INDEPENDENT SYSTEM OPERATOR (ISO) FOR A COMPETITIVE ELECTRICITY MARKET

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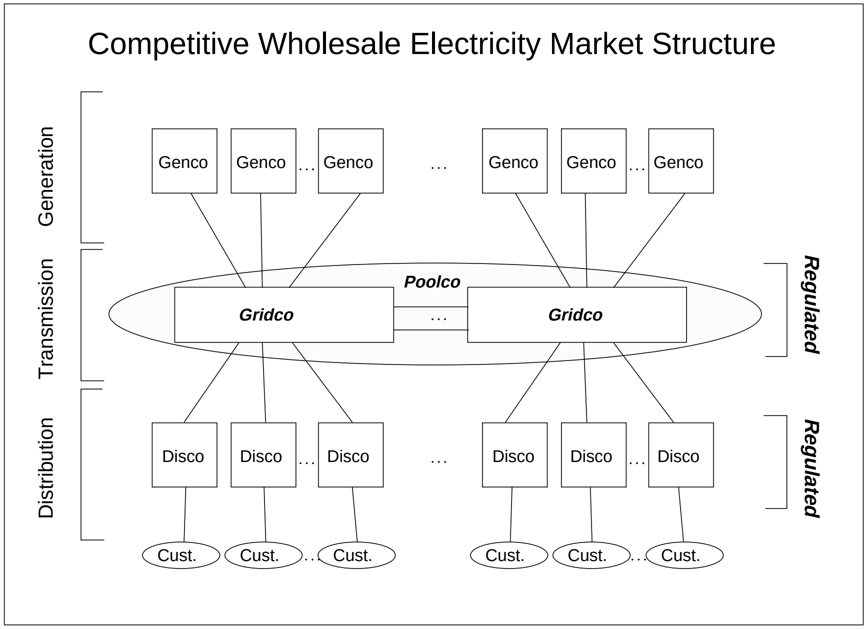
The usual separation into generation, transmission, and distribution is insufficient. In an electricity market, the transmission wires and the pool dispatch are distinct essential facilities.



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.

Is a system coordinator required in support of a market? Always.

- **In England and Wales it is the "Pool."**
- **In New Zealand it is "Trans Power."**
- **In Norway and Sweden it is "Statnett Marked."**
- **Pool-based systems exist in Chile, Argentina, Alberta, Australia and so on. New names keep cropping up but the basic coordination functions will always be there, somewhere. The critical issue is access and pricing, especially transmission pricing.**
- **In the debate in the United States the coordinator has come to be called the "Independent System Operator."**

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."
>
> (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.)

The United States is at the "beginning of the beginning" of its experience with the development and implementation of independent system operators. Motivated by the problem of market power, the ISO is the means for providing access to the essential facility. The relevant objectives include:

Reliability. The ISO responsibilities should include coordinating short-term operations to ensure reliability while supporting the competitive spot market.

Independence. The governance structure and incentives for the ISO should be designed to ensure that no one subset of the market participants is allowed to control the criteria or operating procedures.

Non-Discrimination. Access to and pricing of services should be applied to all market participants without distinction as to customer identity or affiliation.

Unbundling. Services should be unbundled when possible for acquisition from the competitive market and for utilization by the market participants.

Efficiency. Operating procedures and pricing of services should support an efficient, competitive market for electricity. Attributable costs should be paid by the responsible parties. There should be no cost shifting. Joint costs should be allocated fairly with minimal impact on efficient incentives. Pricing and access rules should reinforce efforts to mitigate market power in generation.

The Federal Energy Regulatory Commission outlined 11 principles for ISOs in its Order No. 888 of May 10, 1996.

1. The ISO's governance should be structured in a fair and non-discriminatory manner.

2. An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards.

3. An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a non-discriminatory manner.

4. An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role in this responsibility should be well-defined and comply with applicable standards set by NERC and the regional reliability council.

5. An ISO should have control over the operation of interconnected transmission facilities within its region.

6. An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.

The Federal Energy Regulatory Commission ISO principles (continued).

7. The ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open and competitive market.

8. An ISO's transmission and ancillary services pricing policies should promote the efficient use and investment in generation, transmission, and consumption. An ISO or an RTG (regional transmission group) of which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions.

9. An ISO should make transmission system information publicly available on a timely basis via an electronic information network consistent with the Commission's requirements.

10. An ISO should develop mechanisms to coordinate with neighboring control areas.

11. An ISO should establish an ADR (alternative dispute resolution) process to resolve disputes in the first instance.

There are many ISOs at various stages of design, approval and implementation.

WEPEX Western Power Exchange. The California ISO and Power Exchange (PX). The FERC approved the structure and governance mechanisms in October 1997, subject to extensive reporting requirements to monitor market performance and identify market power problems. Many details of access and pricing were unspecified or being changed after initial operations began on March 31, 1998. The structure involves novel mechanisms for coordination among the ISO, PX and parallel scheduling coordinators with several markets for energy and services.

PJM Pennsylvania-New Jersey-Maryland Interconnection. An ISO with no separate power exchange. Two tiered governance structure with an independent board and a member committee to advise the board. Structure includes locational marginal cost pricing and transmission congestion contracts to deal with transmission access. FERC asked for some modifications to improve price protections for market participants. The FERC approved plan in November 1997. After completing training requirements, the new system went into effect in April 1998.

NYPP New York Power Pool. January 1997 filing with FERC to establish an ISO, Reliability Council and Power Exchange. The ISO would administer the dispatch and spot market for power exchange, like PJM but unlike WEPEX. Revised FERC filing at end of 1997. Plan includes locational marginal cost pricing and transmission congestion contracts to deal with transmission access. Two settlement system and transmission congestion contract auction provide price protection for market participants.

There are many ISOs at various stages of design, approval and implementation.

NEPOOL New England Power Pool. In June 1997, the FERC granted conditional approval for creation of the "ISO New England." Interim operation was approved for July 1997, with the New England electricity market scheduled to open to competition on April 1, 1998, subsequently delayed until some time in the Fall of 1998. Governance structure includes an independent board of directors. The ISO will administer a bid-based dispatching system for NEPOOL with no separate power exchange. The bidding system will include seven separate markets for energy services. The proposed transmission congestion management system spreads the costs across all users and appears similar to an earlier failed experiment in PJM.

ERCOT Electric Reliability Council of Texas. An ISO in operation in 1997 for the larger part of the state of Texas. The ISO schedules transmission usage and administers a cost sharing scheme to deal both with current congestion and planned transmission expansion. From January through October 1997, more than 19,000 unplanned transactions were scheduled through the ISO.

INDEGO The Independent Grid Operator. Initial development discussion included 21 Pacific Northwest and Western utilities. The system included use of transmission zones and transmission capacity reservation trading to manage access and congestion. Implementation problems and tariff design disputes led to the official demise of the plan, at least for 1998.

There are many ISOs at various stages of design, approval and implementation.

MISO Midwest ISO covering more than 26 utilities in several states. After a long process working towards a December 17, 1997 filing at FERC, the MISO appeared to collapse at the last minute, with only four of the utilities pledging to support implementation. Subsequent support by regulators led to new members joining and a revival of interest by the Spring of 1998

Alliance Eleven of the original MISO group. This group of utilities covers the eastern and northern border of the MISO group, and announced in December 1997 they would pursue an alternative ISO based on the long standing investigations of the General Agreement on Parallel Paths. Proposal includes a residual spot market with locational pricing. Two major members involved in merger talks subsequently left and joined the Midwest ISO..

DesertSTAR Desert Southwest Transmission and Reliability Operator. The eleven participating utilities concluded in late October 1997 that an ISO for the area of Arizona, New Mexico, Southern nevada and West Texas is feasible. The details have not been developed, but the group’s goal is to have FERC-approved operational ISO status by July 2002.

The Federal Energy Regulatory Commission's Order on the Pennsylvania-New Jersey-Maryland (PJM) restructuring includes elements for transmission access and pricing that support a competitive electricity market.

> Under the PJM Transmission Tariff, PJM-OI (the ISO) will offer pool-wide open access transmission service throughout the PJM Pool via the facilities of the eight PJM Companies. All transmission services will be subject to a single, non-pancaked rate based on the costs of the individual utility's transmission system where the point of delivery is located. Supporting Companies propose the locational marginal pricing approach for calculating and recovering the costs of transmission congestion. In general, under locational marginal pricing, transmission congestion costs are calculated based on differences in the marginal price of generation at each location on the transmission grid. [1]
>
> ... We are directing PJM-OI to implement Supporting Companies' proposal prospectively, effective January 1, 1998, subject to further modification in accordance with our findings herein.[2]

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[1] Federal Energy Regulatory Commission, "Pennsylvania-New Jersey-Maryland Interconnection: Order Conditionally Accepting Open Access Transmission Tariff and Power Pool Agreements, Conditionally Authorizing Establishment of an Independent System Operator and Disposition of Control over Jurisdictional Facilities, and Denying Rehearings," Docket No. OA97-261-000, et al., Washington, D.C., November 25, 1997, p. 6.

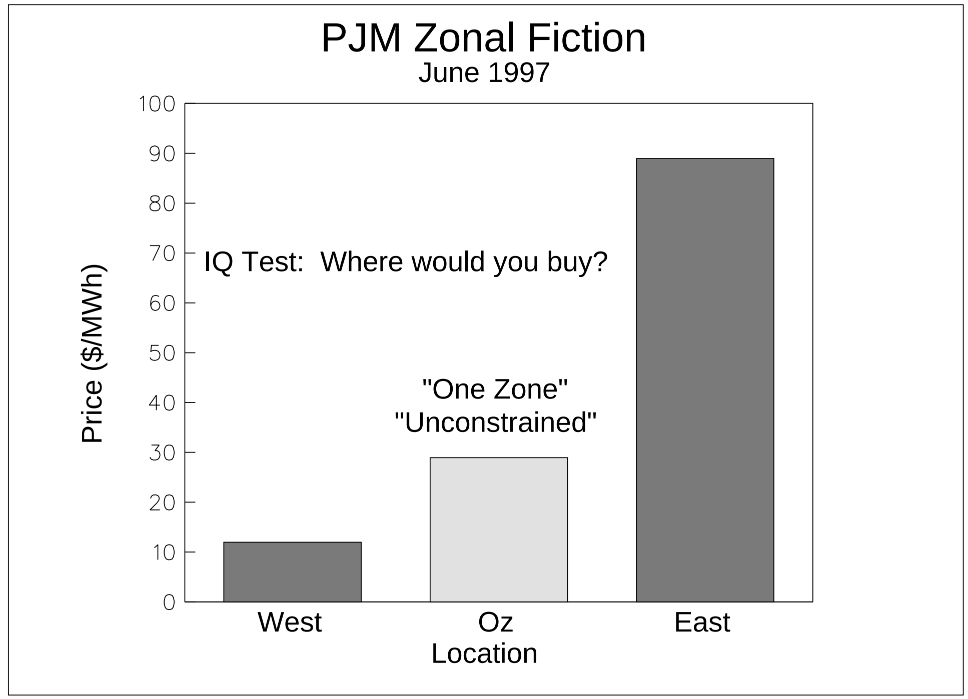
[2] FERC, PJM Order, pp. 13-14.

The PJM order includes a number of important elements that support both open access and competition in the electricity generation market.

- Open access with non-discriminatory pricing.
- Transmission fixed cost recovery through system-wide (but not necessarily uniform) access charges.
- The ISO administers both a spot market and bilateral schedules, while maintaining reliability under principles of bid-based, economic, security-constrained dispatch.
- Transmission congestion charges determined by locational prices from the bid-based spot market.
- Fixed transmission rights (i.e., transmission congestion contracts) for congestion costs between locations.
- Future developments to include multi-settlement systems, other bidding protocols and transmission right trading.

In June of 1997, PJM saw marginal cost in the east at about $89 per MWh, when at the same time the marginal cost in the west was $12 per Mwh. The "unconstrained" price for the "One Zone" (Oz) was approximately $29 per MWh.

A customer could buy from the spot-market dispatch at $29, or it could arrange a bilateral transaction with a constrained-off generator in the west at a price closer to $12. The choice presented a low-level IQ test. Market participants passed the test. Constrained-off generators quickly arranged bilateral transactions and scheduled their power for delivery. Soon the ISO had no more controllable generating units with which to manage the transmission constraints. Unable to fix the perverse pricing incentives, the ISO prohibited bilateral transactions. The unintended consequences of superficially simple pricing spawned administrative rules to foreclose the market.



A challenge for transmission pricing and access is to balance the goals of commercial practicality and flexibility in customer choice.

- If customers have flexibility in the choice of generation, spot purchases, bilateral transactions, and so on -- then prices must reflect the cost impacts.

- If prices do not reflect cost impacts, customers will respond and the system will be driven to a combination of reduced choice, higher costs and accretion of administrative fixes.

- The focal point for the tradeoff has been in transmission congestion pricing. The FERC order for PJM has set us on the right path with locational prices at nodes -- "We have seen the future and it is PJM." However, the debate will continue elsewhere with proposals to average congestion costs across one or more zones. The simplicity of zones is deceptive; in the end, nodal pricing is simpler in the context of competitive markets and customer choice.

