission grid. Second, they would be perfectly tradable in a secondary market that would support full reconfiguration of the patterns of network use at no transaction cost. This is impossible with any known system of physical transmission rights that parcel up the transmission grid. However, in a competitive electricity market with a bid-based, security-constrained economic dispatch, transmission congestion contracts are equivalent to just such perfectly tradable transmission rights. Hence we can describe transmission congestion contracts either as financial contracts for congestion rents or as perfectly tradable physical transmission rights.

If the transmission congestion contracts have been fully allocated, then the system operator will be simply a conduit for the distribution of the congestion rentals. The operator would no longer have an incentive to increase congestion rentals: any increase in congestion payments would flow only to the holders of the transmission congestion contracts. The problem of supervising the dispatch monopoly would be greatly reduced. And through a combination of generation contracts and transmission congestion contracts, participants in the electricity market could arrange price hedges that would provide the economic equivalent of a long-term contract for specific power delivered to a specific customer.

Further to the application of these ideas, locational marginal cost pricing lends itself to a natural decomposition. For example, even with loops in a network, market information could be transformed easily into a hub-and-spoke framework with locational price differences on a spoke defining the cost of moving to and from the local hub, and then between hubs. This would simplify without distorting the locational prices. A contract network could develop that would be different from the real network without affecting the meaning or interpretation of the locational prices.

With the market hubs, the participants would see the simplification of having a few hubs that capture most of the price differences of long-distance transmission. Contracts could develop relative to the hubs. The rest of the sometimes important difference in locational prices would appear in the cost of moving power to and from the local hub. Commercial connections in the network could follow a configuration convenient for contracting and trading. The separation of physical and financial flows would allow this flexibility.

The creation or elimination of hubs would require no intervention by regulators or the system operator. New hubs could arise as the market requires, or disappear when not important. A hub is simply a special node within a zone. The system operator still would work with the locational prices, but the market would decide on the degree of simplification needed. However, everyone would still be responsible for the opportunity cost of moving power to and from the local hub. There would be locational prices and this would avoid the substantial incentive problems of averaging prices.

Long-Term Market Investment

Within the contract environment of the competitive electricity market, new investment occurs principally in generating plants, customer facilities and transmission expansions. In each case, corresponding contract-right opportunities appear that can be used to hedge the price uncertainty inherent in the operation of the competitive short-run market.

In the case of investment in new generating plants or consuming facilities, the process is straightforward. Under the competitive assumption, no single generator or customer is a large part of the market, there are no significant economies of scale, and there are no barriers to entry. Generators or customers can connect to the transmission grid at any point subject only to technical requirements defining the physical standards for hookup. If they choose, new customers or new generators have the option of relying solely on the short-run market, buying and selling power at the locational price determined as part of the half-hourly dispatch. The system operator makes no guarantees as to the price at the location. The system operator only guarantees open access to the spot market at a price consistent with the equilibrium market. The investor takes all the business risk of generating or consuming power at an acceptable price.

If the generator or customer wants price certainty, then new generation contracts can be struck between a willing buyer and a willing seller. The complexity and reach of these contracts would be limited only by the needs of the market. Typically we expect a new generator to look for a customer who wants a price hedge, and for the generators to defer investing in new plant until sufficient long-term contracts with customers can be arranged to cover a sufficient portion of the required investment. The generation contracts could be with one or more customers and might involve a mix of fixed charges coupled with the obligations to compensate for price differences relative to the spot-market price. But the customer and generator would ultimately buy and sell power at their location at the half-hourly price.

If either party expects significant transmission congestion, then a transmission congestion contract would be indicated in any case that would otherwise benefit from point-to-point physical rights were they available. If transmission congestion contracts are for sale between the two points, then a contract can be obtained from the holder(s) of existing rights. Or new investment can create new capacity that would support additional transmission congestion contracts. The system operator would participate in the process only to verify that the newly created transmission congestion contracts would be feasible and consistent with the obligation to preserve any existing set of transmission congestion contracts on the existing grid. Unlike the ambiguity in the traditional definition of transmission transfer capacity, there is a direct test to determine the feasibility of any new set of transmission congestion contracts for compensation – while protecting the existing rights – and the test is independent of the actual loads that may develop. Hence, incremental investments in the grid would be possible anywhere without requiring that everyone connected to the grid participate in the negotiations or agree to the allocation of the new transmission congestion contracts.

This happy resolution of the puzzle of transmission expansion and pricing through voluntary market forces alone is subject to at least two other important caveats. First, there still may be market failures even with the definition of a workable set of equivalent property rights. For example, with many small market participants, each benefiting a little from a large transmission investment, the temptation to free-ride on the economies of scale and scope may create a kind of prisoner's dilemma. Everyone would be better off sharing in the investment, but the temptation to free ride and avoid paying for the expense may overcome any ability to form a consortium or negotiate a contract. It may be that the investment could not go forward in a timely manner, at the right scale, or at all, without some entity that can mandate payment of the costs.[11] In this case, however, the task should be simplified by the ability to simultaneously allocate the benefits in the form of a share of the transmission congestion contracts. The market could take care of many, perhaps most, investments, and the regulatory option would be easier to implement when needed.

A related problem could appear in the circumstances where the pattern of transmission use was so uncertain and the network so interconnected that no set of point-to-point rights would be capable of capturing enough of the economic benefits of grid investment. This would be true, of course, for both physical rights were they possible, as well as for the transmission congestion contracts. In effect, there would be significant economies of scope in transmission investment that would go well beyond the benefits of any reasonable patterns of point-to-point rights. If the benefits could not be assigned, then the market-based investments would not follow.

