Electricity Scarcity Pricing Through Operating Reserves:

An ERCOT Window of Opportunity

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Texas has a window of opportunity to complement its resource adequacy initiatives with an accelerated program to adopt an operating reserve demand curve. Suppressed prices in real-time markets provide inadequate incentives for both generation investment and active participation by demand bidding. An operating reserve demand curve developed from first principles would improve reliability, support adequate scarcity pricing, and be straightforward to implement within the framework of economic dispatch. This approach would be fully compatible with other market-oriented policies, the existing Texas "energy only" market design, and the proposed options for long-term resource adequacy.

Introduction

The Public Utility Commission of Texas (PUCT) recently confirmed it plans to increase generator offer caps.[1] At the same time, the PUCT has been reviewing recommendations for possible modifications of the wholesale electricity market in the Electric Reliability Council of Texas (ERCOT). (Newell, 2012) A common feature of these policies is a concern with the conundrum created by inadequate scarcity pricing in the short run and the possibility that resources will not be adequate to meet reliability requirements in the near future. (Newell et al., 2012)

The proposed solutions before the PUCT include a mix of innovations in forward markets for generators and demand response. Whatever is done in this regard, the incentives in real-time will be critical as part of the overall attempt to provide efficient markets within the constraint of meeting reliability requirements. Increased offer caps may help in this regard. However, increasing the generator offer cap may not be enough, and this is not the only path to improved scarcity pricing in real-time operations.

The additional tool of pursuing better scarcity pricing through improved operating reserve demand curves has not been fully addressed in public reports or discussion of the PUCT. The idea of increasing operating reserve requirements has been mentioned, but it has not been carried forward to embrace the full design based on first principles.

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[1] On October 25, 2012, the PUCT confirmed that "[t]he maximum wholesale rate will rise from $4,500 a megawatt hour now to $5,000 in June 2013, $7,000 in June 2014 and $9,000 in June 2015." http://www.star-telegram.com/2012/10/25/4365061/texas-regulators-vote-to-double.html.

Forward markets focus on long-term incentives. But the long-term is a succession of short-term markets. Inadequate scarcity pricing in the short-term design makes everything harder, now and in the future. Better scarcity pricing incentives would reinforce reliable operations now and in the expected future. A focus on forward market cures should not overlook the immediate implications of the diagnosis of inadequate short-term scarcity pricing.

Whatever choices are made in the redesign of forward capacity markets, the eventual reliability performance of the system will depend critically on the operating procedures and incentives of the real-time market. (Anderson, 2012) A well-designed operating reserve demand curve would integrate naturally with the existing ERCOT market design, could be implemented without the delay of waiting for new forward markets and new construction, and would go a long way to meeting the reliability and investment needs promised by better scarcity pricing.

Other wholesale electricity markets have demonstrated the feasibility of including operating reserve demand curves as part of economic dispatch. While demonstrating the practical possibilities, these other market implementations have not gone far enough incorporating first principles of economics and reliability to design the prices and related parameters of an operating reserve demand curve.

The PUCT surmounted the biggest hurdle by demonstrating the political will to incorporate scarcity pricing at an adequate level. The PUCT now has a window of opportunity to both address its immediate needs and advance the state-of-the art by embracing without delay a sound foundation for an operating reserve demand curve and better scarcity pricing.

Scarcity Pricing and Electricity Market Design

Efficient electricity market design follows the principles of bid-based, security-constrained, economic dispatch with locational prices. The prices for energy and ancillary services reflect the underlying requirements of the electricity system. These prices can vary substantially across locations, reflecting congestion in the transmission grid. Prices also vary over time due to the large differences in opportunity costs of different electric load and generation alternatives. These efficient prices are highly volatile. Efficient electricity market design incorporates a variety of forward contacting opportunities and financial transmission rights to share the risks through market operations.

