Putting Duct Tape on North America's Last Energy-Only Market: ERCOT

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Abstract

Facing the prospect of a 7.4% reserve margin in the summer of 2019 and continued low planning reserves in subsequent years, the Public Utility Commission of Texas (PUCT) approved changes to the Electric Reliability Council of Texas (ERCOT) operating reserves demand curve (ORDC) in January 2019, to raise wholesale prices during periods of low operating reserves. This is because the PUCT concluded that the economically-optimal or market equilibrium levels of generating capacity that an "energy-only" wholesale market yield were too low from a policy and economic development perspective. While higher prices likely slow the exit of generators and encourage new investment, our backcasts suggest that the approved changes to the ORDC could have highly uncertain impacts on market prices. With the projected large-scale development in renewable generation that tends to suppress market prices, we question the latest ORDC revision's effectiveness in solving Texas's problem of shrinking operation reserves.

1. Background

Until recently, the Electric Reliability Council of Texas (ERCOT) market relied solely on market forces to provide incentives to retain the generating capacity and incent the new investment necessary to ensure long-term reliability. It introduced in June 2014 an operating reserves demand curve (ORDC) to raise wholesale prices during times of scarcity (Hogan, 2013), with a limited impact on wholesale electricity prices to date. In 2016, for example, the ORDC represented about 1% of the total price of energy paid by a consumer of wholesale energy in the

ERCOT market.[1] The ORDC provided $81 million and $750 million in revenues to generators in 2017 and 2018, respectively. While significant, this is a fairly small amount in a market where about $9 to $14 billion of energy settled annually in the real-time market.

Shown in Fig.1, the projected reserve margin for the summer 2019 is 7.4% (ERCOT, 2019), far below the 13.75% target level approved by ERCOT's Board of Directors.[2] It has prompted the Public Utility Commission of Texas (PUCT) to dramatically revise the ORDC, so as to increase prices and provide greater revenues to generators when operating reserves decline. On 17 January 2019, ERCOT revised the ORDC to increase the frequency of high real-time market prices, as the prospect of a capacity market or resource resource adequacy requirements remains politically unpopular. Consequently, an overhaul of this administrative mechanism was found necessary, as it appeared to be the remaining feasible option.

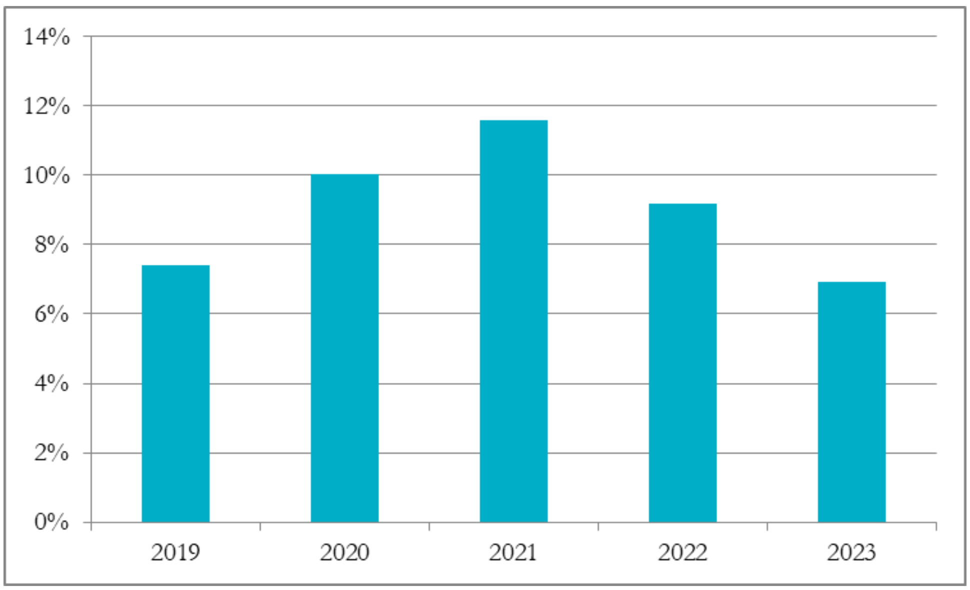

Fig. 1. Projected Summer Reserve Margins in ERCOT (Source: ERCOT's December CDR Report, but adjusted to reflect the announced closure of the 470 MW Gibbons Creek coal plant in January 2019)

