ELECTRICITY MARKET DESIGN
PRICE FORMATION 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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Electricity restructuring presents twin challenges with a broad theme.

- **Create an effective electricity market design with associated transmission access rules.**
    - An electricity market must be designed.
    - The market cannot solve the problem of market design.
    - Incentives should drive decisions and innovation.

- **Provide compatible market interventions to compensate for market imperfections.**
    - Market imperfections exist under the best designs.
    - Network interactions make the obvious answers wrong or even dangerous.
    - Poor market design makes interventions more necessary, more common, and more difficult.

There is a close connection between the twin challenges, and the slippery slope of intervention can lead to an electricity market that may be worse than the system it was to replace.

If the central planners (or regulators) know what to do, then do it.

But if true, what is the need for electricity restructuring and markets?

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

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

  Provide good short-run operating incentives.

  Support forward markets and long-run investments.

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

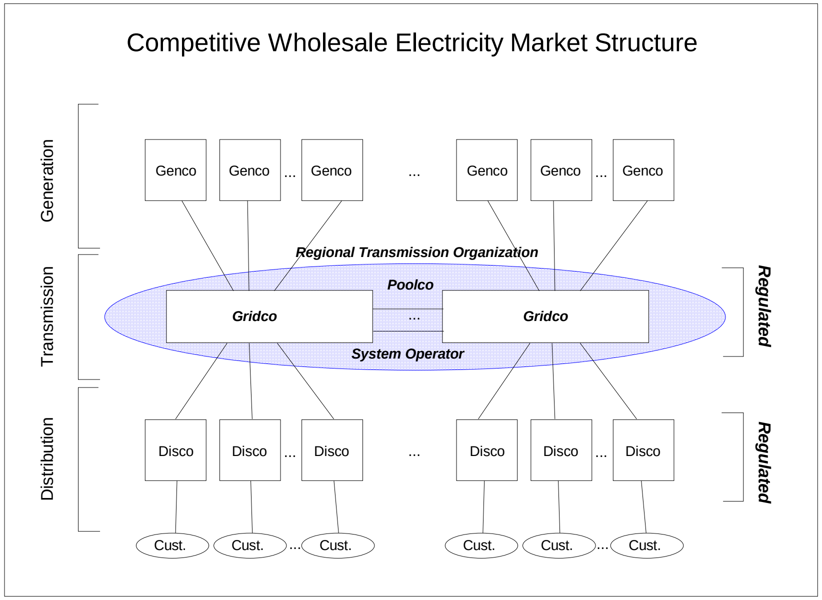
  Locational Marginal Prices (LMP) with granularity to match system operations.

  Financial Transmission Rights (FTRs).

- **Design Implementation: Pricing Evolution**

  Better scarcity pricing to support resource adequacy.

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



- **Design Challenge: Infrastructure Investment**

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

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

The independent system operator provides a dispatch function. Three questions remain. Just say yes, and the market can decide on the split between bilateral and coordinated exchange.

- **Should the system operator be allowed to offer an economic dispatch service for some plants?**

The alternative would be to define a set of administrative procedures and rules for system balancing that purposely ignore the information about the costs of running particular plants. It seems more natural that the system operator considers customer bids and provides economic dispatch for some plants.

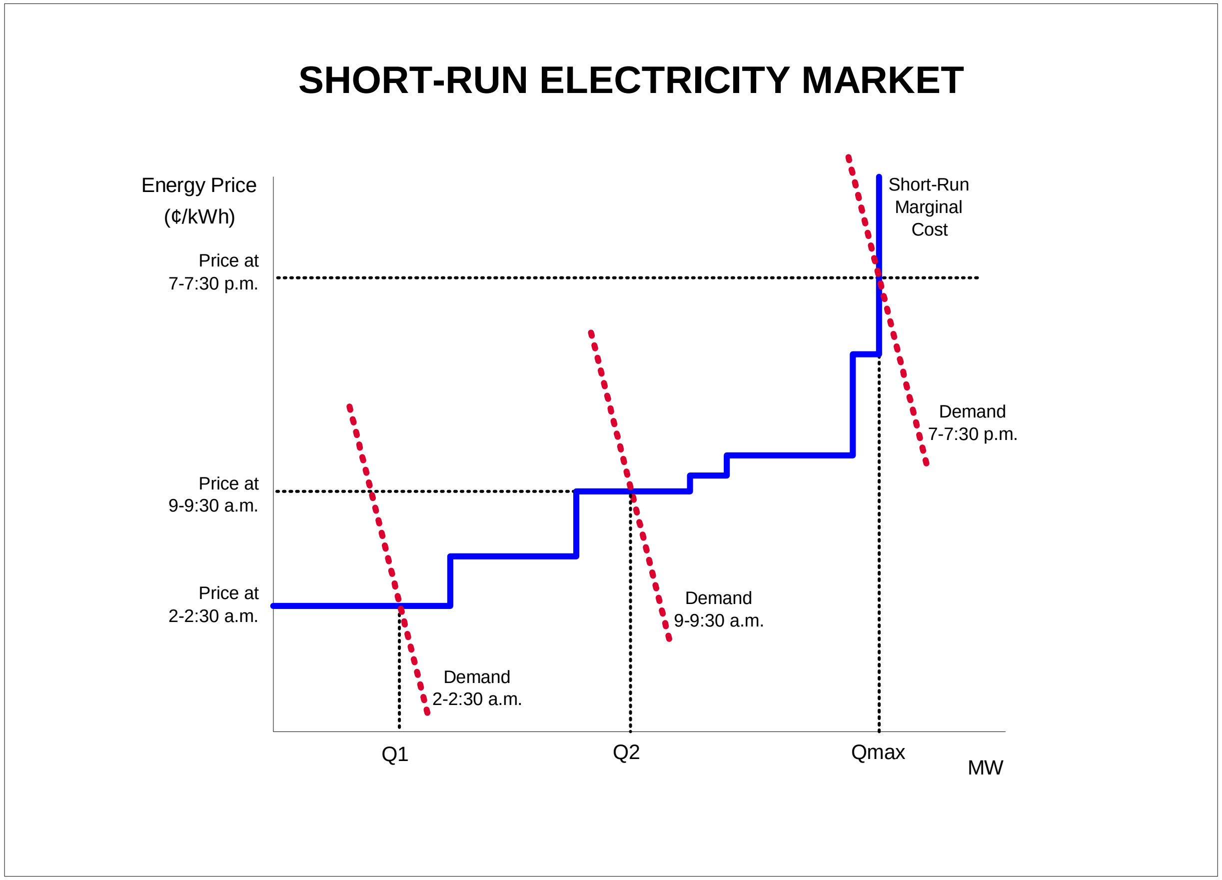
- **Should the system operator apply marginal cost prices for power provided through the dispatch?**

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

- **Should generators and customers be allowed to participate in the economic dispatch offered by the system operator?**

The natural extension of open access and the principles of choice would suggest that participation should be voluntary. Market participants can evaluate their own economic situation and make their own choice about participating in the operator's economic dispatch or finding similar services elsewhere.