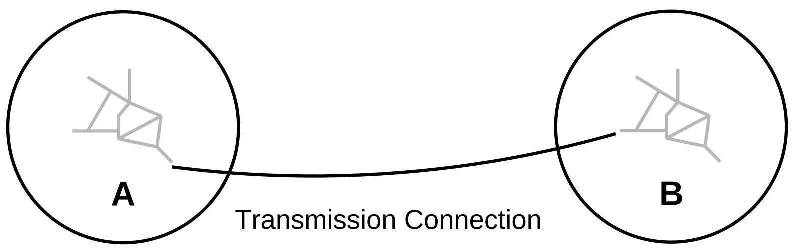
"A theory should be as simple as possible -- and no simpler." (Einstein)

Marginal cost pricing in an open access, competitive electricity market implies different prices at every location in the network. This sounds complicated. Aggregation of locations into zones is offered as an obvious simplification.

Zones Appear Simpler With a Single Connection

With a Single Connection and Constraint

- All prices within a zone would be the same.
- Prices for zones A and B differ only if transmission connection is constrained.



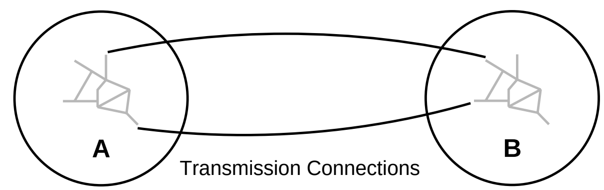
If the world divided naturally into zones, life would be simpler. However, aggregation of a real world with true locational differences into a fictional world with zones would not be as simple as it seems. As always, for competition to be flexible and to work well, it will be important to get the prices right. A number of questions arise when we look further into the choice between aggregation into zones or using the actual locational prices.

- **If Zones are Defined by Nodes with Common Prices, Why Bother?**
- **How Would We Define the Zonal Prices?**
- **Would Locational Prices Be Hard to Calculate and Come from a Black Box?**
- **Would It Be an Easy Matter to Set and Later Change the Zonal Boundaries?**
- **Is Transmission Congestion a Small Problem?**
- **Would Zonal Pricing Mitigate Market Power?**
- **Can the Market Operate With a Simpler System?**

Zones Are Not As Simple With Parallel Connections

With a Single Connection and Constraint

- All prices within a zone would be the same.
- Prices for zones A and B differ only if transmission connection is constrained.



With a Parallel Connection and Constraints

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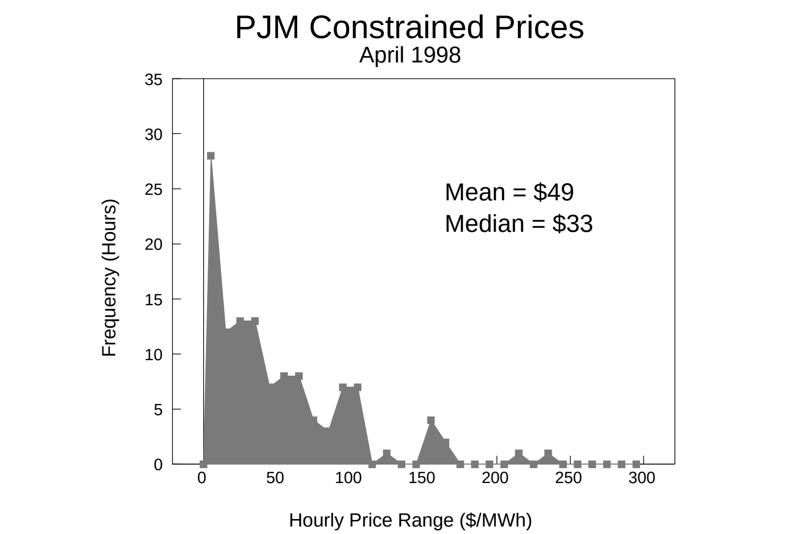
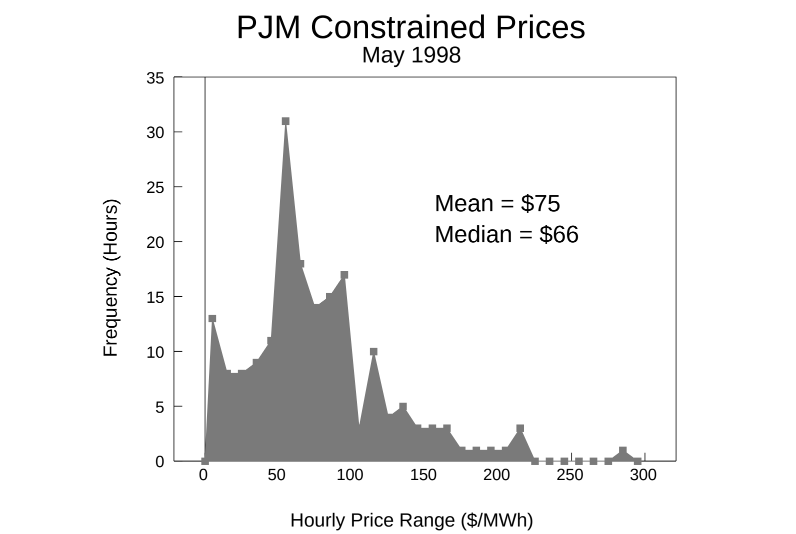
- *None of the above.*

The range of prices and degree of congestion exhibited in the first two months of operation of the PJM locational pricing system disproved the oft repeated argument that transmission congestion was rare and inconsequential.

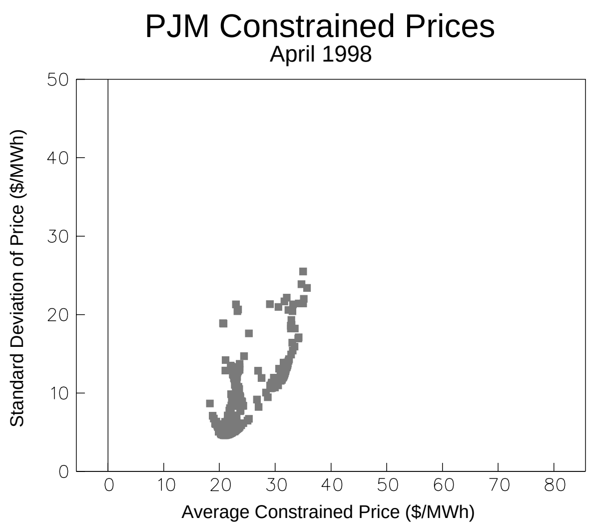


Maximum difference in locational prices for constrained hours.

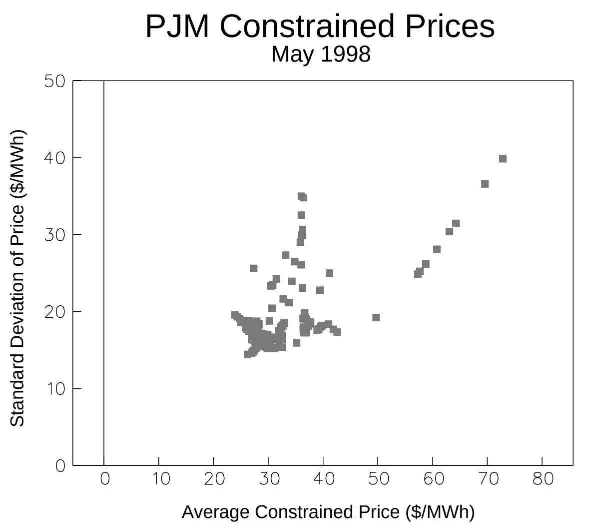


Maximum difference in locational prices for constrained hours.

An argument applied around the world evokes the use of zones to average or aggregate transmission congestion prices. The argument was made that PJM would have only a few zones with clusters of similar locational prices. Results from April and May 1998 reject that hypothesis. Using a threshold of an average congestion difference of $1 MWh over a month, there were at least 132 zones required to capture the price differences in PJM, so far. The zonal approach is neither accurate nor simple.



Mean and standard deviation over 119 constrained hours at different locations.



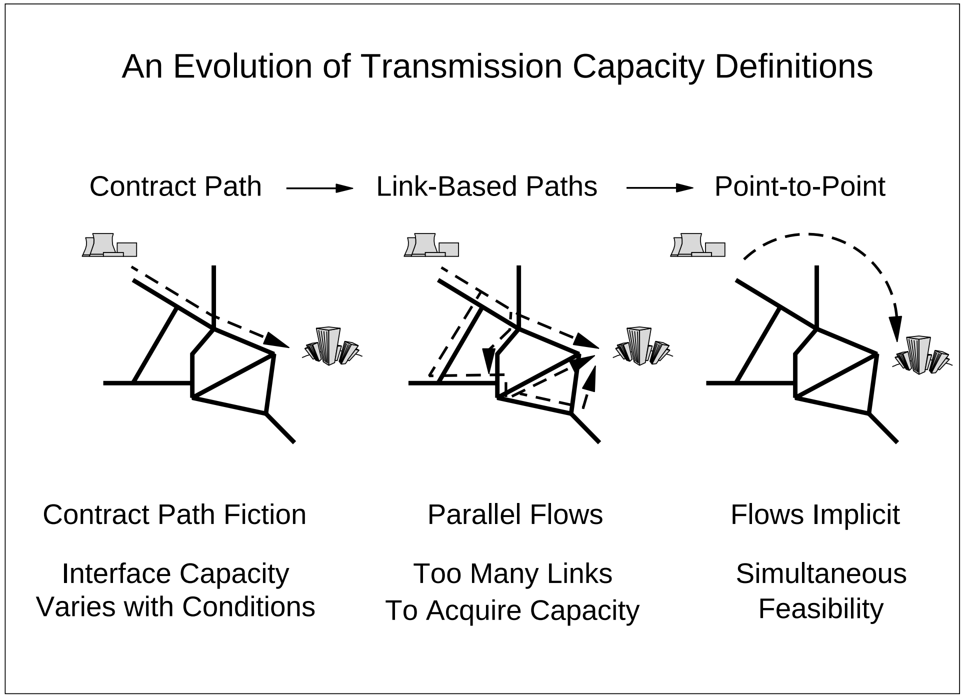
Mean and standard deviation over 183 constrained hours at different locations.

The FERC CRT proposal contained a critical innovation in moving to point-to-point rights in place of the flawed contract path approach. We are only part way there, but it is the future.

- **Point-to-Point Transmission Capacity Rights.** Abandoned contract path and link-based approaches for tradeable point-to-point rights. Handles all constraints

- **Physical vs. Financial Rights.** Industry response emphasized the difficulty of trading rights and matching with physical transmission use. Alternative interpretation emphasized financial contracts.

- **Coordinated Trading of Rights.** Transmission right trading requires coordination to respect network interactions. A role for the ISOs?

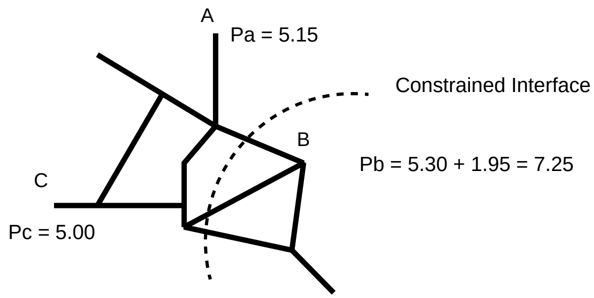


- **PJM Implementation.** The CRT is alive and working in the PJM implementation with Fixed Transmission Rights to receive congestion payments. Proposed in New York with equivalent transmission congestion contracts.

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

Bus Price = Generation Cost + Marginal Losses + Congestion Costs



Pcb = Pb - Pc = Marginal Losses + Congestion Costs = 0.3 + 1.95 = 2.25

- 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.

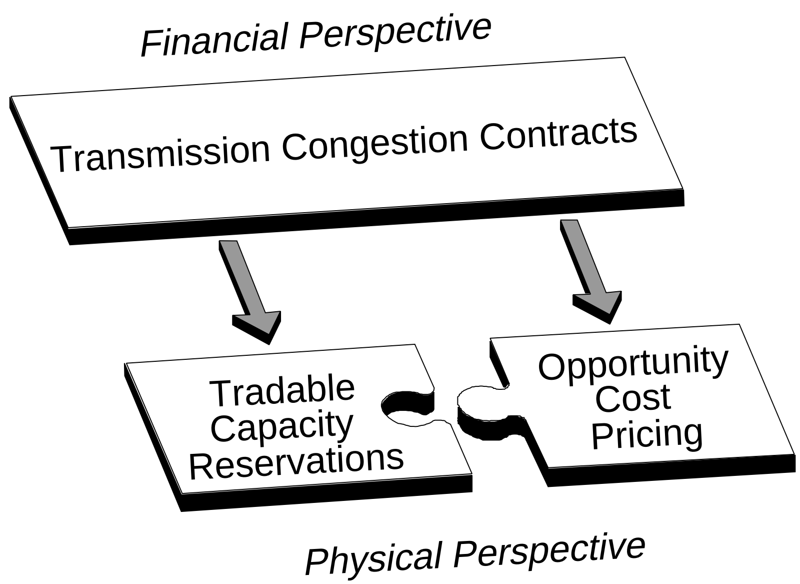
- **Dispatch with No Congestion Payment**. Inject and remove a fixed quantity of power without any congestion payment.

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.

