ELECTRICITY MARKET DESIGN AND THE GREEN AGENDA

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The focus on the electricity sector's role in addressing climate change through improved efficiency, development of renewable energy, and use of low carbon fuels creates expanded demands for and of electricity restructuring.

The transformation envisioned is massive, long term, and affects every aspect of electricity production and use.

- Uncertain conditions require a broad range of activities to integrate new technology and practices.
- Innovation requires promoting technologies and practices not yet identified or imagined. "Silver buckshot rather than silver bullets."
- Smart grids can facilitate smart decisions, but only if the electricity structure provides the right information and incentives.
    - Open access to expand entry and innovation.
    - Smart pricing to support the smart grid technologies and information.
    - Internalizing externalities, while exploiting the wisdom of crowds.
        - Price on carbon emissions.
        - ***Good market design with efficient prices.***
        - Compatible infrastructure expansion rules.

Policies for smart grids emphasize better deployment of information and incentives. A major challenge is to improve the information and rationalize the incentives deployed. According to the White House plan:

> "A smarter, modernized, and expanded grid will be pivotal to the United States' world leadership in a clean energy future. This policy framework focuses on the deployment of information and communications technologies in the electricity sector. As they are developed and deployed, these smart grid technologies and applications will bring new capabilities to utilities and their customers. In tandem with the development and deployment of high-capacity transmission lines, which is a topic beyond the scope of this report, smart grid technologies will play an important role in supporting the increased use of clean energy.
>
> …
>
> This framework is premised on four pillars:
>
> 1. Enabling cost-effective smart grid investments
> 2. Unlocking the potential for innovation in the electric sector
> 3. Empowering consumers and enabling them to make informed decisions, and
> 4. Securing the grid." [1]

At least three of the four pillars imply a need for better pricing structures and signals.

[1] Subcommittee on Smart Grid of the National Science and Technology Council, Committee on Technology, *A POLICY FRAMEWORK FOR THE 21st CENTURY GRID: Enabling Our Secure Energy Future*, White House, June 13, 2011, p. v.

The US 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**

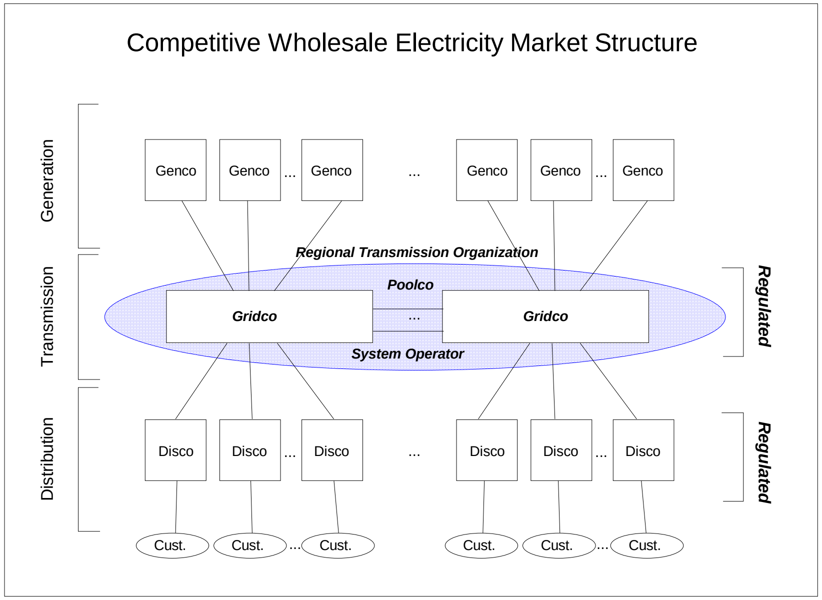
  Better scarcity pricing to support resource adequacy.

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

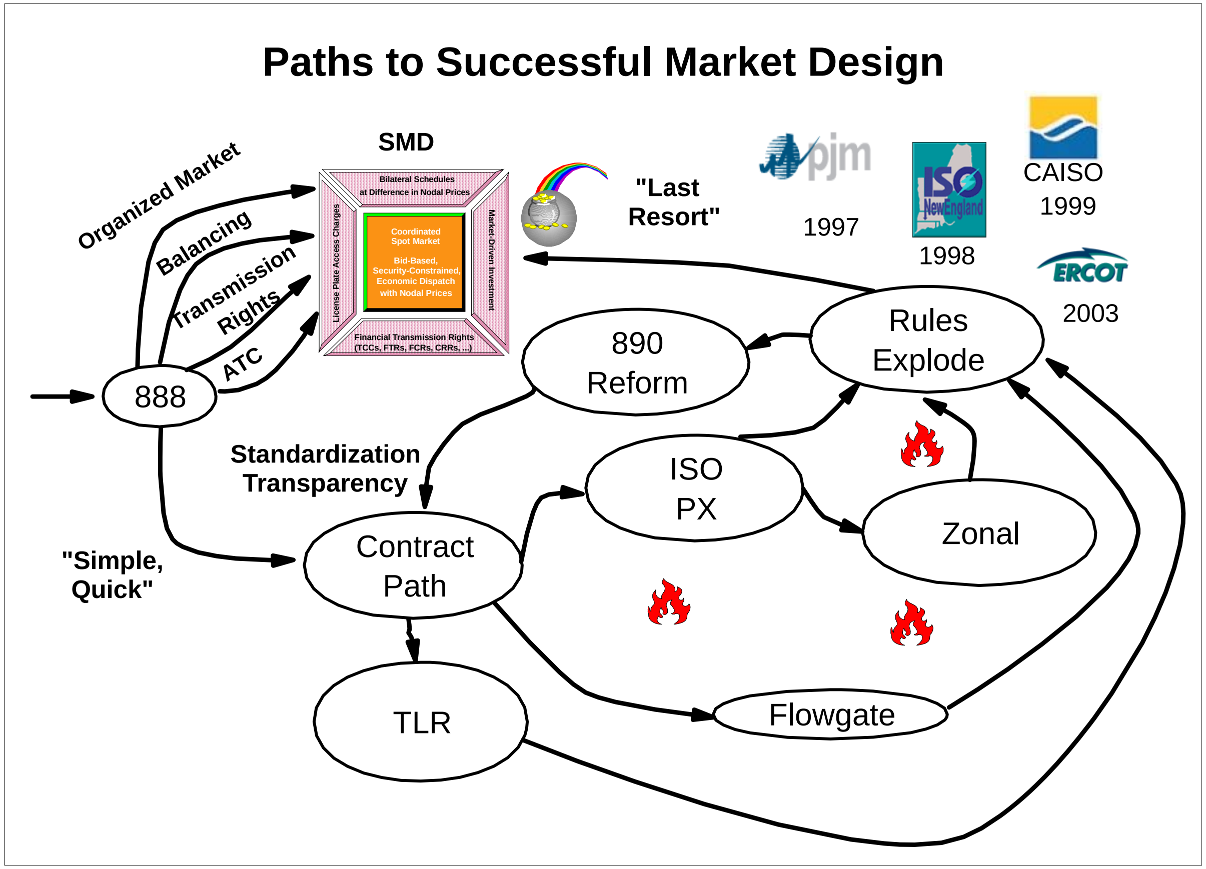
- **Design Challenge: Infrastructure Investment**