Recent events in ERCOT bring to memory what DuPuis (1844) and Hotelling (1938) concluded many years ago: in a very capital intensive industry with high fixed costs, using short-run marginal costs to set prices may not provide sufficient revenues to provide a reasonable return to existing suppliers, let alone sufficient incentive to attract new investment. A 'missing money' problem arises when the expected net revenues from sales of energy and ancillary services at market prices fail to provide adequate incentives for merchant investors in new generating capacity to meet administratively-established reliability criteria (Joskow, 2013; Milstein and Tishler, 2012). In recent years, keeping existing generation capacity profitable may be at least as important as attracting new investment.

[1] Calculation by one of the authors.
[2] http://www.ercot.com/gridinfo/resource

Not everyone is convinced that a capacity market or some administrative intervention is necessary in order to keep the lights on (e.g., Kielsing and Kleit, 2009). In their textbook on electricity market design, Biggar and Hesamzaden (2014) argue:

> This analysis can be summarised as asserting that (at least under certain assumptions, such as the assumption that the market is competitive) an energy-only market will deliver an efficient level of investment. This result is not at all controversial in most markets in a modern economy. Nearly all modern economies rely on conventional market forces to deliver an efficient level of hotel rooms, aircraft flights, hairdressers and so on. In all of these markets we expect entrepreneurs to earn sufficient revenue from the sale of their services alone, whether those services are hotel rooms, flights or haircuts. We do not refer to these markets as service-only markets. We do not expect that other mechanisms will be developed to compensate investors in hotels, airlines or hairdressing salons.

To remedy the missing money problem, capacity markets were introduced in the late 1990s in the U.S. deregulated markets of New York, PJM, and New England (Spees et al., 2013). The notable exception is Texas, which continues to rely on an energy-only market design with a high price cap of US$9,000/MWh to provide generation investment incentives.

Can an energy-only wholesale electricity market succeed in providing sufficient capacity to meet politically-acceptable long-term reliability standards? Is an ORDC mechanism an acceptable alternative to the introduction of a capacity market? To answer these two questions, we backcast the possible impacts of the lastest ORDC change, thereby inferring ERCOT's effectiveness in addressing the missing money problem in Texas.

2. ERCOT

ERCOT is an important case study of the missing money problem because it serves 85% of the electrical needs of the largest electricity-consuming state in the U.S. It is the only wholesale electricity market in the U.S. using an energy-only market design to implement wholesale market competition and meet resource adequacy.

ERCOT's 5-minute real-time locational marginal pricing (LMP) prices are based on a real-time security-constrained economic dispatch (SCED) that simultaneously manages energy, system power balance, and network congestion. As part of this process, ERCOT procures operating reserves through a day-ahead market to control frequency and resolve potential reliability problems. The zonal settlement price for a load serving entity's (LSE's) real-time energy purchase is a load-weighted average of all (normally) 5-minute LMP prices in a load zone, converted to 15-minute values.

The PUCT and ERCOT have adopted a target planning reserve margin of 13.75%, deemed lower than the levels necessary to achieve the traditional 1-in-10 years Loss-of-Load Expectation ("LOLE") standard. Meeting the traditional standard might require a reserve margin around 16.75% (Astrapé, 2015) or 17.6% Northbridge, 2017).

In ERCOT, the reserve margin is ultimately determined by suppliers' willingness to invest based on their costs and the market prices. ERCOT's RTM energy prices are determined by market fundamentals, with price adders contributed by the administratively-determined ORDC during tight market conditions. Market forces alone are projected to yield an "economically-optimal" reserve margin of 9% and a market equilibrium reserve margin (additionally reflecting the ORDC's impact) of 10.25% (Brattle, 2018). Various reserve margin levels are compared in Fig. 2.

