White Paper

Playing ERCOT's Shortage in 2018

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Shareables

- ERCOT's market design creates larger swings in cyclicality and greater potential for above-Net CONE earnings.
- Higher forward energy prices recently create opportunities for generators to hedge against volatility and uncertainty.
- Because of the magnitude of capacity shortage, demand growth, and a lean interconnection queue, shortage conditions may persist well beyond 2018.

Executive Summary

Three months ago, ERCOT's December Capacity, Demand and Resources (CDR) report projected a reserve margin of just 9.3% going into 2018. This is below both the estimates for economic equilibrium reserve margin[1] and the 1-in-10 Loss of Load (LoLE) target[2] , and is one of lowest projected reserve margins in the recent history for any organized market in North America. Investors now have the opportunity to earn much greater returns than have been seen over the past seven years. This opportunity arose in large part because of ERCOT's unique energy-only market design. Further, the price results this summer and stakeholder reactions will constitute its first major test since overhaul in 2014.

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[1] For example, Brattle estimates 11.2 percent in 2014.

[2] 1-day-in-10-years loss-of-load expectation. ERCOT last estimated this will occur at around 13.75% RM; Brattle reports 14.1% RM

Anticipating the Summer

As the summer draws closer, speculation on pricing has started to heat up. In February, we published a short blog piece flagging the weak forward market for July and August; barely two months later, August peak prices have fully doubled from just over $100/MWh to over $200/MWh, and July peak forwards have now also crossed $100/MWh. These forward prices suggest total annual scarcity in the neighborhood of approximately $100-110/kW-yr—much closer to our expectations. We continue to believe that prices could go even higher—ICF's expectation is that scarcity in excess of $140/kW-yr or higher is possible. This entails compensation much greater than net cost of new entry (net CONE).

Market Design, Timing, and Price Signals

ERCOT's market structure contributed heavily to creating this opportunity for generators. In regions with forward capacity market designs, capacity price levels have rarely surpassed net CONE levels since the markets were established, nor are they as likely to do so going forward. Because the bulk of capacity requirements are procured three years forward, developers can bid potential projects at a high price (their own net CONE) and simply not proceed if those prices do not clear. Similarly, costly existing units thinking about exit can simply bid high prices and only retire if they do not clear.

This illustrates a primary challenge—and opportunity—posed by the current ERCOT market design: the difference in timeframes associated with entry and exit decisions and the corresponding price signals. In PJM and ISO-NE, for example, the primary auctions give a price signal to capacity three years ahead of time. This timeframe gives developers enough lead time to decide whether they will build or not; to exit the system or to remain in it.

While it is true that both systems also have shorter-term reconfiguration auctions (and allow retirements on relatively short notice that could result in high prices), these affect comparatively smaller amounts of capacity than the base auction. In contrast, ERCOT takes this to an extreme and effectively "clears" all capacity only in real-time. The market-wide price signal for capacity is given every five minutes and retirement decisions carry a 150-day notice, but new thermal builds still take between two and three years to conceive and carry out.

This has implications for pricing and market behavior. For example, consider several recent ERCOT market decisions: the Panda Temple 1 combined cycle plant came online in 2014 and may have, at least theoretically, been influenced by the very high price events in 2011. However, by the time the plant came online, the price signals were over. Two years later, the plant declared bankruptcy. On the other hand, the recent new combined cycles Wolf Hollow II and Colorado Bend II (Exelon) both came online in 2017. No definitive price signals had been given for new entry since 2011. At the time, many market participants lamented what was perceived as poor timing.

On the exit side, the situation is reversed: Vistra was able to react to very low price signals in a short timeframe by retiring four large coal plants[3] in just 90- and 120-day windows. However, few new builds are able to react so quickly; for combined cycles like Panda and Wolf Hollow II, developers had to have been speculating about the timing long before. So, while all markets go through cycles of being long or short on capacity, the lag time between price signal and capacity reaction in ERCOT makes it susceptible to much wider swings and an increased likelihood of short conditions that can be leveraged.

How Short?

Complicating the picture, however, is the wide volatility inherent in the scarcity market structure. As we have previously noted, the expected variability (total MW) in summer peak load, wind output, and outages are large compared to the relatively narrow range, whereby scarcity prices transition from zero to $9,000/MWh. Even going into 2018, continued low scarcity is not an impossible outcome.

