ELECTRICITY MARKET DESIGN
ENERGY AND CAPACITY MARKETS
AND RESOURCE ADEQUACY

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Capacity Markets: Gauging Their Real Impact on Resource Development and Reliability

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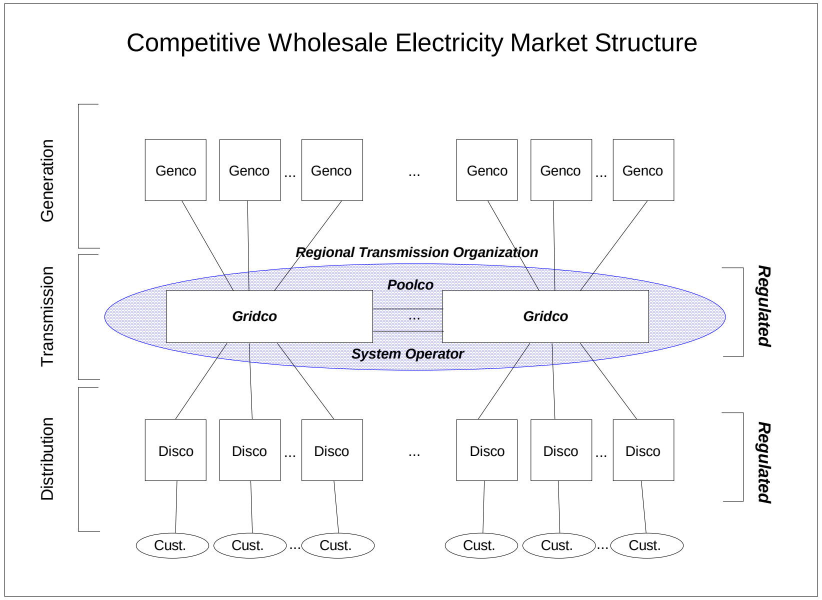
The U.S. experience illustrates successful market design and remaining challenges for both theory and implementation.

- **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.

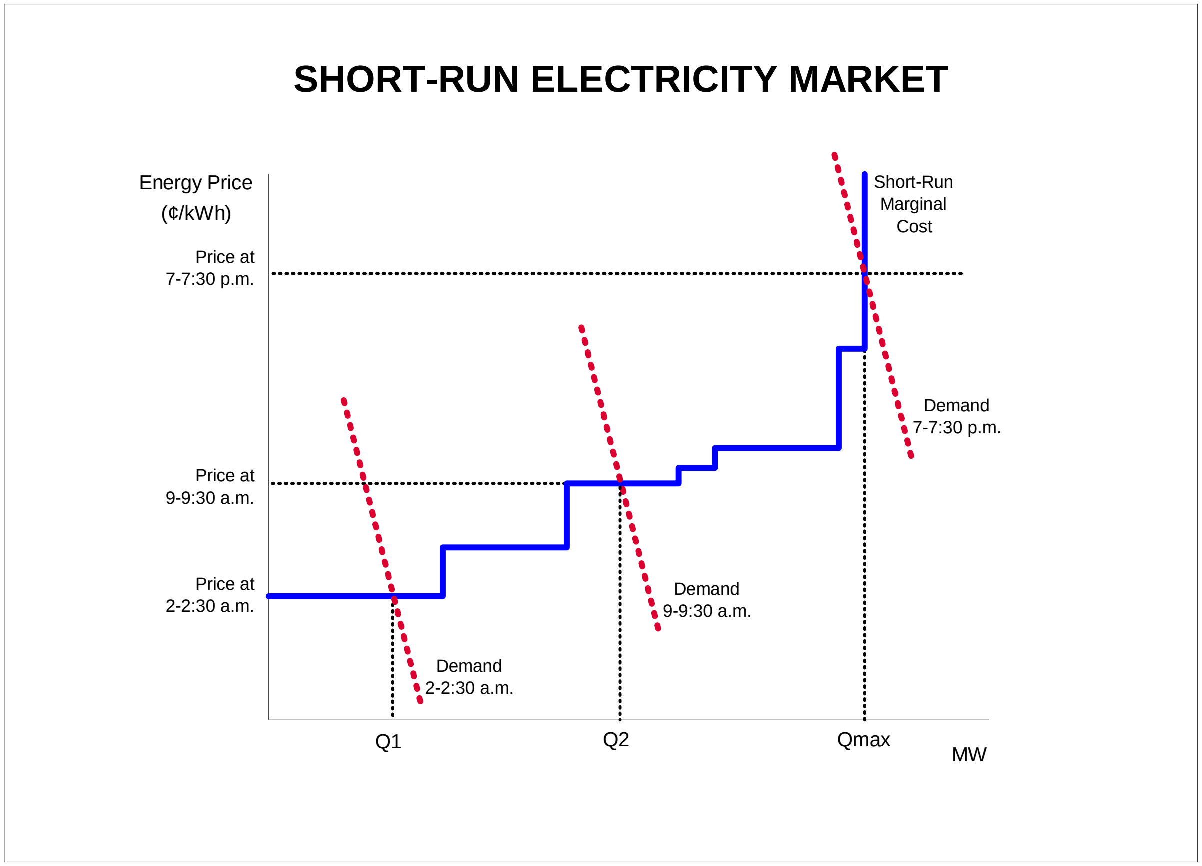
  Unit commitment and lumpy decisions with coordination, bid guarantees and uplift payments.

