ELECTRICITY MARKET DESIGN AND THE GREEN AGENDA

William W. Hogan

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

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The case of electricity restructuring presents examples of fundamental problems that challenge regulation of markets.

- **Marriage of Engineering and Economics.**
  - **Loop Flow.**
  - **Reliability Requirements.**
  - **Incentives and Equilibrium.**

- **Devilish Details.**
  - **Market Power Mitigation.**
  - **Coordination for Competition.**

- **Jurisdictional Disputes.**
  - **US State vs. Federal Regulators.**
  - **European Subsidiarity Principle.**

The Federal Energy Regulatory Commission has responsibility for regulating wholesale electricity markets. The stated framework emphasizes support for competition in wholesale markets as 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]

A task for regulation is to support this policy framework while developing hybrid markets and dealing with both the limits of markets and the failures of market designs.

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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.

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." [3]

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

[3] 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**

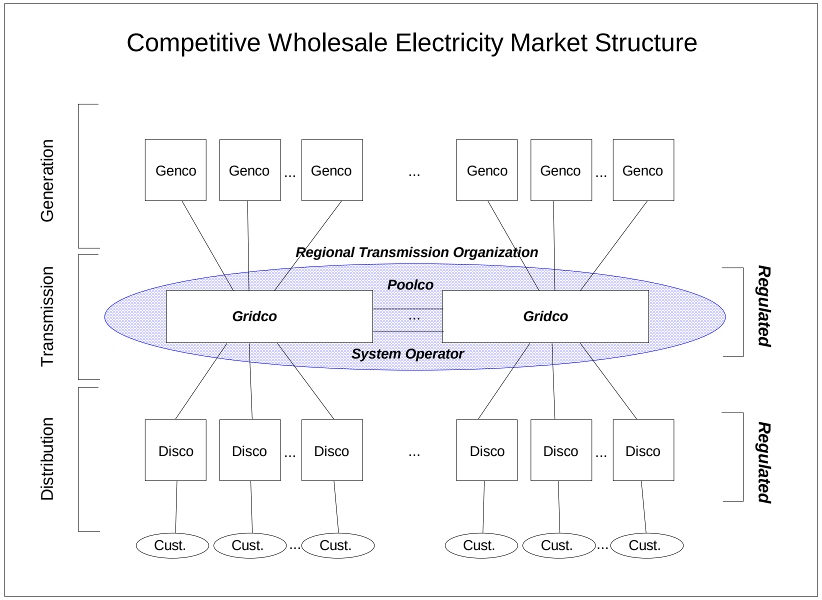
  Locational Marginal Prices (LMP) with granularity to match system operations.

  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.

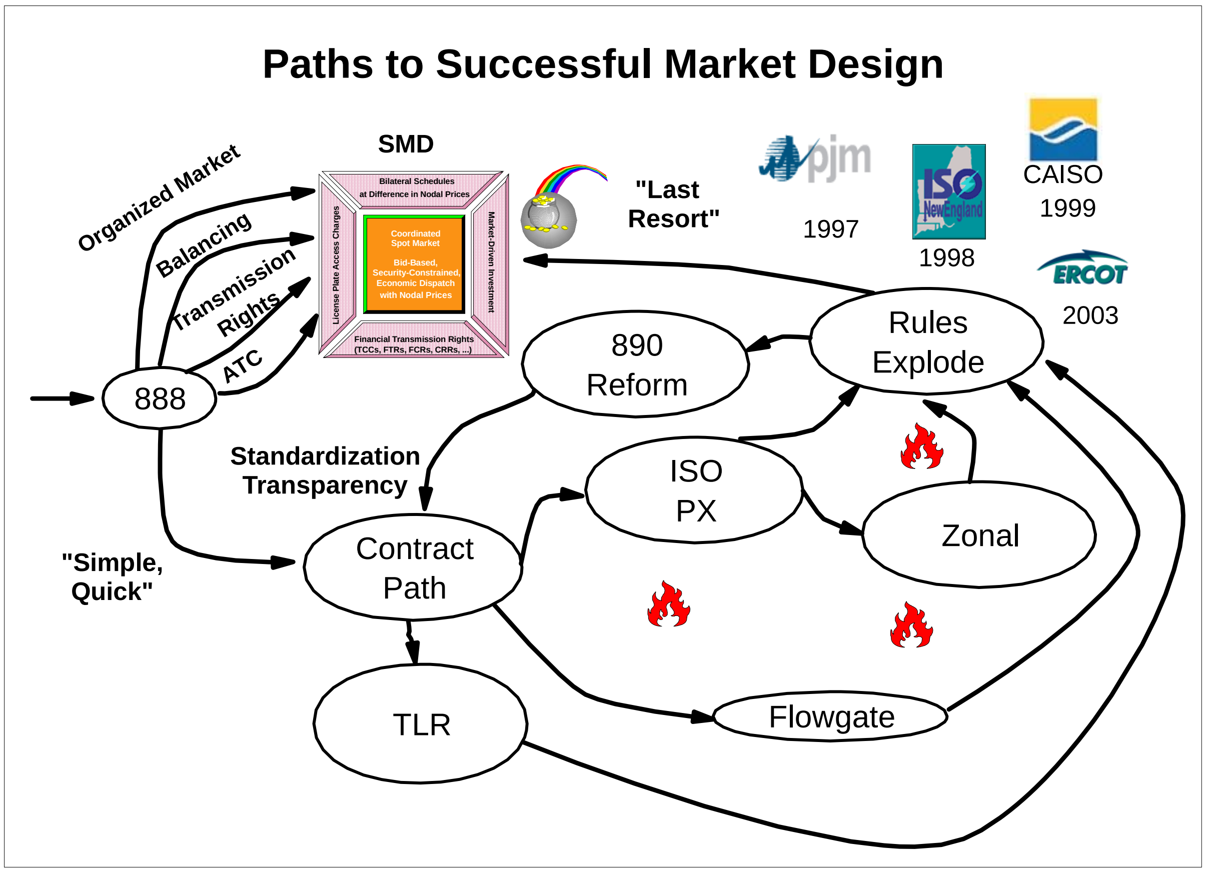


- **Design Challenge: Infrastructure Investment**

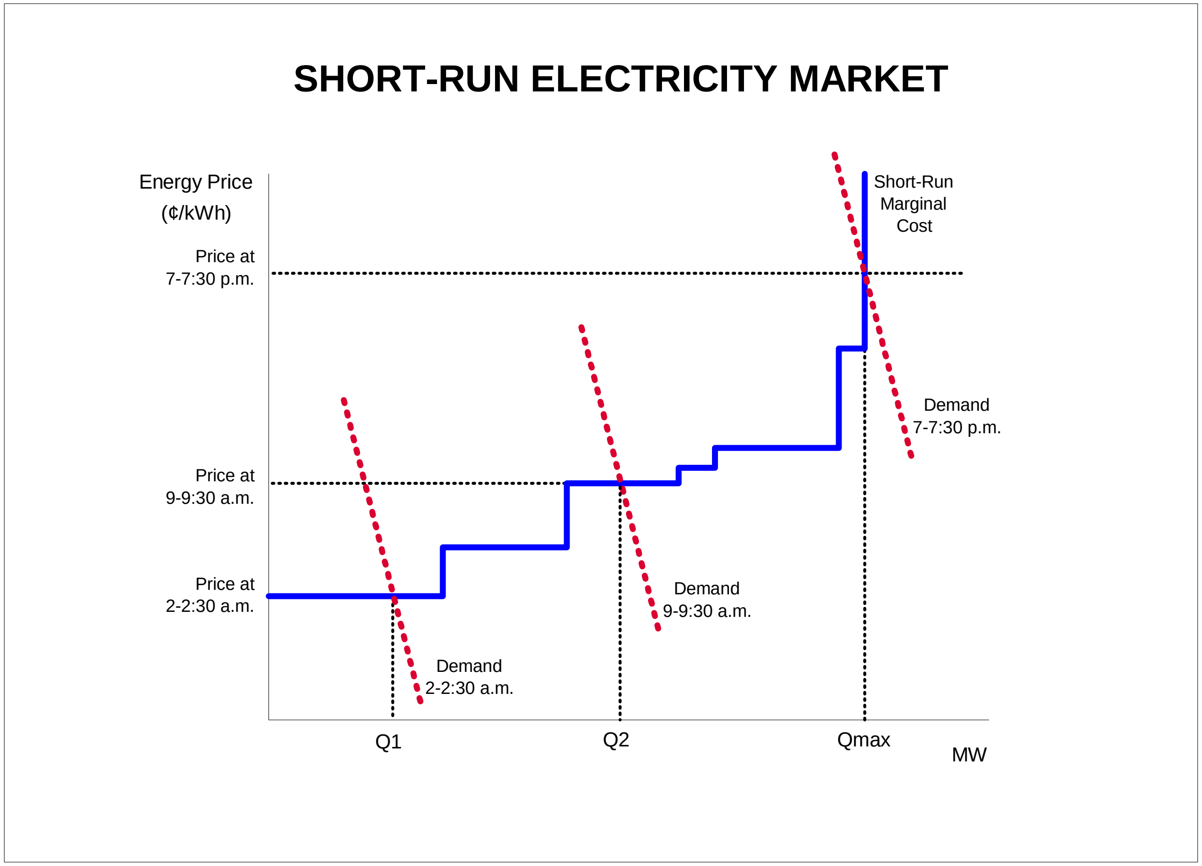
  Hybrid models to accommodate both market-based and regulated transmission investments.

  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.



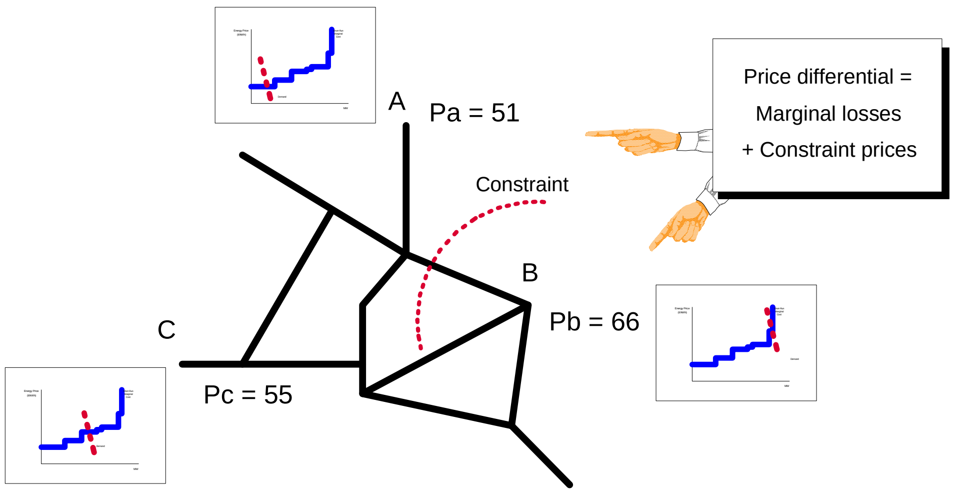
An efficient short-run electricity market determines a market clearing price based on conditions of supply and demand balanced in an economic dispatch. Everyone pays or is paid the same price.



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

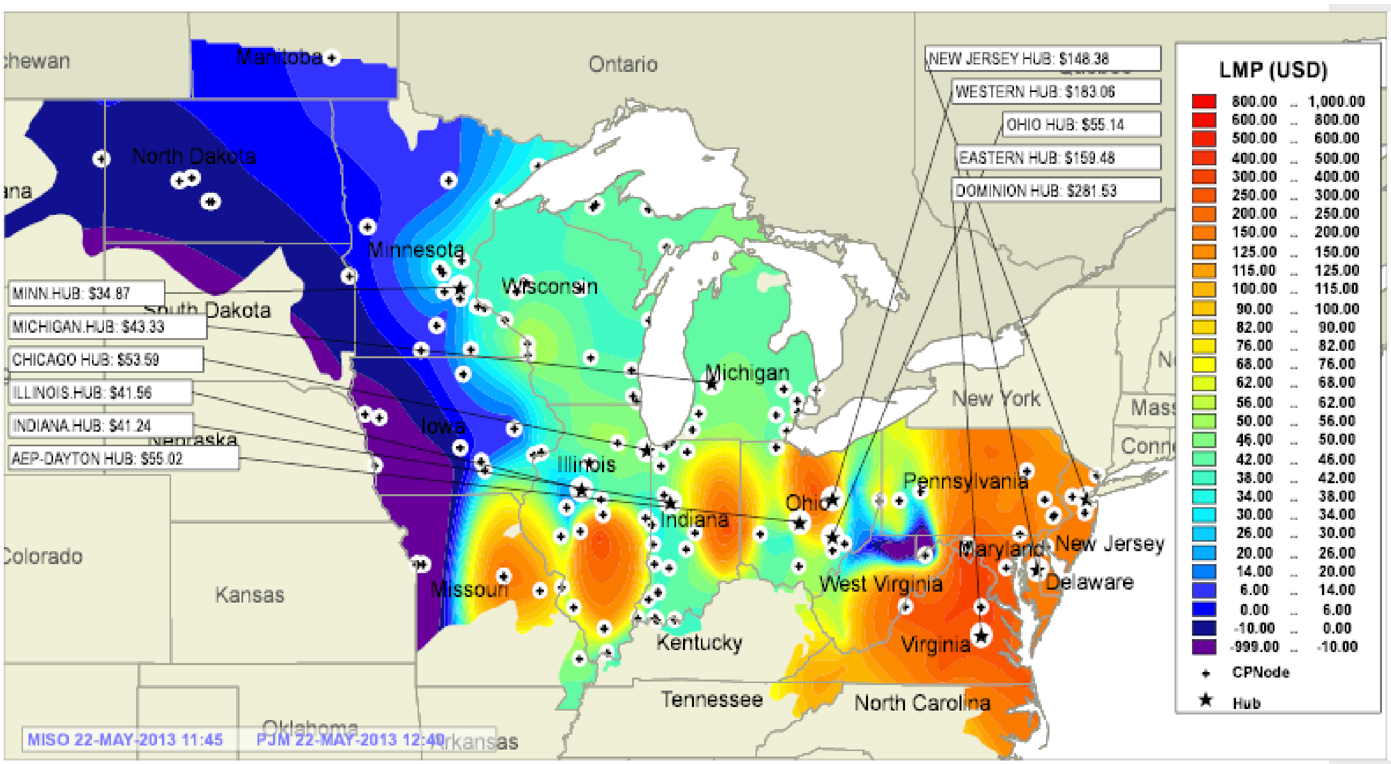
- It is a straightforward matter to compute "Schweppe" spot prices based on marginal costs at each location.
- Transmission spot prices arise as the difference in the locational prices.

LOCATIONAL SPOT PRICE OF "TRANSMISSION"



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

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.

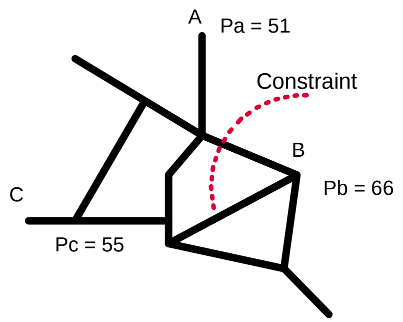


Missouri MPS -$71.25, Dominion Hub $281.53. May 22, 2013, 12:40pm.

