ELECTRICITY MARKET DESIGN
INTERACTIONS OF MULTIPLE MARKETS

William W. Hogan

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

The Future of Power Markets in a Low Marginal Cost World
Resources for the Future-National Renewable Energy Laboratory Workshop
Washington, DC
September 14, 2017
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 original arguments for greater reliance on markets emphasized the effects of non-utility generators and the reduction or elimination of the conditions for natural monopoly in generation.
The solution to open access and non-discrimination inherently involves market design. Good design begins with the real-time market, and works backward. A common failure mode starts with the forward market, without specifying the rules and prices that would apply in real time.

Market expectations determine incentives. Start at the end. Work backward, not forward, in setting 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.
ELECTRICITY MARKET

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. (Schwepp, 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.

Price of "Transmission" from A to B = Pb - Pa = 15
Price of "Transmission" from C to A = Pa - Pc = -4
The spot price in an electricity market can be highly volatile. A contract for differences offers a simple financial contract that replicates a fixed price contract. The seller sells to the pool. The buyer buys from the pool. The CFD provides a means to replicate a bilateral transaction.
SPOT MARKET

Volatile Spot Prices

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

Price of "Transmission" from C to B = Pb - Pc = Volatile Price
A mechanism for hedging volatile transmission prices can be established by defining financial transmission rights to collect the congestion rents inherent in efficient, short-run spot prices.

**NETWORK TRANSMISSION FINANCIAL RIGHTS**

- **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.**

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

\[\begin{align*}
Pa &= 51 \\
Pc &= 55 \\
Pb &= 66 \\
\end{align*}\]
NETWORK INTERACTIONS

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

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

The Last Should Be First

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.

- **Financial Transmission Rights**: Coordinated auctions allocate and reallocate feasible sets of financial transmission rights. Simultaneously feasible sets within the constraints of the actual dispatch system ensure revenue adequacy.

- **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.
The basic economic dispatch formulation stands at the core of electricity market design and implementation. Under certain conditions, the solution is a market equilibrium.

- **Deterministic**
  - Real-time spot market for physical dispatch and balancing settlements.
  - Day-ahead dispatch and scheduling.

- **Continuous convex economic dispatch**
  - Electric power systems are almost convex, and use convex approximations for dispatch. (Lavaei & Low, 2012),
  - System marginal costs provide locational, market-clearing, linear prices.
  - Linear prices support the economic dispatch.
  - Locational prices provide foundation for financial transmission right (FTRs).

- **Security conditions**
  - Contingency constraints.
  - Operating reserves.

- **Competitive assumption for market design**
  - Price-taking behavior by market participants.
  - Bid-based, security constrained, economic dispatch.
  - Market power mitigation with consistent offer caps.
ELECTRICITY MARKET

The expected value of the real-time dispatch can differ from the day-ahead dispatch.

Notified bilateral trades pay locational transmission charge but are settled outside pool.
Other trades settle at day-ahead price.
Locational congestion rents paid to transmission right holders along with excess congestion costs.

Payments for deviations from day-ahead trades at spot price for all transactions.
Uplift covers ancillary services and other costs.
Excess congestion costs paid to holders of transmission rights.

Spot Price Applies to Deviations from Scheduled Quantities
ELECTRICITY MARKET Pricing Challenges

The hourly average prices capture very little of the total real-time price variation.

Newark Bay Real-Time LMP, Days in Feb. 2013

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

**Day-Ahead Price Equilibrium**

\[
\begin{align*}
P_A & \quad -K \leq \text{Flow} \leq K \\
A & \quad \text{B}
\end{align*}
\]

**Expected Values**

\[
\begin{align*}
E(P_A) &= P_A \\
E(\mu_{ab}) &= 0.5(P_B^H - P_A) \\
E(\mu_{ba}) &= 0.5(P_B^{lo} - P_B^l) \\
E(P_B) &= 0.5(P_B^{lo} + P_B^H) > P_A \\
E(\text{Flow}) &= 0.5(K) + 0.5(-K) = 0
\end{align*}
\]

**Day-Ahead Dispatch**

\[
\begin{align*}
P_{DA}^A &= P_A \\
P_{DA}^B &= E(P_B) \\
\mu_{DA} &= E(P_B) - P_A < E(\mu_{ab}) \\
\mu_{ba} &= 0 < E(\mu_{ba}) \\
\text{Flow}_{DA} &= K
\end{align*}
\]

\[\mu: \text{Constraint Shadow Price} \quad \pi: \text{Scenario Probability}\]
ELECTRICITY MARKET

