ELECTRICITY SCARCITY PRICING WITH AN OPERATING RESERVE DEMAND CURVE

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Are Capacity Markets Necessary to Ensure Adequate Generating Reserves?

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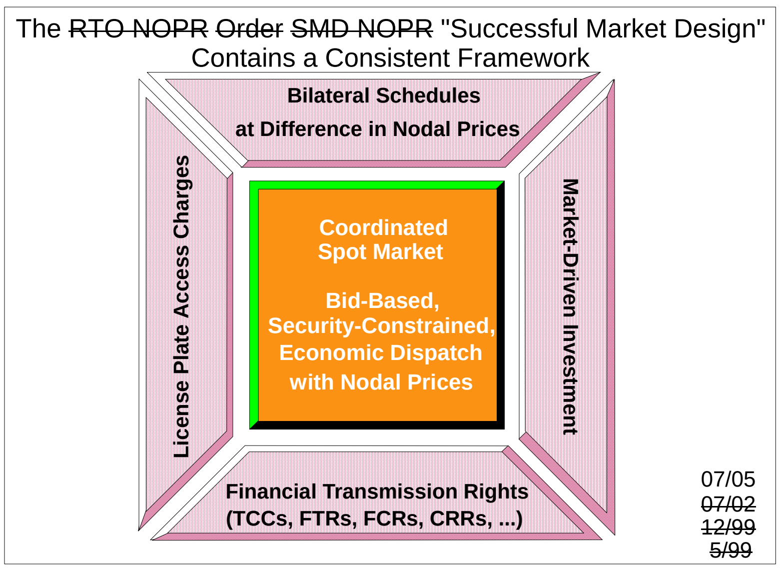
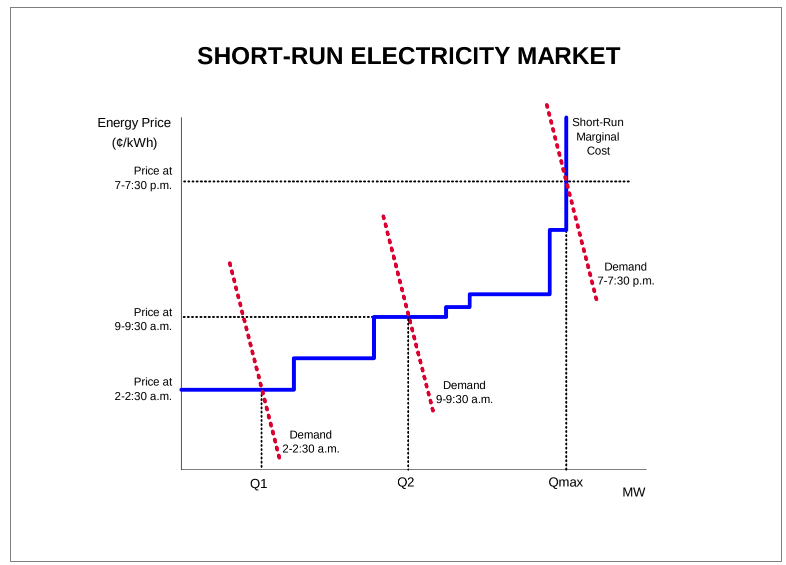
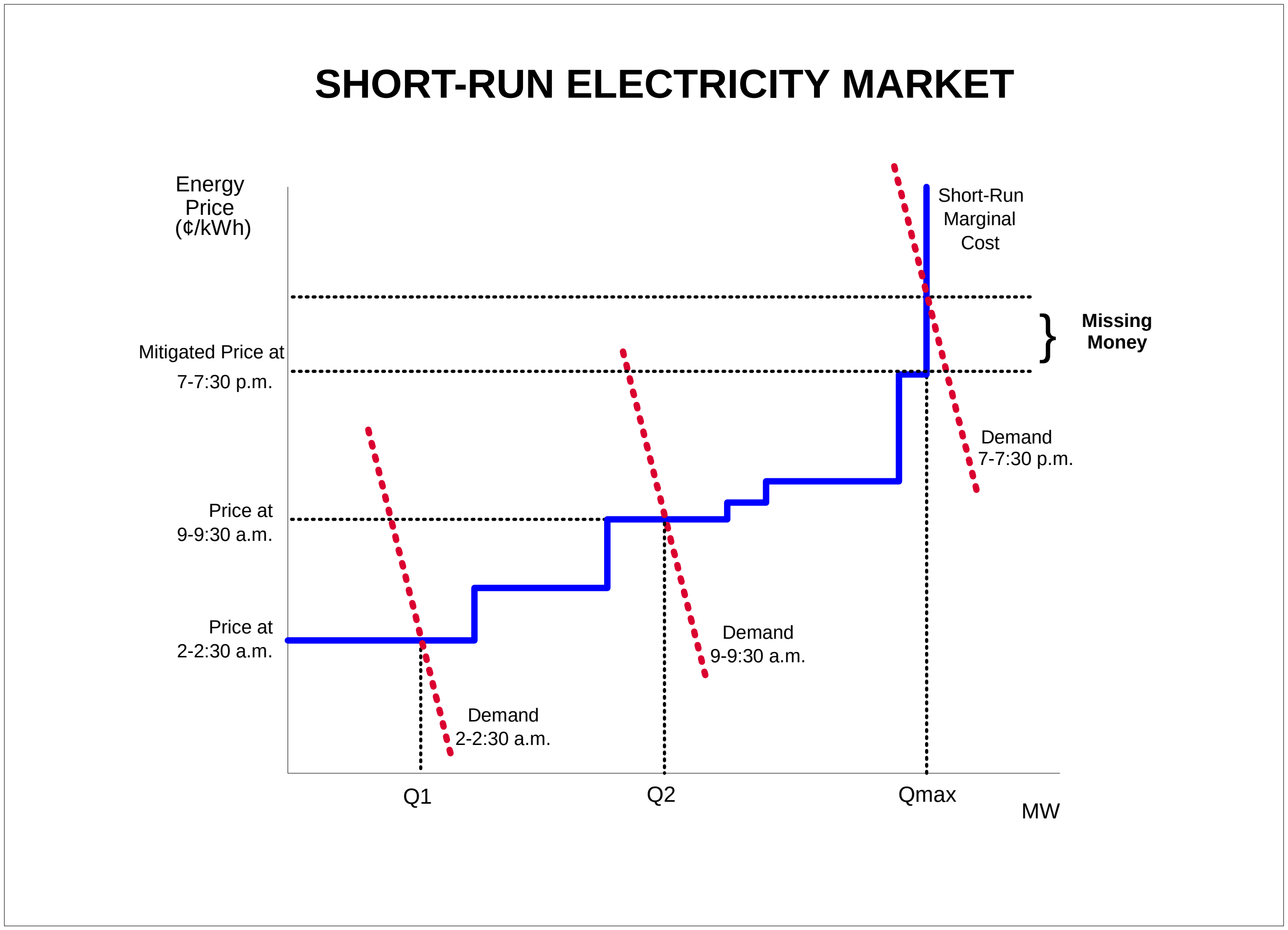
The example of successful central coordination, ~~CRT, Regional Transmission Organization (RTO) Millennium Order (Order 2000)~~ ~~Standard Market Design (SMD) Notice of Proposed Rulemaking (NOPR),~~ "Successful Market Design" provides a workable market framework that is working in places like New York,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