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

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

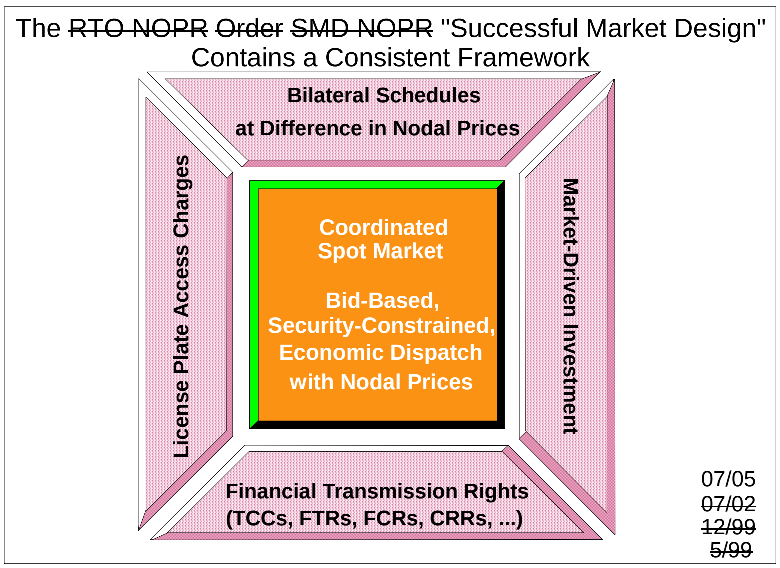


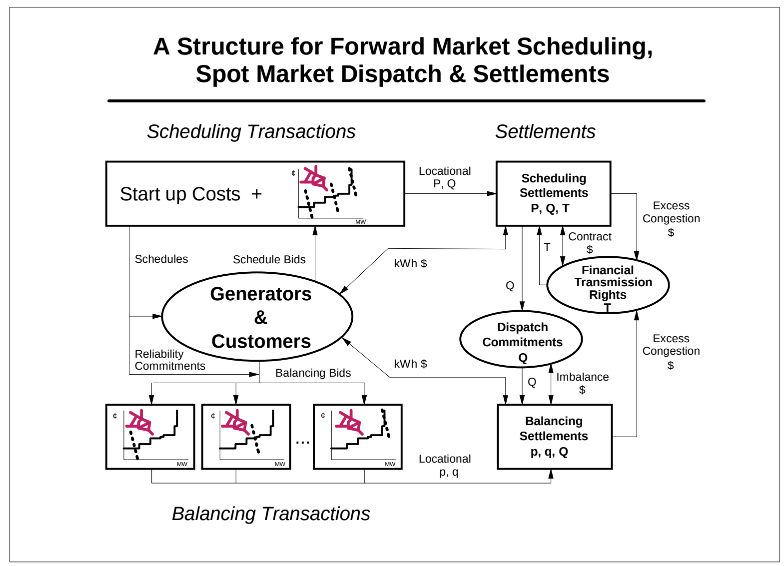
Price of "Transmission" from A to B = Pb - Pa = 15
Price of "Transmission" from A to C = Pc - Pa = -4

- 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. 116.)





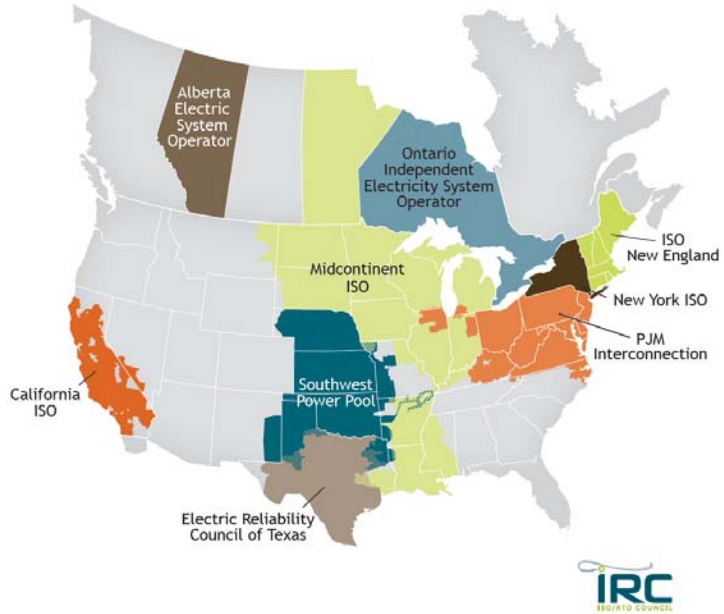
Market design in RTOs/ISOs is well advanced but still incomplete.[4]

- **Regional Markets Not Fully Deployed**

- **Reforms of Reforms**
  California MRTU (April 1, 2009) and ERCOT Texas Nodal (December 1, 2010) reforms. Now cover two-thirds of United States electricity consumers.

- **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).



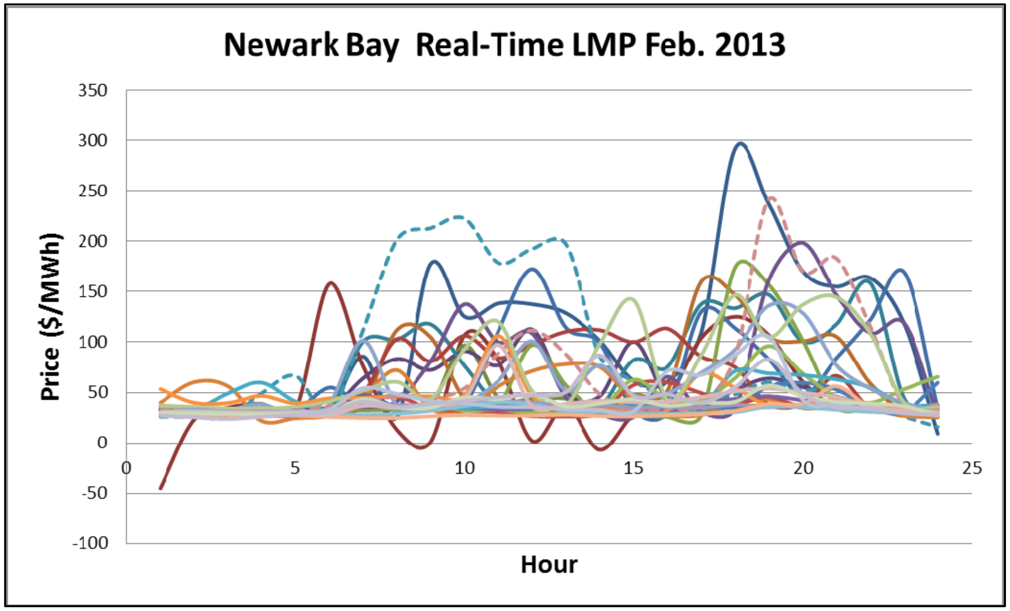
- **Market Challenge: Address Requirements for Climate Change Policy**

4 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).

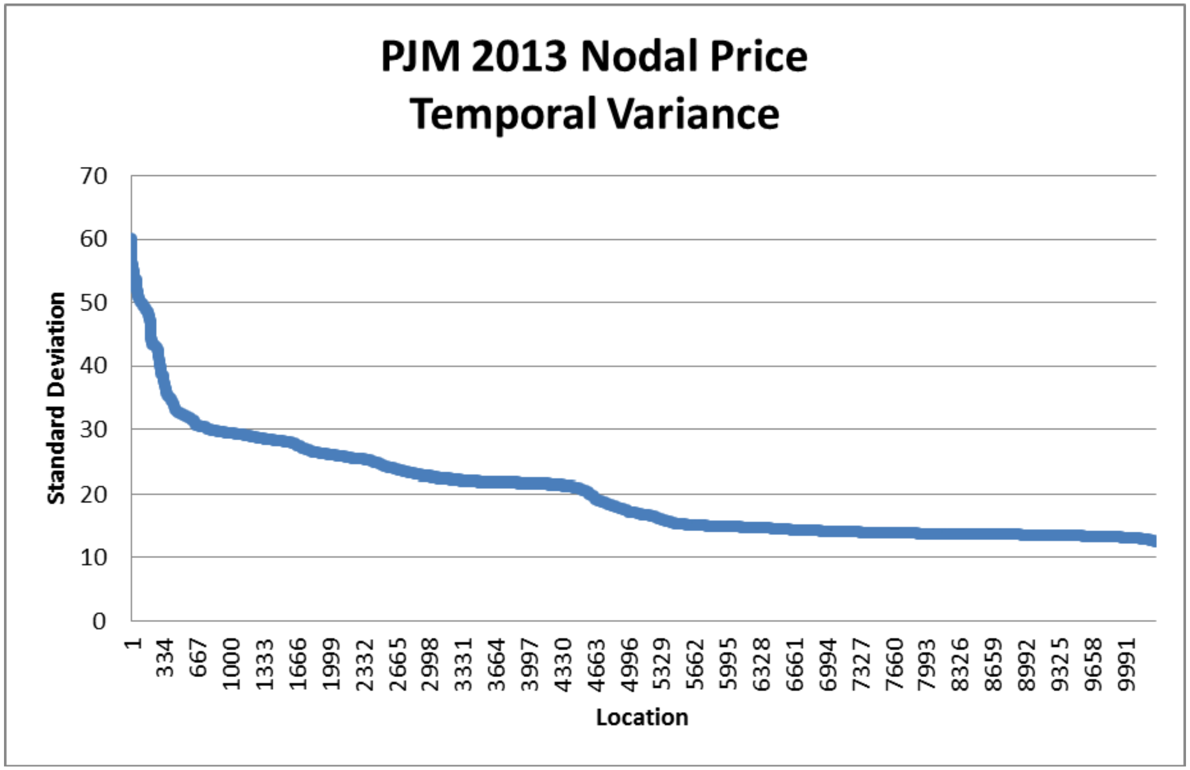
Smarter pricing provides an opportunity for enhancing efficiency and the range of alternative technologies.

- **Smarter Pricing Challenges**
  - Average energy prices: $50/MWh.
  - Canonical bid baps: $1,000/MWh. $4,500/MWh in ERCOT. $12,500/MWh in Australia.
  - 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.



Volatile electricity prices provide an opportunity for inter-temporal price arbitrage. The variance in prices differs across locations.



Source: Sandesh Kataria extract of PJM 2013 hourly price data for 10,296 locations, www.pjm.com.

Experience with market design reform suggests examples of bad and good practice. A bad month for FERC illustrates what can go wrong as a result of flawed regulatory choices.

- **Order 745. The demand response policy.**
  - A flawed pricing mechanism.
    - Selling without Buying. The “negawatt” doubletalk.
    - Order 745 cost-benefit test for negawatts was prima facie evidence of flawed incentives.
  - “Ultimately, given Order 745’s direct regulation of the retail market, we vacate the rule in its entirety as ultra vires agency action. … if FERC thinks its jurisdictional struggles are its only concern with Order 745, it is mistaken. We would still vacate the Rule if we engaged the Petitioners’ substantive arguments.”” (DC Circuit, May 23, 2014)
- **Order 1000. Transmission cost allocation.**
  - **In Theory:** “The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. … Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those facilities.” (FERC Order 1000, ¶ 622, 637)
  - **In Practice:** “To summarize, the lines at issue in this case are part of a regional grid that includes the western utilities. But the lines at issue are all located in PJM’s eastern region, primarily benefit that region, and should not be allowed to shift a grossly disproportionate share of their costs to western utilities on which the eastern projects will confer only future, speculative, and limited benefits. … The petitions for review are granted and the matter once again remanded to the Commission for new proceedings.”(7^{th} Circuit, June 25, 2014)

More promising is the FERC initiative to consider an array of issues affecting price formation.

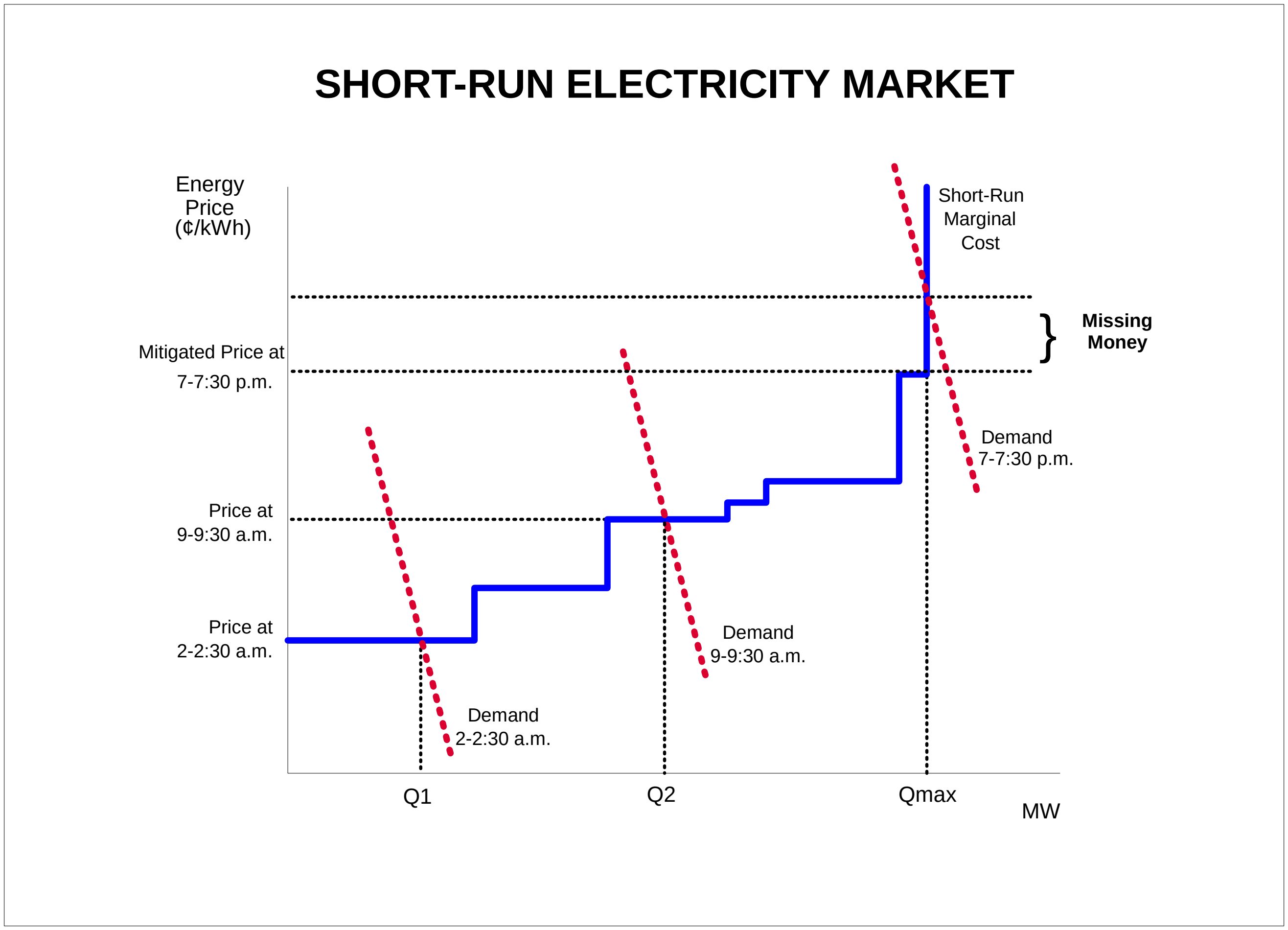
"…the Commission believes there may be opportunities for RTOs/ISOs to improve the energy and ancillary service price formation process. (FERC Notice, June 23, 2014)

- **Use of uplift payments:** Use of uplift payments can undermine the market's ability to send actionable price signals.
- **Offer price mitigation and offer price caps:** All RTOs/ISOs have protocols that endeavor to identify resources with market power and ensure that such resources bid in a manner consistent with their marginal cost.
- **Scarcity and shortage pricing:** All RTOs/ISOs have tariff provisions governing operational actions (e.g., dispatching emergency demand response, voltage reductions, etc.) to manage operating reserves as they approach a reserve deficiency. These actions often are tied to administrative pricing rules designed to reflect degrees of scarcity in the energy and ancillary services markets. … To the extent that actions taken to avoid reserve deficiencies are not priced appropriately or not priced in a manner consistent with the prices set during a reserve deficiency, the price signals sent when the system is tight will not incent appropriate short and long-term actions by resources and loads.
- **Operator actions that affect prices:** … to the extent RTOs/ISOs regularly commit excess resources, such actions may artificially suppress energy and ancillary service prices or otherwise interfere with price formation."

