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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Wholesale Markets: Strengths and Weaknesses for a Decarbonizing Future

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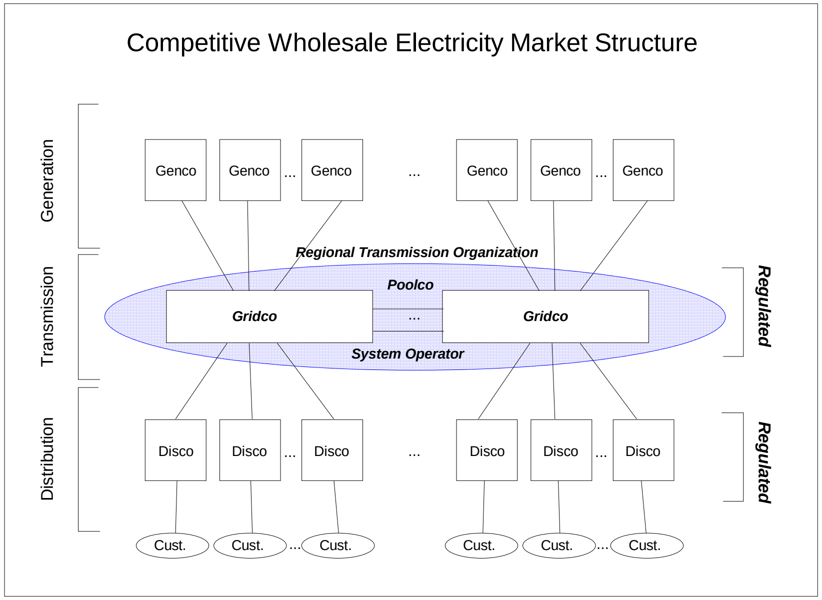
The U.S. experience illustrates successful market design and remaining challenges for both theory and implementation.

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

  Provide good short-run operating incentives.

  Support forward markets and long-run investments.



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

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

  Financial Transmission Rights (FTRs).

- **Design Implementation: Pricing Evolution**

  Better scarcity pricing to support resource adequacy.

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

- **Design Challenge: Infrastructure Investment**

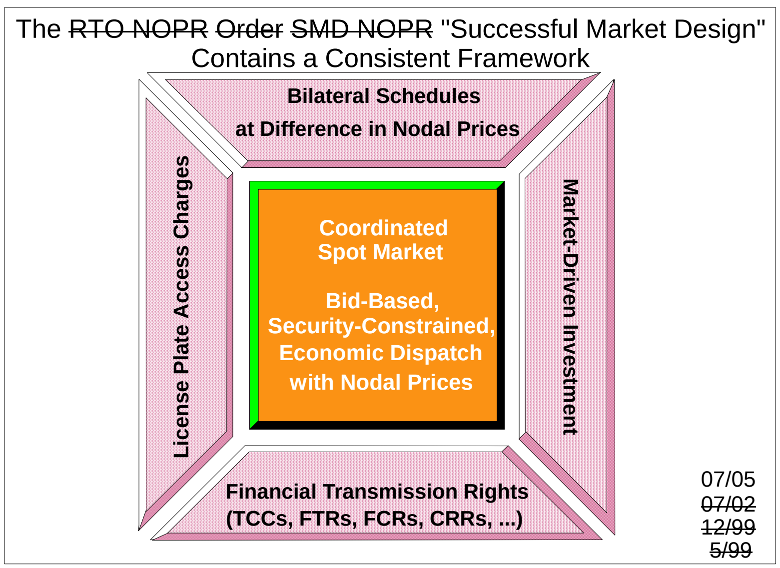
  Hybrid models to accommodate both market-based and regulated transmission investments.

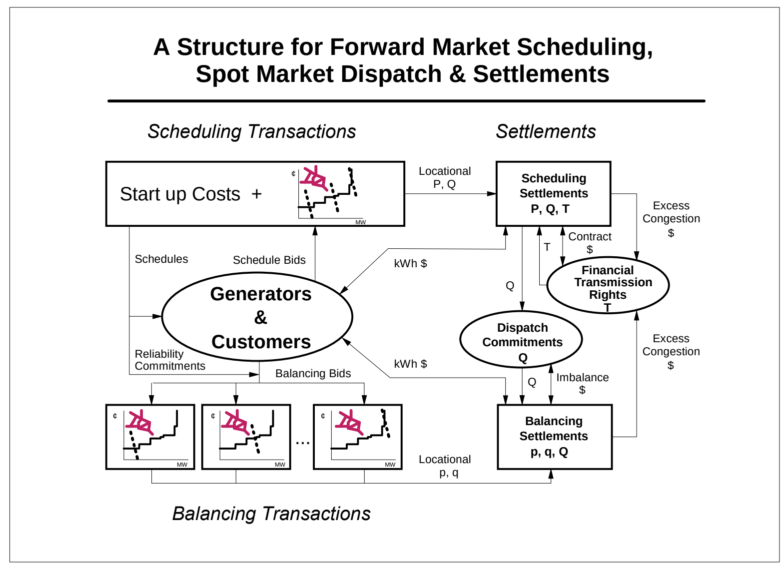
  Beneficiary-pays principle to support integration with rest of the market design.