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

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



The 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.



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.

> "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?**
- **Is it possible to reform Order 888 to achieve the open access objective to remove impediments to competition?**

Can open access not be about market design?

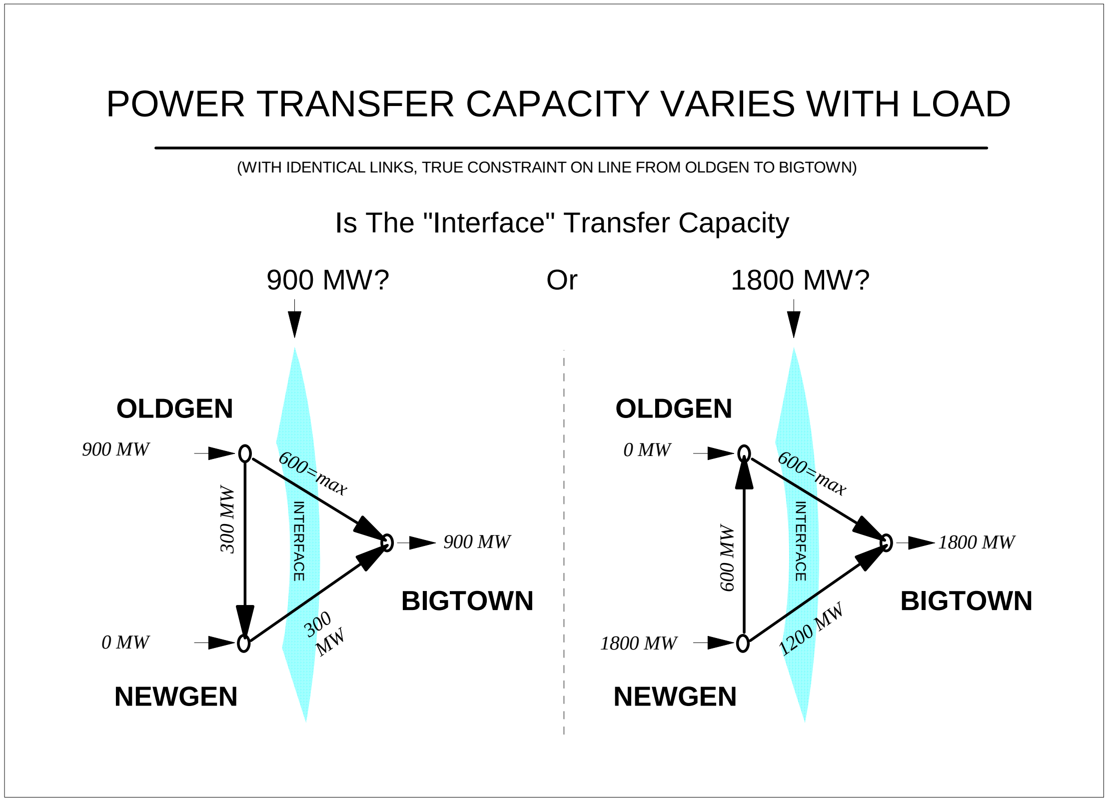
Under Order 888 the FERC made a crucial choice regarding a central complication of the electricity system.

> "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.)