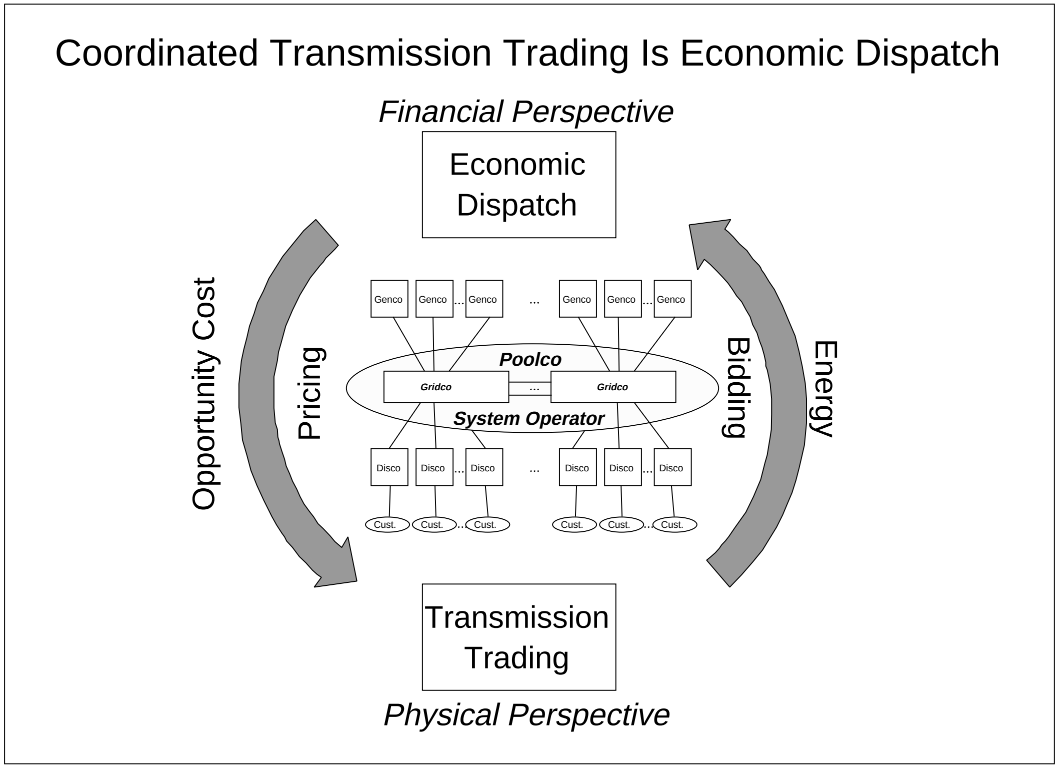
Many variants are possible, allowing great flexibility in developing and trading contracts. The contract network can allow great commercial flexibility while respecting the reality of the actual network in determining the locational prices.

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.

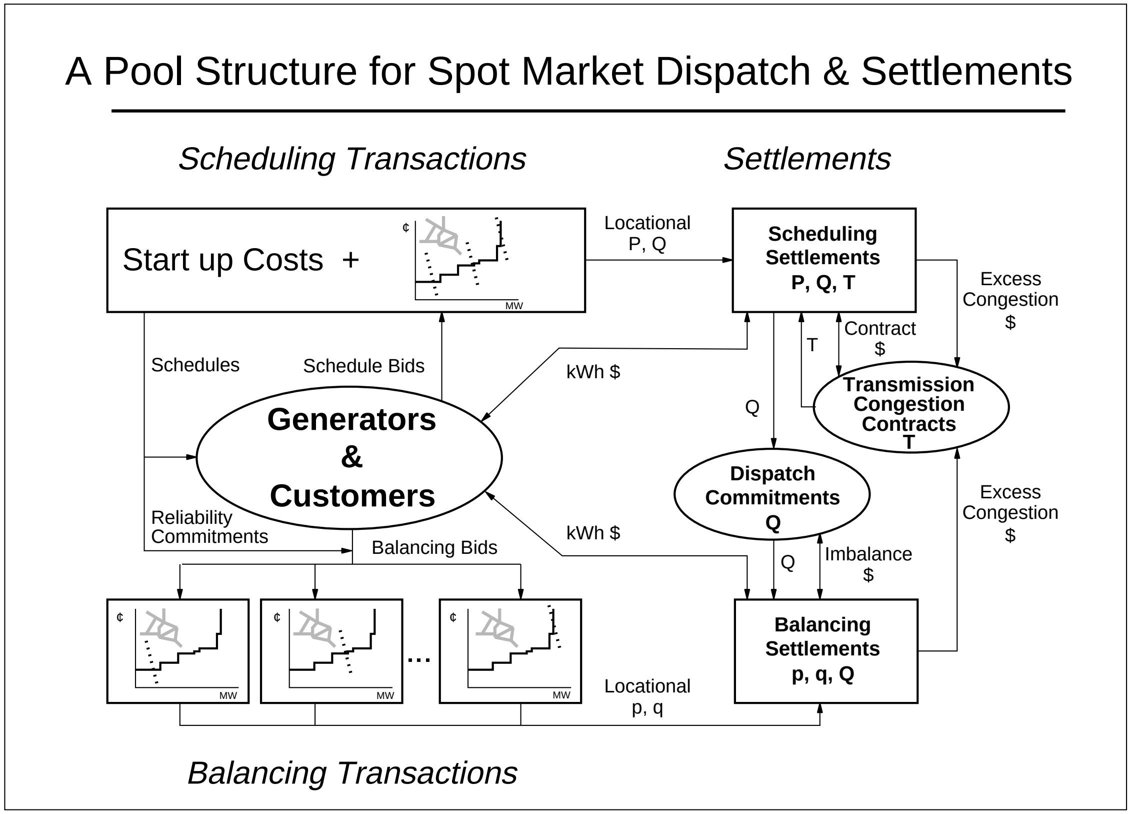
Transmission Capacity Reservations & Congestion Contracts



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.

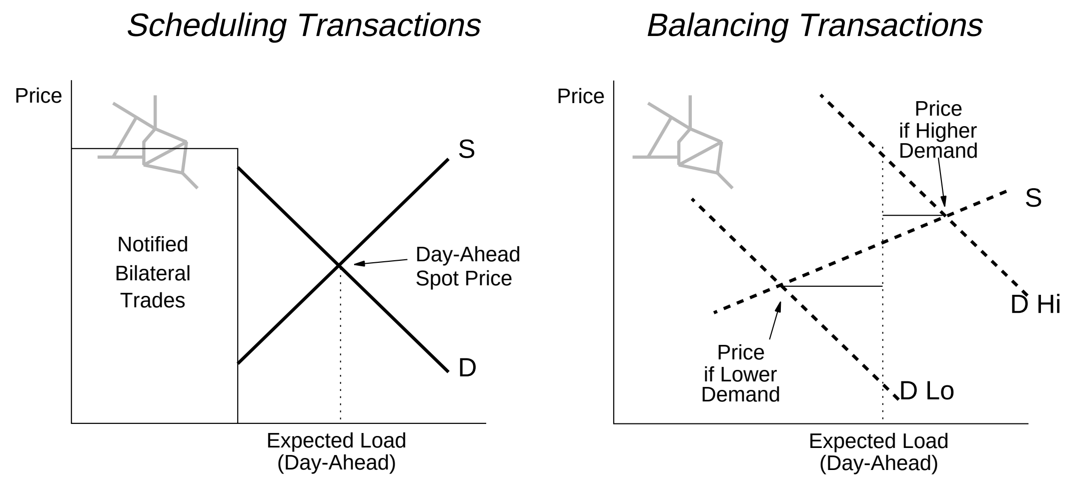


The pool-based market structure could include scheduling transactions to deal with unit commitment issues and balancing transactions for the final dispatch. Contract-network transmission congestion contracts would be valued for the scheduling transactions. Bidding for the scheduling transactions would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

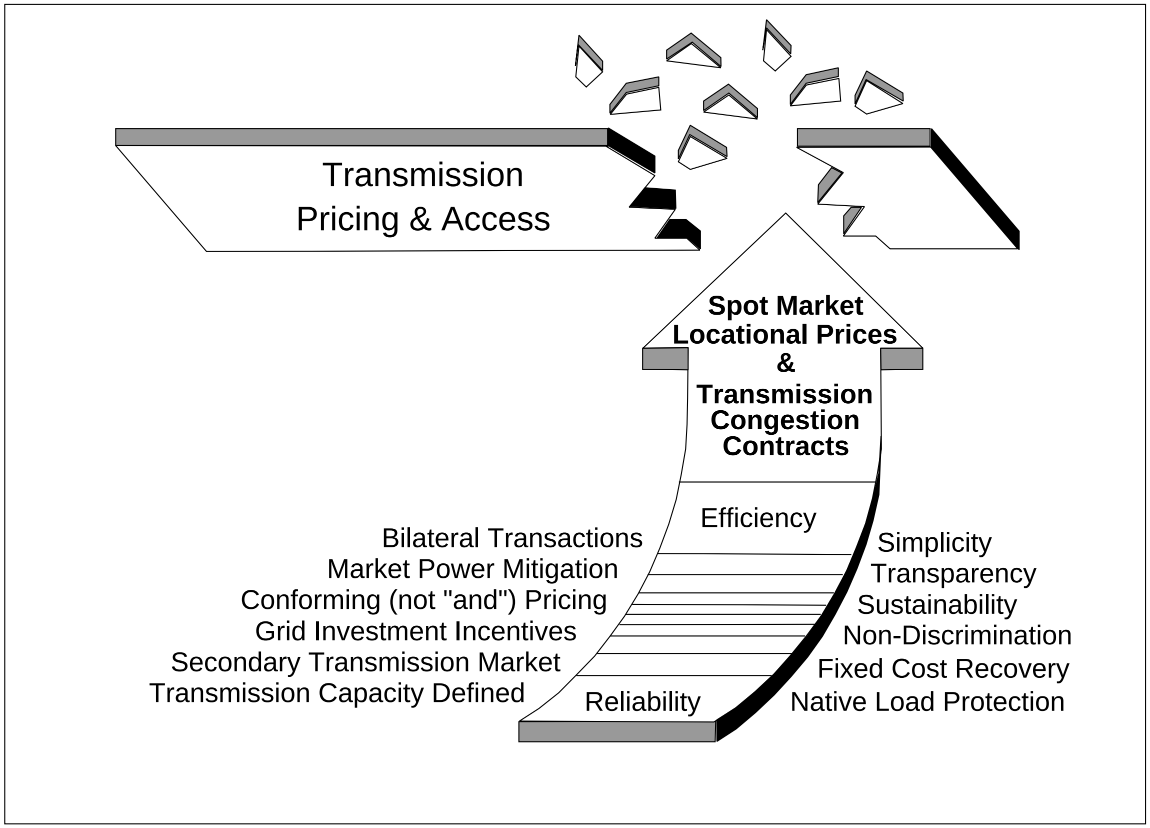
Balancing Price for Deviations from Scheduled Commitments



- Notified bilateral trades pay locational transmission charge but are settled outside pool
- Other trades settle at day-ahead price
- Locational congestion rents paid under transmission congestion contracts along with excess congestion costs

- Payments for deviations from day-ahead trades at balancing price for all transactions
- Uplift covers ancillary services and other costs
- Excess congestion costs paid to holders of transmission congestion contracts

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.



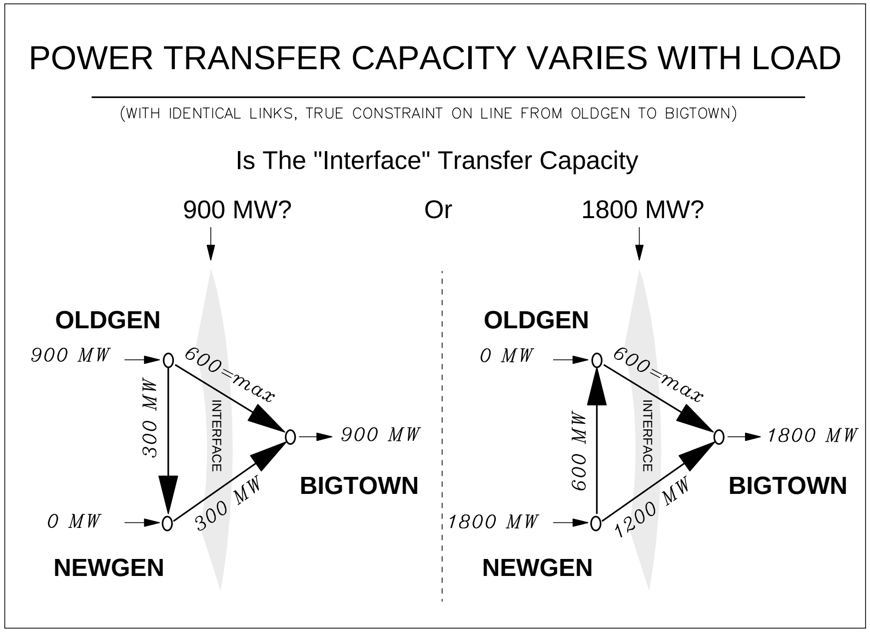
Appendix

Contract Networks:
Transmission Congestion, Locational Pricing and Transmission Congestion Contracts