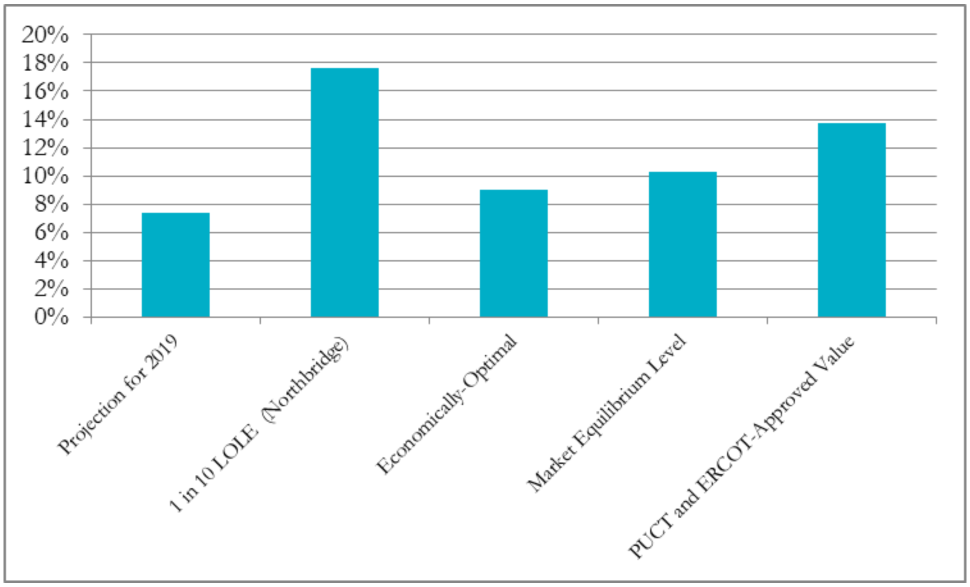

Fig. 2. Reserve Margin Levels Need to Meet Various Criteria

Much of the resource adequacy problem in Texas is related to recent closures of aging coal plants. Three large coal plants retired in early 2018: the 1,865-MW Monticello plant; the 1,200-MW Sandow (4 & 5) plant; and the 1,208-MW Big Brown plant. The Gibbons Creek coal plant may be closed before the summer of 2019, while the 700 MW Okalunion coal plant is scheduled for closure in 2020. Low natural gas prices due to the explosive growth in shale gas have rendered the continued operation of many coal plants uneconomical. Further, the state's renewable energy development has lowered wholesale market prices via the merit order effect (Woo et al, 2011a, 2012; Zarnikau et al 2016, 2019a, 2019b).

3. ERCOT's ORDC

Depicted in Figure 3, ERCOT's ORDC scarcity pricing mechanism results in a price adder to the LMP prices calculated by ERCOT's SCED when operating reserves fall below a preset level (ERCOT, 2014) ERCOT's definition of operating reserves includes responsive reserves, regulation, non-spinning reserves, and resources that can be started and available within 30 minutes. Online generators who are producing energy or contributing reserves receive ORDC payments, reflecting the expected benefits of their capacities that help mitigate load curtailments.

In contrast to PJM's ORDC tied to the supply costs of likely providers of energy and ancillary services, ERCOT's ORDC is linked to the value of operating reserves (Hogan and Pope, 2017). As a part of its market reform, Mexico has also implemented an ORDC (Bajo-Buenestado, 2017).