- **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.

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.



Energy and capacity markets interact to support investment in and availability of infrastructure to provide reliable service.

- **Energy Only Markets.** In principle an "energy only" market could provide sufficient incentives to support resource adequacy.
- **Missing Money.** In practice, prices in energy markets have been found to be inadequate to meet resource adequacy objectives.
    - **Market Design Failures.** Implementation problems appear that collectively tend to suppress prices. A principal feature is inadequate scarcity pricing.
    - **Gaps Between Economic Reserve Levels and Planning Standards.** Economic analysis based on value of loss load produces a lower level of investment and reserves that the traditional planning standard.
- **Providing Resource Adequacy.** There are several approaches to address the gap.
    - **Market Design Reform.** A good idea that should be the first priority.
    - **Security Margin of Safety.** Recognize and define the economics of a security standard.
        - **Conservative Short-term Scarcity Pricing.** Addresses missing money and performance.
        - **Conservative Long-term Capacity Mechanisms.**
            - **Capacity Payments.** Administrative payments and penalty mechanisms.
            - **Capacity Markets.** Auction markets and administrative penalty mechanisms.

A promising direction 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."

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."[1]
- **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.

[1] Cervigni, G., & Perekhodtsev, D. (2013). Wholesale Electricity Markets. In P. Rinci & G. Cervigni (Eds.), *The Economics of Electricity Markets : Theory and Policy*. Edward Elgar, p. 53.

The purpose of *ex post* or dispatch-based pricing is to determine "prices consistent with the actual usage by applying the marginal tests of economic dispatch."[2] Examples include:

- **Ex Post LMP:** Utilize the actual dispatch to simplify the model for calculating consistent locational prices.
- **Scarcity Pricing and the Operating Reserve Demand Curve:** Price the scarcity of operating reserves and stimulate demand participation.
- **Demand Response:** Incorporate demand response in the pricing model to reflect scarcity conditions and avoid price reversals.
- **Reliability Unit Commitment:** Recognize reliability constraints in the dispatch and the pricing model.
- **Voltage Support:** Recognize operator actions for difficult to model problems in the economic dispatch by incorporating constraint approximations in the dispatch.
- **Extend Locational Marginal Pricing (ELMP):** Incorporate the effects of unit commitment, block loaded units, and other lumpy decisions in prices to minimize the related uplift charges.

