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PROCEEDING REGARDING POLICY OPTIONS ON RESOURCE ADEQUACY	§ § § §	**PUBLIC UTILITY COMMISSION OF TEXAS**

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COMMISSION PROCEEDING TO ENSURE RESOURCE ADEQUACY IN TEXAS - COMMENTS OF ROBERT L. BORLICK

On June 1, 2012, the Brattle Group released its final report that examined the investment incentives and their resource adequacy consequences in the ERCOT wholesale power market.[1] On August 24, 2012 the Commission requested additional information regarding the policy options set out in Table 1 of the Brattle report. These comments respond to that request.

ABOUT THE AUTHOR

Robert Borlick is an energy consultant with more than 30 years experience related to the economics underlying competitive, wholesale electric power markets. He contributed to the design and implementation of the energy-only electricity markets in Australia and New Zealand as well as to restructured electricity markets in a number of other countries, including the US. In 2005 he co-authored a White Paper for the Midwest ISO describing an energy-only market designed for the Midwest.[2] In addition, for the past six years Mr. Borlick has extensively assisted the Midwest ISO with the development of their demand response programs and has actively participated in a number FERC dockets related to demand response. From 1999 to 2007 Mr. Borlick was a Senior Advisor with the Brattle Group.

THE ONE-IN-TEN RELIABILITY STANDARD

In a memo dated August 16, 2012, Chairman Nelson advocated adoption of the one-in-ten reliability standard that the industry has employed for many decades. Doing this may *de facto*

[1] The Brattle Group, ERCOT Investment Incentives and Resource Adequacy, June 1, 2012.

[2] Midwest ISO, AN ENERGY ONLY MARKET FOR RESOURCE ADEQUACY IN THE MIDWEST, November 23, 2005.

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disqualify the Brattle Group's Option 1 because an unfettered energy-only market may not meet that standard – certainly not by 2014. This is not a weakness of the energy-only market; it is one of its strengths because the level of reliability it produces is the OPTIMAL one. Rather than being administratively determined by bureaucrats, consumers collectively determine the reliability level they want through their disaggregated individual decisions to pay (or not) the market prices for energy in each hour.[3] Of course, for consumers to do so they must be exposed to those hourly market prices through dynamic retail tariffs. Today most of ERCOT's retail consumers are not served under such tariffs but they most likely will be in the near future.

The risk in adopting the one-in-ten standard before price responsive demand (PRD) can develop through dynamic pricing is that ERCOT could be saddled with an uneconomic, excessively costly capacity market that would be difficult to change *ex post* due to the lobbying activities of special interest groups, primarily the unregulated generators. Such a market design would impose unnecessary costs on ERCOT's electricity consumers, particularly the industrial and commercial customers that the state of Texas wants to attract and retain.

At the July 27 workshop Dr. Newell presented a persuasive argument for relaxing the one-in-ten reliability standard when he pointed out that transmission and distribution (T&D) failures within the ERCOT footprint impose customer outage times that exceed by an order of magnitude the outage times imposed by generation shortfalls.[4] These facts alone suggest that the one-in-ten standard would produce a misallocation of resources. Texas electricity consumers may well forgive outages caused by storms and other natural disasters but they are unlikely to forgive the Commission for allowing the Transmission and Distribution Service Providers (TDSPs) to underinvest in T&D redundancy and rapid response teams that can minimize the seriousness of such outages while forcing overinvestment in new generating plants.[5] From the consumer's

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[3] As the Brattle Group report points out [at 100-101] there is no rigorous economic basis for the one-in-ten standard. In fact, we don't even know where it came from! Yet the industry worships it as if it were Aaron's golden calf.

[4] Also see the T&D outage statistics on Table 17 [at 102] of the Brattle Group report.

[5] An example of such consumer backlash is currently on display in the Washington DC area as a result of PEPCO's lackluster response in restoring service to its customers following several storms that occurred over the past year. PEPCO's customer revolt forced the DC and Maryland Public Service Commissions to hold hearings and to impose fines and other monetary sanctions on the utility.

perspective, paying for investments in T&D is no different than paying for investments in generation.

Lastly, there is no need for the Commission to commit to the one-in-ten standard today because ERCOT is unlikely to meet that standard by 2014 given the short time left for remedial action. Rather than spend any more time and effort worrying about what is the "right" reliability standard, the Commission should focus on bringing into service as much additional resources as possible to minimize the likelihood and severity of outages in 2014 and beyond.

OPTION FEASIBILITY

In this section I address the feasibility of implementing each of the Brattle Group's five options by the summer of 2014 and briefly comment on their relative attractiveness in the long run.