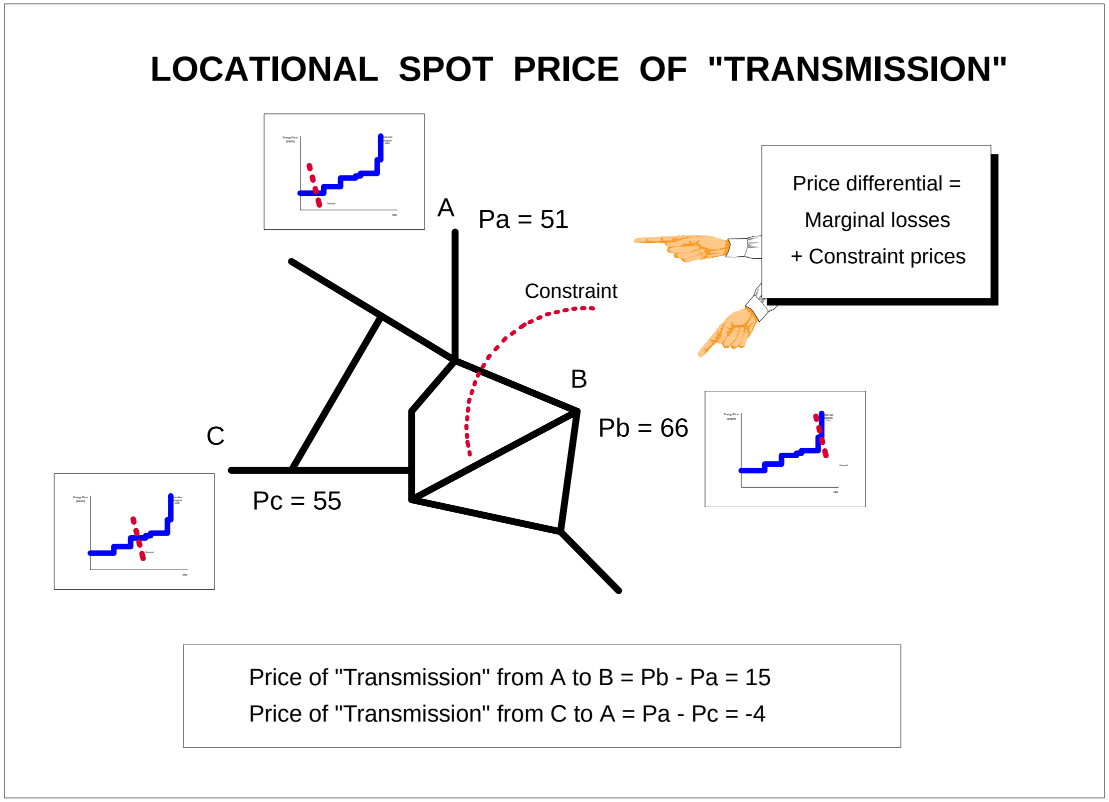
An efficient short-run electricity market determines a market clearing price based on conditions of supply and demand balanced in an economic dispatch. Everyone pays or is paid the same price. The same principles apply in an electric network. (Schweppe, Caramanis, Tabors, & Bohn, 1988) (Hogan, 1992)



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

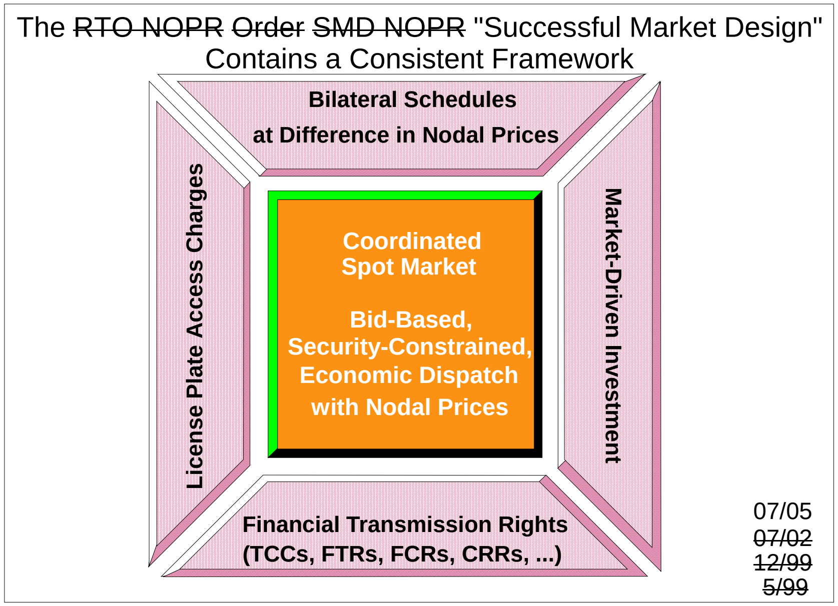
- It is a straightforward matter to compute "Schweppe" spot prices based on marginal costs at each location.

- Transmission spot prices arise as the difference in the locational prices.



ELECTRICITY MARKET A Consistent Framework

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



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

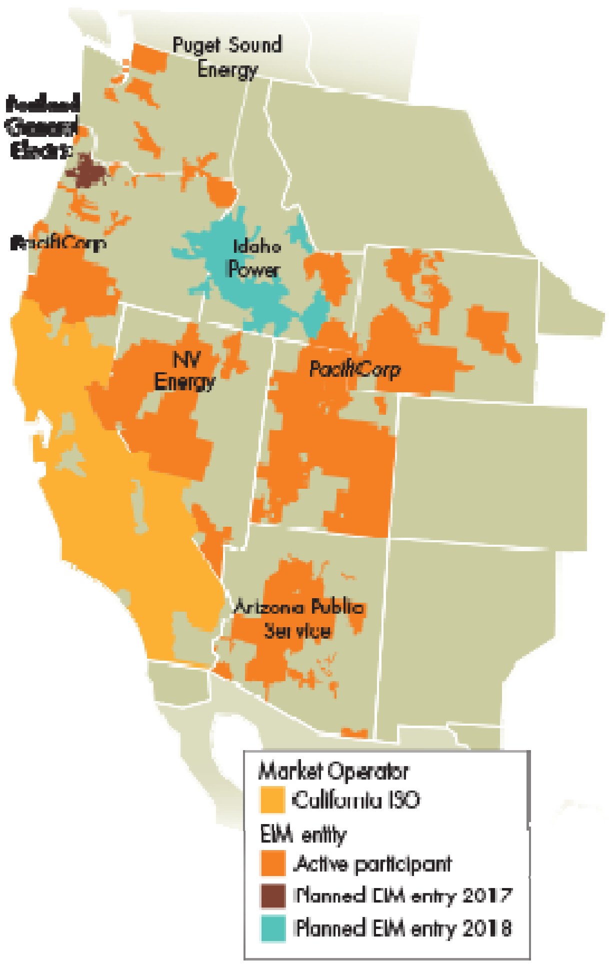
"Locational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers. A trading arrangement based on LMP takes all relevant generation and transmission costs appropriately into account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

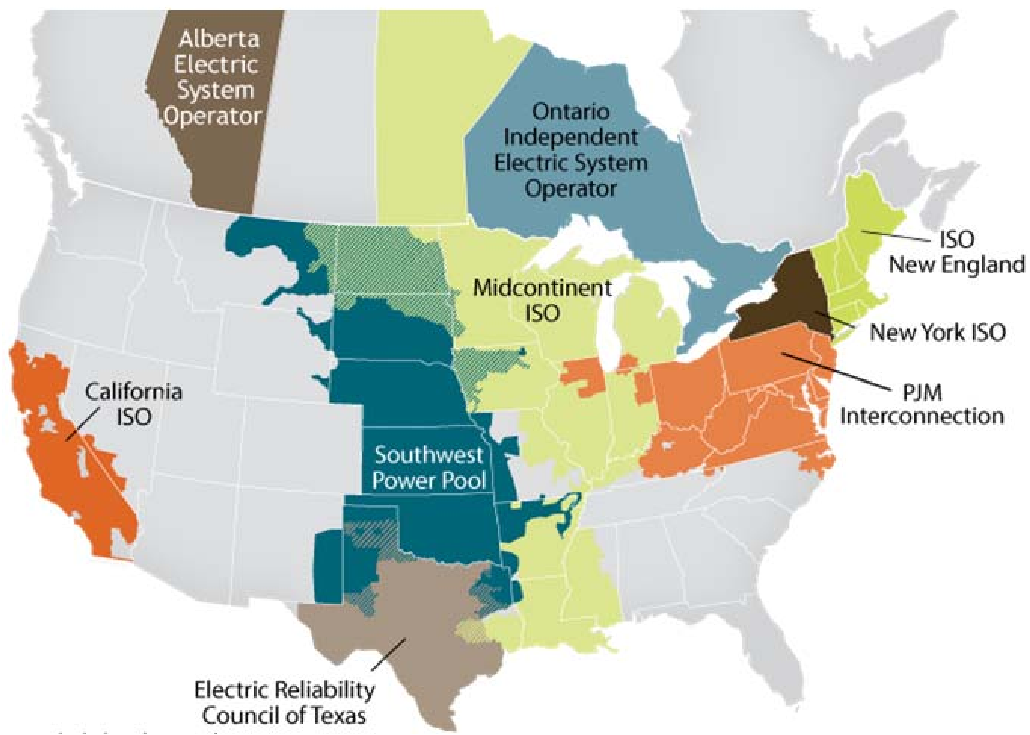
This is the only model that can meet the tests of open access and non-discrimination.