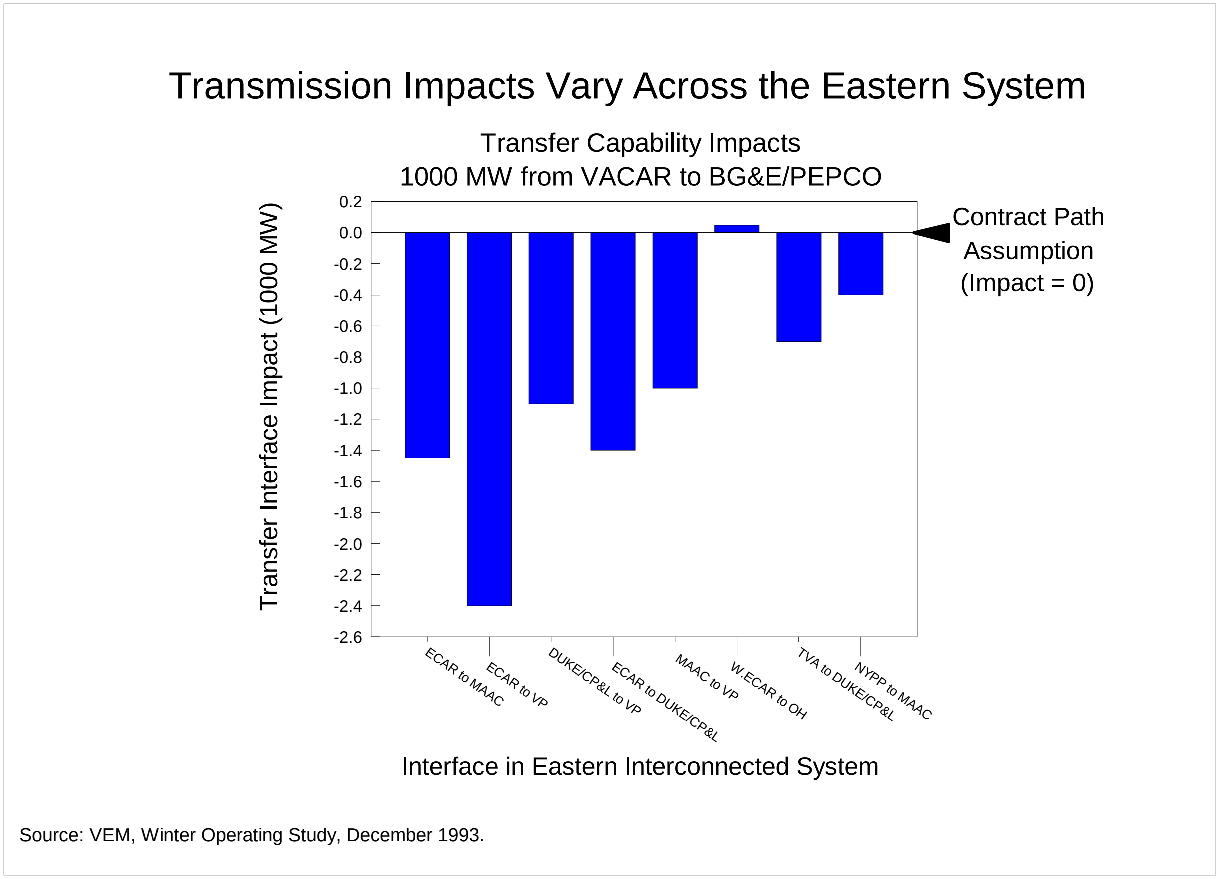
Why is this important?

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.



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. They 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)

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

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> "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!

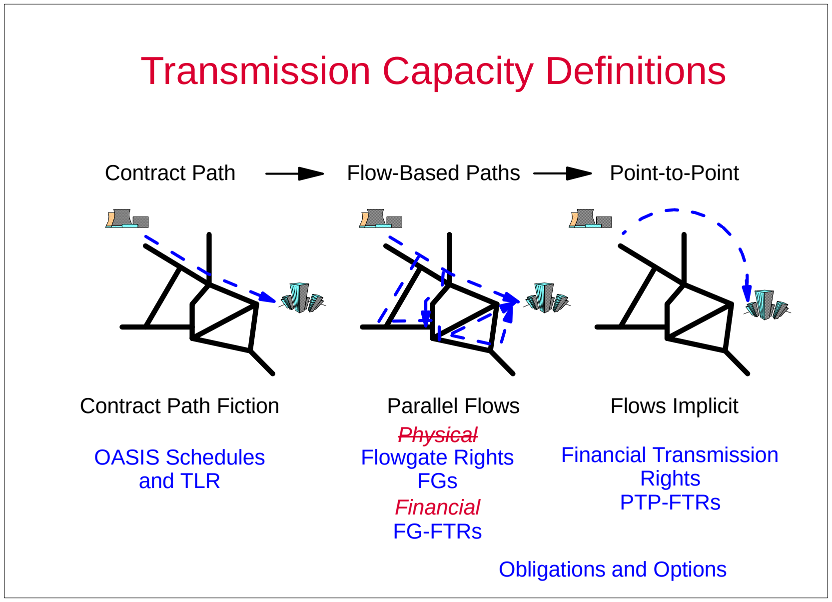
The evolution of electricity restructuring contains a thread of issues related to counterintuitive market design requirements requiring coordination for competition.

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 ..."[2]

- **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. Too late?

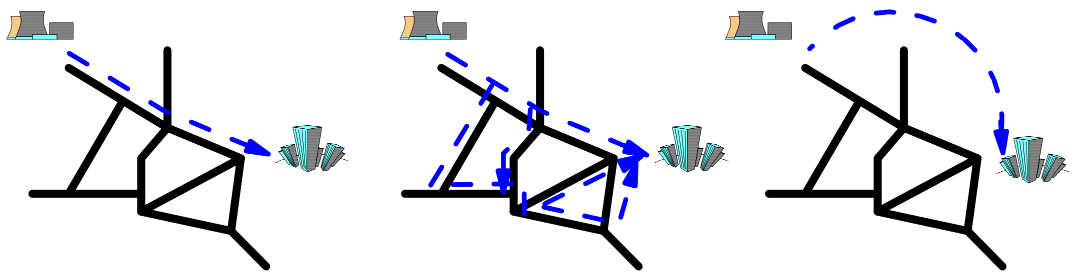


[2] Federal Energy Regulatory Commission, "Capacity Reservation Open Access Transmission Tariffs," Notice of Proposed Rulemaking, RM96-11-000, Washington DC, April 24, 1996, p. 1.

Defining and managing transmission usage is a principal challenge in electricity markets.