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.

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



Scarcity pricing presents an important challenge 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.

Smarter scarcity pricing would mitigate or substantially remove the problems in all these areas. While long-recognized, the need for smarter prices for a smarter grid promotes interest in better theory and practice of scarcity pricing.[5]

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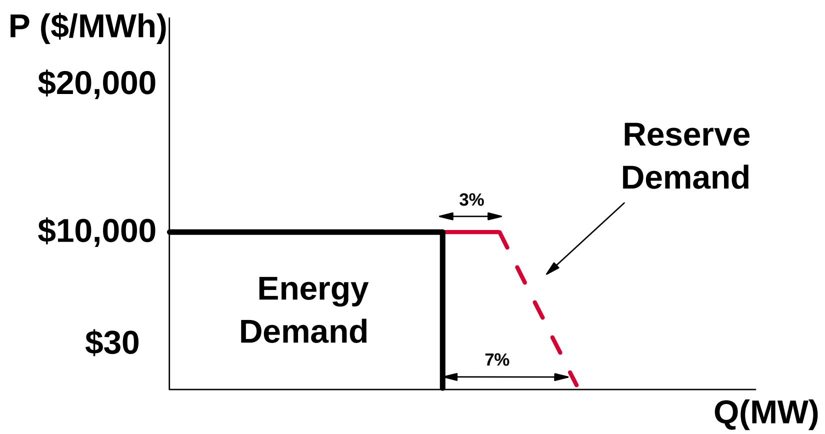
5 FERC, Order 719, October 17, 2008.

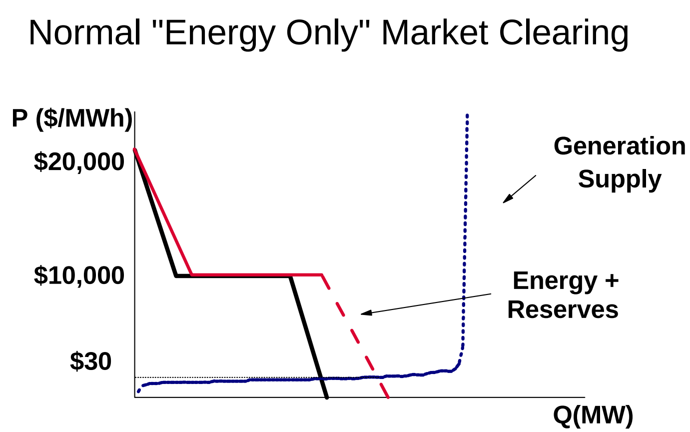
Operating reserve demand curve would reflect capacity scarcity.

Illustrative Reserve Demand

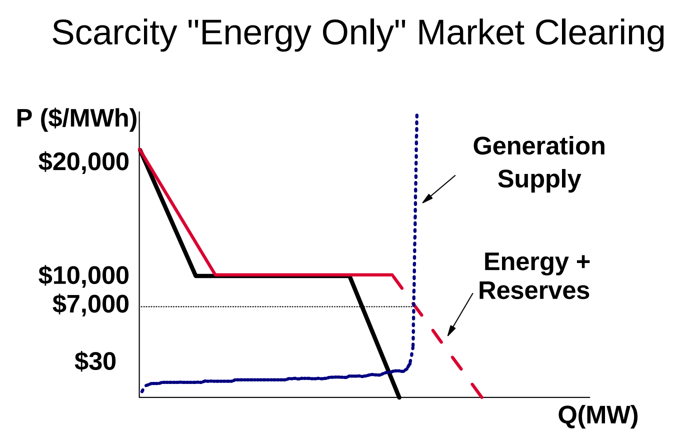


There is a minimum level of operating reserve (e.g., 3%) to protect against system-wide failure. Above the minimum reserve, reductions below a nominal reserve target (e.g., 7%) are price senstive.

Market clearing addresses the "missing money."



When demand is low and capacity available, reserves hit nominal targets at a low price.



When demand is high and reserve reductions apply, there is a high price.

A critical connection is the treatment of operating reserves and construction of operating reserve demand curves. The basic idea of applying operating reserve demand curves is well tested and found in operation in important RTOs.

- **NYISO.** See NYISO Ancillary Service Manual, Volume 3.11, Draft, April 14, 2008, pp. 6-19-6-22.
- **ISONE.** FERC Electric Tariff No. 3, Market Rule I, Section III.2.7, February 6, 2006.
- **MISO.** FERC Electric Tariff, Volume No. 1, Schedule 28, January 22, 2009.[6]
- **PJM.** PJM Manual 11, Energy & Ancillary Services Market Operations, Revision: 59, April 1, 2013.

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.

6 "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.

What are the relevant first principles that could guide better scarcity pricing? There are many ideas that would be included under the general framework of economic dispatch. A suggestive list for operating reserve pricing would include:

- Connecting to the value of loss load and other emergency actions.
- Including a representation of the uncertainty of net load changes and the loss of load probability.
- Integrating minimum contingency reserve requirements.
- Maintaining consistency between energy and reserve prices.
- Coordinating day-ahead and real-time settlements.
- Co-optimization of reserves and energy.
- Providing a consistent representation of any locational differences in valuing reserves.

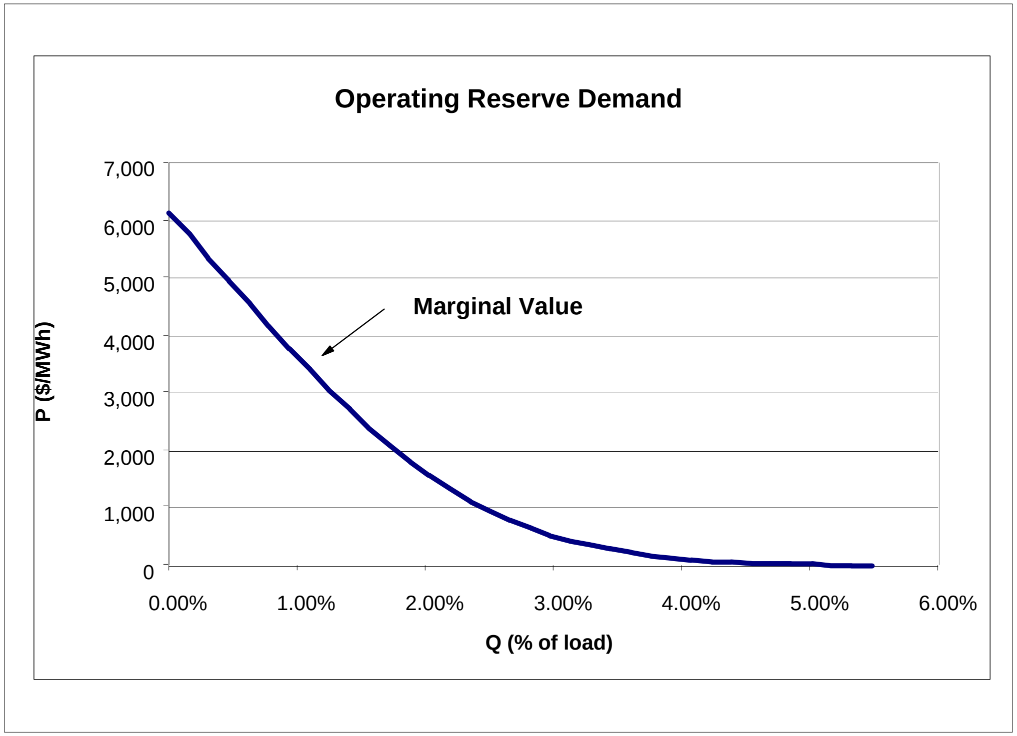
The most general principle would be to provide a pricing framework that incorporates reasonable prices for actions that the system operator may take to provide a security constrained economic dispatch. "As a general principle, competitive and efficient market prices should be consistent with the marginal cost of the marginal action taken to satisfy the market's demand." (IMM, ERCOT 2012 State of the Market Report, p. 82)

Operating reserve demand curve (ORDC) is a complement to energy demand for electricity. The probabilistic demand for operating reserves reflects the cost and probability of lost load.[7]

Example Assumptions

Expected Load (MW)	34000
Std Dev %	1.50%
Expected Outage %	0.45%
Std Dev %	0.45%
Expected Total (MW)	153
Std Dev (MW)	532.46
VOLL ($/MWh)	10000

Under the simplifying assumptions, if the dispersion of the LOLP distribution is proportional to the expected load, the operating reserve demand is proportional to the expected load.



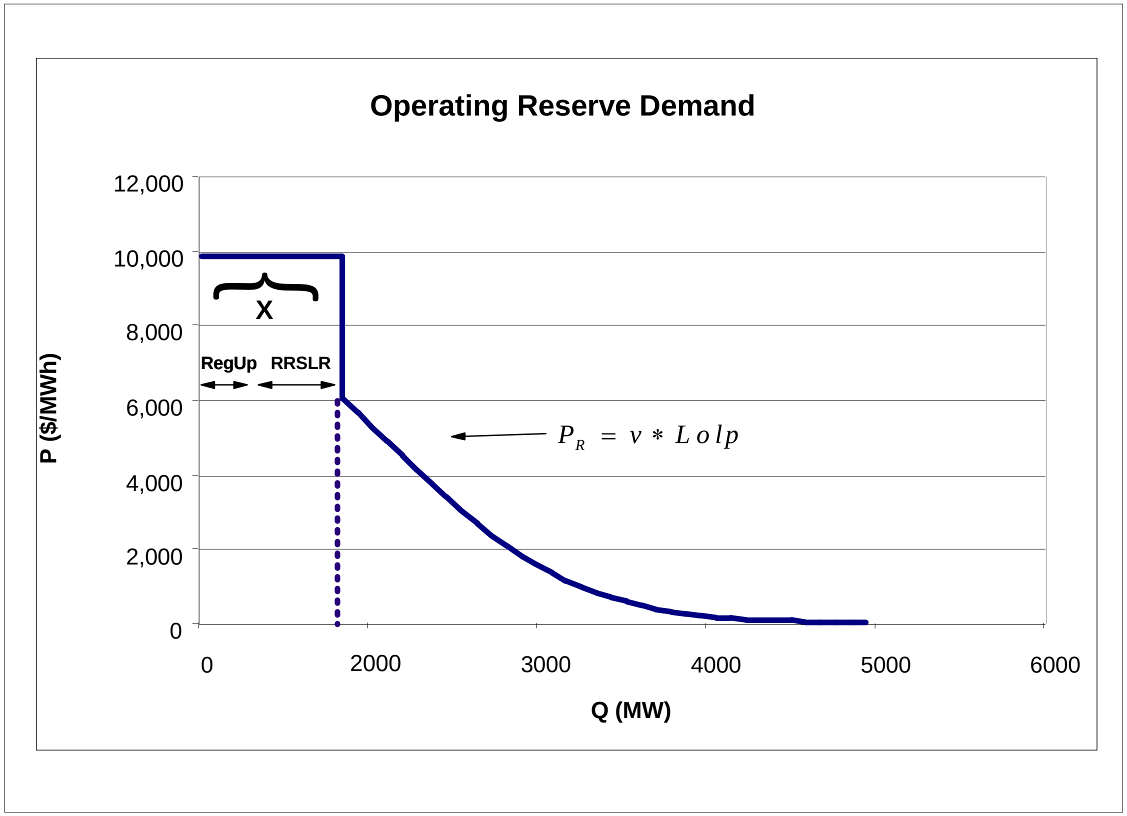
[7] "For each cleared Operating Reserve level less than the Market-Wide Operating Reserve Requirement, the Market-Wide Operating Reserve Demand Curve price shall be equal to the product of (i) the Value of Lost Load ("VOLL") and (ii) the estimated conditional probability of a loss of load given that 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.

The deterministic approach to security constrained economic dispatch includes lower bounds on the required reserve to ensure that for a set of monitored contingencies (e.g., an n-1 standard) there is sufficient operating reserve to maintain the system for an emergency period.

Suppose that the maximum generation outage contingency quantity is $r_{Min}\left(d^0, g^0, u\right)$. Then we would have the constraint:

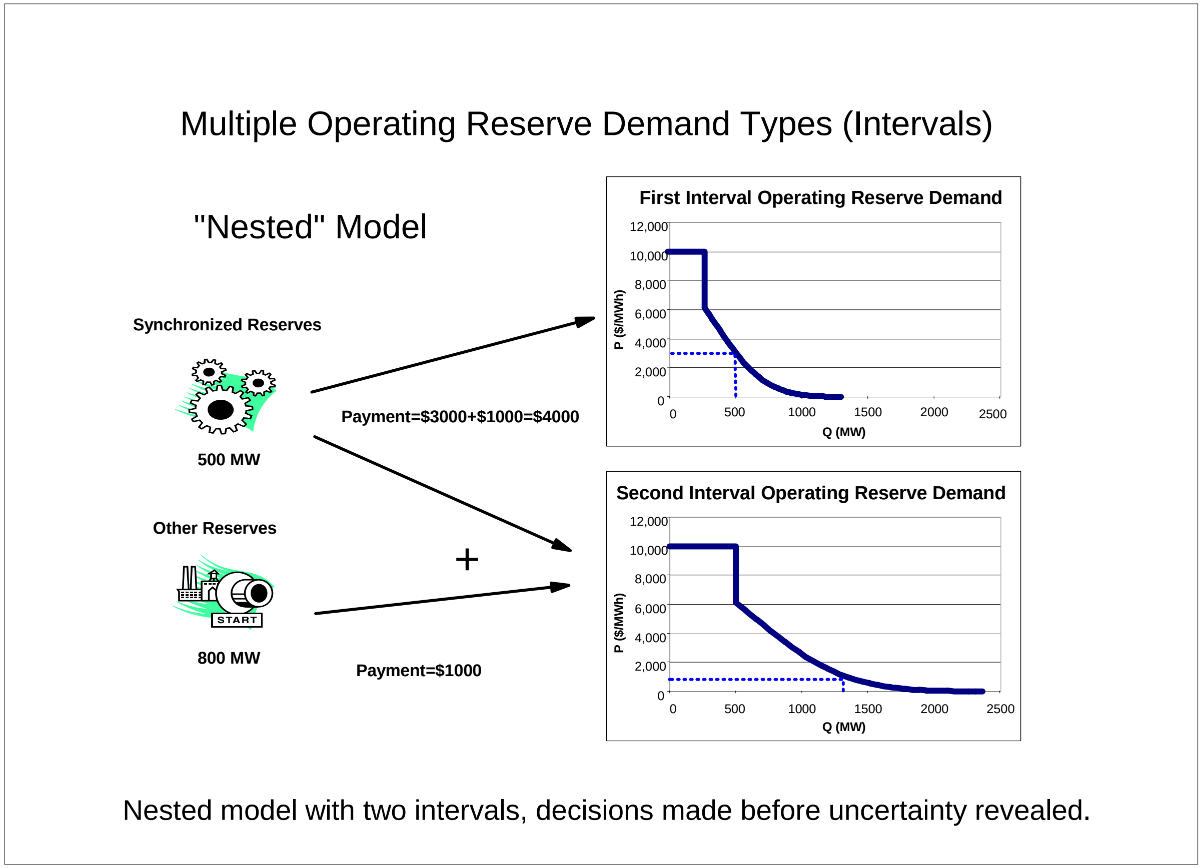
$$r \geq r_{Min}\left(d^0, g^0, u\right) = X.$$

In effect, the contingency constraint provides a vertical demand curve that adds horizontally to the probabilistic operating reserve demand curve.