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

ELECTRICITY MARKET A Consistent Framework

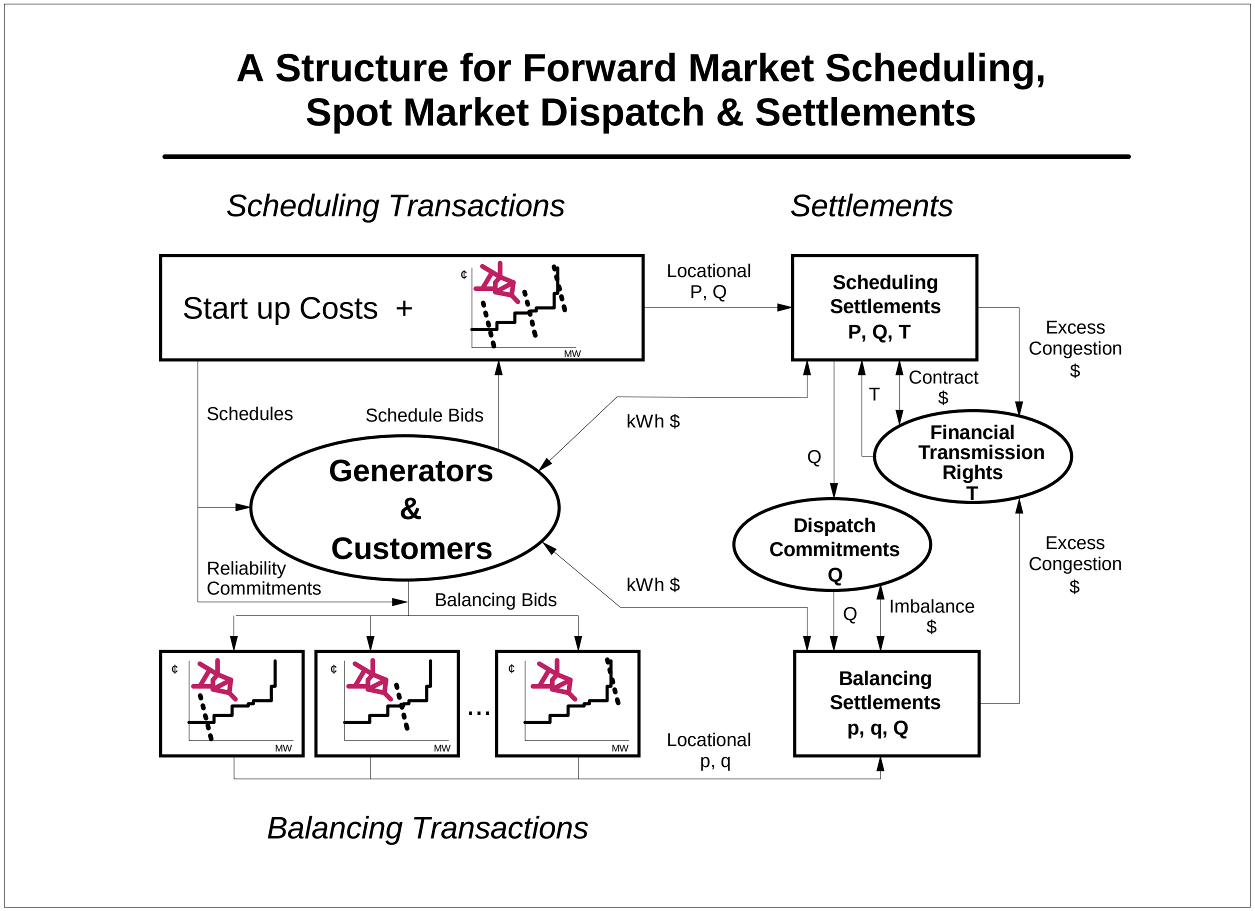
The basic model covers the existing Regional Transmission Organizations and is expanding through the Wester Energy Imbalance Market. ([www.westerneim.com)](http://www.westerneim.com)





(IRC Council and CAISO maps)

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



The unit commitment problem implies discrete choices that create non-convexities and computational problems. A stylized version of the unit commitment and dispatch problem for a fixed demand $\mathbf{y}$ as formulated in (Gribik, Hogan, & Pope, 2007)**:**

Constants:	Variables:
$\mathbf{y}_t =$ vector of nodal loads in period t $m_{it} =$ minimum output from unit i in period t if unit is on $M_{it} =$ maximum output from unit i in period t if unit is on $ramp_{it} =$ maximum ramp from unit i between period t-1 and period t $StartCost_{it} =$ Cost to start unit i in period t $NoLoad_{it} =$ No load cost for unit i in period t if unit is on $\overline{F}_{kt}^{\max} =$ Maximum flow on transmission constraint k in period t.	$start_{it} = \begin{cases} 0 \text{ if unit i is not started in period t} \\ 1 \text{ if unit i is started in period t} \end{cases}$ $on_{it} = \begin{cases} 0 \text{ if unit i is off in period t} \\ 1 \text{ if unit i is on in period t} \end{cases}$ $g_{it} =$ output of unit i in period t $\mathbf{d}_t =$ vector of nodal demands in period t.

$$v\left(\{\mathbf{y}_t\}\right) = \inf_{\text{g,d,on,start}} \sum_t \sum_i \left(StartCost_{it} \cdot start_{it} + NoLoad_{it} \cdot on_{it} + GenCost_{it}\left(g_{it}\right) \right)$$

subject to

$$\begin{array}{ll}
m_{it} \cdot on_{it} \le g_{it} \le M_{it} \cdot on_{it} & \forall i,t \\
-ramp_{it} \le g_{it} - g_{i,t-1} \le ramp_{it} & \forall i,t \\
start_{it} \le on_{it} \le start_{it} + on_{i,t-1} & \forall i,t \\
start_{it} = 0 \text{ or } 1 & \forall i,t \\
on_{it} = 0 \text{ or } 1 & \forall i,t \\
\mathbf{e}^T\left(\mathbf{g}_t - \mathbf{d}_t\right) - LossFn_t\left(\mathbf{d}_t - \mathbf{g}_t\right) = 0 & \forall t \\
Flow_{kt}\left(\mathbf{g}_t - \mathbf{d}_t\right) \le \overline{F}_{kt}^{\max} & \forall k,t \\
\mathbf{d}_t = \mathbf{y}_t & \forall t.
\end{array}$$

