

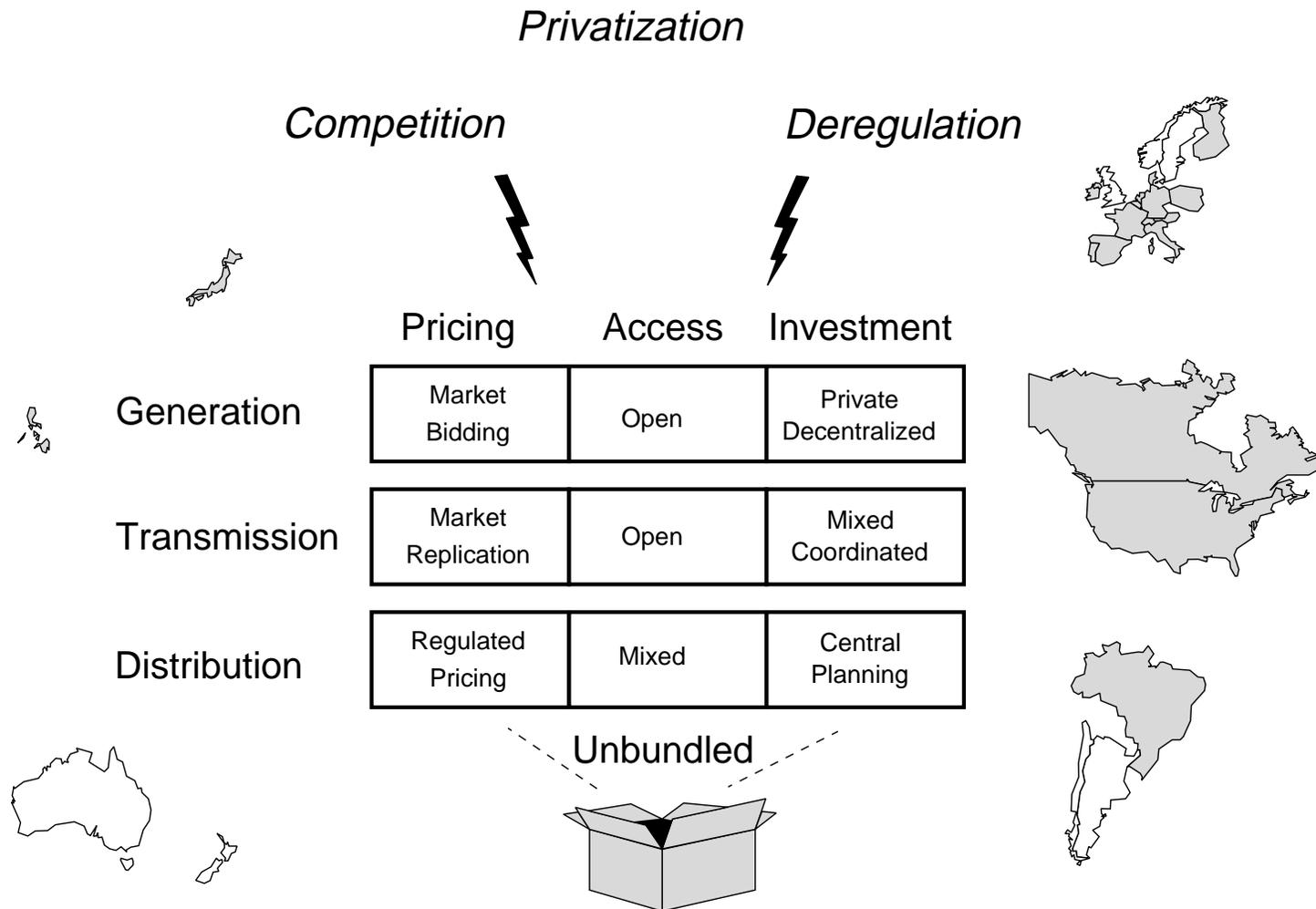
Reshaping the Electricity Industry

**William W. Hogan
Center for Business and Government
John F. Kennedy School of Government
Harvard University
Cambridge, Massachusetts 02138**

**International Program on Privatization and Regulatory Reform
Harvard Institute for International Development**

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The electricity industry is heading towards vertical separation, open access, competition and unbundled services.



Support of competition must be recast within the context of the future of a very different electricity market.

- **Open Access.** Virtually anyone will be able to obtain access to essential facilities and participate in the market.
- **Comparability of Service.** The non-discrimination rules will require comparability of terms and conditions for monopoly provision of services in essential facilities.

We are likely today to underestimate just how different some things may be, and in the transition to the new era there will be many opportunities to revisit and revise the conventional wisdom.

- **Reliability Will Be Maintained.** When you flip the switch, the lights will come on.
- **Everything Else Will Change.** For example, by now everyone knows that the old truth of the contract path for transmission was only a workable fiction with no relation to reality and which is now collapsing under the pressures of the competitive market. This is only the tip of the iceberg.

Electricity industry reform is proceeding in many countries, at different rates, and with different emphases. There is an opportunity to learn from the various laboratories.

- **Not Just Fifty States:** The United States has proceeding underway in most states. Previous and parallel activities can be found in many other countries.
- **Privatization:** The transition from government ownership to private markets motivates market restructuring in many countries.
- **Deregulation:** The movement from regulation to reliance on the forces of competition provides an ideological complement.
- **Competition in Generation:** A common feature is an acceptance or hope for workable competition in electricity generation.
- **Customer Access:** A principal difference across countries can be found in the degree of customer access.

Two elements stand at the core of a new market structure that can be fashioned consistent with this set of objectives.

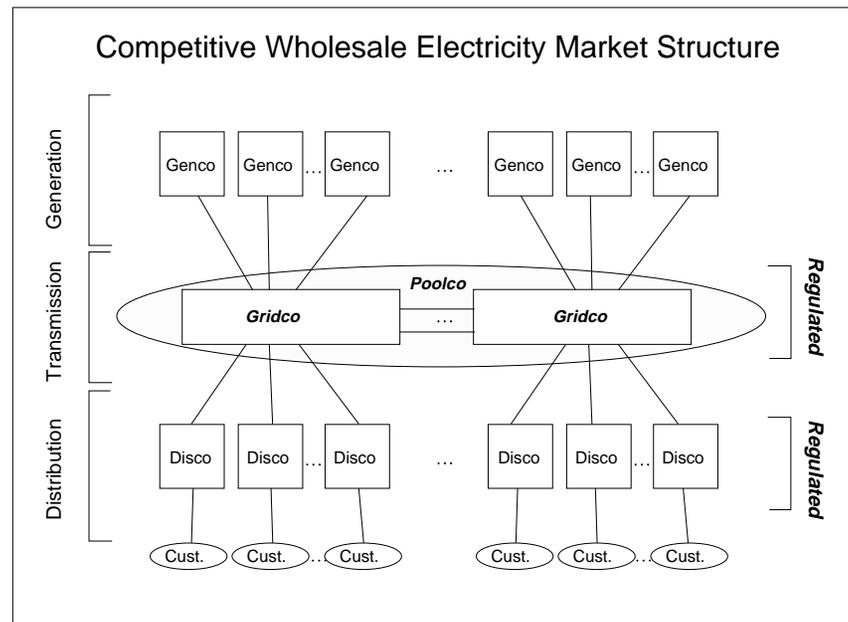
- **Pool-Based Market:** Operation of the short-term market through a closely coordinated or pool-based dispatch. System security and network congestion problems handled as part of the dispatch. Transmission capacity rights allocated along with grid costs but implemented through short-term pool pricing and rental payments for use of allocated capacity. Long-run investment and contracts for energy handled in bilateral markets.
- **Customer Choice:** It is possible to provide a wide range of customer choice. And systems with full access for all customers are in place. The alternative is competition at the wholesale level but a single buyer in a region for final provision to retail customers. There is great variation around the world in the degree and timing of retail customer access. However, the trend is for greater access, sometime.

The pool-based, short-term electricity market addresses the few necessary constraints and technical issues by coordinating system operations and power plant dispatch. Customers, brokers and aggregators enjoy free choice to make long-term arrangements with any supplier or rely solely on access to the short-term market.

ELECTRICITY MARKET

Competitive Structure

The usual separation into generation, transmission, and distribution is insufficient. In an electricity market, the transmission wires and the pool dispatch are distinct essential facilities.



The special conditions in the electricity system stand as barriers to an efficient, large-scale bilateral market in electricity. A pool based market model helps overcome these barriers. But close inspection will show that the two approaches have much in common. The immediate need is to define further the problems and craft workable solutions.

The independent system operator provides a dispatch function. Three questions remain. Just say yes, and the market can decide on the split between bilateral and coordinated exchange.

- **Should the system operator be allowed to offer an economic dispatch service for some plants?**

The alternative would be to define a set of administrative procedures and rules for system balancing that purposely ignore the information about the costs of running particular plants. It seems more natural that the operator consider customer bids and provide economic dispatch for some plants.

- **Should the system operator apply marginal cost prices for power provided through the dispatch?**

Under an economic dispatch for the flexible plants and loads, it is a straightforward matter to determine the locational marginal costs of additional power. These marginal costs are also the prices that would apply in the case of a perfect competitive market at equilibrium. In addition, these locational marginal cost prices provide the consistent foundation for the design of a comparable transmission tariff.

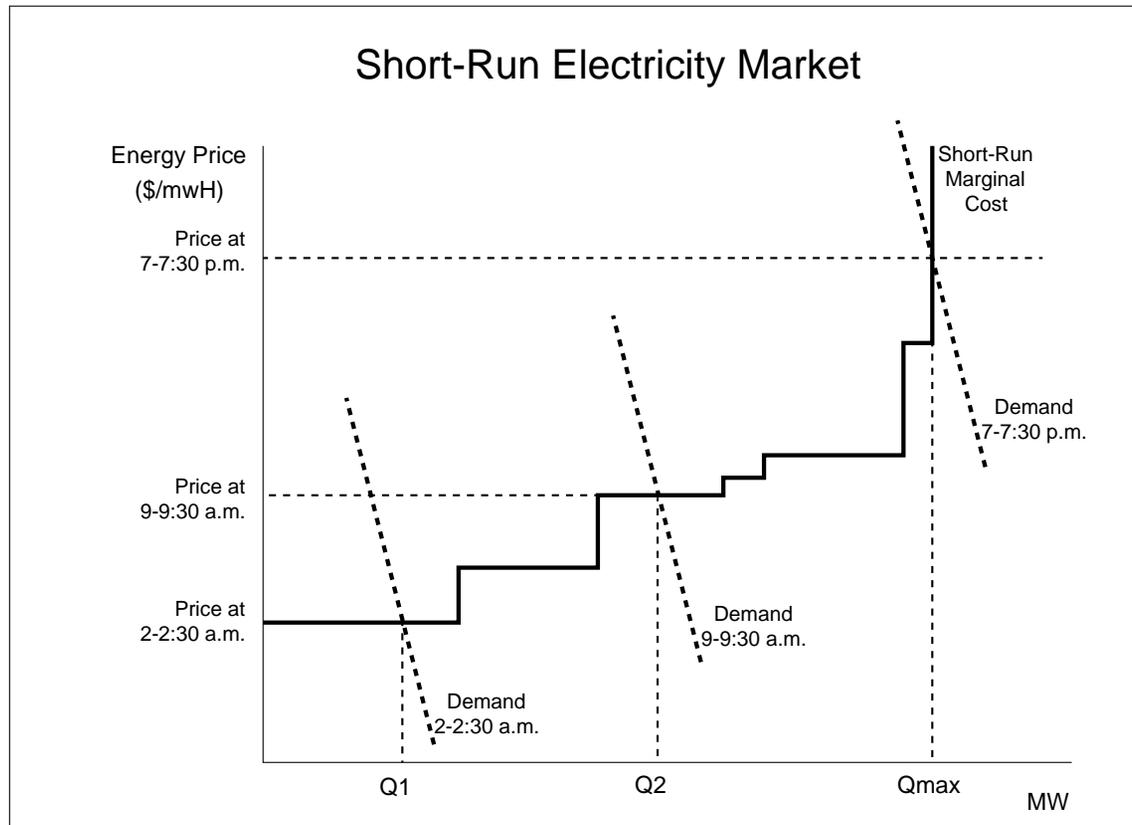
- **Should generators and customers be allowed to participate in the economic dispatch offered by the system operator?**

The natural extension of open access and the principles of choice would suggest that participation should be voluntary. Market participants can evaluate their own economic situation and make their own choice about participating in the operator's economic dispatch or finding similar services elsewhere.

ELECTRICITY MARKET

Pool Dispatch

An efficient short-run electricity market determines a market clearing price based on conditions of supply and demand. Everyone pays or is paid the same price.



The new electricity market will follow new principles. Examples of basic principles that have emerged with special importance in the case of electricity include:

- **Separate Ownership from Use of Essential Facilities:** Everyone should have equal access to and use of essential facilities, particularly transmission, with the rights of ownership limited to compensation consistent with opportunity costs in a competitive market;
- **Separate Physical Delivery from Financial Transactions:** Market institutions and operations should allow for financial transactions that implement bilateral commercial arrangements while separately coordinating the spot market interactions of physical delivery of electricity in the transmission network;

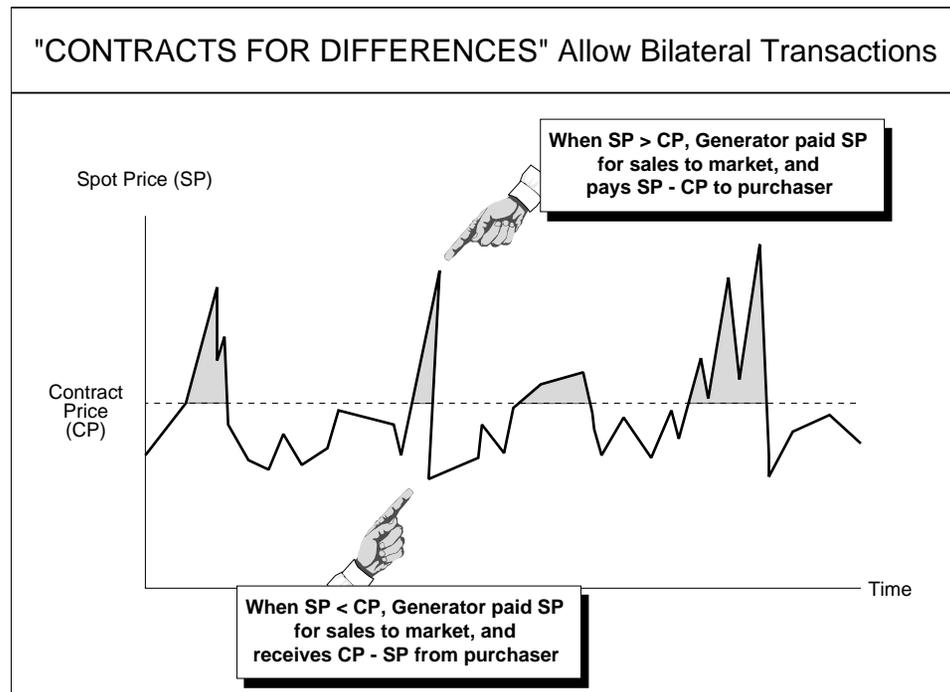
With a competitive spot market, separation of physical delivery from financial transactions allows contracts to evolve that reference the spot market. These "Contracts for Differences" recognize that delivery takes place in the spot market, and price agreements can be honored through a simple settlements process:

- **Spot Price Below Contract:** Customer uses savings to pay difference to the generator.
- **Spot Price Above Contract:** Generator uses profits to pay difference to customer.

ELECTRICITY MARKET

Contracts For Differences

With an efficient wholesale market available, a "Contract for Differences" can provide generators and purchasers the ability to execute bilateral contracts without requiring physical control. Contract imbalances in production or use settle automatically at the market price.



A system coordinator or pool is required in support of a competitive market. The basic pool functions will always be there, somewhere:

"The importance of effective Pooling arrangements in a competitive [Electric Supply Industry] cannot be overstated. The Pool provides:

- a source of firm back-up and top-up power to support either generators or suppliers offering long-term contracts to final customers; without access to a Pool firm power could only be offered by generators owning a portfolio of plant and to the extent that firm power is a necessary requirement of consumers the competitiveness of both the generation market and the final supply would be limited;
- a ready market for generators unable to sell their power under contract or wanting a market for spill or excess production;
- a reference price for long or short-term contracts struck outside the Pool which provide participants with price stability not immediately available inside the Pool;
- a reference price to be used in signalling the optimal development of generation and transmission capacity on the system.

In addition, of course, the Pool provides the traditional means by which generation costs can be minimized through merit order operation and the aggregation of reserve requirements."

(J. Moen, "Electric Utility Regulation, Structure and Competition. Experiences from the Norwegian Electric Supply Industry (ESI)," Norwegian Water Resources and Energy Administration, NVE, Oslo, April 1994, p. II-5.)

RETAIL ACCESS

The old model of retail wheeling envisions customers "leaving" the local utility to arrange separately to purchase their power from a different supplier who uses different generating units. In the context of a competitive market, the old model of retail wheeling is revealed as a fiction.

- **Customers Never Leave.** The customers remain attached to the same wires, over which the power flows.
- **Power Never Moves.** To the extent that there is an efficient wholesale market, the same power plants run and there is no change in the pattern of power flows.
- **Wheeling Dollars Not Electrons.** The real movement with conventional retail wheeling is in the distribution of the dollars. Often suggested as a criticism, seen properly this can be its great strength.

Both the fear and attraction of retail wheeling follow from the implications of the elaborate fiction under which some customers will be able to leave the local utility. Opponents of retail wheeling argue for a continuation of traditional cost-of-service regulation for all customers to avoid bypass of the distribution system.

Customer choice through *Efficient Direct Access* builds on the reality of a competitive market with open access and comparability of service. It provides real customer choice through access to the wholesale market consistent with jurisdictional boundaries and incentives for efficient decisions.