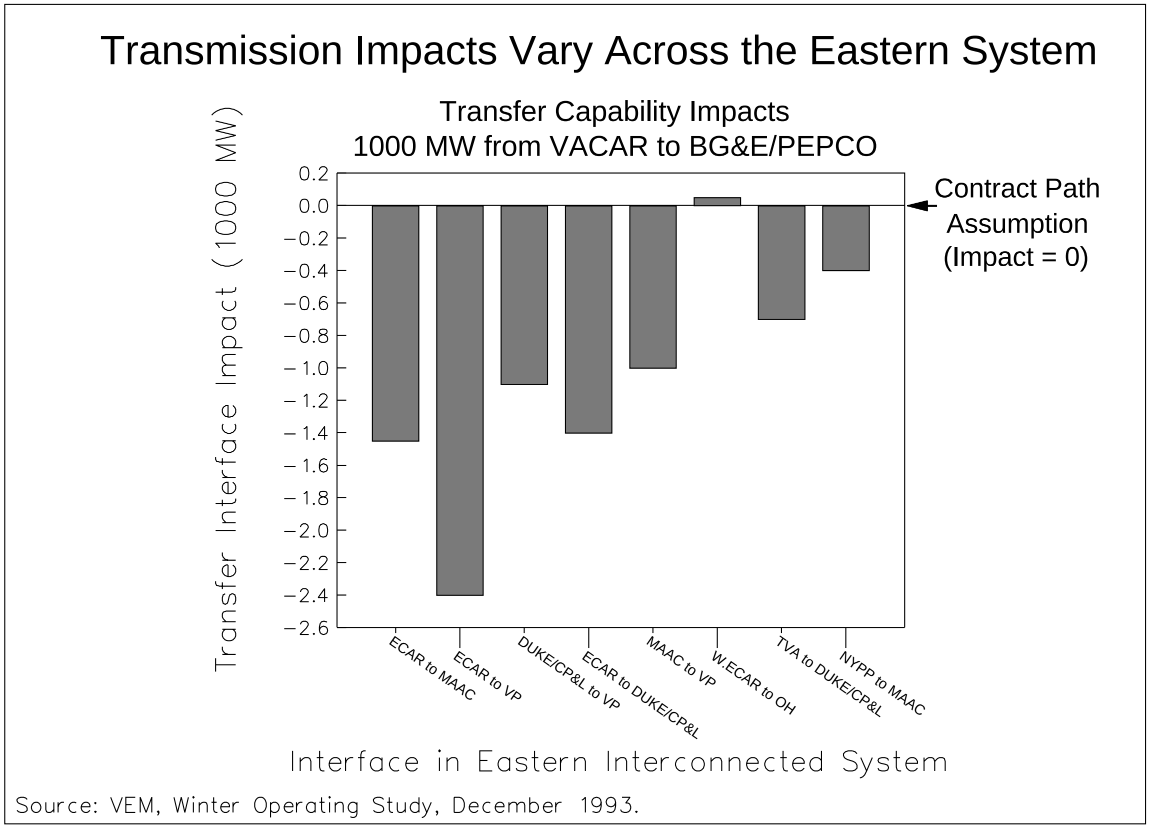
Electric transmission network interactions can be large and important.

- Conventional definitions of network "Interface" transfer capacity depend on the assumed load conditions.

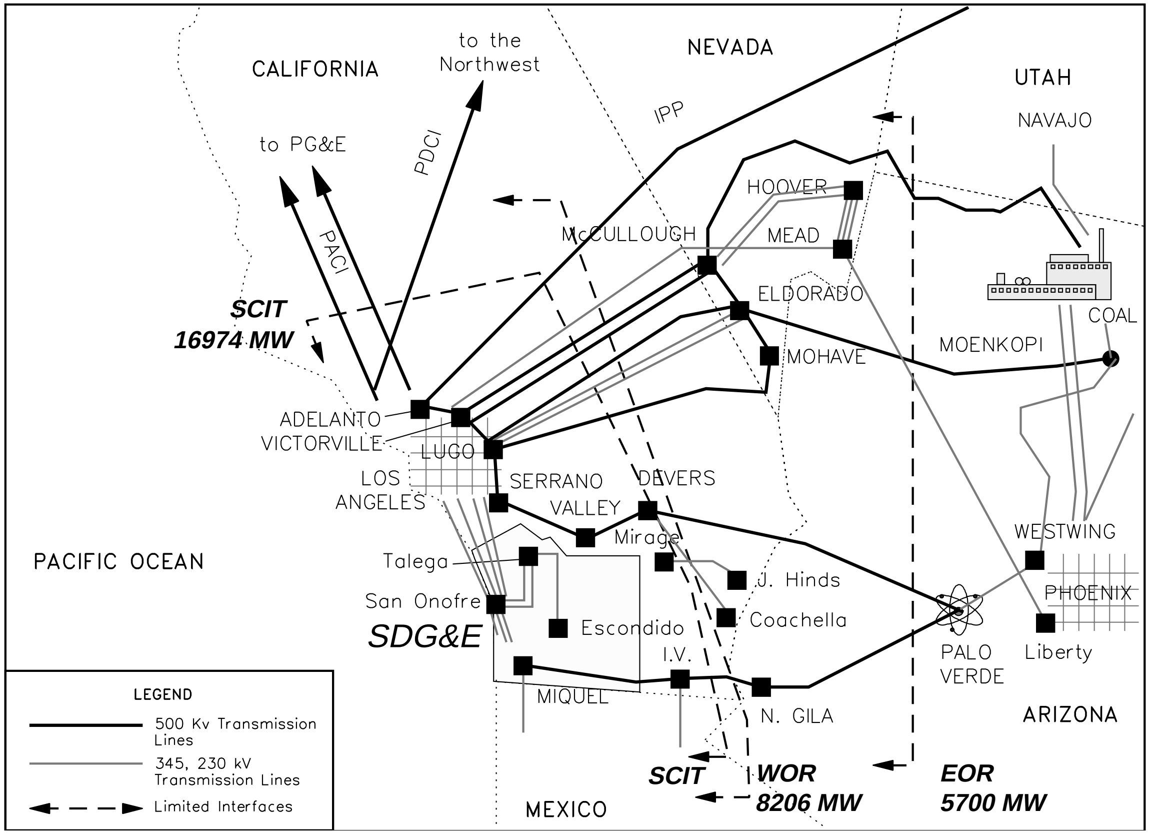
- Transfer capacity cannot be defined or guaranteed over any reasonable horizon.



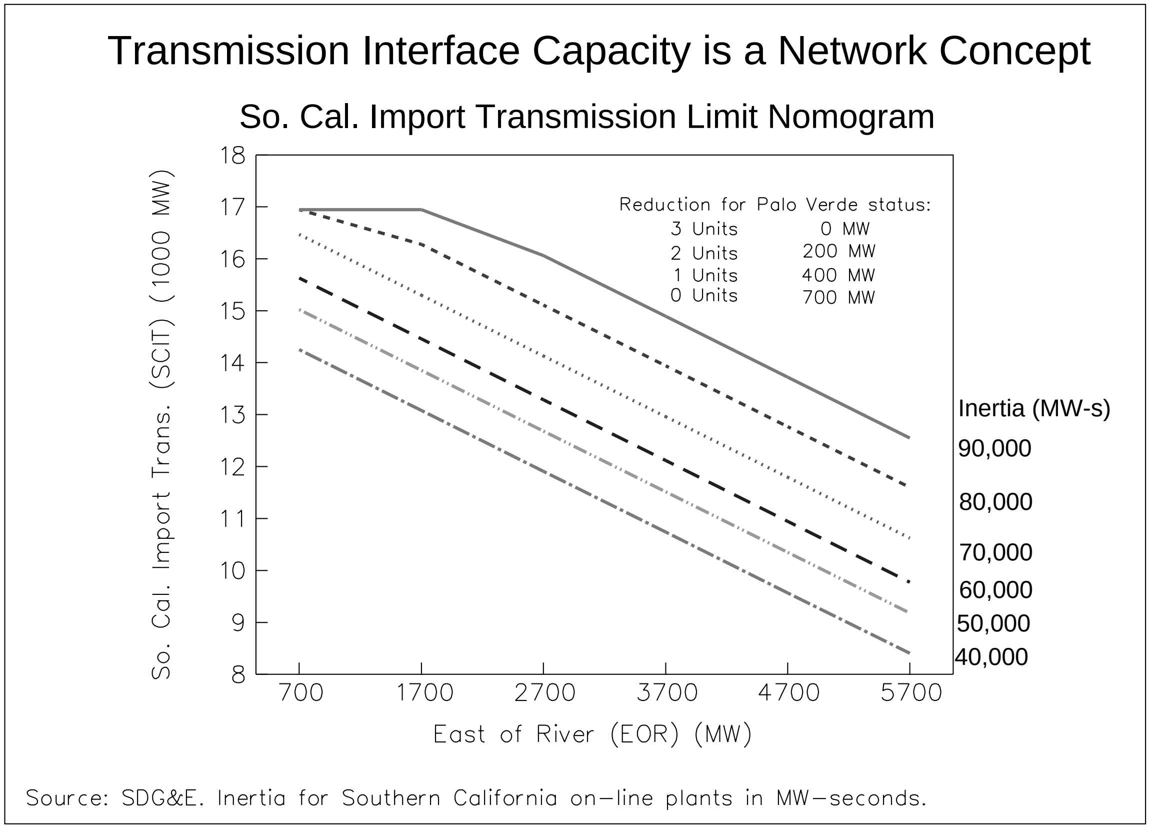
There is a fatal flaw in the old "contract path" model of power moving between locations along a designated path. The network effects are strong. Power flows across one "interface" can have a dramatic effect on the capacity of other, distant interfaces.



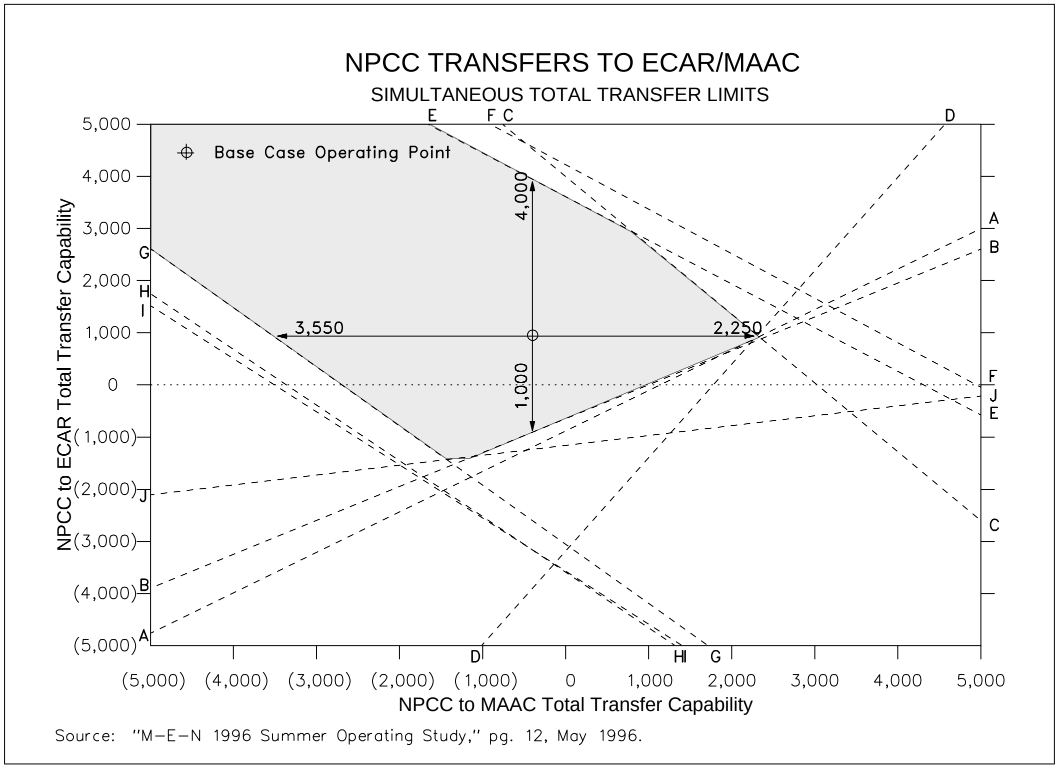
The strong network effects apply in most, or all interconnected grids. In southern California, for example, there are important interfaces with maximum limits that cannot be achieved simultaneously. Complex "nomograms" summarize the simultaneous constraints. (see next page)



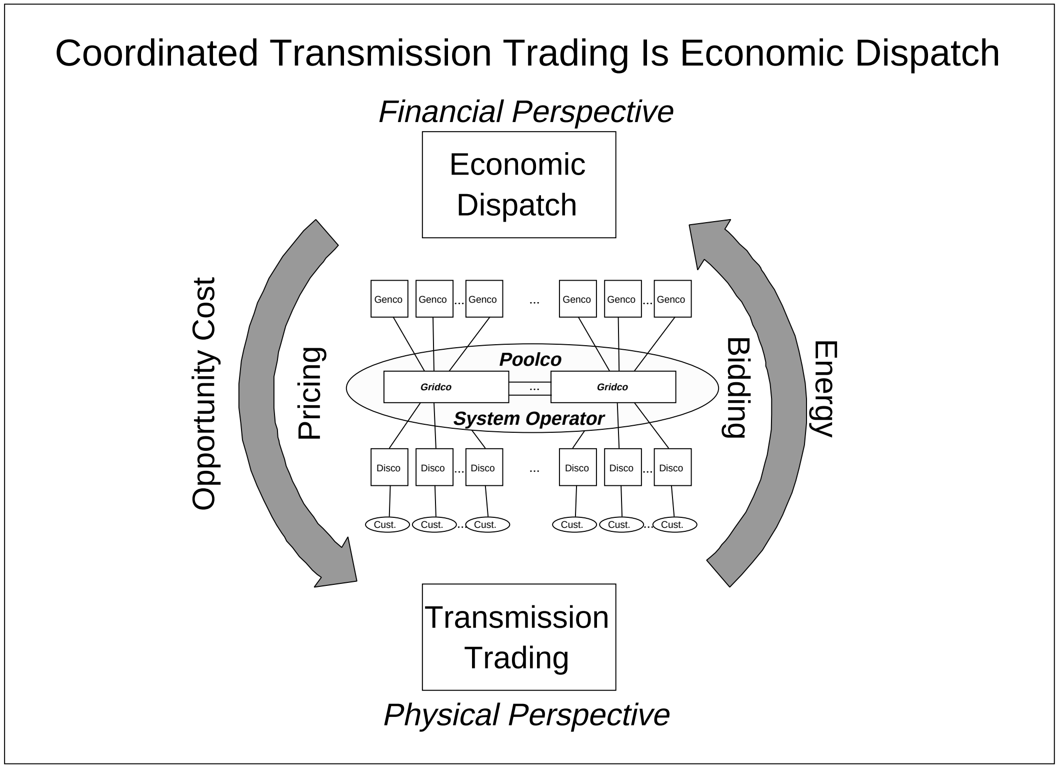
The SCIT "nomogram" for southern California illustrates the strong interdependencies of network flows and the breakdown of the contract path model. Management of this system requires a network perspective and a network coordinator, here Southern California Edison.