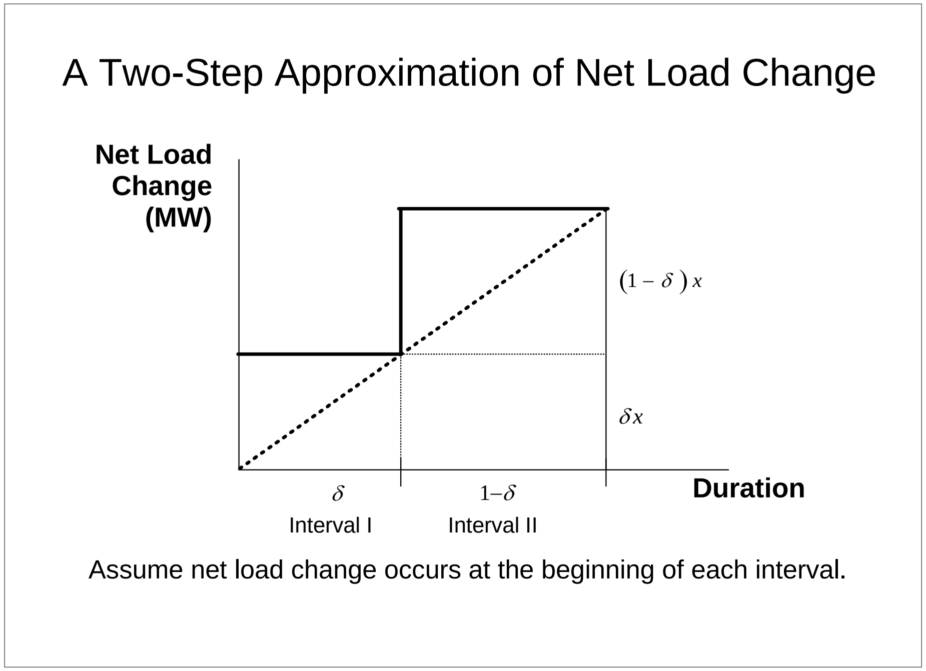
If the security minimum will always be maintained over the monitored period, the marginal price at r=0 applies. If the outage shocks allow excursions below the security minimum during the period, the reserve price starts at the security minimum.

Multiple types of operating reserves exist according to response time. A nested model divides the period into consecutive intervals. Reserve schedules set before the period. Uncertainty revealed after the start of the period. Faster responding reserves modeled as available for subsequent intervals. The operating reserve demand curves apply to intervals and the payments to generators include the sum of the prices for the available intervals.



The nested ORDC includes responsive or spinning reserves (R) and non-spin reserves (NS). The responsive are available for both intervals and the non-spin are available for the second interval. Assume net scarcity value v (VOLL - marginal generation cost) gives reserves prices (P_R, P_{NS}) .

Marginal Reserve Values		
	Interval I	Interval II
Duration	δ	1-δ
P_R	$vLolp(r_R)$	$vLolp(r_R + r_{NS})$
P_{NS}	0	$vLolp(r_R + r_{NS})$



The resulting reserve prices before shifting before the minimum contingency level are:

$$P_R = v*\left(\delta * Lolp(r_R) + (1-\delta)*Lolp(r_R + r_{NS})\right) = v*\delta*Lolp(r_R) + P_{NS},$$

$$P_{NS} = v*(1-\delta)*Lolp(r_R + r_{NS}).$$

An application of the model for the case of ERCOT illustrates the possible scale of the impacts.

Back Cast of Interim Solution B+ to Improve Real-time Scarcity Pricing ERCOT Public

Back Cast of Interim Solution B+ to Improve Real-Time Scarcity Pricing

Whitepaper

March 21, 2013

William W. Hogan, Harvard University

ERCOT Staff

Better scarcity pricing would improve many aspects of market efficiency. In addition, better scarcity pricing would contribute towards making up the missing money and supporting resource adequacy. Would better scarcity pricing be enough to resolve the resource adequacy problem?

- **Posing a choice between capacity markets and better scarcity pricing is a false dichotomy.** Even if the scarcity pricing is not enough and a long-term capacity market is necessary, better scarcity pricing would make the capacity market less important and thereby mitigate some of the unintended consequences.

- **Resource adequacy depends on the planning standard.** The planning reserve margin rests on criteria such as the 1-event-in-10-years standard that appears to be a rule of thumb rather than a result derived from first principles. Depending on the details of filling in missing pieces in the economic analysis, the VOLL implied by the reliability standard is at least an order of magnitude larger than the range that would be consistent with actual choices and technology opportunities. There is general agreement that applying reasonable estimates of VOLL and the cost-benefit criterion of welfare maximization would not support the typical planning reliability standards.

- **Justification of the planning standard would depend on a more nuanced argument for market failure that goes well beyond suppressed scarcity prices.** A more complicated argument might address dynamic issues about the credibility of future market returns versus future regulatory mandates. The volatility and uncertainty of market forces might tip the argument one way or the other. Or a different engineering argument might call for efforts to compensate for the errors of approximation in the engineering models that underpin both the reliability planning studies and the cost-benefit analyses. These efforts might include a margin of safety beyond the already conservative assumptions of security constrained n-1 contingency analysis.

Assuming there is a reliability requirement beyond the simple economic equilibrium, basic ORDC scarcity pricing may not be enough to make up the missing money. What policy approaches are available? Two major approaches focus on either forward capacity markets or energy spot markets.

- **Capacity Forward Markets.** The most common approach is to create a capacity market that contracts forward for capacity resources to be available in future years. Better scarcity pricing would affect forward capacity prices, and could simplify capacity performance incentives.
- **"Energy Only" Spot Markets.** Higher prices could be allowed or supported in real-time spot markets. This would reduce or eliminate the missing money problem, and could provide incentives that reflect operating conditions.
    - **High or No Offer Caps in Spot Markets.** The implication is that generators will be allowed to economically withhold capacity in order to increase spot prices, at least until there is no missing money. Alberta is a North American example where there is an explicit recognition allowing such an exercise of unilateral market power. Alberta has seen adequate capacity investment without forward capacity contracts.
    - **Higher Scarcity Prices.** The ORDC does not require market power to induce high scarcity prices, and would be consistent with high spot-market-clearing prices and low offer caps. If there is a policy to achieve a higher capacity reserve, one approach to provide the incentive could be to construct an augmented ORDC that incorporates a reliability margin of safety.

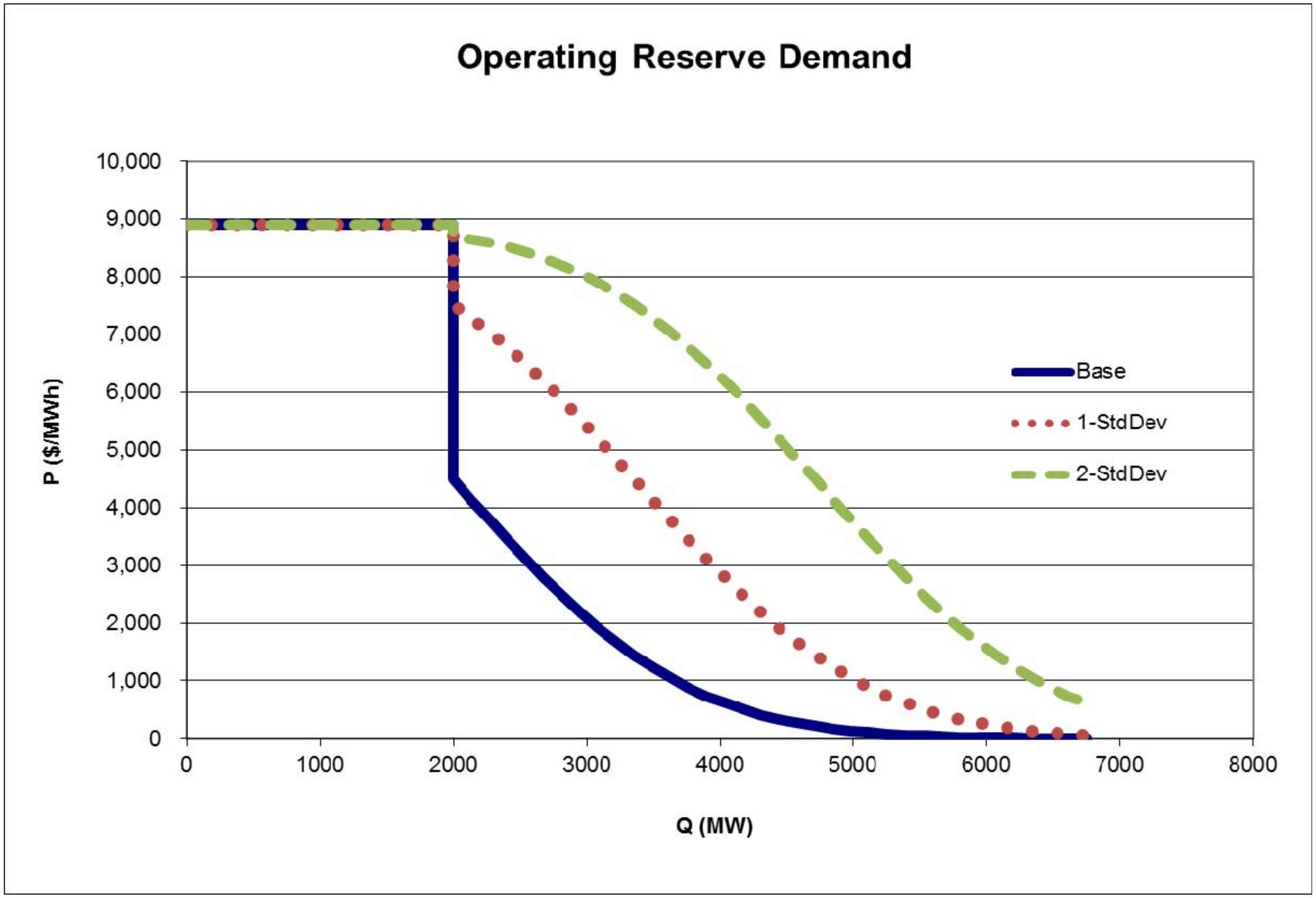
An augmented ORDC would impose conservative assumptions on the basic model. The intent would be to provide both a reliability margin of safety, an associated increase in total operating reserves, and energy payments to address the missing money problem. The three principal parameters of the ORDC are the value of lost load (VOLL), the minimum contingency level (X), and the loss of load probability (LOLP).

- **VOLL.** The VOLL price applies when conditions require involuntary load curtailment. It is important that this price be paid to generation and charged to remaining load. Hence, an upper bound on a conservative VOLL would be the maximum price we were willing to charge in the face of load curtailment. It may be better to err in the direction of a higher VOLL, but this may not be enough to address the reliability goal and provide the missing money.

- **X.** The minimum contingency level is more directly connected to reliability. However, if the minimum contingency threshold is set too high, we would produce periods when VOLL prices were being imposed but no non-market interventions were needed. Regulators would have to defend applying the VOLL when it was not required.

- **LOLP.** The short-term load and generation changes that give rise to the LOLP summarize a complex process. The models applied employ certain assumptions about the accuracy of the system approximations and the ability to avoid problems like human error typically found in events that threaten the stability of the system. A conservative approach to reliability is already part of the motivation for the use of contingency constraints to define secure operations. However, it would be consistent to extend this reliability motivation to a conservative estimation of the LOLP. This would avoid the conflicts that arise with too high a VOLL or too high an X.

A conservative assumption addressed at reliability would be to increase the estimate of the loss of load probability. A shift of one standard deviation would have a material impact on the estimated scarcity prices. The choice would depend on the margin of safety beyond the economic base.



The focus of capacity reserves is to ensure that capacity is available. In the same spirit, the focus of the augmented ORDC could be on the augmented loss of load probability ($Lolp_A$) that applied for the non-spin reserves.

The resulting reserves prices before shifting for the minimum contingency level would be:

$$P_R = v * \left(\delta * Lolp\left(r_R\right) + \left(1-\delta\right) * Lolp_A\left(r_R + r_{NS}\right)\right) = v * \delta * Lolp\left(r_R\right) + P_{NS},$$
$$P_{NS} = v * \left(1-\delta\right) * Lolp_A\left(r_R + r_{NS}\right).$$

Hence, the differential between spin and non-spin would remain unchanged:

$$P_R - P_{NS} = v * \delta * Lolp\left(r_R\right).$$

There would be no increased incentive to incur the costs of spinning above the economic benefit. The conservative scarcity pricing would affect the total value of spin and non-spin, but the increase in availability would be for non-spin capacity.

Using the augmented ORDC would automatically provide real-time performance incentives for capacity, simplifying by removing one of the complications of forward capacity markets. The higher real-time prices would apply to load as well as generation, providing incentives for demand participation.

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: NYISO, ISONE, MISO and PJM 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: Day-ahead and longer term forward markets can reflect expected scarcity costs, and price in the risk.

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.

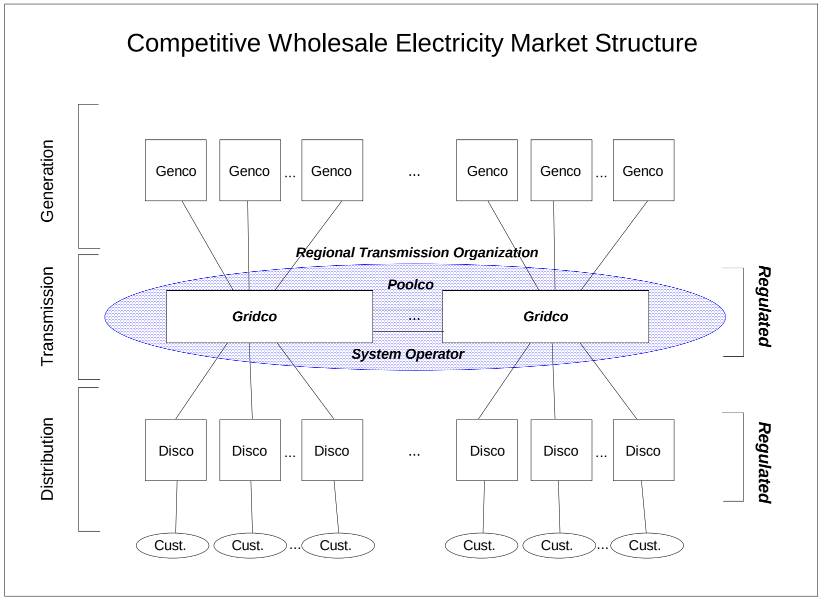
Appendix

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

- **PURPA, 1978.** The rise of the new generators.