> "Locational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market design – the textbook ideal that should be the target for policy makers. A trading arrangement based on LMP takes all relevant generation and transmission costs appropriately into account and hence supports optimal investments."(International Energy Agency, Tackling Investment Challenges in Power Generation in IEA Countries: Energy Market Experience, Paris, 2007, p. 16.)





Early market designs presumed a significant demand response. 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.

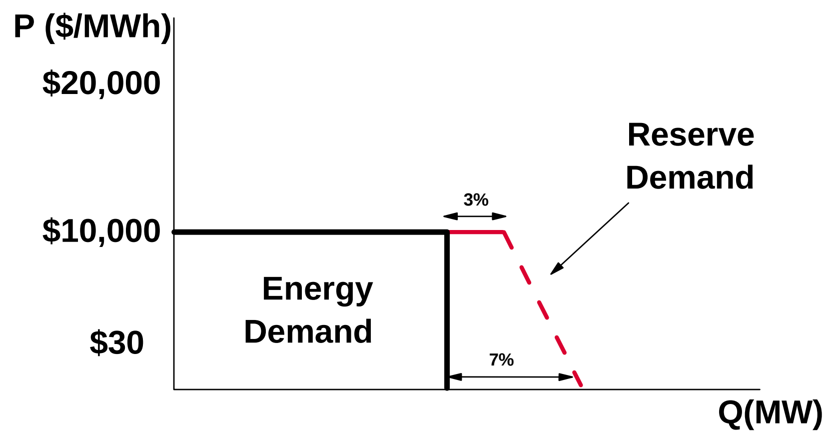
- **Transmission Pricing.** Scarcity pricing interacts with transmission congestion. Better scarcity pricing would provide better signals for transmission investment.