- **Arm's Length Spot Price.** The wholesale market will develop a transparent arm's length spot price. It may be through hubs--such as in natural gas--or a pool, or some mixture of a bilateral and a pool-based market. The more efficient the wholesale market, the better, but some price will appear against which buyers and sellers can trade.
- **Time-of-Use Tariff.** All customers remain with the distribution utility under traditional cost-of-service rate principles. However, customers have a time-of-use tariff with the energy component set to the observed arm's length spot price. This approach is related to "net back" pricing principles familiar from other regulatory settings and as advanced by many others (Moskovitz).

With such time-of-use rates, customers have real access to the wholesale market. They can enter into contracts for differences with generators, to provide whatever security or flexibility that they are prepared to pay for in the market. This moves the obligation to invest in commodity energy from regulated monopoly to a competitive market.

- **Commodity Energy Investments Left to Market.** Regulated utilities stop making investments in new long-term energy or generation capacity commitments under cost-of-service regulation.

Efficient Direct Access requires only a competitive wholesale market and a modest rate innovation. This approach to direct access is functionally equivalent to "physical direct access" but easier to implement. **Efficient Direct Access (aka "virtual direct access" by the CPUC):**

- **Changes No Jurisdiction.** Customers never leave the local utility. Formally the utility buys from the wholesale market and resells at the spot price. There are no changes in cost-of-service principles or formal entry into the FERC regulated wholesale market.
- **Requires No New Legislation.** State regulatory authorities have long set the time-of-use tariffs. The extension to using the arm's length spot price is important, but it is a difference only in a small detail that should raise no controversy.
- **Strands No Assets.** All customers remain under the cost-of-service tariff. Decisions on rates and cost recovery can proceed as before, independent of the existence of Efficient Direct Access and customer choice.
- **Abandons No Worthy Programs.** Whatever can be done under traditional cost-of-service regulation--limited by the inevitable pressures of a more open wholesale market--can be continued under Efficient Direct Access. Universal service support, investments in energy efficiency, and subsidies for renewable and other environmentally preferred alternatives could be made when justified, and included in the cost of service applied to all customers separate from the time-of-use energy charges.

Efficient Direct Access provides real benefits consistent with the many other goals of the partially competitive and partially regulated electricity market. **Efficient Direct Access:**

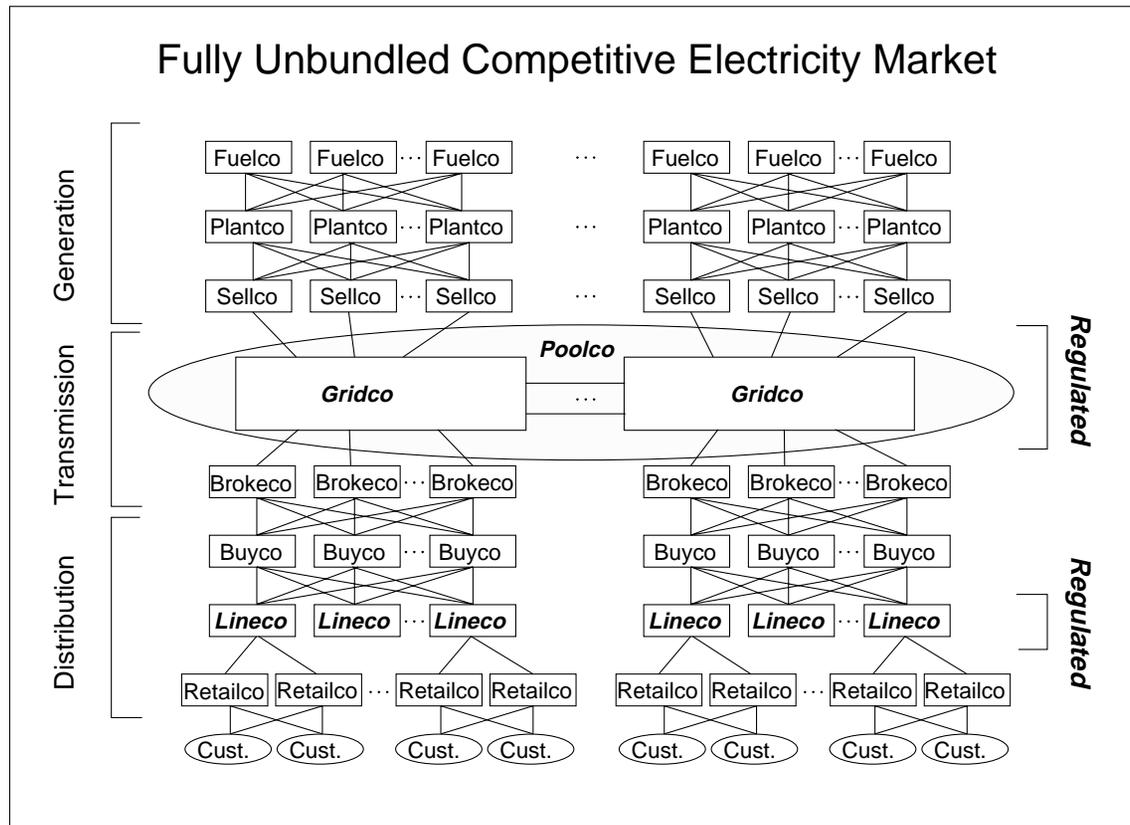
- **Provides Customer Choice.** Customers who wish to make long-term arrangements for contracts with generators have full freedom through the mechanism of contracts for differences, which conform to the reality of the electricity market.
- **Reduces Regulatory Demands.** Central planning for all commodity resource procurement can move to the decentralized decisions of the competitive market.
- **Supports Efficient Investment.** Since payment for sunk costs or other mandated programs is independent of the source of power or the arrangements under long-term contracts, the incentives support efficient investment in new facilities and services for commodity electricity.
- **Gives Utilities an Exit Strategy.** Since there is no need to delay Efficient Direct Access to allow for recovery of sunk costs, regulated utilities can immediately stop investment in new regulated generation commitments, redefining the obligation to serve as the obligation to deliver.

Efficient Direct Access need not disrupt the market, and retail wheeling can be abandoned as a fiction from the past, like the contract path for transmission. Attention should return to the development of the wholesale market and regulation of the remaining monopoly elements.

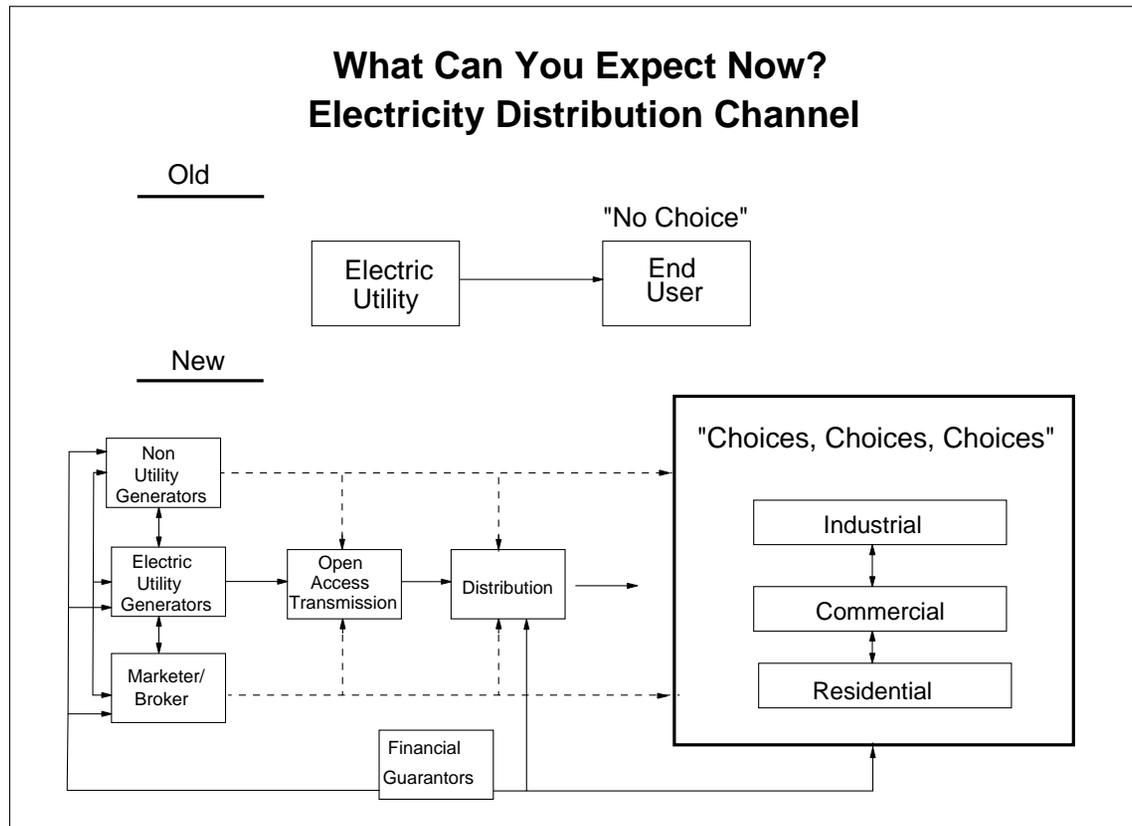
ELECTRICITY MARKET

Fully Unbundled

The degree of unbundling and competition, whether wholesale or retail, is a policy choice. In designing a competitive market, a focus should remain on providing nondiscriminatory, equal access to the essential facilities.



The future electricity market will replace vertical monopolies with unbundling and choice.



TRANSITION COSTS

In a competitive market, price is set not by average cost but by the equilibrium in the market. The difference between the competitive market value and the regulated book value is the value of the potential stranded asset. For many companies, the value of the total potential stranded assets is larger than the book equity of the firm.

- **Power Plants.** In the competitive world, the price of the power from expensive power plants is determined in the wholesale market for the commodity energy output. In a market like that of many regions of the U.S., where there is excess capacity and many available sources of power supply, the market price may be relatively low, too low to support the historical capital costs of the existing power plants.
- **NUG Contracts.** Nationwide, non-utility generators (NUGs) have responded vigorously to the PURPA legislation of 1978 and to subsequent state legislative and regulatory initiatives. The majority of new generation built in recent years or currently planned new capacity is from NUGs. Many of these contracts include prices that are well above the marginal cost of energy in the current market.
- **Other Regulatory Assets.** Regulatory assets are accounting concepts; their value rests on the strength of a state regulatory decision to allow future recovery of certain costs from ratepayers. The assets are on the books, but require regulation to retain their value. Examples include capitalized demand-side management expenditures, deferred taxes and capitalization of retirement obligations.

One basis for a normative theory of compensation after legal transition emphasizes the incentive effects on investment.¹ Should investors be compensated for the effects of the transition, or should they bear the risk of gains and losses?

- Under the assumptions of a beneficial change in government policy and no independent cost to the credibility of government, the general case suggests that compensation would create inefficient incentives and should not be provided as a matter of policy.
- The risks should be matched with the rewards. If investors are not taxed for gains, but are compensated for losses, the imbalance of incentives would lead to overinvestment.
- The basic analysis and argument is similar to the case of moral hazard and insurance. Should the government provide free or subsidized flood insurance for people who choose to live in flood plains?
- Exceptions may be made in transitions to restrain government behavior or preserve government credibility. This leads to the common practice of "grandfathering" many new tax provisions or other regulatory requirements.

¹ L. Kaplow, "An Ex Ante Perspective on Deregulation, Viewed Ex Post," Resources and Energy, Vol. 15, 1993, pp. 153-173.

The regulatory transition in the electric utility industry differs from the general case in a number of important conditions. Different facts can produce a different answer.

- **Symmetry.** For many of the assets at risk, there is an inherent lack of the symmetry assumed in the general case. Under regulation, customers receive the benefits of low cost assets. Should customers be able to elect to avoid the high cost assets? In the presence of asymmetric cost disallowances, the cost of capital theory is inconsistent with cost of service regulation.
- **Choice.** The general case assumes that investors have discretion regarding investment commitments. But with the obligation to serve, managers of regulated companies may not have discretion, and only incremental investors have the choice to invest new funds.
- **Contracts.** Implicit and explicit promises have been made by regulators to accept customer responsibility but defer recovery of certain costs. These regulatory assets can be recovered only through monopoly activities under regulatory control and approval.
- **Ownership.** Under regulation, legal ownership may differ from the ownership of the beneficial interest in the assets. Customers, or regulators acting on their behalf, may be seen as the "owners" consistent with the theory of legal transition and compensation.

The allocation of sunk costs has important equity effects--cutting up the pie--but the allocation can induce economic responses that have costs in that they actually change the size of the pie. Everyone shares an interest in expanding the size of the pie. Examples of real costs from the allocation of sunk costs include:

- **Transition Overhead Costs.** The costs of this meeting and the many others underway.
- **Price Distortions.** With excess capacity and sunk costs allocated to customer energy prices, average costs will be higher than marginal costs. With prices too high, there is too little consumption of electricity.
- **Bankruptcy and Financial Health.** Managers faced with the potential bankruptcy will go to great lengths to avoid the final step, often at the expense of efficiency and quality of service. Some argue that the after effects of bankruptcy will leave financially weaker companies who cannot provide efficient electricity services.
- **Credibility of Government.** Providing stable rules for the market is an important responsibility of government. A pattern of random or capricious change undermines credibility for all markets, including the electricity industry.
- **Transition Cooperation.** Creating an efficient, open access market that allows for increased competition in electricity is not easy and will require the cooperation of regulators, customers, new entrants and existing utilities. If the allocation of sunk costs is not settled, strategic behavior will both the transition process and destination.

In part, the public policy motivation for developing a transition strategy depends on the potential magnitude of these costs of allocating sunk costs. Preliminary review suggests the priorities:

- **Transition Overhead Costs.** Meetings and other overheads are comparatively cheap.
- **Price Distortions.** With relatively low elasticities of demand given the existing stock of electricity-using equipment, the short-term price distortions are small. This is a frequent result in economic analyses of the "deadweight" loss of short-term mispricing.
- **Bankruptcy and Financial Health.** Pre-bankruptcy costs could be large, but post-bankruptcy costs tend to be small or non-existent. This is a common argument for quick reorganization of troubled companies.
- **Credibility of Government.** The potential impact is large, but there is a familiar public goods problem: the independent effect on electricity is likely to be difficult to estimate.
- **Transition Cooperation.** The experience in railroads and other industries suggest that this cost could be very large. Managers at many companies are "mesmerized" by the stranded asset problem. Reallocation of the pie may be far more important to each individual interest group, even though collectively the disputes will delay and constrain the benefits of a more efficient electricity market.

The recovery of sunk investments that are stranded assets is a key issue in the transition to a competitive generation market.

- If stranded asset costs are large and recovery is not envisioned, any smooth transition to a deregulated generation market would be thwarted and costs increased.
- The transition to a competitive generation market is not a zero sum game. The greater the costs savings that accompany the transition to competition, the easier the transition to a competitive market will be for customers, regulators, and utilities. If operating costs fall, rates can be lower than under current regulatory projections.
- Recovery of sunk costs need not forestall a transition to a more competitive market. The goal here is to design recovery mechanisms that are compatible with competition.
- If stranded costs are to be recovered in a more competitive market, the costs must be collected through a monopoly segment. The most direct mechanism is through access fees for connection to the wires, or a functional equivalent.

WHOLESALE MARKETS AND TRANSMISSION RIGHTS

I Can Get It for You Retail!

This is Easy

I Can Get It for You Wholesale!

This is the Hard Part

Efficient markets depend upon well-defined and meaningful property rights.

"The Problem of the Commons"

Electricity markets confront an unusual combination of difficulties that have some of the features of other previously regulated markets, and some important differences. The transmission network is an essential facility for which it is difficult to define property rights, without which there will be overuse of the commons. There is a (very) large network externality problem. The more options we give market participants, the greater the pressure created by these externalities. The solution to the "network externality" depends critically on getting the pricing rules right.

This is not an easy problem.

It is important.

The public debate is noisy.

But there is a relatively simple solution.

The FERC is moving in this direction, beyond Order 888.

The goal is worth the effort.

Electricity restructuring requires open access to the transmission essential facility. A fully decentralized competitive market would benefit from tradable property rights in the transmission grid. However, the industry has never been able to define workable transmission property rights:

"A primary purpose of the RIN is for users to learn what Available Transmission Capacity (ATC) may be available for their use. Because of effects of ongoing and changing transactions, changes in system conditions, loop flows, unforeseen outages, etc., ATC is not capable of precise determination or definition. "

Comments of the Members of the PJM Interconnection, Request for Comments Regarding Real-Time Information Networks, Docket No. RM95-9-000, FERC, July 5, 1995, p. 8.

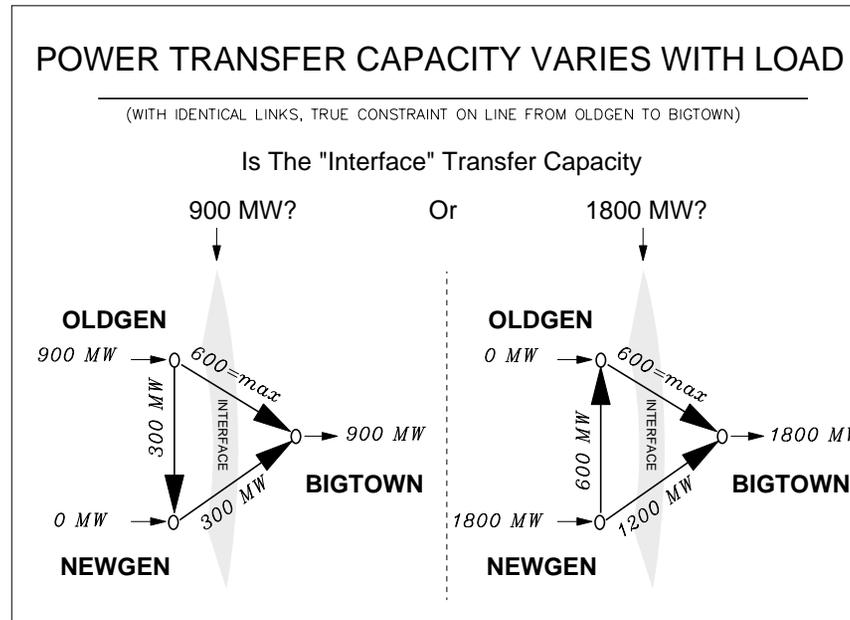
The difficulty is fundamental.