- **Markets for Power, 1983.** Joskow and Schmalensee.

"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."[8]



- **Schweppe et al., 1988.** Spot Pricing of Electricity, Kluwer. Using prices to direct the dispatch.

- **Hogan, 1992.** "Contract Networks for Electric Power Transmission," JRE. Spot market pricing and financial transmission rights.

- **EPAct, 1992.** The 'camel's nose' of wholesale competition.

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8 Paul L. Joskow and Richard Schmalensee, Markets for Power: An Analysis of Electric Utility Deregulation, MIT Press, 1983, p. 63.

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.

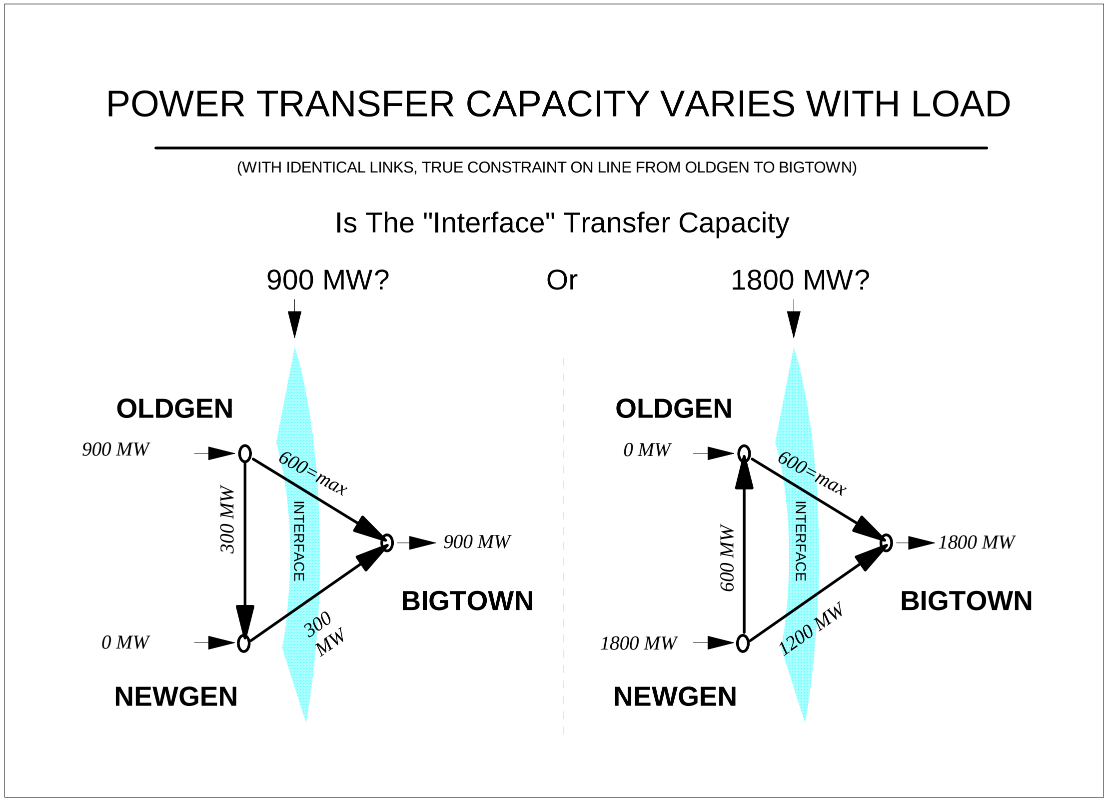
> "A contract path is simply a path that can be designated to form a single continuous electrical path between the parties to an agreement. Because of the laws of physics, it is unlikely that the actual power flow will follow that contract path. … Flow-based pricing or contracting would be designed to 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?

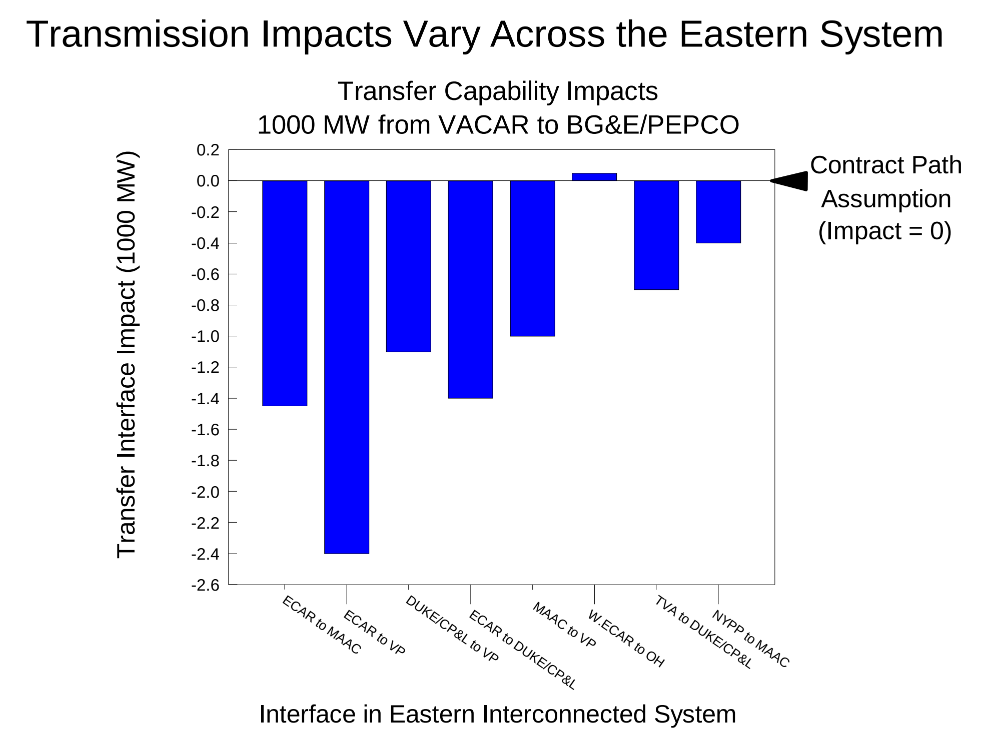
Electric transmission network interactions can be large and important.

- 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.



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. 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.

> “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!

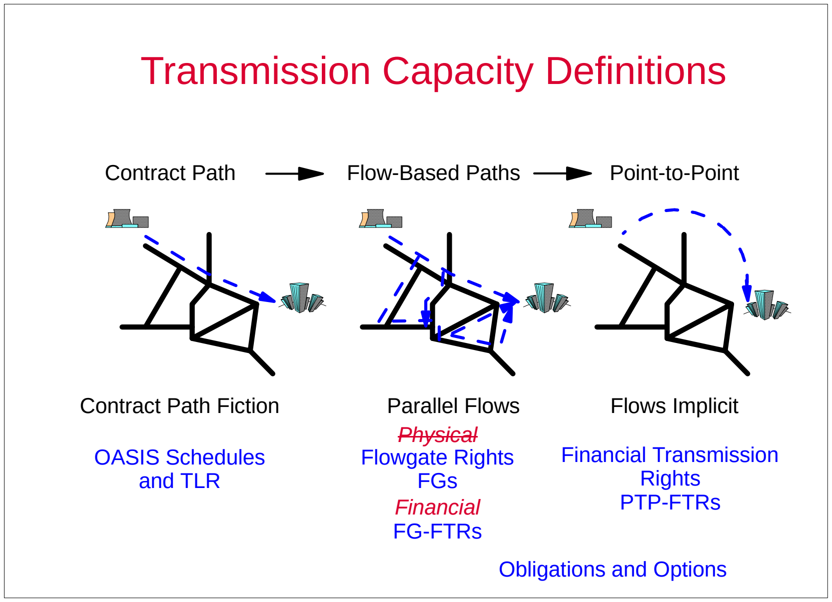
The evolution of electricity restructuring contains a thread of issues related to counterintuitive market design requirements requiring coordination for competition.

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.

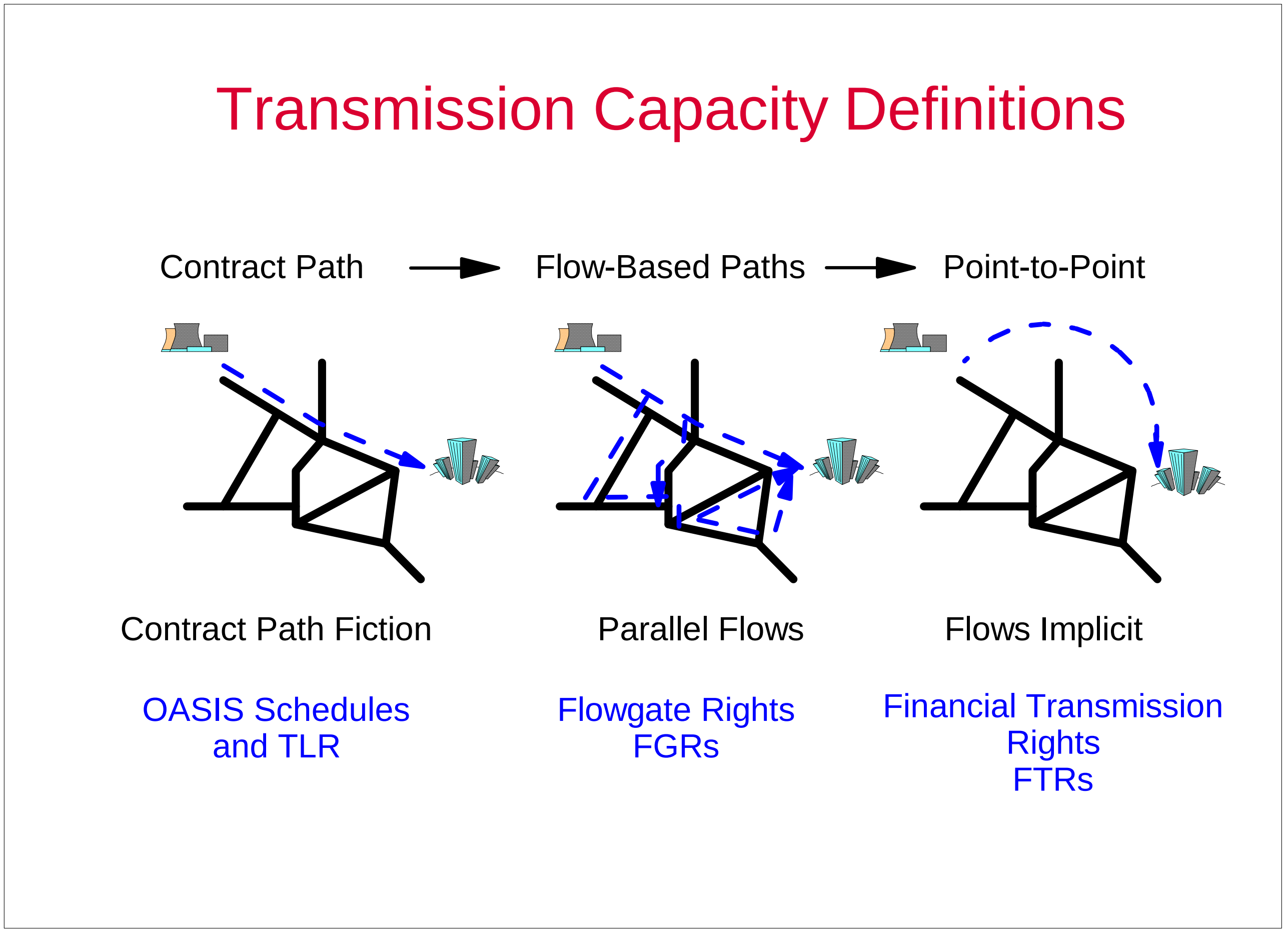
"The proposed capacity reservation open access transmission tariff, if adopted, would replace the open access transmission tariff required by the Commission ..."[9]

- **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?

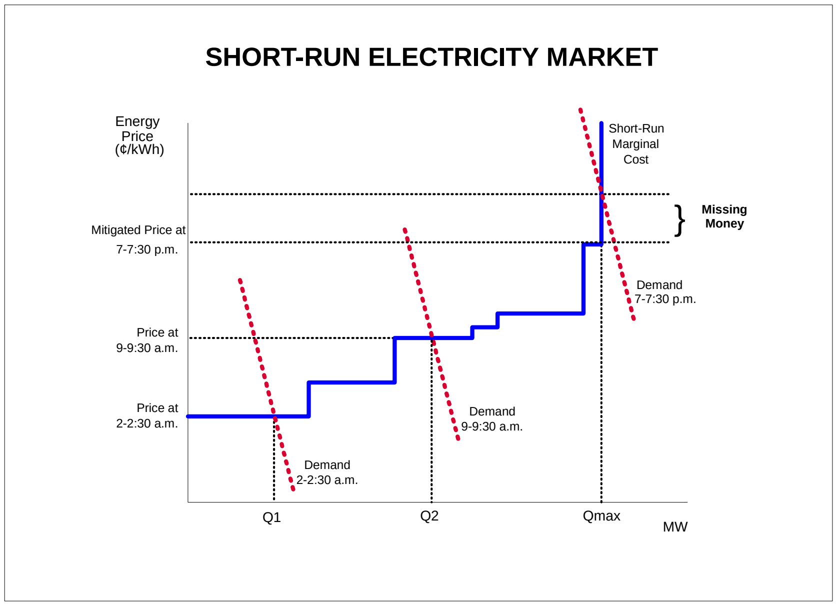


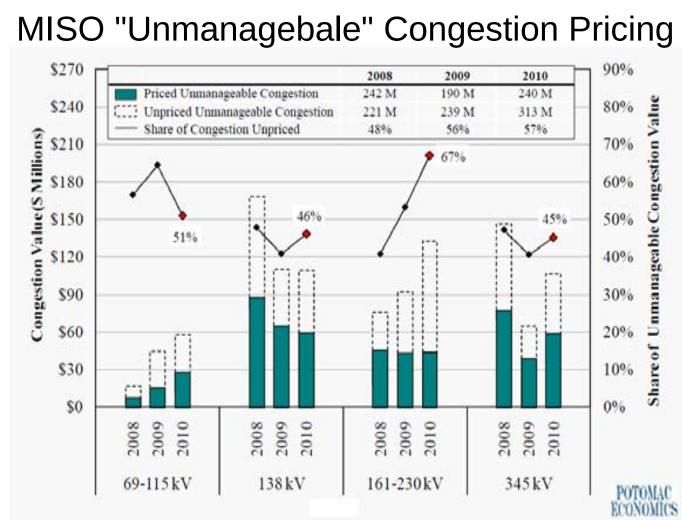
9 Federal Energy Regulatory Commission, "Capacity Reservation Open Access Transmission Tariffs," Notice of Proposed Rulemaking, RM96-11-000, Washington DC, April 24, 1996, p. 1.

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



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.