In principle, efficient electricity prices provide good incentives for both short-run operations and long-run investments. In the short run, prices reward generators who make their plants available when needed and in response to the changing dispatch conditions. The same prices provide incentives for loads to moderate demand during the most expensive hours and manage load to shift requirements to lower priced hours. In the long run, the expected value of future short-run payments for energy and ancillary services provides the revenue for investment in new generating facilities or energy conservation.

In an idealized setting, this efficient design and associated electricity prices should be sufficient to support new investment when it is needed. In practice, as is now well known, actual electricity markets often produce results where energy and ancillary services prices are not sufficient to support new investment. (Newell et al., 2012) There are many practices that contribute to the aggregate pressure to keep prices too low to provide adequate incentives for load and generation, but the primary explanation is that prices do not adequately reflect the value of capacity scarcity. (Joskow, 2008) This focus on scarcity pricing provides a useful analytical framework and can incorporate many of the other practices that suppress electricity prices.

When there is excess available capacity, competitive pressure should drive the electricity market-clearing energy price to the variable opportunity cost of the most expensive generator running. Simultaneous consideration in the economic dispatch should produce compatible prices for ancillary services, with little or no value for additional capacity. This is the commonplace rule that animates most discussion about normal pricing conditions. However, when generating capacity becomes scarce it should become valuable. The price for operating reserve capacity should rise to reflect the scarcity conditions. The corresponding price for energy should increase to reflect this opportunity cost of reserve scarcity. This scarcity pricing could and should produce a large increase in prices under scarcity conditions, providing just the right incentives at a time where capacity would be especially needed.

In a fully developed wholesale electricity market, demand bidding would interact with scarcity prices in a natural way. Loads would specify the schedule of maximum willingness to pay, i.e., the energy demand curve, and when prices rose above these levels the load would dispatch down. In short-run equilibrium the resulting electricity price would be set by the variable opportunity cost of the least-expensive load being served. The electricity price would be different than the variable energy cost of the most expensive generator running, with the difference being the short-run scarcity price. In the long-run equilibrium the expected future scarcity prices would be just high enough to justify the capacity costs of new investment in generation and load management.

In the actual wholesale electricity markets we have, in ERCOT and elsewhere, this idealized version of the "energy-only" electricity market does not exist. In particular, a missing part of the picture is the active participation of demand response bidding in the short-run market. This combines with the practices that suppress energy and ancillary services prices to create a type of vicious circle. With prices suppressed, there is not much incentive to participate in demand bidding or make the investments needed for active load management. The absence of demand bidding keeps demand up and prompts system operators to intervene in short-run operations in ways that suppress energy prices.

The result in wholesale electricity markets has been the "missing money" problem.[2] There is money missing in the wholesale electricity market in the sense that average prices are not high enough to sustain new investment. Looking forward, the lack of investment raises the specter of reliability problems. This produces a variety of approaches to address the problem, provide the missing money, and meet the reliability needs of the system. The two most prominent approaches are to create forward capacity markets or to raise generator offer caps. Both methods present their own challenges.

Forward Capacity Markets

The basic idea of a forward capacity market is to arrange additional payments to those who offer capacity up to some estimated level of total capacity needed to meet projected reliability requirements. The total forward installed capacity requirement is either fixed as under the

[2] The characterization as "missing money" comes from Roy Shanker. For example, see (Shanker, 2003).

Independent System Operator New England (ISONE) or set according to a demand curve as in PJM. Generators and demand resources then compete in a forward auction by making offers to supply capacity. The auction determines a market-clearing price for capacity that is paid to all clearing resources.

The capacity payment is intended to cover the missing money. The putative product is installed capacity and not energy, and the capacity payment is generally separate from the energy market payments. This approach, therefore, requires a regulatory definition of a "capacity product" that is unlike energy in that there is no simple way to measure and observe delivery. This forward capacity product definition is distinct from the definition and provision of short-run operating reserve capacity where the uncertainties are reduced from looking ahead years to looking ahead minutes or hours.