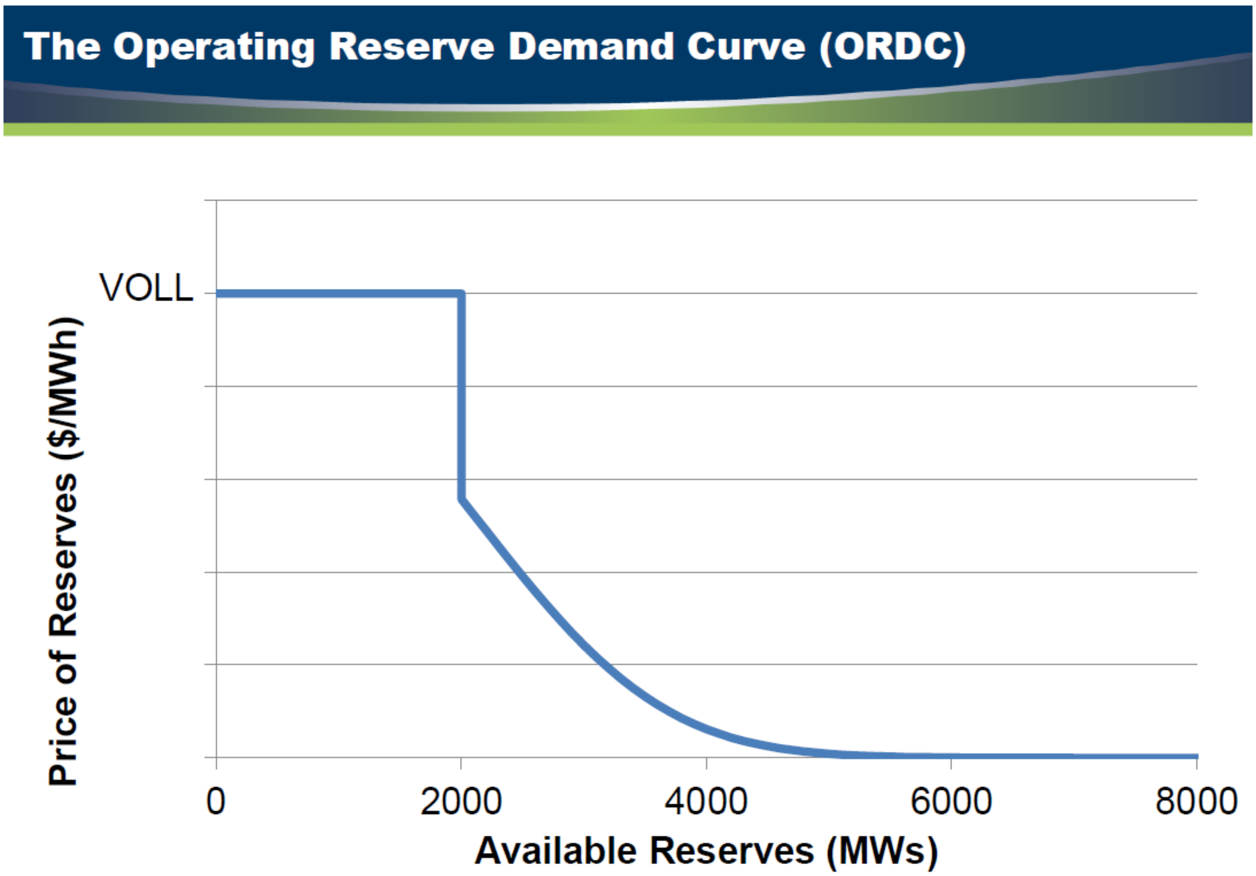

Fig. 3. Relationship between operating reserves and an ORDC price adder (Source: ERCOT)

ERCOT's LMP prices and ORDC price adders are calculated, at most, every 5 minutes (the "SCED interval). There are limitations to the ORDC mechanism, as discussed in a series of papers by Wakeland (2018a through 2018e).

When ERCOT's total operating reserves are less the minimum reserve level (MRL) of 2,000 MW, the ORDC sets prices equal to the value of loss-of-load (VOLL), presently set at $9,000 per MWh. If operating reserves are within this range, ERCOT is in an emergency condition and the ORDC ensures that this situation is reflected in the real-time price of energy. There is some "safety" built into this calculation, since a level of reserves of 2,000 MW may trigger emergency alerts and make a system operator uncomfortable, but would not result in rolling blackouts.

