ELECTRICITY SCARCITY PRICING AND RESOURCE ADEQUACY

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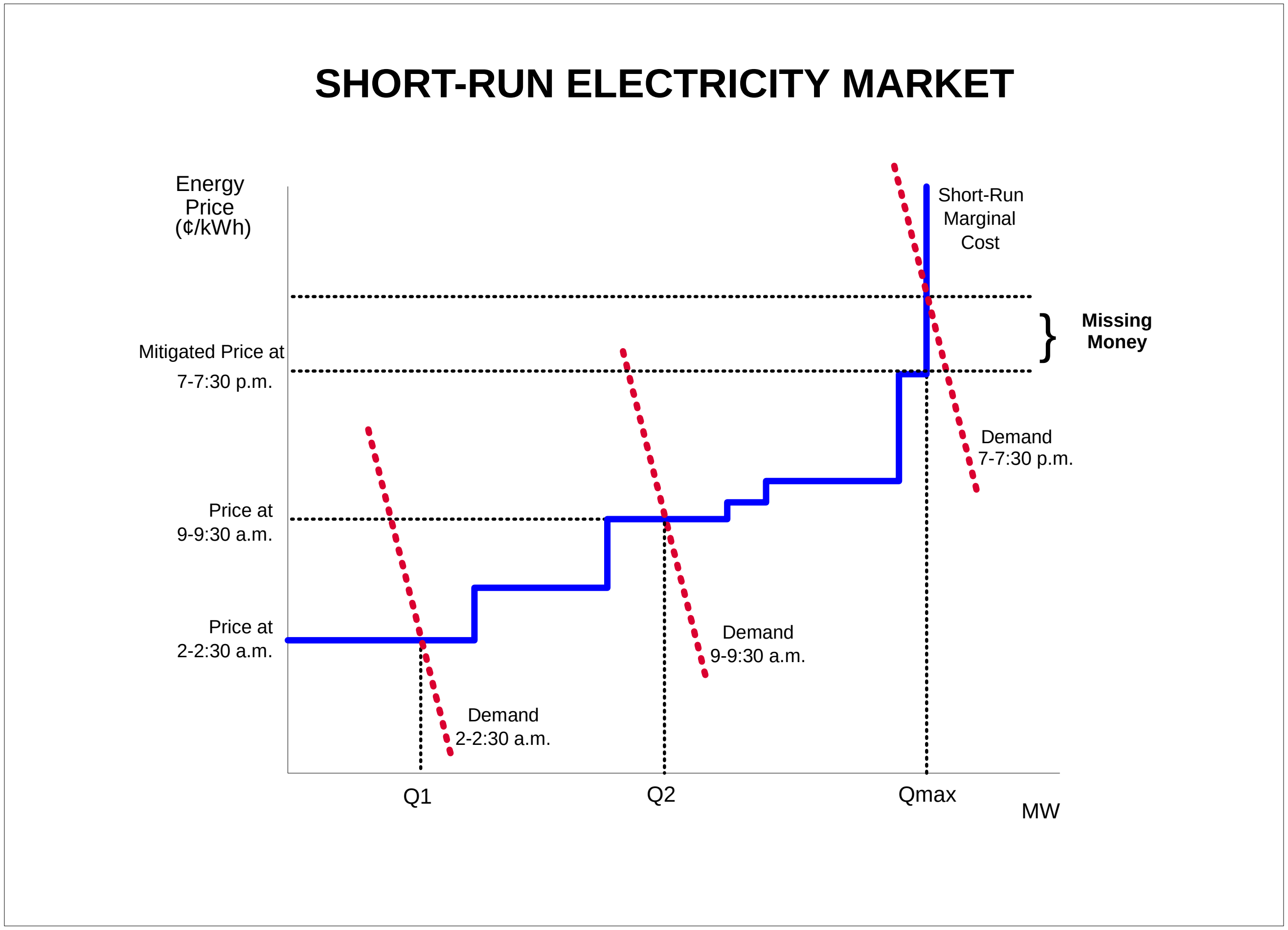
Early market designs presumed significant demand participation. Absent this demand participation most markets implemented inadequate pricing rules equating prices to variable costs even when capacity is constrained. This produces a "missing money" problem.