Transmission Capacity Definitions

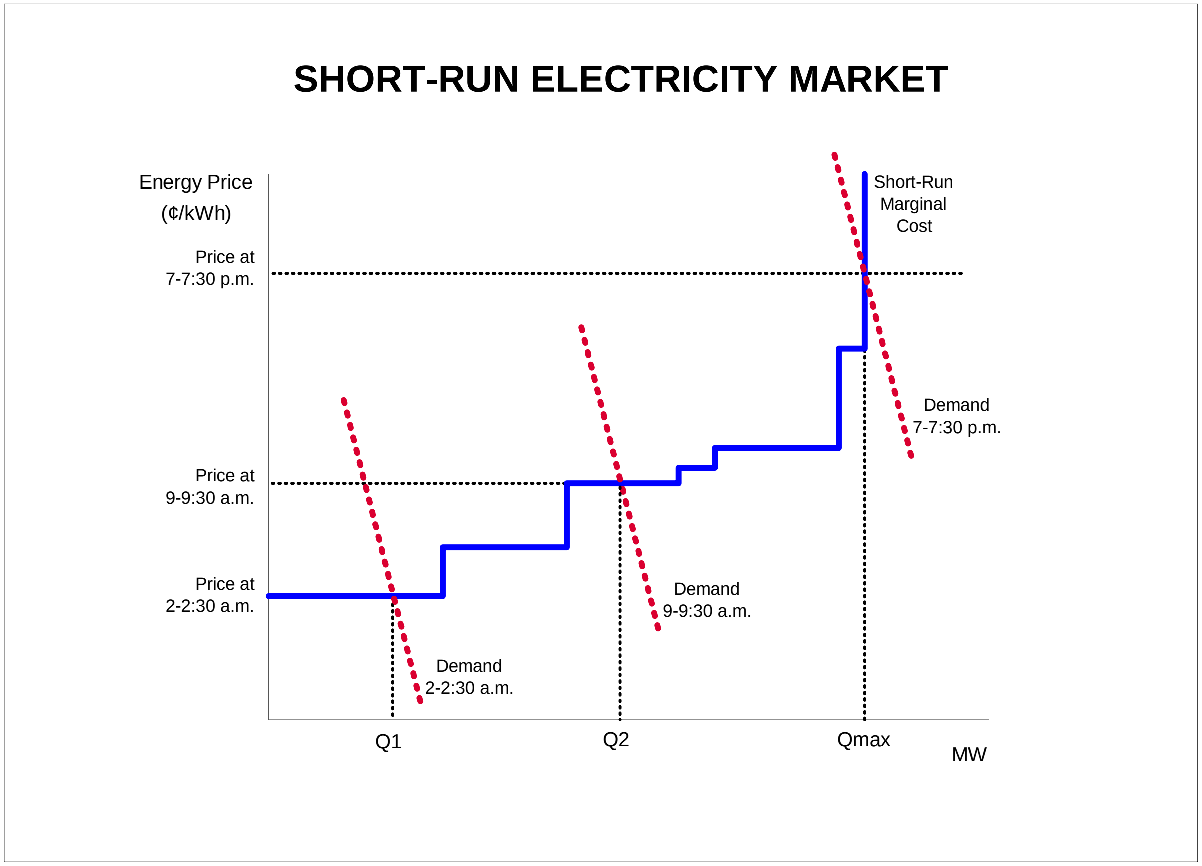
Contract Path → Flow-Based Paths → Point-to-Point



Contract Path Fiction | Parallel Flows | Flows Implicit

OASIS Schedules and TLR | Flowgate Rights FGRs | Financial Transmission Rights FTRs

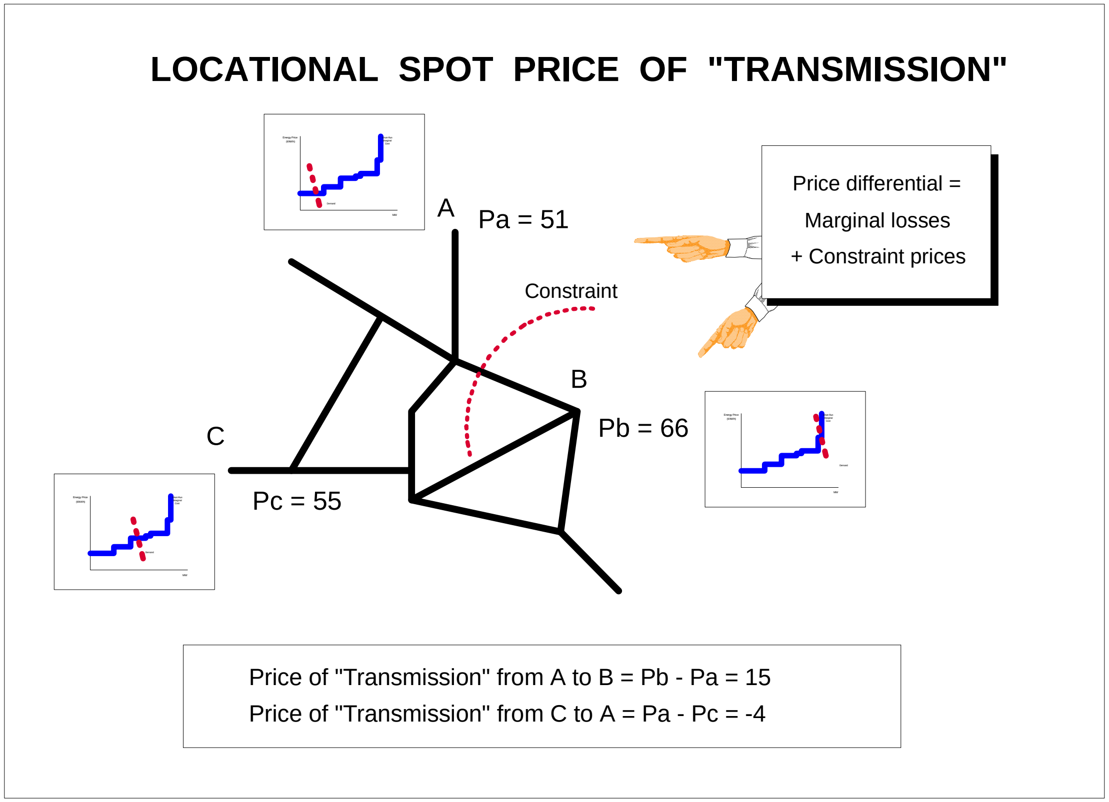
An efficient short-run electricity market determines a market clearing price based on conditions of supply and demand balanced in an economic dispatch. Everyone pays or is paid the same price.