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.[1]

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

Operating reserve demand curve would reflect capacity scarcity.

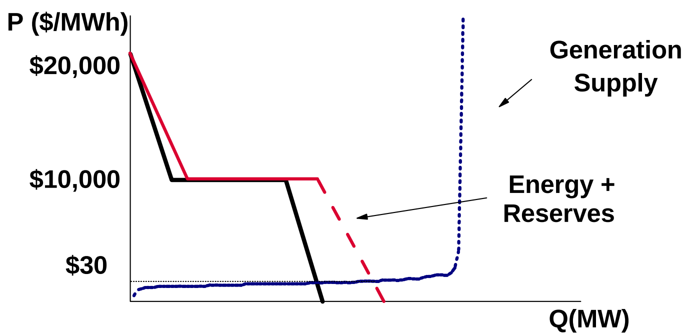
Illustrative Reserve Demand



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

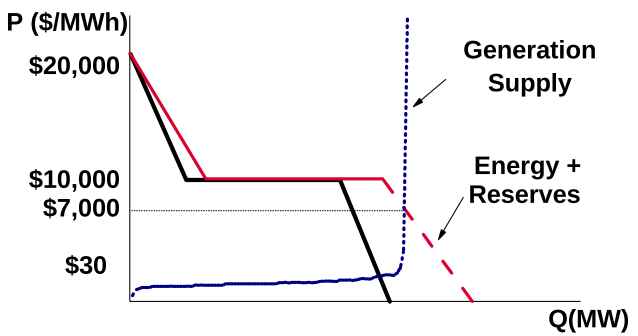
Market clearing addresses the “missing money.”

Normal "Energy Only" Market Clearing



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

Scarcity "Energy Only" Market Clearing



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

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.[2]
- **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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[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.

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

Whitepaper

March 21, 2013

William W. Hogan, Harvard University

ERCOT Staff

An application of the model for the case of ERCOT illustrates the possible scale of the impacts. The purpose of the back cast was to suggest the scale of the scarcity prices that would have been relevant under the tight conditions that existed in 2011 and the greater abundance of capacity in 2012. The charge was not to simulate the full system to include changes in behavior and dispatch, which could be expected to occur. Rather the mandate was to assume the same offers, bids and dispatch that actually occurred, and then recalculate the energy and reserve prices. This provides a first order approximation of the effects of scarcity pricing.

By way of comparison, the "ERCOT-wide load-weighted average real-time energy price was $53.23 per MWh in 2011, a 35 percent increase from $39.40 per MWh in 2010." (Potomac Economics, 2012)

Table 1 : Energy-weighted average energy price adder (and Online reserve price) ($/MWh) for 2011 & 2012 for different VOLLs and minimum contingency levels (X)

VOLL	Energy-weighted average price increase with X at 1375 MW ($/MWh)			Energy-weighted average price increase with X at 1750 MW ($/MWh)		
	2011	2012	2011 & 2012 combined	2011	2012	2011 & 2012 combined
$5000/MWh	7.00	1.08	4.08	12.03	2.40	7.28
$7000/MWh	11.27	1.56	6.48	19.06	3.45	11.35
$9000/MWh	15.54	2.05	8.87	26.08	4.50	15.42

Source:(ERCOT Staff & Hogan, 2013)

ERCOT Staff, & Hogan, W. W. (2013). "Back Cast of Interim Solution B + to Improve Real-Time Scarcity Pricing White Paper." Potomac Economics. (2012). "2011 State of the Market Report for the ERCOT Wholesale Electricity Markets."

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.

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.

On the development of an operating reserve demand curve.