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.

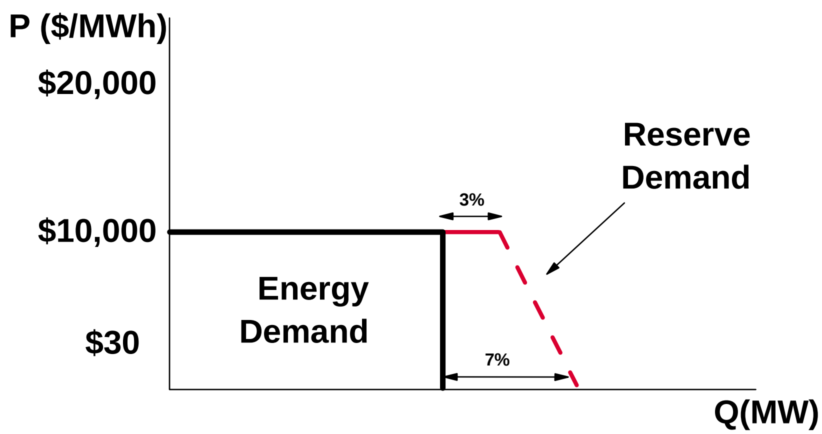
- **Transmission Pricing.** Scarcity pricing interacts with transmission congestion. Better scarcity pricing would provide better signals for transmission investment.

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.[1]

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

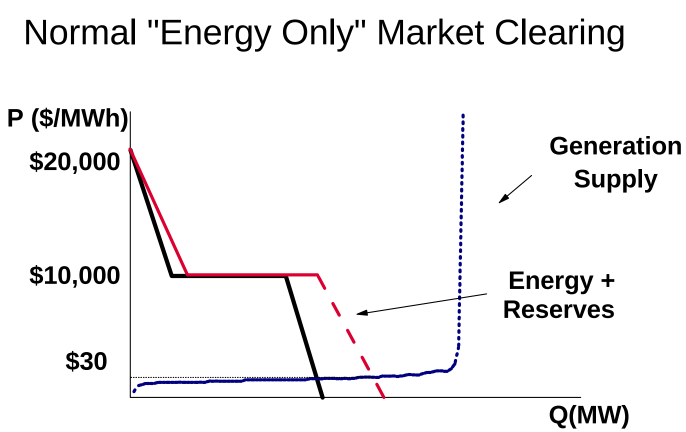
Operating reserve demand curve would reflect capacity scarcity.

Illustrative Reserve Demand

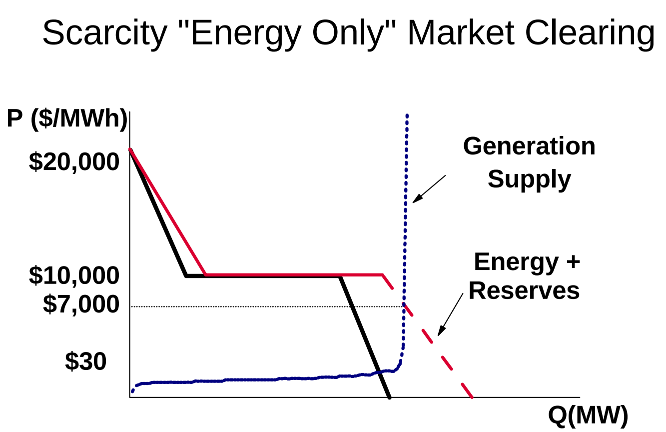


There is a minimum level of operating reserve (e.g., 3%) to protect against system-wide failure. Above the minimum reserve, reductions below a nominal reserve target (e.g., 7%) are price senstive.

Market clearing addresses the "missing money."



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



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.

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.