Second, operation of voluntary market forces would have little sway in the allocation of the costs for an existing transmission grid that already provides open access. The costs are sunk, and typically the sunk costs of the wires exceed the transmission congestion opportunity costs of using the grid. This is due, in large part, to the effects of the economies of scale. Hence, given the choice of paying the sunk costs but avoiding the congestion costs, versus avoiding the sunk costs while using the system and paying the continuing cost of congestion, most users would prefer the latter. If the sunk costs are to be recovered in prospective payments, therefore, there must be some form of requirement to pay these costs as a condition for using the grid. The resulting access charges would be the functional equivalent of the contract payments for new investment.

The need for access charges would not dictate the form of the charges. From an efficiency perspective, the preference would be to divorce the charge from usage levels, such as through a meter connection charge. In practice, the access charge might be collected proportional

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[11] This situation appears to be what is described often as investments for reliability. However, with price-responsive demand and security-constrained economic dispatch, there is in principle no difference in reliability investments and economic investments. The only difference created by the investment would be in the economic benefits of the actual dispatch.

to usage, but in this case it should be at the last point of connection in order to minimize perverse incentives for inefficient bypass to avoid paying for sunk costs.

Assignment of the access charges could be simplified by the simultaneous allocation of the benefits of the existing grid through the award of transmission congestion contracts. One approach might be to award the initial ownership of the contract along with a long-term obligation to pay the access charges. Another possibility would be to auction the transmission congestion contracts and apply the revenues to reduce the required payment for the transmission grid. The remaining costs would be collected as access charges for all users of the grid. In effect, these access charges would pay for the assets of the grid in a system allowing open access for full use of the system. Everyone who used the system would pay the transmission usage charge for congestion, the second part of a two-part tariff, and the holders of transmission congestion contracts would have the transmission hedge.

Allocation of embedded costs and transmission rights for the existing system presents a major transitional challenge. However, this challenge must be met. To support a competitive market, and to meet the test of comparability, the old implicit allocations of rights must be made explicit. There will be many issues to resolve in this transition, and many ways to allocate costs and benefits without distorting the market. Looking forward, however, the market framework would condition system expansion decisions.

Grid expansion and pricing would continue to present a need for regulatory oversight, but the existence of workable transmission congestion contracts would substantially simplify transmission investment decisions. The users of the system who are buying and selling electricity without a complete hedge through transmission congestion contracts would face the short-term market clearing price. In the face of transmission congestion, the locational prices provide the proper incentive for investment in transmission facilities. Investments should be made when justified by the savings in congestion costs. Those who are prepared to make the investment would obtain the associated transmission congestion contracts. The role of regulators, therefore, would be to review requests for transmission expansion, examine the compatibility with the companion request for new transmission contracts, and ensure an open process for all to join in developing combined transmission investments recognizing the interactions in the network.

The regulator would be responsible for enforcing a requirement for existing transmission facility owners to support expansions and reinforcements at a traditional regulated cost that recovered the incremental investment, and then to assign the corresponding transmission contracts. If no coalition of grid users were able to agree to pay for a grid expansion that appears to be beneficial for the system as a whole, any interested party could propose a project and an allocation of its costs among those grid users who would benefit. Regulatory procedures, similar to those used now, would determine whether the project should go forward and how its costs should be allocated to those expected to benefit from the effect on future locational spot market prices, with the payers granted rights to compensation to assure that future congestion does not rob them of the benefits they are paying for.[12] This would also be the place to take up the related question of providing adequate incentives, and the form of incentive regulation, for transmission providers who provide connection to the existing grid and construction of expansions that would not take place under the market-based framework.

The transmission congestion contracts, once created, would no longer need any special regulation. Although investments in the transmission grid would be lumpy and would require the cooperation of the owners of existing facilities, the transmission congestion contracts would be divisible and freely tradable in a secondary market. This secondary market would provide a ready source of transmission hedges that would serve as an alternative to system expansion. The price of the transmission contracts should never rise above the long-term expected congestion opportunity costs or the cost of incremental expansion of the grid. In this way, the unregulated market for transmission congestion contracts would emulate the broad outlines of FERC's pricing policy. Transmission contracts would be obtained at the lesser of opportunity costs or incremental costs. Holders of existing transmission rights, converted into the appropriate transmission congestion contracts, would pay embedded costs but not opportunity costs. Those using the transmission grid without holding transmission congestion contracts would pay opportunity costs but not any embedded costs other than the costs of any stranded assets that would be collected from all users.[13] Most important of all, the long-term transmission market could be more like a market, relying as much as possible on the incentives and forces of competition, limiting the role of planning and regulation to address the unavoidable interactions in the transmission grid. Investment decisions would be made at the initiative and with the agreement of those required to bear the cost.

Regional Transmission Organizations

The basic components of this competitive market structure appear in the proposed requirements for Regional Transmission Organizations.[14] The key element is in the recognition of the importance of a coordinated spot market. In the RTO NOPR this appears as the balancing market, which is equivalent to the "net pool" arrangement outlined above. In particular, FERC recognizes that "[r]eal-time balancing is usually achieved through the direct control of select generators (and, in some cases, loads) who increase or decrease their output (or consumption in the case of loads) in response to instructions from the system operator."[15] To be consistent with the competitive market, it is essential that this be through a bid-based security-constrained