At levels of reserves above MRL, the ORDC price adder is the VOLL times the loss-of-load probability (LOLP) of firm load shedding within one hour. As a reuslt, the LOLP calculation is a function of ERCOT's accuracy in forecasting the level of hour-ahead reserves.[3] The adders decline to $0/MWh as ERCOT's total physical operating reserves approach ~5,000 MW, reflecting the LOLP estimate's rapid shrinkage to zero. ERCOT periodically updates the ORDC's parameters of μ and σ, the mean and the standard deviation of the operating reserve forecast error's distribution, reflecting the changes in the distribution of its hour-ahead forecast errors.

Traditionally, different ORDC curves have been constructed for different seasons of the year and times of the day. Under recent changes to the ORDC ordered by the PUCT, ERCOT is likely to move by this summer to single "blended" curves for each of four seasons in a year.

To calculate the ORDC adder in each SCED interval, ERCOT first identifies the present amount of real-time operating reserves. Next, it then calculates the LOLP estimates based on probability that operating reserves might fall below a minimum threshold of 2,000 MW within one hour. ERCOT does this by estimating the potential distribution of reserves an hour hence, given current real-time reserves and the distribution of reserve forecast errors and the MRL. Fig. 4 is an example of how the current level of operating reserves and the distribution of reserves after one hour is used to estimate the LOLP.

[3] This "operating reserve forecast error" might result from errors in forecasts of system load, projections of wind generation, solar energy performance, generator outages, and a variety of other factors.

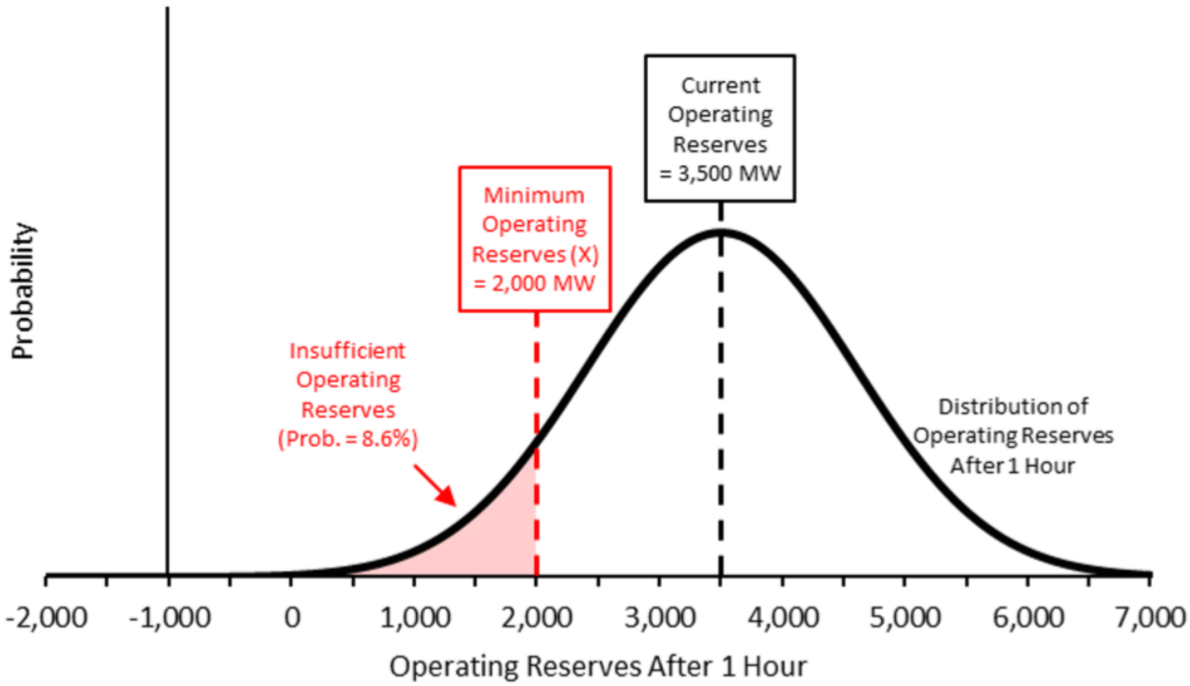

Fig. 4. Calculation of the LOLP at an example level of operating reserves (From Northbridge, 2017)