1. Energy- Only with Market-Based Reserve Margin

Obviously this option is feasible because it is already in place. However, as I pointed out in my earlier comments, an energy-only market will not function efficiently and effectively without a substantial amount of PRD, which is currently lacking in ERCOT. Furthermore, it will take more than two years for sufficient PRD to develop because most of it will have to come from residential and small business customers through dynamic pricing implemented by the Retail Electricity Providers (REPs). A substantial educational effort will be needed to enlighten small customers regarding how they can benefit from dynamic pricing. Because PRD is the ideal long-run solution, the Commission should promote its development even though it is unlikely to contribute much to resolve ERCOT's looming 2014 crisis.

2. Energy-Only With Adders to Support a Target Reserve Margin

As the Brattle Group report points out, this option contains substantial uncertainty regarding what reserve margins it would bring forth.[6] Regarding resolution of the near-term crisis, this option is a non-starter; regarding the long-term solution, it is inferior to Options 1 and 3. The Commission should not give this option any further consideration.

[6] Brattle, at 106.

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3. ENERGY-ONLY WITH BACKSTOP PROCUREMENT AT MINIMUM ACCEPTABLE RELIABILITY

This option can be implemented in time to provide the short lead-time, supply-side and demand-side resources needed to meet the anticipated 2014 peak demand. Furthermore, in the longer run it is compatible with the energy-only market in that it merely adds a "safety net" – as long as the "minimum acceptable reliability" level triggering its use is set below that which the energy-only market will endogenously produce most of the time. ***I recommend that the Commission pursue this option without further delay.***

4. MANDATORY RESOURCE ADEQUACY REQUIREMENT FOR LSEs

This option is infeasible in the short run and inferior to Options 1 and 3 in the long run. It does not deserve further consideration.

The option is infeasible because it would assign resource adequacy requirements to REPs, who operate in a competitive environment that allows retail customers to switch suppliers, potentially leaving the REP with excess capacity that it had procured to serve the exiting customers. While this option would undoubtedly include a liquid capacity market where excess capacity could be sold, the market prices would be uncertain thereby exposing REPs to substantial financial risk. While these problems are not insurmountable, designing and implementing such a market could easily take more than two years. One need only look at how long it took the Midwest ISO to develop its current capacity market, which is similar to this option.

5. RESOURCE ADEQUACY REQUIREMENT WITH CENTRALIZED FORWARD CAPACITY MARKET

This last option, patterned after PJM's capacity market, clearly cannot be implemented by 2014. In addition, it is inferior to Options 1 and 3 in the long run. It deserves no further consideration.

The PJM market is the result of years of fractious negotiations among the stakeholders, which ultimately produced in an administratively designed "variable resource requirement (VRR) curve that overcompensates generators during times of surplus generating capacity while insufficiently compensating them during times of severe capacity shortages. Many state regulators within the PJM footprint oppose the high capacity prices that the VRR curve imposes on their retail customers - so much so that Maryland and New Jersey have devised schemes for subsidizing new generation additions within their states, primarily to depress PJM's capacity prices. Furthermore, despite the excessive capacity prices, PJM's auctions have attracted relatively little new generating capacity. Most of the capacity additions have been demand response. The following table summarizes the results of PJM's two most recent Base Residual Auctions.

	New Generation	Generation Uprates	Demand Response	Energy Efficiency
2015/2016 BRA	4,898.9	447.4	14,832.8	922.5
2014/2015 BRA	415.5	341.1	14,118.4	822.1

Source: PJM

FACILITATING DEMAND RESPONSE

Given the short time frame, demand response and energy efficiency are about the only resources that can be brought into service in substantial amounts by 2014. Described below are three actions the Commission can take to facilitate their development.

Facilitate Participation of Third Party Curtailment Service Providers

My previous comments recommended that the Commission facilitate the wholesale market entry of third-party Curtailment Service Providers (CSPs). These entities would contract with retail customers to provide both economic demand response (i.e., customers reducing loads when the hourly wholesale market prices exceed the marginal energy price in their retail contracts or utility tariffs) and reliability demand response (i.e., customers agreeing to interrupt loads during supply scarcity events). The CSPs would then sell the demand response to ERCOT, which would recover the payments from each retail customer's REP or LSE.

Because CSPs primarily target medium-to-large commercial and industrial customers the amount of demand response that can be tapped through CSPs is limited in ERCOT, where these customers that are not already buying directly from the wholesale market account for less than 30 percent of the peak demand.