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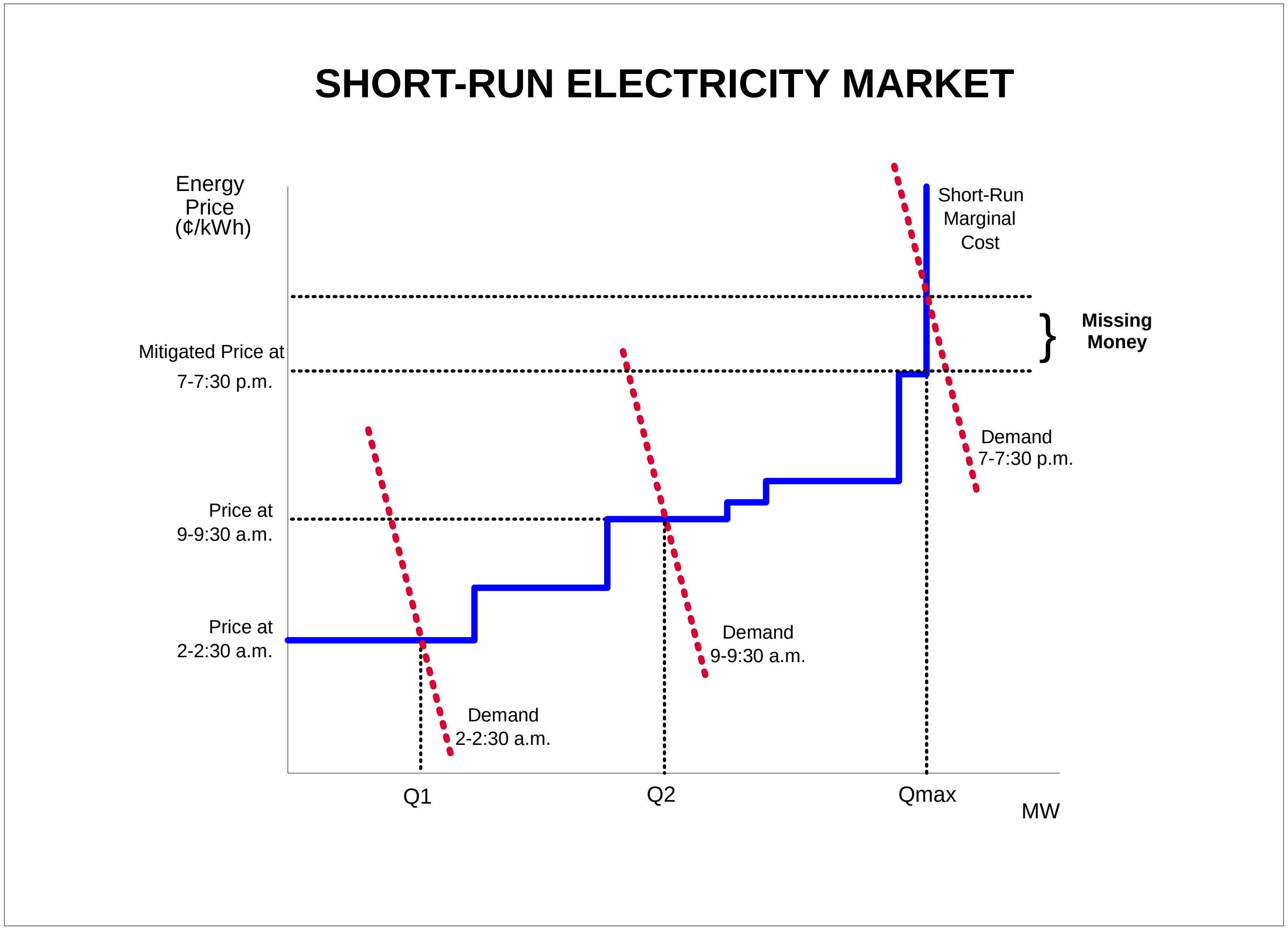
2 See W. Hogan, "Electricity Market Design and Efficient Pricing: Applications for New England and Beyond," June 24, 2014, at www.whogan.com.

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.[3]

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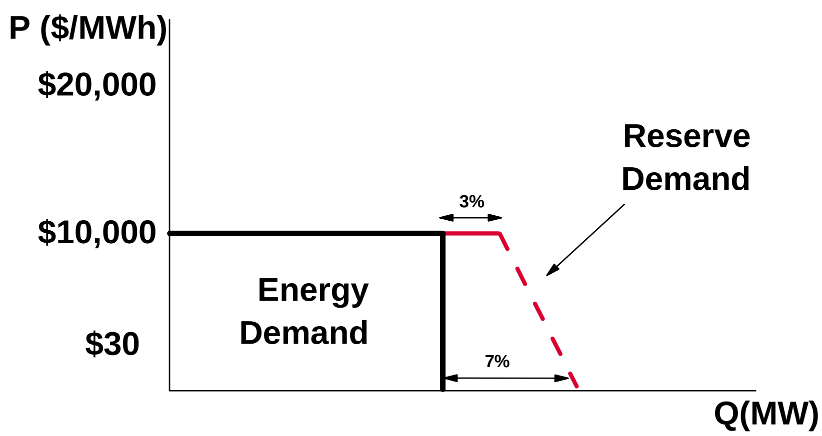
[3] FERC, Order 719, October 17, 2008.