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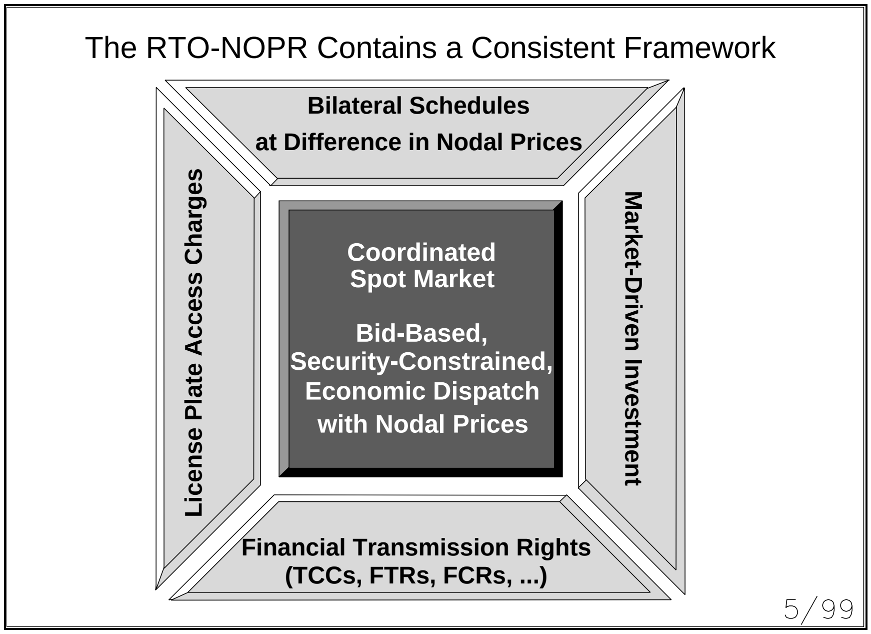
[12] D. Garber, W. Hogan, L. Ruff, "An Efficient Electricity Market: Using a Pool to Support *Real* Competition," The Electricity Journal, Vol. 7, No. 7, September 1994, pp. 48-60.

[13] These stranded assets might include transmission sunk costs that could not be recouped through a sale of transmission rights.

[14] (RTO NOPR) Federal Energy Regulatory Commission, "Regional Transmission Organizations", Notice of Proposed Rulemaking, Docket No. RM99-2-000, Washington DC, May 13, 1999.

[15] RTO NOPR, p. 175.



economic dispatch: "Proposals should ... ensure that the generators that are dispatched in the presence of transmission constraints must be those that can serve system loads at least cost, and limited transmission capacity should be used by market participants that value that use most highly."[16]

Everyone would be able to participate in this coordinated spot market, at the efficient, and necessarily locational or nodal, prices: "The market mechanisms must accommodate broad participation by all market participants, and must provide all transmission customers with efficient price signals regarding the consequences of their transmission usage decisions."[17] Furthermore, "... the Commission proposes to require that RTOs operate a real-time balancing market that would be available to all transmission customers, or ensure that this task is performed by another entity not affiliated with market participants."[18]

Given the availability of this coordinated spot market and these efficient locational prices, market participants could schedule bilateral transactions or rely on trade through the spot market. The differences in locational prices would define the opportunity costs of transmission, giving rise to the creation of financial transmission rights.[19] Payment for the existing grid would appear in part as access charges, including the use of the "license plate" approach with region-specific access charges.[20]

This same basic system has been in operation for more than a year in the Pennsylvania-New Jersey-Maryland (PJM) Interconnection, where the financial transmission rights are labeled

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[16] RTO NOPR, p. 198.

[17] RTO NOPR, p.162.

[18] RTO NOPR, p. 176.

[19] RTO NOPR, p. 166.

[20] RTO NOPR, p. 13.

as fixed transmission rights (FTR).[21] In the proposed New York ISO structure, the same basic model applies with equivalent transmission rights called transmission congestion contracts (TCC).[22] In the proposed New England ISO structure, the term of art is a financial congestion right (FCR).[23] There are slight differences in all these approaches, but they stand on the bedrock of a coordinated spot market, implement through a bid-based, security-constrained economic dispatch with locational prices. This supports a high degree of choice by market participants, and is the only known model that provides these benefits in a framework to support competitive electricity markets.

NETWORK EXTERNALITIES AND INVESTMENT INCENTIVES

Complete reliance on market incentives for transmission investment would be unlikely as a practical matter and is subject to a number of theoretical challenges. Perhaps the biggest challenge is to escape from the "Catch 22" neglect of market innovations that creates a self-fulfilling prophecy that only monopoly solutions would be available.

Market institutions can support market-based transmission investments. The tradeoff will be between imperfect markets and imperfect regulation. The existence of a viable system of long-term transmission congestion contracts changes the balance, however, to rely more on market forces. Here we address the challenges to market-based investments that arise because of network externalities and economies of scale and scope.

Allocating Transmission Benefits and Costs

The economies of scale and scope in transmission construction present a number of issues in long-run transmission pricing. Transmission investments and upgrades tend to come in large increments that can have a significant effect on market prices. The facilities are capital intensive, require long investment lead times, and are long lived. Any change in the configuration of the transmission grid can alter the extensive network interactions, thereby affecting virtually all users of the transmission grid. Furthermore, most of the costs for the existing transmission system are sunk. Hence, there is a marked difference between the problems of determining the allocation of the costs for the existing system and the task of defining the

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[21] PJM Interconnection, L.L.C. The PJM system began operation with FTRs and full locational pricing as of April 1, 1998. Details can be obtained from the web site at www.pjm.com.

[22] Federal Energy Regulatory Commission, New York ISO Ruling, Docket Nos. ER97-1523-000, OA97-470-000 and ER97-4234-000, January 27, 1999. See also, "Order Denying in Part and Granting in Part Rehearing and Clarification and Conditionally Accepting Compliance Filing," Dockets Nos. ER97-1523-003 and -004, OA97-470-004 and -005, and ER97-4234-002 and -003, Washington DC, July 29, 1999.

