ELECTRICITY MARKET DESIGN
The Value of FTRs

William W. Hogan

Mossavar-Rahmani Center for Business and Government
John F. Kennedy School of Government
Harvard University
Cambridge, Massachusetts 02138

Platts 11th Annual Nodal Trader Conference

New York, NY

October 26, 2018

ELECTRICITY MARKET Financial Transmission Rights

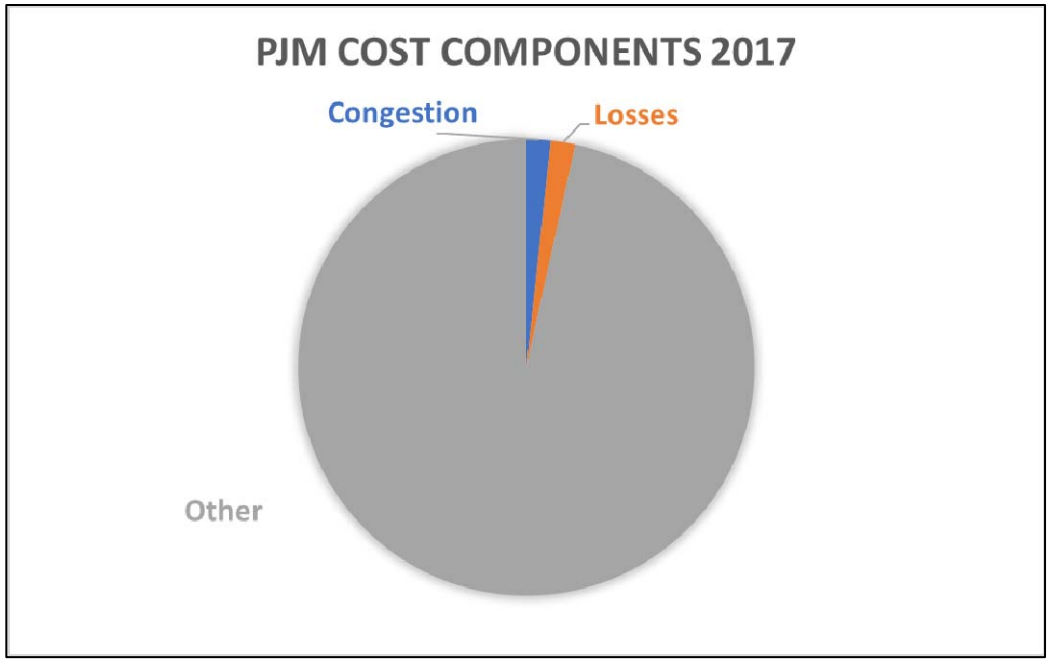
What is the value of Financial Transmission Rights? The discussion today:

- **Financial Transmission Rights (FTR), Transmission Congestion Contracts (TCC), Congestion Revenue Rights (CRR) …**
  - First Principles and Electricity Market Design.
  - Origins and Evolution.
  - FTRs as Obligations.
  - Continuing Challenges.
    - Auction Design and Revenue Adequacy.
    - Auction Revenue Rights (ARR).
    - Transmission Expansion.
    - Up-to-Congestion Products.
    - Eligible Nodal Locations.
- **Related Issues Not Covered Today.**
  - Market Power and Market Manipulation.
  - Credit Issues and FTR Defaults.
  - Long-term FTR Allocations.
  - FTRs as Options.
  - Uplift allocations.

What is the value of Financial Transmission Rights? What is the role of FTRs and how do they relate to the broader issues of electricity market design?

True, But Incomplete: "FTRs were designed to serve as the financial equivalent of firm transmission service and play a key role in ensuring open access to firm transmission service by providing a congestion hedging function. The purpose of FTRs to serve as a congestion hedge has been well established." (Federal Energy Regulatory Commission, 2017, p. 11)

Half True, But Misdirected: "Financial transmission rights and the associated revenues were directly provided to loads in recognition of the fact that loads pay for the transmission system which permits low cost generation to be delivered to load. Another way of describing the result is that FTRs and the associated congestion revenues were directly provided to loads in recognition of the fact that, as a result of LMP, load pays too much for generation. The excess payments are defined to be congestion." (Monitoring Analytics, 2018, p. 577)



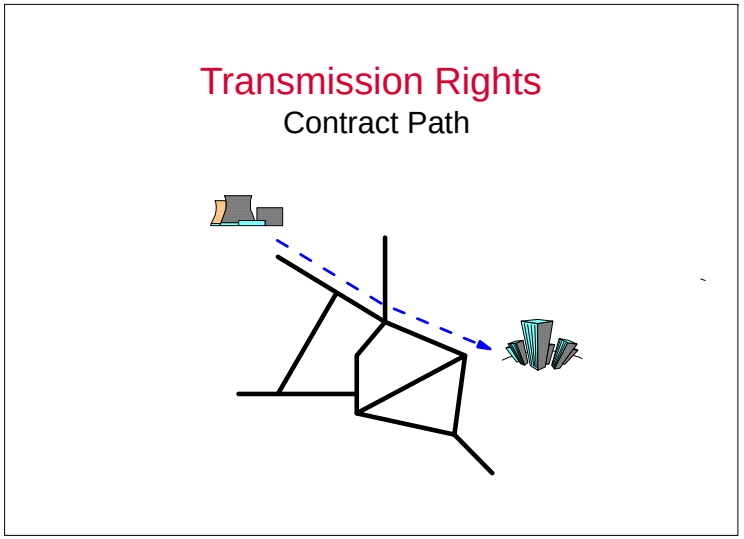
(Monitoring Analytics, 2018, p. 508)

Total congestion cost is a small part of the story. The bigger issue centers on the fundamental structure of market design.

ELECTRICITY MARKET — Financial Transmission Rights

What is the value of Financial Transmission Rights? What is the role of FTRs and how do they relate to the broader issues of electricity market design?

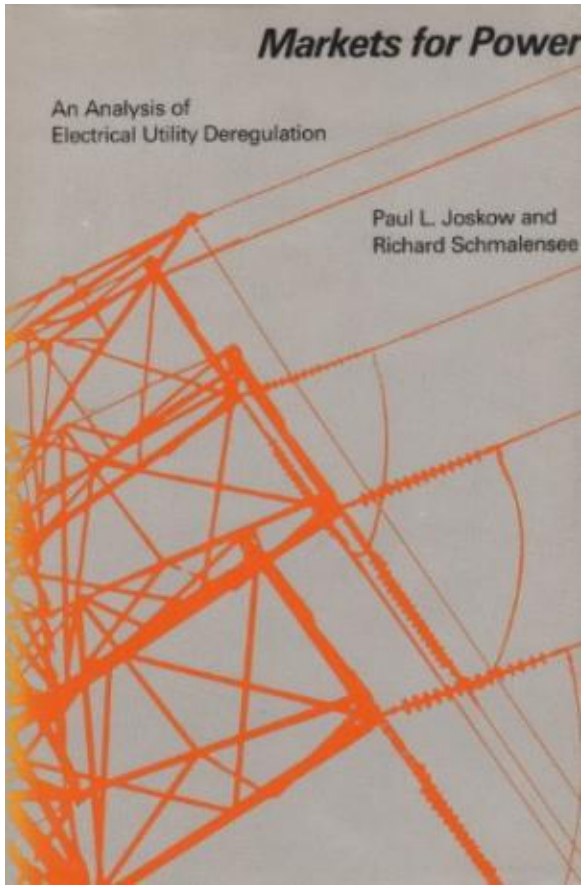
"In an LMP market, the lowest cost generation is dispatched to meet the load, subject to the ability of the transmission system to deliver that energy. When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load. This was true prior to the introduction of LMP markets and continues to be true in LMP markets. ***Prior to the introduction of LMP markets, contracts based on the physical rights associated with the transmission system were the mechanism used to provide for the delivery of low cost generation to load. Firm transmission customers who paid for the transmission system through rates or through bilateral contracts received the low cost generation.***" (Monitoring Analytics, 2018, p. 577, emphasis added)



The "physical rights" model for "firm transmission" never worked as advertised. It is unable to support an efficient open access electricity market.

ELECTRICITY MARKET — Electricity Restructuring

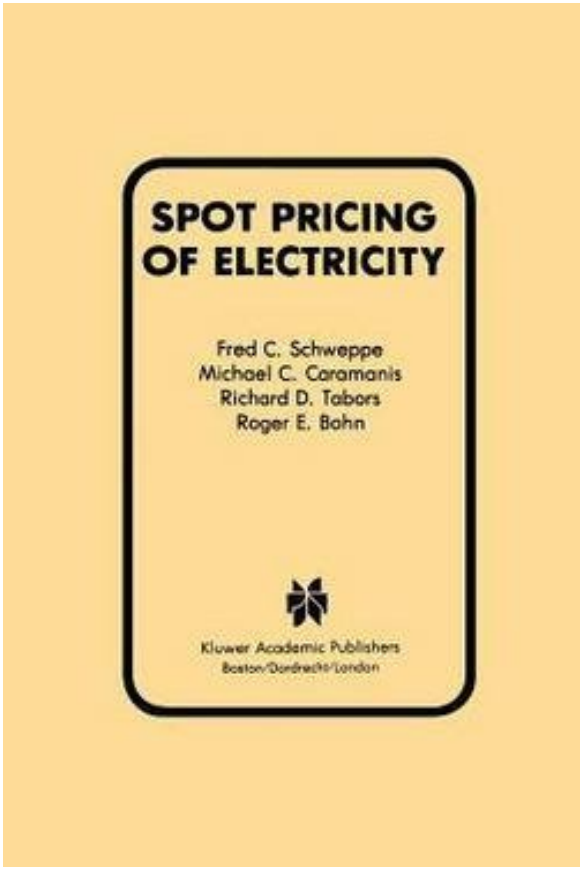
The evolution of electricity restructuring contains a thread of issues related to counterintuitive market design requirements requiring coordination for competition. MIT led the way.



Markets for Power, 1983. Joskow and Schmalensee. Addressed the possibility and problems of introducing competition and markets in the power sector. (Joskow & Schmalensee, 1983)

"*The practice of ignoring the critical functions played by the transmission system in many discussions of deregulation almost certainly leads to incorrect conclusions about the optimal structure of an electric power system.*" (p.63)

Schweppe et al., 1988. Spot Pricing of Electricity, Kluwer. Using prices to direct the dispatch. (Schweppe, Caramanis, Tabors, & Bohn, 1988)



ELECTRICITY MARKET — Energy Market Design

The U.S. experience illustrates successful market design and remaining challenges for both theory and implementation.