When ERCOT first implemented the ORDC in June 2014, it right-shifted the curve by 1,000 MW (slightly more than 1%) relative to a more-accurate reflection of the expected value of lost load to reflect risk aversion to lower reliability (Brattle, 2018, p. v). As ERCOT's reserve margin declined in recent years, a further "shift" was repeatedly proposed as a means of improving the economics of maintaining generating capacity in this market (ERCOT Supply Analysis Working Group, 2015; Hogan and Pope, 2017; Northbridge, 2017; Excelon, 2017; Excelon, 2018; Brattle 2018b; see also the insightful discussion in Wakeland, 2018e), as illustrated in Fig. 5.

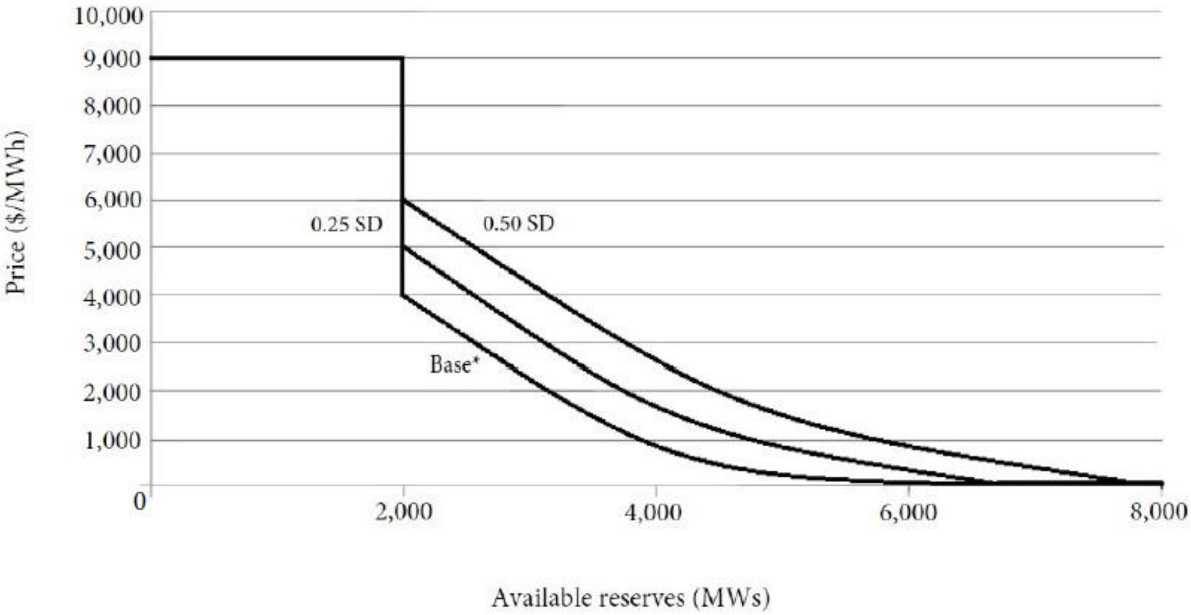

Fig. 5. Illustration of a shifted ORDC curve.

In January 2019, the PUCT approved a change in the ORDC curve based on a shift of 0.25 σ for the summer of 2019. An additional shift of 0.25 σ (for a total shift of 0.5 σ) is scheduled for 2020.