[23] Federal Energy Regulatory Commission, "Order Accepting Preliminary Congestion Management and Multi-Settlement Systems and Providing Guidance," New England Power Pool, Docket No. ER99-2335-000, Washington DC, July 30, 1999.

allocation for system expansion.

The incentive for transmission investment would come from those who did not already have transmission congestion contracts. These market participants would be relying on the spot market. When the anticipated congestion cost and losses become large enough, there would be an economic motivation for investing in transmission. However, the motivation for the investment assumes, at a minimum, that those making the investment would then reduce the cost of the losses and avoid the corresponding congestion payments.

The discussion of the economics of competitive electricity markets emphasizes the importance of defining and allocating benefits of the transmission grid. If there is no method to allocate the benefits of transmission, the strong network interactions exacerbate the difficulty of allocating costs. Without some form of transmission rights, there could be substantial incentives to shift costs to others (i.e., free-riding), it would be difficult to define a standard of performance for transmission providers, and the normal operation of market principles would founder because of the lack of property rights. By contrast, where it is possible to define the equivalent of property rights, free-riding and these difficult allocation problems could be substantially reduced, if not eliminated.

Consider the allocation of the costs for short radial connections from plant to a nearby transmission grid. In the simplest of cases, when connecting a single generator or a single customer, the benefits of the connection seem clear. The benefits would accrue to the facility connected to the grid, and the costs would naturally be allocated to the same facility. The close match between benefits and costs would allow for investment charges that would be consistent with operation of a market. It is for this reason that transmission pricing often treats such investments separately.

When we turn from simple radial connections to the main transmission grid, however, the obvious allocation of costs and benefits is no longer available. This is closely related to the complicating fact of network interactions that make it difficult or impossible to define the total capacity of a network. The simple reality is that in any sufficiently interconnected network, it is not possible to define the capacity of the network without also defining the pattern of usage. Except for truly radial systems, transmission congestion can change the capacity of the grid depending on the configuration of load and generation.

This difficulty in defining the capacity of the grid without specifying the pattern of use does not mean that no definition of capacity or property rights would be available. For example, it is always possible to test easily to determine if a particular pattern of usage of the transmission grid would be within the security-constrained dispatch limits dictated by the requirements of reliable operation. The system operator makes just such judgments on a regular basis, with an affirmative conclusion implicit in every dispatch. Hence, it would be legitimate to define any feasible pattern of system use as within the capacity of the system, and the associated input levels could be defined as transmission rights. With these hypothetical property rights, we would be closer to a method for allocating the benefits of transmission grid to support the allocation of the costs.

One difficulty of this approach in terms of physical property rights would be in the constant need to redefine and reconfigure transmission usage to conform to the actual load patterns. In effect, we would like those who have paid for transmission property rights to be able to sell those rights in a secondary market to support the actual dispatch. Were this possible, many of the most perverse incentives and logical puzzles in transmission pricing would be removed. With well-defined, tradable property rights, the transmission regime could operate more according to market principles. However, a literal system of physical rights traded to match actual use would be impractical as a means to control system dispatch.

This is where the transmission congestion contracts fit into the long-run picture. A transmission congestion contract provides payment equal to the congestion price differential between two locations. In a competitive market setting, these financial contracts are equivalent to perfectly tradable physical transmission rights. Hence, these transmission congestion contracts can be the embodiment of the benefits of transmission investment. Ownership of the transmission congestion contract can be defined as the benefit that comes with paying for transmission investment. The transmission congestion contract provides a perfect hedge against changes in the transmission usage charges arising in the form of congestion costs. The transmission congestion contract internalizes the complicated network interactions, and allows the market to operate with simple point-to-point arrangements that act like property rights.

In some cases, the transmission congestion contracts alone could support market decisions for transmission investment. Faced with transmission congestion and persistent differences in locational prices, market participants could come forward to negotiate a contract for transmission expansion. In exchange for a long-term agreement to pay the costs of the expansion, they would receive a set of transmission congestion contracts that would reflect the incremental transfer capability created by the investment. In general, there would be no unique set of potential transmission congestion contracts, as many patterns of increased flow could be accommodated by the incremental investment. However, the participants would agree on the preferred collection of new transmission congestion contracts, and the assignment of both the costs and the benefits would be established by contract before the investment was made. The system operator would participate to certify the feasibility of the incremental transmission congestion contracts in combination with any other existing rights. The transmission provider would build the transmission enhancement, the customer would pay the investment costs as dictated by the contract, and the system operator would administer the transmission congestion contracts providing the hedge against congestion costs.

The transmission congestion contracts could also provide the definition of the future obligations of the transmission provider. Absent some later change in the explicit contracts, the obligation of the transmission provider would be to maintain the feasibility of the collection of transmission congestion contracts. This could be achieved either by literally maintaining the wires and other facilities to preserve the feasibility of the power flows as specified in the contracts, or by assuming the financial responsibility to make up any payment deficits under the transmission congestion contracts. Hence, the set of transmission congestion contracts could serve as the cornerstone for an incentive pricing scheme for the transmission provider.

If there were no market power present, the value of the opportunity costs under the transmission congestion contracts would define the opportunity costs of any reduction of system capacity. This would set a framework for any payment obligations by the transmission provider. In the presence of market power in generation or load, including the important special case of a radial connection for a single entity, the transmission congestion contract obligation could be adapted to specify obligations of the transmission provider. For example, in case of the loss of a radial line, there would be no observed market clearing price at the plant to define the opportunity cost of the reduced capacity caused by a line outage. However, in the context of a spot market, a pattern of bids from previous periods might establish a workable estimate of the incremental cost of the plant. The difference relative to the grid price at the point of connection could be used as the estimate of the opportunity cost in the rare event of line outage. In this case, the opportunity cost estimate would serve as the implied obligation under the transmission congestion contract. The typical contract might include some limited periods or maximum payments to account for normal outages and maintenance, with any excess payments resting in whole or in part as the responsibility of the transmission provider.