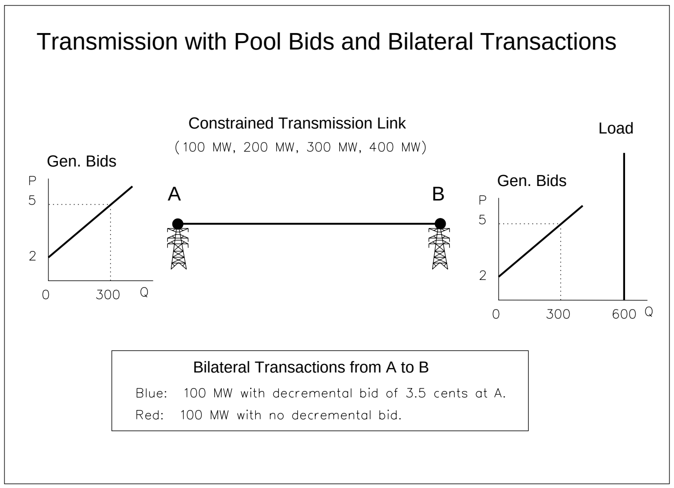
For some network nomograms, the interactions are such that there is no simple exchange ratio of "physical" rights could be guaranteed. Central coordination of trading would be required to reconfigure use on the jointly constrained interfaces. This is well known and is it the root of the extensive NERC efforts to develop flow-based transmission scheduling, reservation, and line relief.



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.



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.



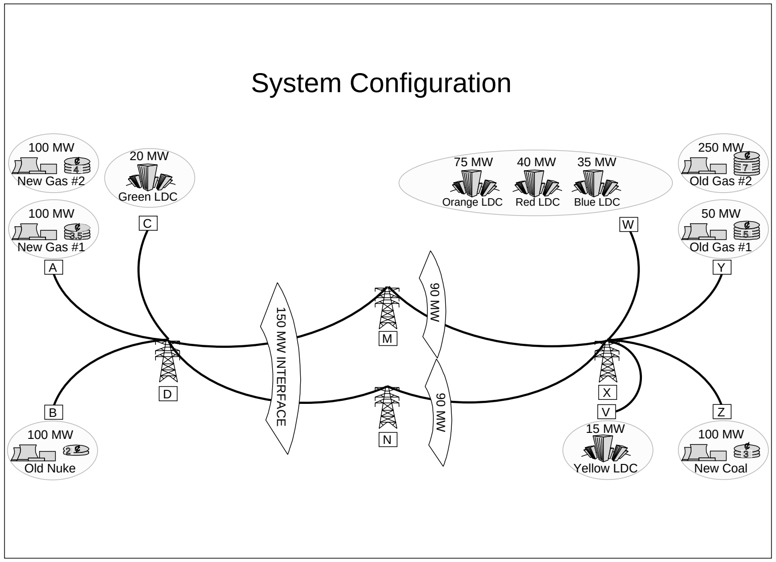
Power Flows and Locational Prices					
	Alternative Cases				
Link Capacity A to B	MW	400	300	200	100
Total Load at B	MW	600	600	600	600
Price at A	cents/kwh	4	3.5	3	2
Price at B	cents/kwh	4	5	6	7
Transmission Price	cents/kwh	0	1.5	3	5
Pool Generation at A	MW	200	150	100	0
Pool Generation at B	MW	200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

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

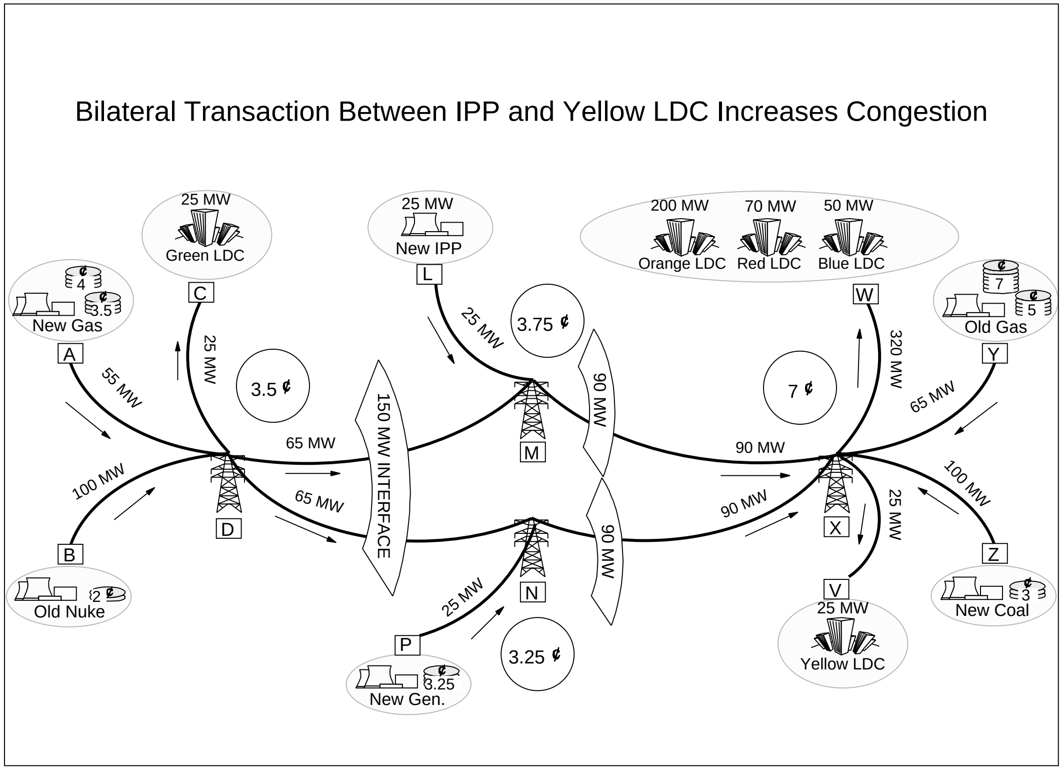
The examples assume a transmission system with the following characteristics:

- 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.

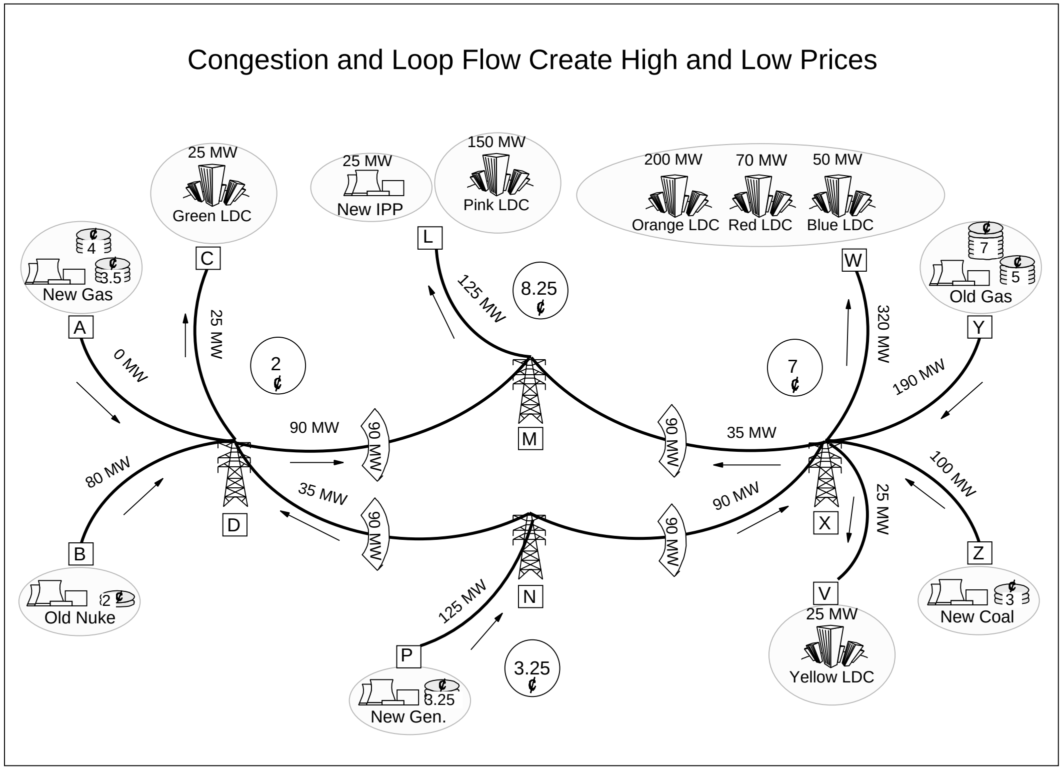


Loads in this figure are illustrative and will vary systematically in each example. For convenience, losses are ignored in all examples.

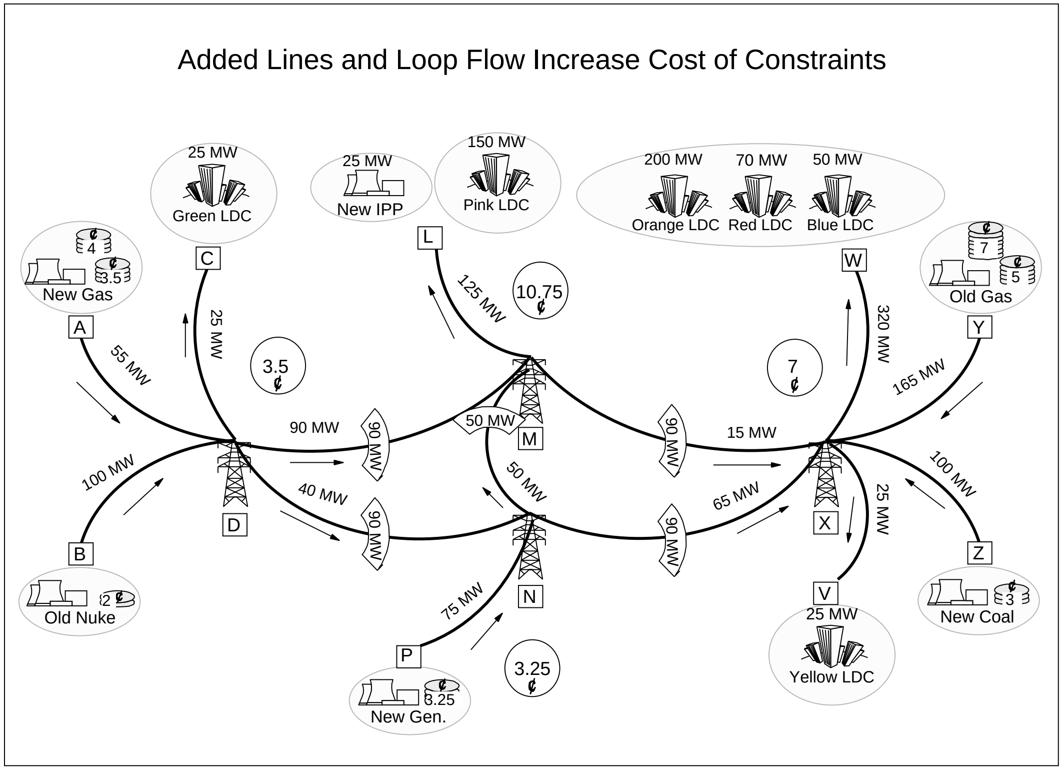
A low cost, large capacity generator becomes available at bus "P." The IPP at bus "L" has bid in a must run plant at 25 MW, having arranged a corresponding sale to the Yellow distribution company at bus "V". Were it not for the IPP sale, more power could be taken from the inexpensive generators at bus "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".