- **Design Principle: Integrate Market Design and System Operations**

  Provide good short-run operating incentives.

  Support forward markets and long-run investments.

- **Design Framework: Bid-Based, Security Constrained Economic Dispatch**

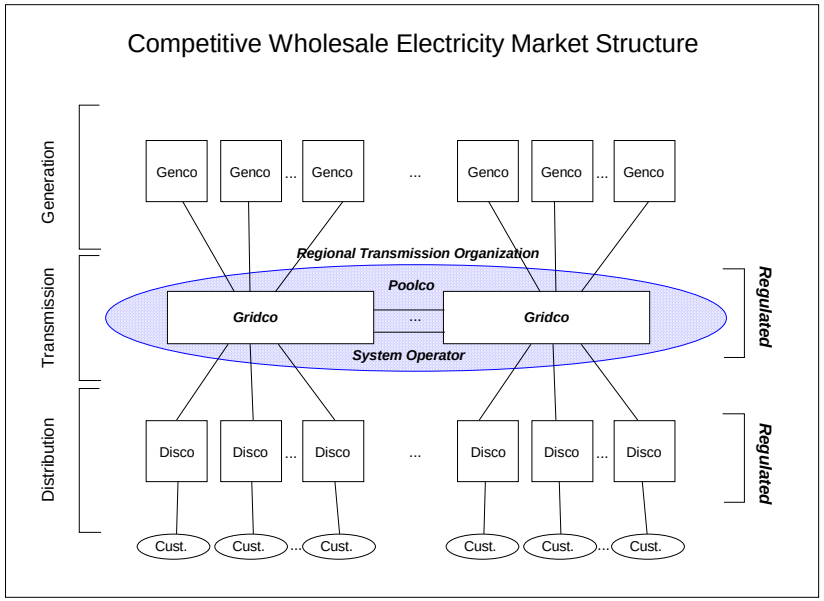
  Locational Marginal Prices (LMP) with granularity to match system operations.

  Financial Transmission Rights (FTRs).

- **Design Implementation: Pricing Evolution**

  Better scarcity pricing to support resource adequacy.

  Unit commitment and lumpy decisions with coordination, bid guarantees and uplift payments.



- **Design Challenge: Infrastructure Investment**

  Hybrid models to accommodate both market-based and regulated transmission investments.

  Beneficiary-pays principle to support integration with rest of the market design.

The Federal Energy Regulatory Commission regulates wholesale electricity markets. Support for competition in wholesale markets is a clear and continuing national policy:

"While competitive markets face challenges, we should acknowledge that competition in wholesale power markets is national policy. The Energy Policy Act of 2005 embraced wholesale competition as national policy for this country. It represented the third major federal law enacted in the last 25 years to embrace wholesale competition. To my mind, the question before the Commission is not whether competition is the correct national policy. That question has been asked and answered three times by Congress.

If we accept the Commission has a duty to guard the consumer, and that competition is national policy, our duty is clear. It is to make existing wholesale markets more competitive. That is the heart of this review: to not only identify the challenges facing competitive wholesale markets but also identify and assess solutions."[1]

"…the Commission has acted over the last few decades to implement Congressional policy to facilitate entry of new participants and to encourage competition in wholesale electric power markets. The Commission's actions include sustained efforts to foster regional power markets."[2]

"The markets were set up to allocate resources more efficiently … to shift investment risk from customers to investors, to run the grid across larger regions so that you'd get more redundancy and more efficiencies, and to reduce regulatory lag when prices came down. The markets have done all those things really quite well."[3]

---

1 Joseph T. Kelliher, "Statement of Chairman Joseph T. Kelliher," Federal Energy Regulatory Commission, Conference on Competition on Wholesale Power Markets AD07-7-000. February 27, 2007.

2 Testimony of Chairman Jon Wellinghoff, Federal Energy Regulatory Commission, Before the Energy and Environment Subcommittee Of the Committee on Energy and Commerce, United States House of Representatives, Oversight Hearing for the Federal Energy Regulatory Commission, March 23, 2010.

3 Chairman Cheryl LaFleur, Federal Energy Regulatory Commission, *EnergyWire,* August 22, 2014.

ELECTRICITY MARKET — Order 888 and Open Access

Order 888, 1996: "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities." The Order followed from a lengthy debate about the many details of electricity markets. The key principles included open access and non-discrimination.

> "Today the Commission issues three final, interrelated rules designed to remove impediments to competition in the wholesale bulk power marketplace … . The legal and policy cornerstone of these rules is to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce." (FERC, Order 888, April 24, 1996, p. 1.)

- **What did Order 888 anticipate for the development of electricity market design?**
- **What other electricity market design options are available to achieve the objectives of open access and Order 888?**
- **Can open access not be about market design?**

ELECTRICITY MARKET Order 888 and the Contract Path

Under Order 888 the FERC made a crucial choice regarding a central complication of the electricity system.

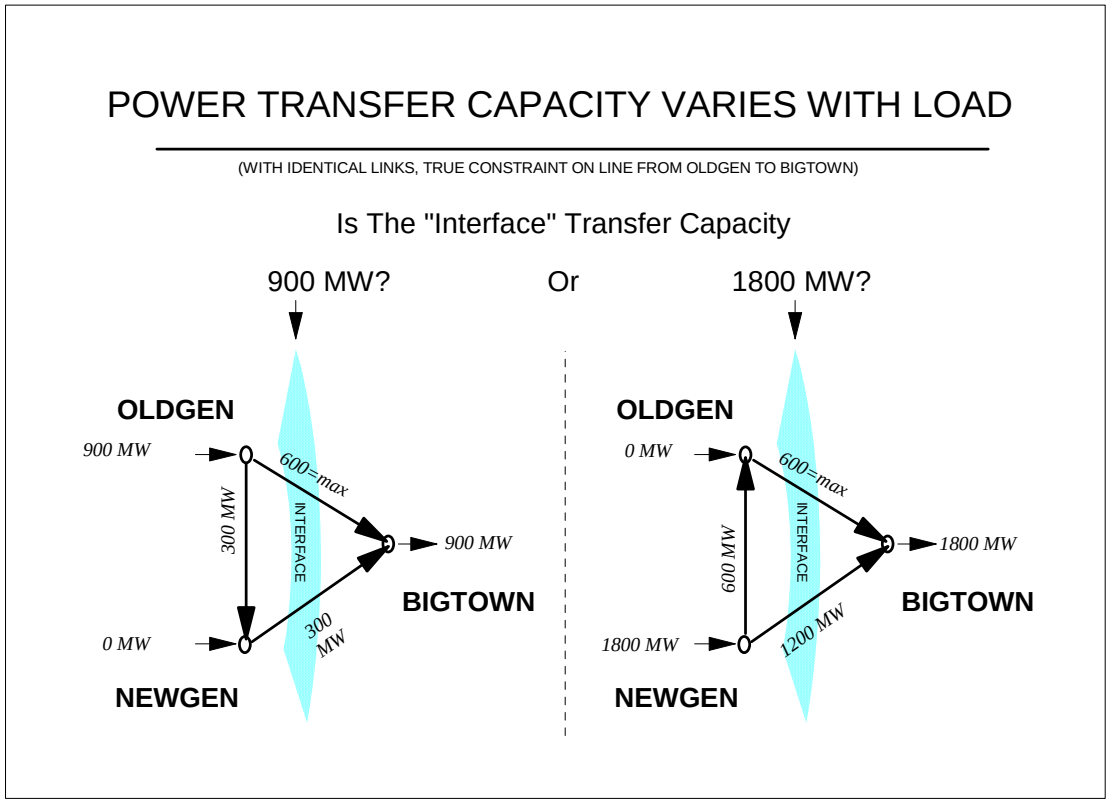
> "A contract path is simply a path that can be designated to form a single continuous electrical path between the parties to an agreement. Because of the laws of physics, it is unlikely that the actual power flow will follow that contract path. … Flow-based pricing or contracting would be designed to account for the actual power flows on a transmission system. It would take into account the "unscheduled flows" that occur under a contract path regime." (FERC, Order 888, April 24, 1996, footnotes 184-185, p. 93.)

Why is this important?

NETWORK INTERACTIONS — Loop Flow

Electric transmission network interactions can be large and important.

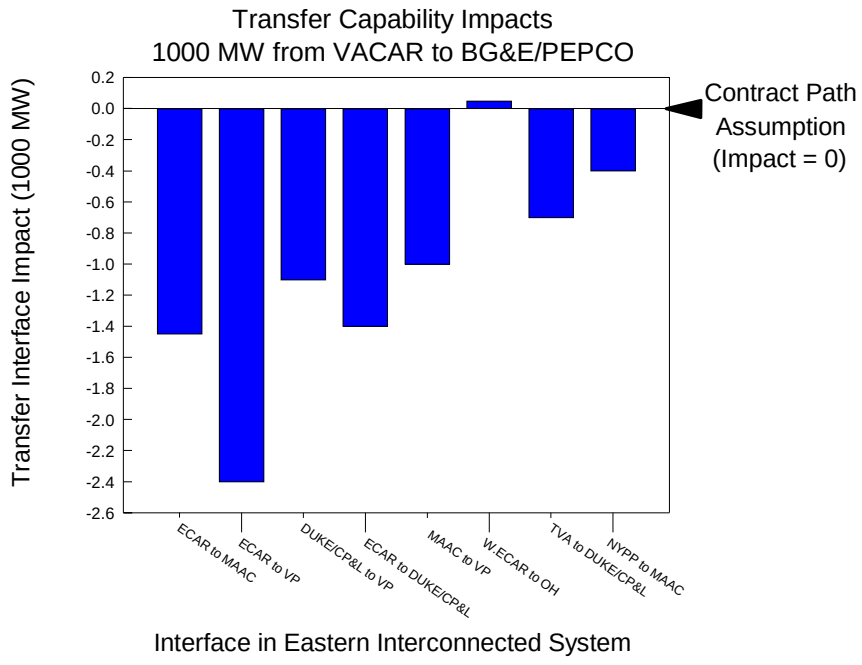
- Conventional definitions of network "Interface" transfer capacity depend on the assumed load conditions.
- Transfer capacity cannot be defined or guaranteed over any reasonable horizon.



NETWORK INTERACTIONS — Loop Flow

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.

Transmission Impacts Vary Across the Eastern System



Source: VEM, Winter Operating Study, December 1993.