In circumstances with multiple owners of the transmission grid and substantial parallel flows, there would be a requirement to define a sharing mechanism of responsibility among the transmission providers. In the case of a significantly interconnected system, the capacity on one part of the system could affect the capacity everywhere, and not all transmission providers would be able to control these impacts. This allocation of responsibility would be similar to the joint cost allocation problem, for which a number of practical allocation approaches would be available.

The transmission grid owner receives embedded costs for the existing grid or investment costs for new increments. The payment for the existing grid or new grid investments can be cost based according to traditional regulation, or allowed to adjust to market prices. Actual construction and ownership of the wires could follow many arrangements, with the ultimate economic value defined in the transmission congestion contracts. Those paying the regulated fixed charges for the existing transmission system receive the associated transmission congestion contracts. The transmission congestion contracts could be allocated to users paying the access charges to the grid or sold in an auction with the revenue used to reduce the access charges. New investment, either by the existing owners of the transmission system or third parties, would create new transmission congestion contracts. If the investment is included in mandatory access charges, the investment would be regulated in a traditional way and the incremental transmission congestion contracts allocated to those paying the access charges. If the investment is market-based and not included in mandatory access charges, the pricing would also follow the market and the investors would receive the incremental transmission congestion contracts.

The spot market participants pay locational prices which include transmission opportunity costs. The difference in locational spot prices defines the opportunity cost of short-term transmission usage. Everyone has access to use the grid and pays the transmission opportunity cost. The transmission congestion contract holders receive the congestion payments. Through the settlement payments, the system operator collects the congestion payments from the system users and disburses the congestion payments to the holders of the transmission congestion contracts. The system operator keeps nothing; the grid owner receives the regulated fixed charges for the existing system; the transmission congestion contract holder receives compensation for out-of-merit dispatch costs; and the transmission user pays the true opportunity cost.

Inefficient Transmission Expansion

Investment in the transmission grid should create new economic capacity. Even in the absence of the special case of electric network externalities, decentralized investment with fixed costs of entry might produce inefficient expansion through too much investment as measured by total welfare.[24] However, the is not the usual focal point for analysis if electric networks. If transmission investment suffered from the problems of hotel construction in producing too much capacity, there would not be much of a public policy concern.

In the case of a regulated industry with large fixed costs, there is the possibility that tariffs would collect some or all of the fixed costs through variable charges. To the extent the system allowed users to avoid these variable charges by making new investments, there would be a familiar incentive for inefficient bypass. For example, we face this form of incentive in electric distribution systems which charge on a kilowatt-hour basis for net load. Investment on the customer side of the meter might be motivated by avoidance of largely sunk and fixed costs. The same problem could arise under the structure of transmission tariffs that follow the contract path and wheeling model, where a new contract path avoids paying the largely sunk costs on other contract paths, even without any change in the real power flows.

Within the framework described here, however, recognition of the network effects and economies of scale leads directly to the use of access charges to recover sunk costs that are not paid under voluntary contracts. The license plate access charges are an example, and the investment in market-based transmission expansion should not affect the allocation of these access charges. Even though final collection from end-users might be on a variable charge basis, these charges could not be avoided by investment in the transmission grid. Hence, the use of congestion pricing for transmission usage and mandatory access charges to pay for regulated fixed costs would avoid the regulatory incentives for inefficient market-based investments in all but the cases where the investment allows for a complete disconnect from the existing grid and exemption from existing regulation.

In the case of electricity, therefore, the focus of inefficient expansion is on reducing

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[24] G. Mankiw and M. Whinston, "Free Entry and Social Inefficiency," Rand Journal of Economics, Vol. 17, Spring, 1986.

the capacity of the network, not expanding too much. It is well known that different pricing regimes can create incentives for "uneconomic" transmission investment in the sense of reducing total welfare by reducing the effective capacity of the system.[25] The simple example of a radial transmission line between two points would illustrate the point. Suppose that the line connects a low cost region to a high cost region. Under market pricing rules, generators in the high cost region would benefit if the capacity of the line were reduced. In an electric grid, a conceptually simple way to reduce the transfer capacity would be to add a weak parallel line between the two regions. Power flow would now split between the two parallel lines. Flow on the original parallel line would then have to be reduced to keep the parallel flow on the new line below its low capacity. It might be worth it to the high cost generators to build such a line, lower transfers, and raise prices in the high cost region. Overall economic efficiency would be reduced, but the profit to the high cost generator could justify the expenditure for the transmission investment.

Most of the examples of such perverse transmission investment incentives rely on this property of parallel flows. This simple perverse example would be easy to dispose of in practice. The regulator might prohibit such degradations of capacity. However, in a real network, with complex interactions, the same effect may be present but less obvious. The analysis to reveal a truly uneconomic investment might be both more difficult and controversial. Hence, we cannot rule out the possibility that real investment incentives would be influenced by wealth transfers that dominate efficiency losses. In theory, decentralized market-based investments could be inefficient.

It would be desirable, therefore, to have a system of property rights that reduced or eliminated the incentives for such perverse investments. In the case of a contract network as described above, the investment incentives would be affected by the existence of the transmission congestion contracts. As demonstrated by Bushnell and Stoft, under certain restrictions, the existence of transmission congestion contracts may even fully internalize the efficiency effects of investment decisions.