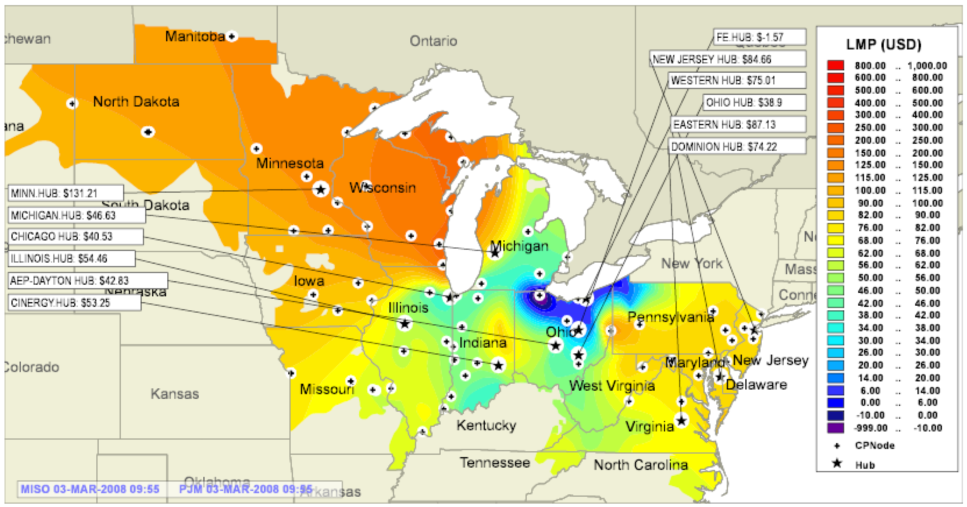
The natural extension of a single price electricity market is to operate a market with locational spot prices.

- 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.



RTOs operate spot markets with locational prices. For example, PJM updates prices and dispatch every five minutes for over 8,000 locations. Locational spot prices for electricity exhibit substantial dynamic variability and persistent long-term average differences.



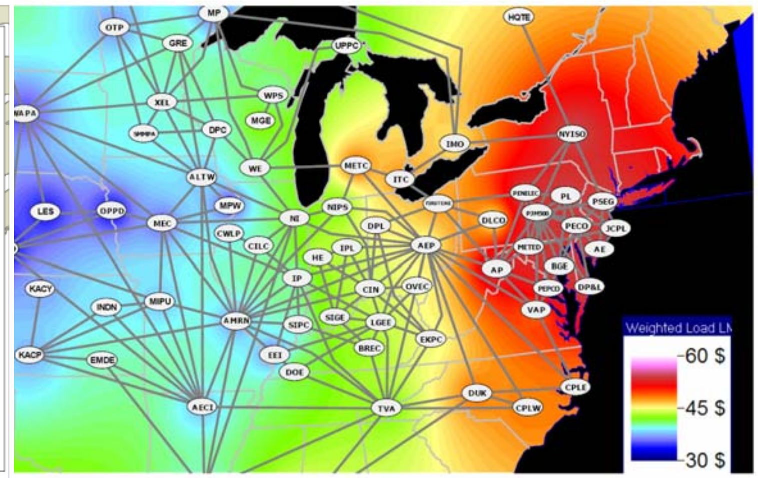


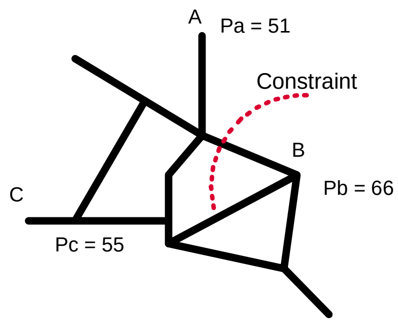
Figure 2.2-3 Contour Map of Annual Load Weighted LMP

Minnesota Hub: $131.21/MWh. First Energy Hub: $-1.57/MWh.

From MISO-PJM Joint and Common Market, http://www.jointandcommon.com/ for March 3, 2008, 9:55am. Projected 2011 annual average from 2006 Midwest ISO-PJM Coordinated System Plan.

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

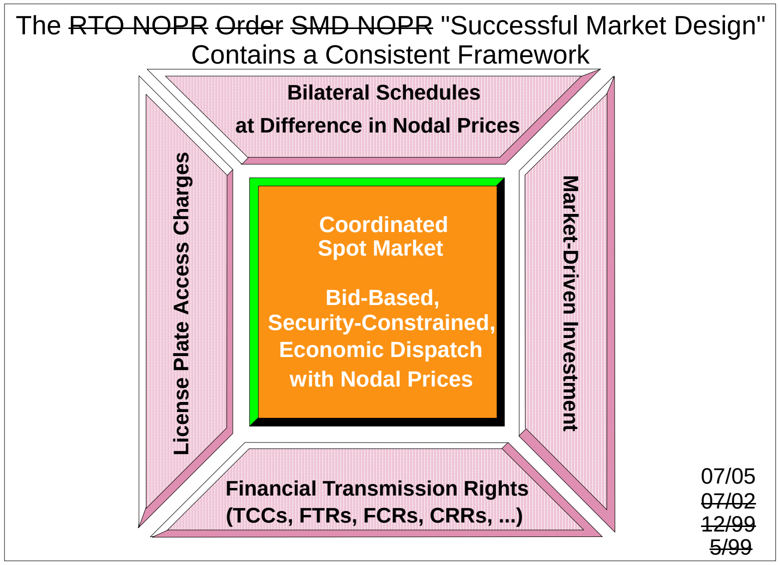


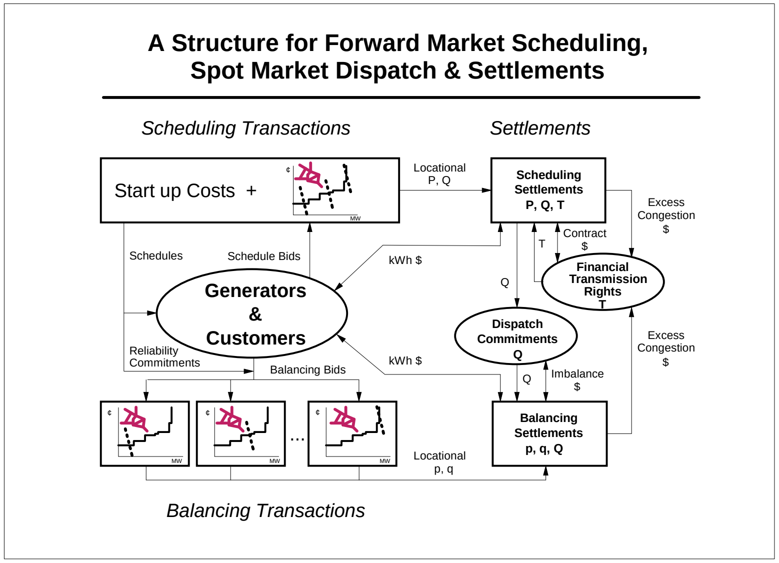
Price of "Transmission" from A to B = Pb - Pa = 15
Price of "Transmission" from A to C = Pc - Pa = -4

- 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.