ELECTRICITY MARKET — A Consistent Framework

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

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

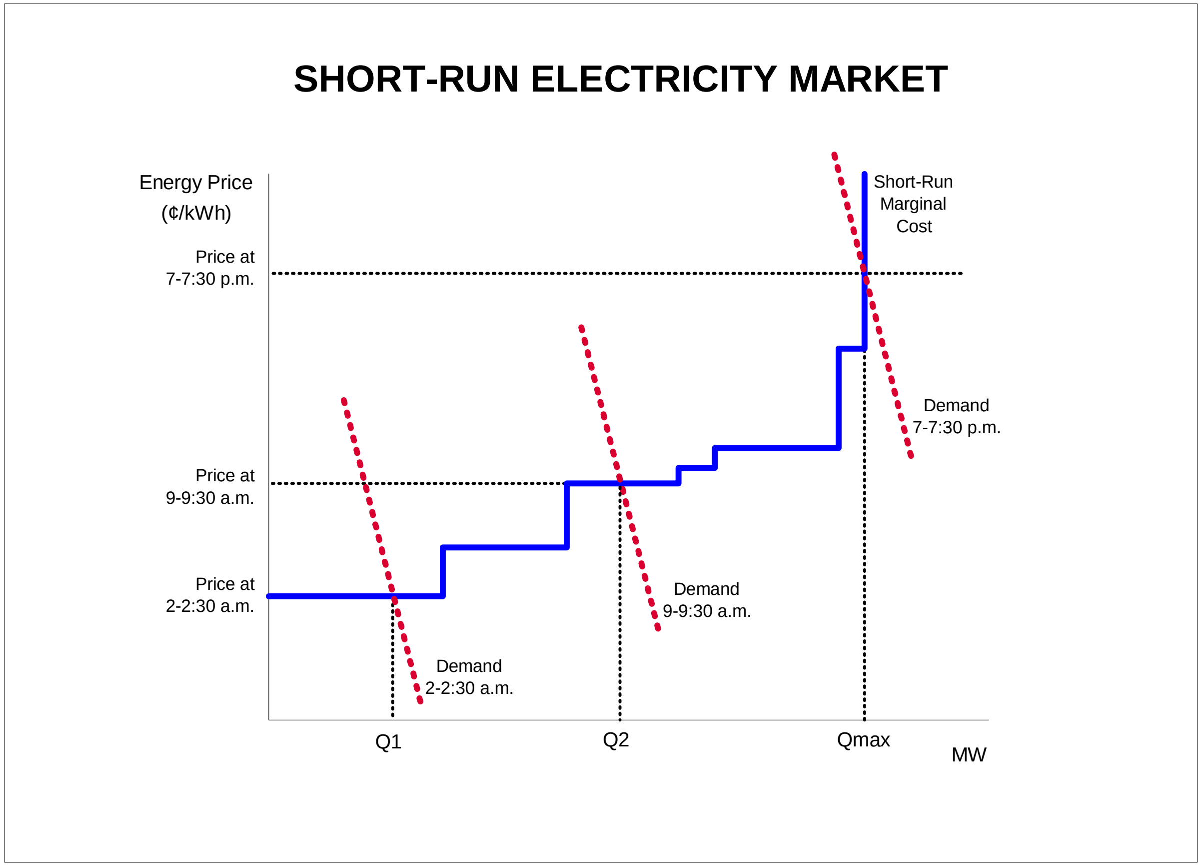




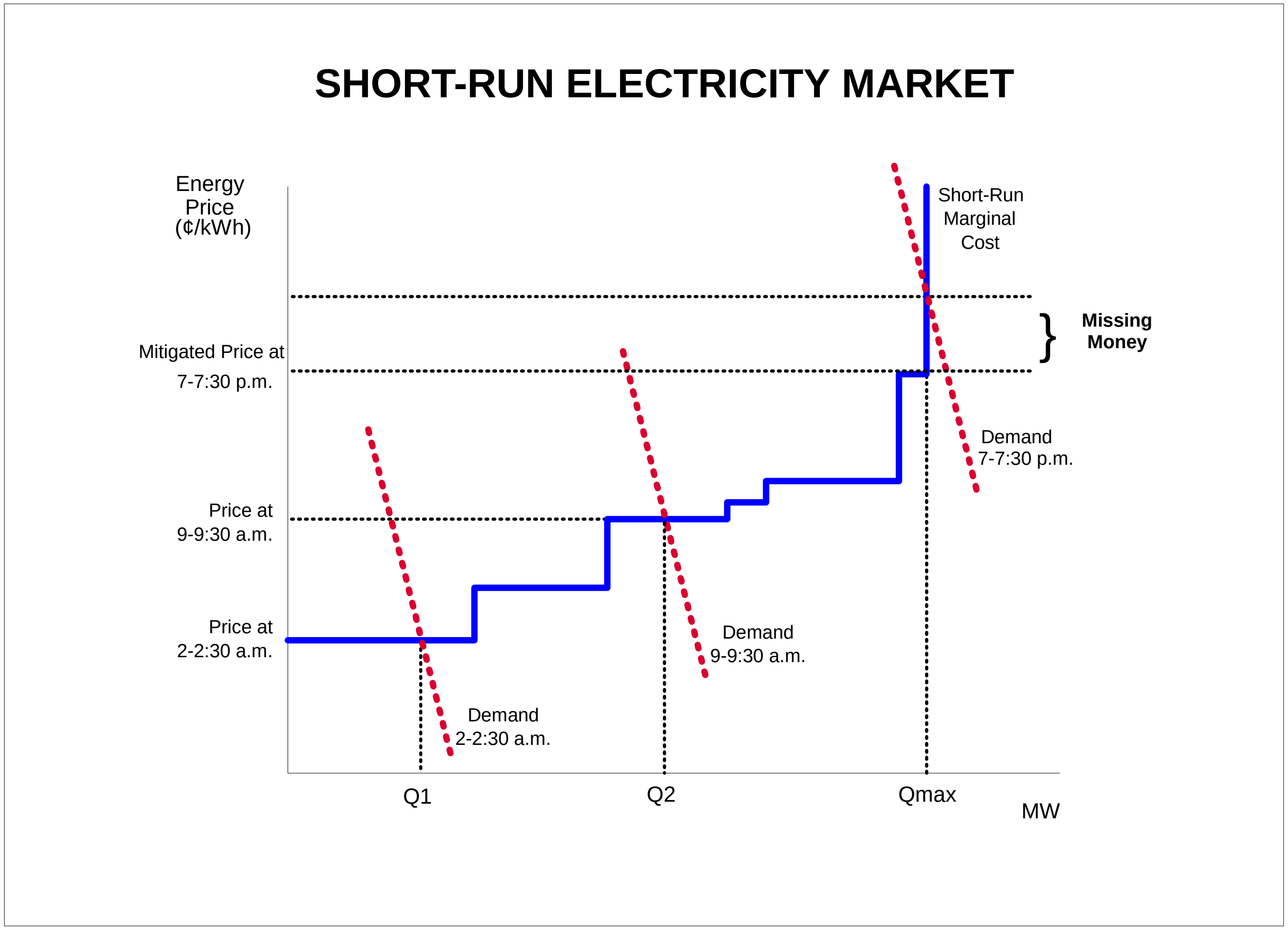
All energy delivery takes place in the real-time market. Market participants will anticipate and make forward decisions based on expectations about real-time prices.