The allocation of transmission congestion contracts under a feasibility rule arises naturally from the interpretation of the transmission congestion contracts as described above. It is clear that simultaneous feasibility of the transmission congestion contracts is necessary to guarantee that the revenues collected by the system operator are sufficient to pay the obligations under the transmission congestion contracts. Furthermore, under certain minimal conditions, the same feasibility condition would be sufficient to guarantee that the revenues from a market equilibrium in the spot market would be sufficient to guarantee this revenue adequacy.[26]

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[25] For a review of the literature on these incentives, see James B. Bushnell and Steven E. Stoft, "Electric Grid Investment Under a Contract Network Regime," Journal of Regulatory Economics, Vol. 10, 1996, pp. 61-79.

[26] Scott M. Harvey, William W. Hogan, and Susan L. Pope, "Transmission Capacity Reservations and Transmission Congestion Contracts," Center for Business and Government, Harvard University, June 6, 1996, (Revised March 8, 1997).

However, in addition, the allocation of transmission congestion contracts under the same feasibility rule mitigates incentives for inefficient transmission investment.

The definition of the simultaneous feasibility test and investment feasibility rule can be stated as:

Feasibility Test: The aggregate of all transmission congestion contracts defines a set of net power injections in the grid. The set of contracts is feasible if these injections and their associated power flows satisfy all the system constraints.

Feasibility Rule: The grid expansion investor selects a set of new transmission congestion contracts with the restriction that both the new and the old transmission congestion contracts will be simultaneously feasible after the system expansion.

Application of this rule would permit a great deal of flexibility. For example, if necessary, the incremental transmission congestion contracts could provide counterflow to eliminate some of the existing contracts and thereby change the pattern of use. This would be equivalent to purchasing the existing contracts, or simple assuming the responsibility to meet the financial obligations under these same contracts.

The feasibility test is (relatively) easy to perform and is a familiar step in any transmission analysis. However, there is an important simplification here compared to the standard analysis of transmission investment. In the traditional analysis of regulated markets, with no response to price changes, it has been necessary to examine the feasibility of any set of transmission flows under a large number of possible patterns of load and system usage. This is one reason that available transmission capacity is defined often with a range of values, or with substantial caveats about the sensitivity to the pattern of future load. In the present case, however, there is no commitment or requirement for feasibility of the set of transmission congestion contracts along with other uses of the system.[27] The only requirement is internal consistency of the set of transmission congestion contracts. Hence, there is only one load flow to analyze, and only for the loads associated with the contracts.[28]

As regards to investment incentives, an obvious point is that any exposure to future

[27] This is true in the case of a complete system. In the case of regional, interconnected systems, the result would not apply to the individual regions, but only to the aggregate. For a further discussion of regional interactions, see Michael Cadwalader, Scott Harvey, William Hogan, and Susan Pope, "Market Coordination of Transmission Loading Relief Across Multiple Regions," Center for Business and Government, Harvard University, December 1, 1998.

[28] This is the case for transmission contracts defined as obligations. For transmission congestion contracts defined as options, the test would be for all combinations of the contracts, but would not require consideration of all combinations of possible usage patterns.

costs or inefficient investment falls on those who are relying solely on the spot market. Future investments in the grid cannot reduce the welfare of aggregate use according to the existing transmission congestion contracts. By definition, it would always be possible to use the system in the manner defined by the pattern of transmission congestion contracts. Therefore, the holders of the transmission congestion contracts could either dispatch their load and generation according to the transmission congestion contracts, or be compensated such that they would be no worse off than using the system in this manner. With private benefits, therefore, all the exposure to rent transfers would be limited to the spot market participation.

This already takes us a long way towards a market-based system. Long-term contracts could, in principle, immunize the parties to the spot-market variations. Exploitation of rent transfers and inefficient investment, if it remains at all, would be only in the spot market. Although any inefficiency would be detrimental, there is likely to be much less concern with designing full protection for spot-market participants who have chosen not to protect themselves through long-term contracts.

Bushnell and Stoft have gone further to show that under certain conditions, there would be an additional reduction in incentives to make investments in inefficient transmission. For example, if transmission congestion contracts initially match dispatch in the aggregate, and new transmission congestion contracts are allocated for transmission investment under the feasibility rule, then the increase in social welfare for any transmission investment will be at least as large as the ex post value of the new contracts.[29] Hence, investors in transmission only, who are profiting only from the new transmission congestion contracts they create, would have no incentive to make inefficient transmission investments. This moves part way to the best possible outcome, but it does not remove the possibility that a combination of rent transfers and profits on generation might outweigh the efficiency loss from perverse transmission investments.

Under more restrictive assumptions, we could improve on this situation. If transmission congestion contracts match dispatch individually, not just in the aggregate, then the allocation of transmission congestion contracts under the feasibility rule ensures that no one can benefit from a network investment that reduces social welfare.[30] In effect, this condition is a limiting case of the point made above. With the dispatch perfectly matching the individual transmission congestion contracts, the spot market net of transmission congestion contract coverage is reduced to zero volume. Any investment and movement in the spot market would impose the costs on the individual making the investment, thereby internalizing the efficiency effects.

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[29] James B. Bushnell and Steven E. Stoft, "Improving Private Incentives for Electric Grid Investment," Resource and Energy Economics, Vol. 19, 1997, pp. 85-108.

[30] James B. Bushnell and Steven E. Stoft, "Electric Grid Investment Under a Contract Network Regime," Journal of Regulatory Economics, Vol. 10, 1996, pp. 61-79. For a related analysis in the context of generator market power, see Yves Smeers and Wei Jing-Yuan, "Transmission Contracts May also Hinder Detrimental Network Investments in Oligopolistic Electricity Markets," CORE, October 28, 1997.