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.

> "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, Tackling Investment Challenges in Power Generation in IEA Countries: Energy Market Experience, Paris, 2007, p. 16.)





Market design in RTOs/ISOs is well advanced but still incomplete.[3]

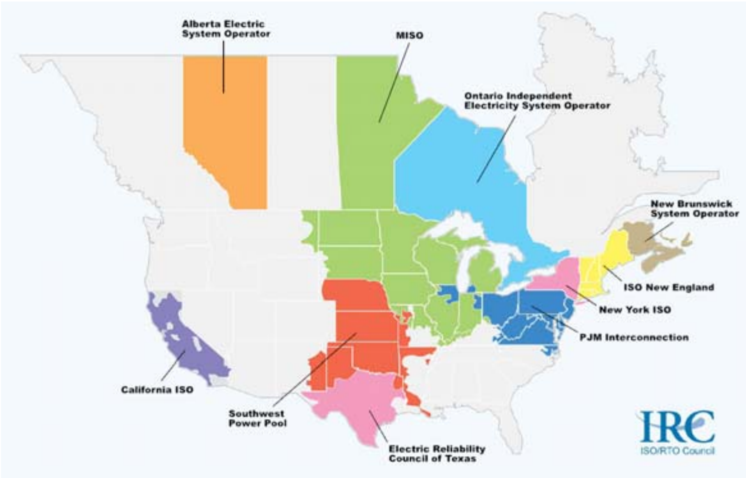
- **Regional Markets Not Fully Deployed**

- **Reforms of Reforms**

  California MRTU (April 1, 2009) and ERCOT Texas Nodal (December 1, 2010) reforms.

- **Market Defect: Scarcity Pricing, Extended LMP**

  Smarter pricing to support operations, infrastructure investment and resource adequacy.



- **Market Failure: Transmission Investment**

  - Regulatory mandates for lumpy transmission mixed with market-based investments.
  - Design principles for cost allocation to support a mixed market (i.e., beneficiary pays).

- **Market Challenge: Address Requirements for Climate Change Policy**

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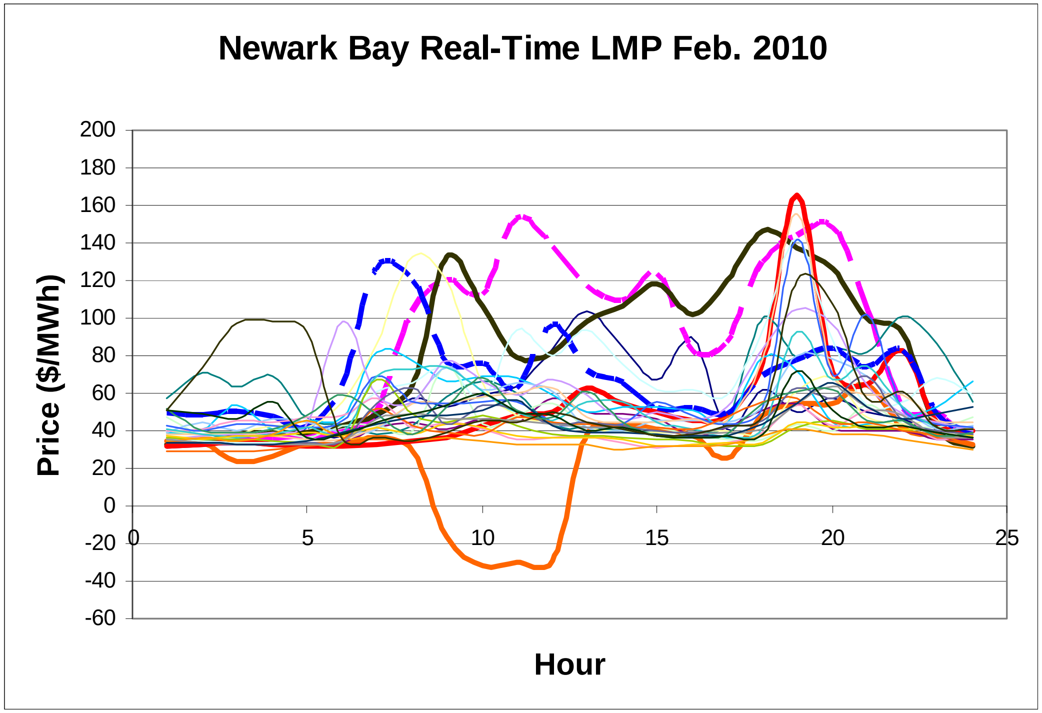
[3] William W. Hogan, "Electricity Market Structure and Infrastructure," Conference on Acting in Time on Energy Policy, Harvard University, September 18-19, 2008. (available at www.whogan.com).

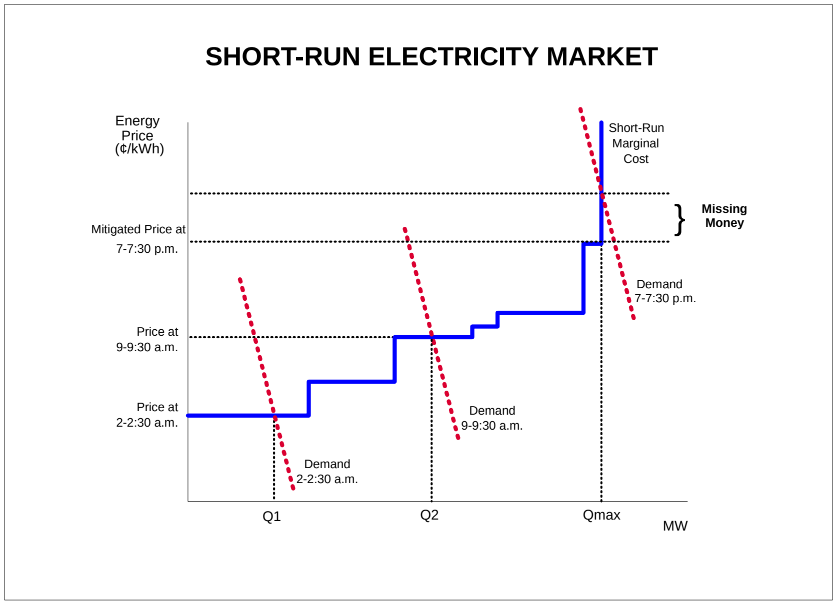
Smarter pricing provides an opportunity for enhancing efficiency and the range of alternative technologies.