- **Real-Time Prices:** In a market where participants have discretion, the most important prices are those in real-time. "Despite the fact that quantities traded in the balancing markets are generally small, the prevailing balancing prices, or real-time prices, may have a strong impact on prices in the wholesale electricity markets. … No generator would want to sell on the wholesale market at a price lower than the expected real-time price, and no consumer would want to buy on the wholesale market at a price higher than the expected real-time price. As a consequence, any distortions in the real-time prices may filter through to the wholesale electricity prices." (Cervigni & Perekhodtsev, 2013)
- **Day-Ahead Prices:** Commitment decisions made day-ahead will be affected by the design of day-ahead pricing rules, but the energy component of day-ahead prices will be dominated by expectations about real-time prices.
- **Forward Prices:** Forward prices will look ahead to the real-time and day-ahead markets. Although forward prices are developed in advance, the last prices in real-time will drive the system.
- **Getting the Prices Right:** The last should be first. The most important focus should be on the models for real-time prices. Only after everything that can be done has been done, would it make sense to focus on out-of-market payments and forward market rules.

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.

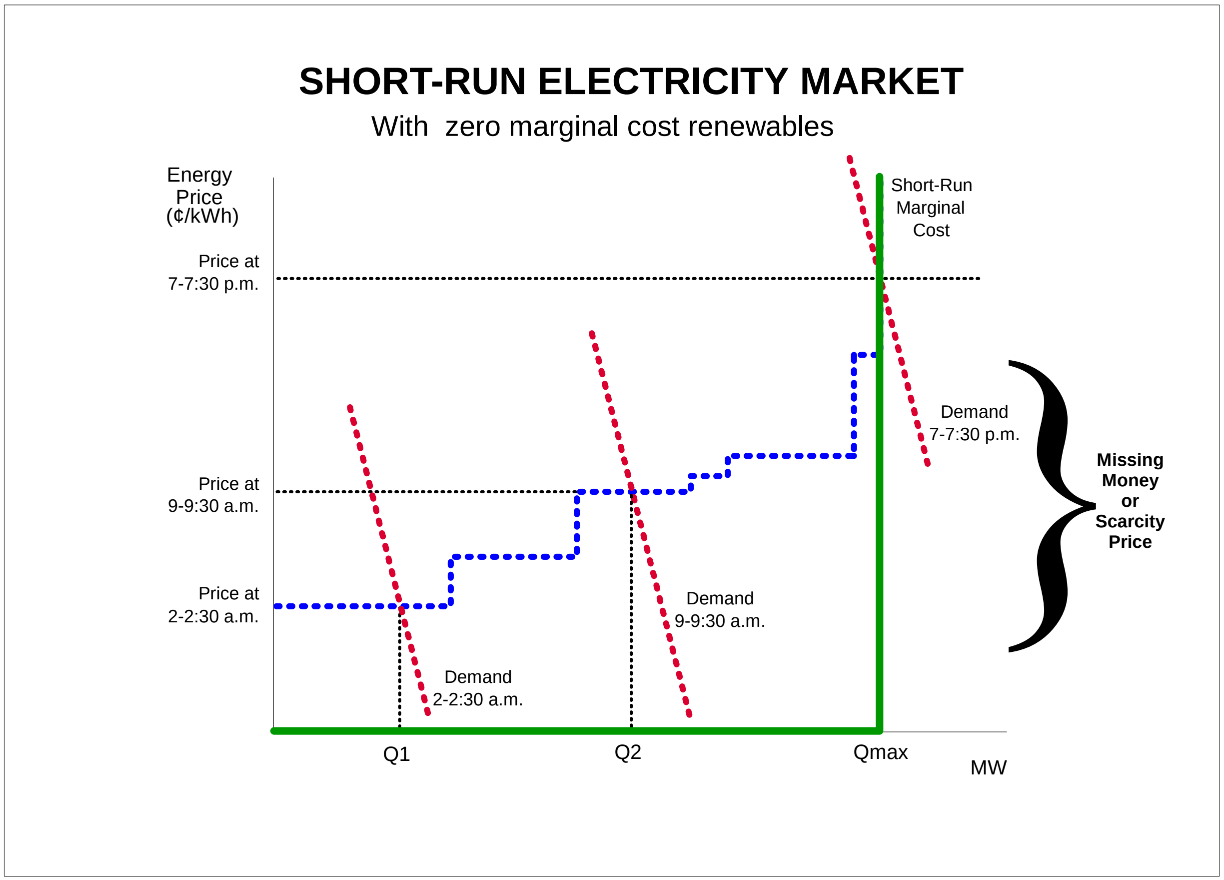


Early market designs presumed significant demand participation. Absent this demand participation most markets implemented inadequate pricing rules equating prices to variable costs even when capacity is constrained. This produces a "missing money" problem.