4. Backcasting the impacts of a shifted ORDC Curve

To understand the impact of ERCOT's revised ORDC on market prices, we perform a backcast of ERCOT's RTM energy prices in 2015, 2016, 2017, and 2018 that would have occurred, had the ORDC had been shifted by .25 and 0.5 σ. We perform this calculation for every SCED interval within these four years, and use these increases to upwardly-revise ERCOT's 15-minute RTM energy prices.

Our backcasts entail the following steps:

(1) Collect the necessary input data from ERCOT.
(2) Set up a spreadsheet to perform the backcasts (about 70 MB in size for a year) based on ERCOT's formulae (ERCOT, 2013).
(3) Check the backcasts in Step (2) by performing the following tasks:
  - Replicate the actual ORDC price adders for each interval of the study period.
  - Match the annual ORDC revenues resulting from our backcasts with those reported by Potomac Economics.

(4) Revise the backcasts to capture the PUCT's order to implement "blended" curves.

Our calculations of the value of energy transacted in ERCOT's real-time market use the settlement point price for the South zone. At the time of writing, ERCOT had not yet released parameters for the ORDC curve for the winter season, consequently we approximated those values.

The actual reserve margins in these years were far above the levels anticipated in 2019 and 2020. For example, the actual reserve margin in the summer of 2018 was 11% and 17% in 2017. Consequently, our backcasts likely underestimate the impact of the ORDC shift in a year of tighter reserves and slim reserve margins, such as are expected in 2019 and 2020. To be sure, this underestimation may be offset by demand-side programs and behind-the-meter resources which were not anticipated in ERCOT's reserve margin calculation in 2015-2018.

Using seasonal blended curves, shifting the ORDC curve would have increased ORDC collections greatly in 2018. Table 1 and Fig. 6 show that in 2018, the total electricity cost was \$14.24 billion, based on the real-time prices times demand at the wholesale level. Within the total cost of \$14.24 billion, \$0.75 billion was due to the ORDC. If single seasonal blended curves were used, shifting the ORDC blended curves by 0.25 σ would increase total ORDC collections to \$2.11 billion, a \$1.36 billion or 180% increase from the actual ORDC payment. There would also be a 9.5% increase (\$1.36/\$14.24 = 9.5%) in total electricity cost for 2018. Shifting the blended curve by 0.5 σ (as planned for 2020) would have increased the total ORDC collection to \$3.25 billion, a \$2.5 billion or 332% increase from the actual ORDC collections. There would also be a 17.6% increase (\$2.5/\$14.24 = 17.6%) in total electricity cost for 2018. However, the impact of altering σ in the other three years, however, would have been not more than \$0.6 billion.

Table 1. Backcast of the ORDC payments (\$Billion)

	2015	2016	2017	2018
Energy Cost	9.63	8.91	9.55	14.24
Actual ORDC payment	0.49	0.1	0.09	0.75
ORDC payment with a 0.25 σ shift	1	0.32	0.29	2.11
ORDC with a 0.5 σ shift	1.57	0.55	0.5	3.25