Operating reserve demand curve would reflect capacity scarcity.

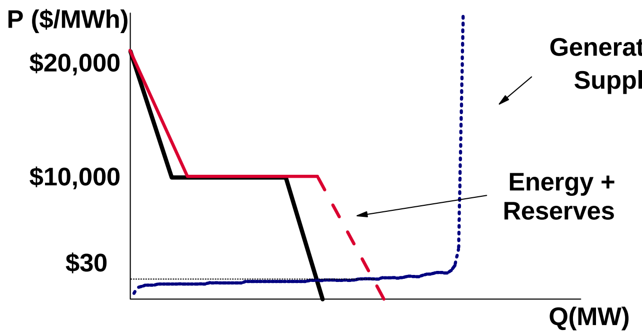
Illustrative Reserve Demand



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.

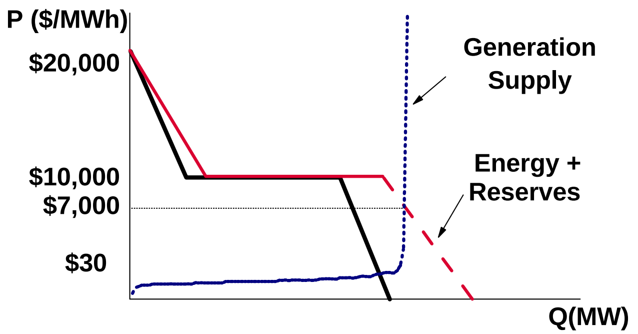
Market clearing addresses the "missing money."

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.

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.[4]
- **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.

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

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:

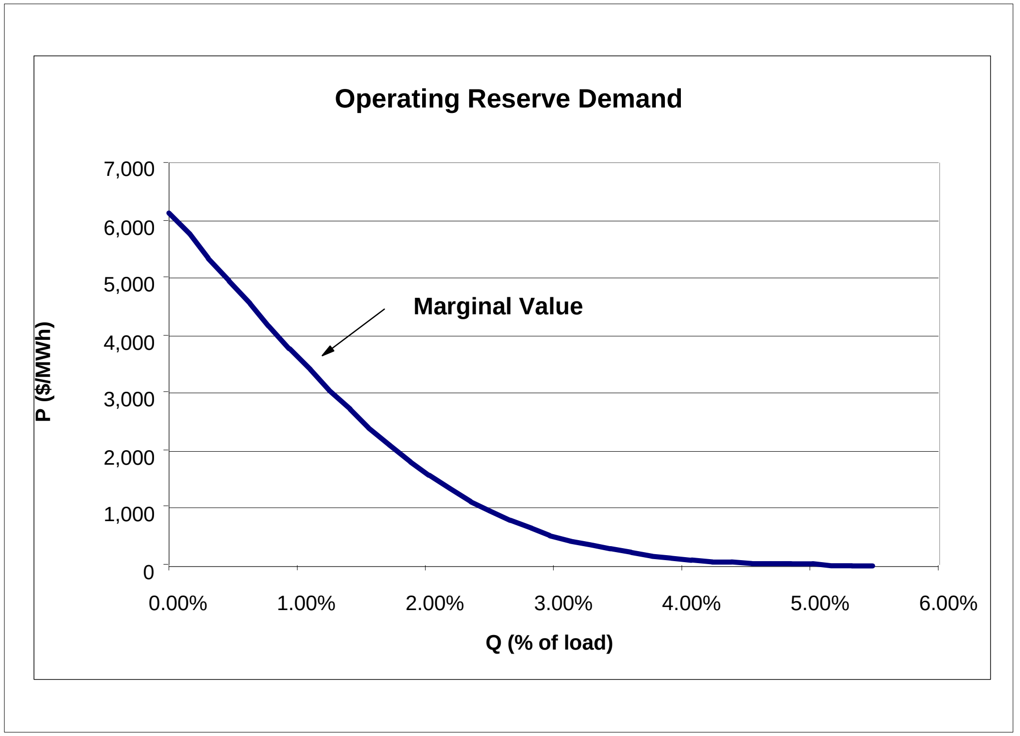
- Connecting to the value of loss load and other emergency actions.
- Including a representation of the uncertainty of net load changes and the loss of load probability.
- Integrating minimum contingency reserve requirements.
- Maintaining consistency between energy and reserve prices.
- Coordinating 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. [5]

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.