- **Contract-Path Fiction:** Electric power does not follow a simple "contract path" through the network. Power flows throughout the network, creating complex interactions that give rise to significant "network externalities" and the failure of property rights.
- **Physical versus Financial Approaches:** Physical property rights, to match with physical flows, have proven to be elusive. There is an alternative through a mixture of physical flows and financial contracts that can internalize the externalities and create the equivalent of property rights in the transmission system.

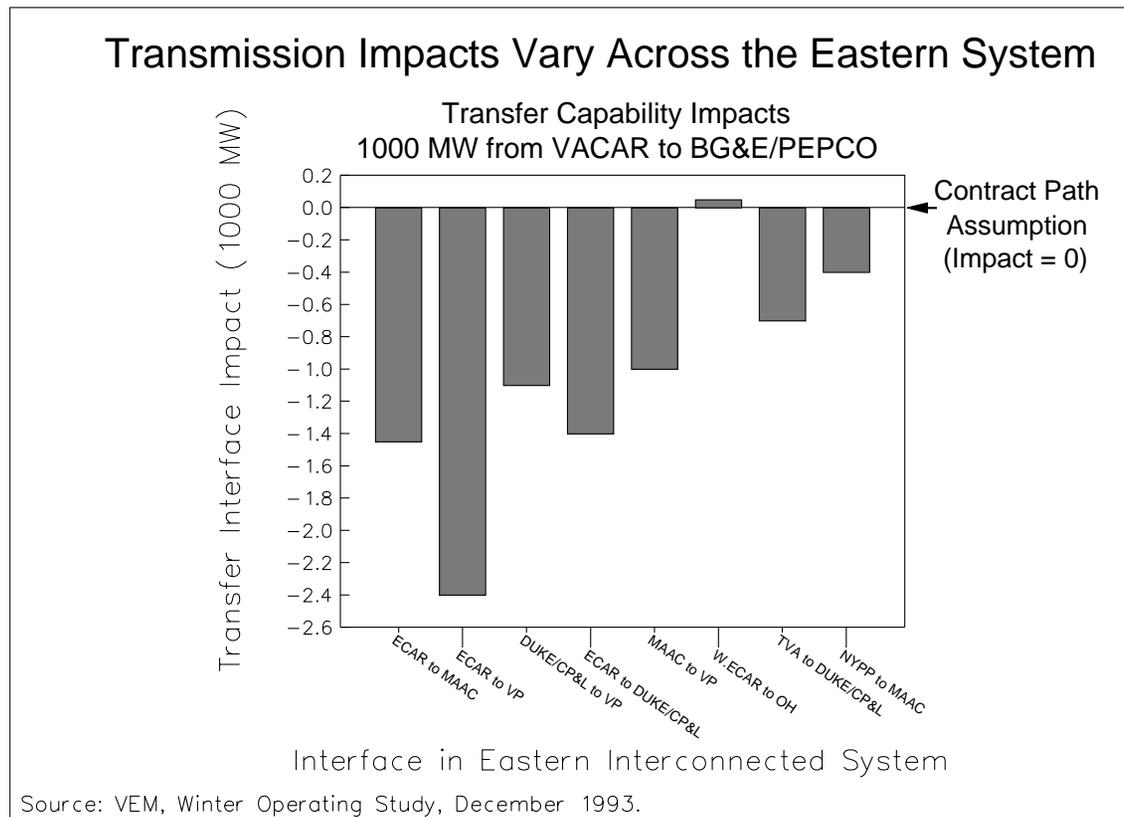
A workable definition of "Available Transmission Capacity" would be radically different from the notional physical right that is the unbuilt foundation of the present regulatory approach.

Electric transmission network interactions can be large and important.

- Conventional definitions of network "Interface" transfer capacity depend on the assumed load conditions.
- Transfer capacity cannot be defined or guaranteed over any reasonable horizon.



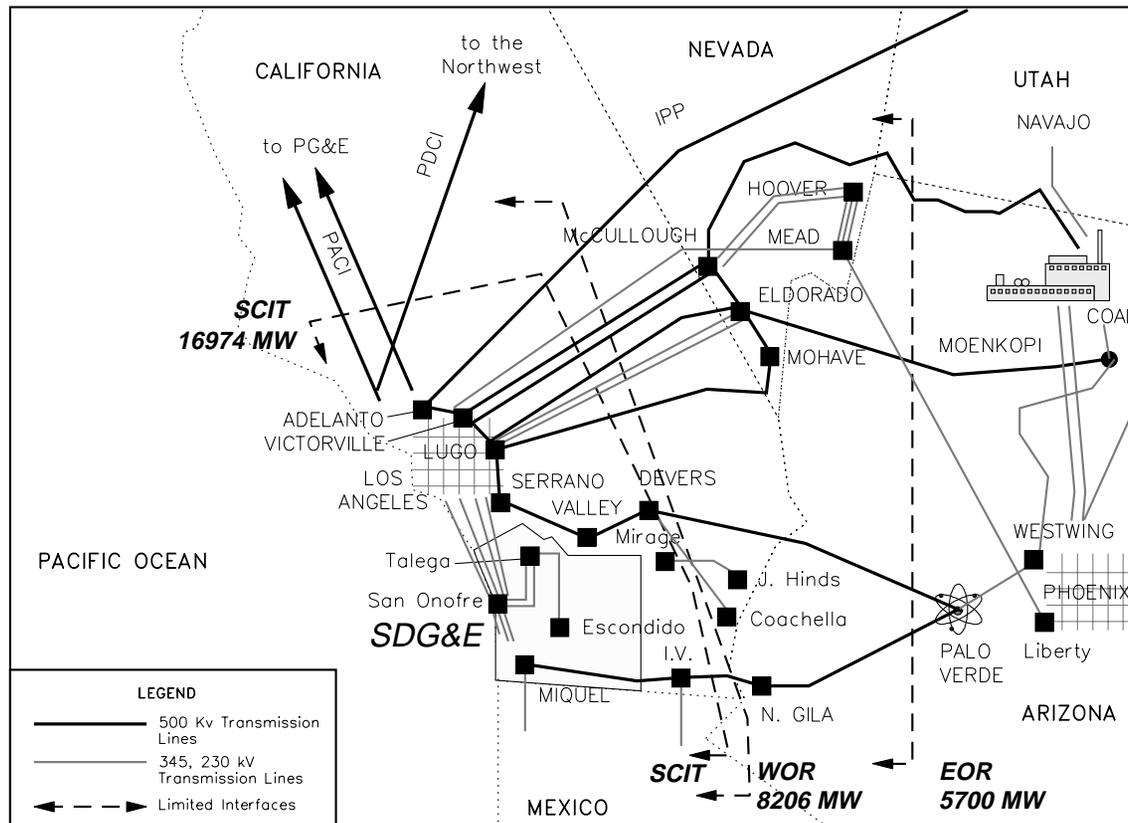
There is a fatal flaw in the old "contract path" model of power moving between locations along a designated path. The network effects are strong. Power flows across one "interface" can have a dramatic effect on the capacity of other, distant interfaces.



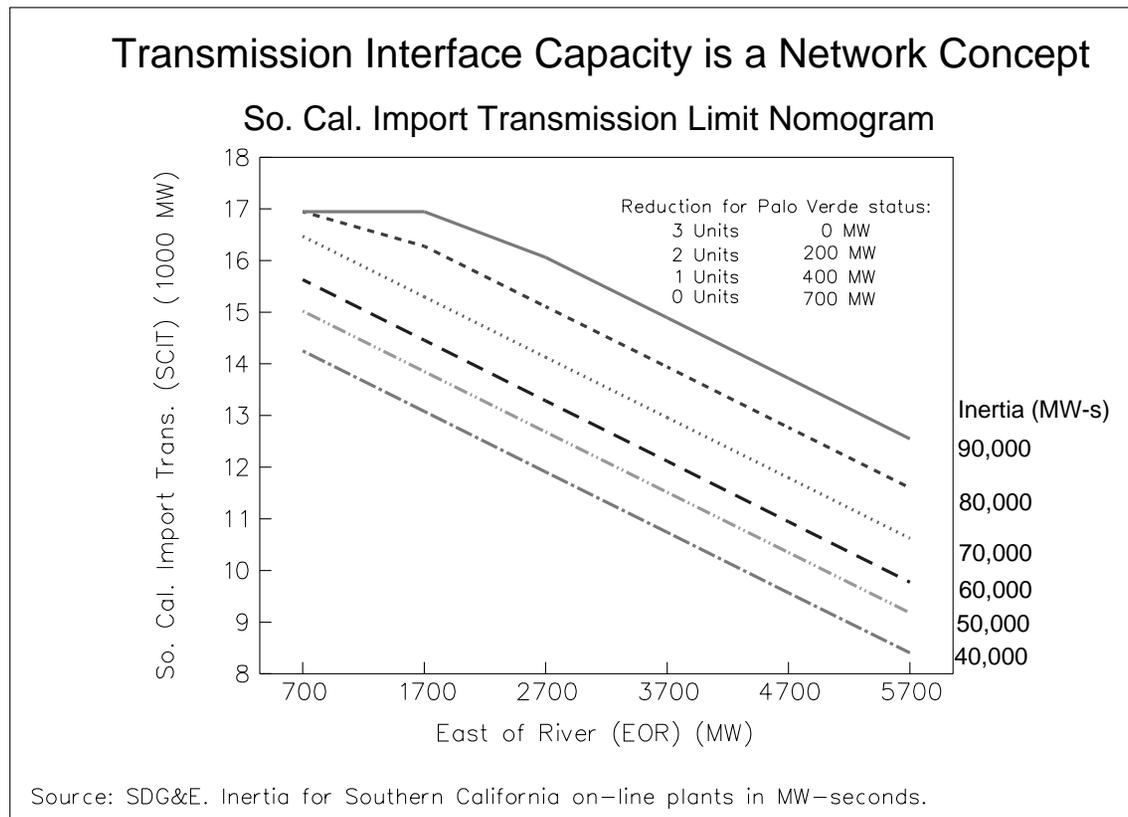
NETWORK INTERACTIONS

Loop Flow

The strong network effects apply in most, or all interconnected grids. In southern California, for example, there are important interfaces with maximum limits that cannot be achieved simultaneously. Complex "nomograms" summarize the simultaneous constraints. (see next page)



The SCIT "nomogram" for southern California illustrates the strong interdependencies of network flows and the breakdown of the contract path model. Management of this system requires a network perspective and a network coordinator, here Southern California Edison.



The role of loop flow and its effects in the system needed to support a competitive market are important matters. The problems are fundamental in the presence of customer choice and competition. The principal implications of the ubiquitous and important effects of loop flow include:

No Property Rights. There is no workable system of property rights governing use of the transmission grid that would support a fully decentralized electricity market.

No Definition of "Available Transmission Capacity." It is not possible to define available transmission capacity (ATC) for a transmission interface without knowing everything about the use of the network at the time.

No Separation of Transmission Pricing and Spot Market. The opportunity cost of transmission depends critically on the marginal costs of power at different locations, and these costs are determined simultaneously with the dispatch and the spot market.

No Escape from the Network Externalities. There is a fundamental externality in transmission use, and decentralized markets do not deal well with externalities.

Two broad approaches suggest themselves for dealing with the problem of the commons associated with network externalities in a manner compatible with a competitive generation market.

- **Monopoly Management with Incentive Pricing:** Treat transmission like a large "black box" run by a monopoly that takes on the 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 is pursued in part in England and Wales. It results in a very powerful monopoly with the familiar problems of finding the "right" incentive regulation. It works in theory, but does it work in practice?
- **Market Mechanisms with Tradeable Transmission "Rights":** Create and allocate a set of transmission "rights" that would be used by market participants to match the actual flow of power or be traded in a secondary market. This is the approach that dominates thinking in the United States and stands behind the policy at the Federal Energy Regulatory Commission and proposals across the country. The central problem is in the impossibility of defining the available physical transmission capacity that would accompany future dispatch requirements. Can it work in both theory and practice?

The pool-based, short-term electricity market provides the foundation for building a system that includes tradeable transmission "rights" in the form of transmission congestion contracts. Coordination through the pool is unavoidable, and the 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.

The Federal Energy Regulatory Commission (FERC) has proposed a system of point-to-point transmission capacity reservations that would govern use of the network. The emphasis is on specific performance and matching use to rights. An alternative contract network perspective would emphasize financial contracts for settlement relative to the actual use of the system. Under competitive market assumptions, the two approaches would be functionally and financially equivalent, although they appear different in their implementation. Exploring the connection between the alternative perspectives illuminates the challenges and provides another, easier path to the objective.

Capacity Reservation Open Access Transmission Tariffs Categories for FERC's Fifteen Proposed Principles²

- | | |
|-----------------------------------------|--------------------------------------------------|
| 1. Purpose of reservation service | 9. Cost allocation and pricing |
| 2. Basic service concept | 10. Standardized products and priority protocols |
| 3. Use of capacity reservations | 11. Service modifications |
| 4. Applicability to all customers | 12. Scheduling flexibility |
| 5. Application of penalties for overuse | 13. Reassigning reservations |
| 6. Standard for accepting nominations | 14. Opportunity Cost Pricing |
| 7. Non-firm transmission service | 15. Planning obligation |
| 8. Open season for new facilities | |

² Federal Energy Regulatory Commission, "Capacity Reservation Open Access Transmission Tariffs," Notice of Proposed Rulemaking, RM96-11-000, Washington DC, April 24, 1996, extract of pp. 20-25.

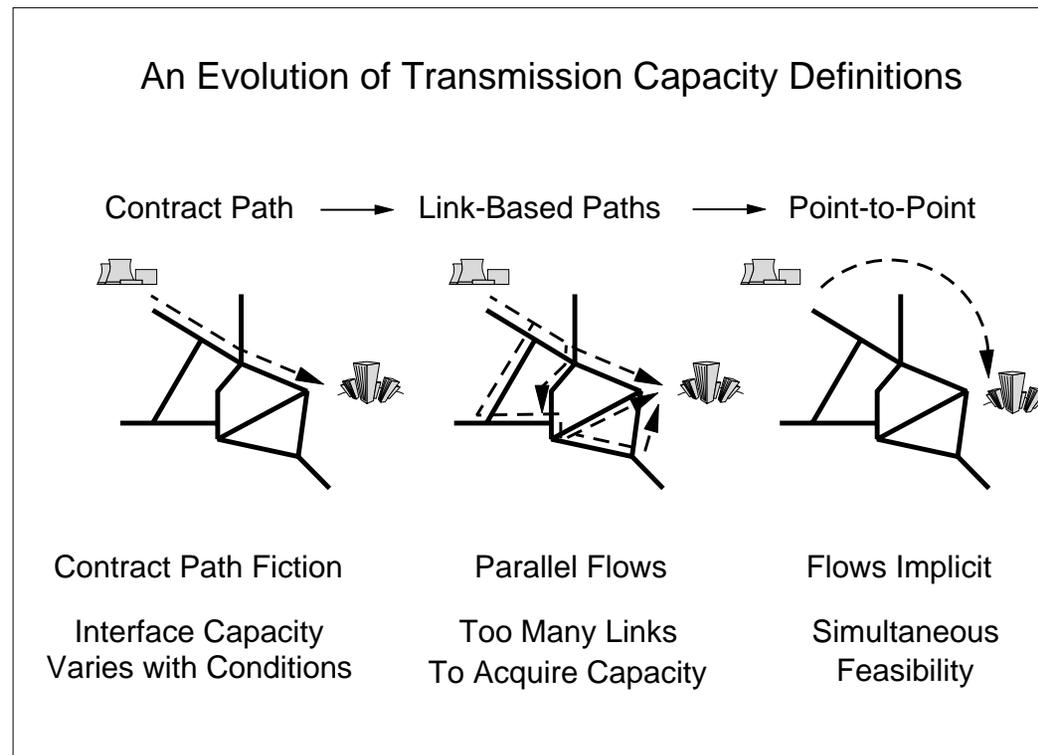
The FERC proposal for point-to-point transmission capacity reservations goes beyond the contract path and provides a meaningful definition of transmission "capacity."

2. Basic service concept

All firm transmission service would be reserved, and all reserved service would be firm service. Reservations of transmission capacity should permit the customer to receive up to a specific amount of power into the grid at specified [Points Of Receipt], and to deliver up to a specific amount of power from the grid at specified [Points Of Delivery], on a firm basis. Individual PORs and PODs need not be "paired" with each other. The customer's capacity reservation would be the higher of either (1) the sum of the reservations at all PORs or (2) the sum of the reservations at all PODs. All nominations for a capacity reservation would be evaluated using the same standard; for example, the utility could apply a feasibility criterion that states that the grid must be able to accommodate the scheduled use of all capacity reservations simultaneously.

This definition sidesteps the complication of identifying the path through the network. The feasibility criterion that the collective reservations must be simultaneously feasible is well-defined. This point-to-point approach to defining transmission service has intuitive appeal and lends itself to a practical implementation.

The movement to point-to-point capacity reservations avoids the pitfalls of earlier approaches. The contract path is a fiction with no definition of capacity. Acquiring rights for the flows on every line would confront the problem of too many links. Point-to-point rights replace a single definition of transmission capacity with the test of simultaneous feasibility. There will be many different capacity reservation configurations that would be simultaneously feasible.