TRANSMISSION CAPACITY Definition

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 problems are not unique to the U. S. The same issue arises in any meshed network, as in Europe and the regulations for European Transmission System Operators [ETSO]:

> "Does the draft Regulation set the right objective when it requires TSOs to compute and publish transfer capacities? ETSO says both yes and no …in many cases the (Net transfer capacity or NTCs) may be a somewhat ambiguous information…The core of the difficulty raised by transfer capacities lies in the fact that they do not obey usual arithmetic: 'it makes no sense to add or subtract the NTC values…' Put it in other ways, in order to compute the maximal use of the network, one needs to make assumptions on the use of the network! This definition is restated and elaborated in ETSO (2001a) (p. 6)."
>
> J. Boucher and Y. Smeers, "Towards a Common European Electricity Market--Paths in the Right Direction…Still Far From an Effective Design," Belgium. September, 2001, pp. 30-31. (see HEPG web page, Harvard University)

ELECTRICITY MARKET Order 888 and the Contract Path

Under Order 888 the FERC made a crucial choice regarding a central complication of the electricity system.

> "A contract path is simply a path that can be designated to form a single continuous electrical path between the parties to an agreement. Because of the laws of physics, it is unlikely that the actual power flow will follow that contract path. … Flow-based pricing or contracting would be designed to account for the actual power flows on a transmission system. It would take into account the "unscheduled flows" that occur under a contract path regime." (FERC, Order 888, April 24, 1996, footnotes 184-185, p. 93.)

> "We will not, at this time, require that flow-based pricing and contracting be used in the electric industry. In reaching this conclusion, we recognize that there may be difficulties in using a traditional contract path approach in a non-discriminatory open access transmission environment, as described by Hogan and others. At the same time, however, contract path pricing and contracting is the longstanding approach used in the electric industry and it is the approach familiar to all participants in the industry. To require now a dramatic overhaul of the traditional approach such as a shift to some form of flow-based pricing and contracting could severely slow, if not derail for some time, the move to open access and more competitive wholesale bulk power markets. In addition, we believe it is premature for the Commission to impose generically a new pricing regime without the benefit of any experience with such pricing. We welcome new and innovative proposals, but we will not impose them in this Rule." (FERC, Order 888, April 24, 1996, p. 96.)

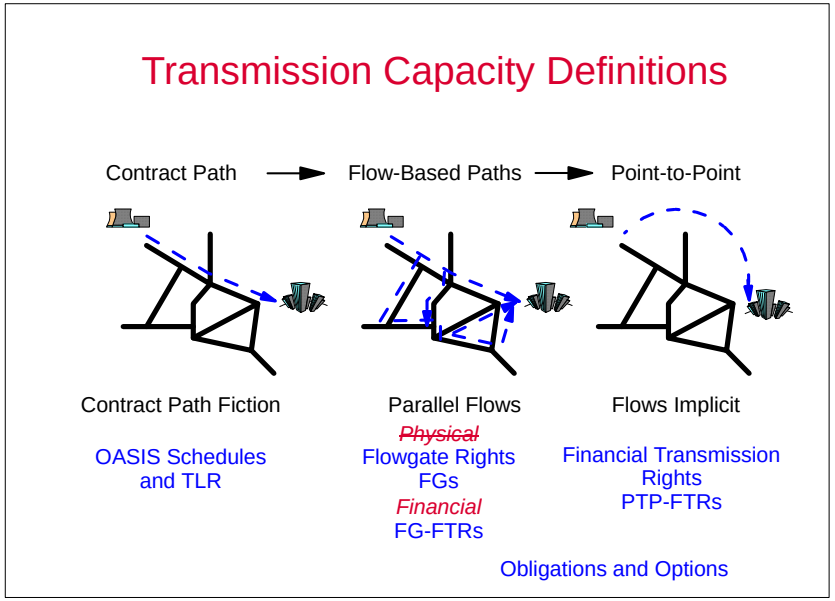
Hence, although the fictional contract path approach would not work in theory, maintaining the fiction would be less disruptive in moving quickly to open access and an expanded competitive market!

The evolution of electricity restructuring contains a thread of issues related to counterintuitive market design requirements requiring coordination for competition.

The "Contract Path" won't work in theory, but will it work in practice?

- **Order 888, 1996.** Non-discrimination, Open Access to Transmission. Contract path fiction would not work in theory.
- **Capacity Reservation Tariff (CRT), 1996.** A new model.

  "The proposed capacity reservation open access transmission tariff, if adopted, would replace the open access transmission tariff required by the Commission ..."[4]
- **NERC Transmission Loading Relief (TLR), 1997.** The unscheduling system to complement Order 888.
- **EPAct 2005.** Continued support for competitive markets but conflicting signals on market design.
- **Order 890 Reform 2007.** Too little.



[4] Federal Energy Regulatory Commission, "Capacity Reservation Open Access Transmission Tariffs," Notice of Proposed Rulemaking, RM96-11-000, Washington DC, April 24, 1996, p. 1.

TRANSMISSION CAPACITY Network Effects

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. Principal implications of the ubiquitous and important effects of loop flow include:

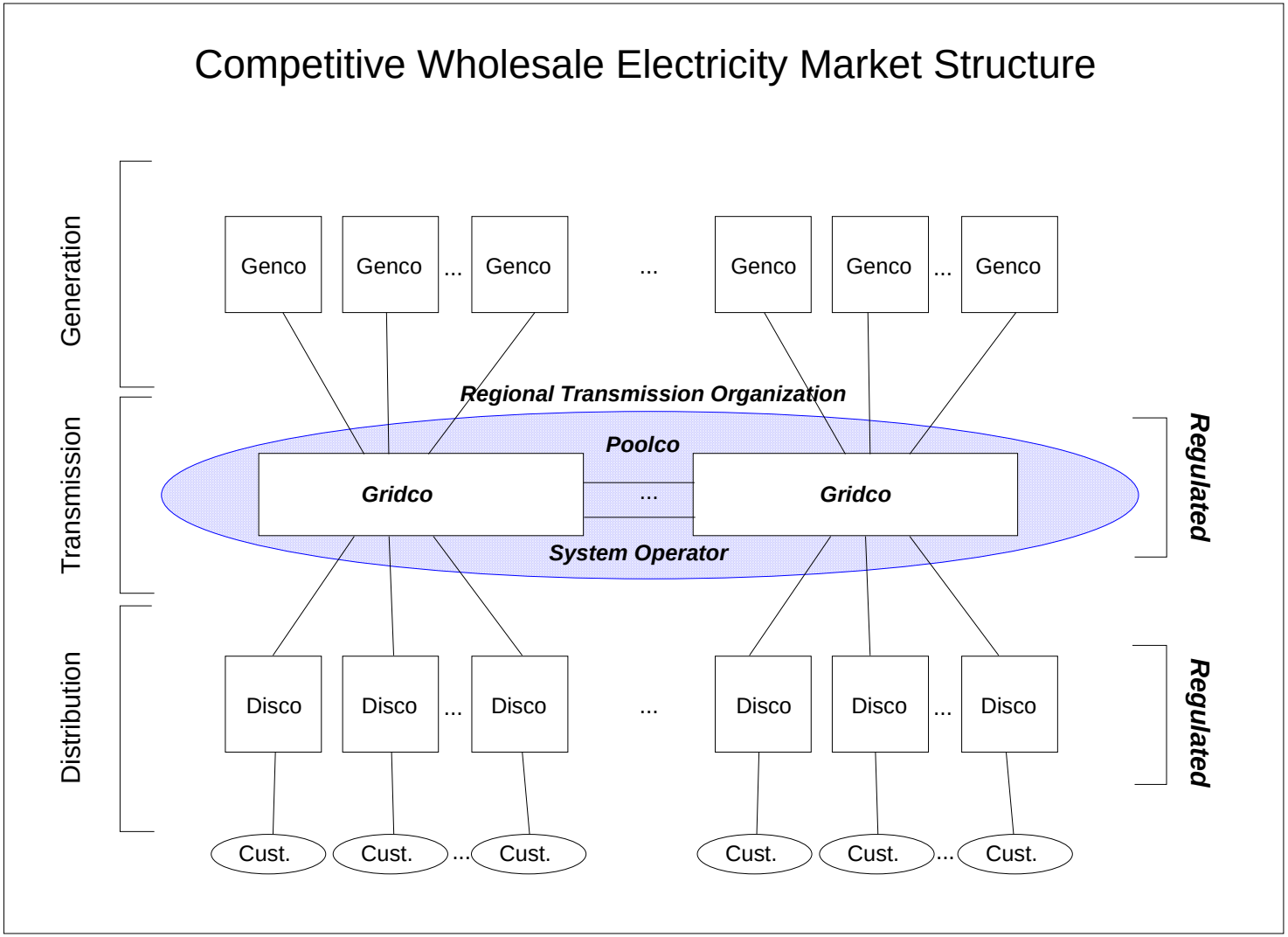
No Property Rights. There is no workable system of property rights governing use of the transmission grid that would support a fully decentralized electricity market.

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.

The original arguments for greater reliance on markets emphasized the effects of non-utility generators and the reduction or elimination of the conditions for natural monopoly in generation.



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 system operator considers customer bids and provides economic dispatch for some plants.