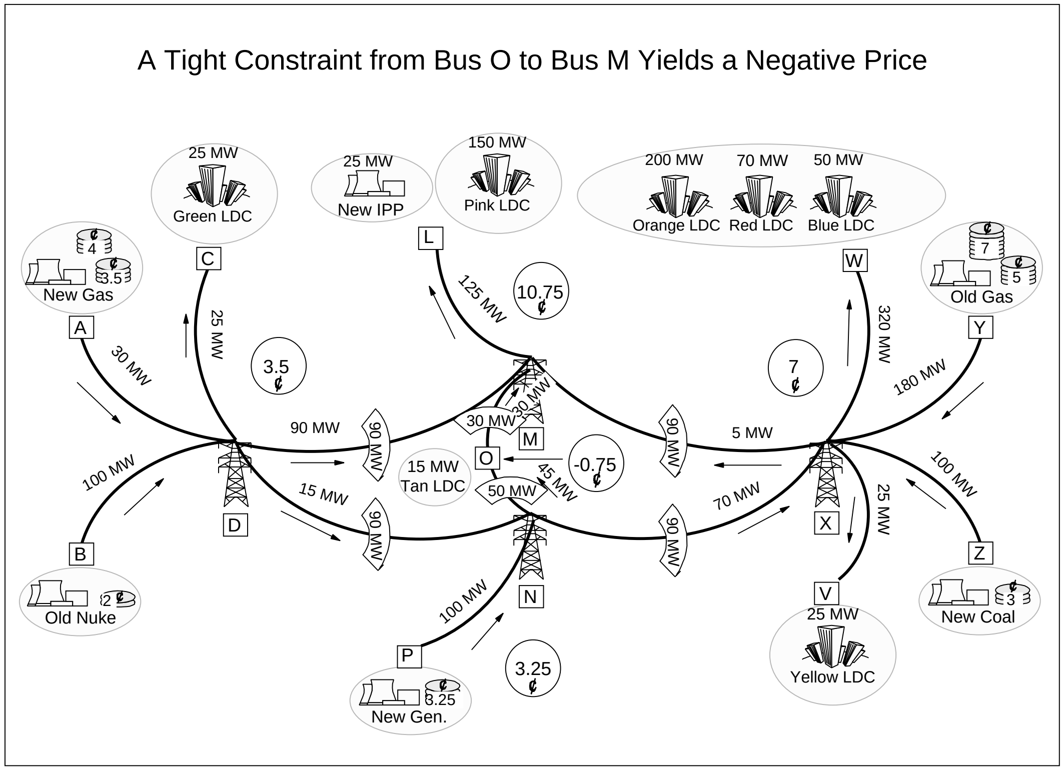
Here every line in the main loop is constrained by a thermal limit of 90 MW, replacing the interface limit. With these constraints, an added load of 150 MW at bus "L" alters the flows for the market equilibrium. In this case, the combined effect of the increased load and the constraints leads to a price 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.



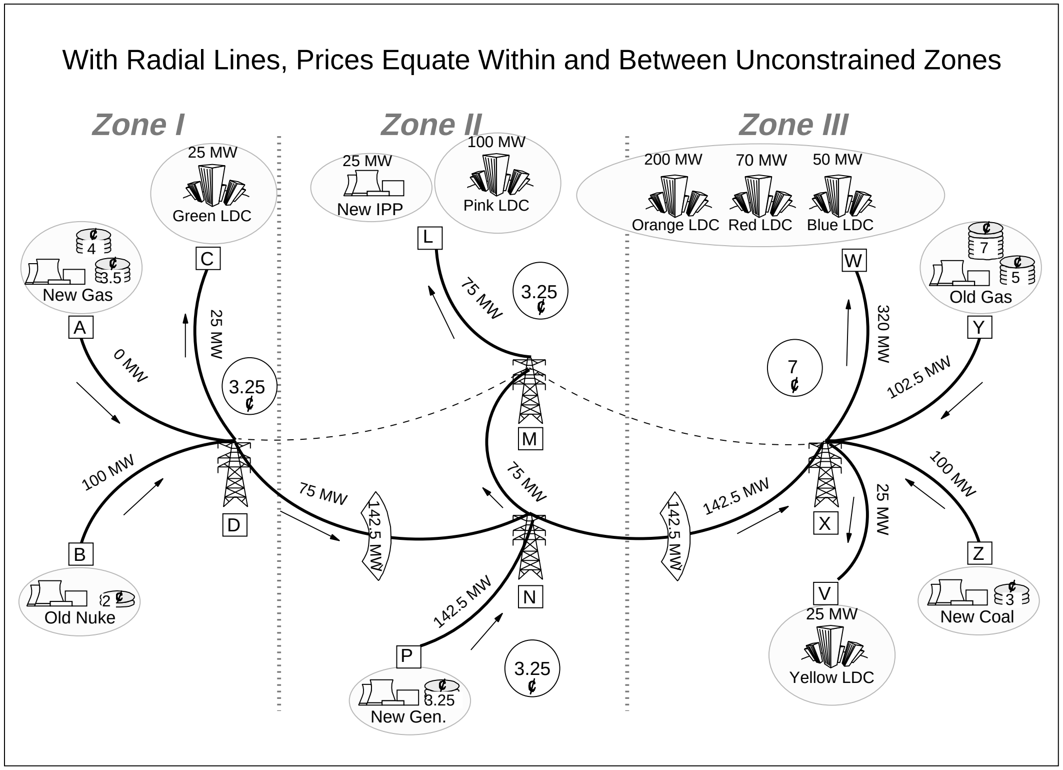
Next a new line has been added to the network, connecting bus "N" to bus "M". This line is assumed to have a thermal limit of 50 MW. The new line adds to the capability of the network in that the new pattern of generation lowers the overall cost of satisfying the same load. The total cost reduces from $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.



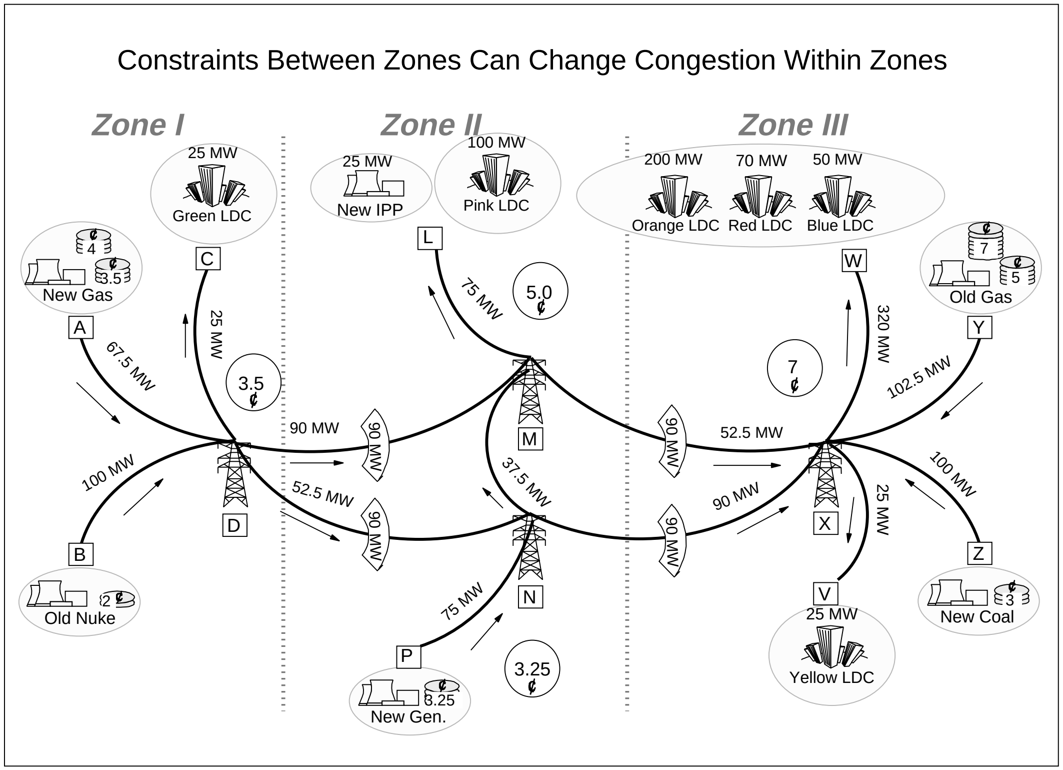
Add a new bus "O" between bus "M" and bus "N", and lower the limit to 30 MW between bus "O" and bus "M". Bus "O" has a small load of 15 MW. The increased load of 15 MW at bus "O" actually lowers the total cost of the dispatch, as reflected in the negative price. Each additional MW of load at bus "O"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



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.



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.



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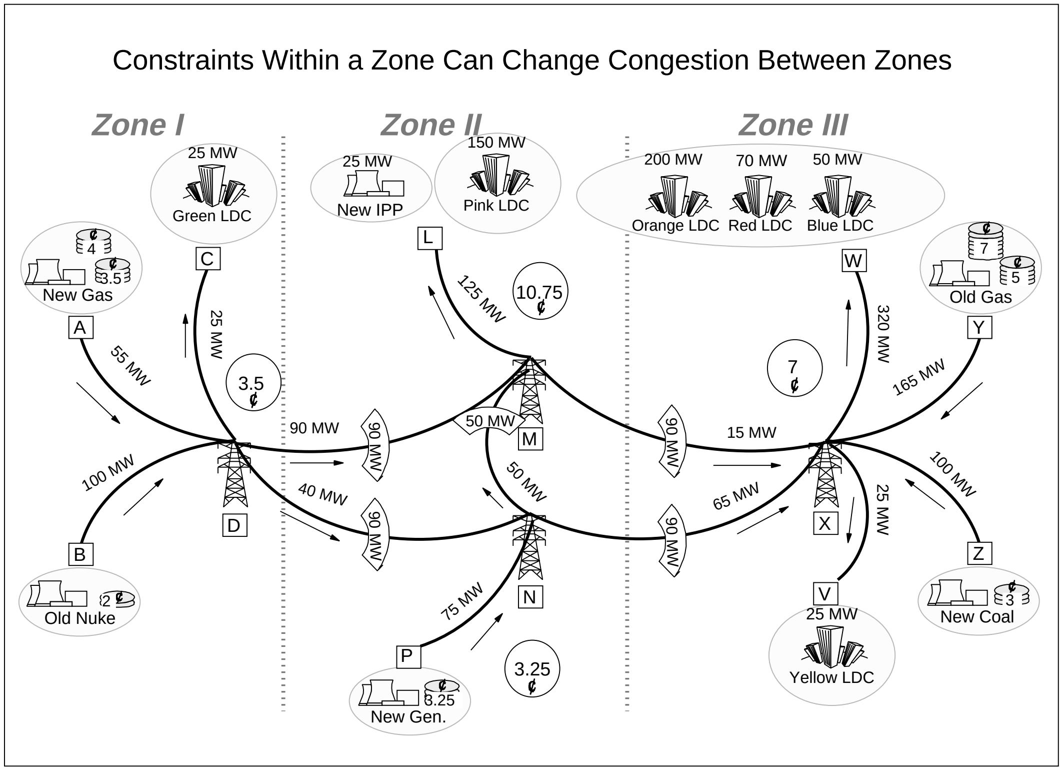


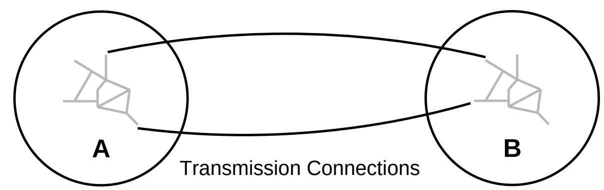
If the world divided naturally into zones, life would be simpler. However, aggregation of a real world with true locational differences into a fictional world with zones would not be as simple as it seems. As always, for competition to be flexible and to work well, it will be important to get the prices right. A number of questions arise when we look further into the choice between aggregation into zones or using the actual locational prices.

- **If Zones are Defined by Nodes with Common Prices, Why Bother?**
- **How Would We Define the Zonal Prices?**
- **Would Locational Prices Be Hard to Calculate and Come from a Black Box?**
- **Would It Be an Easy Matter to Set and Later Change the Zonal Boundaries?**
- **Is Transmission Congestion a Small Problem?**
- **Would Zonal Pricing Mitigate Market Power?**
- **Can the Market Operate With a Simpler System?**

Zones Are Not As Simple With Parallel Connections

With a Single Connection and Constraint

- All prices within a zone would be the same.
- Prices for zones A and B differ only if transmission connection is constrained.



With a Parallel Connection and Constraints

-
- *None of the above.*

With this background on the connections between locational pricing and zones, we can return to the questions:

- **If Zones are Defined by Nodes with Common Prices, Why Bother?**

The definition of a zone is sometimes offered as a group of locations that would have the same locational price. For this to be literally true the connections must be radial connections. In a sufficiently interconnected system, with parallel flows, there will be different prices across any collection of locations, even with constraints that appear to be external to the putative zone. If the locational prices differ by only trivial amounts, then locational pricing and zonal aggregation produce the same end result. There would be no need to aggregate.

Hence, it appears that the real application of zonal aggregation must be in situations where the underlying rationale is compromised. Zonal aggregation would be interesting only in those situations where the aggregation results violated the premise of the creation of the zone.

- **How Would We Define the Zonal Prices?**

If the real application of zones is important only when there is a material difference in the locational prices, then there must be some rule specified for determining the price in the zone. The answer is not obvious. The intuition derived from the analysis of the single radial transmission line connection can mislead.

The usual proposals for price aggregation involve some form of averaging. A typical approach starts with a hypothetical unconstrained price, which is then charged to all customers and paid to all generators. Those generators needed at locations with truly higher prices would be paid their opportunity costs. The difference above the "unconstrained" price is collected in an uplift that is averaged over all customers.

Any such rule immediately raises the question of what happens to the constrained-off generators. The solution in England and Wales has been to pay the generators the profit they would have made if they had run and received the unconstrained price, with the costs added to the uplift and collected again from all customers.

In addition, the English pool prohibits bilateral transactions to avoid the problem of the constrained-off generators going around the price averaging system. This limits the flexibility of the market. However, the importance of such rules was dramatically illustrated by the events in the Pennsylvania-New Jersey-Maryland Interconnection (PJM) system during June of 1997.