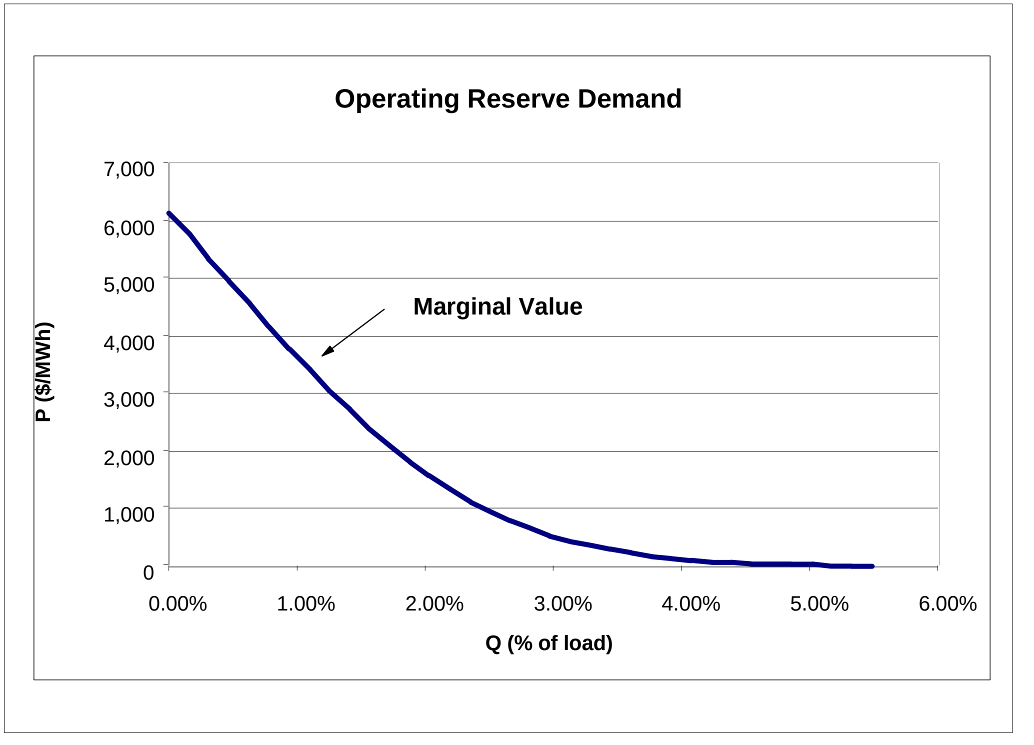
The most general principle would be to provide a pricing framework that incorporates reasonable prices for actions that the system operator may take to provide a security constrained economic dispatch. "As a general principle, competitive and efficient market prices should be consistent with the marginal 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.[3]

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.



3 "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.

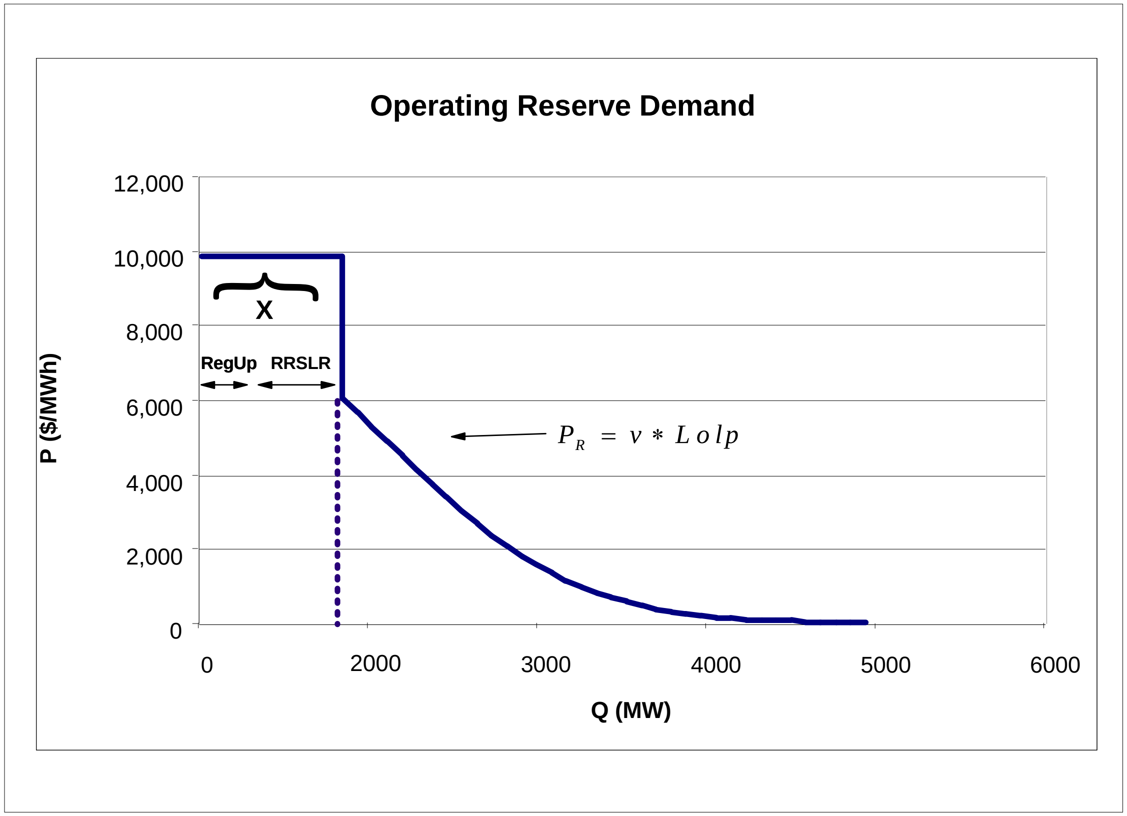
The deterministic approach to security constrained economic dispatch includes lower bounds on the required reserve to ensure that for a set of monitored contingencies (e.g., an n-1 standard) there is sufficient operating reserve to maintain the system for an emergency period.