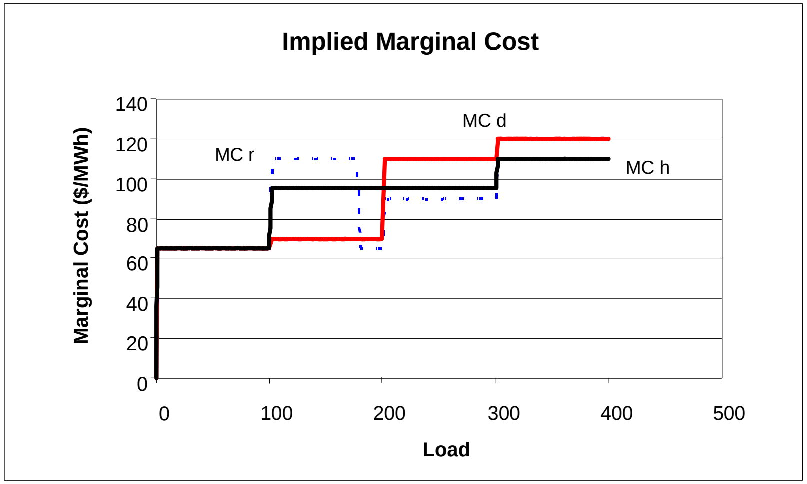
Selecting the appropriate approximation model for defining energy and uplift prices involves practical tradeoffs. All involve "uplift" payments to guarantee payments for bid-based cost to participating bidders (generators and loads), to support the economic commitment and dispatch.

Uplift with Given Energy Prices=Optimal Profit – Actual Profit

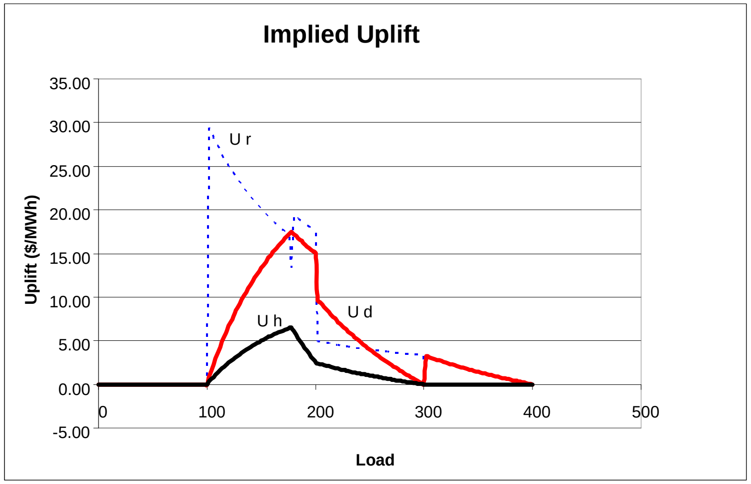
- **Restricted Model (r)**
    - Fix the unit commitment at the optimal solution.
    - Determine energy prices from the convex economic dispatch.
- **Dispatchable Model (d)**
    - Relax the discrete constraints and treat commitment decisions as continuous.
    - Determine energy prices from the relaxed, continuous, convex model.
- **Extended Locational Marginal Pricing (ELMP) Model (h)**
    - Equivalent formulations
        - Select the energy prices from the convex hull of the cost function.
        - Select the energy prices from the Lagrangean relaxation (i.e., usual dual problem for pricing the joint constraints).
    - Resulting energy prices minimize the total uplift.

Comparing illustrative energy pricing and uplift models. (Gribik et al., 2007)

Comparison of Example Marginal Costs



Comparison of Example Uplift Costs



Both the relaxed dispatchable and ELMP models produce a "standard" implied supply curve. The ELMP model produces the minimum uplift.

Alternative pricing models have different features and raise additional questions.

- **Computational Requirements.** Dispatchable model is the easiest case, ELMP model the hardest. But not likely to be a significant issue. Approximate solutions (e.g., NYISO model) may be workable.

- **Network Application.** All models compatible with network pricing and reduce to standard LMP in the convex case.

- **Operating Reserve Demand.** All models compatible with existing and proposed operating reserve demand curves.

- **Solution Independence.** Restricted model sensitive to actual commitment. Relaxed and ELMP models (largely) independent of actual commitment and dispatch.

- **Financial Transmission Rights.** Transmission revenue collected under the market clearing solution would be sufficient to meet the obligations under the FTRs. However, this may not be true for the revenues under the economic dispatch, which is not a market clearing solution at the ELMP prices, even though the FTRs are simultaneously feasible. The FTR uplift amount included in the decomposition of the total uplift that is minimized by the ELMP prices. This uplift payment would be enough to ensure revenue adequacy of FTRs under ELMP pricing.[1]

- **Day-ahead and real-time interaction.** With uncertainty in real-time and virtual bids, expected real-time price is important, and may be similar under all pricing models.

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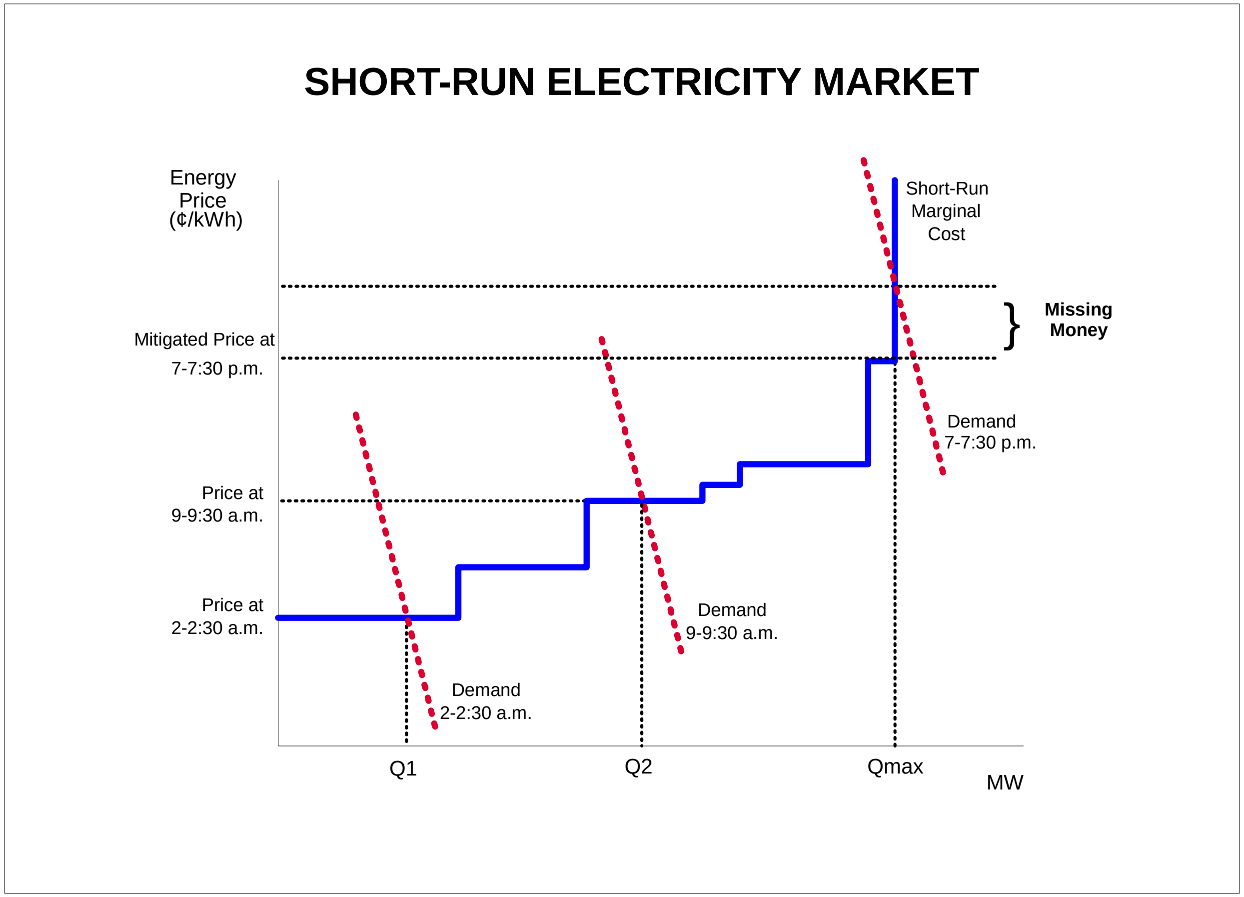
1 (Cadwalader, Gribik, Hogan, & Pope, 2010), “Extended LMP and Financial Transmission Rights.”