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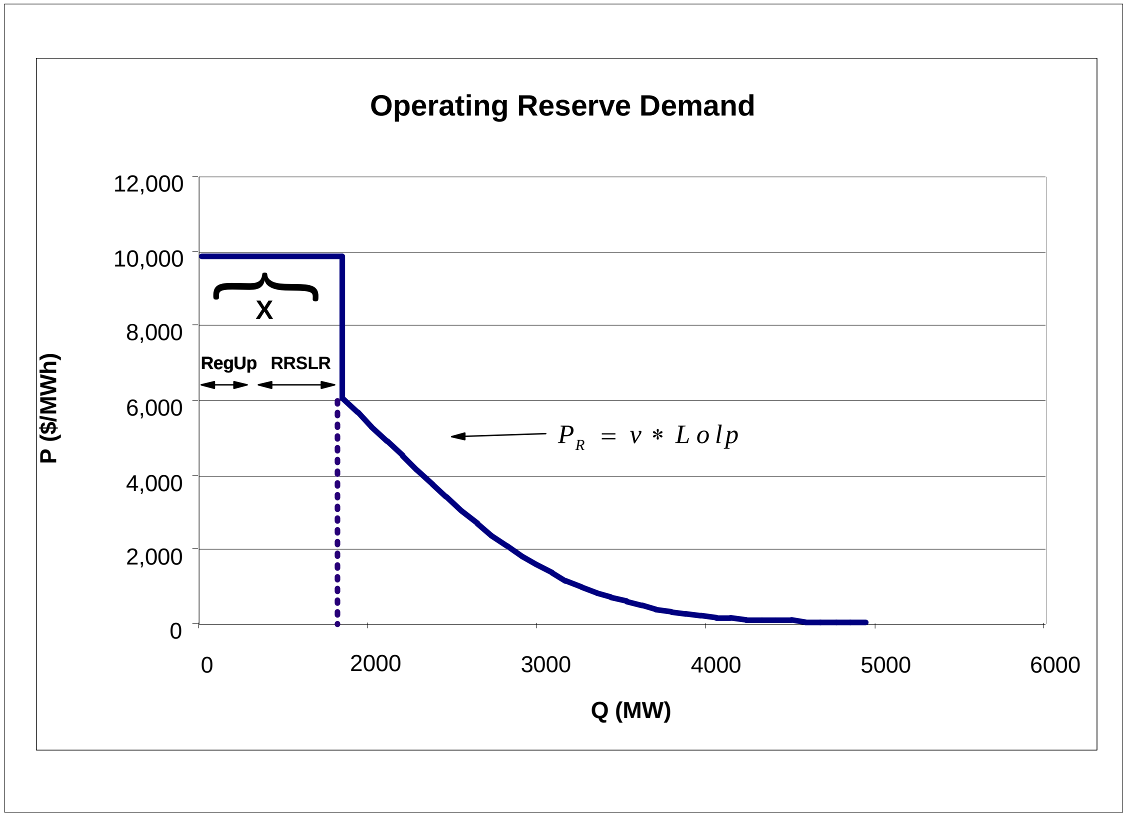
5 "For each cleared Operating Reserve level less than the Market-Wide Operating Reserve Requirement, the Market-Wide Operating Reserve Demand Curve price shall be equal to the product of (i) the Value of Lost Load ("VOLL") and (ii) the estimated conditional probability of a loss of load given that a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