Appendix

Begin with an expected value formulation of economic dispatch that might appeal in principle. Given benefit (*B*) and cost (*C*) functions, demand (*d*), generation (*g*), plant capacity (*Cap*), reserves (*r*), commitment decisions (*u*), transmission constraints (*H*), and state probabilities (*p*):

$$\underset{y^i,d^i,g^i,r,u\in(0,1)}{Max}\; p_0\left(B^0\left(d^0\right)-C^0\left(g^0,r,u\right)\right)+\sum_{i=1}^{N}p_i\left(B^i\left(d^i,d^0\right)-C^i\left(g^i,g^0,r,u\right)\right)$$

$$s.t.$$

$$y^i=d^i-g^i,\quad i=0,2,\cdots,N,$$

$$\iota^t y^i=0,\quad i=0,1,2,\cdots,N,$$

$$H^i y^i\le b^i,\quad i=0,1,2,\cdots,N,$$

$$g^0+r\le u\bullet Cap^0,$$

$$g^i\le g^0+r,\quad i=1,2,\cdots,N,$$

$$g^i\le u\bullet Cap^i,\quad i=0,1,2,\cdots,N.$$

Suppose there are *K* possible contingencies. The interesting cases have $K \gg 10^3$. The number of possible system states is $N=2^K$, or more than the stars in the Milky Way. Some approximation will be in order.[3]

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3 Shams N. Siddiqi and Martin L. Baughman, "Reliability Differentiated Pricing of Spinning Reserve," IEEE Transactions on Power Systems, Vol. 10, No. 3, August 1995, pp.1211-1218. José M. Arroyo and Francisco D. Galiana, "Energy and Reserve Pricing in Security and Network-Constrained Electricity Markets," IEEE Transactions On Power Systems, Vol. 20, No. 2, May 2005, pp. 634-643. François Bouffard, Francisco D. Galiana, and Antonio J. Conejo, "Market-Clearing With Stochastic Security—Part I: Formulation," IEEE Transactions On Power Systems, Vol. 20, No. 4, November 2005, pp. 1818-1826; "Part II: Case Studies," pp. 1827-1835.

The model presented here is a one-period DC-load model with co-optimization of reserves and energy. The dispatch is set at the beginning of the period must include some operating reserves that could deal with uncertain events over the period.

Here the various variables and functions include:

d : Vector of locational demands

g_R : Vector of locational responsive generation

r_R : Vector of locational responsive reserves

r_{NS} : Vector of locational non-spin reserves

r_R^0 : Aggregate responsive reserves

r_{NS}^0 : Aggregate non-spin reserves

g_{NR} : Vector of locational generation not providing reserves

$B(d)$: Benefit function for demand

$C_k(g_k)$: Cost function for generation offers

K_k : Generation Capacity

$R_k(r_k)$: Reserve value function integrating demand curves

$r_k^{\max}$: Maximum Ramp Rate

H, b: Transmission Constraint Parameters

i : Vector of ones.

The stylized economic dispatch model is:

$$\underset{d, g_R, g_{NR}, r_R^0, r_R, r_{NS}^0, r_{NS} \geq 0; y}{Max} \quad B(d) - C_R(g_R) - C_{NR}(g_{NR}) + R_I(r_R^0) + R_{II}(r_{NS}^0)$$

(1)

$d - g_R - g_{NR} = y$	Net Loads	ρ
$i^t y = 0$	Load Balance	λ
$Hy \leq b$	Transmission Limits	μ
$g_R + r_R \leq K_R$	Responsive Capacity	θ_R
$g_{NR} \leq K_{NR}$	Generation Only Capacity	θ_{NR}
$r_{NS} \leq K_{NS}$	Non-Spin Capacity	θ_{NS}
$i^t r_R = r_R^0$	Responsive Reserves	γ_R
$i^t r_R + i^t r_{NS} = r_{NS}^0$	Non-Spin Reserves	γ_{NS}
$r_R \leq r_R^{\max}$	Responsive Ramp Limit	η_R
$r_{NS} \leq r_{NS}^{\max}$	Non-Spin Ramp Limit	η_{NS}.

An interpretation of the prices follows from analysis of the dual variables and the complementarity conditions. For an interior solution, the locational prices are equal to the demand prices for load.

(2) $\rho = \nabla B(d).$

The same locational prices connect to the system lambda and the cost of congestion for the binding transmission constraints in the usual way.

(3) $\rho = \lambda i + \mu^t H.$

In addition, the locational prices equate with the marginal cost of generation plus the cost of scarcity.

(4) $\rho = \nabla C_R\left(g_R\right) + \theta_R.$

A similar relation applies for the value of non-reserve related generation.

(5) $\rho = \nabla C_{NR}\left(g_{NR}\right) + \theta_{NR}.$

The marginal value of responsive reserves connects to the scarcity costs of capacity and ramping limits.

(6) $\theta_R + \eta_R = \gamma_R i + \gamma_{NS} i = \frac{dR_I\left(r_R^0\right)}{dr} i + \frac{dR_{II}\left(r_{NS}^0\right)}{dr} i.$

The corresponding marginal value of non-spin reserves reflects the scarcity value for capacity and ramping limits.