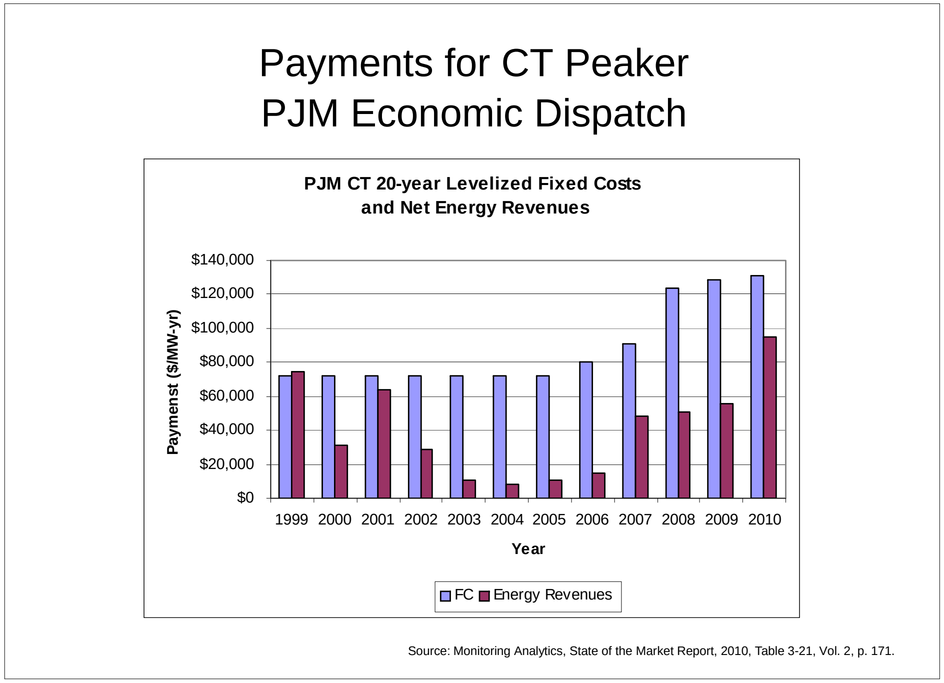
- **PJM, Missing Money, Combustion Turbine (1999-2010, per MW-Year).**

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.)[10]



10 "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.

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.[11]

- 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.

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[11] 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.[12]

Smart Grids Need Smart Prices.

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12 FERC, Order 719, October 17, 2008.

The court has affirmed a cost-benefit standard for transmission evaluation and cost allocation.

> "FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members. … Rather desperately FERC's lawyer, and the lawyer for the eastern utilities that intervened in support of [FERC's] ruling, reminded us at argument that Commission has a great deal of experience with issues of reliability and network needs, and they asked us therefore (in effect) to take the soundness of its decision on faith. But we cannot do that because we are not authorized to uphold a regulatory decision that is not supported by substantial evidence on the record as a whole, or to supply reasons for the decision that did not occur to the regulators. … We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars. … ("we have never required a ratemaking agency to allocate costs with exacting precision"); … If it cannot quantify the benefits to the midwestern utilities from new 500 kV lines in the East, even though it does so for 345 kV lines, but it has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in PJM's region, then fine; the Commission can approve PJM's proposed pricing scheme on that basis. For that matter it can presume that new transmission lines benefit the entire network by reducing the likelihood or severity of outages. … But it cannot use the presumption to avoid the duty of "comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party." [13]

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13 *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 476 (7th Cir., August 6, 2009, citations omitted).

"The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. … Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those facilities." (FERC Order 1000, ¶ 622, 637)

Connecting cost allocation to benefits is a necessary condition for compatibility with an electricity market with decentralized decisions for most investments.

But how can the principle be made operational?

Cost benefit analysis of transmission expansion inherently provides information about the distribution of benefits for use in cost allocation.[14]

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14 W. Hogan, "Transmission Benefits and Cost Allocation," Harvard University, May 31, 2011. (www.whogan.com)

Developing rules for efficient transmission infrastructure investment may be easier said than done.

“Last fall, in early October [2012], utilities across the country began filing tariffs with the Federal Energy Regulatory Commission to explain how they will comply with the commission's Order 1000, issued 18 months ago. That order requires all FERC-jurisdictional transmission service providers to participate in regional grid planning, and forces the planners to take account of state and federal policy governing renewable energy. Costs for projects that pass muster in the regional plan must be allocated in a manner "roughly commensurate" with project benefits.” …

“In truth, Order 1000 is proving troublesome even for RTOs. PJM's comply tariff (*FERC Dkt. ER13-198, filed Oct. 25, 2012*) has drawn protests from nearly a dozen state PUCs. But in non-RTO areas, it's harder still. FERC in effect is forcing utilities in non-RTO areas to do many of the same things that RTOs do, but without market pricing or a centralized regional unit dispatch. The comply filings that have come in so far from non-RTO areas raise some key issues:

• ***Active or Passive***: Does Order 1000 require an ex ante assessment of regional needs and solutions, or can planners just sit tight and wait for developers to come forward?

• ***Production Cost Modeling***: Should planners model energy production costs (congestion, fuel use and prices, plant dispatch and capacity factors, etc.) in calculating project benefits?

• ***Sponsor Fitness***: Rules governing capability and qualifications for project developers seem fine, but do they discriminate against non-incumbents?

• ***Public Power Independence***: How to mandate regional cost allocation and yet preserve the FERC-free status of non-jurisdictional participants from the public power sector?”[15]

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15 Bruce Radford, “*Very* Roughly Commensurate,” Public Utilities Fortnightly, January 2013, pp. 16-18.

Initial tariff proposals are far from meeting the analytical test posed by the 7th Circuit Court.

> "If it cannot quantify the benefits to the midwestern utilities from new 500 kV lines in the East, even though it does so for 345 kV lines, but it has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in PJM's region, then fine; the Commission can approve PJM's proposed pricing scheme on that basis. For that matter it can presume that new transmission lines benefit the entire network by reducing the likelihood or severity of outages. … But it cannot use the presumption to avoid the duty of "comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party." [16]

The *very* rough edges of the tariff filings include: [17]

No definition of benefits: E.g., Carolinas. "No benefit metrics, such as production cost, congestion relief, reserve-sharing, or efficiency."

No benefit methodology: E.g., Florida. "Sponsors insist that production cost modeling is impossible using the publicly available data …"

Incomplete benefit methodology: E.g., Northern Tier. "Will recognize three categories of benefit metrics: 1) change in annual capital costs through either deferral or avoidance of a local project; 2) change in "energy" losses (presumably this means line losses); and 3) reduced reserve requirements or access to lower-cost operating reserves. Declines to calculate benefits based on production costs, explaining that filing deadline was too tight to develop congestion cost modeling for a non-RTO area--area-but promises to further explore production cost modeling and come back to FERC in mid-2013 with revisions…"

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16 *Illinois Commerce Commission v. FERC*, 576 F.3d 470, 476 (7th Cir., August 6, 2009, citations omitted).

17 Bruce Radford, "*Very* Roughly Commensurate," Public Utilities Fortnightly, January 2013, pp. 20-24.

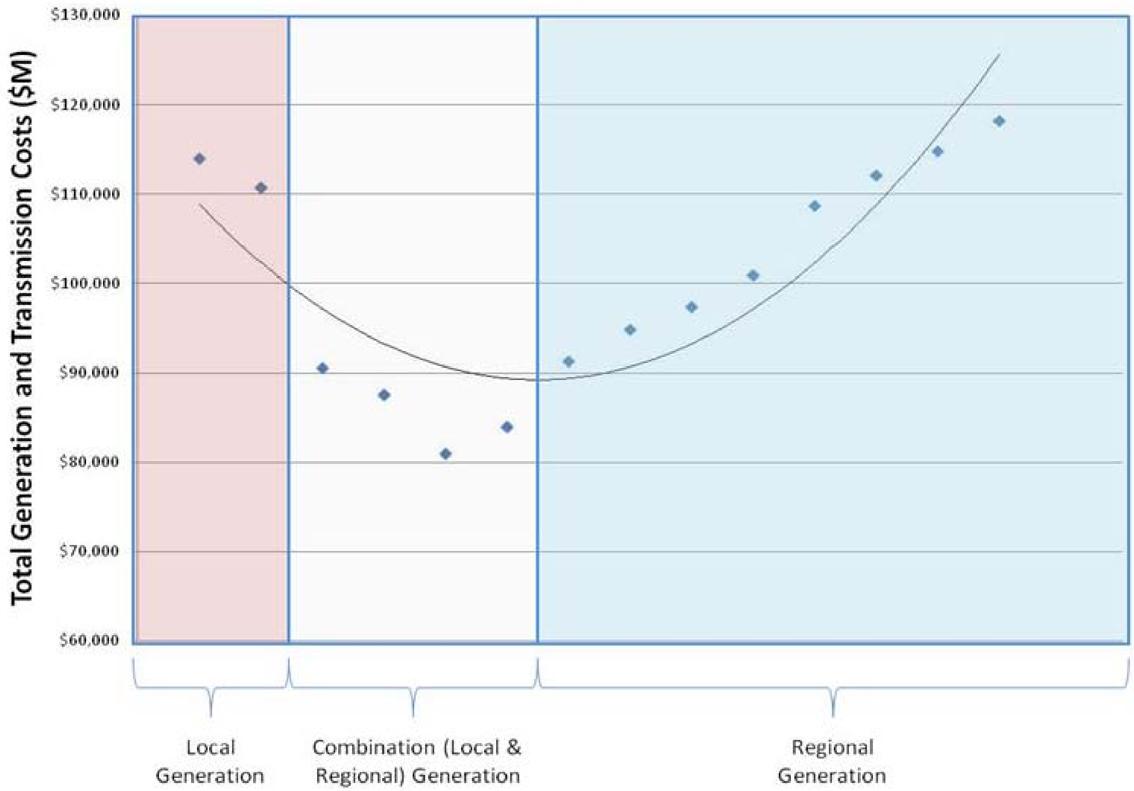
A transmission infrastructure mandatory cost allocation framework requires a hybrid system that is regional in scope and compatible with the larger market design. FERC Order 1000 proposed principles that are compatible with a larger hybrid system. [18] **The broader framework would include:**

- **Cost Benefit Framework**
  - Gold Standard: Net Benefits > Total Cost
  - Cost Sharing: Commensurable with Benefits
  - Compatible with Larger Market Design
- **Ex ante Estimation and Allocation**
- **Net Benefits = Change in Expected Social Welfare**
  - Counterfactual without contracts
  - Uncertainty and Expected Present Value
- **Approximations of Benefits**
  - Reliability
  - Economic
  - Public Policy
- **Benefit estimates commensurable across categories for projects**
  - Transmission lines affect all categories of benefits.
  - Transmission costs cannot be separated into distinct buckets.

[18] Federal Energy Regulatory Commission, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities," Docket No. RM10-23-000; Order No. 1000, Washington DC, July 21, 2011.

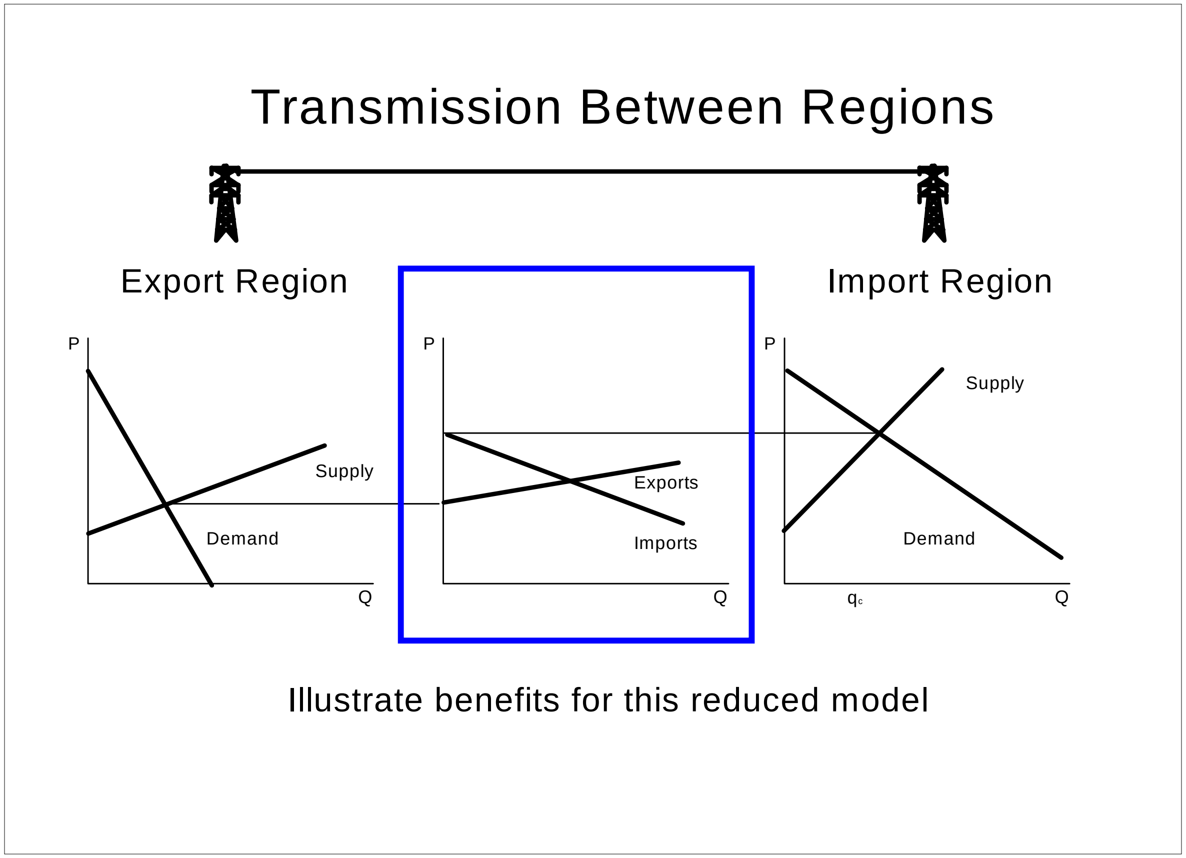
Efficient transmission infrastructure investment interacts with the costs and benefits of types and locations of renewable energy investment.

RGOS Zone Scenario Generation and Transmission Cost Comparison[19]



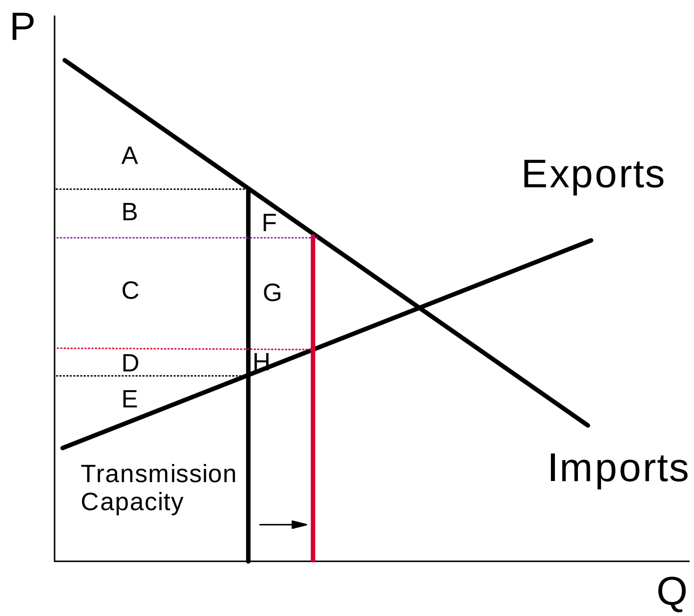
19 Midwest ISO. *Regional Generation Outlet Study*, November 19, 2010, p. 3.