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

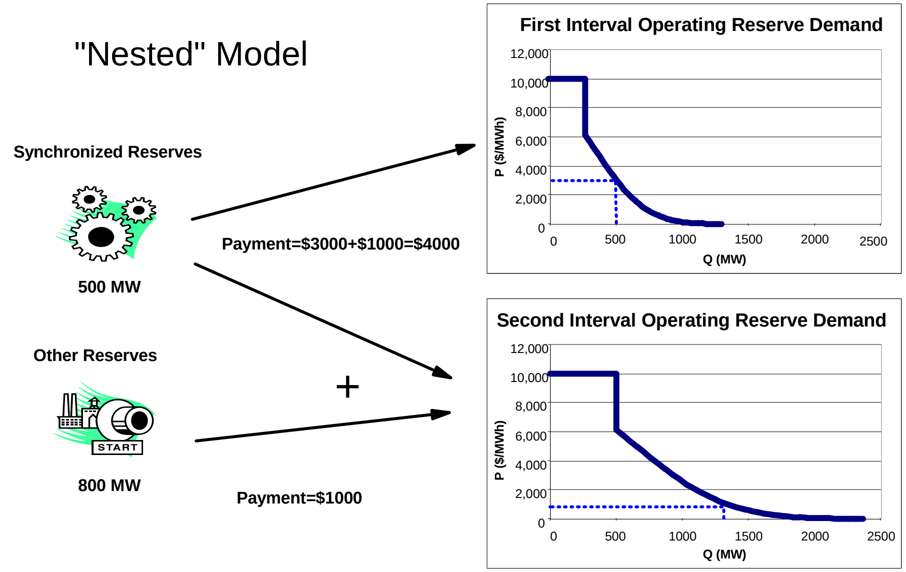
In effect, the contingency constraint provides a vertical demand curve that adds horizontally to the probabilistic operating reserve demand curve.



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.

Multiple Operating Reserve Demand Types (Intervals)

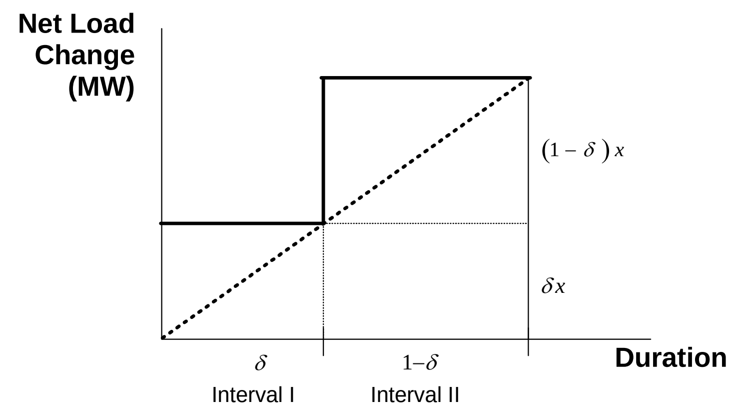


Nested model with two intervals, decisions made before uncertainty revealed.

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	$vLolp(r_R + r_{NS})$

A Two-Step Approximation of Net Load Change



Assume net load change occurs at the beginning of each interval.