The many difficulties of defining and implementing forward capacity markets have been under active discussion in studies and proceedings of the PUCT. It is difficult to properly define the capacity product, determine the amount and location of capacity needed many years ahead, and integrate diverse products that blend capacity and energy in a variety of configurations. Experience has shown that forward capacity markets, with their preset procurements, are subject to manipulation by generators and loads. For example, in PJM the independent market monitor regularly finds that aggregate energy markets are workably competitive and capacity market structures are not competitive. This leads to requirements for capacity market regulations on offers and performance, bid mitigation, and other complications. The problems are fundamental. It is not easy to build a good forward capacity market model based on first principles.

Importantly, whatever the choice of whether to have a capacity market and what design to choose, the focus on the forward market produces at best weak connections with real time operations. The socialization of capacity payments does not send the right scarcity signals to generators or loads in real-time operations. Capacity markets may provide additional capacity that could be available in real-time. But capacity markets themselves do not create the correct incentives to operate capacity or change load in response to short-run scarcity conditions. Something more is needed. (Hogan, 2006) Capacity markets may help with scarcity, but not with scarcity pricing.

Generator Offer Caps and Scarcity Pricing

In principle it would seem that scarcity pricing would arise naturally in the absence of offer caps on generators. An offer cap is one of the mechanisms for suppressing real-time prices. If there is no offer cap, or if the offer cap is very high, then generators could increase the offer prices during periods of scarcity and market-clearing prices would increase accordingly. An increase in offer caps, to $9000/MWh by 2015, has been approved by the PUCT. Similarly, the model for scarcity pricing in PJM is based on increasing under offer caps under certain conditions indicating real-time capacity scarcity. (FERC, 2012a) A similar approach is found in the recent decisions on the Southwest Power Pool (SPP) market design order from the Federal Energy Regulatory Commission (FERC). (FERC, 2012b)

A high offer cap may help in addressing one problem that leads to suppressed prices, but it does not deal with the treatment of operating reserves or the real-time reliability problems that arise under shortage conditions. Furthermore, to the extent that system operators turn to out-of-market interventions to address reliability issues, the scarcity conditions need not translate into higher prices despite the high offer cap.

A problem with increasing offer caps arises in the tradeoff for mitigating market power. A principal purpose of generator offer caps is to mitigate the exercise of market power through economic withholding. The concern with an exercise of market power is especially acute during shortage conditions. However, a high offer-cap policy is built on the expectation that generators will withhold supply under scarcity conditions! This presents a series of problems for generators, other market participants, and regulators. For instance, generators may misjudge and make their offers too high, and their supply not taken in a high price market. Similarly, shortage conditions will give rise to high prices defined by generator offers. The observation of high scarcity prices would be difficult or impossible to distinguish from the exercise of market power. It will be difficult for regulators to maintain a hands-off policy that defends a high offer cap when scarcity conditions arise. And the expectation that regulators of the future may not have the ability to preserve the policy will inevitably dampen incentives for investment today in anticipation of this future.

A high offer cap would be consistent with a reasonable market for addressing market conditions, but it is not likely to be sufficient to ensure the appropriate market response. Furthermore, a high offer cap is not necessary to provide the proper incentives under scarcity conditions. An alternative approach would return to first principles and the role of operating reserves.

Operating Reserve Demand Curves

Operating reserves for spinning and quick start capacity are a regular feature of all electricity markets. These reserves are distinct from the installed capacity that is the focus of forward capacity markets. Operating reserves are a subset of the installed capacity that is both available and standing by to produce energy on short notice. In any given real-time dispatch interval, reserves are maintained to deal with unpredictable events such as a sudden surge in demand, loss of a generator, or loss of a transmission line. Balancing generation needs to ramp up very rapidly to meet the immediate emergency and to give the system operator time to reconfigure the energy dispatch.

Although it is difficult to forecast requirements for installed capacity many years ahead, it is a comparatively easier and more familiar task to forecast operating reserve requirements and availability for the next instant or parts of an hour. Supply, demand and transmission conditions are known. Weather forecasts are on hand. System operators have experience and procedures for defining and evaluating standby capabilities.