A simple model illustrates a basic framework for defining and classifying the impacts of transmission expansion.



Large scale transmission investments can change export and import volumes and have a material effect on expected market prices.

Transmission Expansion Benefits



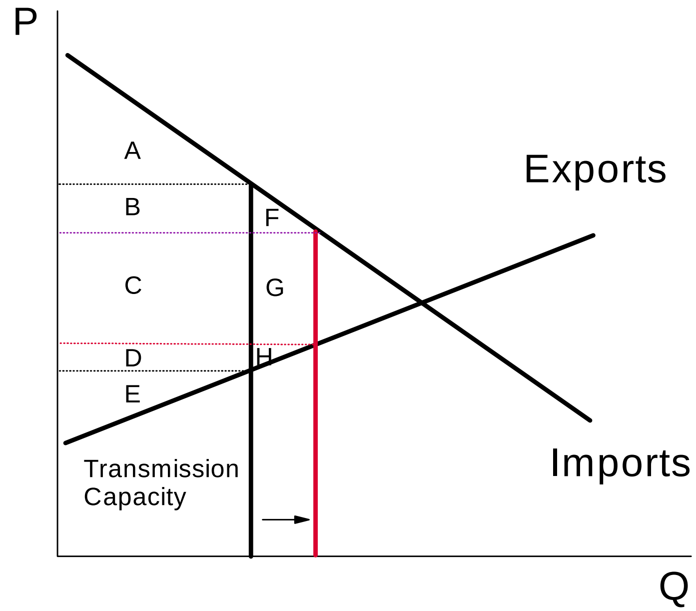
Base Case
Import Benefits=A
Export Benefits=E
Congstion Rents=B+C+D

Expansion Case
Import Benefits=A+B+F
Export Benefits=D+E+H
Congstion Rents=C+G

Net Benefits= F + G + H

Different conditions can arise in parsing the distribution of benefits and the comparison with the total cost of the transmission expansion.

Expansion Total Cost (TC) and Benefits



Gold Standard
F+G+H>TC

Business Stealing
B+F+G+D+H>TC> F + G + H

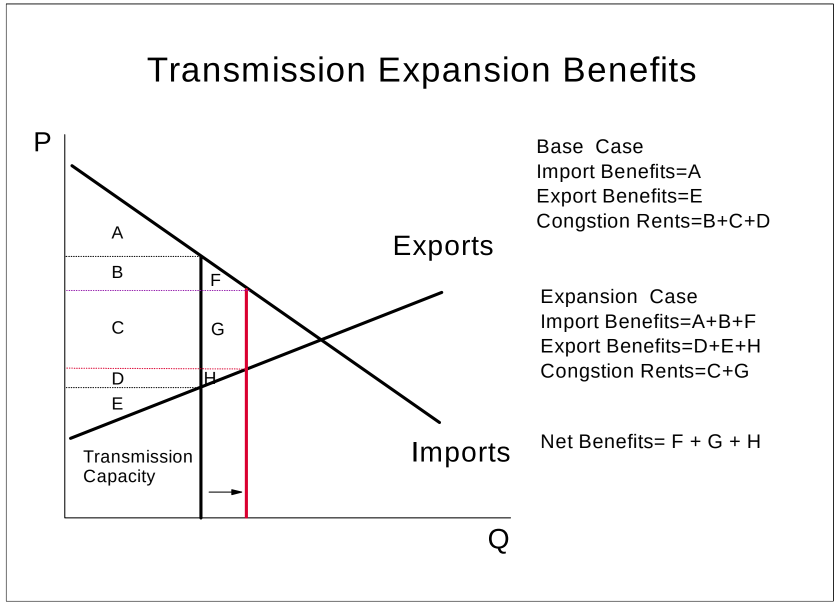
Core Coalition Case
B+F+G+D+H>F+G+H>TC

Strict Merchant Case
G>TC

Past or continuing transmission infrastructure benefits include conflicting definitions that are inconsistent with basic market principles and will create cost allocation problems.

Transmission Benefits

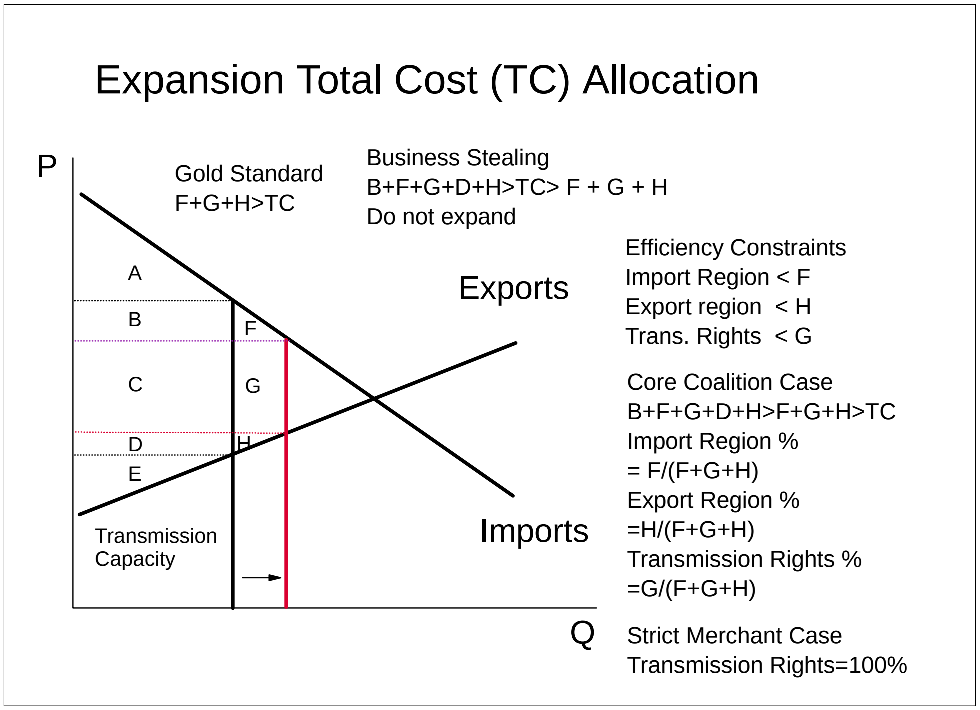
"The Energy Market Benefit component of the Benefit/Cost Ratio is expressed as: Energy Market Benefit = [.70] * [Change in Total Energy Production Cost] + [.30] * [Change in Load Energy Payment]. … Reliability Pricing Benefit = [.70] * [Change in Total System Capacity Cost] + [.30] * Change in Load Capacity Payment]." (PJM, "PJM Region Transmission Planning Process," Revision: 16, Manual 14b, Effective Date: November 18, 2010, p. 75.)



"Market Congestion Benefit: 70% * Adjusted Production Cost Savings + 30% * Load Cost Savings." (MISO, "2010 Transmission Expansion Plan," Nov. 30, 2010, p. 31.)

"Load Cost Savings where load cost represents the annual load payments, measured by projections in hourly load weighted LMP: Load cost savings and Adjusted Production Cost savings are essentially two alternative benefit measures to address a single type of economic value and are not additive measures. Load cost savings were not used to calculate the total value of the RGOS plans in MTEP10. … Value of transmission plan (per future) = Sum of values of financially quantifiable measures = Adjusted Production Cost savings + Capacity loss savings + Carbon emission reductions." (MISO, "2010 Transmission Expansion Plan," Nov. 30, 2010, p. 153-154.)

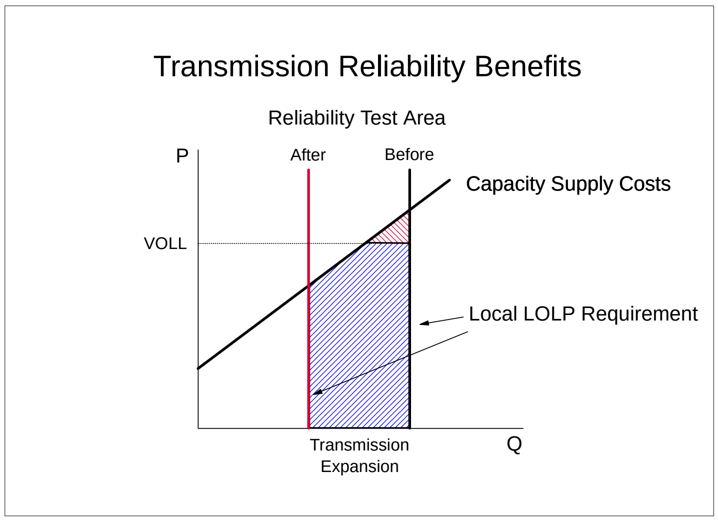
"The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. … Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those facilities." (FERC Order 1000, ¶ 622, 637) Cost benefit analysis of transmission expansion inherently provides information about the distribution of benefits for use in cost allocation.[20]

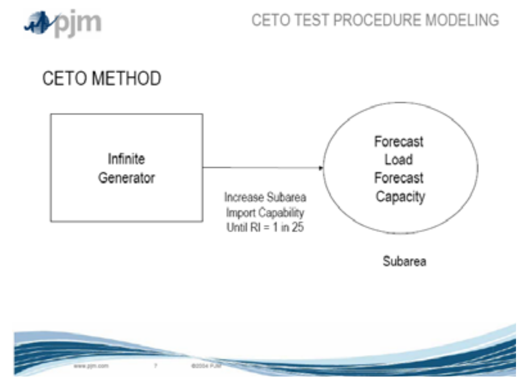


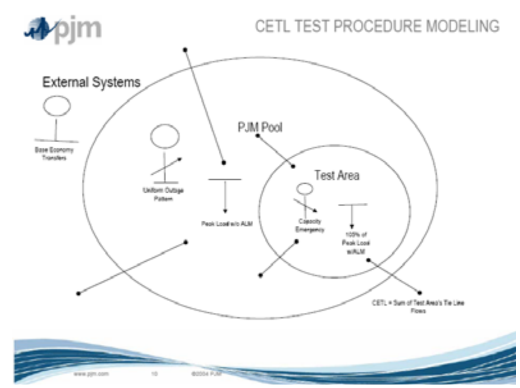
20 W. Hogan, "Transmission Benefits and Cost Allocation," Harvard University, May 31, 2011. (www.whogan.com)

Efficient transmission infrastructure investment includes estimated reliability benefits.

- Reliability modeling in a cost benefit framework.
  - o Reliability constraint and cost minimization.
  - o Change in value of expected curtailments at VOLL.
  - o PJM CETO/CETL method approximates expected curtailments.





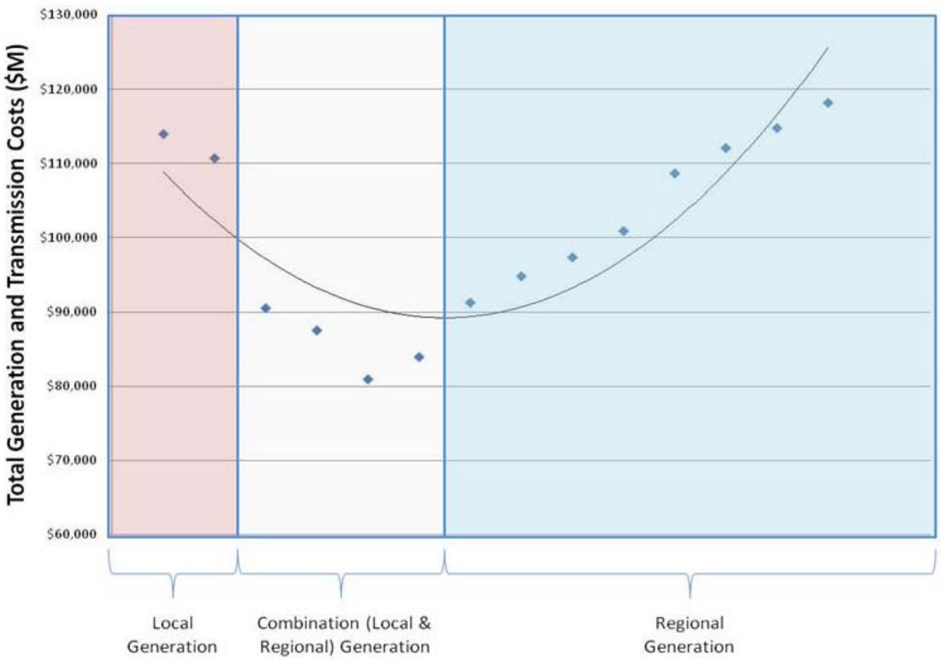


- For example, this is not the same as a DFAX cost allocation "Calculate the Distribution Factor (DFAX), where DFAX represents a measure of the effect of each zone's load on the transmission constraint that requires the mitigating upgrade, as determined by power flow analysis. The source used for the DFAX calculation is the aggregate of all generation external to the study area and the sink is the peak zonal load for each Transmission Owner within the study area. Multiply each DFAX by each zonal load to determine the zone's MW impact on the facility that requires upgrading." (PJM Manual 14B, p. 34)

Efficient transmission infrastructure investment includes benefits of meeting public policy objectives or constraints.

- **Environmental Constraints.** With caps or prices on emissions, environmental costs would be internalized with the cost of generation expansion and dispatch. Public policy objectives become part of standard economic cost benefit analysis.

- **Renewable Portfolio Standards.** The Midwest "RGOS Zone Scenario Generation and Transmission Cost Comparison" provides an example of including public policy constraints. States established the anticipated targets, including local generation requirements. The scenarios considered different mixes of generation and transmission investment subject to the constraint of meeting the RPS mandates.

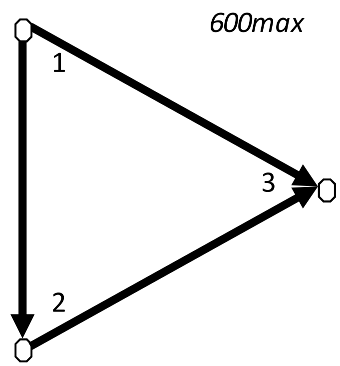


- **Transmission Benefit Calculation.** The benefit of transmission expansion does not include the benefit of the RPS mandate. Evaluating the benefits of public policy is different and more difficult than evaluating the benefits of transmission expansion in meeting public policy objectives.

The simplest network to illustrate locational interactions has three lines and nodes. Consider a lossless approximation with identical lines and one constraint.

The simple supply curves are flat up to the maximum quantity. Generators G1, G4 and G6 are renewable sources. There is a renewable portfolio standard (RPS) of 50% of the load at location 3. The demand curves are price sensitive at locations 1 and 2, but fixed at location 3. The transmission constraint applies to the line between locations 1 and 3.

	P	Max
G1	50.00	1000
G2	40.00	500
L1	75	300



P	Max	
70.00	500	G5
150.00	2000	G6
500	1800	L3

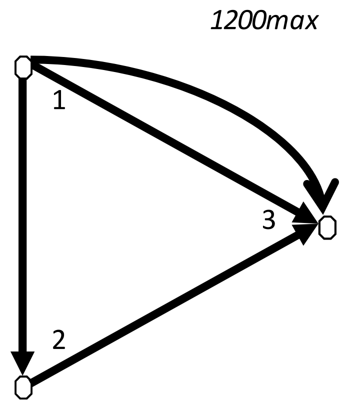
	P	Max
G3	50.00	500
G4	60.00	500
L2	60	50

This network would support Financial Transmission Rights (FTRs) for 900 MW between locations 1 and 3.