Under the FERC proposal, point-to-point rights would be applied to match the use of the transmission grid:

3. Use of capacity reservations

A customer with a capacity reservation could use the reservation to deliver or receive any type of power product (such as firm or non-firm power). That is, use of the capacity reservation should not be restricted to particular power products. Any such restriction would be inconsistent with unbundling. This would allow the capacity reservation holder to combine transmission and power products in any way that satisfies its needs.

In practice, the patterns of load and generation, and the resulting demand for transmission service, will be changing, rapidly and significantly. The location of capacity reservations needed could differ from hour to hour, or even from minute to minute. Hence, in applying this point-to-point approach to operation of the transmission system, there must be a mechanism that allows for trading and reconfiguration of capacity reservations. Some such trading mechanisms are envisioned as critical elements of the FERC proposal.

The FERC recognizes that limiting trading to movements between a few pre-defined receipt and delivery points would substantially reduce the effective capacity of the transmission grid, and would in no way reflect the practice involved in traditional utility management of the flow of power. Hence, the FERC proposal calls for the ability not only to transfer ownership of existing reservations but also to reconfigure the reservations:

11. Service modifications

Customers with a capacity reservation would be allowed to modify their capacity reservations at no additional charge if the modification can be accommodated without infringing upon any other firm capacity reservations. Modifications should not result in the customer's capacity reservation being exceeded. Modifications could include reallocation among the customer's already specified receipt and delivery points or reallocation from existing to new receipt and delivery points.

The step of requiring a "reallocation from existing to new receipt and delivery points" greatly expands the scope and importance of the proposed capacity reservation system. There is a complex relationship among the collection of feasible capacity reservations. It may be that a 1 MW reservation relative to points A and B could be exchanged for a 2.5 MW reservation between C and D "without infringing upon any other firm capacity reservations." The exchange ratio is not one-to-one. Furthermore, the exchange ratio is not fixed in advance. The exact exchange ratio would depend on many factors, including the current status of all other capacity reservations and all other exchanges that are requested.

Coordination of the reconfiguration process will require a criterion for selecting among and matching the many possible exchanges. FERC proposed a market based criterion embedded in the explicit recognition of opportunity cost pricing for actual use of the capacity reservations:

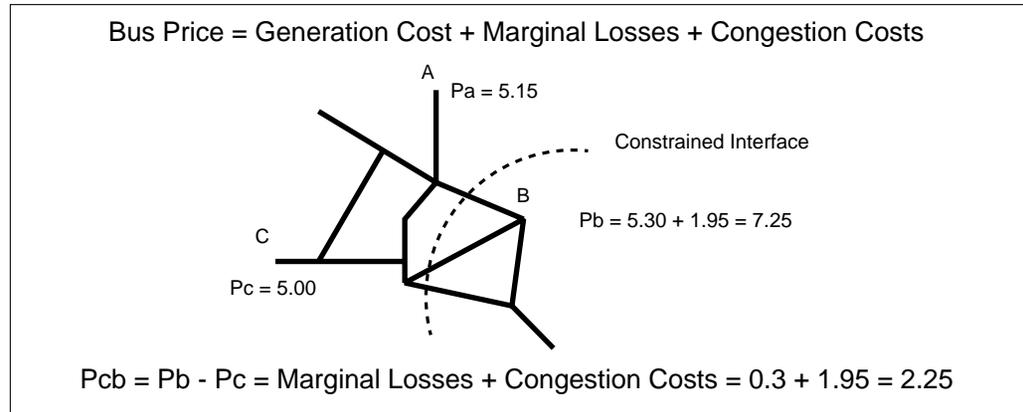
14. Opportunity Cost Pricing

Opportunity cost pricing would still be an option under a capacity reservation service. Under a CRT, a holder of a capacity reservation would not pay opportunity costs for use of its own capacity when the utility encounters a transmission constraint; instead, it would be eligible to receive opportunity cost payments if it did not use its full capacity reservation across the constrained interface. In contrast, a customer seeking a capacity reservation or using non-firm service might have to pay opportunity costs.

This provision goes beyond the usual recognition that competitive market pricing will reflect opportunity costs, with equilibrium prices equal to marginal costs. In the FERC proposal, the opportunity cost pricing principle is extended to reservations that are implicitly service modifications arranged through the system operator. These service modifications will result in some customers not using their original capacity reservation and who would, in turn, "receive opportunity cost payments" and others would request new capacity reservations or service and "might have to pay opportunity costs." This important opportunity cost pricing principle provides a critical part of the puzzle by establishing a decision criterion for the system operator in balancing the complex trades that must occur in great volume and with great frequency if we wish to achieve an efficient outcome in the restructured electricity market.

A mechanism for hedging volatile transmission prices can be established by defining transmission congestion contracts to collect the congestion rents inherent in efficient, short-run spot prices.

NETWORK TRANSMISSION CONGESTION CONTRACTS



- DEFINE TRANSMISSION CONGESTION CONTRACTS BETWEEN LOCATIONS.
- FOR SIMPLICITY, TREAT LOSSES AS OPERATING COSTS.
- RECEIVE CONGESTION PAYMENTS FROM ACTUAL USERS; MAKE CONGESTION PAYMENTS TO HOLDERS OF CONGESTION CONTRACTS.
- TRANSMISSION CONGESTION CONTRACTS PROVIDE PROTECTION AGAINST CHANGING LOCATIONAL DIFFERENCES.

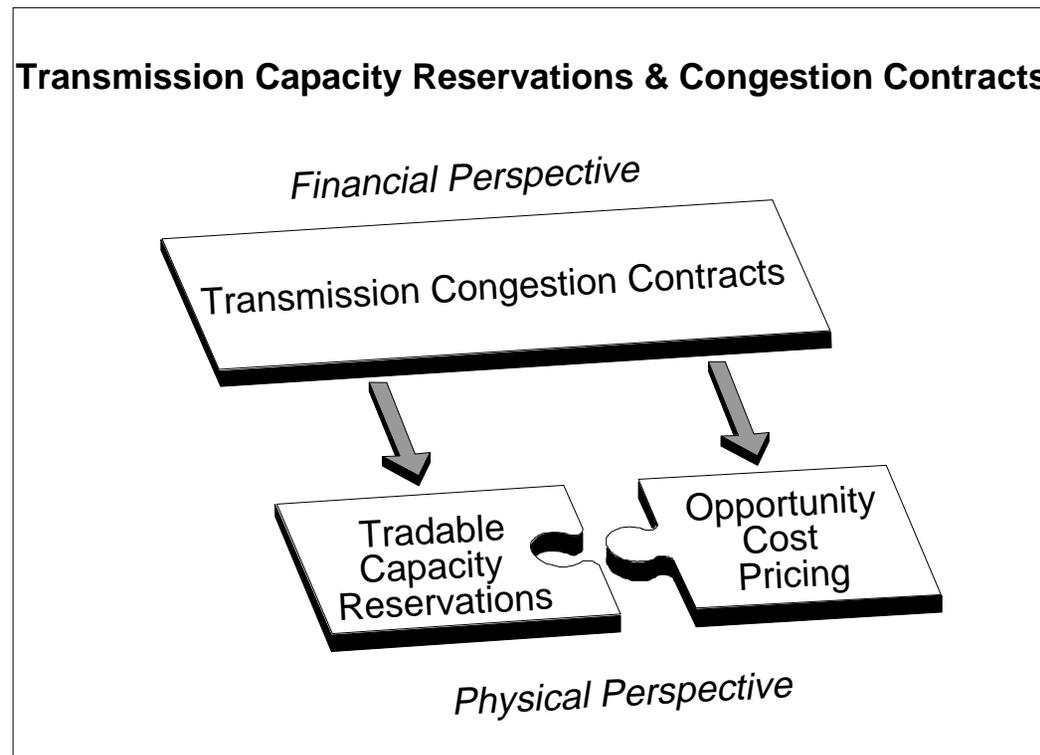
There are alternative interpretations of contract network rights defined as transmission congestion contracts, with various advantages for implementation and interpretation. For example:

- **Difference in Congestion Costs.** Receive the difference in congestion costs between two buses for a fixed quantity of power.
- **Purchase at a Distant Location.** Purchase a fixed quantity of power at one location but pay the price applicable at a distant location.
- **Dispatch with No Congestion Payment.** Inject and remove a fixed quantity of power without any congestion payment.

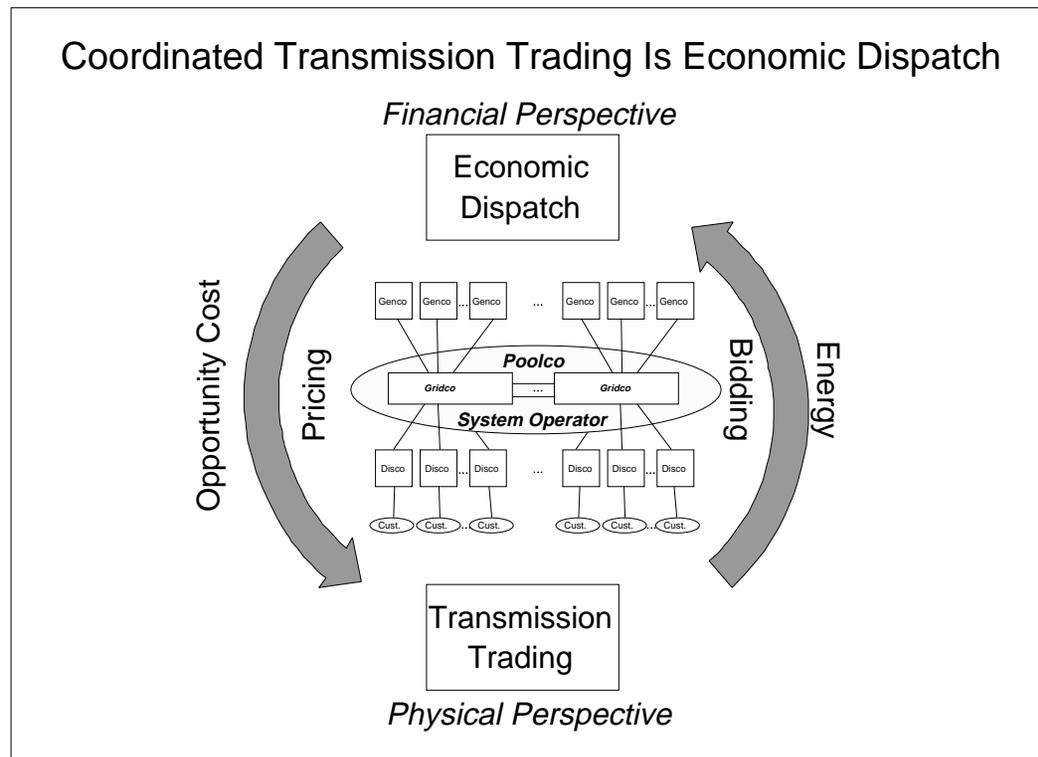
Excess congestion rents may remain after paying all obligations under the transmission congestion contracts. These excess rentals should not remain with the pool operator or grid owner, but could be distributed according to some sharing formula to those paying the fixed costs of the existing grid or along with the payments under transmission congestion contracts.

Many variants are possible, allowing great flexibility in developing and trading contracts. The contract network can allow great commercial flexibility while respecting the reality of the actual network in determining the locational prices.

With opportunity cost pricing and tradable transmission capacity reservations, any use of the system not matched by a reservation would be settled at opportunity cost prices determined by the final dispatch or actual use of the system. This physical perspective becomes indistinguishable from the financial perspective and transmission congestion contracts.



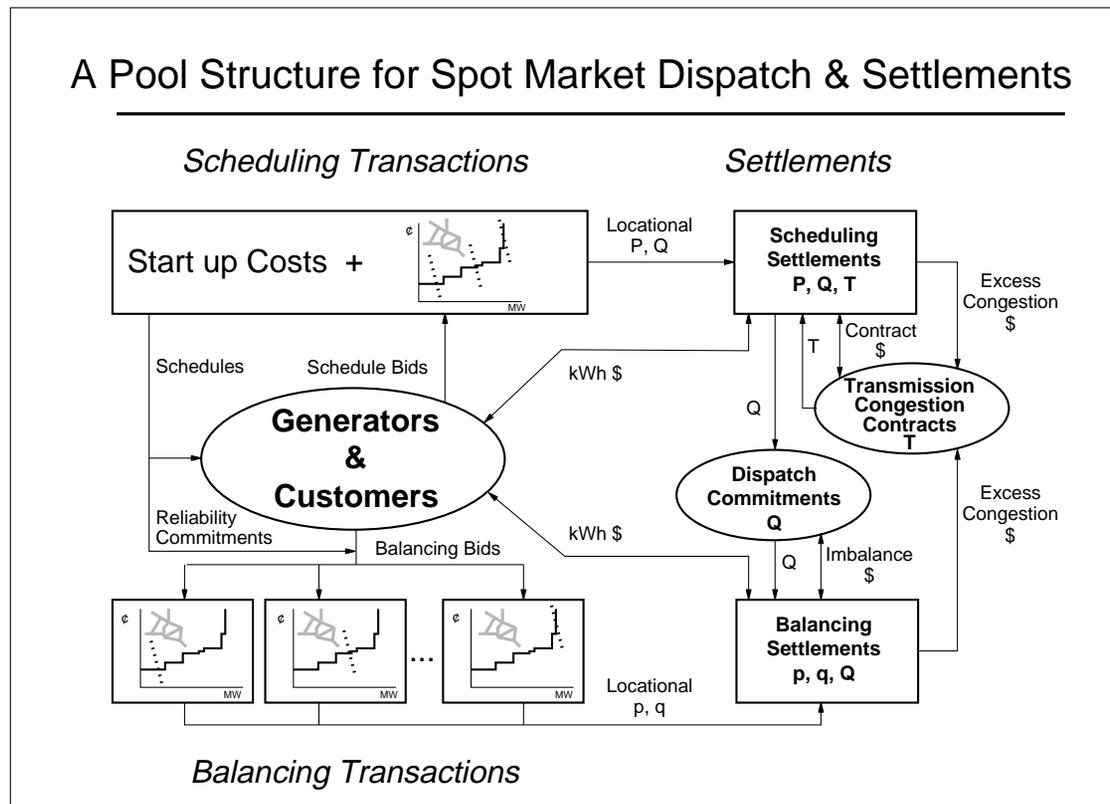
Trading of transmission capacity reservations must be coordinated through the system operator. With opportunity cost pricing, coordinated transmission trading becomes equivalent to economic dispatch. Under competitive conditions, there is a further equivalence between the physical and financial perspectives. The physical perspective may be more intuitive. The financial perspective is easier to implement and has lower transaction costs.