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. (Joskow, 2008)



Different Regions have taken different approaches to achieving resource adequacy.

Administrative and Market-based Constructs for Resource Adequacy

	Administrative Mechanisms (Customers Bear Most Risk)			**Market-based Mechanisms (Suppliers Bear Most Risk)**		
	Regulated Utilities	Administrative Contracting	Capacity Payments	LSE RA Requirement	Capacity Markets	Energy-Only Markets
Examples	SPP, BC Hydro, most of WECC and SERC	Ontario	Spain, South America	California, MISO (both also have regulated IRP)	PJM, NYISO, ISO-NE, Brazil, Italy, Russia	ERCOT, Alberta, Australia's NEM, Scandinavia
Resource Adequacy Requirement?	Yes (Utility IRP)	Yes (Administrative IRP)	Yes (Rules for Payment Size and Eligibility)	Yes (Creates Bilateral Capacity Market)	Yes (Mandatory Capacity Auction)	No (Resource Adequacy not Assured)
How are Capital Costs Recovered?	Rate Recovery	Energy Market plus Administrative Contracts	Energy Market plus Capacity Payments	Bilateral Capacity Payments plus Energy Market	Capacity plus Energy Markets	Energy Market

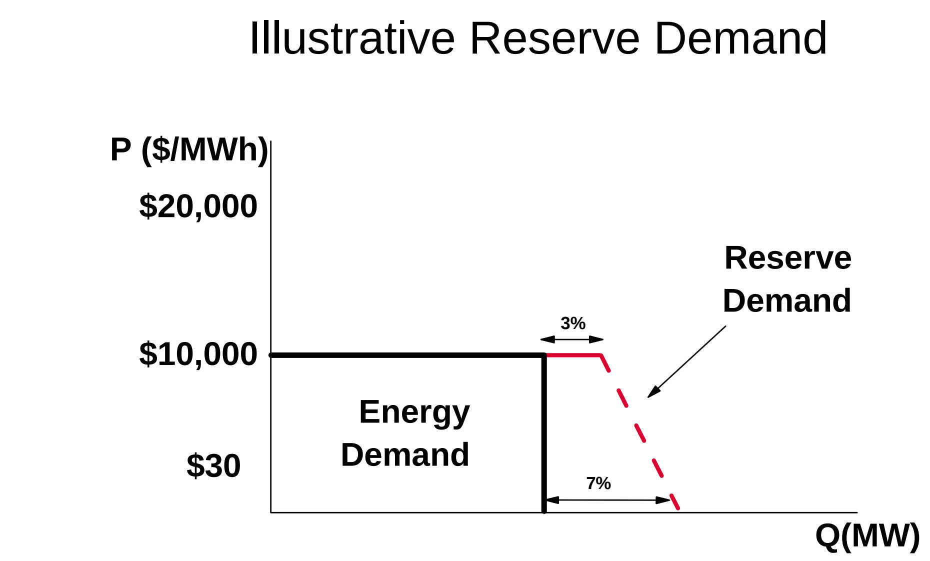
Notes: For a more detailed discussion of these various approaches to resource adequacy see Pfeifenberger, et al. (2009).
Several markets have a mix of regulated and market constructs within their borders and so are not perfectly represented under any one of these categories. For example, MISO's footprint contains predominantly regulated utilities that conduct integrated resource planning, but a resource adequacy requirement is imposed on all LSEs, which include both regulated utilities and competitive suppliers. MISO will also conduct short-term backstop capacity auctions starting 2013/14.

(Spees, Newell, & Pfeifenberger, 2013, p. 4)

The expansion of subsidy systems has implications for electricity market design.

> “The most market-oriented solution with the greatest transparency, simplicity, and, perhaps, efficiency would be to transition over time to an energy-only market. Assuming the scarcity pricing level is set at the appropriate level (the value of lost load), it addresses the “missing money” problem and eliminates the need for a capacity market. But I recognize that it would be a big step for a wholesale market operator to propose an energy-only market – only ERCOT has adopted this design – and that some may be concerned about the politics of scarcity pricing. The trade-off for critics concerned about costs, however, is that there would not be a capacity market. A decade ago, in the aftermath of the Western Power Crisis, there would have been little appetite for an energy-only market. Now, however, the wholesale market operators, market monitors, and FERC do much better market monitoring, FERC has an anti-manipulation authority, and natural gas is abundant and low priced, so there should be less price volatility in most regions.” (Commissioner Norman Bay concurrence) (FERC, 2017, p. 7)

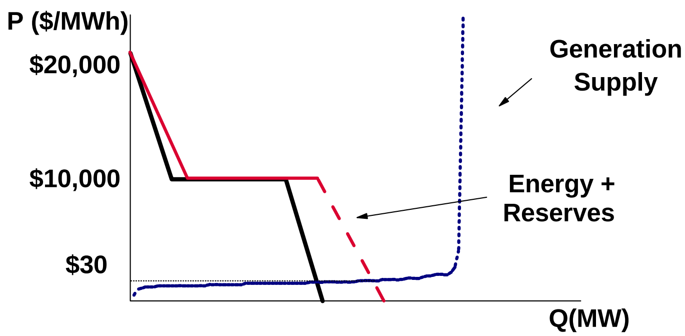
Operating reserve demand curve would reflect capacity scarcity.



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.

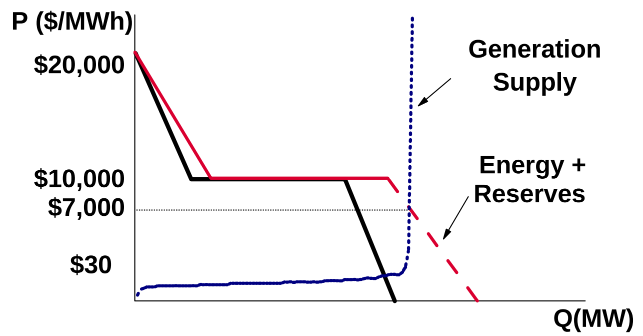
Market clearing addresses the “missing money” that results from inadequate scarcity pricing.