The possible network expansion has identified an additional line between locations 1 and 3 to double the capacity on this segment.

The same supply and demand conditions apply. The expanded grid could provide 1500 MW of FTRs between locations 1 and 3.

	P	Max
G1	50.00	1000
G2	40.00	500
L1	75	300



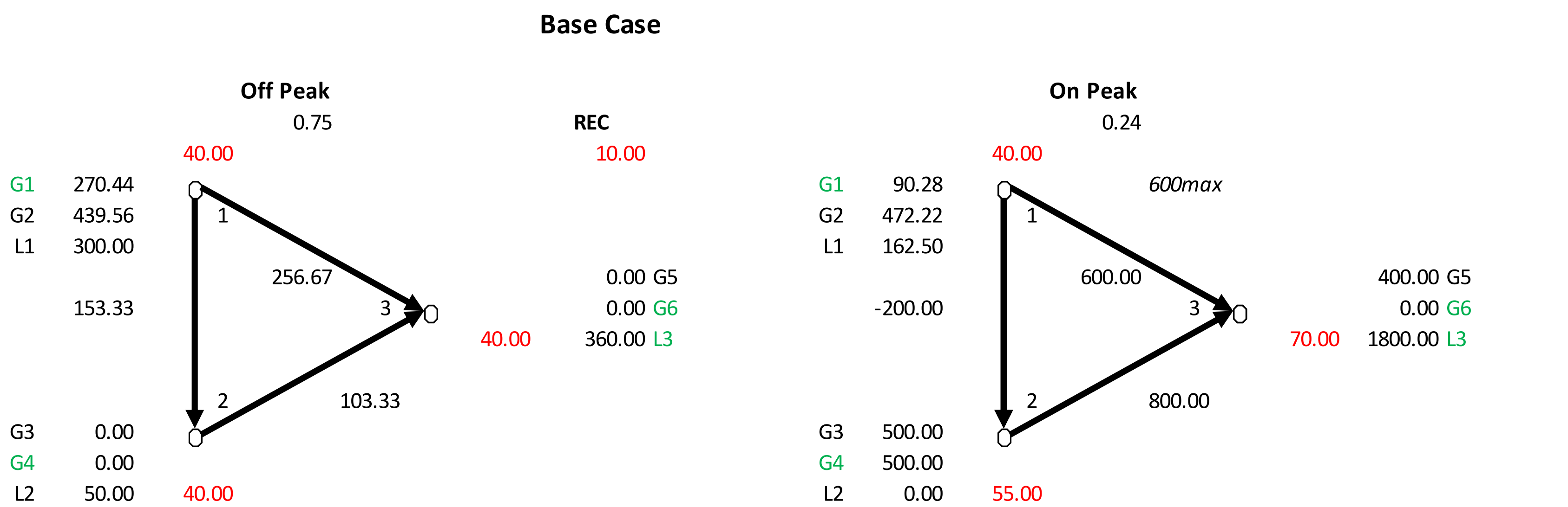
P	Max	
70	500	G5
150	2000	G6
500	1800	L3

	P	Max
G3	50.00	500
G4	60.00	500
L2	60	50

The expanded dispatch would change the patterns of costs and benefits. (Caution: This is a conceptual illustration and does not represent any particular transmission expansion plan.)

The future is uncertain, and conditions differ across different scenarios. The use of two economic scenarios, for peak and off peak conditions, illustrates the idea. A third low probability case proxies for reliability standards.

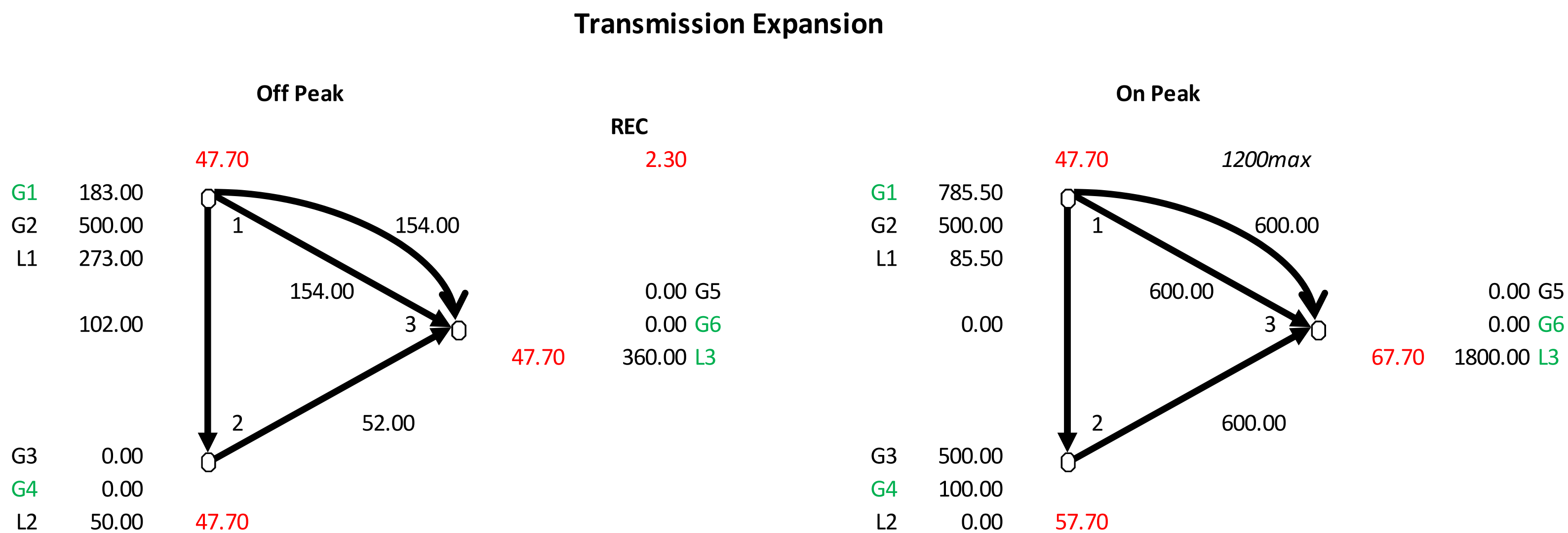
The example ignores contingency constraints, but additional operating constraints would be incorporated as done now in dispatch and planning models. The RPS standard is an expected value constraint across all scenarios and produces a price for a renewable energy credit (REC). The prices and flows include:



The off-peak case has no congestion. The on-peak case shows congestion and this limits access to lower cost generation, including renewables. The REC price is assumed to be paid by RPS load at location 3, and received by the various renewable generators.

The expansion case uses the same economic scenarios, probabilities and RPS requirements.

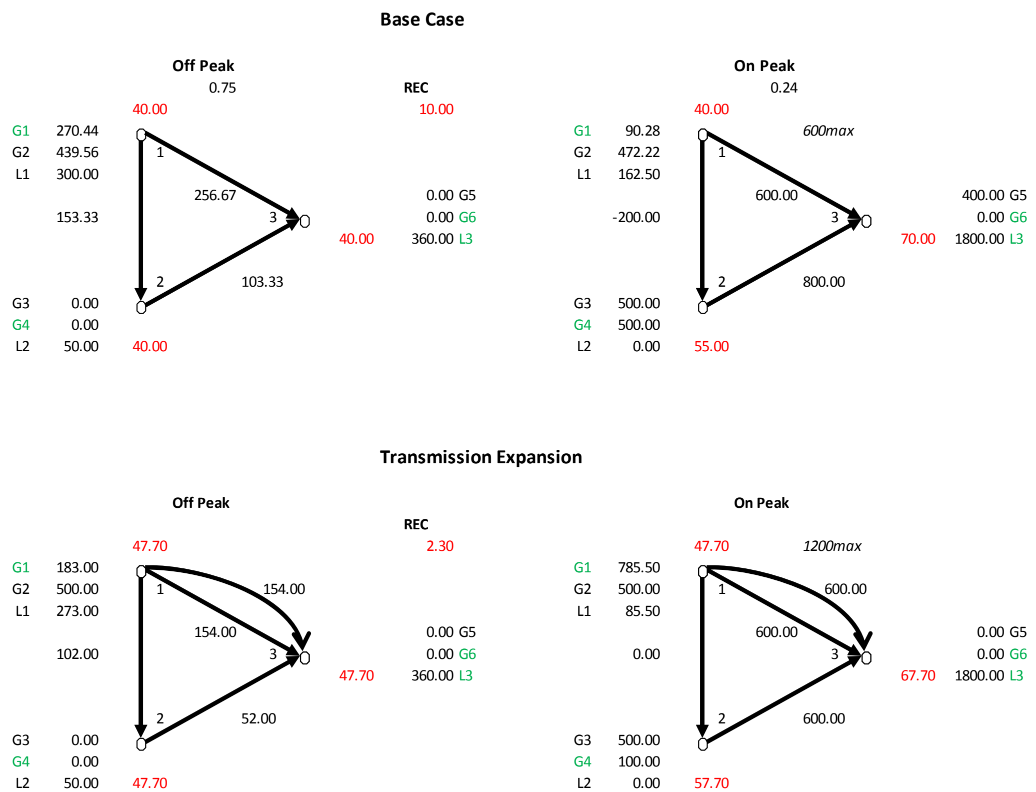
The increase in transmission capacity affects the dispatch, costs and benefits.



Prices change for all scenarios, including the REC price.

A comparison of the base case and expansion case provides the expected costs and benefits in aggregate and for different loads, generators and FTR holders.

The details at each location amount to unpacking the “bid production” costs and revenues. These are the individual consumer and producer surplus, and congestion, calculations.



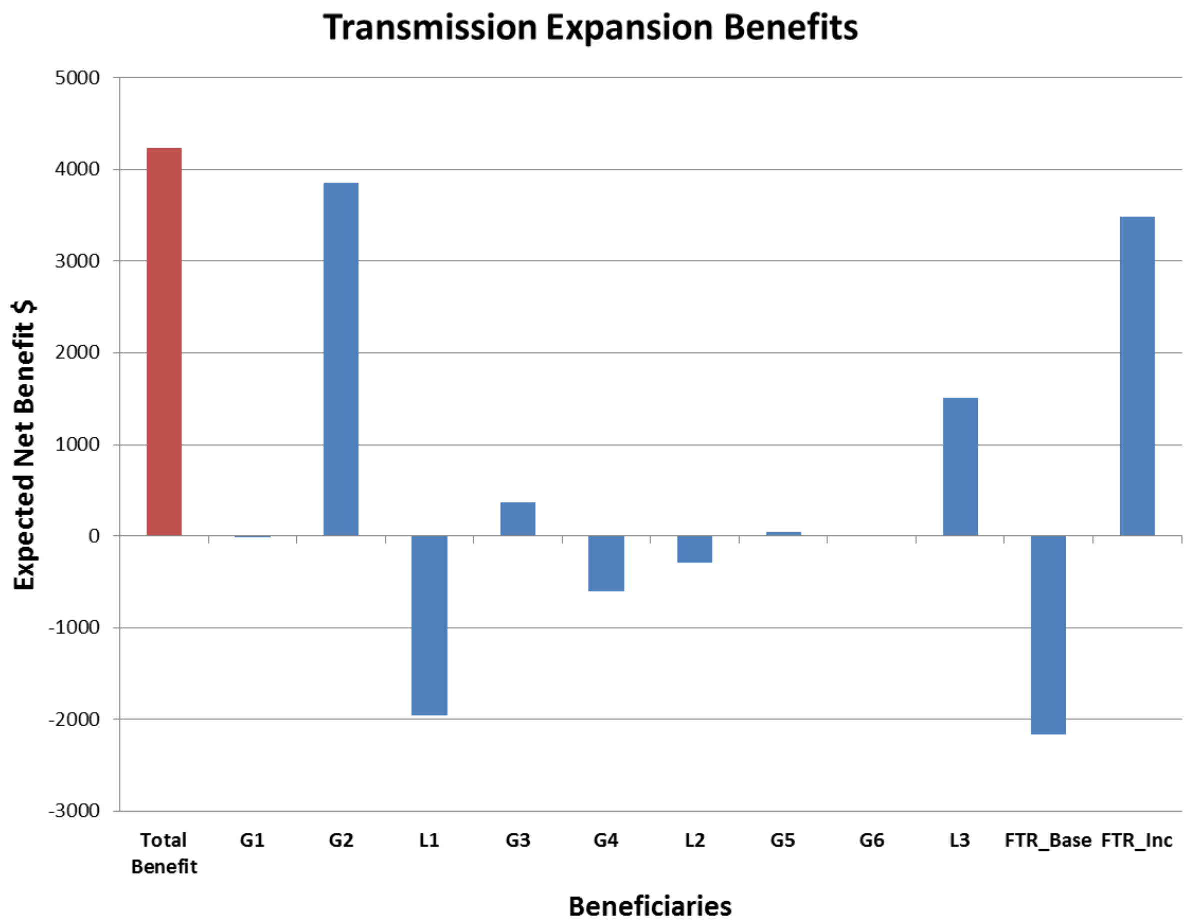
The details are tedious but straightforward.

The total change between cases identifies the total expected benefits. This includes economic benefits, the cost of the RPS, and the cost of meeting the reliability standard. The single line affects all categories of costs and benefits.

The total benefits would be compared with the total cost of the transmission line expansion. The individual benefit estimates include transfer payments resulting from the change in prices.

The transmission line investment cost is not put in buckets defined by type of benefit.

The distribution of the total of economic, reliability and public policy benefits is not uniform. The allocation of the transmission expansion costs could utilize this distribution of expected benefits.



Efficient transmission infrastructure investment inherently requires forecasts of conditions for long-lived infrastructure. This presents challenges for cost benefit analysis and cost allocation.

- **Defining the Horizon of Analysis.** This is a standard problem in planning, but will be more important to the extent it affects cost allocation.
- **Representing Uncertianty.** Scenarios and sensitivity analysis will be more important. And benefits need to be aggregated as expected benefits, probability weighted across anticipated outcomes. This is not new, but cost allocation will make this both more contentious and more necessary.
- **Choosing the Counterfactual.** This seems straightforward in a static one-shot framework. It becomes more difficult in the dynamic setting that includes future transmission investments.
- **Harmoninzing Investment Decisions.** The regional planning function for transmission is not the same thing as integrated regional planning of old. Even if the plan mandates certain transmission investments, the complementary decisions on generation and load will be decentralized.
- **Eliciting Support of Beneficiaries.** "The proposed cost allocation mechanism is based on a 'beneficiaries pay' approach, consistent with the Commission's longstanding cost causation principles. … Beneficiaries will be those entities that economically benefit from the project, and the cost allocation among them will be based upon their relative economic benefit. … The proposed cost allocation mechanism will apply only if a super-majority of a project's beneficiaries agree that an economic project should proceed. The super-majority required to proceed equals 80 percent of the weighted vote of the beneficiaries associated with the project that are present at the time of the vote." (New York Independent System Operator, Inc Docket No. OA08-13-000, "Order No. 890 Transmission Planning Compliance Filing," Cover Letter Submitted to Federal Energy Regulatory Commission, December 7, 2007, pp. 14-15.)
- **Other?**

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, 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 Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, Energy Endeavors LP, Exelon, Financial Marketers Coalition, 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, 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, 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).