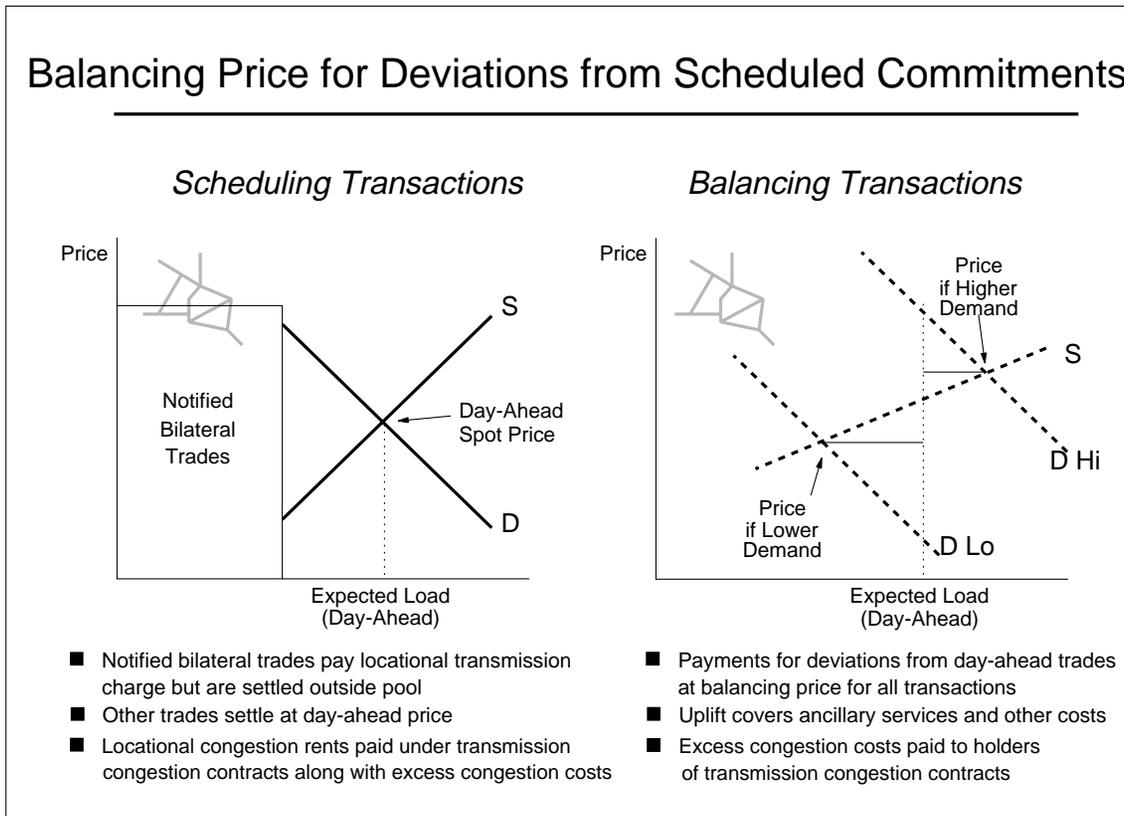
OPERATING RULES AND PROCEDURES

Bidding, Dispatch and Settlements

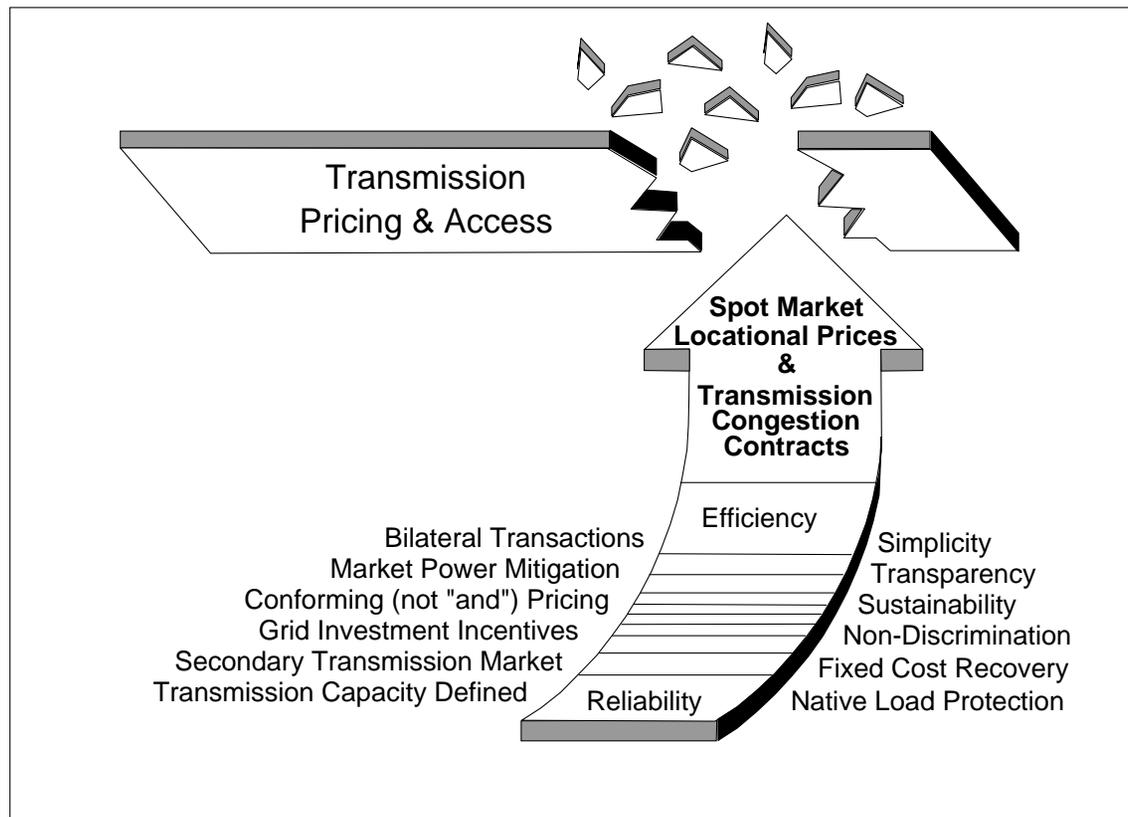
The pool-based market structure could include scheduling transactions to deal with unit commitment issues and balancing transactions for the final dispatch. Contract-network transmission congestion contracts would be valued for the scheduling transactions. Bidding for the scheduling transactions would determine final dispatch commitments.



The scheduled loads from the day-ahead bids establish the dispatch commitments for the spot market. Scheduling settlements are at the day-ahead price and final balancing settlements apply the imbalance price to deviations from the scheduled quantities.



The Contract Network model built on spot locational prices and transmission congestion contracts provides a consistent approach addressing a wide array of problems in providing transmission pricing and access rules for a competitive electricity market.



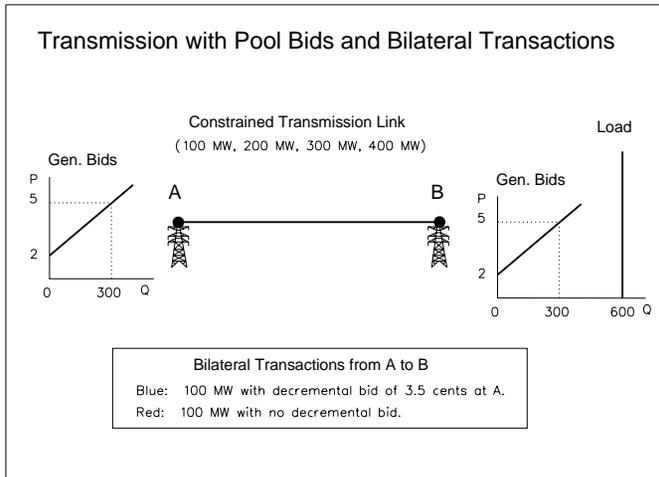
Appendix

Contract Network Background Materials

NETWORK INTERACTIONS

Locational Spot Prices

Locational spot prices define the opportunity cost of transmission usage. The pricing principles for a single line apply to complex networks, even though the physical flows would no longer follow a contract path. Pricing offers an alternative to physical property rights.



Power Flows and Locational Prices					
	Alternative Cases				
Link Capacity A to B	MW	400	300	200	100
Total Load at B	MW	600	600	600	600
Price at A	cents/kwh	4	3.5	3	2
Price at B	cents/kwh	4	5	6	7
Transmission Price	cents/kwh	0	1.5	3	5
Pool Generation at A	MW	200	150	100	0
Pool Generation at B	MW	200	300	400	500
Blue Bilateral Input at A	MW	100	50	0	0
Red Bilateral Input at A	MW	100	100	100	100

NETWORK INTERACTIONS

Locational Spot Prices (cont.)

Payments to the system operator are for pool purchases and sales, transmission, and imbalances. The net payments equal the costs of congestion.

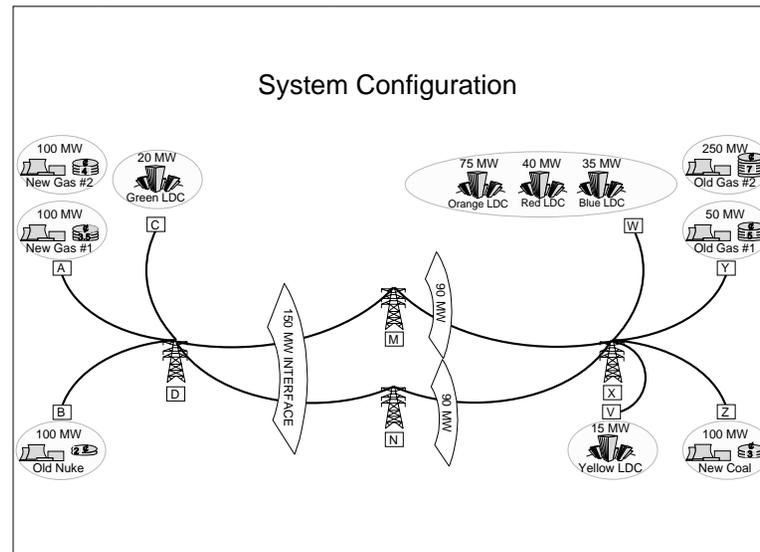
Power Flows and Locational Prices					
	Alternative Cases				
Link Capacity A to B	MW	400	300	200	100
Price at A	cents/kwh	4	3.5	3	2
Price at B	cents/kwh	4	5	6	7
Transmission Price	cents/kwh	0	1.5	3	5
Payments to Independent System Operator					
Pool Load at B (400 MW)	cents (x1000)	1,600	2,000	2,400	2,800
Contract Load at B (200 MW)	cents (x1000)	0	0	0	0
Generation at A	cents (x1000)	(800)	(525)	(300)	0
Generation at B	cents (x1000)	(800)	(1,500)	(2,400)	(3,500)
Blue Transmission	cents (x1000)	0	75	0	0
Blue Imbalance at B	cents (x1000)	0	250	600	700
Red Transmission	cents (x1000)	0	150	300	500
Red Imbalance at B	cents (x1000)	0	0	0	0
Net to Independent System Operator	cents (x1000)	0	450	600	500

NETWORK PRICING EXAMPLES

System Configuration

The examples assume a transmission system with the following characteristics:

- Generation available at four locations in the East (Y, Z) and West (A, B).
- Load in the East, consisting of the Yellow LDC at V and the Orange, Red and Blue LDCs at W.
- Load in the West, consisting of a Green LDC at C.
- Interface constraint of 150 MW between bus D and buses M and N.
- Thermal constraints of 90 MW between M and X and between N and X.
- The New Gas and Old Gas generating facilities each consist of two generating units whose marginal costs of production differ.

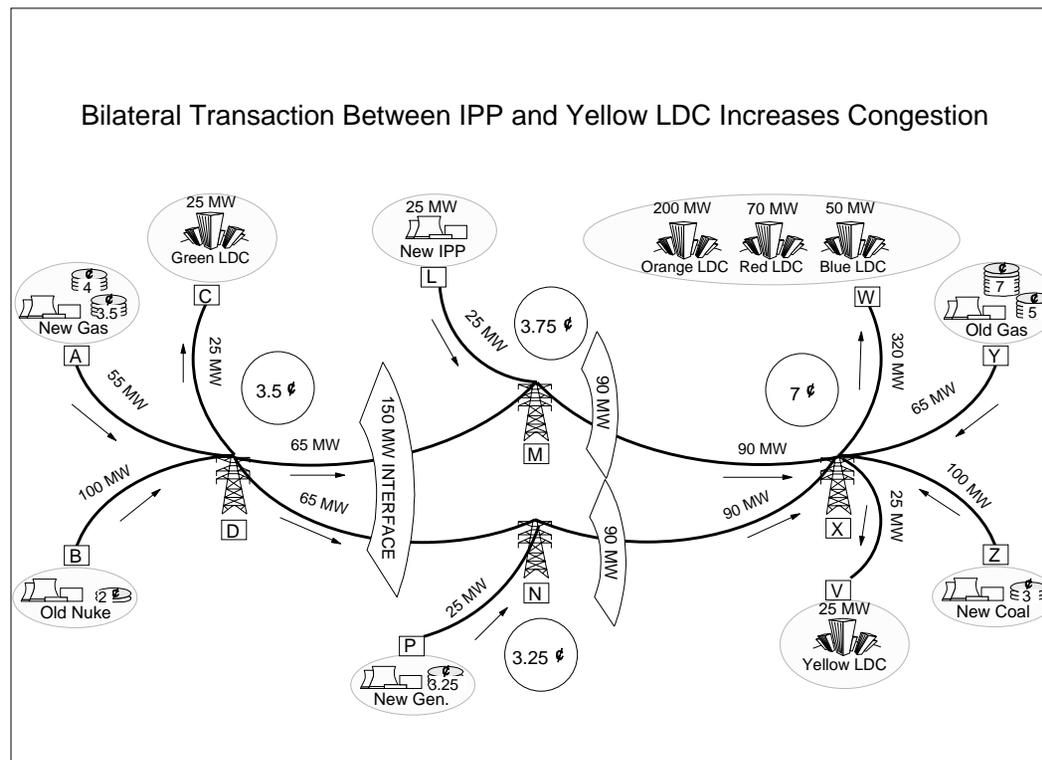


Loads in this figure are illustrative and will vary systematically in each example. For convenience, losses are ignored in all examples.

NETWORK PRICING EXAMPLES

Congestion

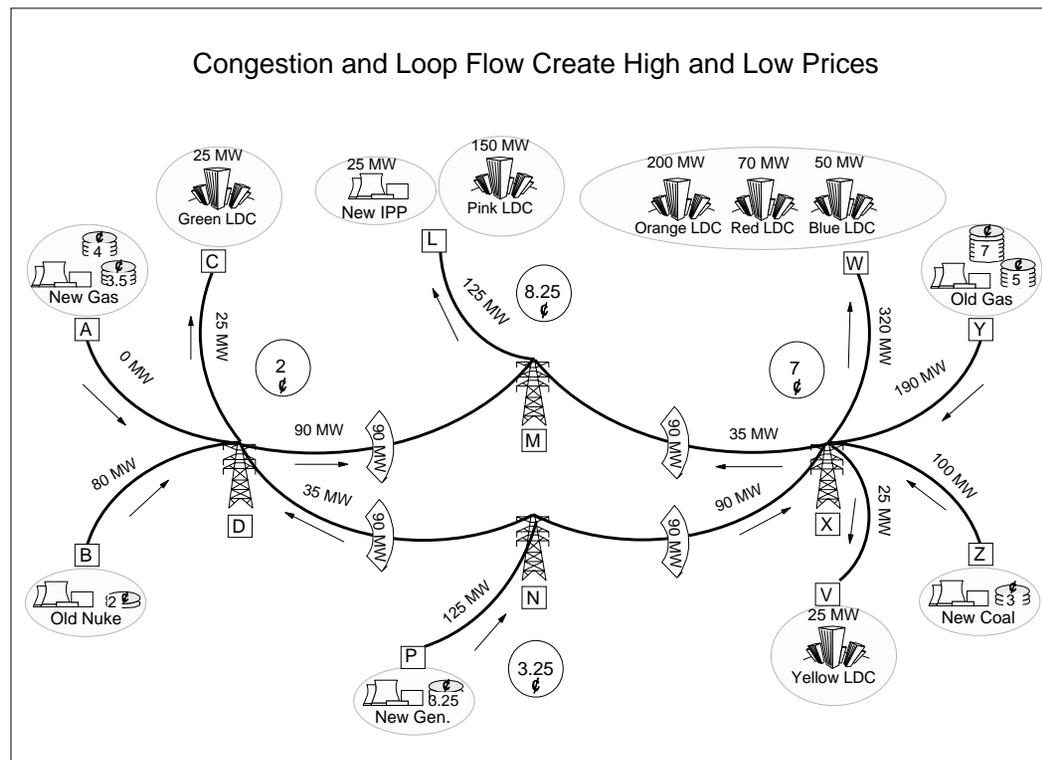
A low cost, large capacity generator becomes available at bus "P." The IPP at bus "L" has bid in a must run plant at 25 MW, having arranged a corresponding sale to the Yellow distribution company at bus "V". Were it not for the IPP sale, more power could be taken from the inexpensive generators at bus "P" and at bus "A". However, because of the effects of loop flow, these plants are constrained in output, and there are different prices applicable at buses "D", "M", "N", and "X".



NETWORK PRICING EXAMPLES

Congestion

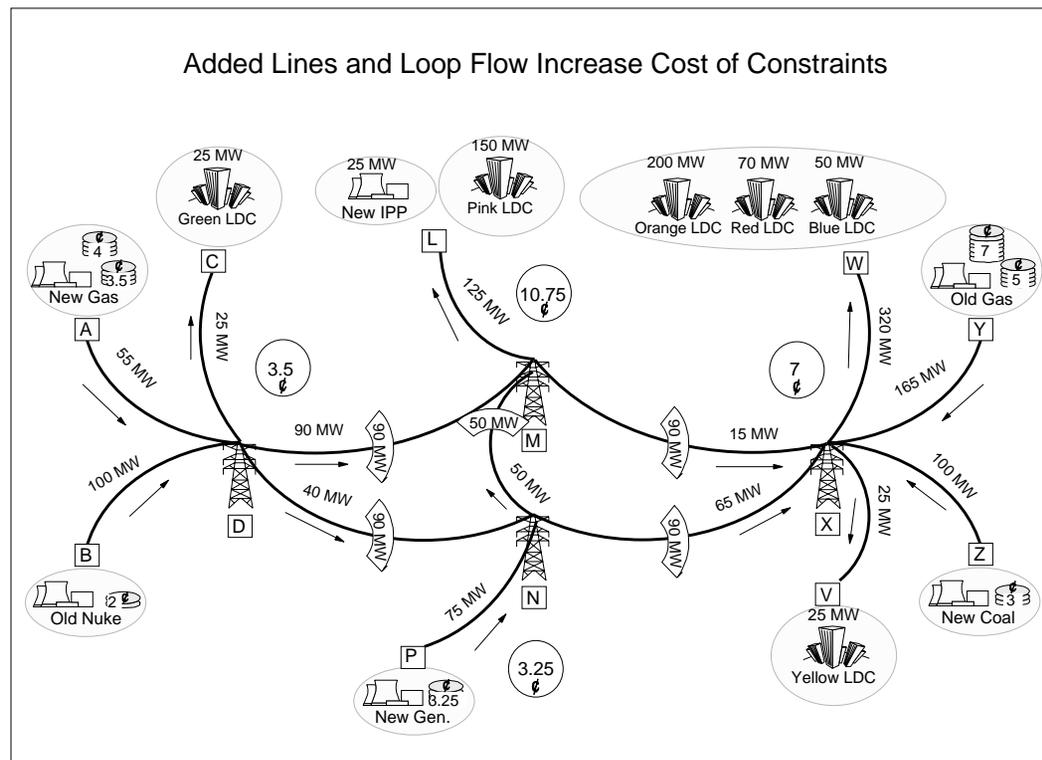
Here every line in the main loop is constrained by a thermal limit of 90 MW, replacing the interface limit. With these constraints, an added load of 150 MW at bus "L" alters the flows for the market equilibrium. In this case, the combined effect of the increased load and the constraints leads to a price of 8.25¢ per kWh at bus "L". This price is higher than the 7¢ marginal running cost of the old gas plant at bus "Y", the most expensive plant in the system.



NETWORK PRICING EXAMPLES

Congestion

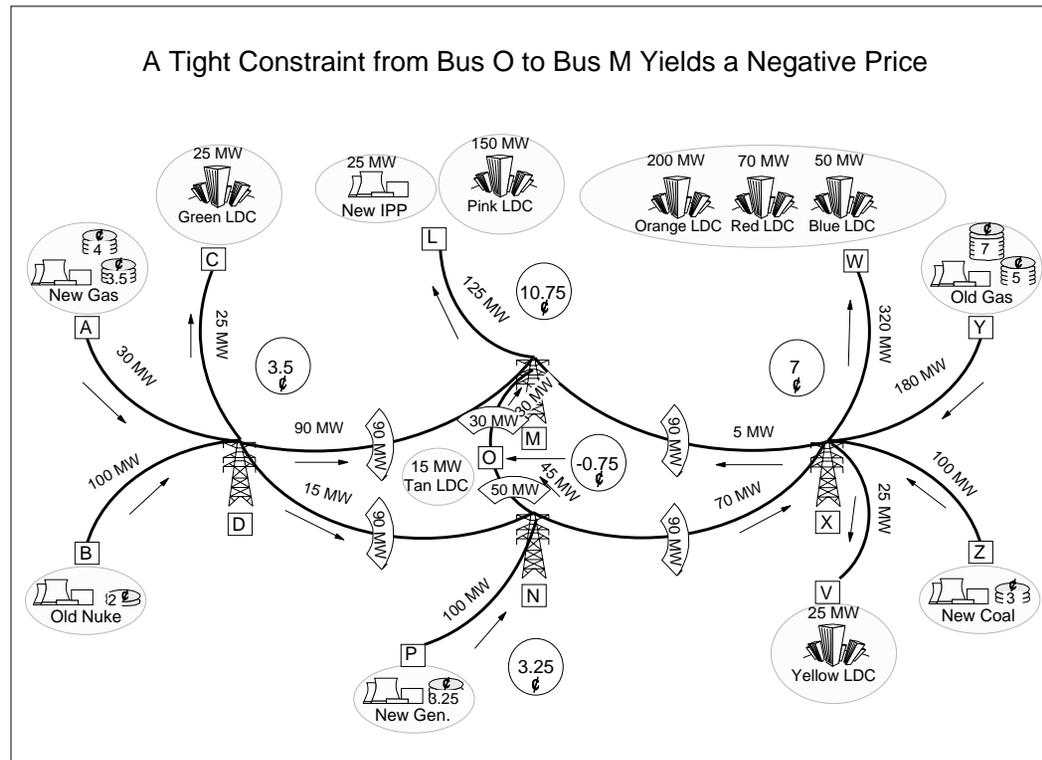
Next a new line has been added to the network, connecting bus "N" to bus "M". This line is assumed to have a thermal limit of 50 MW. The new line adds to the capability of the network in that the new pattern of generation lowers the overall cost of satisfying the same load. The total cost reduces from \$20,962.50 to \$19,912.50. Although the average cost of power generation fell, the marginal cost of power increased at bus "L", where the price is now 10.75¢ per kWh.



NETWORK PRICING EXAMPLES

Congestion

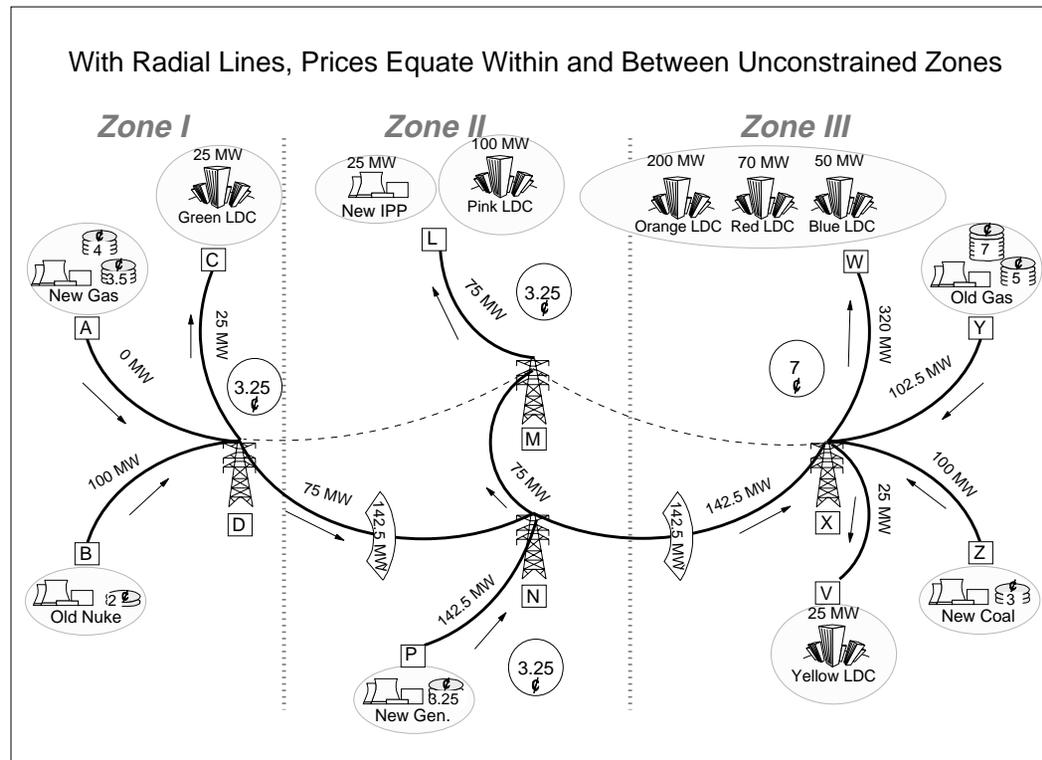
Add a new bus "O" between bus "M" and bus "N", and lower the limit to 30 MW between bus "O" and bus "M". Bus "O" has a small load of 15 MW. The increased load of 15 MW at bus "O" actually lowers the total cost of the dispatch, as reflected in the negative price. Each additional MW of load at bus "O" changes the flows to allow a dispatch that lowers the overall cost of meeting the total load.



NETWORK PRICING EXAMPLES

Zones

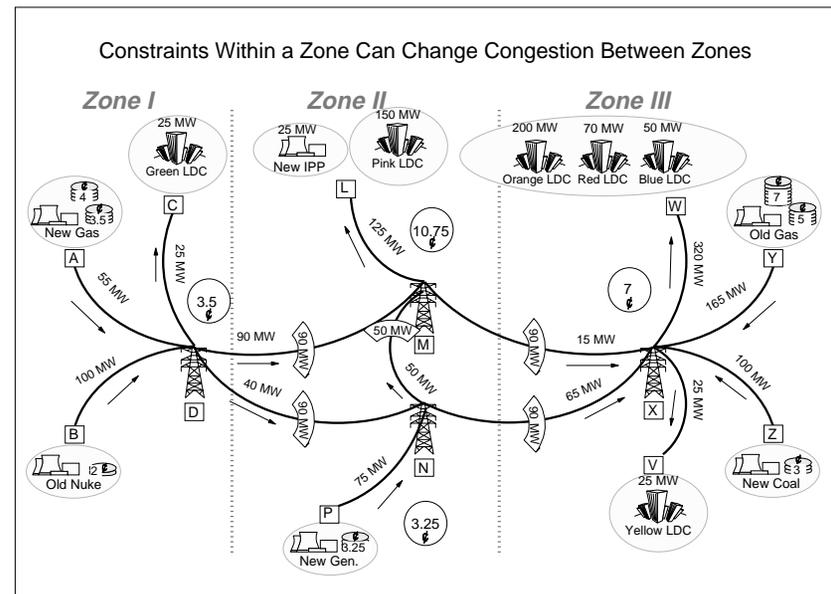
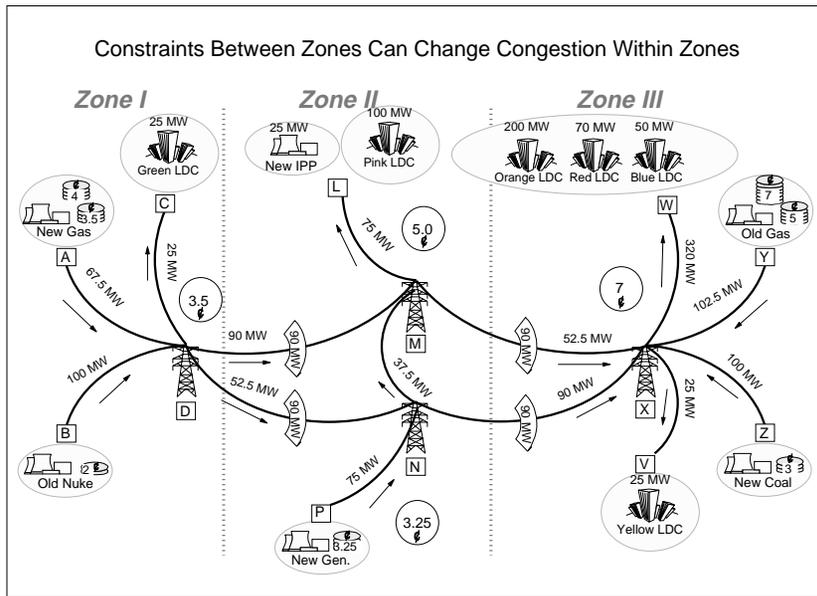
With strictly radial connections, locations within and between unconstrained zones would have a common price. Hence, aggregation of locations offers an apparent simplification by reducing to a few distinct zones.



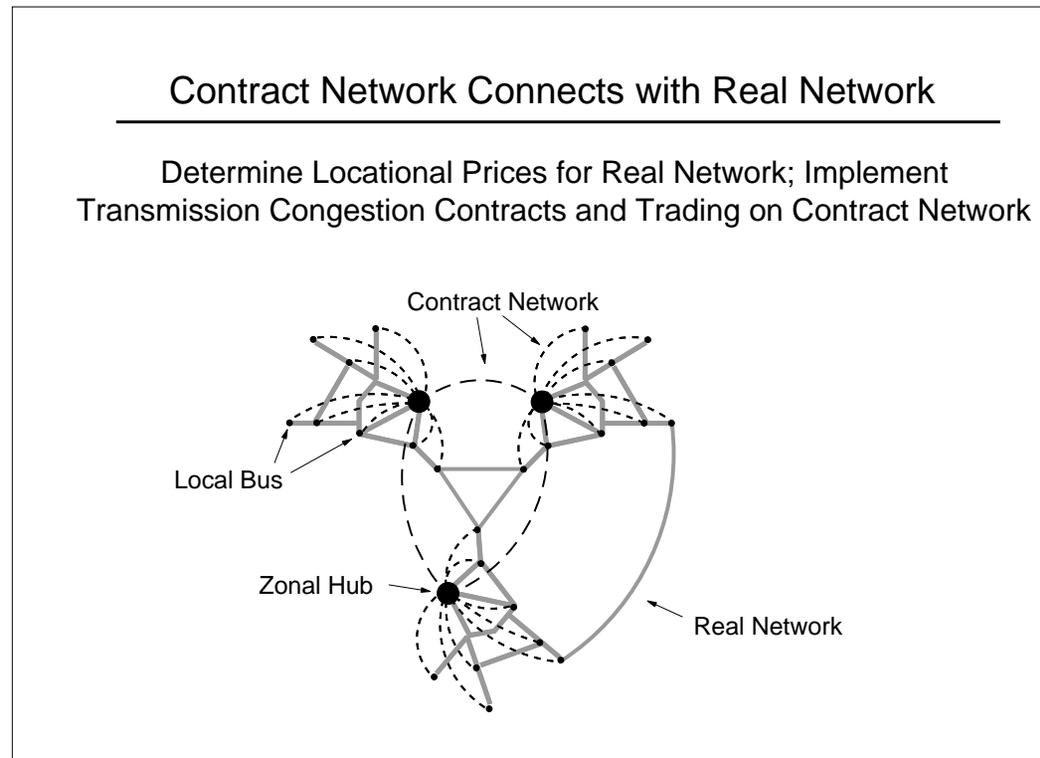
NETWORK PRICING EXAMPLES

Zones (cont.)

With the more typical case of loops in a network, prices could differ within and between "unconstrained" zones due to the indirect effects of "distant" constraints. Aggregation into zones may add to complexity and distort price incentives.



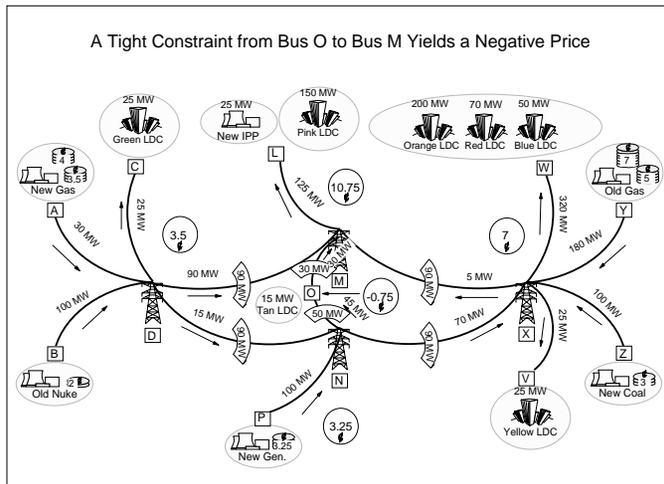
With loops in a network, market information could be transformed easily into a hub-and-spoke framework with locational price differences on a spoke defining the cost of moving to and from the local hub, and then between hubs. This simplifies without distorting the prices.



NETWORK PRICING EXAMPLES

Transmission Congestion Contracts

The simultaneous set of transmission congestion contracts defines the "Available Transmission Capacity." Consider the example network with two feasible sets of transmission congestion contracts (TCC) for hub at "O".



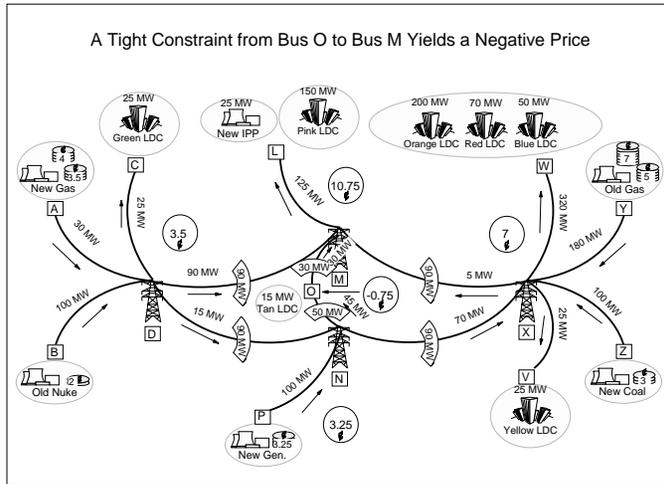
From-To	TCC 1 (MW)	TCC 2 (MW)
"D-O"	180	160
"O-X"	180	160
"M-O"	30	10
"N-O"	30	70

Either set of TCCs would be feasible by itself in this network. However, subsets of the contracts may not be feasible. Hence, the *definition* of available transmission capacity would be as a simultaneously feasible set of contracts.

NETWORK PRICING EXAMPLES

Transmission Congestion Contracts

The congestion costs collected will always be sufficient to meet obligations under transmission congestion contracts. Excess congestion rents, after paying TCC obligations, could be returned under a sharing formula.



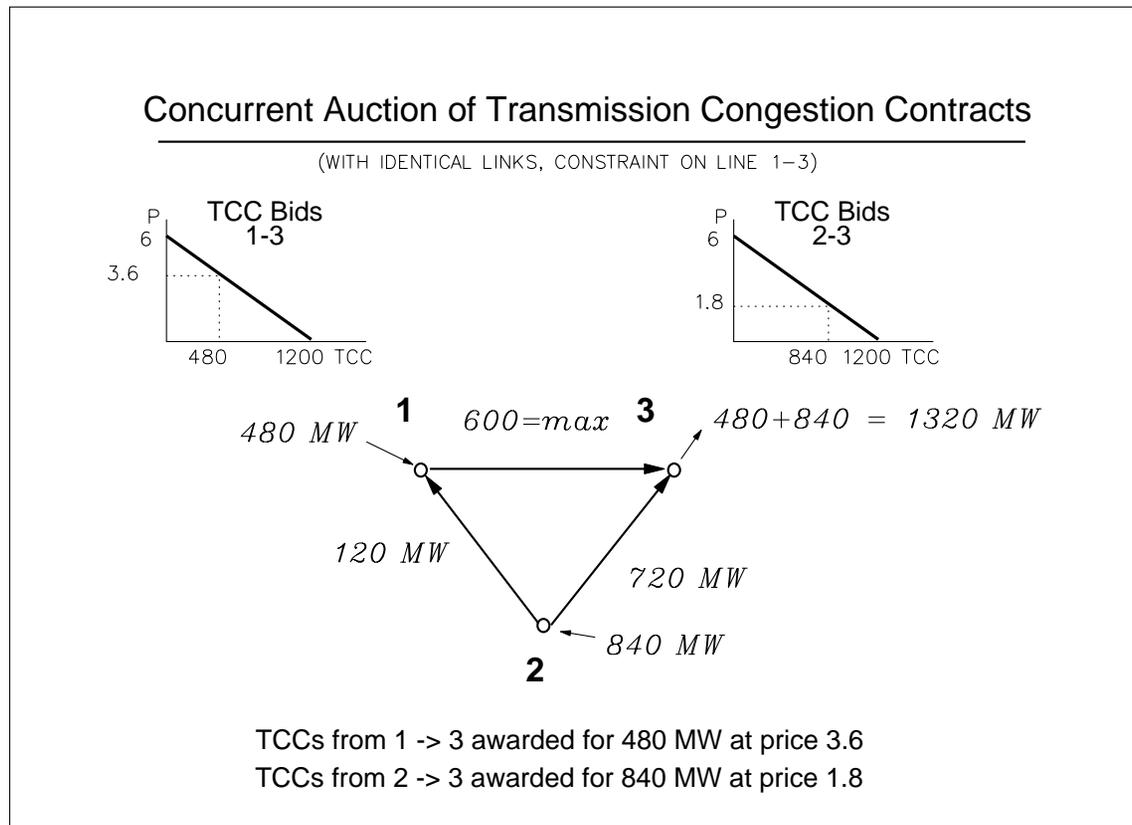
From-To	TCC 1 (MW)	TCC 2 (MW)
"D-O"	180	160
"O-X"	180	160
"M-O"	30	10
"N-O"	30	70

Load at "L"	Bus Prices ¢/kWh					Total Rents \$	TCC 1	TCC 2
	"D"	"M"	"N"	"O"	"X"			
MW	"D"	"M"	"N"	"O"	"X"			
0	3.50	3.75	3.25	3.50	7.00	6300	6300	5750
50	3.50	5.58	3.25	4.15	7.00	6300	6138	6084
150	3.50	10.75	3.25	-0.75	7.00	10950	1650	1650

TRANSMISSION CONGESTION CONTRACT

Auction

Transmission congestion contracts for the grid could be defined and awarded through an open auction. The collective bids would define demand schedules for TCCs. The concurrent auction would respect the transmission system constraints to assure simultaneous feasibility.



TRANSMISSION CONGESTION CONTRACT

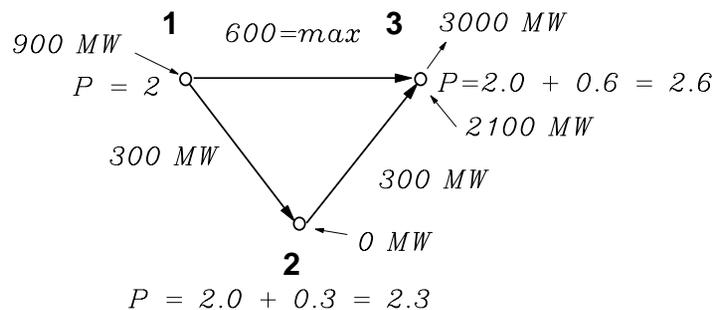
Revenue Adequacy

With spot locational prices, transmission congestion contracts provide price protection. Even with changing load patterns, the congestion revenues collected by the system operator will be at least enough to cover the obligations for all the TCCs.

Constraints with Out-Of-Merit Costs

(WITH IDENTICAL LINKS, CONSTRAINT ON LINE 1-3)

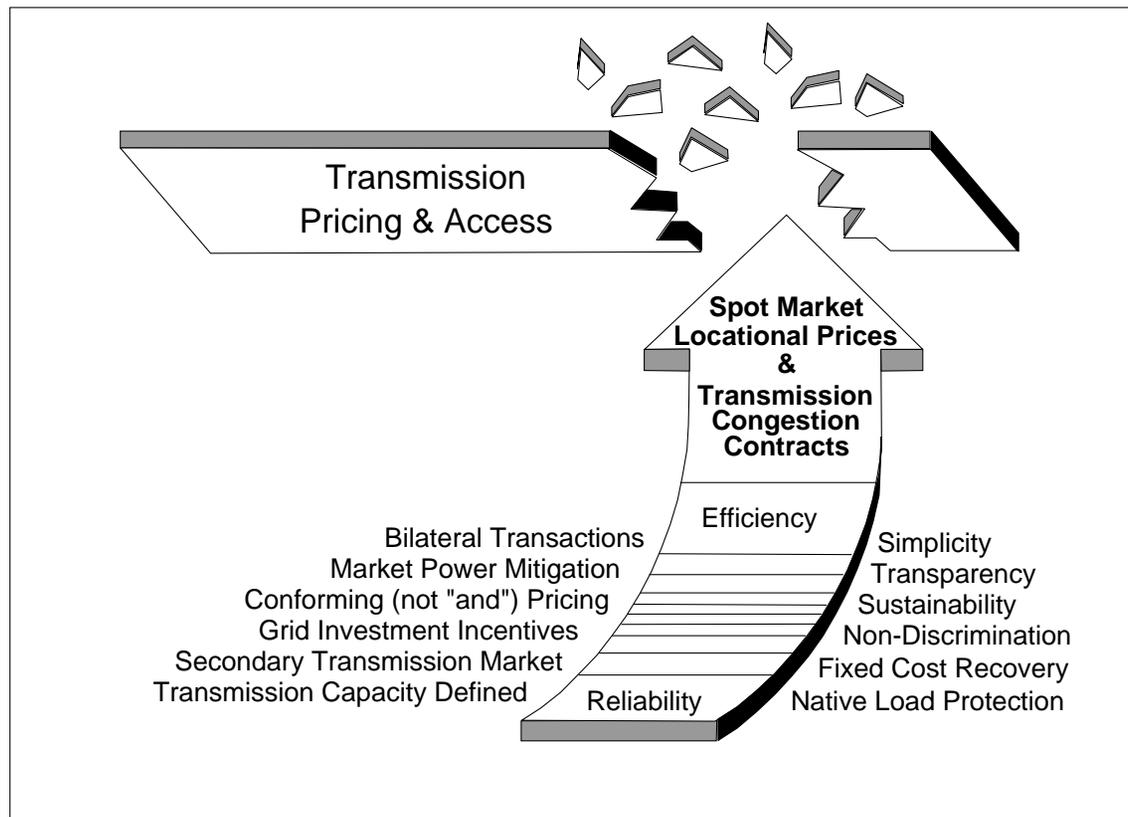
Bus 2 generation cost goes above 2.3
 Load and flows change; constraint binds
 Price includes congestion charge



System Operator Revenues

	Quantity	Price	\$
Bus 1	900	2	(\$1,800)
Bus 2	0	2.3	\$0
Bus 3	2100	2.6	(\$5,460)
Bus 3	-3000	2.6	\$7,800
TCC 1-3	480	0.6	(\$288)
TCC 2-3	840	0.3	(\$252)
Net Total			\$0

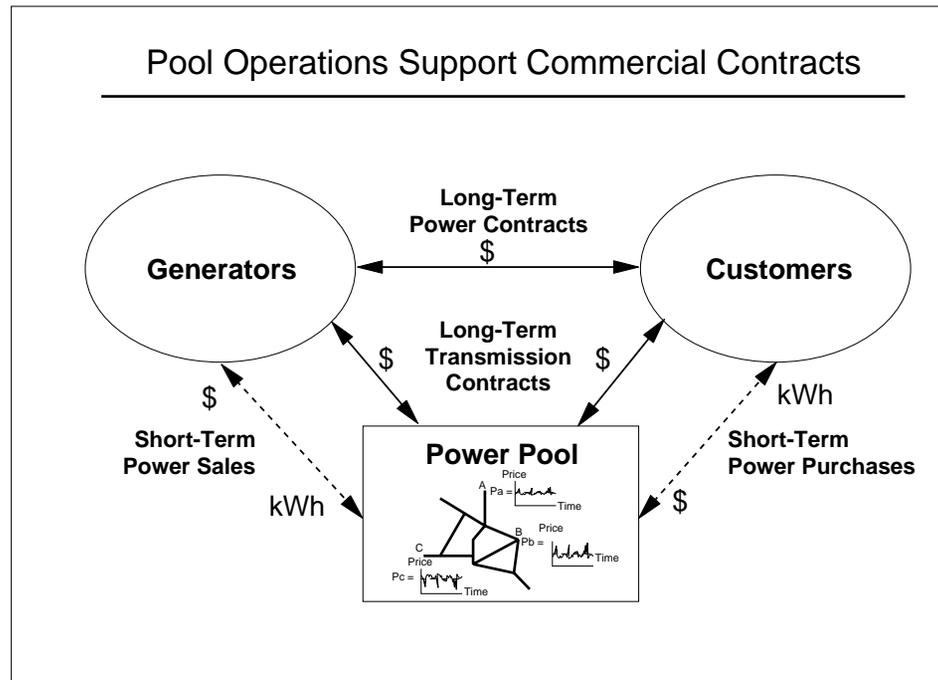
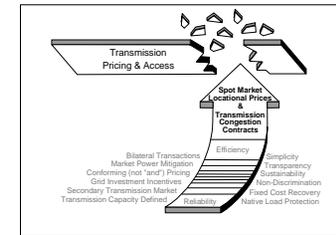
The Contract Network model built on spot locational prices and transmission congestion contracts provides a consistent approach addressing a wide array of problems in providing transmission pricing and access rules for a competitive electricity market.



TRANSMISSION PRICING & ACCESS

Contracts

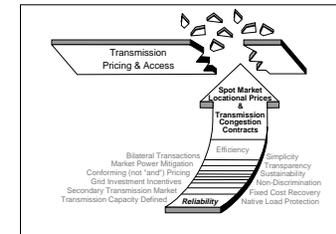
Market participants can achieve price stability through contracts. Bilateral contracts can share risks for electricity prices at a location. Spot-market locational prices apply to all transmission and transactions coordinated through the dispatch. Transmission contracts can protect buyers and sellers against system congestion.



TRANSMISSION PRICING & ACCESS

Reliability

Any proposal for transmission open access must preserve the reliability of the system. The contract network approach starts with the existing reliability standards:

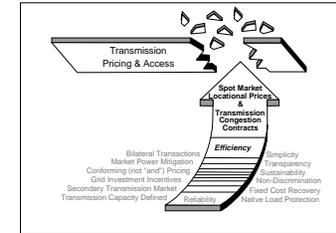


- **Preserve Existing Dispatch Rules.** The full array of dispatch rules and procedures is preserved as today, but under an independent system operator.
- **Ex Post prices.** Locational prices can be obtained consistent with the actual dispatch and the preferences of the market participants as expressed in short-term dispatch related bids.
- **Settlements System Handles Transmission Contracts.** Transmission congestion contracts define financial settlements. System operators do not have to consider contracts in determining short-term balancing and economic dispatch.

TRANSMISSION PRICING & ACCESS

Efficiency

Economic dispatch would be achieved by the competitive market -- if there were well-defined transmission property rights and no transaction costs. Hence, efficient transmission pricing and access should be consistent with economic dispatch. Without the necessary property rights, and to reduce coordination costs, the natural approach is for the independent system operator to provide an economic dispatch based on the bids of the market participants. Spot market locational prices are defined immediately by the results of this economic dispatch.

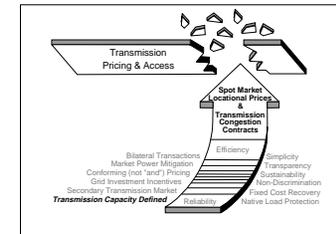


- **Discretionary Bids.** The market participants decide on what to bid based on their own preferences. This could include deciding to make no bid at all. The system operator matches the short-term offers and determines both the dispatch and the associated spot-market locational prices. All transactions through the spot market are at the locational prices.
- **Follow Current Dispatch Procedures.** The form of the bids can follow the current practices for all the details of running costs, minimum loads, etc., replacing the engineering cost estimates with the bidders' preferences.
- **Open Access.** Everyone must coordinate through the system operator, and everyone has the option to provide bids signalling preferences to guide the operator's decisions.

TRANSMISSION PRICING & ACCESS

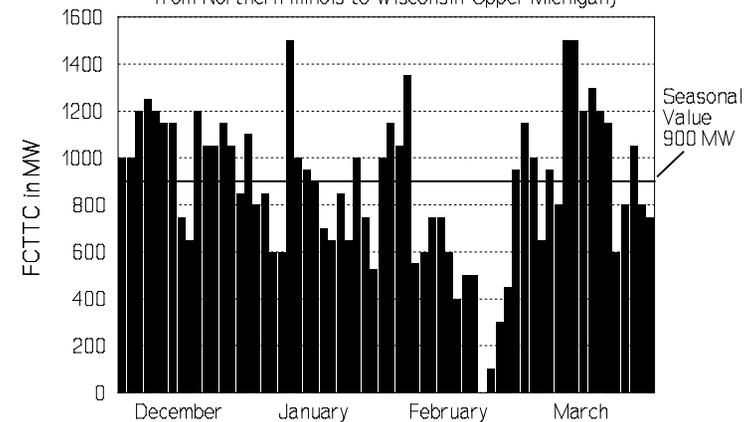
Capacity Defined

The vexing problem of defining long-term physical transmission capacity for future power flows is replaced by the (relatively) simple problem of defining a consistent set of transmission congestion contracts.



"The calculation of transfer capability is generally based on a computer simulation of the operation of the interconnected electric systems under a specific set of assumed operating conditions. Each simulation represents a single "snapshot" of the operation of the interconnected systems based on the projections of many factors. Among these factors are the expected customer demands, generation dispatch, the configuration of the systems, and the interchange among the systems. ... The actual transfer capability available at any particular time may differ from that calculated in simulation studies because in the simulation studies only a limited set of operating conditions can be evaluated, whereas in real time, widely different conditions may exist." (NERC)

MAIN Daily FCTTC Monitoring - 1993/94 Winter
(First Contingency Total Transfer Capability from Northern Illinois to Wisconsin-Upper Michigan)

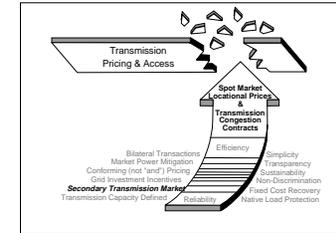


The long-term feasibility of the set of transmission congestion contracts depends only on a "single snapshot" based on the contracts themselves. The system operator need take no financial risks in guaranteeing the payments of congestion rentals. Locational price charges from actual users of the system will fund the payments of the congestion contracts.

TRANSMISSION PRICING & ACCESS

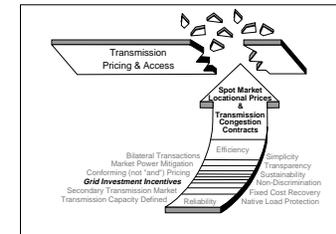
Secondary Market

The financial transmission congestion contracts stand in the place of physical transmission property rights. The congestion contracts provide long-term protection against the changing costs of transmission flows. Once created, the transmission congestion contracts can be traded in a secondary market.



- **Competition in Secondary Market.** Once obtained after investing in the grid, transmission congestion contracts can be divided and rearranged. Even with a monopoly grid, the secondary market can have multiple participants and competitive pricing.
- **Prices Limited by Spot Market Option.** With open access and spot market locational prices, the value of the transmission congestion contracts should not deviate much from the expected cost of congestion. Holding the contract confers no control over the dispatch, and everyone is free to rely only on spot market prices.

Avoiding sustained locational cost differences defines the economic rationale for investing in transmission. With prices set equal to locational marginal costs, market participants have an incentive to initiate and pay for transmission investments.



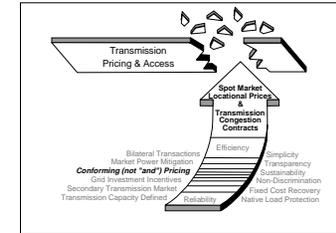
- **Transmission Benefits Along with Transmission Costs.** Transmission congestion contracts provide a mechanism to award the transmission benefits along with the transmission investment costs. The contracts protect the holders from future changes in congestion costs.
- **Free Riders May Force a Residual Role for Monopoly Investment.** Due to economies of scale and network effects, there may be situations where many would benefit from a transmission expansion but no coalition is prepared to make the investment. In this case, a regulatory decision to approve the investment and allocate the costs may be required.

Without well-defined property rights, the alternative would be to rely solely on the monopoly grid owner to expand the grid and send everyone the bills.

TRANSMISSION PRICING & ACCESS

Conforming Pricing

The contract network approach with spot market locational prices and transmission congestion contracts is a "conforming" pricing proposal under the FERC criteria.

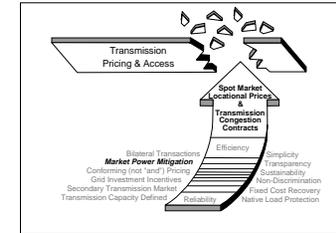


- **Grid Company Receives Embedded Costs.** The payment for the existing grid or new grid investments can be cost based according to traditional regulation. Those paying the regulated fixed charges for transmission receive the transmission congestion contracts.
- **Spot Market Participants Pay Locational 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.
- **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; the transmission congestion contract holder receives compensation for out-of-merit dispatch costs; and the transmission user pays the true opportunity cost.

TRANSMISSION PRICING & ACCESS Market Power Mitigation

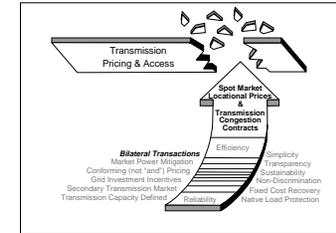
Transmission pricing systems that do not include locational prices reinforce market power by substantially reducing competitive demand and supply responses. In the presence of transmission congestion, local market power may exit, such as for a generator that must run in a particular location. The usual mitigation mechanisms are demand responses, supply responses and regulation.



- **Demand Response.** With locational prices, high prices set by the generator translate into high local prices and a demand response. Without locational prices, the higher costs are averaged across the system and there is little demand response to help constrain the exercise of market power.
- **Supply Response.** Similarly, with locational prices, new suppliers could obtain long-term contracts and enter the market to compete with the local generator. Without locational prices, the suppliers will be unable to obtain long-term contracts at anything above the average system price. The only market option would be the unattractive choice of investing based on expected spot prices in a market that, by definition, is subject to manipulation through market power.
- **Regulation.** The only defense against the market power would be through direct regulation of the generators or through a monopoly, such as the grid, that could support local generation investments and pass the cost on to the users.

TRANSMISSION PRICING & ACCESS Bilateral Transactions

The contract network approach is designed to fully support commercial bilateral contracts. The role of the system operator is to coordinate the short-term dispatch. The use of locational prices and transmission congestion contracts makes a virtue out of the necessity of central coordination.

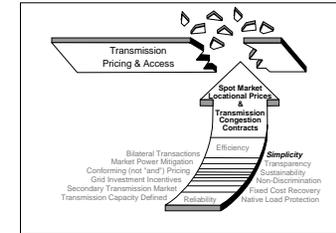


- **Contracts for Differences.** Financial contracts for differences, coupled with transmission congestion contracts, provide full support for commercial transactions. The option to buy and sell in the short-term dispatch increases flexibility and expands choices.
- **"Physical" Bilateral Transactions.** At the risk of creating jurisdictional problems, and with additional accounting procedures to track contract injections and withdrawals, the fiction of "physical" movement of power from point to point can be accommodated. The charge for transmission would simply be the difference in the locational prices. Imbalances would be charged or credited at these same locational prices.

TRANSMISSION PRICING & ACCESS

Simplicity

The result of an efficient dispatch produces different prices at each location to reflect marginal losses and congestion costs. This may seem more complicated than setting a single price for a wide area, but so is the reality.



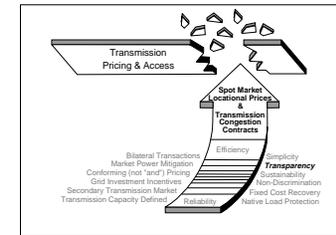
- **No Difference, No Problem.** If the prices do not differ by much for many hours, there will be no complexity. Most markets have different prices for similar products at different locations.
- **Big Difference, Problem Solved.** If the prices differ substantially across locations, then the reality is that there are substantial cost differences. Failure to recognize these differences will lead to cost-shifting and artificial arbitrage profits.
- **No Computational Obstacle.** Since prices are calculated ex post from the actual dispatch, there is no computational difficulty in determining prices for every location in the real system.

"A theory should be as simple as possible -- and no simpler." (Einstein)

TRANSMISSION PRICING & ACCESS

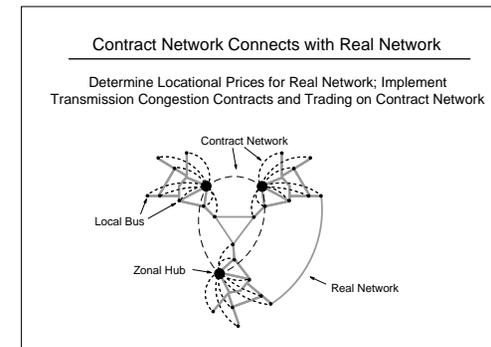
Transparency

The determination of spot-market locational prices takes place in a translucent box. This is an improvement over the black box of physical transmission capacity allocation.



- **No Decisions Beyond Those Required for the Dispatch.** The complex but unavoidable decisions from the dispatch, along with the participant bids, provide all the information needed to determine a set of consistent prices that incorporate all the effects of loop flow and network interactions. There is no requirement for considering multiple alternative dispatches, a common but more complex practice.

- **Presentation Can Adapt to a Hub and Spoke Framework.** The 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.

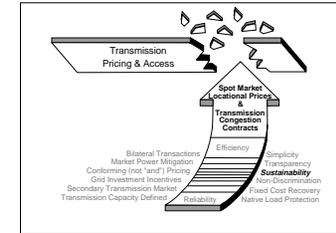


- **Ex post Price Subject to Easy and Quick Audit.** The calculation of prices requires solution of a simple set of equations. Given the dispatch, network parameters, and access to the confidential bids, any authorized auditor could easily verify the calculations. Furthermore, every market participant would be satisfied according to the criterion of meeting their own stated preferences.

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Sustainability

Any averaging of locational prices inherently creates artificial arbitrage opportunities. The experience of power pools with "split-savings" pricing shows that once participants have options, arbitrage pressures can destroy the pricing system, even if there is economic dispatch.



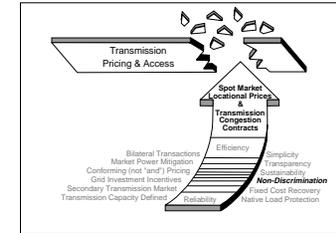
- **Low Marginal Cost Regions.** Purchasers paying an average price will see local, low-cost generation that is not being fully utilized. There will be great pressure to allow trading around the system pricing mechanism.
- **High Marginal Cost Regions.** Sellers in high cost regions will raise their bids to capture the high local prices that will then go into the increased average costs across the system.
- **Arbitrage Pressures Drive Towards Locational Prices.** If participants have options, the transactions will be reconfigured to capture the artificial arbitrage created by price averaging. In the best of circumstances, with no attendant inefficiency or artificial profits, the system would move towards locational differences in prices.

Maintaining average prices in the face of real cost differences requires a strong regulatory hand.

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Non-Discrimination

Everyone at a particular location, at a particular time, faces the same short-term economics and pays the same price at the margin. There is no distinction according to participant identity or affiliation.

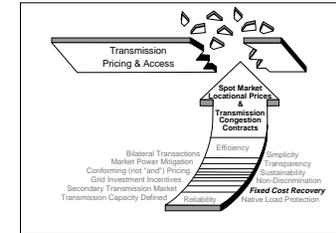


- **Independent System Operator.** The transfer of dispatch control to an independent system operator removes any participation in the energy market. The operator serves as the coordinator and matches buyer and sellers, much as with the New York Stock Exchange.
- **Comparability Becomes Non-Discrimination.** The "golden rule" of comparability is replaced with the easier to enforce principle of nondiscrimination. The system operator is not a competitor in the energy market, and therefore has no treatment of itself to make comparable.

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Fixed Cost Recovery

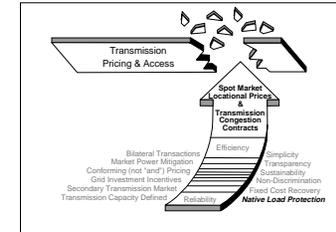
The fixed costs of the transmission grid are paid by those who receive the benefits of transmission congestion contracts.



- **Embedded Costs of the Existing Grid.** Responsibility for the fixed costs of the existing system can remain as now, with a corresponding allocation of the transmission congestion contracts. Or, transmission congestion contracts can be assigned to new entrants with a corresponding payment to reduce the existing fixed charge responsibility.
- **Investment Cost of Grid Expansion.** New investment in the grid would be paid for by those requesting the associated allocation of transmission congestion contracts.

TRANSMISSION PRICING & ACCESS Native Load Protection

There is a well-defined mechanism for protecting native load. Assignment of transmission congestion contracts for the existing system can protect existing dispatch contracts and patterns.



- **Allocate According to Historical Usage.** Transmission congestion contracts can be allocated to match the traditional pattern of native load generation and consumption. This would protect existing rights and, if necessary, be extended to allow for expected growth. Once defined, the allocation would be known and not subject to uncertainty about future usage patterns.
- **Auction Incremental Contracts.** To the extent that incremental transmission contracts can be assigned within the existing system, an auction can allow all participants to obtain such rights. The revenue from the auction can be used to reduce the fixed charges assigned to the native load.

Misconceptions or mischaracterizations abound. But because ISO rules embodied in the contract network approach have a coherent theoretical foundation, the pieces fit together and there are good answers available for the objections raised.

"We want transmission service for a simple (low) price per unit for use of the system. We should treat electric transmission just like any other transport system."

Electric transmission is not like any other transport system, chiefly because it is not a switchable network. Interactions throughout the network, known collectively as "loop flow," make it impossible to isolate or even identify in advance the impacts of an individual transaction. Each transaction can impose (sometimes substantial) costs on others. If users are not paying the opportunity costs of their transactions, then there is by definition cost shifting.

"OK. If we have to pay the opportunity cost of transmission for our bilateral transactions, tell us in advance what it will be so we can get on with our business."

In a perfectly competitive market or under an economic dispatch, the marginal opportunity cost of transmission between two points is the difference in the spot market locational prices. The locational prices cannot be known without knowing everything else about the dispatch. Hence, these prices cannot be set in advance.

"Then just give us property rights in the transmission grid so we know how much power we can send through the system."

The difficulty is the flip side of the opportunity cost problem. We can't say how much power can flow from anywhere to anywhere else without knowing how everybody else is using the grid. Hence, we have not been able to define workable property rights to govern the physical flow of power through the transmission grid. And without such property rights, decentralized decisions alone cannot be economically efficient. Some form of coordinated trading is required, i.e. a pool-based mechanism. By contrast, transmission congestion contracts supported in conjunction with locational pricing could provide the economic equivalent of the impossible to design physical property rights.

"Then at least let us bid for the transmission links through an open and transparent auction."

The difficulty is that bidding and trading for transmission is intimately connected to the bidding and trading for power. When we combine the two auctions, we get the familiar economic dispatch problem. When we try to separate them, we have a difficult and complex coordination problem. Nobody has been able to demonstrate a workable mechanism for how to coordinate such a complex process other than through bidding into an ISO and letting the ISO determine the economic dispatch.

"The focus should be on investment and other cost savings, not on the few efficiencies that can be achieved in a better short-term dispatch."

The framework of the short-term least-cost dispatch serves precisely to get the incentives right for the market to produce better long-term investment and other decisions. In the absence of well-defined property rights, the efficiency of market equilibrium depends centrally on getting the prices for transmission use to conform to a competitive market without cost-shifting or artificial arbitrage. Since an efficient market should produce a least-cost dispatch, the prices from the least-cost dispatch must be the same as would result from an efficient market. The importance of the least-cost dispatch is only secondarily to achieve cost savings in the short run. The real purpose is to compensate for the lack of transmission property rights that could control the use of the grid and to send the correct price signals incorporating the complications of network interactions and loop flow.

"If transmission congestion costs are stable and predictable, then these can be published without the need for any dispatch decisions by the independent system operator."

Transmission congestion costs can be volatile and would be difficult to predict over any significant time horizon. Furthermore, the analysis needed to do the prediction would amount to the same thing as simulating a short-run central dispatch. The easiest and most reliable way to do this dispatch is with information on the real preferences of the market participants; in other words, by allowing voluntary participation in a least-cost dispatch conducted by the independent system operator to ensure system balance within the constraints of the transmission system.

"But economic dispatch implemented by the independent system operator creates an inherent conflict of interest with an unavoidable bias in favor of transactions through the pool."

Actually, it doesn't. The ISO is independent of the participants in the market and is responsible for determining an economic or least-cost dispatch based on the stated preferences of everyone in the interconnected system covered by the ISO's activities. The use of an economic dispatch with locational prices is precisely a means to ensure that both the spot-market bids and bilateral transactions are treated in the same way. Basing the payments for transmission opportunity costs on the locational price differences eliminates any bias in favor of *or against* the spot market.

"Locational marginal cost based prices would be too volatile. The market could not deal with the associated uncertainty."

The marginal costs measure the impact on the system and, hence, the magnitude of the externalities. The more the costs change the more important it would be to recognize the impacts, get the prices right, and avoid cost shifting. For those who want to protect themselves against price changes, a combination of a power contract and a transmission congestion contract can lock in the average delivered price of energy.

"Locational prices would be both hard to calculate and come from a black box. The electricity market cannot function without a simpler system."

The prices would be determined by the actual dispatch, which makes the problem simple. The computations are easy, and have been available for years in power pools; they just haven't been used. Calculating locational marginal costs for the actual dispatch is easier than the familiar and widely used split-savings methodology. Furthermore, since locational pricing is already done (almost in full) in Argentina, Chile, New Zealand, and Norway, there is a demonstration that the technical computation is straightforward. Once the method is explained, system operators always say the prices could be computed easily. This brings us to the issue of the perception and comprehension of the market participants. At the moment the majority of market participants would claim that the idea of using locational prices is too complicated. However, the view of the moment should not be all that concerns us. So far, every simple alternative proposed has turned out to be pretty complicated, once the implications of the full package unfolded to include the extensive regulatory rules needed to negate the incentives of incorrect prices. Furthermore, there is a way to implement and discuss locational pricing within a hub-and-spoke model that captures the major simplification that has been suggested.

"Locational marginal cost pricing is opportunity cost pricing which makes this a non-conforming proposal."

One feature of transmission congestion contracts is the essential redistribution of the opportunity cost payments to those holding the contracts, not to the owners of the transmission grid. The owners of the grid would receive a regulated payment. The ISO would collect the opportunity costs payments from the users of the grid and redistribute these payments to those who held the transmission congestion contracts but were redispatched consistent with the open access, least-cost result. Hence, the opportunity cost payments simply compensate those who incur higher dispatch costs, and the package of locational marginal cost pricing and transmission congestion contracts would be a conforming proposal.

"Transmission congestion is a small problem. This is much ado about nothing."

To argue that transmission congestion is and will be minor is to argue that there should be no interest in gaining transmission rights. Given the keen interest in tradable transmission capacity rights, the behavior of the market participants already contradicts the assertion that this is a minor issue. Furthermore, if it is a minor issue, then the locational prices will not differ most of the time, except for losses, and nothing could be simpler than this outcome. Even if congestion costs were small in the past under the regime of vertically integrated utilities, the incentives will be different in the competitive market where customers have choices. As seen elsewhere, small differences in costs could be a large part of the profit on a transaction, and would lead to substantial differences in behavior. If we give market participants choices, such as between pool and bilateral transactions, it will be important to get the prices right.

"This problem makes my head hurt. We can think about it later, and correct any mistakes. The perfect is the enemy of the good."

If the issues were not tightly interconnected, and if it were easy to make changes that produce winners and losers, there would be something to this point of view. However, the transmission, dispatch, and pricing rules are more intimately connected than most recognize or many want to admit. And changing the rules is hard enough now when everything is changing. The British made the mistake of assuming that dispatch and transmission pricing rules could be separated, and set the dispatch rules in place. The result was that it became very difficult to put in place a sensible transmission pricing system, and they have chosen instead to rely more and more on the decisions of an increasingly powerful (and rich) monopoly. This is an example of a simple solution that was inconsistent with the reality and turned out to be not so simple.

"The Poolco model replaces voluntary market approaches with mandatory central planning."

The basic approach of bidding and least-cost dispatch relies on the discretionary bids of the participants. The only mandatory parts that are essential are that everyone must be given the option of expressing their dispatch preferences and the prices must be applied consistently to all participants. But anyone could provide a must-run bid or its equivalent, and refuse to participate in the dispatch. Those who did so would have to pay the opportunity costs of their choice, and could not impose their choice on others. Furthermore, the dispatch would cover only a short horizon, probably no more than a day ahead. This is hardly planning, and since everyone's preferences would be honored, at the market prices, the approach is more like a central exchange than central planning.

"The Poolco approach with market clearing locational prices creates market power for the big utilities."

The ISO provides open access to the grid at opportunity cost prices. This unbundles the system and eliminates vertical market power. Horizontal market power arises from concentration of ownership of generation plants. The auction mechanism in the bid and dispatch system does not create market power; a dominant firm would not need the auction to manipulate market prices. Furthermore, compared to charging locational marginal cost prices, all the alternatives involve some form of averaging, which would both enhance and hide horizontal market power. Hence, locational marginal cost pricing would reduce market power relative to the alternatives and make the exercise of market power more transparent.

"The Poolco approach would preclude the development of a futures market by limiting the ability to buy and sell in a spot market."

A principal feature of a pool-based system is to simplify the task of buying and selling in a spot market. The only limitation on the ability of anyone to buy and sell would be in their own discretionary bid setting a reservation price. Hence, the pool based mechanism provides the most accessible spot market. Furthermore, the use of transmission congestion contracts would help reduce locational basis risk that could otherwise be a major problem for trading in futures. If prices are volatile enough, then the pool-based mechanism would simplify the operation of a futures market and complement the efficiencies that could be achieved through futures trading. Of course, there is the possibility that spot price volatility would be so low and spot transactions so easy that there would be no demand for futures trading. Although unlikely, this would be evidence of a happy condition, not a problem to be solved.

"Regulators could never understand or implement the rules. A more simple-minded solution is required."

The rules would not be that complicated, they simply would be different. We are now in the midst of a learning period, but as witnessed by the experience elsewhere, this not an insurmountable barrier. After all, the split-savings systems have existed for years, and these are actually more complicated than locational marginal cost pricing.

"Regulators would understand the rules too well and would be able to interfere with the market in pursuit of their own ends."

True, but this fact is not unique to locational marginal cost pricing, and the possibility of interference cannot be avoided. Since there must be a central coordinator, there must be some pricing rule. Any rule other than locational marginal cost pricing must include a degree of averaging, which would be arbitrary and provide an even greater opportunity to obscure the effects of interventions in the market.

And, finally, the most illogical of the arguments in favor of restricting access to the ISO:

"I don't want to be forced to trade through the ISO, so such trading should not be allowed."

Surprisingly, this logical fallacy seems hard to kill. The principle of voluntarism and discretionary bidding is at the core of the pool-based ISO proposal. Anyone who does not want to participate in the spot market coordinated by the ISO may choose to schedule their own transactions, subject only to the unavoidable requirement of notifying the ISO of the schedules and paying any associated costs. However, there is no good reason that the option not to participate should be extended to a prohibition that prevents others from participating in the ISO coordinated spot market. No market participant should be required to participate in the economic dispatch offered by the ISO, but at the same time no market participant should be prevented from using this service as one of the many options that will expand customer choice.

Supporting papers and additional detail can be obtained from the author. William W. Hogan is the Thornton Bradshaw Professor of Public Policy and Management, John F. Kennedy School of Government, Harvard University, and Director, Putnam, Hayes & Bartlett, Inc., Cambridge MA. This presentation draws on work for the Harvard Electricity Policy Group and the Harvard-Japan Project on Energy and the Environment. Many individuals have provided helpful comments, especially Robert Arnold, John Ballance, Jeff Bastian, Ashley Brown, Michael Cadwalader, Judith Cardell, John Chandley, Doug Foy, Hamish Fraser, Geoff Gaebe, Don Garber, Stephen Henderson, Carrie Hitt, Jere Jacobi, Paul Joskow, Maria Ilic, Laurence Kirsch, Jim Kritikson, Dale Landgren, William Lindsay, Amory Lovins, Rana Mukerji, Richard O'Neill, Howard Pifer, Grant Read, Bill Reed, Brendan Ring, Larry Ruff, Michael Schnitzer, Hoff Stauffer, Irwin Stelzer, Jan Strack, Steve Stoft, Richard Tabors, Julie Voeck, Carter Wall and Assef Zobian. The author is or has been a consultant on electric market reform and transmission issues for British National Grid Company, General Public Utilities Corporation (working with the "supporting" companies of the PJM proposal), Duquesne Light Company, Electricity Corporation of New Zealand, National Independent Energy Producers, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, San Diego Gas & Electric Corporation, Trans Power of New Zealand, and Wisconsin Electric Power Company. The views presented here are not necessarily attributable to any of those mentioned, and the remaining errors are solely the responsibility of the author.