- **Would Locational Prices Be Hard to Calculate and Come from a Black Box?**

Locational 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 for pricing purposes. 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. Part of the misunderstanding on this point is the distinction between determining an economic dispatch (difficult) and determining the prices given the dispatch (easy). The hard part in dispatching is both unavoidable and already done. The easy part of calculating the prices is a detail. At a recent FERC Technical Conference, the ISO for PJM explained how to calculate the prices and described the software used to determine the prices. An independent auditor verified that the system was understood and auditable. The PJM system produces prices posted every five minutes on the Internet. (www.pjm.com)

- **Would It Be an Easy Matter to Set and Later Change the Zonal Boundaries?**

The rationale for zones rests in part on the assumption that the zones would be easy to define and would be stable for long periods. However, when conditions changed, the zones would be redefined to come back into compliance with the original definition that there would be no difference in locational prices within the zones.

Each of these points raises a number of complications that must be recognized. First, it is not so obvious where the zonal boundaries should be set. For example, recent PJM "[O]perating data show that, during the past 14 months, 70 percent of the out-of-merit costs for transmission control in PJM resulted from thermal contingencies." These thermal limits are exactly the type of constraints that create the looped interactions.

Since establishment and reconfiguration of the pattern of subsidies will depend on extensive analysis of prospective conditions, there will be many assumptions and points of debate about what the appropriate boundaries should be next week or next year. Although the computational challenge of computing locational prices for the actual dispatch is trivial, the process of forecasting these prices is another matter entirely, one that promises to be controversial. At the risk of understatement, there is little in past regulatory experience which gives confidence that this creation and rearrangement of subsidies will be either swift or simple. Policy makers who think that zonal aggregation and cross subsidies will simplify the process should look again.

- **Is Transmission Congestion a Small Problem?**

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. 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. If we give market participants choices, such as between pool and bilateral transactions, it will be important to get the prices right.

When transmission constraints do apply, the price differences can be surprisingly large. In August for example, the reports were that PJM single zone again was operating with "dispatch rates," which would be similar to the locational prices if they were being charged, that were 8.9 cents in the constrained-on regions and 1.2 cents in the constrained-off regions of the zone. The "widely differing dispatch rates were repeated for several days last week." When constraints bind, therefore, the incentives created can be much larger than most people imagine. If participants were given the choice and flexibility that we think of as appropriate for the competitive market, these incentives would overwhelm the system as long as the prices charged diverged from the underlying locational marginal prices.

- **Would Zonal Pricing Mitigate Market Power?**

To the extent that there is a high concentration of control of generation or load, there will continue to be a potential for an exercise of market power. At first glance there would appear to be advantages to aggregation into zones. As the argument goes, the use of locational pricing would imply small local markets. By contrast, it seems logical that aggregation into zones would expand the geographic scope of the market and bring more actors into competition, thereby mitigating market power.

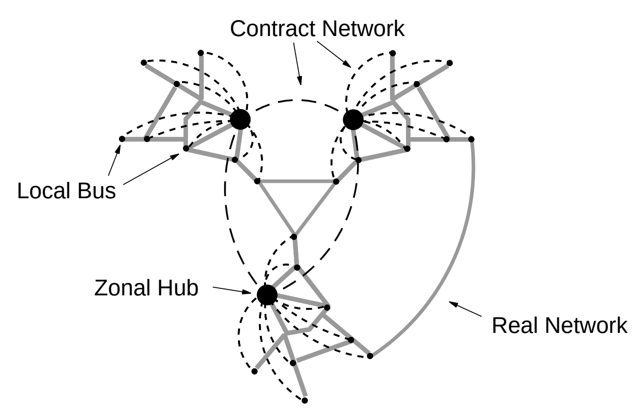
If the separation into local markets and locational marginal cost differences were simply an artificial institutional constraint, there might be something to this story, especially if the local generators were not competing with other generators in the network. In the present case, however, the facts are different. The constraints are real, and aggregation into zones would not remove the transmission constraints. Aggregation into zones would be likely to hide market power and remove some of the most important limitations on market power; namely, the demand side response and the ability of new entrants to challenge the dominant generator.

Zonal aggregation would not expand the real geographic scope of competition unless the aggregation rule implied setting all prices at the price of the dominant firm, which would create another set of problems. Hence, locational marginal cost pricing would reduce market power relative to the common zonal alternatives, and locational pricing would make the exercise of market power more transparent.

- **Can the Market Operate With a Simpler System?**

Contract Network Connects with Real Network

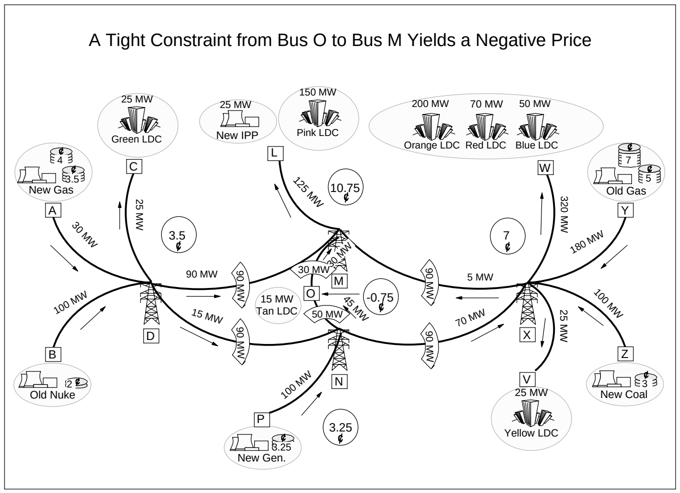
Determine Locational Prices for Real Network; Implement Transmission Congestion Contracts and Trading on Contract Network



Locational marginal cost pricing lends itself to a natural decomposition. For example, even with loops in a network, market information could be transformed easily into a hub-and-spoke framework with locational price differences on a spoke defining the cost of moving to and from the local hub, and then between hubs.

Creation or elimination of hubs would require no intervention by regulators or the ISO. New hubs could arise as the market requires, or disappear when not important. A hub is simply a special node within a zone. The ISO still would work with the locational prices, but the market would decide on the degree of simplification needed. However, everyone would still be responsible for the opportunity cost of moving power to and from the local hub. There would be locational prices and this would avoid the substantial incentive problems of averaging prices. This would simplify without distorting the locational prices.

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".

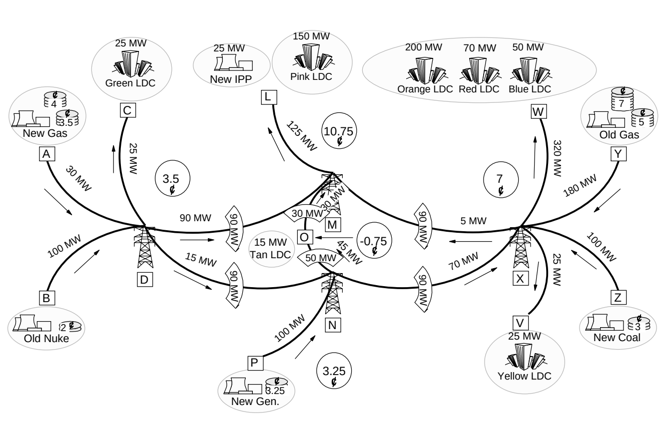


From-To	TCC 1 (MW)	TCC 2 (MW)
"D-O"	180	160
"O-X"	180	160
"M-O"	30	10
"N-O"	30	70

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.

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.

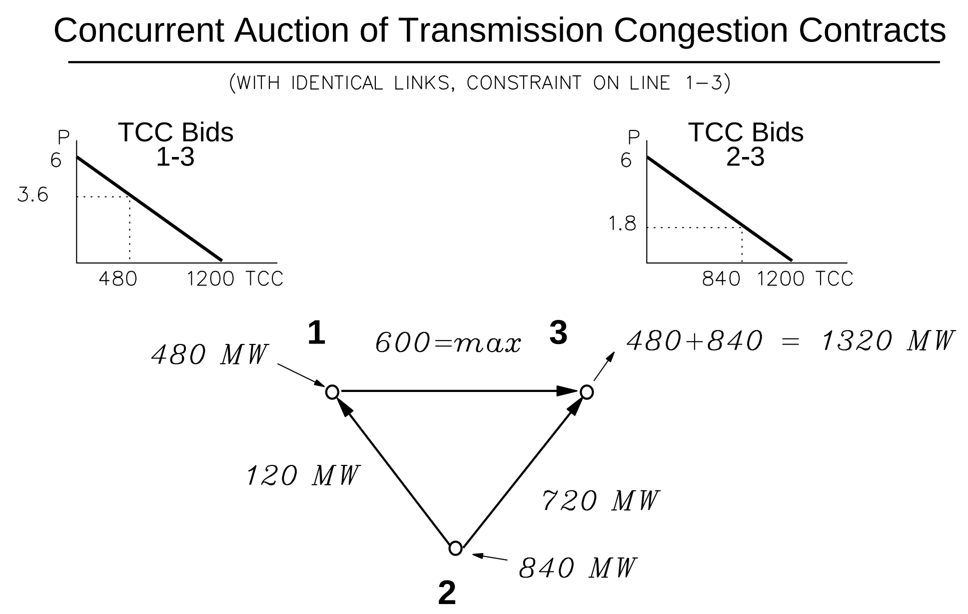
A Tight Constraint from Bus O to Bus M Yields a Negative Price



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

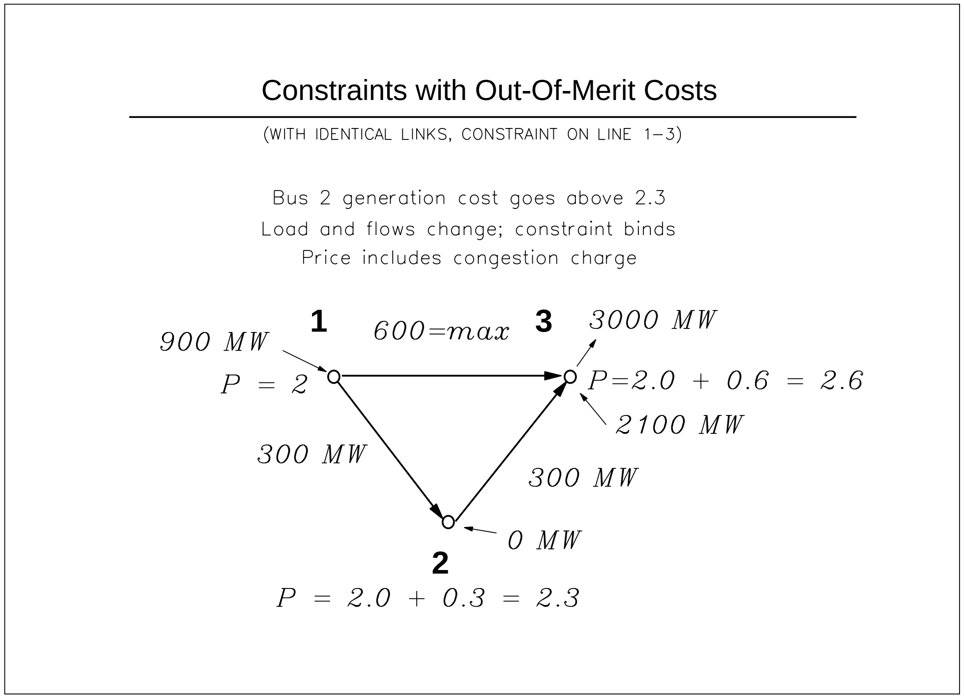
Load at "L"	Bus Prices ¢/kWh					Total Rents $	TCC 1	TCC 2
MW	"D"	"M"	"N"	"O"	"X"			
0	3.50	3.75	3.25	3.50	7.00	6300	6300	5750
50	3.50	5.58	3.25	4.15	7.00	6300	6138	6084
150	3.50	10.75	3.25	-0.75	7.00	10950	1650	1650

Transmission congestion 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.