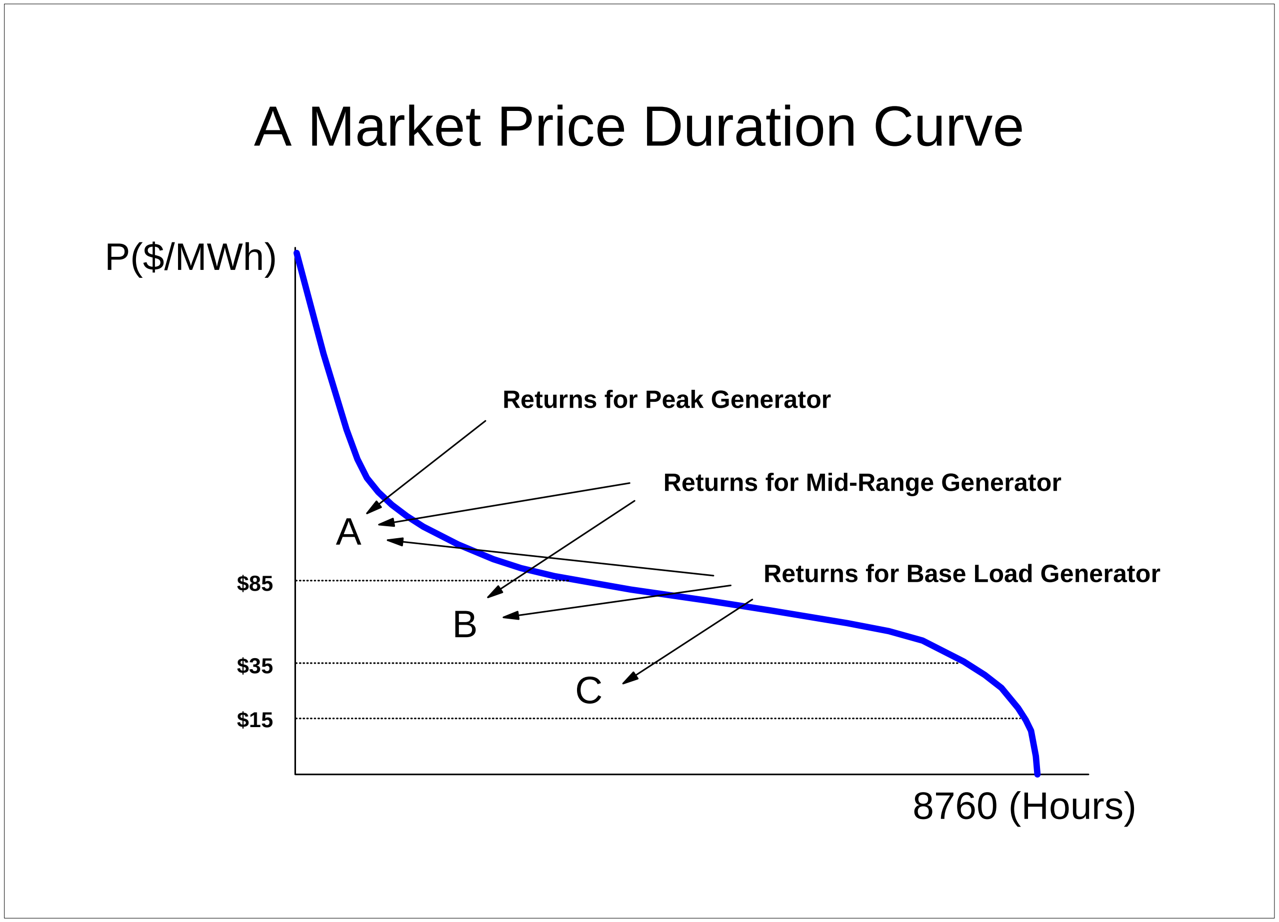


ELECTRICITY MARKET — Pricing and Demand

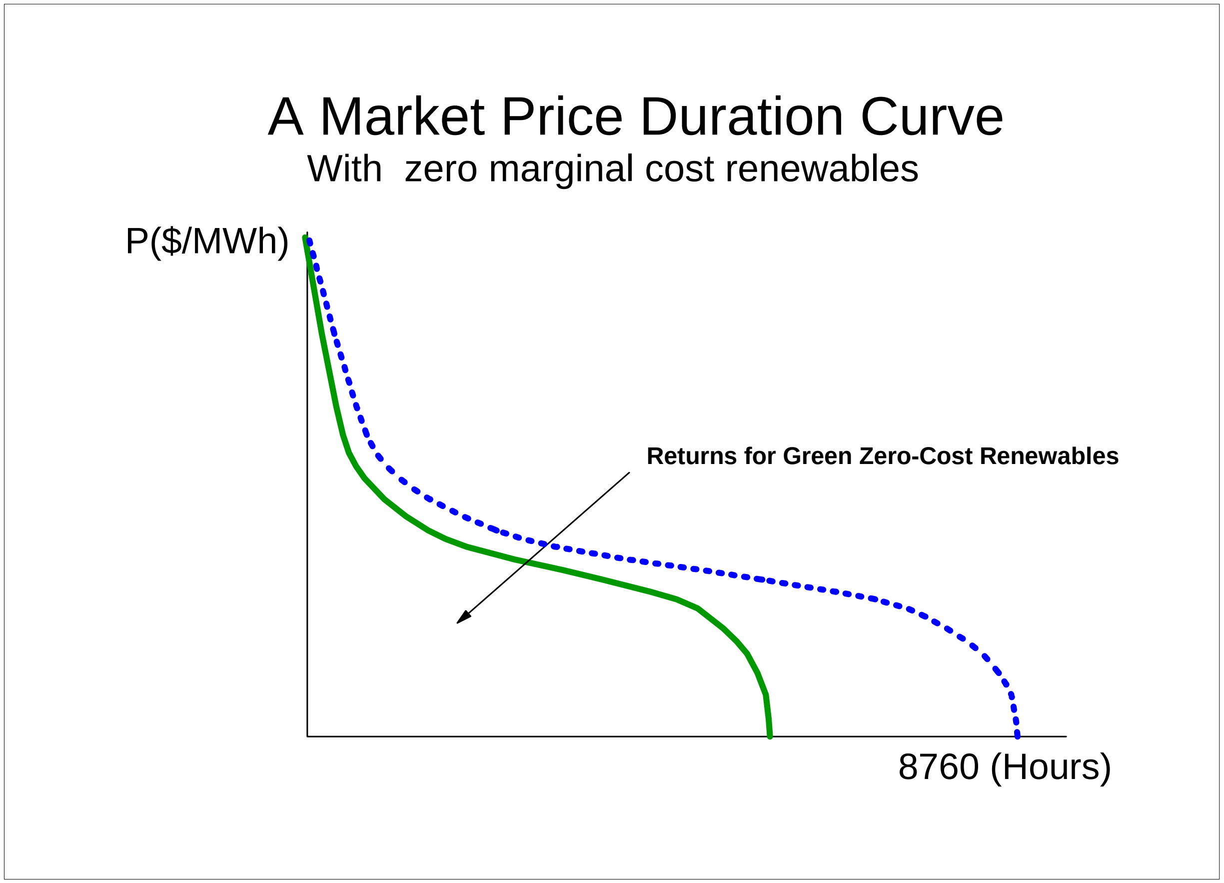
A limiting case illustrates a key issue. Electricity market design with even complete penetration by zero-variable cost renewables would follow the same analysis. But scarcity pricing would be critical to provide efficient incentives.



The equilibrium analysis with a price duration curve identifies the returns to compensate for capital costs of different plant types.