Day-Ahead Commitments

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

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

Scheduling Transactions

Generators & Customers

Start up Costs +

Schedules
Schedule Bids
Reliability Commitments
Balancing Bids

Settlements

Scheduling Settlements P, Q, T
Locational P, Q

Dispatch Commitments Q

Financial Transmission Rights

Excess Congestion $

Contract $

Imbalance $

Excess Congestion $

Balancing Transactions

Scheduling Transactions

Balancing Bids
Reliability Commitments

Balancing Settlements p, q, Q
Locational p, q

Locational P, Q

kWh $

kWh $

kWh $

MW €

MW €

MW €

Reliability Commitments

Schedule Bids

Schedules

MW €

MW €

MW €

MW €
ELECTRICITY MARKET

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 $y$ as formulated in (Gribik, Hogan, & Pope, 2007):

<table>
<thead>
<tr>
<th>Constants:</th>
<th>Variables:</th>
</tr>
</thead>
<tbody>
<tr>
<td>$y_t = \text{vector of nodal loads in period } t$</td>
<td>$\text{start}_i = \begin{cases} 0 &amp; \text{if unit } i \text{ is not started in period } t \ 1 &amp; \text{if unit } i \text{ is started in period } t \end{cases}$</td>
</tr>
<tr>
<td>$m_{it} = \text{minimum output from unit } i \text{ in period } t$</td>
<td>$\text{on}_i = \begin{cases} 0 &amp; \text{if unit } i \text{ is off in period } t \ 1 &amp; \text{if unit } i \text{ is on in period } t \end{cases}$</td>
</tr>
<tr>
<td>$M_{it} = \text{maximum output from unit } i \text{ in period } t$</td>
<td>$g_{it} = \text{output of unit } i \text{ in period } t$</td>
</tr>
<tr>
<td>$\text{ramp}_{it} = \text{maximum ramp from unit } i \text{ between period } t-1 \text{ and period } t$</td>
<td>$d_t = \text{vector of nodal demands in period } t$</td>
</tr>
<tr>
<td>$\text{StartCost}_{it} = \text{Cost to start unit } i \text{ in period } t$</td>
<td></td>
</tr>
<tr>
<td>$\text{NoLoad}_{it} = \text{No load cost for unit } i \text{ in period } t$</td>
<td></td>
</tr>
<tr>
<td>$F_{kt}^{\max} = \text{Maximum flow on transmission constraint } k \text{ in period } t$</td>
<td></td>
</tr>
</tbody>
</table>

$$v(y_t) = \inf_{g_t, d_t, \text{on}, \text{start}} \sum_t \sum_i (\text{StartCost}_{it} \cdot \text{start}_i + \text{NoLoad}_{it} \cdot \text{on}_i + \text{GenCost}_{it}(g_{it}))$$

subject to

$m_{it} \cdot \text{on}_i \leq g_{it} \leq M_{it} \cdot \text{on}_i$ $\forall i, t$

$-\text{ramp}_{it} \leq g_{it} - g_{i,t-1} \leq \text{ramp}_{it}$ $\forall i, t$

$\text{start}_i \leq \text{on}_i \leq \text{start}_i + \text{on}_{i,t-1}$ $\forall i, t$

$\text{start}_i = 0$ or $1$ $\forall i, t$

$\text{on}_i = 0$ or $1$ $\forall i, t$

$e^T(g_t - d_t) - \text{LossFn}_t(d_t - g_t) = 0$ $\forall t$

$\text{Flow}_{kt}(g_t - d_t) \leq F_{kt}^{\max}$ $\forall k, t$

$d_t = y_t$ $\forall t.$
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.
Both the relaxed dispatchable and ELMP models produce a “standard” implied supply curve. The ELMP model produces the minimum uplift.
**ELECTRICITY MARKET**

**Energy Pricing and 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.

---

\(^1\) (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)
ELECTRICITY MARKET

Resource Adequacy

Different Regions have taken different approaches to achieving resource adequacy.