As summarized by Bushnell and Stoft:

> "Any evaluation of investment incentives provided by transmission property rights must take into account the rules for allocating rights to the new property produced by grid modifications. Measuring the new property can be difficult. In fact, some 'expansions' of the network can increase congestion and in effect destroy *existing* property.
>
> [Transmission congestion contracts], when allocated according to the feasibility rule, can, under some conditions, account for this destruction of property and penalize those responsible. This could pave the way for a market that properly accounts for the complex externalities of the electric grid."[31]

In practice, of course, the actual dispatch for changing market conditions will never fully match the allocation of transmission congestion contracts. A more complete analysis of the investment incentives, therefore, would depend on an expected value calculation. Bushnell and Stoft conjecture that any deviations from efficiency would be small. It is clear that the existence of transmission congestion contracts, or any system of perfectly tradeable physical rights, would improve the investment incentives, even while not completely internalizing all the network externalities. And for those who want to protect a long-term contract from future inefficient investment, the feasibility rule provides the mechanism whereby the guarantee could be available. Any inefficiency would be isolated with loads relying solely on the spot market.

Economies of Scale and Free-Rider Effects

The locational opportunity cost pricing system would not pay for the existing grid. The fixed charges of the grid reflect investments that, in principle, have been made to avoid paying the opportunity costs of congestion, losses, and more expensive generation. Typically, because of economies of scale and scope, the fixed charges would be greater than the congestion opportunity costs after the investment was made. It follows that fixed cost recovery for "first-best" or fully efficient grid investments would be through a combination of access charges and long-term contracts. The transmission congestion contracts would be the embodiment of the long-term guarantee that would be obtained in exchange for the fixed charge payments. Transmission congestion contracts would provide a way to untangle the network and convert short-run opportunity cost prices into long-term transmission arrangements.

The key incentive problem for market-based investments in the grid would arise in those cases where there would be a material change in the equilibrium prices. If the prices change significantly, it may be that the prices after the investment would not support the investment. However, this is not the only possible outcome, and the focus should be not on

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[31] James B. Bushnell and Steven E. Stoft, "Grid Investment: Can a Market Do the Job?", The Electricity Journal, January-February, 1996, p. 79. (emphasis in original)

economies of scale, but on the impact on market prices. Economies of scale may be necessary for the investment to have a large impact on market prices, but not sufficient. In many cases, such as de-bottlenecking through improvements in voltage support, the optimal investment may be lumpy, but it need not be large enough to have a major impact on the market.

If the transmission investments can be made in small increments relative to the size of the market as a whole, they should have a minimal effect on market prices. In this case, acquisition of the financial transmission rights could provide the right market incentive. Prices after the modular expansion would not be materially different than before, even though there would an increase in capacity and throughput. The transmission rights would provide the hedge against transmission prices, and for the investor the arbitrage opportunity in the spot market would be sufficient to justify the investment.

Closely related to the case of relatively small modular expansions would be those conditions where the transmission investment could be connected to a power-purchase contract at a location. The contract would be arranged, presumably, at a price lower than would exist without the transmission investment, but higher than would prevail after the lumpy expansion reduced the congestion differential. If the cost of transmission investment were relatively low compared to the power purchase arrangement, then the economics of generation should dominate, not the disparity in ex ante and ex post locational price differences that determine transmission congestion. The linkage between price differences and marginal cost of transmission would not hold, so that an isolated transmission upgrade would not be profitable by itself. But as part of the larger arrangement, the market-based investment in transmission might go forward. The terms of the contract would provide the counterpart to the fixed access charges to pay for the cost of the expansion that exceeded the resulting congestion induced price differences.

Accommodating Economies of Scale

The electricity industry with transmission investment is not the only industry that can face significant economies of scale in investment. Very large electric transmission expansions might be an extreme case, but the principle applies elsewhere in expansion of aluminum production capacity, steel plants, hotels and so on. In these other markets, we accept and accommodate the effects of economies of scale. The result is a "second-best" outcome, narrowly defined. But we accept the benefit of the compromise given the reality of an imperfect market, and do not reject the results of this market in the absence of a better solution through regulation. If we have a better approach through regulation, we should take it. But if not, we should enjoy the second-best outcome of the market. The same approach could be extended to electricity transmission investment.

One accommodation would take the form of allowing market-based investments that are scaled to be small enough to have a minimal impact on market prices. Hence, the investor would be able to profit from the remaining price differences in the spot market, while enjoying the increased throughput provided by the transmission expansion. A careful engineering analysis might show that a larger project would be more "efficient," but in the absence of volunteers to pay for the expansion, it would be better to have a smaller expansion than no expansion at all. The principal public policy requirement would be to ensure that the project did not fully occupy some unique resource, such as a right of way, that would no longer be available once the investment went forward. As long as the investment would be subject to further entry and competition, the second-best argument would be to support the market-based investment and its contribution to dynamic efficiency.

More controversial would be to encourage market-based investment at a greater scale but to allow a period of time where the investment would be operated at reduced capacity. Here there would be an analogy to patents on inventions. With a patent, an inventor can restrict use of an invention that could easily be used much more widely, but only at the cost of dissipating the profits. The withholding limit applies for a period of time, judged sufficient to stimulate the effort of invention. Similarly, the transmission investor would enjoy a period of time where the profits from the resulting locational price differences would be sufficient to justify the investment, even though operation at full capacity would make the investment unprofitable.

There would be no technical difficulty in operating these incremental investments at less than the full name-plate capacity. All that would be required would be the cooperation of the system operator in specifying the limits to apply in the security-constrained economic dispatch. In the very nature of the security-constrained dispatch, with multiple contingency constraints, the limit is monitored based on a calculation, not just from measuring the power flow over a line. The calculation could just as well be based on the commercial limit for the investment as on the physical limit.