With zero variable cost renewables the price duration curve would change. The equilibrium condition would identify returns for the marginal renewable generator. In principle, nothing changes from the general case, except to increase the importance of scarcity pricing.



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 main 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.[1]

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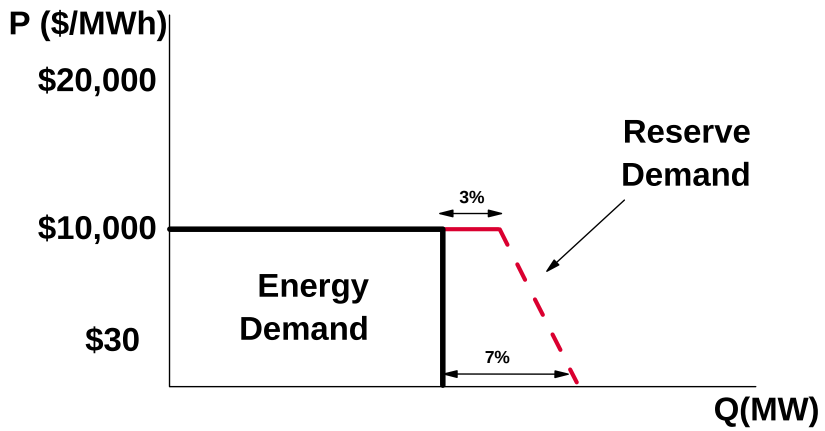
1 FERC, Order 719, October 17, 2008.

Operating reserve demand curve would reflect capacity scarcity.