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



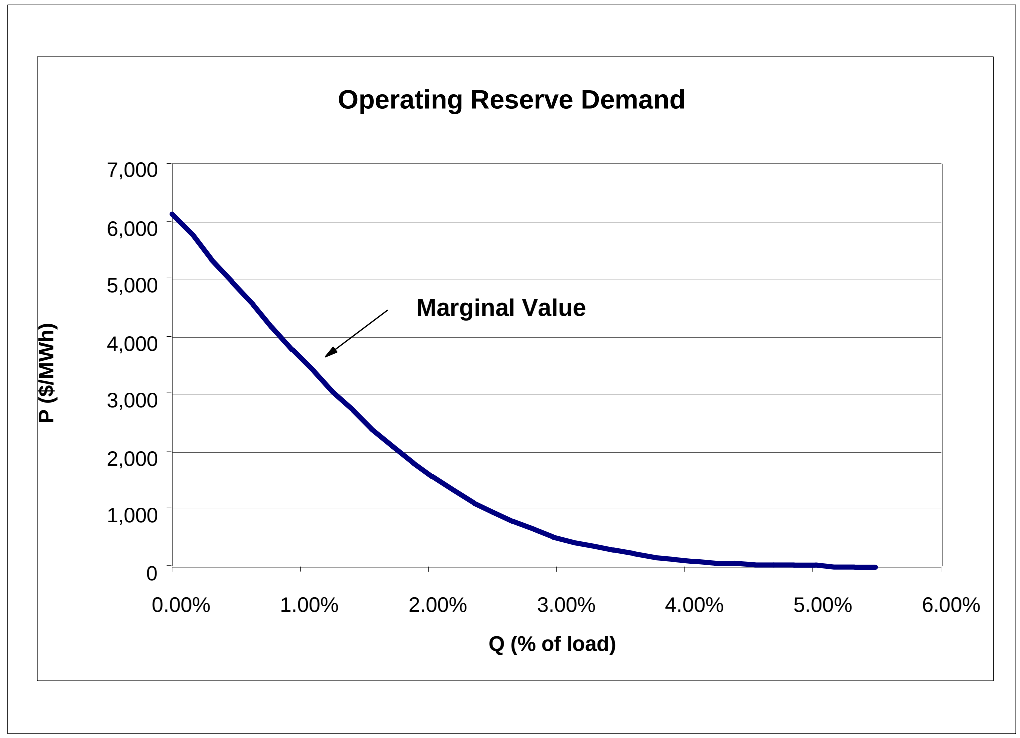
When demand is high and reserve reductions apply, there is a high price.

Operating reserve demand is a complement to energy demand for electricity. The probabilistic demand for operating reserves reflects the cost and probability of lost load.[2]

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.



[2] "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.

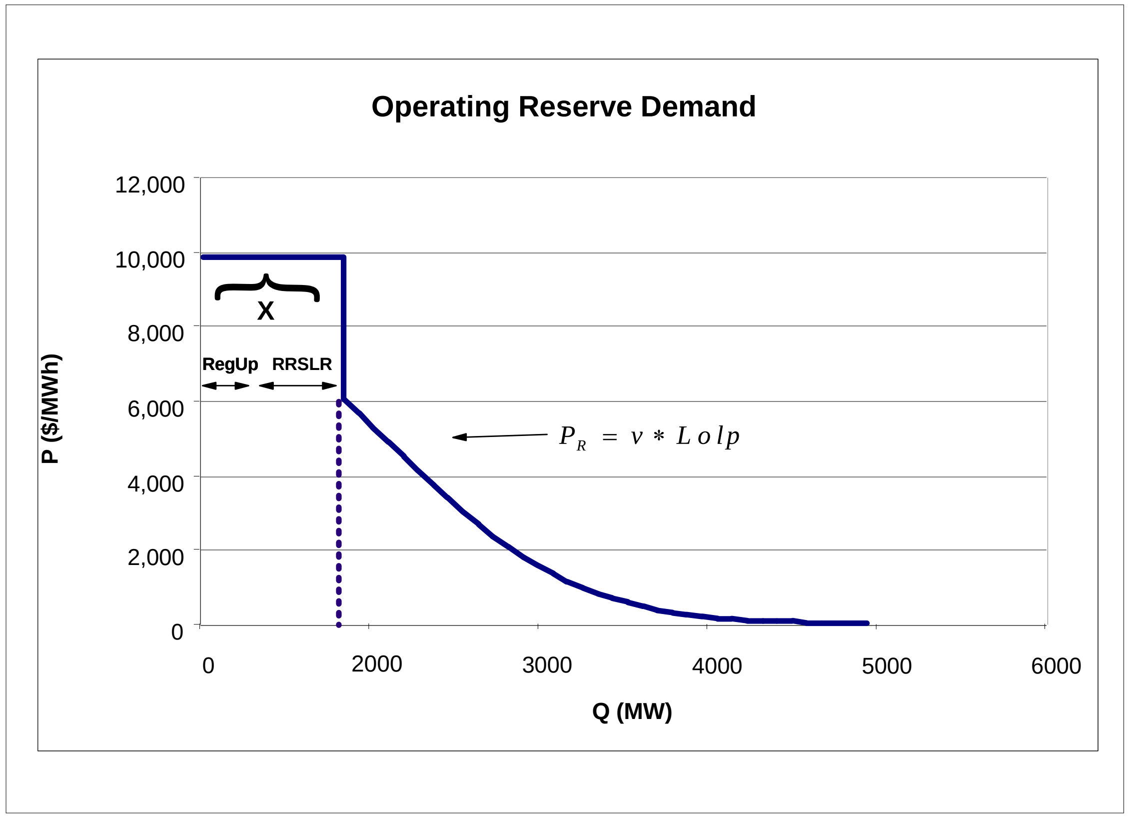
The deterministic approach to security constrained economic dispatch includes lower bounds on the required reserve to ensure that for a set of monitored contingencies (e.g., an n-1 standard) there is sufficient operating reserve to maintain the system for an emergency period.

Suppose that the maximum generation outage contingency quantity is r_{Min}. Then we would have the constraint:

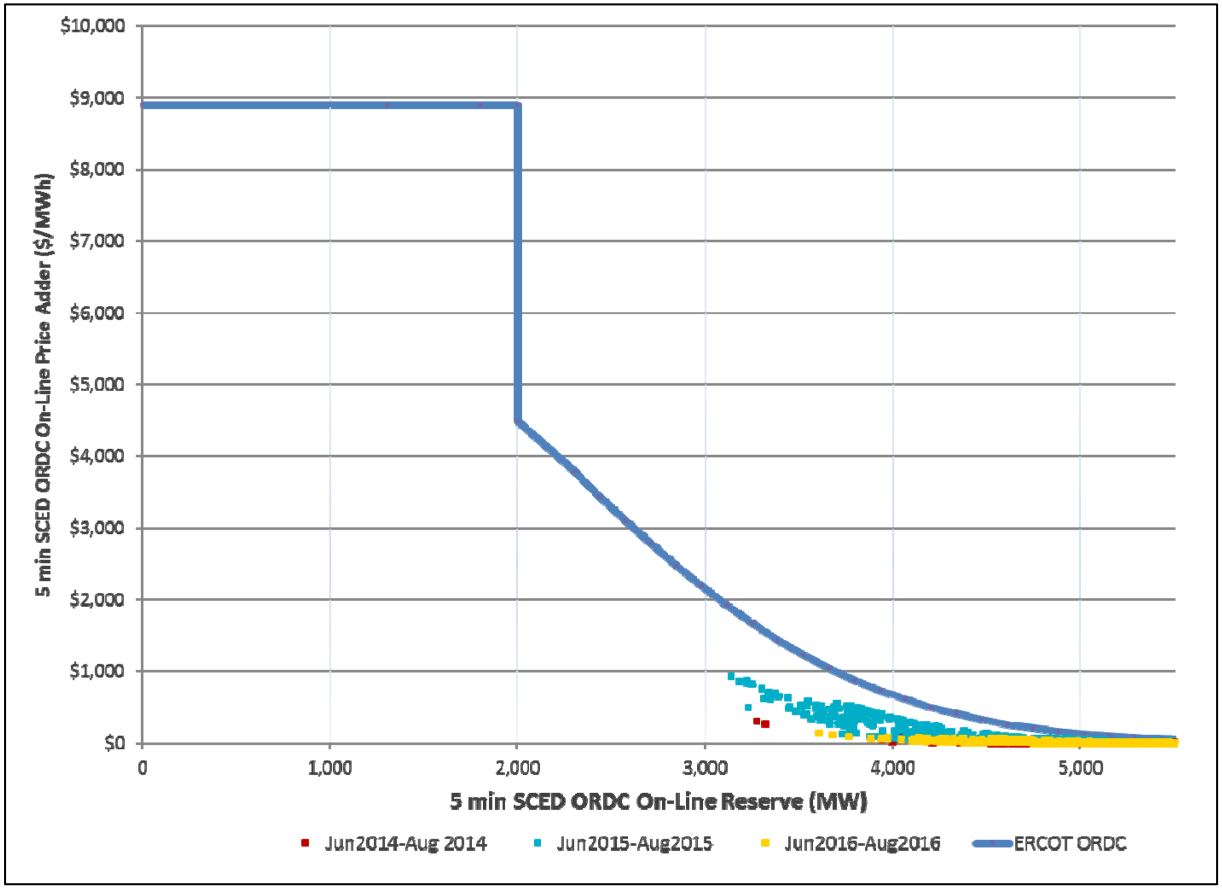
$$r \geq r_{Min}.$$

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.