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

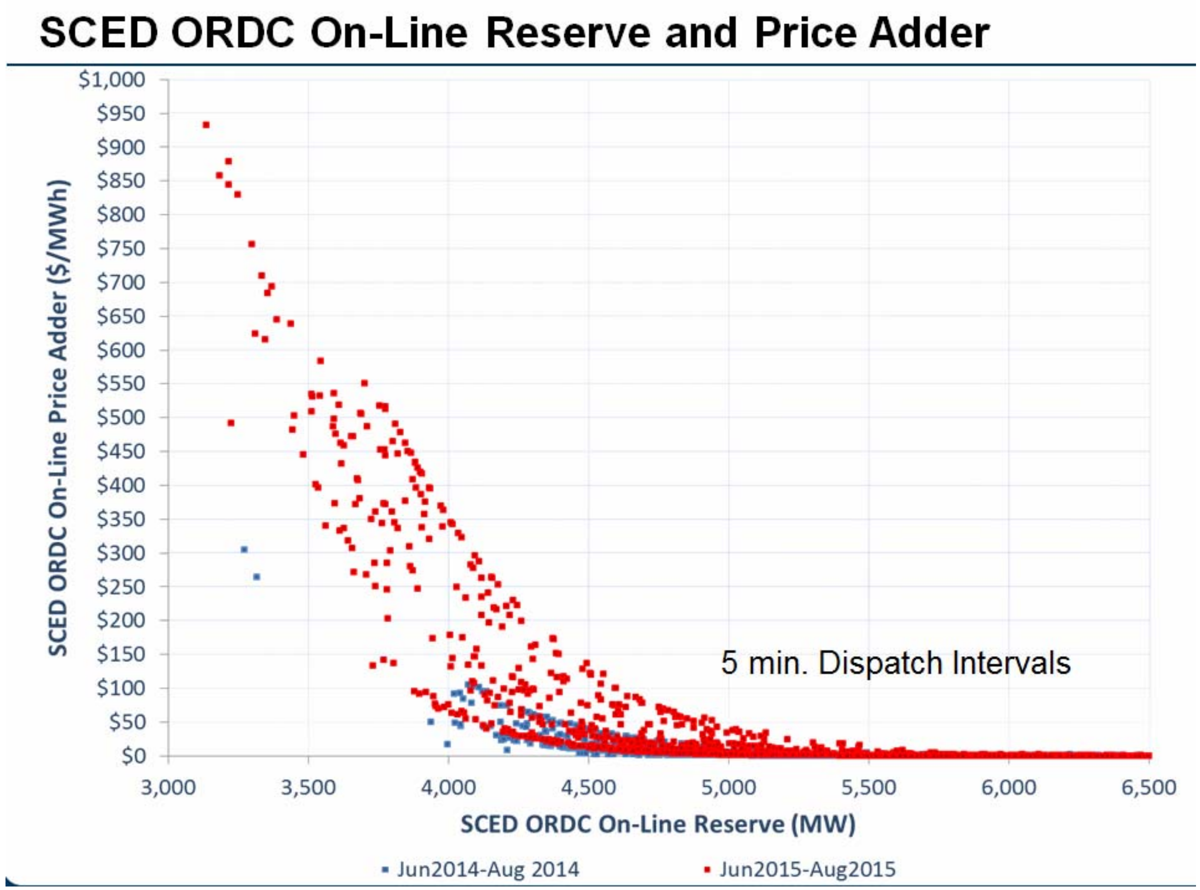
Whitepaper

March 21, 2013

William W. Hogan, Harvard University

ERCOT Staff

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.

Capacity markets in New England experienced increasing problems of unit unavailability.

> "In New England, concerns with resource performance and flexibility arise from several sources. One risk is the operational performance of existing resources during stressed system conditions—times when resources' performance is essential to reliability. ISO analyses indicate that older units that are relied upon for peaking service, ramping, or reserves are not performing within their offered parameters. These shortcomings became manifest in operational events on June 24, 2010, September 2, 2010, and January 24, 2011 (including a NERC violation related to inadequate generation contingency response on September 2). More generally, an examination of dispatch response performance following the 36 largest system contingency events over the last three years indicates that, on average, New England's non-hydro generating fleet delivered less than 60% of the additional power requested of these resources by the ISO." …
>
> "Although capacity auctions can identify the missing money amount, a crucial second problem must be addressed. The under-pricing of electricity at times when demand reaches short-run capacity not only creates missing money, it also undermines suppliers' incentives for resource performance and availability. This occurs because at times when capacity constraints bind—and the need for a supplier's energy is greatest—suppliers are paid marginal cost (or an administratively set shortage price), which is less than the proper market clearing price."

ISONE, "FCM Performance Incentives October 2012," Strategic Planning Initiative, p. 1, 7.

The ISONE capacity market pay-for-performance reform provides for penalty payments during shortage periods. A shortage period is defined as a 5-minute interval when any of the several operating reserve penalty factors are invoked.

Performance Scoring

The performance score is the difference between the resource's actual performance and a share of its capacity supply obligation (CSO). Actual MW is the dispatch of energy and reserves in the shortage interval. There are no exemptions or exceptions.

Score = *Actual* MW – CSO MW × *Balancing Ratio.*

Balancing Ratio = (*Load* + *Reserve Requirement*) */ Total CSO MW*.

FCM Performance Payments

FCM Payment = Base Payment + Performance Payment

*Base Payment = (*FCA *Price [-PER])* × CSO MW*.*

Performance Payment = Performance Payment Rate × Total Score

ISONE, "FCM Performance Incentives October 2012," Strategic Planning Initiative, p. 14-15.

"ISO-NE proposes to phase-in this [Pay for Performance] rate as follows: $2,000/MWh for the period June 1, 2018 through May 31, 2021; $3,500/MWh for the period June 1, 2021 through May 31, 2024; and $5,455/MWh for the open-ended period starting June 1, 2024." FERC Docket ER14-050, January 17, 2014, p. 4.

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."