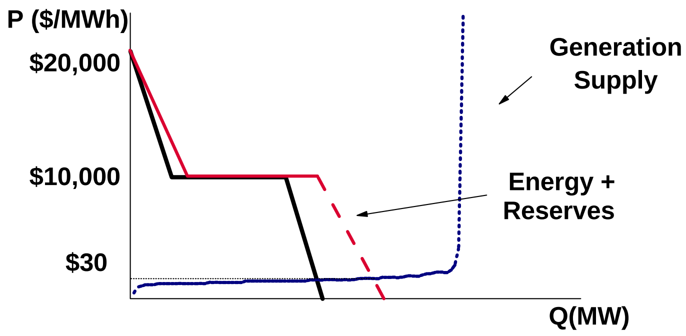
Illustrative Reserve Demand



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.

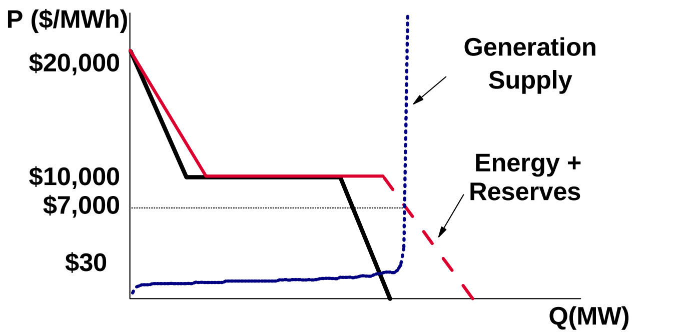
Market clearing addresses the "missing money."

Normal "Energy Only" Market Clearing



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

Scarcity "Energy Only" Market Clearing



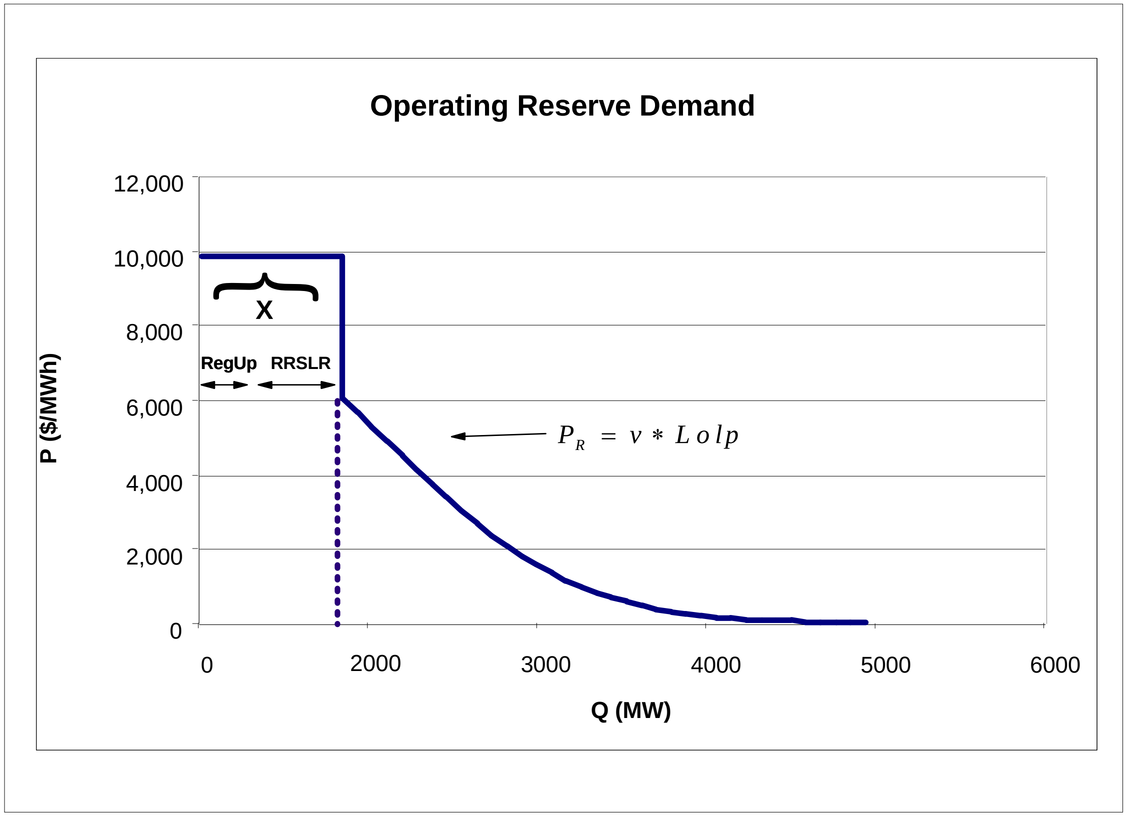
When demand is high and reserve reductions apply, there is a high price.

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.