The most immediate requirement is for the operating reserves needed to meet security contingency conditions. The flows of electricity respond much faster than operators to sudden events such as the loss of a generator. In order to avoid cascading failures that could blackout most or all of the system, operators must maintain a minimum level of contingency reserves. From an economic perspective, a way to interpret and define these contingency reserves would be as the level at which the system operator would impose involuntary controlled curtailment on selected loads in anticipation of the contingency in order to maintain minimum adequate capacity that could provide additional energy but must be kept in reserve.

System reliability would be improved if more operating reserves than the minimum were available in terms of response to increase generation or quickly decrease load. Over the next few minutes or parts of an hour, events may arise that deplete operating reserves and bring the system below the minimum contingency requirement, in which case the operator will have to impose involuntary load curtailments to restore the minimum contingency protection.

The importance of operating reserves has always been known, but the requirements for operating reserves were given only a simplified consideration in wholesale electricity market design. The assumption was that the operating reserve requirement at any moment and location could be represented by a fixed requirement, and that economic dispatch would produce simultaneous optimization that would incorporate the dispatch of energy and reserves. Pricing, especially during shortage conditions, would be provided by demand bidding to voluntarily reduce load at high prices, and the value of operating reserves would be determined by the implied scarcity prices. While this was a workable approximation in theory, it failed in practice when the associated demand bidding did not materialize.

One solution to this problem is to revisit the treatment of operating reserves. In effect, the administrative requirement for a fixed level of operating reserves is equivalent to a vertical demand curve. As outlined above, this cannot be correct from first principles. The error and its impact could have been small with vigorous demand bidding in the dispatch, but the chicken-and-egg problem of inadequate scarcity pricing inhibiting demand bidding makes the error much more important and calls for a better representation an operating reserve demand curve.

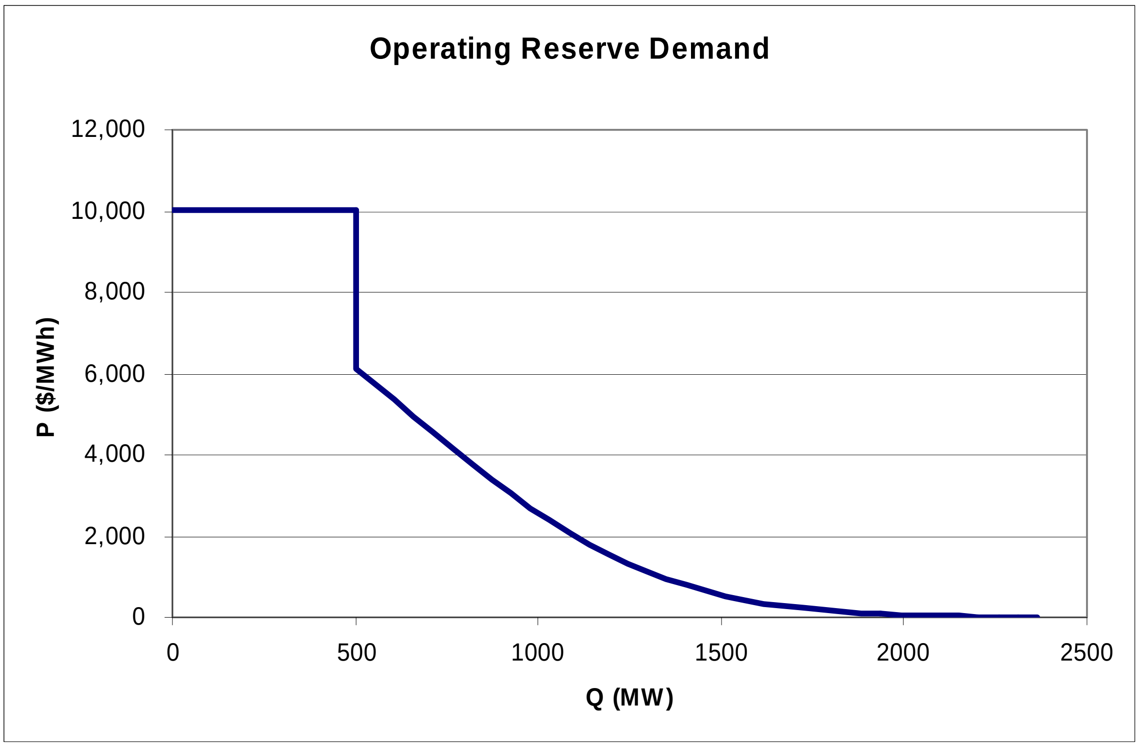
To be sure, an operating reserve demand curve would be an administrative intervention in the market. But this is already true of the administrative requirement for operating reserves. In the presence of a necessary and inevitable operating reserve requirement, it is clear that the superior administrative rule would be a better model of the demand for operating reserves that goes beyond the fixed quantity requirement. (Hogan, 2005)