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

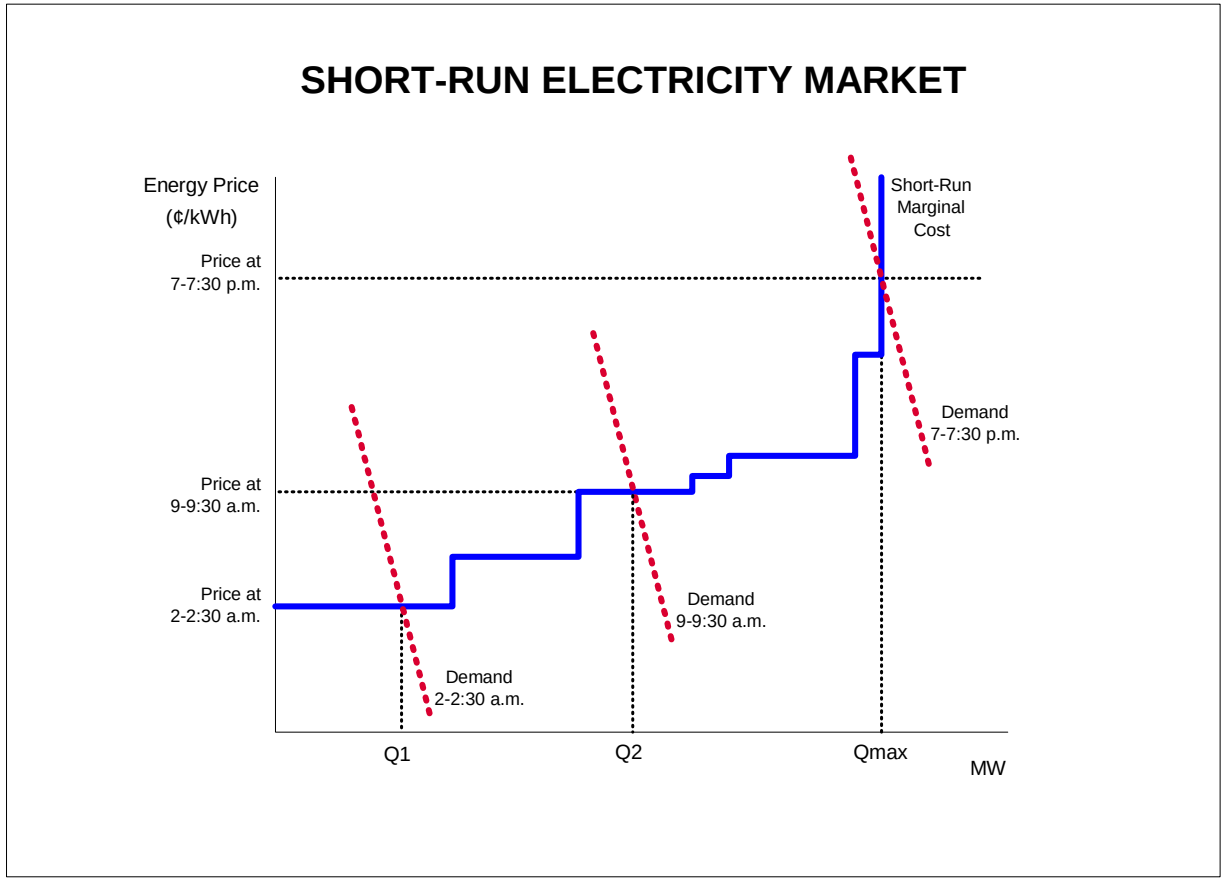
Under an economic dispatch for the flexible plants and loads, it is a straightforward matter to determine the locational marginal costs of additional power. These marginal costs are also the prices that would apply in the case of a perfect competitive market at equilibrium. In addition, these locational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

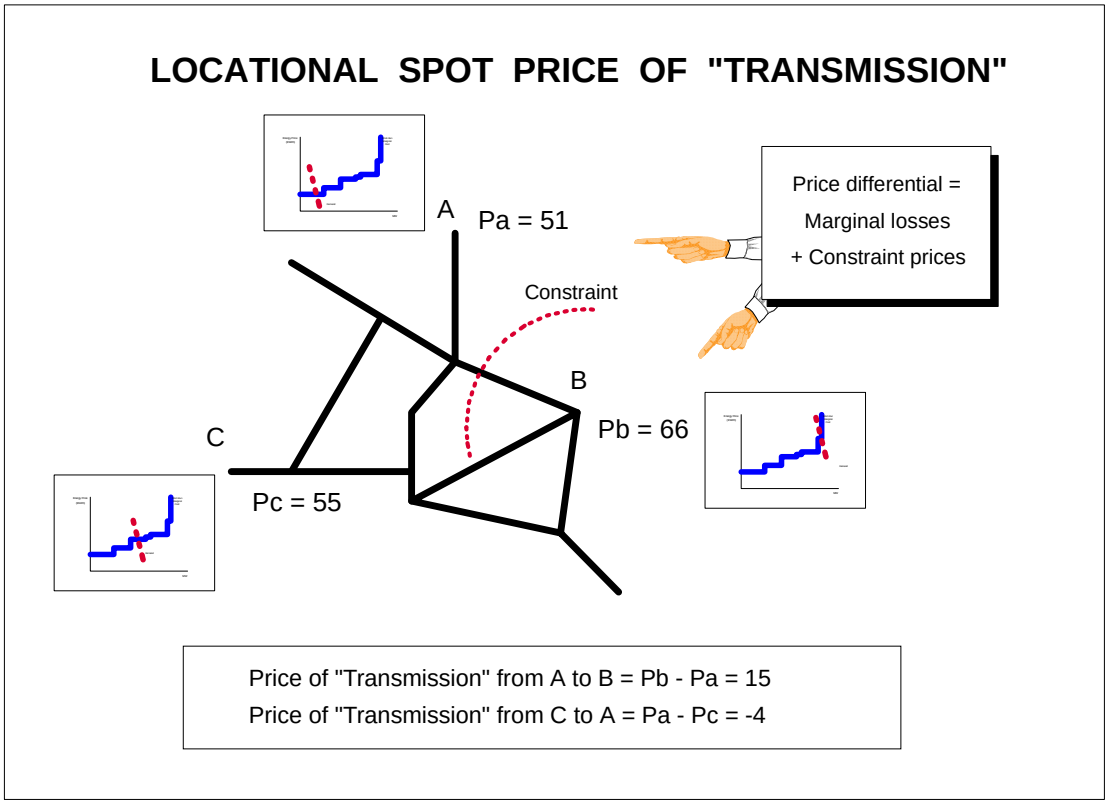
ELECTRICITY MARKET — Pool Dispatch

An efficient short-run electricity market determines a market clearing price based on conditions of supply and demand balanced in an economic dispatch. Everyone pays or is paid the same price. The same principles apply in an electric network. (Schweppe et al., 1988)



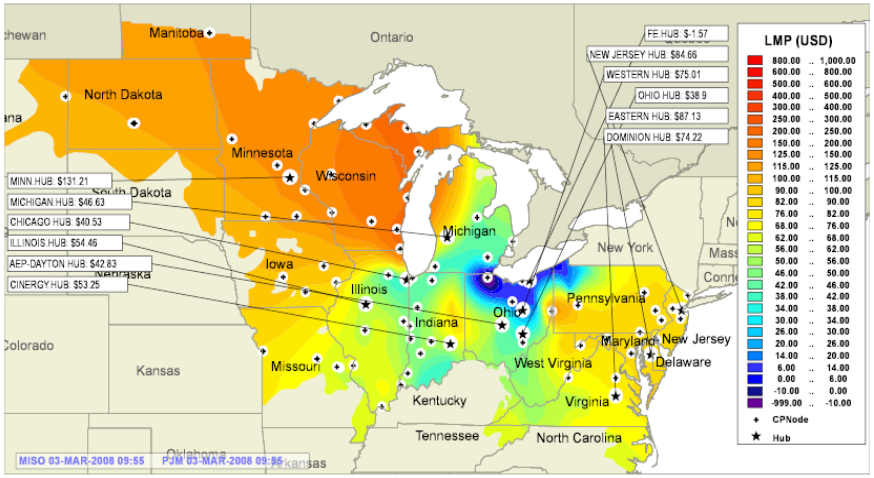
The natural extension of a single price electricity market is to operate a market with locational spot prices.

- It is a straightforward matter to compute "Schweppe" spot prices based on marginal costs at each location.
- Transmission spot prices arise as the difference in the locational prices.

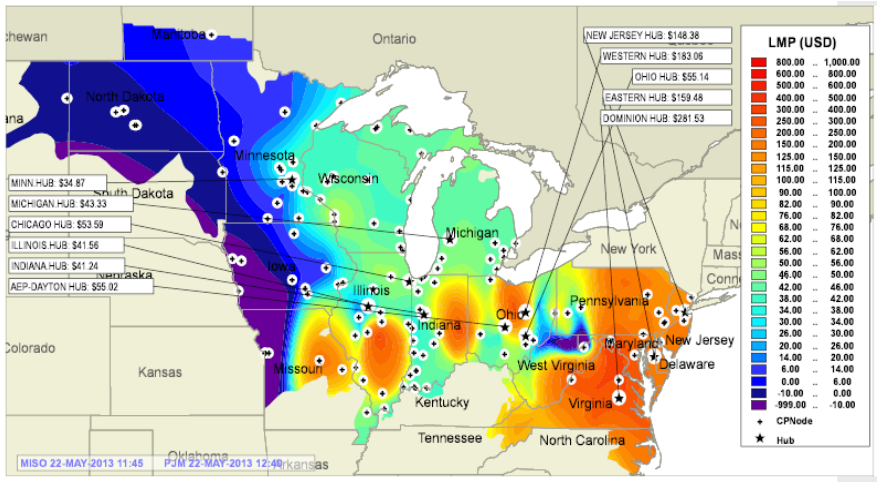


NETWORK INTERACTIONS — Locational Spot Prices

RTOs operate spot markets with locational prices. For example, PJM updates prices and dispatch every five minutes for over 10,000 locations. Locational spot prices for electricity exhibit substantial dynamic variability and persistent long-term average differences.