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

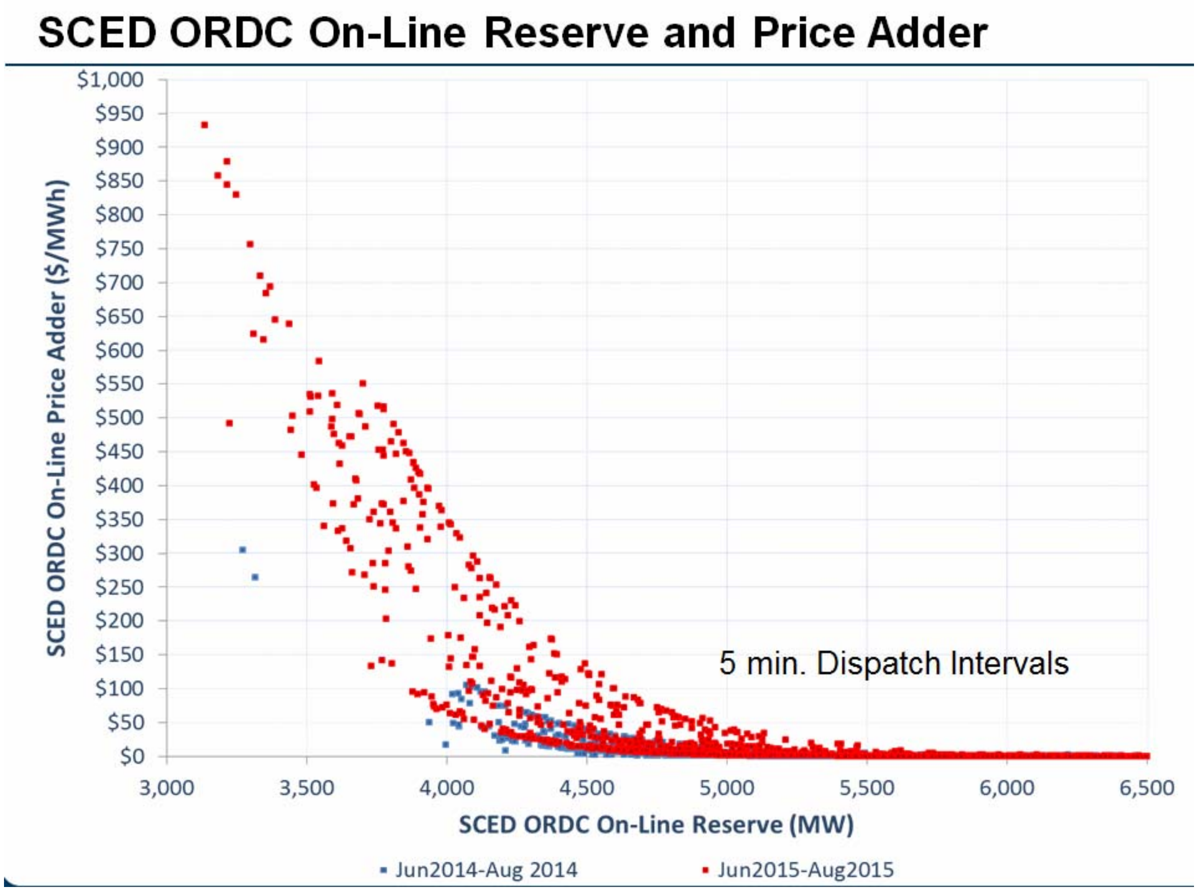
Whitepaper

March 21, 2013

William W. Hogan, Harvard University

ERCOT Staff

ERCOT launched implementation of the ORDC in in 2014. The summer peak is the most important period. The first year results showed high availability of reserves and low reserve prices. The experience in 2015 illustrates the fundamental properties of the ORDC, and higher reserve prices.



Source: Resmi Surendran, *Analysis of Reserves and Prices, July 2, 2015-August 23: Hour Ending 17:00*, ERCOT TAC Presentation, August 27, 2015.

Higher reserve prices, especially in August of 2015, contributed more than half the peaker net margin (PNM, equal to the real-time price minus the peak operating costs set as ten times the Houston ship channel gas price index of the previous day). The PNM in 2011 was $ $125,001.

SCED ORDC Impact

	First one year	June 2015	July 2015	August 2015 until 21st
Settlement for Energy	**$132.5 M**	$5.4 M	$79.2 M	**$305.7M**
Settlement for Ancillary Service	$1.6 M	$0.09 M	$(0.44) M	$(0.9) M
Avg Online Reserve Price (Peak)	**$0.51**	$0.25	$3.50	**22.6**
Avg Online Reserve Price (Off Peak)	$0.26	$0.07	$0.53	$0.33
Max Online Reserve Price (Peak)	$202.9	$28.3	$434.0	$798.4
PNM	$29,308.0	$738.4	$2,945.7	$7,574.0*
PNM from ORDC	**$2,731.8**	$95.3	$1,185.9	**$4,506.1***

Source: Resmi Surendran, *Analysis of Reserves and Prices, July 2, 2015-August 23: Hour Ending 17:00*, ERCOT TAC Presentation, August 27, 2015.