The basic outline of an operating reserve demand curve follows from the description above. The key connection is with the value of lost load (VOLL) and the probability that the load will be curtailed. Whenever there is involuntary load curtailment and the system has just the minimum of contingency operating reserves, then any increment of reserves would correspondingly reduce the load curtailment. Hence the price of operating reserves should be set at the value of lost load.

At any other level of operating reserves, set to protect the system for events in the immediate future, the value of an increment of operating reserves would be the same VOLL multiplied by the probability that net load would increase enough in the coming interval to reduce reserves to the minimum level where load would be curtailed to restore contingency reserves. Hence the incremental value of operating reserves would be the analogous to the product of the loss of load probability (LOLP) and VOLL, or LOLP*VOLL. The clearest example of the application of this logic is from the implementation by the Midwest Independent System Operator (MISO).

> "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 2009, Schedule 28, Sheet 2226).

Combining this with the treatment of minimum contingency reserves, the resulting operating reserve demand curves would look like the hypothetical illustration in the accompanying figure drawn from a similar analysis in another region. Here the assumed VOLL is $10,000/MWh and the minimum contingency reserve requirement is assumed to be 500MW. The discontinuity at 500MW occurs because of the probability that load will reduce over the interval more than the expected generation losses, in which case there is no need for load curtailment. Above the minimum reserve level, the shape of the demand curve follows the LOLP distribution. Importantly, a general property of an operating reserve demand curve derived from first principles is that the demand is not vertical and price does not drop to zero. Scarcity pricing would arise to some degree for all hours.



Depending on the needs in ERCOT, the same principles could be generalized to include zonal requirements for operating reserves that interact with energy and economic dispatch, incorporate local interface constraints, and provide compatible short-term prices for operating reserves and interface capacity. (Hogan, 2010) With simultaneous optimization in the economic dispatch, the scarcity prices attributed to operating reserves apply as well to energy whenever there is a tradeoff between energy dispatch and operating reserve capacity. Hence, the scarcity prices would contribute to resolving the missing money problem for all generators actually providing energy or reserves.

Features of Operating Reserve Demand Curves

The essential features of operating reserve demand curves include various properties that complement the basic electricity market design.

Reliability

Market price incentives for energy and reserves would be better aligned with reliability requirements. By design, the scarcity prices would reflect the immediate reliability conditions, and both generators and load would see the benefits of responding to the market reliability needs. The focus on short-term operations would provide incentives that are difficult or impossible to capture in forward markets. Short-term changes in fuel availability, plant outages, demand conditions, load management practices and so on, would be reflected in current prices; emergency actions would be compatible with rather than in conflict with market incentives.

Consistent Design

Since the operating reserve demand curve is indicated by first principles, it is inherently compatible with either an “energy only” ERCOT market design or the various forward-market constructs under consideration. There is a possibility that an operating reserve demand curve by itself would provide sufficient incentives to support resource adequacy without further developing forward capacity markets. However, the benefits do not depend on resolving this larger question. There is no need to choose between the operating reserve demand curve and the other elements of electricity market design. Better scarcity pricing would help in all cases. Fixing the fundamental scarcity pricing related incentives should be the first order of business.

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. This would help resolve the chicken-and-egg problem. Higher scarcity prices in some hours would provide the incentive for demand bidding and voluntary demand reductions. The demand bids could become more important and more significant than the operating reserve scarcity prices determined as part of the dispatch simultaneous optimization. The incentives would be reinforcing, with voluntary demand response supplementing operating reserves.

Price Spikes

A higher price in some hours 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. Unlike relying only on high generator offers, which may exist for a few hours, higher prices would reflect the entire range of scarcity conditions. Only when conditions are truly extreme and there is a material threat to reliability, would and should prices approach the VOLL.

Practical Implementation

The technical requirements for inclusion in economic dispatch and simultaneous optimization of energy and reserves are known and demonstrated. The New York Independent System Operator (NYISO, 2012), ISONE (ISONE, 2012) and MISO implementations dispose of any argument that it would be impractical to employ an operating reserve demand curve. The only material issues for ERCOT to address are the level of the appropriate VOLL price and the preferred model of locational reserves.

Operating Procedures

Implementing an operating reserve demand curve does not require changing the dispatch 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. There would be a requirement to translate other emergency actions, such as voltage reductions, into equivalent operating reserve contributions. Emergency action policies could remain as at present, but the operating reserve demand impacts would be incorporated to make sure that out of market actions resulted in higher and not lower prices.

Multiple Reserves

The demand curve would include different kinds of operating reserves, from spinning reserves to standby reserves. This would be similar to the cascade models for reserves and other ancillary services found in other market designs. For example, suppose there are two types of reserve categories, spinning and half-hour standby. The same rule described for the generic operating reserve demand curve would produce two demand curves derived from the VOLL and corresponding LOLP distribution over the relevant period. Spinning reserves would be able to meet both requirements. Standby reserves that could be available in thirty minutes would be able to provide only the second type of operating reserves. Hence, the price of spinning reserves would never be less, and likely would be more, than the price for standby reserves.

Market Power

Better reserve 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. Hence, lower generator offer caps would not be inconsistent with high market clearing prices for energy and reserves. But the higher market-clearing prices would be determined by the operating reserve demand curve. Generators would not have to withhold, economically or physically, to realizer high market clearing prices. And during scarcity conditions regulators would have a simple explanation pointing to the operating reserve scarcity prices rather than trying to explain high offers by generators.

Hedging

Forward contracts could still hedge forward loads. The contracts would reflect expected scarcity costs, and price in the risk, but there is nothing that would prevent the market from deploying a variety of financial contracts that incorporated scarcity prices on average while retaining efficient incentives at the margin.

Increased Costs

The higher average energy costs from use of an operating reserve demand curve do not automatically translate into higher total system costs. In the aggregate, there is an argument that costs would be lower. Opportunities to meet reliability requirements would expand, with the stimulus of better scarcity pricing. Investments in responsive generation and load management that would be difficult or impossible without smarter prices could appear, and this would lower average costs. Higher scarcity prices would lower the missing money challenge, and thereby reduce the impacts of problems in any forward capacity markets that might exist.

Conclusion

The fundamental problem of inadequate real-time scarcity pricing has a fundamental solution. The need for a well-designed operating reserve demand curve was overlooked in early wholesale electricity market designs. There is today a much better understanding of why better scarcity pricing is essential, why demand bidding has not solved the problem, and how a well-designed operating reserve demand curve could fill in this significant gap. The PUCT has a window of opportunity to complement its resource adequacy discussions with an accelerated program to adopt an operating reserve demand curve. This approach would be fully compatible with other PUCT market-oriented policies, the general ERCOT market design, and the proposed options for long-term resource adequacy.

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