(7) $\theta_{NS} + \eta_{NS} = \gamma_{NS} i = \frac{dR_{II}\left(r_{NS}^0\right)}{dr} i.$

The assumption of a benefit function for reserves simplifies the analysis. The derivative of the reserve benefit defines an operating reserve demand curve. The basic framework approximates the complex problem with a wide range of uncertainties.

- **Single Period Model.** A static representation of the underlying dynamic problem. A building block for a multi-period framework.
- **Deterministic Representation.** The single period dispatch formulation based on bids, offers, and expected network conditions.
- **Security Constrained.** The dispatch model includes n-1 contingency constraints to preclude cascading failures.
- **Ex Ante Dispatch.** The dispatch is determined before uncertainty revealed.
- **Administrative Balancing.** Uncertain events treated according to administrative rules to utilize operating reserves to maintain system balance and minimize load curtailments.
- **Expected Value for Reserves.** The reserve benefit function represents the expected value of avoiding involuntary load curtailments and similar emergency actions.
- **Consistent Prices.** The ex ante model co-optimizes the dispatch of energy and reserves and produces a consistent set of prices for the period.

The assumption of a benefit function for reserves simplifies the analysis. Here, a derivation of a possible approximation of a reserve benefit function provides a background for describing the form of an Operating Reserve Demand Curve (ORDC).

Let $f(x)$ be the probability of net load change. Treat net load change x and use of reserve, δ_x , to avoid involuntary curtailment. Reserves protect against involuntary load curtailment at the value of lost load (VOLL).

$$\max_{d, g_R, g_{NR}, r_R, \delta_x \geq 0; y} B(d) - C_R(g_R) - C_{NR}(g_{NR}) + \sum_{x \geq 0} \left(VOLL\, i^t \delta_x - \left(C_R(g_R + \delta_x) - C_R(g_R) \right) \right) f(x)$$

$$(8) \qquad \begin{array}{lll} d - g_R - g_{NR} = y & \text{Net Loads} & \rho \\ i^t y = 0 & \text{Load Balance} & \lambda \\ Hy \leq b & \text{Transmission Limits} & \mu \\ g_R + r_R \leq K_R & \text{Responsive Capacity} & \theta_R \\ i^t \delta_x \leq x, \forall x & \text{Responsive Utilization} & \gamma_x \\ \delta_x \leq r_R, \forall x & \text{Responsive Limit} & \varphi_x \\ g_{NR} \leq K_{NR} & \text{Generation Only Capacity} & \theta_{NR}. \end{array}$$

After some simplification for a system wide reserve requirement, *r*, we obtain the approximation:

$$(9) \qquad \rho \approx \nabla C_R(g_R) + \left(VOLL - \partial \hat{C}_R(i^t g_R) \right) (1 - F(r))\, i.$$

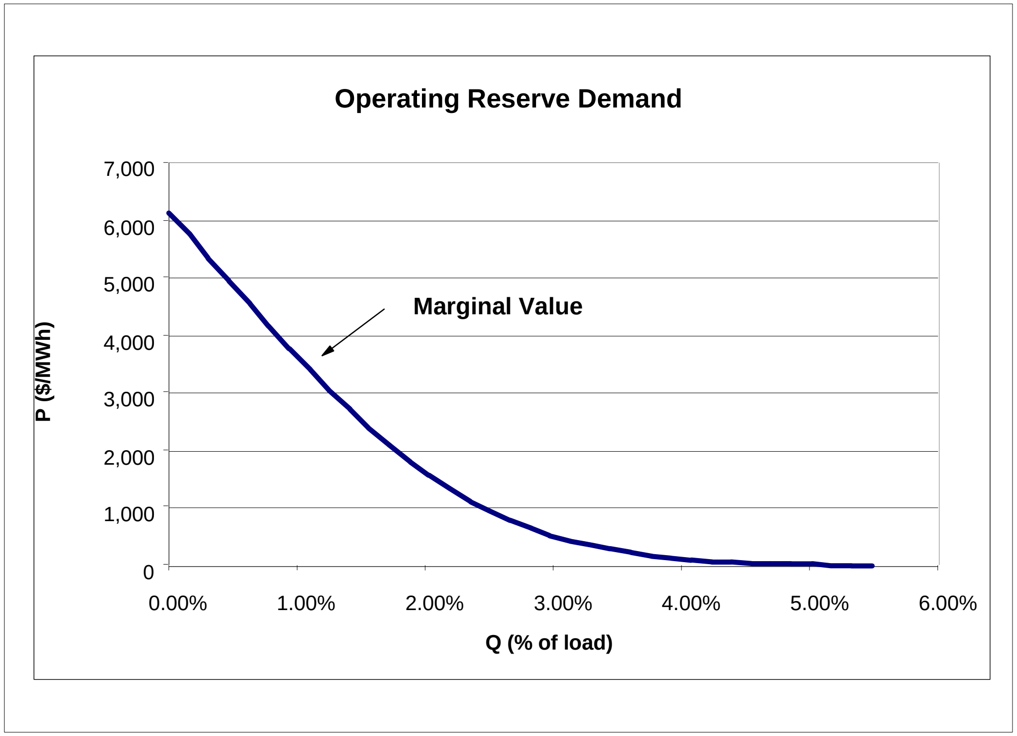
Here $1 - F(r) = Lolp(r) = \text{Probability}(\text{Net Load Change} \geq r)$, is the loss of load probability. The result is an easy calculation in the term $\left(VOLL - \partial \hat{C}_R(i^t g_R) \right) Lolp(r)$ in (9), which is the scarcity price defining the ORDC.