Peter Campton Testimony, ISO New England Inc. and New England Power Pool, Filings of Performance Incentives Market Rule Changes, Docket ER14-050, January 17, 2014, p. 4.

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.

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

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.

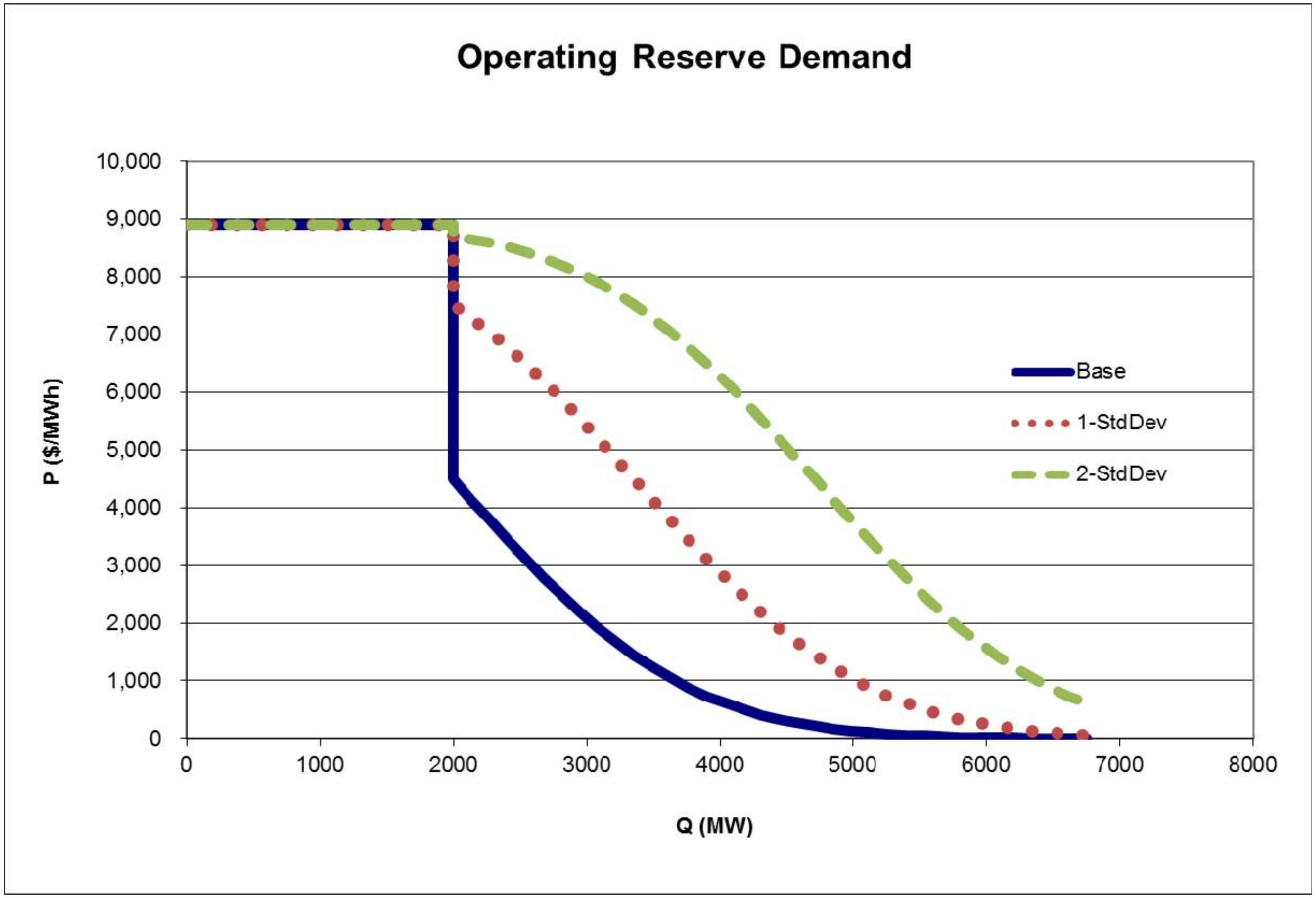
An augmented ORDC would impose conservative assumptions on the basic model. The intent would be to provide both a reliability margin of safety, an associated increase in total operating reserves, and energy payments to address the missing money problem. The three principal parameters of the ORDC are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

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