Minnesota Hub: $131.21/MWh. First Energy Hub: $-1.57/MWh. March 3, 2008, 9:55am

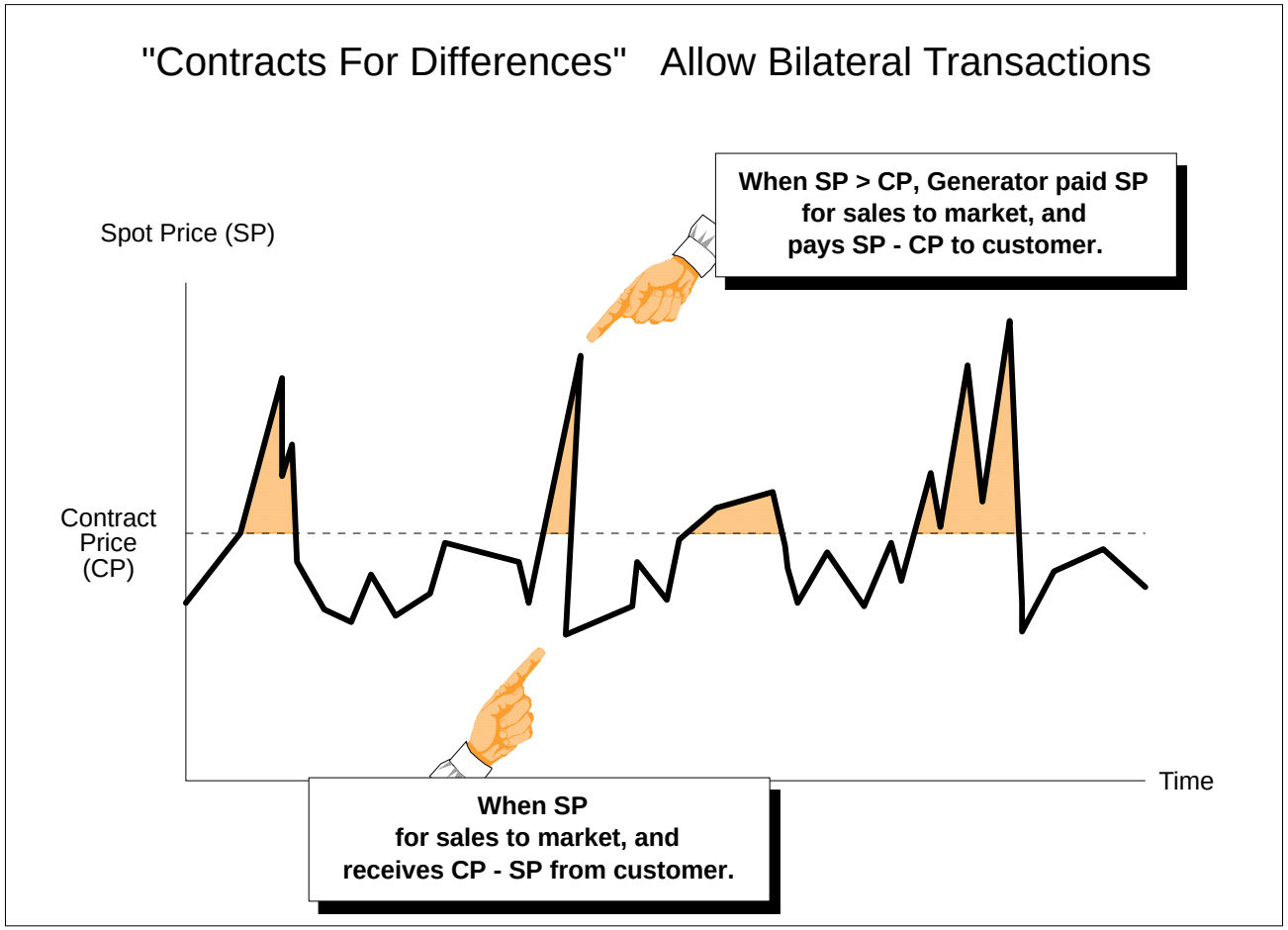


Missouri MPS -$71.25, Dominion Hub $281.53. May 22, 2013, 12:40pm.

From MISO-PJM Joint and Common Market, http://www.jointandcommon.com

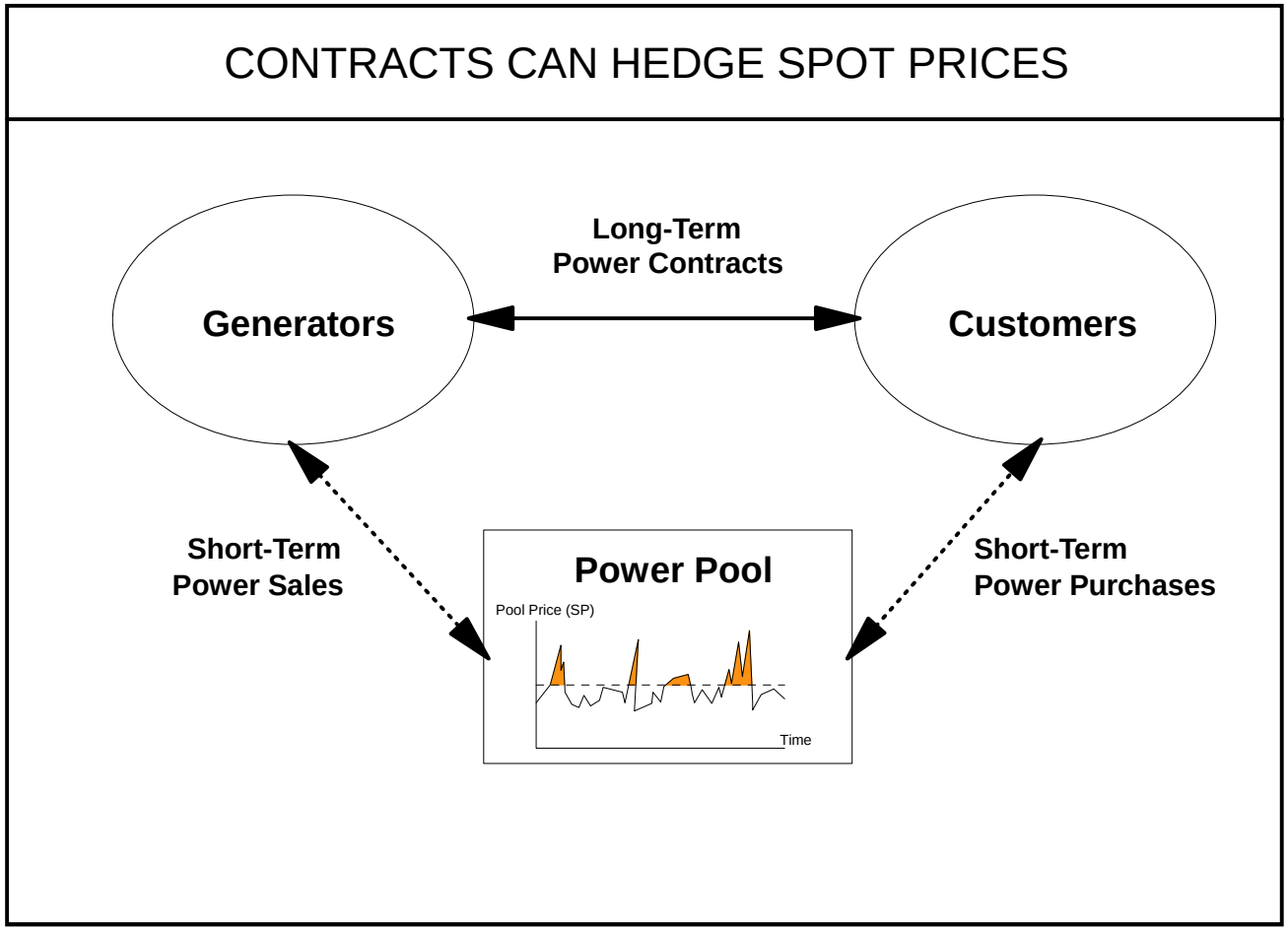
SPOT MARKET — Volatile Spot Prices

The spot price in an electricity market can be highly volatile. A contract for differences offers a simple financial contract that replicates a fixed price contract. The seller sells to the pool. The buyer buys from the pool. The CFD provides a means to replicate a bilateral transaction.



SPOT MARKET — Volatile Spot Prices

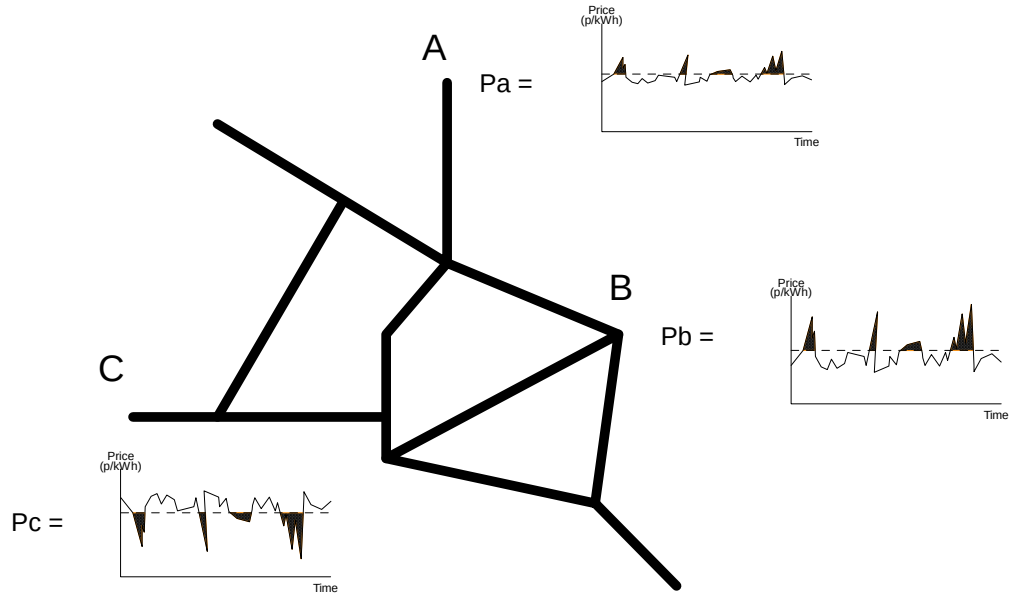
With the contracts for differences, the physical operation of the power pool becomes independent of the long-term contracts. Importantly, deliverability of the power does not depend on the contracts. The pool operates a spot market and produces spot prices for settlements.



SPOT MARKET — Volatile Spot Prices

For transmission between locations, the transmission opportunity cost is the difference in the locational prices. This difference of volatile prices will be even more volatile.

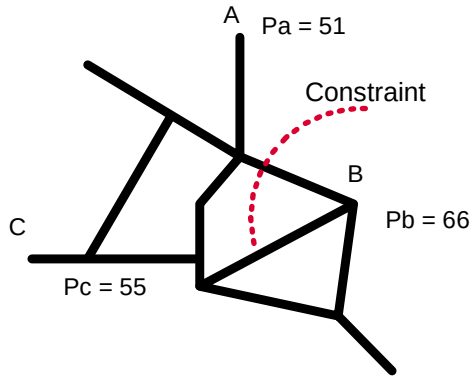
NEED "Hedges" FOR LOCATIONAL PRICING



Price of "Transmission" from C to B = Pb - Pc = Volatile Price

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

NETWORK TRANSMISSION FINANCIAL RIGHTS



Price of "Transmission" from A to B = Pb - Pa = 15
Price of "Transmission" from C to A = Pa - Pc = -4

- 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.

FINANCIAL TRANSMISSION RIGHTS — Revenue Adequacy

The market equilibrium satisfies a "no arbitrage" condition which implies that feasible financial transmission rights must be revenue adequate.

Under the current grid configuration, with a set of simultaneously feasible financial transmission rights, the revenues from the current spot market congestion rents must be at least as large as the obligations under the set of FTRs. This result holds for any economic dispatch and any configuration of FTRs. This is unlike any set of physical transmission rights where: "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.

- **Auction Revenue Rights**. Financial Transmission Rights may be assigned directly or obtained through a forward auction. The Auction Revenue Rights (ARRs) follow similar properties. If the ARRs are simultaneously feasible in the grid configuration for the auction, then the individual ARRs could be preserved through bids for FTRs.