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.[4]

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.



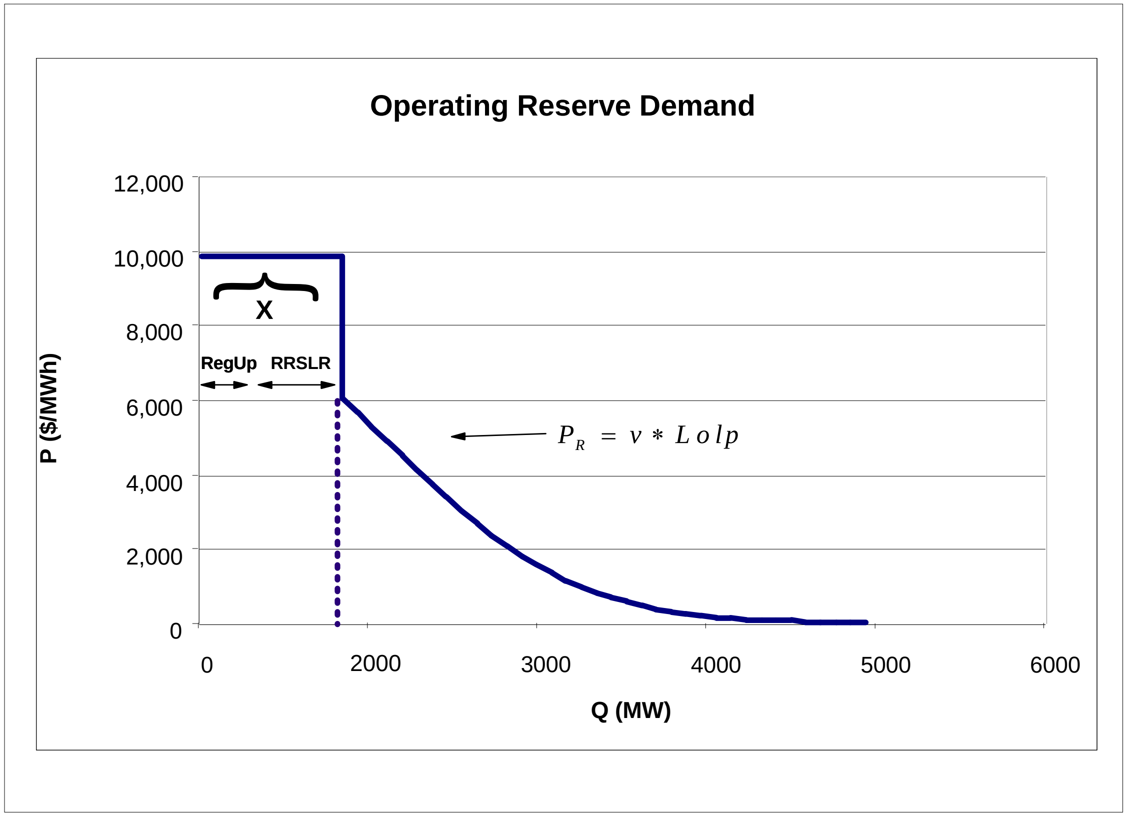
[4] "For each cleared Operating Reserve level less than the Market-Wide Operating Reserve Requirement, the Market-Wide Operating Reserve Demand Curve price shall be equal to the product of (i) the Value of Lost Load ("VOLL") and (ii) the estimated conditional probability of a loss of load given that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