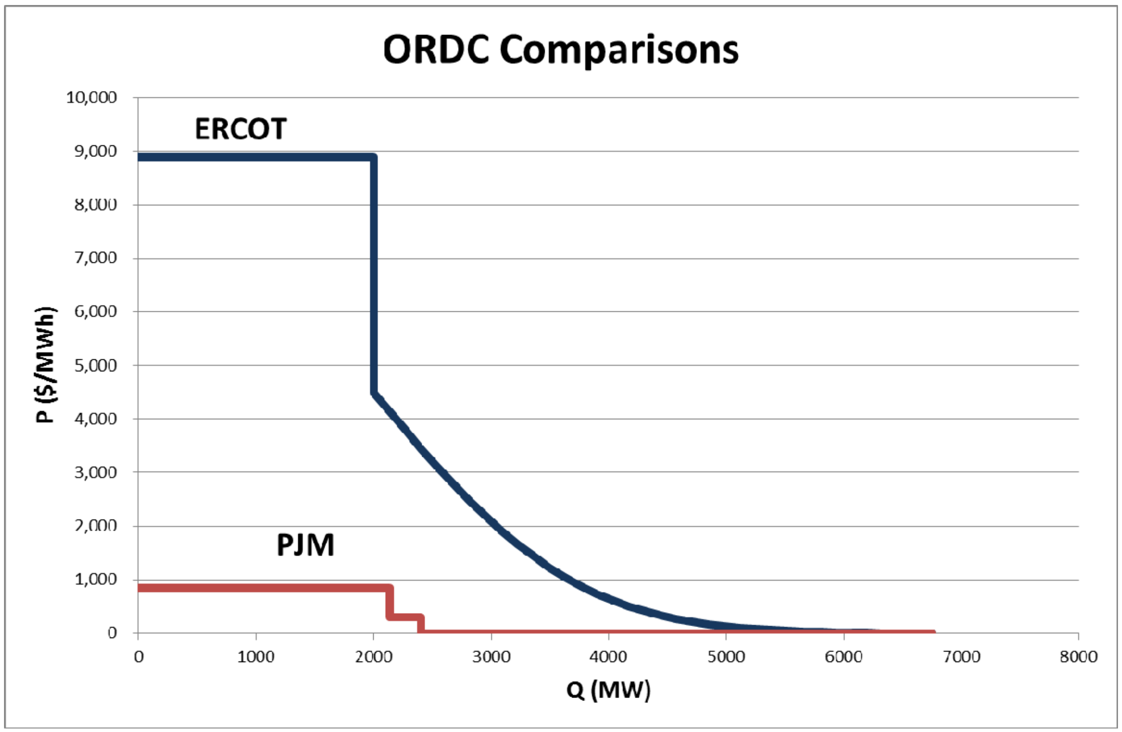
ERCOT launched implementation of the ORDC in in 2014. The summer peak is the most important period. The first three years results showed high availability of reserves and low reserve prices.



Source: Resmi Surendran, ERCOT, EUCI Presentation, April 10, 2017. The ORDC is illustrative. See also (Hogan & Pope, 2017)

Other RTOs have long used ORDCs, but without building the design on basic principles.

- **Limited to Declared Shortage Conditions.** "The ORDCs PJM currently utilizes were designed under the assumption that shortage pricing would only occur during emergency operating conditions and therefore the curves are a step function." (PJM and SPP, "Joint Comments Of PJM Interconnection, L.L.C And Southwest Power Pool, Inc. Addressing Shortage Pricing," FERC Docket No. RM15-24-000, November 30, 2015.)
- **Based on the Cost of Supply, not the Value of Demand.** "[T]he $300/MWh price is appropriate for reserves on the second step of the proposed ORDC based on an internal analysis of offer data for resources that are likely to be called on to provide reserves in the Operating Day." (PJM, Proposed Tariff Revisions of PJM Interconnection, L.L.C., Docket No. ER15-643-000, December 17, 2014)



Simulations for ERCOT market illustrate the connection between the missing money and reliability standards. The Texas PUC adopted the economic equilibrium approach. (Anderson, 2017)