- **Day-Ahead Transmission Commitments**. With a day-ahead market, the cleared day-ahead schedules amount to a forward contract to use the available grid capacity.
  - Financial Transmission Rights must be settled at the day-ahead prices. If the FTRs are simultaneously feasible under the day-ahead grid configuration, the day-ahead market clearing will be revenue adequate.
  - Day-Ahead Schedules must be settled at the real-time prices. If the day-ahead schedules are simultaneously feasible under the real-time grid configuration, the real-time market clearing will be revenue adequate. This property holds independent of the existence of FTRs. Hence, the so-called "Balancing Congestion" is independent of FTRs.

TRANSMISSION INVESTMENT FTR Allocation and Efficient Investment

Investment in the transmission grid should create new economic capacity. The allocation of FTRs under a feasibility rule mitigates incentives for inefficient transmission investment.

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

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

- If the set of FTRs is feasible then the future payments required for the FTRs will never exceed the congestion revenues collected through the spot market dispatch.

- Future investments in the grid cannot reduce the welfare of aggregate use according to the existing FTRs. Hence, exposure to rent transfers is limited to the spot market.

- (Bushnell and Stoft, 1997). If PTP-FTR obligations initially match dispatch in the aggregate and new FTRs are allocated under the feasibility rule, then the increase in social welfare will be at least as large as the ex post value of new contracts.

- (Bushnell and Stoft, 1996). If PTP-FTR obligations match dispatch individually, then the allocation of FTRs under the feasibility rule ensures that no one can benefit from a network investment that reduces social welfare.

FINANCIAL TRANSMISSION RIGHTS — Market Efficiency

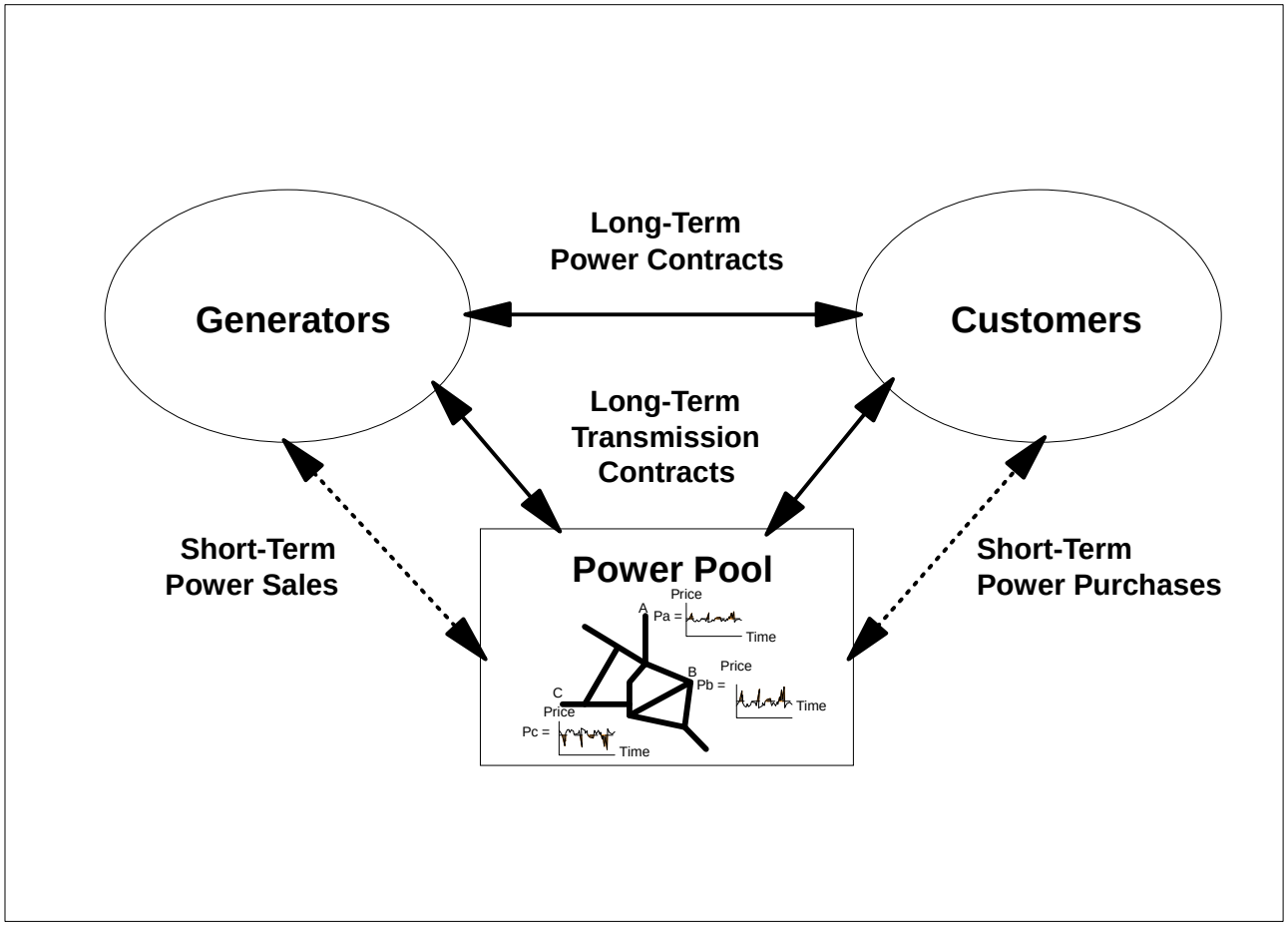
Financial transmission rights are long-term contracts that hedge short-term congestion costs. This is more than a convenient way to distribute congestion rents. FTRs are critical elements of efficient market design.

> "FTRs are financial contracts that entitle their holders to day-ahead hourly congestion revenue (a Transmission Congestion Credit), as measured between the location at which power is injected into the system and the location at which it is withdrawn. The hourly economic value of an FTR is based on the FTR MW reservation and the difference between day-ahead congestion prices at the sink point (point of delivery) and the source point (point of receipt) designated in the FTR." (FERC, *Order Addressing Filing and Issues Raised at Technical Conference,* PJM Interconnection, L.L.C., Docket Nos. EL16-6-001, ER16-121-000, September 15. 2016.)

- Long-term contracts hedge spot-market prices and support investment.
- Physical transmission rights are not available as a method of controlling system dispatch or as a tool for long-term contracting.
- Long-term financial contracts need to hedge both the price at locations, through contracts for differences, and the price differential between locations, through financial transmission rights.
- Real-time "Balancing Congestion" is separate from and independent of congestion in the day-ahead market with financial transmission rights.
- The revenue adequacy property points to congestion payments as the natural source of funding for financial transmission rights.
- Any other use of congestion payments would undermine the essential market design.

NETWORK INTERACTIONS — Market Efficiency

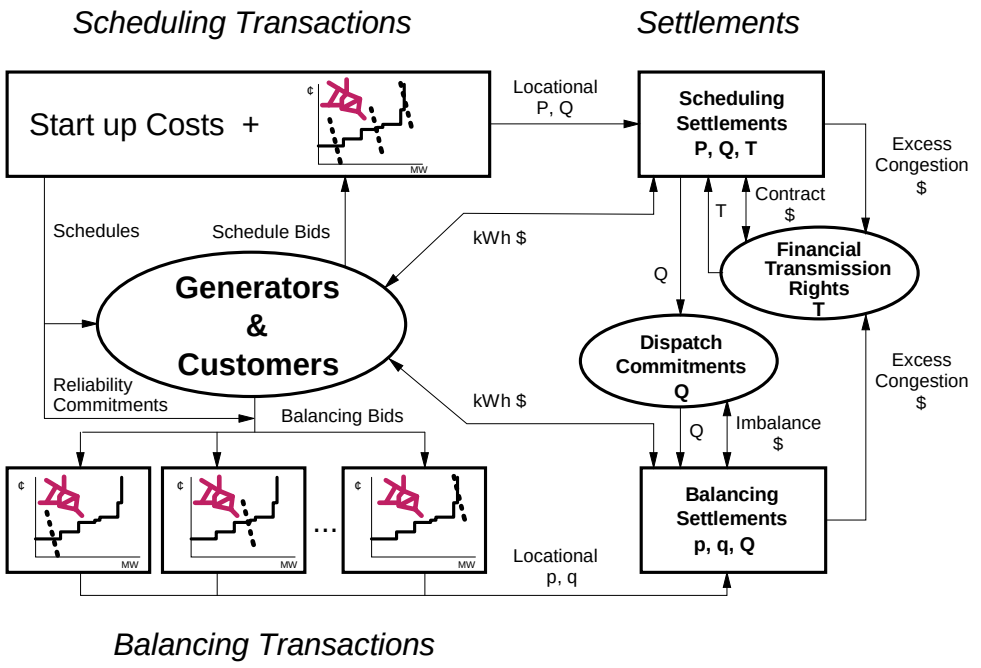
Combining contracts for differences between parties, and financial transmission rights offered by the system operator, the electricity market can support efficient operations, open access, non-discrimination and long-term contracts.



ELECTRICITY MARKET — Day-Ahead Commitments

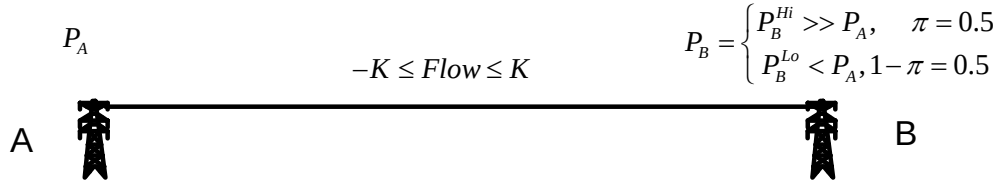
Organized electricity markets utilize day-ahead markets with bid-in loads and generation offers. In addition, day-ahead markets include a reliability commitment to ensure that adequate capacity will be available in real time to meet the actual load.