FACILITATE SMALL CUSTOMER DEMAND RESPONSE THROUGH THE TDSPs

The quickest way to reduce the peak loads of residential and small business customers is through direct load control programs implemented by the TDSPs (which the Commission directly regulates). These load control programs would specifically target customers' air conditioners, electric water heaters and pool pumps. Similar load control programs have successfully operated for many years in Florida and currently amount to about 5.5 percent of the summer peak load on Florida's transmission-constrained peninsula.[7] In stark contrast, ERCOT has *essentially no* load enrolled in such programs![8]

The Commission should consider ordering mandatory participation of all residential customers in direct load control programs, where such participation is cost-effective, until such time as it is clear that ERCOT can maintain resource adequacy with voluntary customer participation. The TDSPs have the capability to assess cost-effectiveness based on each customer's historical electricity usage profile.[9]

A number of residential/small customer pricing pilot studies have revealed that response to dynamic pricing is greatly enhanced through enabling technology.[10] This same technology can be used by the TDSPs to directly control a customer's largest loads. Once dynamic pricing is fully implemented control of the enabling devices could be transferred to the retail customers.

The TDSPs could ratebase their investments in the load control program or they could directly recover the costs associated with each customer from that customer, as decided by the Commission. In addition, when a TDSP reduces a customer's load that customer should be credited for the saved energy at a price equal to the difference between the hourly wholesale

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7 North American Reliability Council, 2011 Long Term Reliability Assessment, November 2011, at 216.π

8 *Id.*, at 200.

9 For example, if the installed cost of the enabling technology is $300 (Brattle at 93) and it is expected to shave a residential customer's air conditioning load during peak hours by 1.0 KW, assuming 50 percent cycling, (FERC, National Assessment of Demand Response Potential, June 2009, at 211) the incremental investment is $300 per KW of peaking capacity. For comparison, the "overnight" installed cost of a simple cycle combustion turbine peaking plant is estimated to cost about $667 per KW (Brattle Group Report at 23).

10 Faruqui, Ahmad, et al, Dynamic Pricing of Electricity for Residential Customers: The Evidence from Michigan, June 1, 2012, at 20.

market price and the energy price in the customer's REP contract.[11] The TDSP would then recover this revenue from the customer's REP. This recovery scheme would not disadvantage the REP because the amount recovered would equal the windfall profit the REP would gain from not having to purchase the saved energy at the wholesale market prices (discussed further below). Once dynamic pricing is implemented the TDSP direct load control programs would be converted to enable customer responses to energy prices.

INCENT DEMAND RESPONSE THROUGH DYNAMIC PRICING IN RETAIL TARIFFS

This action is unlikely to produce much demand response by 2014 but will support energy-only market viability in the long run. Developing PRD through dynamic retail pricing will be difficult because:

- most customers (particularly small customers) see little need to become more involved in managing their electricity consumption. This is partly due to human nature, which opposes to change, and partly due to customers' ignorance regarding the potential bill savings that dynamic pricing can provide
- Retail Electricity Providers (REPs) will not be motivated to offer dynamic pricing tariffs if there is little or no customer demand.

As I stated in my earlier comments, the Commission should launch a full-scale effort to educate retail customers on the benefits to be derived from dynamic pricing. The TDSPs are well positioned to implement such education programs because most retail customers are captive to these entities and the TDSPs can easily recover their program costs through T&D surcharges.

Although the Commission has no authority to order REPs to implement dynamic pricing, this may be a nonissue because the REPs have a financial incentive to do so. Reducing a customer's on-peak consumption causes the REP to reap substantial savings by not having to procure energy at the high on-peak prices (or equivalently, to resell the foregone energy back into the wholesale

[11] The wholesale market prices could even grossed up to account for the avoided distribution system losses, which typically average about seven percent of the energy withdrawn from the transmission system.

market at those high prices) while still collecting most of the procurement costs, which the REP originally included in the fixed-price contract offered to the retail customers.[12]

One palatable way to sell dynamic pricing to retail customers would be for the REPs to offer their conventional, fixed-price contracts bundled with a buy-back feature that would pay customers for their foregone energy at the hourly wholesale market prices. The REPs could then pass on the avoided costs to their customers.

CONCLUSIONS

I stand by my earlier comments, which stated that ERCOT's energy-only market has served Texas consumers well for many years and should be continued, albeit with a substantial amount of PRD. The Commission should not prematurely judge this energy-only market before it has the necessary ingredient to succeed, i.e., PRD. Moving to a capacity market would be a big mistake.

Regarding the near-term crisis that ERCOT faces, the Commission needs to take prompt actions to develop interruptible loads among large industrial and commercial customers through CSPs and among residential and small business customers though the TDSPs. It should not delay these actions by spending any more time and resources to determine the "right" reliability standard for ERCOT to employ in its planning.

Respectfully submitted by,

Robert L Borlick

Robert L. Borlick

August 30, 2012
Washington, DC

[12] This is why it is equitable, as well as economically efficient, for the TDSPs to bill back to the REPs the foregone energy credits associated with the direct load control programs described above.

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