Suppose that the maximum generation outage contingency quantity is $r_{Min}\left(d^0, g^0, u\right)$. Then we would have the constraint:

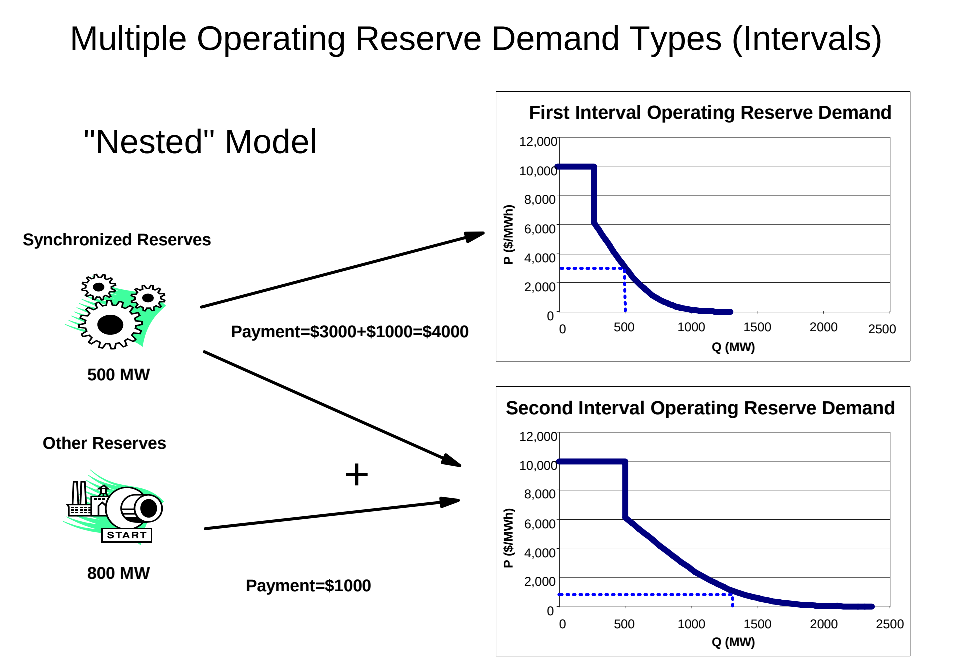
$$r \geq r_{Min}\left(d^0, g^0, u\right) = X.$$

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.