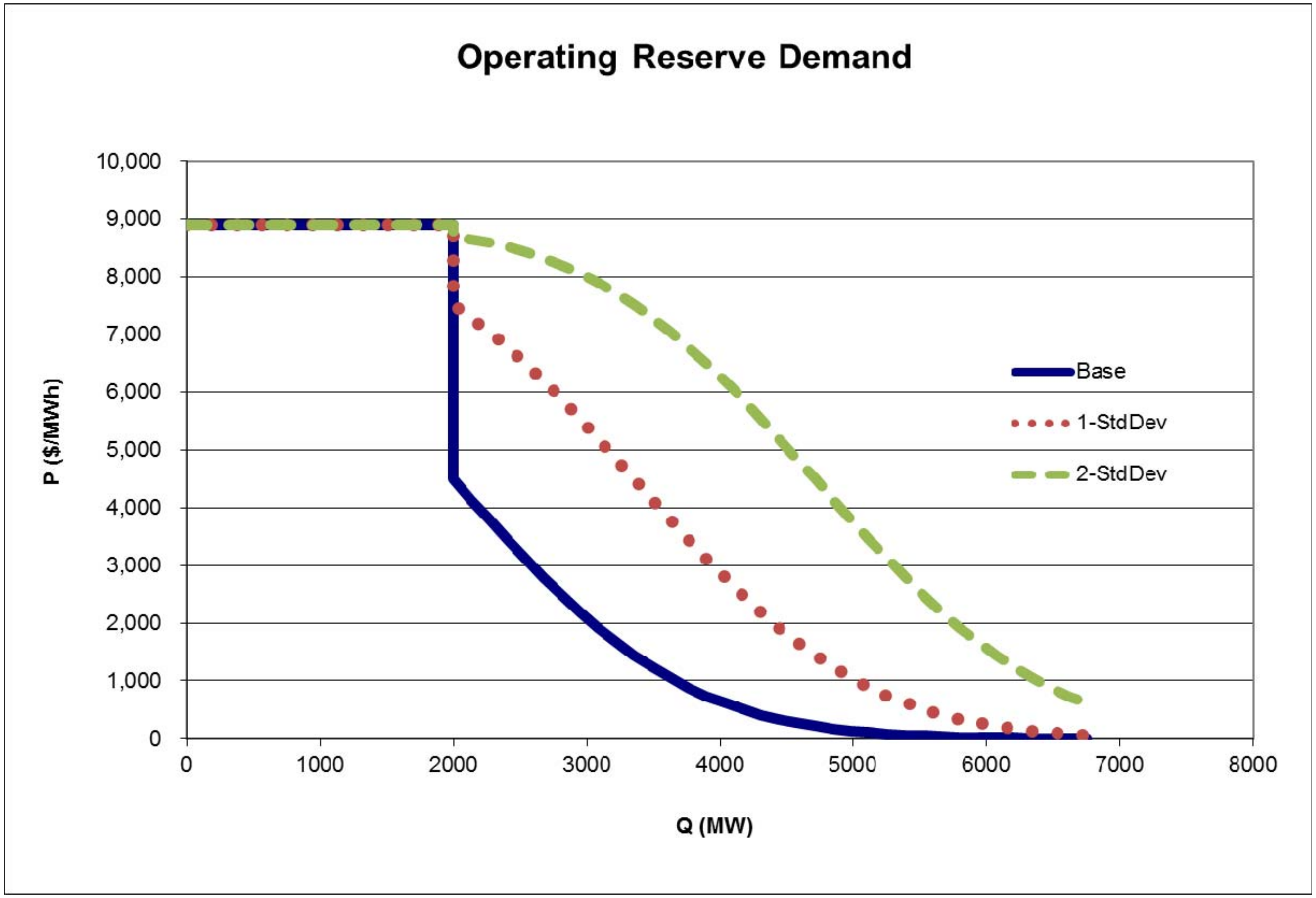
An augmented ORDC would impose conservative assumptions on the basic model. The intent would be to provide both a reliability margin of safety, an associated increase in total operating reserves, and energy payments to address the missing money problem. The three principal parameters of the ORDC are 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.



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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, FirstEnergy Corporation, FTI Consulting, GenOn Energy, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd., GDF SUEZ Energy Resources NA, Great Bay Energy LLC, GWF Energy, Independent Energy Producers Assn, ISO New England, Koch Energy Trading, Inc., JP Morgan, LECG LLC, Luz del Sur, Maine Public Advocate, Maine Public Utilities Commission, Merrill Lynch, Midwest ISO, Mirant Corporation, MIT Grid Study, Monterey Enterprises LLC, MPS Merchant Services, Inc. (f/k/a Aquila Power Corporation), JP Morgan Ventures Energy Corp., Morgan Stanley Capital Group, Morrison & Foerster LLP, National Independent Energy Producers, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, NRG Energy, Inc., Ontario Attorney General, Ontario IMO, Ontario Ministries of Energy and Infrastructure, Pepco, Pinpoint Power, PJM Office of Interconnection, PJM Power Provider (P3) Group, Powerex Corp., Powhatan Energy Fund LLC, PPL Corporation, PPL Montana LLC, PPL EnergyPlus LLC, Public Service Company of Colorado, Public Service Electric & Gas Company, Public Service New Mexico, PSEG Companies, Red Wolf Energy Trading, Reliant Energy, Rhode Island Public Utilities Commission, Round Rock Energy LP, San Diego Gas & Electric Company, Secretaría de Energía (SENER, Mexico), Sempra Energy, SESCO LLC, Shell Energy North America (U.S.) L.P., SPP, Texas Genco, Texas Utilities Co, Tokyo Electric Power Company, Toronto Dominion Bank, Transalta, TransAlta Energy Marketing (California), TransAlta Energy Marketing (U.S.) Inc., Transcanada, TransCanada Energy LTD., TransÉnergie, Transpower of New Zealand, Tucson Electric Power, Twin Cities Power LLC, Vitol Inc., Westbrook Power, Western Power Trading Forum, Williams Energy Group, Wisconsin Electric Power Company, and XO Energy. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the author. (Related papers can be found on the web at www.whogan.com).