Additionally, one factor that may play an increasingly significant role going forward is the uncertainty in total price responsive load. ERCOT's load forecast attempts to measure price-sensitive load and large consumers responding to 4CP charges (ERCOT's transmission cost allocation; there is an incentive to reduce demand during anticipated peak load hours). However, this behavior is somewhat difficult to measure, and it has been seven years since ERCOT has experienced very high prices. The total MW response in 2018 may be higher than historical levels, but it is difficult to speculate how much higher.

Nevertheless, the 2018 Summer Assessment (SARA) report, which projects operating reserves at peak, leaves little doubt as to the situation. In February, in our blog post measuring existing capacity and projected demand, we expected that the SARA would forecast about 1 GW of operating reserves at peak, where 2.3 GW "indicates risk of EEA1" at which point the price is likely $9,000/MWh—a shortage of 1.3 GW. We estimated that nine hours in the course of a normal year are within 1.3 GW of the peak demand—and if each hour is at the price cap, that yields $81/kW-yr just across those nine hours.

The final report, released in March, shows just 553 MW of expected reserves at peak—a shortage of nearly 1.8 GW. Updating the same analysis, given average load shape, a full 14 hours are within 1.8 GW of the peak demand—good for $126/kW-yr just in those price cap hours alone.

[3] Big Brown 1-2 (1200 MW), Monticello 1-3 (1800 MW), Sandow 4 and 5 (1200 MW)

How to Play

So, where does that leave us? Amidst all of this, generation owners and investors can consider a few strategies:

For 2018

- **Thermal:** Existing capacity sees very, very high upside, but not without risk. Therefore, it's a matter of trading off forward power sales with merchant appropriately to manage risk. The forward market may continue to march up if more mini-scarcity events occur in the next few months. August forward peak prices moving into the mid-$200/MWh range becomes a reasonable price, and it may be worth contracting part of capacity for while leaving some open, depending on risk tolerance. Investors without current capacity may still be able to find assets before the summer.
- **Renewable:** Any merchant exposure in solar is well-positioned to capture scarcity: we estimate that a typical solar profile can pick up approximately 60-75% of scarcity, especially while total solar in the system remains low. Wind also has upside, but plants under fixed-volume hedges take on risk of buyback at a high price. It may be worth considering buying forward power to cover the summer peak periods. Similarly, off-peak forward prices remain low (approximately $20-30/MWh), yet some scarcity potential also exists there—this may be an opportunity to buy forward, take a fairly small loss against the fixed price, but cut risk and open up merchant opportunity. There is upside potential on the merchant side, more so for plants with unusual wind profiles (e.g. coastal, or otherwise not located in the West wind belt).

For 2019

The December 2017 CDR projects a 9.3% reserve margin for 2018, equivalent to a 3.2 GW deficit compared to the unforced RM target of 13.75%. Then, between 2018 and 2019, 1.5 GW of demand growth is projected, for a total shortage of 4.7 GW. As it stands in the March 2018 interconnection queue, there are 1.8 GW of gas projects with IA planning to come online between summer 2018 and summer 2019. However, many of these projects are not yet under construction and will not likely be able to come online by summer. Next, only 524 MW of solar finds itself in the same position, and 4.5 GW of wind, equivalent to a little over 1 GW of likely peak impact. So, even if every single plant current scheduled in the queue comes online, 2019 will still be short. Therefore, it is very likely that 2019 will also anticipate shortage conditions and high scarcity, similar to 2018.

However, the strategy also depends somewhat on the results of 2018:

- If 2018 turns out with low scarcity, due to very mild summer: buy, buy, buy. Although this could be seen as a contrarian play, given continued bad outcomes, despite all the sound and noise and promise. If this situation occurs, first, there will be a clamor about the market, and there will be tremendous pressure to sweeten up the ORDC as has been proposed or other fundamental changes to support generators. At the same time, forwards could drop, and potential new builds will find greater difficulty, which would only further exacerbate shortage conditions and true fundamental scarcity prospects going into 2019.
- If 2018 turns out with high scarcity: replicate the 2018 strategy. Even if prices are very high in 2018, there is a large capacity deficit going into 2019 that will be hard to make up in just one year. Further, if 2018 sees a very hot summer and significant blackouts occur, it is conceivable that both existing units and new entrants could see a return of long-term contracting or other regulatory intervention that would allow them to lock in high revenues.

Proper market function requires that cyclicality on the upside balances out the downside. ERCOT has seen a lot of downside over the past seven years, but its unique structure has allowed it to turn around sharply. The market should not miss this chance.

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