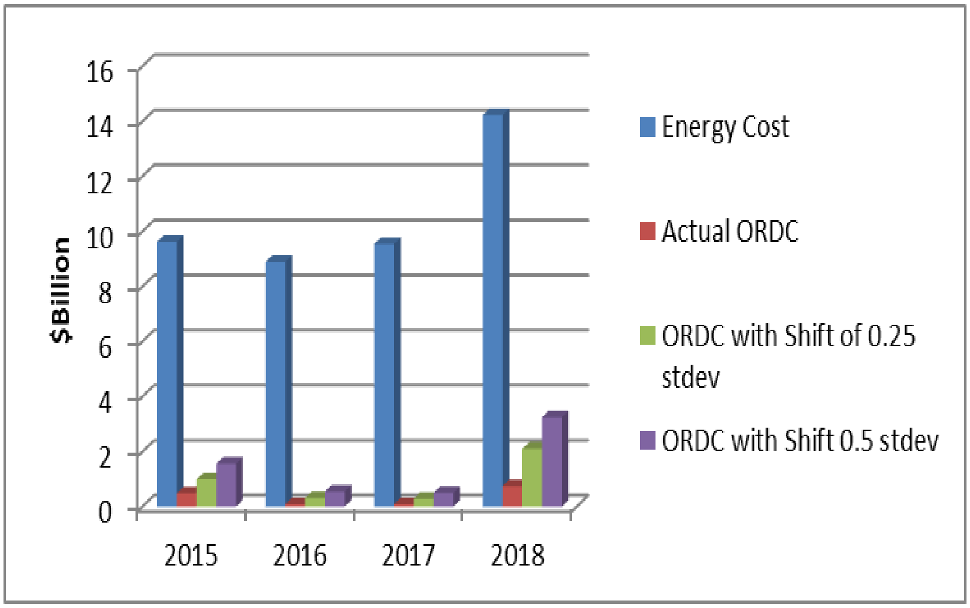

Fig. 6. Back Cast of Shifts in the ORDC Curve

Table 2 and Fig. 7 present this same information on an "incremental" basis, while the Appendix displays the impacts of these shifts in the ORDC curve upon a hypothetical energy consumer with a 1 MW constant load who might pay the wholesale real-time price of energy through a real-time pricing tariff.

Table 2. Incremental Impacts from Shifts in the ORDC Curve from Back Casts ($Billion)

	2015	2016	2017	2018
Energy Cost	9.63	8.91	9.55	14.24
Actual ORDC	0.49	0.1	0.09	0.75
Incremental Impact of 0.25 σ Shift	0.51	0.22	0.2	1.36
Incremental Impact of 0.5 σ Shift	1.06	0.33	0.3	1.89

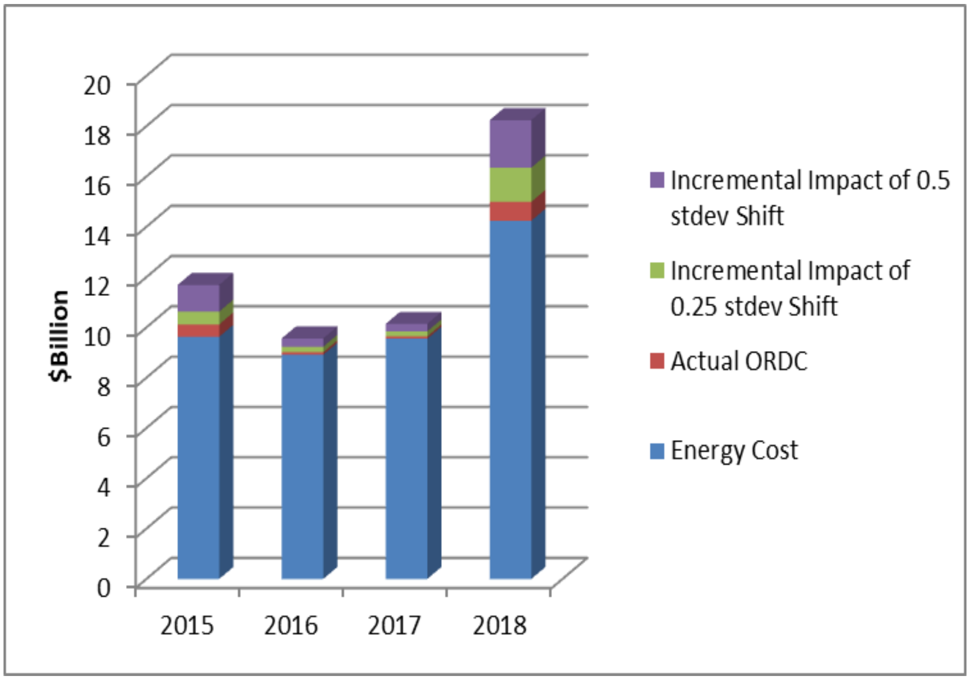

Fig. 7. Incremental Impacts from Shifts in the ORDC Curve from Back Casts

5. