Three Simple Steps to Clip the Peak in the Texas (ERCOT) Electricity Market

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Electricity resource adequacy is the most urgent and controversial challenge facing the Electric Reliability Council of Texas (ERCOT) market. The policy discussions have neglected some very simple steps that could be taken to promote demand response and reduce peak demand. An allocation of some of the responsibility for non-spinning reserves based on the contribution of a load serving entity (LSE) to peak demand would encourage LSEs to undertake programs to reduce their contribution to the peak. An extension of the four coincident peak (4 CP) pricing used to charge large industrial energy consumers for transmission services to smaller commercial and residential loads would encourage smaller consumers to reduce their peak usage. Narrowing the definition of "peak demand" in the Public Utility Commission of Texas (PUCT) energy efficiency rules would encourage energy efficiency measures better focused on peak demand reduction.

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Introduction

With low natural gas prices depressing the market price of electricity and reducing incentives to construct new generating capacity, great concern has been raised in recent years over the ability of Electric Reliability Council of Texas (ERCOT) wholesale market's energy-only structure to maintain reliability. The growth in energy demand has outpaced resource additions in this rapidly growing state. Calculations completed by the ERCOT staff in May 2013 suggest that ERCOT's planning reserve margin will fall below the 13.75% target level beginning in the summer of 2015 (ERCOT, 2013), and below levels that the North American Reliability Council deems acceptable. (NERC, 2013) Nonetheless, some analysts see the resulting level of investment in new generation resources as efficient and reasonable, in light of the underlying economics. (Kleit and Michaels, 2012) Since ERCOT is widely regarded as North America's most successful restructured market (Distributed Energy Financial Group, 2011; Alliance for Retail Choice, 2007) the problems in Texas have attracted international attention. How well this market addresses its resource adequacy challenges will affect restructuring efforts elsewhere.

ERCOT is the only U.S. power market administered by an centralized Independent System Operator or Regional Transmission Operator that does not have either a capacity market or a requirement that LSEs demonstrate that they have sufficient capacity resource to meet future needs, and the Commission has been deadlocked over proposals to introduce such mechanisms. Capacity markets or LSE obligations to procure capacity are viewed as an effective and efficient means of ensuring that target reserve margins will be reached. (Brattle, 2012) Yet, consumer interests and retail electric providers have been concerned over the costs that might be added to retail prices. Those advocating greater competition and minimal regulatory oversight fear that the introduction of a capacity market would be seen as an admission that the simple forces of supply and demand in an energy-only market are insufficient to ensure a reliable supply. Thus far, it has been the hope of the Public Utility Commission of Texas (PUCT or Commission) that better price signals will suffice in remedying the situation.

The Commission has put into place a plan to gradually increase offer caps in the ERCOT wholesale market to $9,000 per MWh. During scarcity conditions, prices will be raised up to the system-wide offer cap when operating reserves are deployed. Similarly, energy from units selected by the reliability unit commitment process to provide reliability must-run services will be priced at the cap. Minimum offer prices have been set for energy deployed from units providing non-spinning reserves. Market changes to discourage prices from dropping when additional resources are deployed during emergency conditions are under debate. The PUCT is also actively considering demand curves for operating reserves to purportedly improve reliability and support scarcity pricing. (Hogan, 2013)

Demand response is viewed as at least part of the answer and changes in market prices impact the economics of demand response as well as incentives to construct new supply-side resources. It is widely recognized that the absence of any significant response by consumers in an energy market to price changes can introduce a host of problems. While ERCOT has been very successful in encouraging the participation of interruptible or curtailable loads in its markets for ancillary services (Zarnikau, 2006; Zarnikau, 2009), passive or voluntary response to price signals in the energy market has been very limited (Zarnikau and Hallett, 2008). The level of demand response in ERCOT is a small fraction of its potential (Elliot et al, 2007; FERC, 2009).

Modest steps have been taken to facilitate demand response in the ERCOT market. Forecasts of wholesale prices for a period of two hours into the future are now available to the market to alert industrial energy consumers and LSEs exposed to market prices when a spike in prices is likely. These price forecasts are designed to replace the binding real-time prices which were made available with 8 to 10 minutes of advance notice prior to the change in ERCOT's market structure to a nodal design in December 2010.

Plans have been approved to more-formally allow consumers or loads to participate in the real-time energy market. LSEs will be able to submit demand curves into the security-constrained economic dispatch (SCED) model used to deploy resources. Wholesale prices would then better reflect consumers' willingness-to-pay for electricity. However, load participation in SCED is expected to be limited, at least initially. To the consumer, the advantages of direct participation through SCED as opposed to voluntary or passive response to price signals are limited. The onerous penalties for failure to follow dispatch instructions will limit participation to only those loads which can be highly controlled. While ERCOT has taken many steps recently to better accommodate aggregations of curtailable loads, such aggregations are unlikely to be allowed to participate in the initial release of the "Loads in SCED" project.

The PUCT has shown little appetite for new "out-of-market" demand response programs. To the contrary, better integration of ERCOT's existing Emergency Response Service (ERS) program and some utility-administered programs into ERCOT's markets for ancillary services has attracted some interest.

Greater demand response could certainly contribute to solving ERCOT's resource adequacy woes. Yet, LSEs and the national providers of curtailment services complain that the economics of demand response remain marginal in the ERCOT energy market even with the recent market changes. The forces of supply and demand dictate the economics of demand response in the energy market. The benefits of demand response are dependent upon the costs that may be avoided through curtailments in consumer purchases of electricity during price spikes. Higher price caps foster the economics of demand response, but price spikes need to occur with sufficient frequency. While the summer of 2011 – the hottest in the recorded history in the state – saw many price spikes, high prices were infrequent during the subsequent two years. The changes in market structure noted above are in the right direction, yet perhaps still too modest to garner widespread interest in demand response.

While hundreds of comments have now been filed at the PUCT suggesting changes to address the resource adequacy challenge,[1] some simple steps have been overlooked. In this paper, three steps are examined:

- Allocate some of the responsibility for non-spinning reserves based on the contribution of an LSE's load to total system peak demand.
- Extend the four coincident peak (4 CP) pricing used to charge large industrial energy consumers for transmission services to smaller commercial and residential loads.
- Narrow the definition of "peak demand" in the PUCT's energy efficiency rules.

These steps would enhance the economics of demand response. Regardless of whether the PUCT eventually opts to adopt a capacity market, these changes could yield efficiencies. Alas -- as with any change in cost allocation or policy, there will winners and losers. Social and equity considerations must be weighed against the likely improvement in economic efficiency and resource adequacy.

Allocate some of the responsibility for non-spinning reserves based on the contribution of an LSE's load to system peak demand

Non-spinning reserves, as well as responsive reserves, protect the system against unforeseen contingencies (e.g., unplanned generator outages, load forecast error, and error in forecasts of wind power generation). Non-spinning reserves consist of power plants capable of being ramped to a specified output level within thirty minutes or load resources that are capable of being interrupted within thirty minutes. ERCOT's requirements for non-spinning reserves typically vary between 500 MW and 2,000 MW, depending upon expected system conditions. During peak hours, at least 1,375 MW is required.

Under the procedures which have been in place since retail competition was introduced in the service areas of the investor-owned utilities in January 2002, ERCOT establishes a plan for operating reserves and other ancillary services on a day-ahead basis. Each LSE has an obligation for a share of the target level of each ancillary service. Under Section 4.2.1.2 of ERCOT's Protocols, obligations are assigned to LSEs by ERCOT on a load-ratio share basis. The load ratio share is the ratio of the LSE's

[1] These may be viewed under *Project No. 40000: Commission Proceeding to Ensure Resource Adequacy in Texas* at: http://www.puc.texas.gov/industry/filings/Default.aspx

adjusted metered load to ERCOT's total adjusted metered load during the most recent historical same hour and day of week for which settlement statements are available. In practice, this is typically the same hour and day of the previous week. Per Section 4.4.7.1 of the Protocols, an LSE may meet its obligations by self-arranging those services with a provider of resources (i.e., a party which can provide the ancillary service with a qualifying power plant or interruptible load) or by allowing ERCOT to procure the service on the LSE's behalf.

ERCOT operates day-ahead markets for non-spinning reserves, as well as regulation services and responsive reserves. Reliance by LSEs upon ERCOT's market for non-spinning reserves has increased in recent years.

Over the long-term, an allocation of obligations for non-spinning reserves and other ancillary services based on the load ratio share of the LSE is essentially an allocation based on the energy consumption satisfied through each LSE. This approach is simple and has been adopted in many competitive wholesale markets. However, by using it we may be missing an opportunity to send a price signal that could discourage peak period consumption.

ERCOT (2012) notes: "Examples of circumstances when NSRS has been used are . . . Afternoons during summer seasons when high loads and unit outages outstripped the capability of base load and normal cyclic units . . . ." Thus, need for non-spinning reserves is partly attributable to peak demand, and an argument could be made that some portion of the cost of non-spinning reserves should accordingly be tied to the LSE's contribution to system peak demand. Thus a cost allocation method that recognizes both drivers – akin to the "average and excess" or "average and peak" allocation schemes often used to allocate generation assets in traditional rate cases – would seem appropriate. The demand-related billing determinants could be the LSE's contribution to ERCOT's system-wide four coincident peaks, as discussed below, although other measures could be considered.

From the perspective of economic efficiency, there may be superior ways to allocate obligations to provide ancillary services to market participants, including assignment to generators and customer-specific fees. (Hirst and Kirby, 2003) Yet, the complexities and equity concerns that have prevented implementation of more-complicated cost allocation in other markets are just as strong in Texas. An allocation of a portion of non-spinning reserves obligations on the basis of a LSE's contribution to peak demand would constitute a very modest step in the right direction.

For illustrative purposes, assume that 25% of the cost of non-spinning reserves was collected from LSEs based on a demand-related billing determinant. To simplify the calculations, assume that all non-spinning reserves were procured through ERCOT's day-ahead market and that ERCOT's target level of non-spinning reserves was 1,200 MW. Using some reasonable assumptions, this would increase an LSE's cost of meeting the peak demand needs of its customers by $153.92 per MW, while reducing the amounts paid on load-ratio share basis by an equivalent amount. This calculation is presented in Table 1. This is small relative to the $25,000 per MW charges that LSEs pay for transmission services based on their contribution to 4 CPs, but would nonetheless send a price signal to encourage LSEs to take steps to reduce their peak requirements through energy efficiency programs and demand response actions.

Table 1.
Non Spinning Reserve Service Allocation with 25% Allocated Based on a Measure of Peak Demand

Typical Non-Spinning Reserve Service Price	4	$/MW	
Average Amount of Obligation for System per Hour	1200	MW	
	$4,800	Value per Hour	
Fraction to Allocate Based on Peak Measure	0.25		
	$1,200	Value per Hour	
Hours per Year	8760	Hours	
Annual Amount Allocated Based on Peak Measure	$10,512,000		
Peak in ERCOT in 2011	68,294	MW	
Cost per Peak MW	$153.92	per MW at Peak	

In the near term, such a change might shift non-spinning reserves costs onto LSEs serving residential loads, given that residential air conditioning comprises such a large component of peaks in Texas. Thus, this shift could lead to higher prices to residential consumers in the short run. Yet the increase in costs to residential consumers from this change might be quite small relative to the cost increases that could result if a capacity market was established and the cost of that market was assigned to consumer groups based on their contribution to peaks.

Extend four coincident peak (4 CP) pricing for transmission services to smaller loads

In ERCOT, large industrial energy consumers with interval data recorders (IDRs) are charged for transmission services based on the individual consumer's contribution to four coincident peaks (4 CPs), i.e., the 15-minute intervals of highest demand on the ERCOT system in each of four summer months -- June, July, August, and September. The total level of compensation provided to transmission owners is approved by the PUCT each year. Transmission costs are then apportioned to each load, or user of the transmission system, based on its share of total demand during these 4 CPs. The costs are recovered through levelized monthly charges paid the following year. Revenues from the transmission charges are collected by the retail electric provider (REP) providing electricity to the consumer at the retail level and these revenues are ultimately passed-through to transmission owners.

A consumer that can reduce its demand for electricity by 1 MW during each of the four CPs can save about $25,000 in transmission charges the following year. This potential avoidance of transmission charges provides a strong incentive for industrial energy consumers with some flexibility in their operations to engage in "4 CP chasing."

Until recently, the contribution of smaller consumers (e.g., residential and commercial energy consumers) to the 4 CPs was difficult to cost-effectively measure, so generic profiles were used to approximate their level of demand during various time periods, including the 4 CP periods. The tariffs approved by the PUCT still convert a residential energy consumer's assumed contribution to the 4 CP into an energy charge.[2] As a result, there is no incentive for a residential or small commercial energy consumer to reduce consumption during periods which could potentially set a summer monthly peak, unless the consumer is participating in a demand response program.

With the deployment of advanced metering systems in the areas of ERCOT open to retail competition, there is no longer a technical impediment to charging smaller consumers for transmission services based on their contribution to the 4 CPs. The requisite 15-minute data are already being used in ERCOT's settlement process for other purposes.

If the transmission tariffs approved by the PUCT were appropriately modified, transmission charges could be directly assigned to residential and small commercial energy consumers in the same manner in which they are assigned to large industrials. While retail pricing is an unregulated function in areas of ERCOT served by investor-owned transmission and distribution utilities, a direct assignment by ERCOT could lead to a pass-through of the 4 CP demand charges to residential and small energy consumers, as is now typical for larger consumers. This would, in turn, provide a better price signal to smaller energy consumers during peak periods.

The introduction of a demand charge on residential electric bills reflecting the customer's contribution to ERCOT peaks during the previous year would no-doubt be controversial. Smaller consumers are not accustomed to seeing demand charges on their electric bills. Even large industrial loads have difficulty in assessing the probability that a peak will occur in any given 15-minute period. Consumers with limited financial resources might also be among those who would experience the greatest

[2] Tariffs for transmission service may be found at: http://www.puc.texas.gov/industry/electric/rates/TDR.aspx. The design of these rates may be traced to Order 40 in PUCT Docket No. 22344: Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA Section 39.201 and PUCT Subst. R. 25.344.

difficulty in responding to price signals. However, this change would incent LSEs to implement load control programs to help their customers reduce electricity purchases during peak periods and improve the economics of many load control technologies.

Industrial energy consumers served at transmission voltage reduce their energy purchased by up to 4% in response to 4 CP transmission charges. (Zarnikau and Thal, 2013) It is unclear how residential and small commercial customers might respond, although experiments in critical peak pricing suggest the peak reduction could be quite significant. (Faruqui and Sergici, 2010)

Narrow the definition of "peak demand" in the PUCT's energy efficiency rules.

The investor-owned transmission and distribution utilities (TDUs) in the ERCOT market spend nearly $100 million per year to meet goals for energy efficiency set by the state legislature. In the 2000s, these programs were largely focused on producing demand reduction at the time of the utility's (or ERCOT's) system peak. Peak was generally defined as the 15-minute interval or hour at which demand was its highest during the summer.

In the late 2000s, the definition of "peak demand reduction" was modified numerous times and the concept of a wide "peak period" was introduced. The peak period is now "the hours from one p.m. to seven p.m., during the months of June, July, August, and September, and the hours of 6 to 10 a.m. and 6 to 10 p.m., during the months of December, January, and February, excluding weekends and Federal holidays." The change was designed to promote measures with impacts that did not necessarily correspond to the exact interval or hour of the summer peaks, yet had value nonetheless. The inclusion of a winter peak period was prompted by reliability problems following severe cold weather in early February 2011.

By expanding the definition of peak demand, the energy efficiency efforts of the state's utilities have become less-focused on what system planners would normally consider to be peak demand. Measures such as outdoor lighting that might provide some savings during an early-morning peak in a winter month can now contribute to meeting a utility's peak demand goal.

Refocusing the energy efficiency programs to better target periods when demand reduction would make its greatest contribution to maintaining reliability could enhance the value of these programs towards resource adequacy.

Conclusion

Additional steps could be taken to reduce peak demand in the ERCOT market and improve the outlook for future reserve margins. An allocation of some of the responsibility for non-spinning reserves based on the contribution of an LSE to peak demand would encourage LSEs to undertake programs to reduce their contribution to the peak. An extension of the 4 CP pricing used to charge large industrial energy consumers for transmission services to smaller commercial and residential loads would encourage smaller consumers to reduce their peak usage. Narrowing the definition of "peak demand" in the PUCT's energy efficiency rules would encourage energy efficiency measures and programs better focused on peak demand. Two of these three steps would provide better price signals during peak periods, consistent with other steps taken by the PUCT to increase prices during scarcity conditions.

The political difficulties in implementing these changes may be greater than any technical barriers. Any changes in market rules result in winners and losers. Yet careful consideration of how costs are allocated among LSEs, improved exposure of smaller consumers to time-differentiated energy and transmission costs, and more-focused energy efficiency efforts could yield long-term benefits.

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