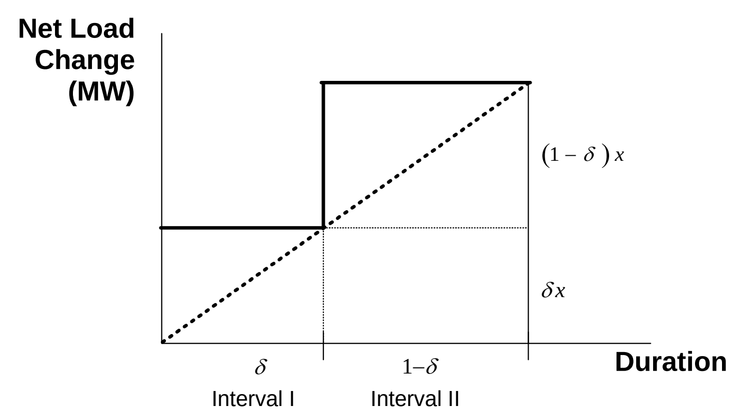


Nested model with two intervals, decisions made before uncertainty revealed.

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

Whitepaper

March 21, 2013

William W. Hogan, Harvard University

ERCOT Staff

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.

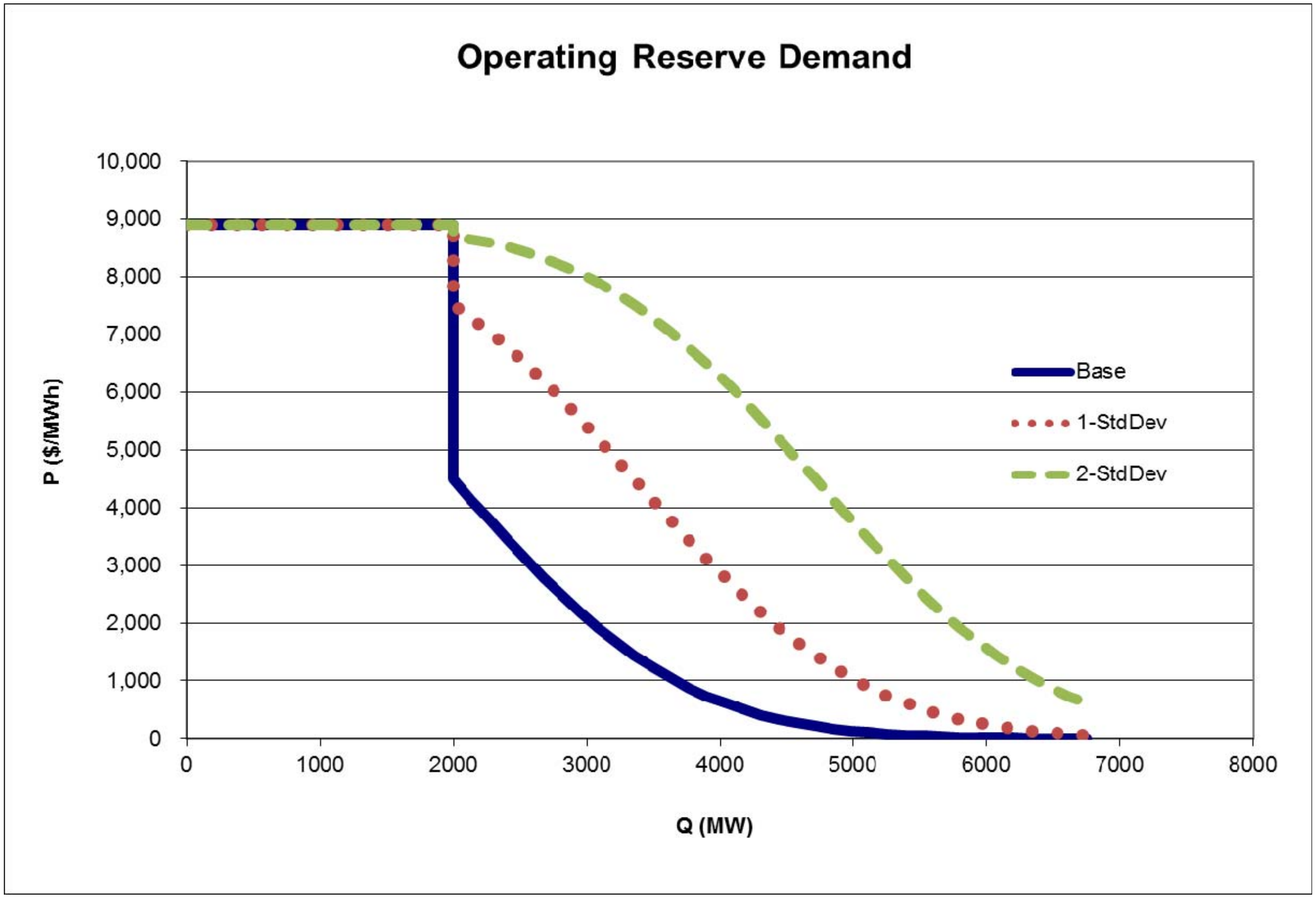
An augmented ORDC would impose conservative assumptions on the basic model. The intent would be to provide both a reliability margin of safety, an associated increase in total operating reserves, and energy payments to address the missing money problem. The three principal parameters of the ORDC are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