The idea of allowing withholding of actual physical capacity seems at odds with he policy of open access and full utilization of the existing grid. However, on closer inspection there is no fundamental contradiction. The market-based investment would not be like the regulated investment. In particular, there would be no rate-base protection or inclusion of the investment cost in mandatory access charges. For the capacity associated with regulated investments, there would be no withholding.[32] But for market-based investments, we recognize that the investment might not be made if the profit incentive were removed by requiring optimal exploitation of economies of scale and immediate utilization of the full capacity. The investor would bear the risk of the market-based investment, but would require the reward of charging a price to justify the investment.

As long as the investment did not foreclose competitive entry, the withholding should not be seen as the deleterious exercise of market power. Rather, the temporary withholding could be seen as part of the process of dynamic adjustment in the market, with the profit incentive originating in the scarcity rents. It is precisely the pursuit of these scarcity rents which motivates entry and the investment. Eventually, further entry would dissipate the scarcity rents or the period of "patent" protection would expire. In the interim, the expansion would provide direct

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[32] This is for regulated investments under the model envisioned here. Under the contract path model, the variable wheeling charges independent of congestion amount to withholding through price.

incremental benefits to the energy market, and the cushion between commercial and physical capacity would provide an improvement in overall reliability.

The logic here would be the same as applied to the other industries. We do not expect investors to build hotels with the promise to lease out rooms at the marginal cost of maintenance until the hotel is full, when the scarcity rent applies; at least not before the fact for the hotels that we will not pay for through mandatory charges. So too here we would not expect the investor in market-based transmission to expect to incur a loss.

Furthermore, it would be difficult to make an operational distinction between smaller scale investments with the commercial capacity equal to the physical capacity, and those larger scale investments where there was an acknowledged gap. Measurement of physical capacity is not without some judgment, so the issue could be clouded. Furthermore, at some cost it would be possible to downgrade the physical capacity to match the commercial requirements. It would be more efficient, therefore, to allow operation of the dispatch where new investment could be defined as an increment to capacity that would be acceptable to the investor, as long as the physical capacity at least equaled the commercial recognition of the capacity.

This dynamic investment process stands behind the expansion rules in the new investment policy in Australia.[33] The basic idea was to provide an incentive for market-based transmission investment. In the case of Australia, there is a safe harbor provision that allows the investor to effectively control the capacity of a new transmission line. In effect, this allows the investor to limit the use of the line whenever the locational price difference is too low. To the extent that this maintains higher price differences, the withholding is justified as the necessary cost of reaping the benefits of the expansion. As a result, more power flows and congestion costs are reduced, compared to the case without the investment.

In the case of the Australian safe harbor provision, application is limited to the case of "controllable" lines. This simplifies the model substantially, because it mitigates or eliminates the network externalities. Furthermore, the use of a controllable line approximately restores the linkage between the identifiable increment in system capacity and the actual flow over the line. In practice, therefore, this allows for a payment method that is equivalent to charging a fee for using the line. In this Australian case, the limitation to a controllable line is necessary because Australia does not have the foundation of a bid-based, security-constrained economic dispatch with fully locational prices. Hence, there are unaccounted-for network interactions, and the counterparts to TCCs have not been implemented. For a controllable line the economic model is still well-defined by the flows over the line. However, if Australia were to adopt full locational pricing, which would be advantageous for other reasons, it would be possible to expand the safe harbor provisions to transmission investments other than physically controllable lines. This would encompass all the possible investments, including new free-flowing lines, capacitor and transformer upgrades, and so on.

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[33] National Electricity Code Administrator, "Entrepreneurial Interconnectors: Safe Harbour Provisions," Transmission and Distribution Pricing Review, Australia, November 1998.

In the event, as soon as Australia created this small niche for a market-based transmission investment, construction began on just such an expansion. This is the 180 MW Direct Link project connecting the regional electricity markets in Queensland and New South Wales.[34] This is the cleanest demonstration in support of the argument that market-based investment in transmission can and will be done, given the right institutional framework. The project is a pure transmission investment, and the investor is taking the risk while expecting to arbitrage the price differences between the markets. The project is a controllable underground DC line, which provides a number of special features. But the principle could be applied to support other types of market-based investments.

Absent artificial barriers to entry, the market could discipline this process. Furthermore, this institutional innovation would not foreclose the regulatory alternative. The investor could always agree to make available the full capacity in exchange for a sufficient payment to cover the cost of the investment. But now the regulator, rather than the customer, would be making the deal. And the collection of the fixed charges would be part of the mandatory regime of access charges.

CONCLUSION

Market-based transmission investments can play a significant role in a competitive electricity market, if given the opportunity. However, market institutions must be designed to support the competitive market and the transmission investments. A short-term electricity market coordinated by a system operator through a bid-based, security-constrained economic dispatch provides a foundation for building a system that includes tradeable transmission property rights in the form of transmission congestion contracts. Coordination through the system operator is unavoidable, and spot-market locational prices define the opportunity costs of transmission that would determine the market value of the transmission rights without requiring physical trading and without restricting the actual use of the system. In this setting, these transmission congestion contracts are equivalent to perfectly tradeable physical rights. Hence, this organization of the market defines a context where it would be possible to rely more on market forces, partly if not completely, to drive transmission expansion. In the case of market failure, transmission investment would still require some regulatory supervision, but this case would be simplified through the use of transmission congestion contracts to allocate the transmission benefits along with the transmission costs.

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[34] The Direct Link project is a merchant transmission line in Australia developed by TransÉnergie. Further details on the Direct Link project can be found on the TransÉnergie web page at www.transenergie.com.au. The author has been advising TransÉnergie U.S. Ltd. in considering merchant transmission investments in the United States.