A Structure for Forward Market Scheduling, Spot Market Dispatch & Settlements



Equilibration of day-ahead prices and expected real-time prices does not mean that expected dispatch in real-time will be the same as the dispatch day-ahead, nor does it imply that the same transmission constraints will be binding or have the same congestion costs. (Hogan, 2016)

Day-Ahead Price Equilibrium



Expected Values

$$E(P_A) = P_A$$
$$E(\mu_{ab}) = 0.5\left(P_B^{Hi} - P_A\right)$$
$$E(\mu_{ba}) = 0.5\left(P_A - P_B^{Lo}\right)$$
$$E(P_B) = 0.5\left(P_B^{Lo} + P_B^{Hi}\right) > P_A$$
$$E(Flow) = 0.5(K) + 0.5(-K) = 0$$

Day-Ahead Dispatch

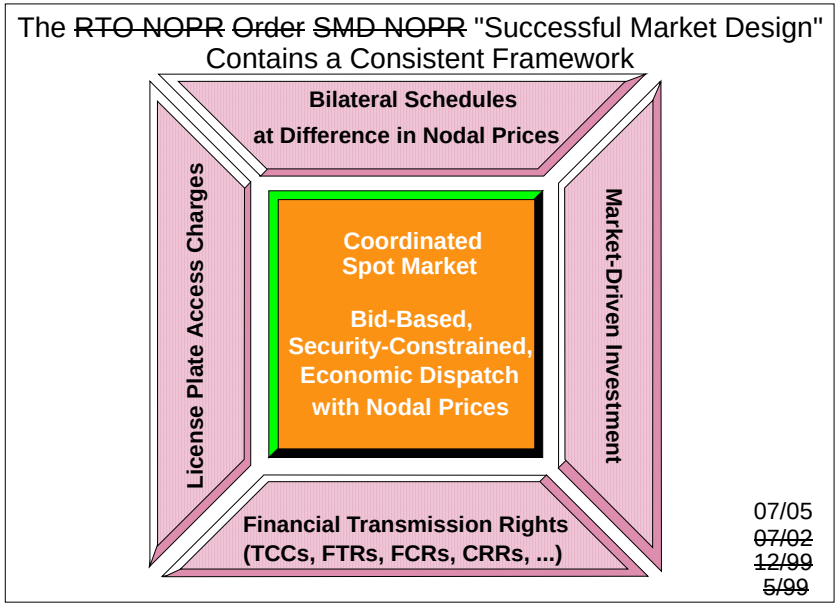
$$P_A^{DA} = P_A$$
$$P_B^{DA} = E(P_B)$$
$$\mu_{ab}^{DA} = E(P_B) - P_A < E(\mu_{ab})$$
$$\mu_{ba}^{DA} = 0 < E(\mu_{ba})$$
$$Flow^{DA} = K$$

μ: Constraint Shadow Price

π: Scenario Probability

ELECTRICITY MARKET — A Consistent Framework

The example of successful central coordination, ~~CRT, Regional Transmission Organization (RTO) Millennium Order (Order 2000) Standard Market Design (SMD) Notice of Proposed Rulemaking (NOPR),~~ "Successful Market Design" provides a workable market framework that is working in places like New York, PJM in the Mid-Atlantic Region, New England, the Midwest, California, SPP, and Texas. This efficient market design is under (constant) attack.



Poolco…OPCO…ISO…IMO…Transco…RTO…ITP…WMP…: "A rose by any other name …"

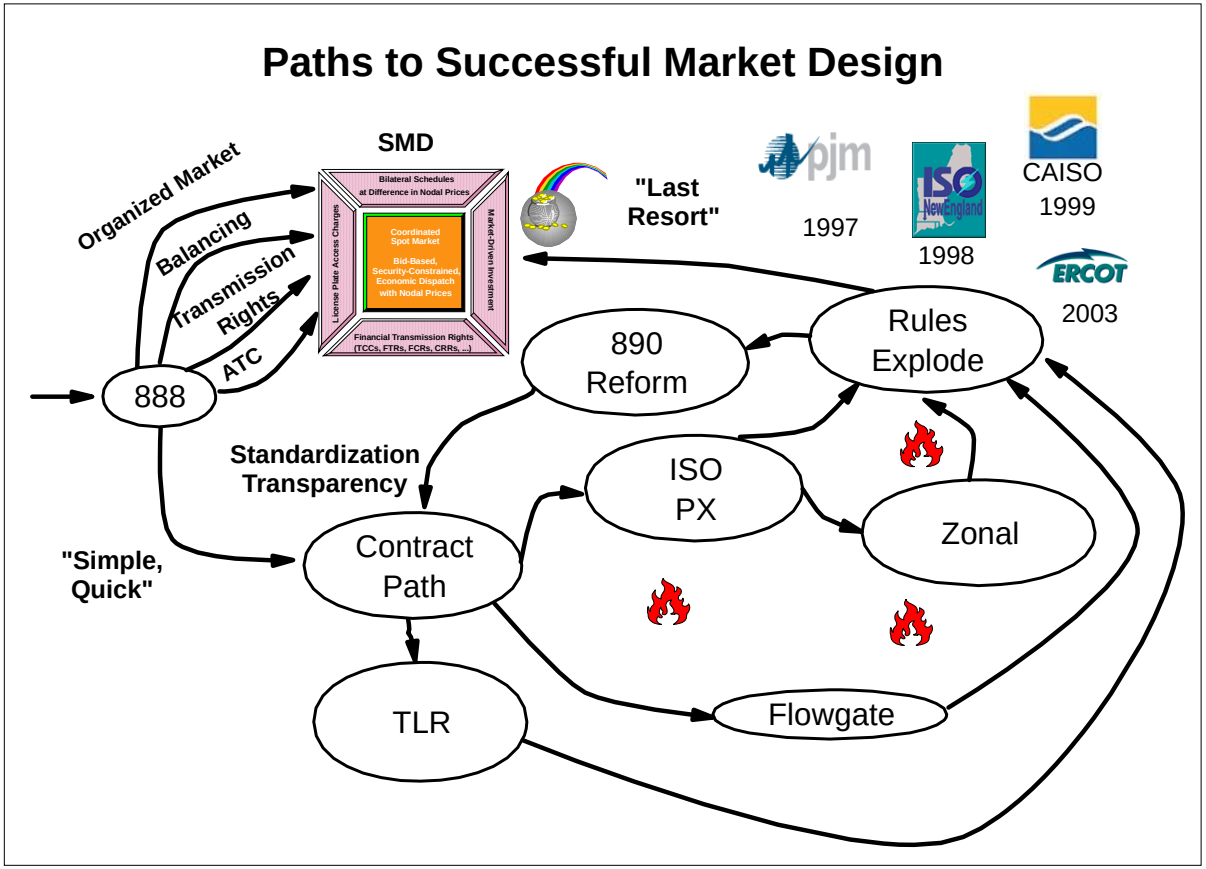
"Locational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers. A trading arrangement based on LMP takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments." (International Energy Agency, 2007)

This is the only model that can meet the tests of open access and non-discrimination.

Anything that upsets this design will unravel the wholesale electricity market. The basic economic dispatch model accommodates the green energy agenda, as in the expanding Western Energy Imbalance Market (EIM).

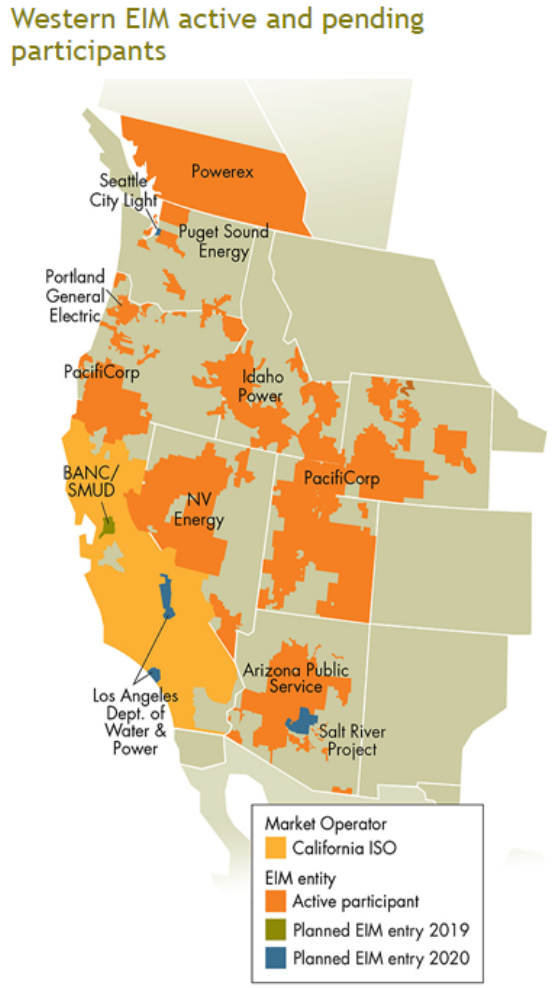
ELECTRICITY MARKET — Path Dependence

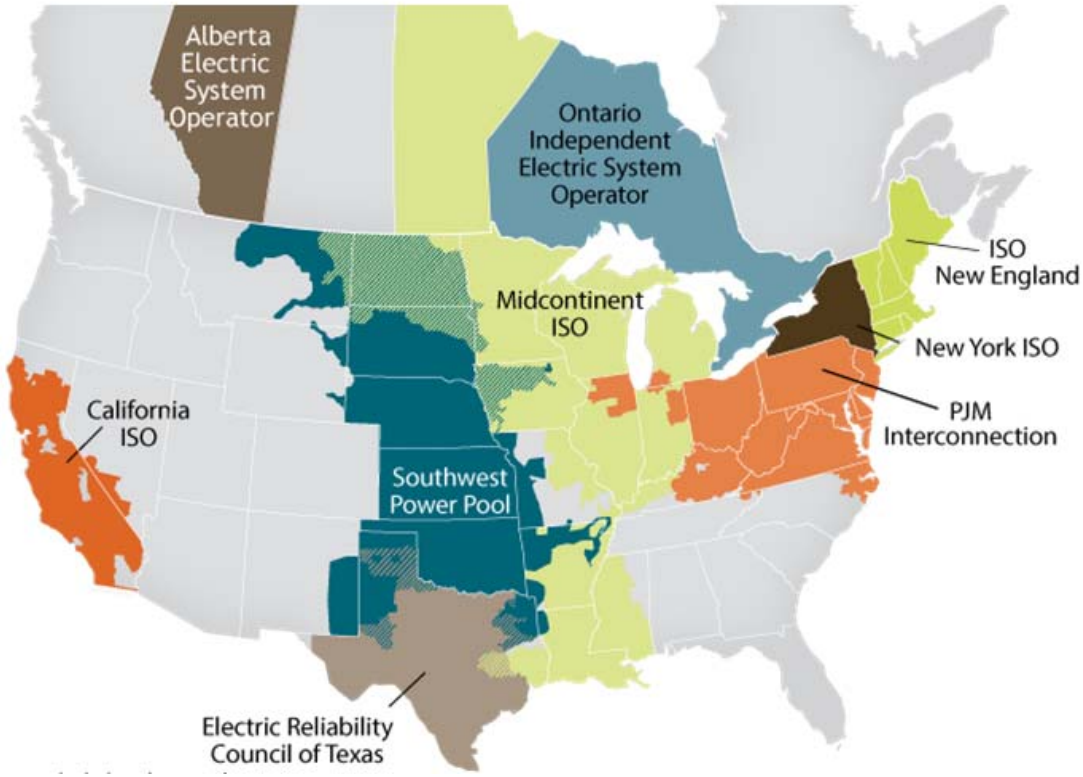
The path to successful market design can be circuitous and costly. The FERC "reforms" in Order 890 illustrate "path dependence," where the path chosen constrains the choices ahead. Early attempts with contract path, flowgate and zonal models led to design failures in PJM (`97), New England (`98), California (`99), and Texas (`03). Regional aggregation creates conflicts with system operations. Successful market design integrates the market with system operations.