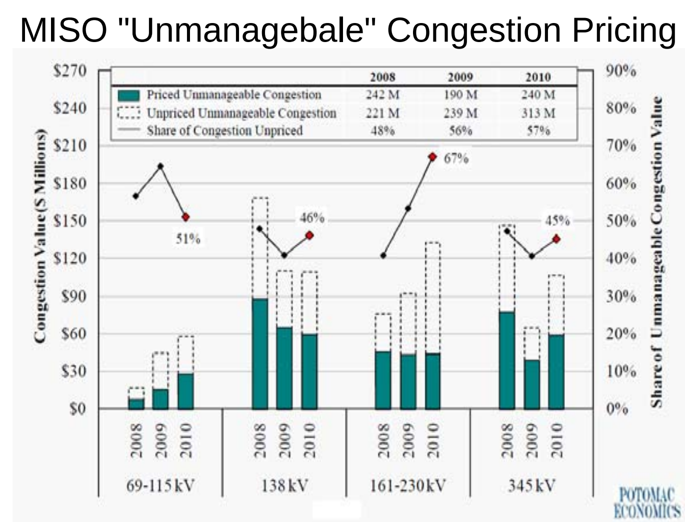
- **Smarter Pricing Challenges**
    - Average energy prices: $50/MWh.
    - Canonical bid baps: $1,000/MWh.
    - MISO average value of lost load: $3,500/MWh.
    - Reliability standard VOLL: $500,000/MWh.

- **Real Time Pricing**
    - Time of Use (TOU) approximations do not track real-time prices: RTP >> CPP > CPR >> PP >> FR.
    - There is substantial geographic and temporal variability of real-time prices.



Early market designs presumed a significant demand response. Absent this demand participation most markets implemented inadequate pricing rules equating prices to marginal costs even when capacity is constrained. This produces a "missing money" problem.





Source: David Patton, *2010 State of the Market Report, Midwest ISO*, Potomac Economics, May 2011, p. 171.

The "missing money" problem is material and has a significant impact on investment incentives. Major efforts have been focused on defining new products and better pricing methods to address the incentives, ensure resource adequacy, and improve efficiency.

- **PJM, Missing Money, Combustion Turbine (1999-2010, per MW-Year).**

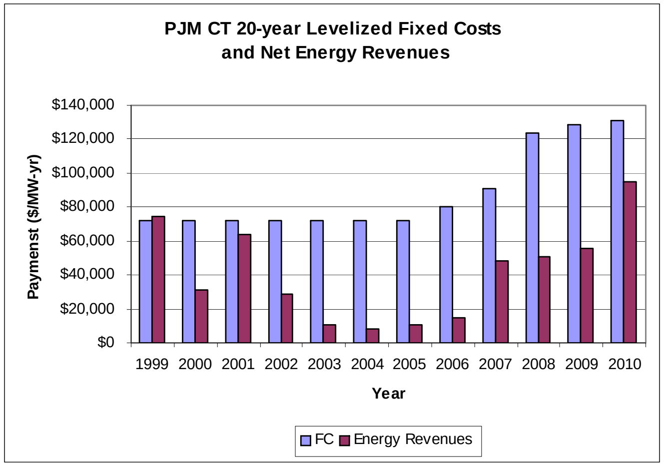
Average Net Energy Revenue = $40,943

Average Levelized Fixed Cost = $88,317

(PJM, State of Market Report, 2010, Vol. 2, p. 176)

- **Capacity Markets.** ISONE, NYISO, PJM, SWIS.
- **Scarcity Pricing.** Operating Reserve Demand Curve in MISO, NYISO, ISONE. (MISO FERC Electric Tariff, Volume No. 1, Schedule 28, January 22, 2009.)[4]

Payments for CT Peaker
PJM Economic Dispatch



Source: Monitoring Analytics, State of the Market Report, 2010, Table 3-21, Vol. 2, p. 171.

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4 "For each cleared Operating Reserve level less than the Market-Wide Operating Reserve Requirement, the Market-Wide Operating Reserve Demand Curve price shall be equal to the product of (i) the Value of Lost Load ("VOLL") and (ii) the estimated conditional probability of a loss of load given that a single forced Resource outage of 100 MW or greater will occur at the cleared Market-Wide Operating Reserve level for which the price is being determined. … The VOLL shall be equal to $3,500 per MWh." MISO, FERC Electric Tariff, Volume No. 1, Schedule 28, January 22, 2009, Sheet 2226.

Inadequate scarcity pricing dampens real-time price volatility, and has a material impact on incentives for innovation. Fixed rates, including pre-determined time-of-use rates, dampen volatility. Levelized rates and socialized costs eliminate volatility. Accurate scarcity prices would capture the marginal welfare effects of consumption and generation. Assuming cost recovery on average, incomplete scarcity pricing implies various forms of inefficiency.

- **Energy Efficiency and Distributed Generation.** With levelized rates, passive energy efficiency changes such as insulation are efficient only for customers with the average load profile. Customer load profiles are heterogeneous, so there is too little or too much incentive for most. For distributed generation and active load management, such as turning down air conditioning when away from home, sees too little incentive when it is needed most during high periods of (implicit) scarcity prices.
- **Load Management.** Changing the load profile to arbitrage price differences over time depends on exploiting price volatility. Suppressing and socializing scarcity prices dampens incentives for load management.
  - **Load Shifting.** Cycling equipment of moving consumption to "off-peak" hours receives too little incentive.
  - **PHEV/EV.** Managing the charging cycle for electric vehicles will affect the economics of both cars and the electricity system. Inadequate scarcity pricing and rate smoothing dampen incentives and raise costs.
  - **Batteries.** The principal benefit of batteries, from high tech flow batteries to low tech ceramic bricks, is profit from price arbitrage. Smooth prices undo the incentives for battery deployment.