William W. Hogan is the Raymond Plank Professor of Global Energy Policy, John F. Kennedy School of Government, Harvard University. This paper draws on research for the Harvard Electricity Policy Group and for the Harvard-Japan Project on Energy and the Environment. The author is or has been a consultant on electric market reform and transmission issues for Allegheny Electric Global Market, American Electric Power, American National Power, Aquila, Atlantic Wind Connection, Australian Gas Light Company, Avista Corporation, Avista Utilities, Avista Energy, Barclays Bank PLC, Brazil Power Exchange Administrator (ASMAE), British National Grid Company, California Independent Energy Producers Association, California Independent System Operator, California Suppliers Group, Calpine Corporation, CAM Energy, Canadian Imperial Bank of Commerce, Centerpoint Energy, Central Maine Power Company, Chubu Electric Power Company, Citigroup, City Power Marketing LLC, Cobalt Capital Management LLC, Comision Reguladora De Energia (CRE, Mexico), Commonwealth Edison Company, COMPETE Coalition, Conectiv, Constellation Energy, Constellation Energy Commodities Group, Constellation Power Source, Coral Power, Credit First Suisse Boston, DC Energy, Detroit Edison Company, Deutsche Bank, Deutsche Bank Energy Trading LLC, Duquesne Light Company, Dyon LLC, Dynegy, Edison Electric Institute, Edison Mission Energy, Electricity Corporation of New Zealand, Electric Power Supply Association, El Paso Electric, 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, Great Bay Energy LLC, GWF Energy, Independent Energy Producers Assn, ISO New England, Koch Energy Trading, Inc., JP Morgan, LECG LLC, Luz del Sur, Maine Public Advocate, Maine Public Utilities Commission, Merrill Lynch, Midwest ISO, Mirant Corporation, MIT Grid Study, Monterey Enterprises LLC, MPS Merchant Services, Inc. (f/k/a Aquila Power Corporation), JP Morgan Ventures Energy Corp., Morgan Stanley Capital Group, National Independent Energy Producers, New England Power Company, New York Independent System Operator, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, NRG Energy, Inc., Ontario Attorney General, Ontario IMO, Ontario Ministries of Energy and Infrastructure, Pepco, Pinpoint Power, PJM Office of Interconnection, PJM Power Provider (P3) Group, Powerex Corp., Powhatan Energy Fund LLC, PPL Corporation, PPL Montana LLC, PPL EnergyPlus LLC, Public Service Company of Colorado, Public Service Electric & Gas Company, Public Service New Mexico, PSEG Companies, Red Wolf Energy Trading, Reliant Energy, Rhode Island Public Utilities Commission, San Diego Gas & Electric Company, Sempra Energy, SESCO LLC, Shell Energy North America (U.S.) L.P., SPP, Texas Genco, Texas Utilities Co, Tokyo Electric Power Company, Toronto Dominion Bank, Transalta, TransAlta Energy Marketing (California), TransAlta Energy Marketing (U.S.) Inc., Transcanada, TransCanada Energy LTD., TransÉnergie, Transpower of New Zealand, Tucson Electric Power, Twin Cities Power LLC, Vitol Corp., Westbrook Power, Western Power Trading Forum, Williams Energy Group, Wisconsin Electric Power Company, and XO Energy. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the author. (Related papers can be found on the web at www.whogan.com).