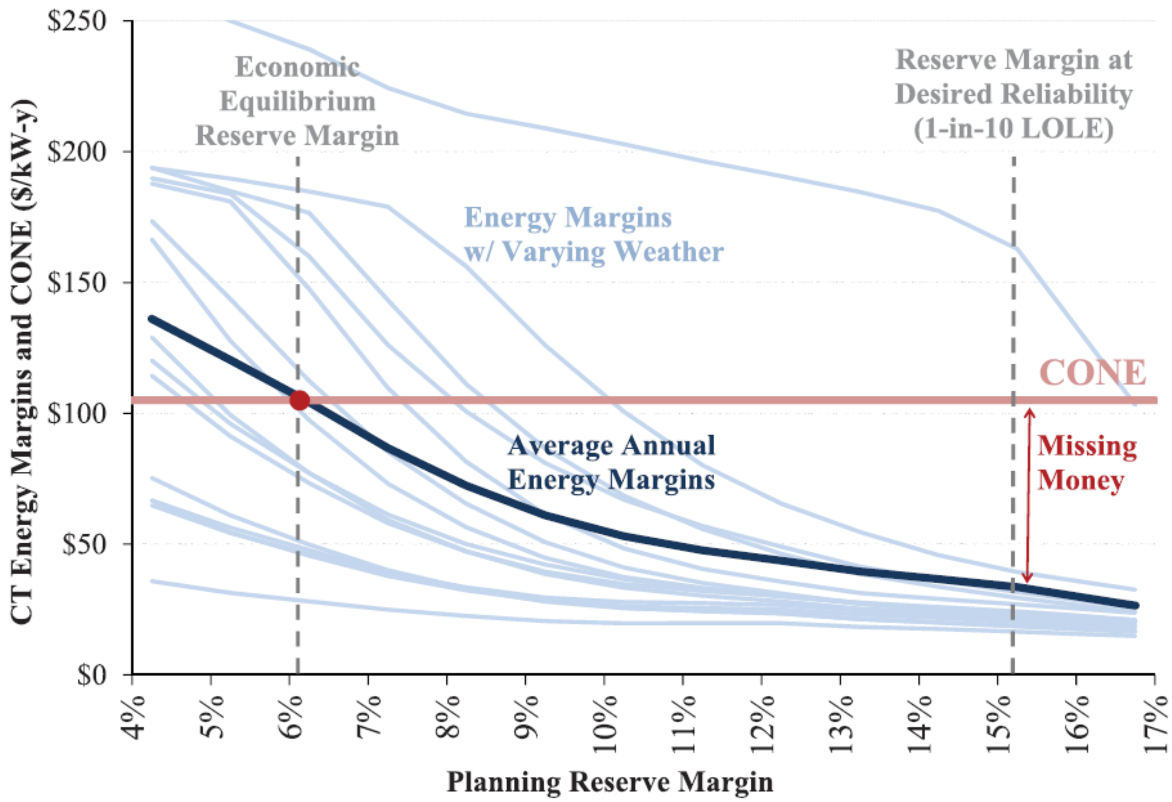


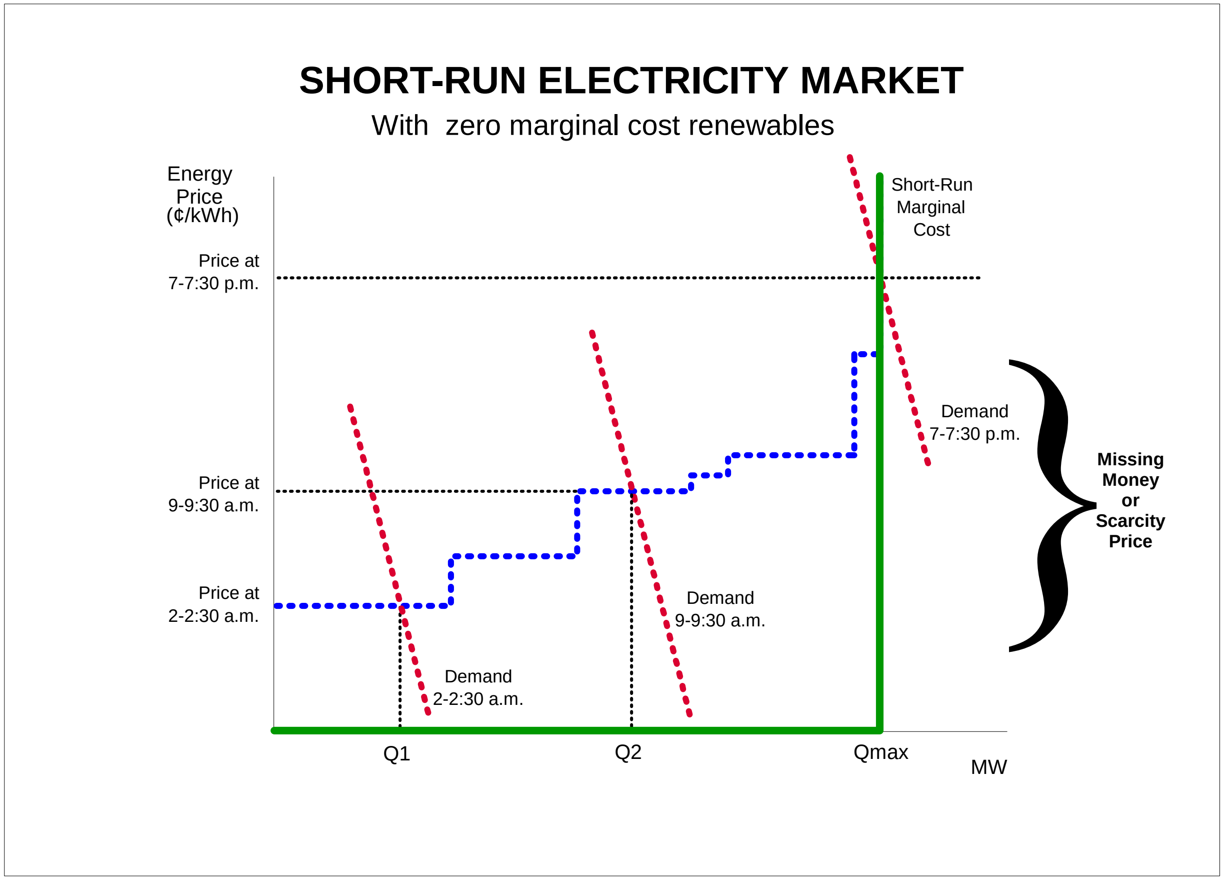
FIGURE 1
Equilibrium Reserve Margin and Missing Money in ERCOT's Energy-Only Market

(Spees et al., 2013, p. 7) See also (Telson, 1973) (Wilson, 2010)

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

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

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.

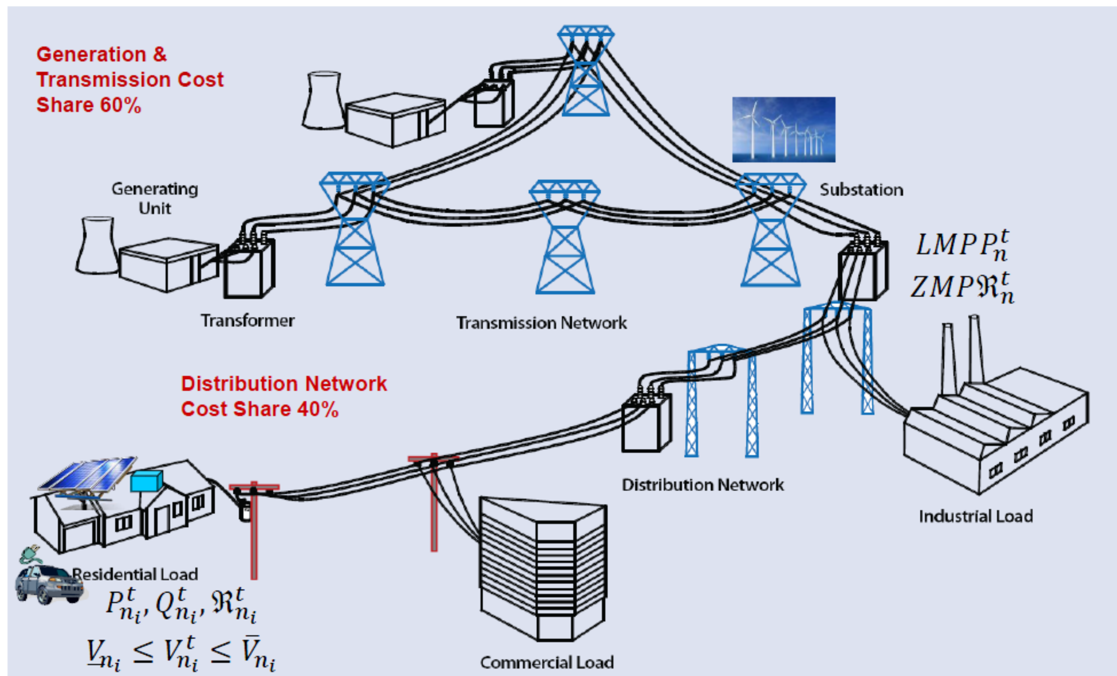


The integration of flexible distributed energy resources presents challenges and opportunities for "Reforming the Energy Vision."

"Drawing from an exhaustive analysis of trends in technology, markets, and environmental policy, the Commission has concluded that its core statutory duties can no longer be met with the utility regulatory model of the previous century. … The ratemaking changes adopted in this order add to other actions taken by the State and by this Commission under REV to enable the growth of a retail market and a modernized power system that is increasingly clean, efficient, transactive and adaptable to integrating and optimizing resources in front of and behind the meter." (New York Public Utilities Commission, 2016)

"Choose the core electric products to be transacted on the financial digital platform. The paper presents a rationale for choosing real energy (real power), reactive power, and reserves." (Tabors, Parker, Centolella, & Caramanis, 2016)

Incurred Cost Distribution, Congestion, Reserves, Voltage Control, Losses, Transformers, Deliverability



$LMPP_n^t = \Pi_n^{E,t}$ = Locational Marginal Price of Real Power at bus n, during hour t

$ZMP\Re_n^t = \Pi_n^{\Re,t}$ = Locational Zonal Price of Reserves at bus n $\in$ zone Z, during hour t

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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).