<table>
<thead>
<tr>
<th>Administrative Mechanisms (Customers Bear Most Risk)</th>
<th>Market-based Mechanisms (Suppliers Bear Most Risk)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulated Utilities</td>
<td>LSE RA Requirement</td>
</tr>
<tr>
<td>Administrative Contracting</td>
<td>Capacity Markets</td>
</tr>
<tr>
<td>Capacity Payments</td>
<td>California, MISO (both also have regulated IRP)</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>Examples</td>
<td></td>
</tr>
<tr>
<td>SPP, BC Hydro, most of WECC and SERC</td>
<td>Ontario</td>
</tr>
<tr>
<td>Yes (Utility IRP)</td>
<td>Yes (Administrative IRP)</td>
</tr>
<tr>
<td>Yes (IRP)</td>
<td>Yes (IRP)</td>
</tr>
<tr>
<td>Resource Adequacy Requirement?</td>
<td>How are Capital Costs Recovered?</td>
</tr>
<tr>
<td>Rate Recovery</td>
<td>Energy Market plus Administrative Contracts</td>
</tr>
<tr>
<td>Energy Market plus Capacity Payments</td>
<td>Bilateral Capacity Payments plus Energy Market</td>
</tr>
<tr>
<td>Capacity plus Energy Markets</td>
<td>Energy Market</td>
</tr>
</tbody>
</table>

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 backup capacity auctions starting 2013/14.

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

Capacity market “demand” is more about the supply of capacity and the reliability requirements. This PJM RPM model dropped the term “demand” and refers to the variable revenue requirement (VRR). (PJM Manual 18: PJM Capacity Market Revision: 15 Effective Date: June 28, 2012, pp. 19-21.)

Exhibit 1: Illustrative Example of a Variable Resource Requirement Curve
ELECTRICITY MARKET Capacity Market Demand Curves

The variety of “demand curves” for capacity for different RTOs show similar approaches that have more to do with supply than with demand.

(Spees et al., 2013, p. 12)
ELECTRICITY MARKET Capacity Market Performance

Capacity markets have many problems, such as non-performance when capacity has not been available when needed. The ISONE pay-for-performance reform addresses many of the problems of the forward capacity market, but not all. But the stakeholder process of discussion and final regulatory decision takes a long time, and the capacity market solutions can create new problems.


The pay for performance incentive mechanisms will begin taking effect June 1 2018.

PJM called for “pseudo-ties” to ensure real-time capacity delivery: “One of the primary benefits of locational marginal pricing ("LMP") in energy markets is the ability to efficiently and reliably manage network congestion through the commitment and dispatch processes. This is achieved because the RTO can optimize the output of each resource that affects the flow over a transmission constraint positively or negatively. Not only does this reduce costs for an RTO’s customers, it also ensures system reliability. Pseudo-ties are fundamentally inconsistent with this foundational principle underlying competitive electricity markets…” (Potomac Economics, 2017)
ELECTRICITY MARKET  
Capacity Market Performance

The capacity performance proposals address some of the problems of market design, but do not fully address the critical issue. For example, consider the ISONE testimony:

“The motivation for the capacity market is to address a demand-side flaw, the absence of demand response. This causes the energy price to be set too low during periods of scarcity, creating missing money. One could restore the missing money with an “energy only” design by setting a high scarcity price during hours of reserve shortage. The scarcity price would be set in the ISO Tariff to induce the desired level of reliability. The PFP design in the FCM works in the same way as the “energy only” design, but with a forward contracting model that addresses several problems of the “energy only” design. Specifically, the forward contracting coordinates investment at the desired reliability level, reduces payment risk for both consumers and generators, and mitigates market power in the energy market during periods of scarcity.”


Is it true?

“The PFP design in the FCM works in the same way as the “energy only” design.”

Not if prices facing the demand-side do not reflect the true scarcity conditions. Forward contracting could hedge the prices on average, but need not hedge prices on the margin. This choice is not available to participants in PJM or ISONE. The “performance prices” are restricted to transfers among generators.

Neither PJM nor ISONE make the logical connection between the analysis of the real-time pricing problem and the prescription of a solution.
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 sensitive.
ELECTRICITY MARKET

Generation Resource Adequacy

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.
ELECTRICITY MARKET

Operating Reserve Demand

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 $r_{\text{Min}}$. Then we would have the constraint:

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

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 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)

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

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.
ELECTRICITY MARKET  

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

(IRC Council and CAISO maps)
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)
References