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:

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

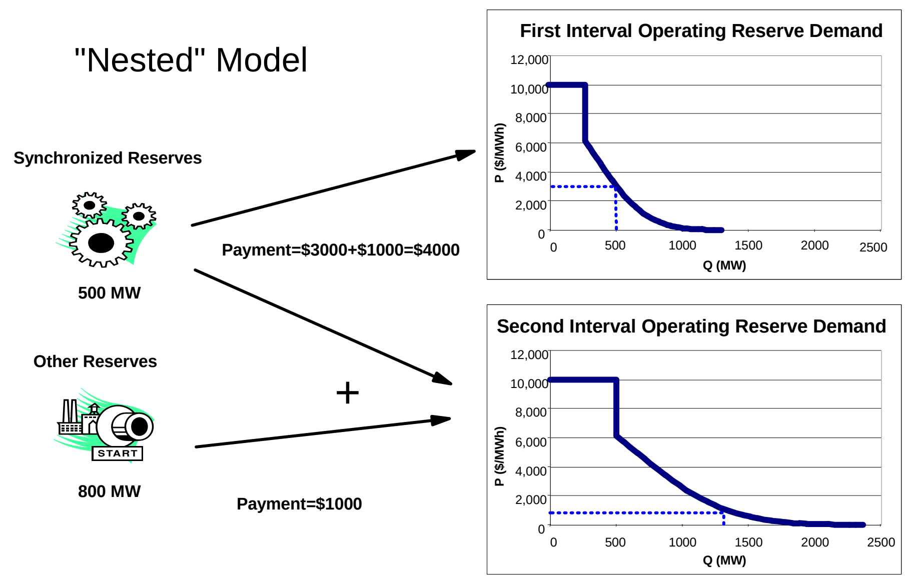
In effect, the contingency constraint provides a vertical demand curve that adds horizontally to the probabilistic operating reserve demand curve.



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.

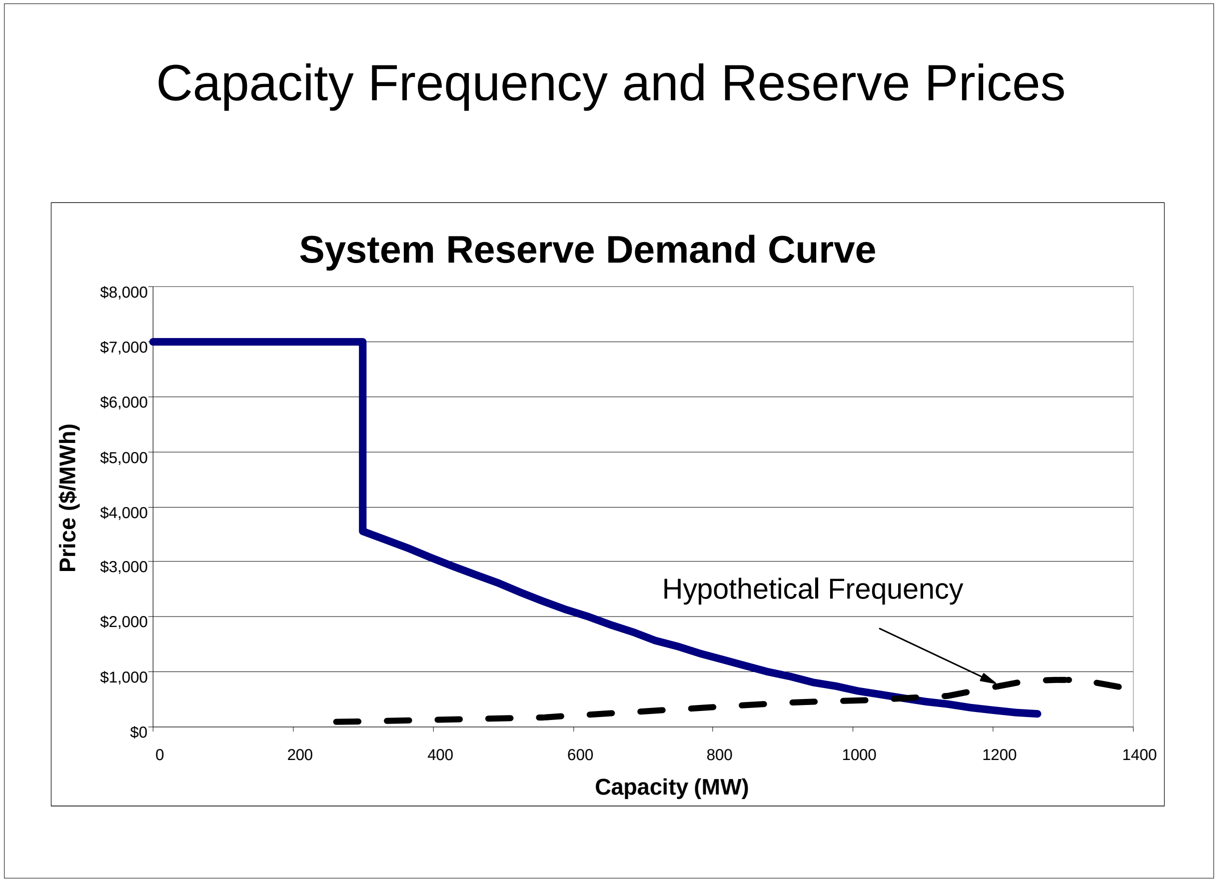
Multiple types of operating reserves exist according to response time. A nested model divides the period into consecutive intervals. Reserve schedules set before the period. Uncertainty revealed after the start of the period. Faster responding reserves modeled as available for subsequent intervals. The 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.