The underlying models of operating reserve demand curves differ across RTOs. One need is for a framework that develops operating reserve demand curves from first principles to provide a benchmark for the comparison of different implementations.

- **Operating Reserve Demand Curve Components.** The inputs to the operating reserve demand curve construction can differ and a more general model would help specify the result.
- **Locational Differences and Interactions.** The design of locational operating reserve demand curves presents added complications in accounting for transmission constraints.
- **Economic Dispatch.** The derivation of the locational operating demand curves has implications for the integration with economic dispatch models for simultaneous optimization of energy and reserves.

A series of approximations to a probabilistic unit commitment and economic dispatch models provides a framework for incorporating scarcity pricing and operating reserve demand curves. The resulting model is a workable extension of existing unit commitment and economic dispatch formulations.

Improved pricing through an explicit operating reserve demand curve raises a number of issues.

Demand Response: Better pricing implemented through the operating reserve demand curve would provide an important signal and incentive for flexible demand participation in spot markets.

Price Spikes: A higher price would be part of the solution. Furthermore, the contribution to the "missing money" from better pricing would involve many more hours and smaller price increases.

Practical Implementation: The NYISO, ISONE and MISO implementations dispose of any argument that it would be impractical to implement an operating reserve demand curve. The only issues are the level of the appropriate price and the preferred model of locational reserves.

Operating Procedures: Implementing an operating reserve demand curve does not require changing the practices of system operators. Reserve and energy prices would be determined simultaneously treating decisions by the operators as being consistent with the adopted operating reserve demand curve.

Multiple Reserves: The demand curve would include different kinds of operating reserves, from spinning reserves to standby reserves.

Reliability: Market operating incentives would be better aligned with reliability requirements.

Market Power: Better pricing would remove ambiguity from analyses of high prices and distinguish (inefficient) economic withholding through high offers from (efficient) scarcity pricing derived from the operating reserve demand curve.

Hedging: The Basic Generation Service auction in New Jersey provides a prominent example that would yield an easy means for hedging small customers with better pricing.

Increased Costs: The higher average energy costs from use of an operating reserve demand curve do not automatically translate into higher costs for customers. In the aggregate, there is an argument that costs would be lower.

Fairness issues of electricity market design focus on residential and small electricity customers; industrial and large commercial customers are different and capable of hedging real-time prices.[5]

- The default choice (e.g., NJ Basic Generation Service (BGS) versus Dynamic Pricing) is crucial.
  - Transactions costs are not zero.
  - Signaling through implicit endorsement.
  - Behavioral biases. (see pension research and status quo bias)
- For large industrial and commercial customers, the default option would be dynamic pricing and the market can provide alternative hedging instruments.
- For other customers, a default option could be like the New Jersey BGS, with dynamic pricing and demand response.
- Customers could elect in advance to have a fixed load profile, and buy-and sell at real-time prices for any surplus or deficit.
- Or customers could choose to have a full requirement contact and participate with efficient pricing at real-time prices for demand response.
- For more vulnerable customers, means testing provides access to rate assistance payments.
- If there are large economies for comprehensive installation of AMI, then the joint cost allocation would be according to a share in the benefits.

[5] W. Hogan, :Fairness and Dynamic Pricing: Comment," *The Electricity Journal*, Volume 23, Issue 6, July 2010, Pages 28-35

Better scarcity pricing is an example of smarter pricing to reflect dynamic conditions in electricity systems and better match prices and costs. The alternative includes regulatory mandates and standards that create perverse incentives.

- **Mandates and Standards.** Regulatory mandates often raise average costs but dampen apparent price volatility. For example, capacity payments for the "missing money" induced by inadequate scarcity pricing are typically recovered through socialized and levelized rates.
- **Supply Creates Demand for Mandates.** Socialized costs produce inadequate signals and incentives for distributed generation, variable energy resources, and demand response. The pressure is for more mandates to overcome the poor incentives created by other mandates.
- **Efficient Market Design Competes with Regulatory Rent Seeking.** The principles of workable market design suffer from (constant) collateral attack in the give-and-take of regulatory rent seeking.

A challenge for regulators is to internalize and adhere to the principles of good market design. This often requires making distinctions that are not natural.

- **Between Costs and Prices.** Minimizing welfare costs is not the same as minimizing consumer prices.
- **Between Short-Run and Long-Run.** A familiar human challenge: "Penny wise and pound foolish."
- **Between Local and Global Optimization.** Seemingly attractive market design features can be collectively inconsistent. Better design seeks consistency to minimize unintended consequences.

Efficient pricing presents one of the important challenges for Regional Transmission Organizations (RTOs) and electricity market design. Simple in principle, but more complicated in practice, inadequate scarcity pricing is implicated in several problems associated with electricity markets.

- **Investment Incentives.** Inadequate scarcity pricing contributes to the "missing money" needed to support new generation investment. The policy response has been to create capacity markets. Better scarcity pricing would reduce the challenges of operating good capacity markets.

- **Demand Response.** Higher prices during critical periods would facilitate demand response and distributed generation when it is most needed. The practice of socializing payments for capacity investments compromises the incentives for demand response and distributed generation.

- **Renewable Energy.** Intermittent energy sources such as solar and wind present complications in providing a level playing field in pricing. Better scarcity pricing would reduce the size and importance of capacity payments and improve incentives for renewable energy.

- **Transmission Pricing.** Scarcity pricing interacts with transmission congestion. Better scarcity pricing would provide better signals for transmission investment.

Improved pricing would mitigate or substantially remove the problems in all these areas.[6]

Smart Grids Need Smart Prices.

[6] FERC, Order 719, October 17, 2008.

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