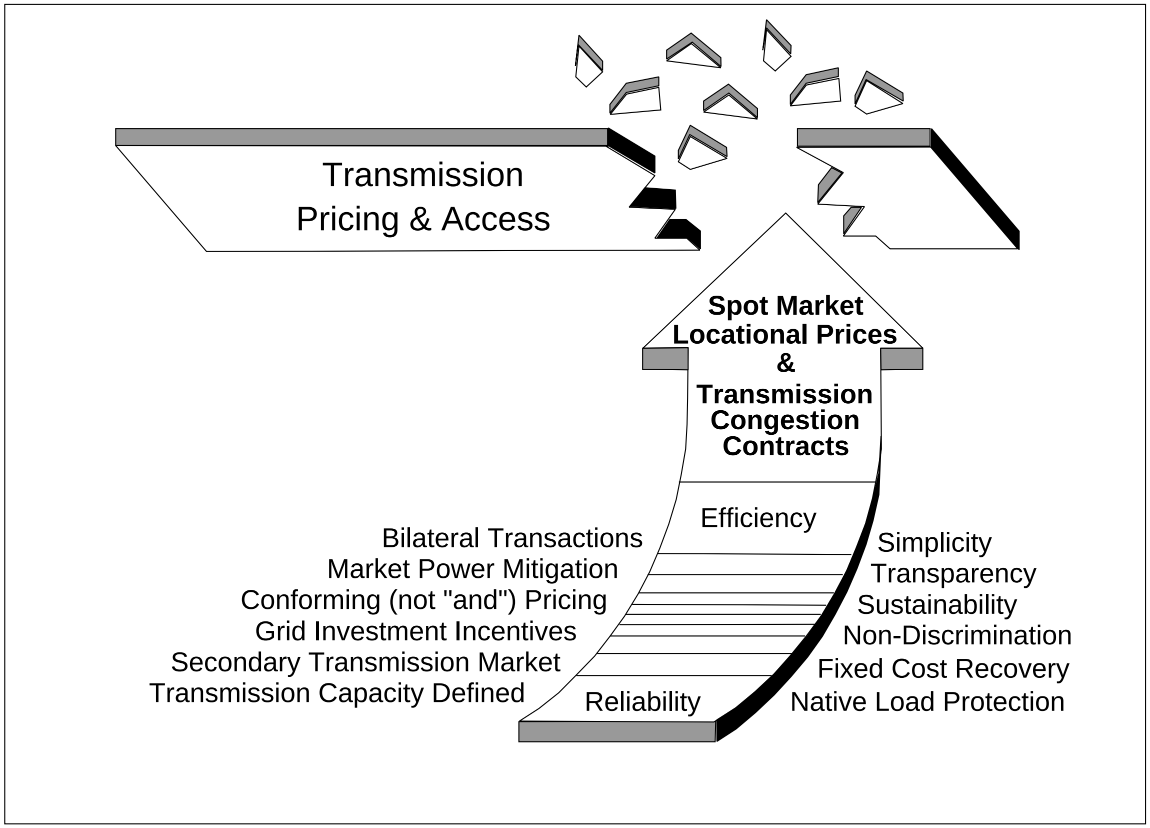
TCCs from 1 -> 3 awarded for 480 MW at price 3.6
TCCs from 2 -> 3 awarded for 840 MW at price 1.8

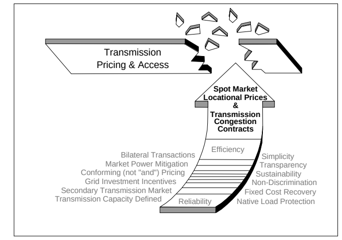
With spot locational prices, transmission congestion contracts provide price protection. Even with changing load patterns, the congestion revenues collected by the system operator will be at least enough to cover the obligations for all the TCCs.



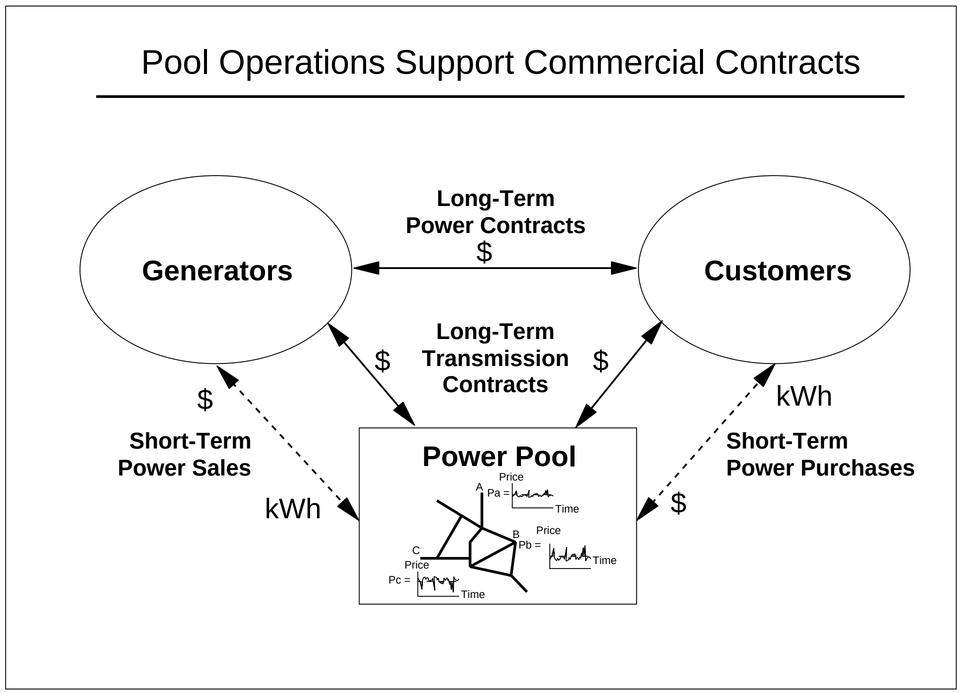
System Operator Revenues			
	Quantity	Price	$
Bus 1	900	2	($1,800)
Bus 2	0	2.3	$0
Bus 3	2100	2.6	($5,460)
Bus 3	-3000	2.6	$7,800
TCC 1-3	480	0.6	($288)
TCC 2-3	840	0.3	($252)
Net Total			$0

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.

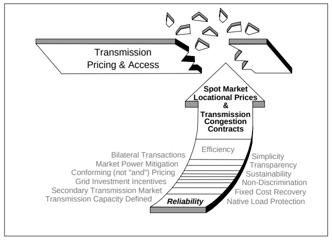




Market participants can achieve price stability through contracts. Bilateral contracts can share risks for electricity prices at a location. Spot-market locational prices apply to all transmission and transactions coordinated through the dispatch. Transmission contracts can protect buyers and sellers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



TRANSMISSION PRICING & ACCESS — Reliability



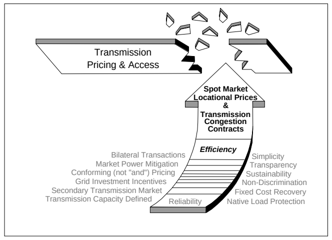
Any proposal for transmission open access must preserve the reliability of the system. The contract network approach starts with the existing reliability standards:

- **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

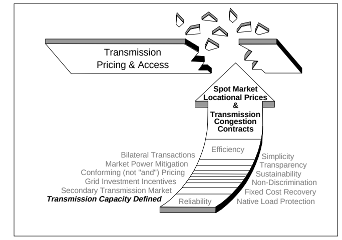


Economic dispatch would be achieved by the competitive market -- if there were well-defined transmission property rights and no transaction costs. Hence, efficient transmission pricing and access should be consistent with economic dispatch. Without the necessary property rights, and to reduce coordination 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.

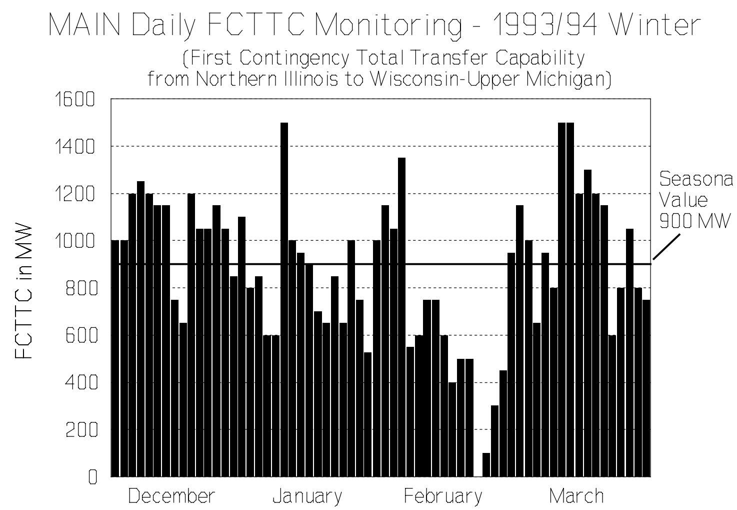
- **Follow Current Dispatch Procedures**. The form of the bids can follow the current practices for all the details of running costs, minimum loads, etc., replacing the engineering cost estimates with the bidders' preferences.

- **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.



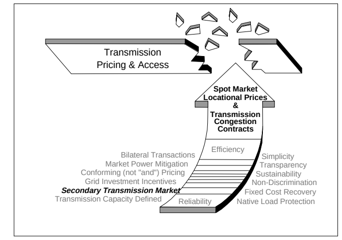
The vexing problem of defining long-term physical transmission capacity for future power flows is replaced by the (relatively) simple problem of defining a consistent set of transmission congestion contracts.

"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)



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.

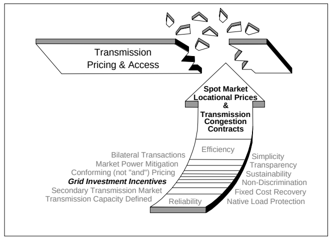
TRANSMISSION PRICING & ACCESS — Secondary Market



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.

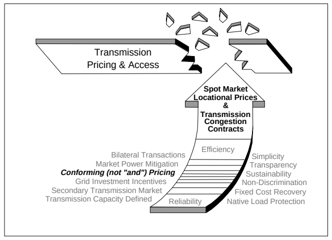


Avoiding sustained locational cost differences defines the economic rationale for investing in transmission. With prices set equal to locational marginal costs, market participants have an incentive to initiate and pay for transmission investments.

- **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 he 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.



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

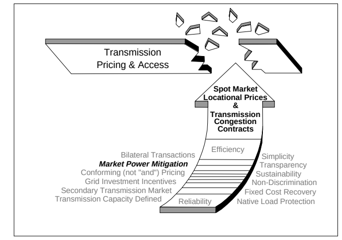
- **Grid Company Receives Embedded Costs**. The payment for the existing grid or new grid investments can be cost based according to traditional regulation. Those paying the regulated fixed charges for transmission receive the transmission congestion contracts.

- **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.

Market Power Mitigation



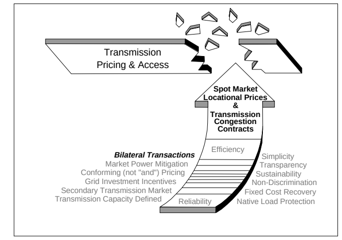
Transmission pricing systems that do not include locational prices reinforce market power by substantially reducing competitive demand and supply responses. In the presence of transmission congestion, local market power may exit, such as for a generator that must run in a particular location. The usual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

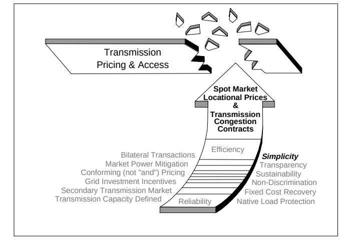
TRANSMISSION PRICING & ACCESS Bilateral Transactions



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.



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.

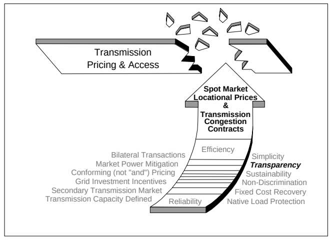
- **No Difference, No Problem**. If the prices do not differ by much for many hours, there will be no complexity. Most markets have different prices for similar products at different locations.

- **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.

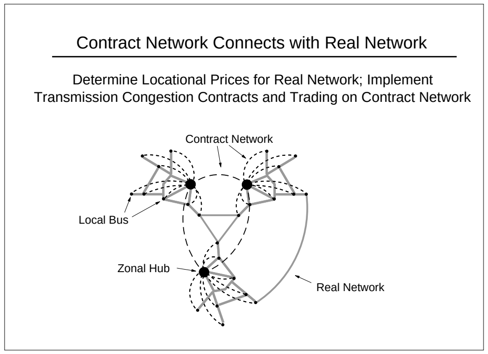
"A theory should be as simple as possible -- and no simpler." (Einstein)

TRANSMISSION PRICING & ACCESS — Transparency



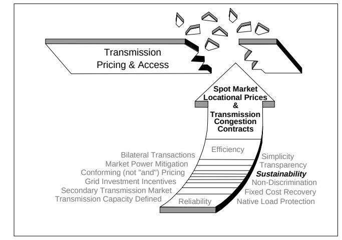
The determination of spot-market locational prices takes place in a translucent box. This is an improvement over the black box of physical transmission capacity allocation.

- **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.



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.

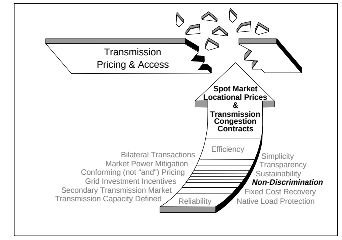
- **Low Marginal Cost Regions**. Purchasers paying an average price will see local, low-cost generation that is not being fully utilized. There will be great pressure to allow trading around the system pricing mechanism.

- **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.

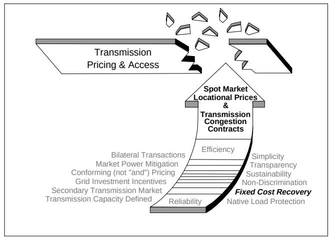
TRANSMISSION PRICING & ACCESS Non-Discrimination



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.

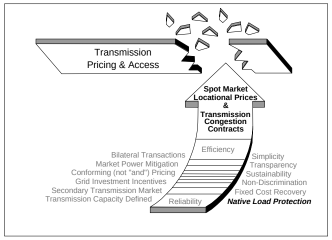


The fixed costs of the transmission grid are paid by those who receive the benefits of transmission congestion contracts.

- **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 to one degree or another in Argentina, Chile, New Zealand, Norway and PJM, 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 Lucius N. Littauer Professor of Public Policy and Administration, John F. Kennedy School of Government, Harvard University, and Senior Advisor, Putnam, Hayes & Bartlett, Inc. This paper 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, Scott Harvey, 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, Susan Pope, Grant Read, Bill Reed, Joseph R. Ribeiro, 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 (and the Supporting Companies of PJM), Duquesne Light Company, Electricity Corporation of New Zealand, National Independent Energy Producers, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, PJM Office of Interconnection, San Diego Gas & Electric Corporation, Trans Power of New Zealand, Williams Energy Group, and Wisconsin Electric Power Company. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the author. (http://ksgwww.harvard.edu/people/whogan).