An interesting question is the frequency of different reserve levels and the interaction with the operating reserve demand curve. This will determine the scarcity price duration curve.



As a transition to full implementation with co-optimization, pricing and settlements for real time energy and operating reserves, ERCOT could adapt the existing dispatch model to approximate the scarcity price and incorporate an operating reserve demand curve in energy prices.

- **Focus on Aggregate Capacity, Energy and Reserves.** The real-time dispatch would include a model to incorporate the tradeoff between reserves and energy.
- **Incorporate Aggregate Scarcity Price in Energy.** The real-time price for energy would include the scarcity price as the opportunity costs of reserves.
- **Modify the Real-Time Settlements System.** Pay for operating reserves provided in real time, net of obligations from day-ahead.
- **Continue Day-Ahead Market Co-optimization.** Day-ahead procurement of operating reserves would be continued, with expected real-time conditions driving virtual offers. This could include a day-ahead version of the operating reserve demand curve.
- **Develop Real-Time Co-optimization.** ERCOT would develop software and protocols for later implementation of full real-time reserve pricing and settlements.

William W. Hogan is the Raymond Plank Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University. The work is based on research for the Harvard Electricity Policy Group and for the Harvard-Japan Project on Energy and the Environment. This paper draws joint work with John Dumas, David Maggio, Sai Moorty, Resmi Surendran of ERCOT. Support was provided by GDF SUEZ Energy Resources NA. 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 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, Canadian Imperial Bank of Commerce, Centerpoint Energy, Central Maine Power Company, Chubu Electric Power Company, Citigroup, 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, Dynegy, Edison Electric Institute, Edison Mission Energy, Electricity Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, Exelon, Financial Marketers Coalition, FTI Consulting, GenOn Energy, GPU Inc. (and the Supporting Companies of PJM), GPU PowerNet Pty Ltd., GDF SUEZ Energy Resources NA, GWF Energy, Independent Energy Producers Assn, ISO New England, LECG LLC, Luz del Sur, Maine Public Advocate, Maine Public Utilities Commission, Merrill Lynch, Midwest ISO, Mirant Corporation, MIT Grid Study, JP Morgan, Morgan Stanley Capital Group, National Independent Energy Producers, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, NRG Energy, Inc., Ontario Attorney General, Ontario IMO, Pepco, Pinpoint Power, PJM Office of Interconnection, PJM Power Provider (P3) Group, PPL Corporation, Public Service Electric & Gas Company, Public Service New Mexico, PSEG Companies, Reliant Energy, Rhode Island Public Utilities Commission, San Diego Gas & Electric Company, Sempra Energy, SPP, Texas Genco, Texas Utilities Co, Tokyo Electric Power Company, Toronto Dominion Bank, Transalta, Transcanada, TransÉnergie, Transpower of New Zealand, Tucson Electric Power, Westbrook Power, Western Power Trading Forum, Williams Energy Group, and Wisconsin Electric Power Company. 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).