ELECTRICITY MARKET — A Consistent Framework

The basic model covers the existing Regional Transmission Organizations and is expanding through the Wester Energy Imbalance Market. ([www.westerneim.com)](http://www.westerneim.com)





(IRC Council and CAISO maps)

What is the value of Financial Transmission Rights? Summary:

Financial Transmission Rights (FTR), Transmission Congestion Contracts (TCC), Congestion Revenue Rights (CRR) …

- First Principles and Electricity Market Design.
  - Open Access and Non-discrimination.
  - No need to limit types of transactions or participants.
- Origins and Evolution.
  - Physical rights cannot support a market.
  - Financial rights encompass virtual traders and expand liquidity.
- Continuing Challenges.
  - Auction Design and Revenue Adequacy. Simultaneous feasibility.
  - Auction Revenue Rights (ARR). Allocating the value, not the rights.
  - Transmission Expansion. Needs integration with FTR expansion.
  - Up-to-Congestion Products. Relevant for auctions and day-ahead transactions.
  - Eligible Nodal Locations. No theoretical reason for limiting locations.

ELECTRICITY MARKET Efficient Market Design

No design can be perfect, but the record indicates the high costs of ignoring first principles. When "good enough" is good enough, the costs of the unintended consequences can be high. The examples from scarcity pricing, demand response, transmission expansion and the cleaner energy are illustrative but not exhaustive. Many other areas present similar challenges.

- **Extended Locational Marginal Prices (ELMP).** (Gribik, Hogan, & Pope, 2007)
- **Out-of-Market Transactions and Price Formation.** (Hogan, 2014)
- **Renewable Portfolio Standards.** (Schmalensee, 2012)
- **Net Energy Metering.** (Brown & Bunyan, 2014)
- **Market Manipulation.** (Lo Prete & Hogan, 2014)
- **Reforming the Energy Vision.** (NYS Department of Public Service, 2014) (Caramanis, Ntakou, Hogan, Chakrabortty, & Schoene, 2016)
- **Hidden Values and the Value Stack.** (NYS Department of Public Service, 2016)
- **Virtual Bidding and Financial Trading.** (Hogan, 2016)
- **Clean Power Plan.** (Hogan, 2015)
- **Energy Imbalance Markets.** (Hogan, 2017)
- **Other?**

References

Brown, A., & Bunyan, J. (2014). Valuation of Distributed Solar: A Qualitative View. *Electricity Journal*, *27*(10), 27–48. https://doi.org/10.1016/j.tej.2014.11.005

Caramanis, M. C., Ntakou, E., Hogan, W. W., Chakrabortty, A., & Schoene, J. (2016). Co-Optimization of Power and Reserves in Dynamic T & D Power Markets With Nondispatchable Renewable Generation and Distributed Energy Resources. *Proceedings of the IEEE*, *104*(4), 807–836. Retrieved from http://ieeexplore.ieee.org.ezp-prod1.hul.harvard.edu/stamp/stamp.jsp?arnumber=7429676

Federal Energy Regulatory Commission. (2017). Order on Rehearing and Compliance, PJM Dockets EL 16-6-002, 158 FERC ¶ 61,093. Retrieved from https://www.ferc.gov/CalendarFiles/20170131173534-EL16-6-002.pdf

Gribik, P. R., Hogan, W. W., & Pope, S. L. (2007). Market-Clearing Electricity Prices and Energy Uplift. Retrieved from http://www.hks.harvard.edu/fs/whogan/Gribik_Hogan_Pope_Price_Uplift_123107.pdf

Hogan, W. W. (2014). Electricity Market Design and Efficient Pricing: Applications for New England and Beyond. *The Electricity Journal*, *27*(7), 23–49. https://doi.org/10.1016/j.tej.2014.07.009

Hogan, W. W. (2015). Electricity Markets and the Clean Power Plan. *The Electricity Journal*, *28*(9), 9–32. Retrieved from http://www.sciencedirect.com/science/article/pii/S1040619015002006

Hogan, W. W. (2016). Virtual bidding and electricity market design. *The Electricity Journal*, *29*(5), 33–47. https://doi.org/10.1016/j.tej.2016.05.009

Hogan, W. W. (2017). An efficient Western Energy Imbalance Market with conflicting carbon policies. *The Electricity Journal*, *30*(10), 8–15. https://doi.org/10.1016/j.tej.2017.11.001

International Energy Agency. (2007). *Tackling Investment Challenges in Power Generation in IEA Countries: Energy Market Experience*. Paris. Retrieved from http://www.iea.org/publications/freepublications/publication/tackling_investment.pdf

Joskow, P. L., & Schmalensee, R. (1983). *Markets for power: an analysis of electrical utility deregulation*. *MIT Press Books*. MIT Press Book. Retrieved from http://ideas.repec.org/b/mtp/titles/0262600188.html

Lo Prete, C., & Hogan, W. W. (2014). Manipulation of Day-ahead Electricity Prices through Virtual Bidding in the U. S. *IAEE Energy Forum*, 31–32. Retrieved from http://www.iaee.org/en/publications/newsletterdl.aspx?id=244

Monitoring Analytics. (2018). 2017 State of the Market Report for PJM. Retrieved from http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017-som-pjm-volume2.pdf

NYS Department of Public Service. (2014). *Reforming the Energy Vision* (No. CASE 14-M-0101). Retrieved from http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/ATTK0J3L.pdf/Reforming The Energy Vision (REV) REPORT 4.25. 14.pdf

NYS Department of Public Service. (2016). *Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding*. Retrieved from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B59B620E6-87C4-4C80-8BEC-E15BB6E0545E%7D

Schmalensee, R. (2012). Evaluating policies to increase electricity generation from renewable energy. *Review of Environmental Economics and Policy*, *6*(1), 45–64. https://doi.org/10.1093/reep/rer020

Schweppe, F. C., Caramanis, M. C., Tabors, R. D., & Bohn, R. E. (1988). *Spot pricing of electricity*. Kluwer Academic Publishers. Retrieved from

http://books.google.com/books?id=Sg5zRPWrZ_gC&pg=PA265&lpg=PA265&dq=spot+pricing+of+electricity+schweppe&source=bl&ots=1MIUfKBjBk&sig=FXe_GSyf_V_fcIuTmUtH7mKO_PM&hl=en&ei=Ovg7Tt66DO2x0AH50aGNCg&sa=X&oi=book_result&ct=result&resnum=3&ved=0CDYQ6AEwAg#v=onep

William W. Hogan is the Raymond Plank Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University. This paper draws on research for the Harvard Electricity Policy Group and for the Harvard-Japan Project on Energy and the Environment. The author is or has been a consultant on electric market reform and transmission issues for Allegheny Electric Global Market, American Electric Power, American National Power, Aquila, AQUIND Limited, Atlantic Wind Connection, Australian Gas Light Company, Avista Corporation, Avista Utilities, Avista Energy, Barclays Bank PLC, Brazil Power Exchange Administrator (ASMAE), British National Grid Company, California Independent Energy Producers Association, California Independent System Operator, California Suppliers Group, Calpine Corporation, CAM Energy, Canadian Imperial Bank of Commerce, Centerpoint Energy, Central Maine Power Company, Chubu Electric Power Company, Citigroup, City Power Marketing LLC, Cobalt Capital Management LLC, Comision Reguladora De Energia (CRE, Mexico), Commonwealth Edison Company, COMPETE Coalition, Conectiv, Constellation Energy, Constellation Energy Commodities Group, Constellation Power Source, Coral Power, Credit First Suisse Boston, DC Energy, Detroit Edison Company, Deutsche Bank, Deutsche Bank Energy Trading LLC, Duquesne Light Company, Dyon LLC, Dynegy, Edison Electric Institute, Edison Mission Energy, Electricity Authority New Zealand, Electricity Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, Energy Endeavors LP, Exelon, Financial Marketers Coalition, FirstEnergy Corporation, FTI Consulting, GenOn Energy, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd., GDF SUEZ Energy Resources NA, Great Bay Energy LLC, GWF Energy, Independent Energy Producers Assn, ISO New England, Israel Public Utility Authority-Electricity, Koch Energy Trading, Inc., JP Morgan, LECG LLC, Luz del Sur, Maine Public Advocate, Maine Public Utilities Commission, Merrill Lynch, Midwest ISO, Mirant Corporation, MIT Grid Study, Monterey Enterprises LLC, MPS Merchant Services, Inc. (f/k/a Aquila Power Corporation), JP Morgan Ventures Energy Corp., Morgan Stanley Capital Group, Morrison & Foerster LLP, National Independent Energy Producers, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, NRG Energy, Inc., Ontario Attorney General, Ontario IMO, Ontario Ministries of Energy and Infrastructure, Pepco, Pinpoint Power, PJM Office of Interconnection, PJM Power Provider (P3) Group, Powerex Corp., Powhatan Energy Fund LLC, PPL Corporation, PPL Montana LLC, PPL EnergyPlus LLC, Public Service Company of Colorado, Public Service Electric & Gas Company, Public Service New Mexico, PSEG Companies, Red Wolf Energy Trading, Reliant Energy, Rhode Island Public Utilities Commission, Round Rock Energy LP, San Diego Gas & Electric Company, Secretaría de Energía (SENER, Mexico), Sempra Energy, SESCO LLC, Shell Energy North America (U.S.) L.P., SPP, Texas Genco, Texas Utilities Co, Tokyo Electric Power Company, Toronto Dominion Bank, Transalta, TransAlta Energy Marketing (California), TransAlta Energy Marketing (U.S.) Inc., Transcanada, TransCanada Energy LTD., TransÉnergie, Transpower of New Zealand, Tucson Electric Power, Twin Cities Power LLC, Vitol Inc., Westbrook Power, Western Power Trading Forum, Williams Energy Group, Wisconsin Electric Power Company, and XO Energy. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the author. (Related papers can be found on the web at www.whogan.com).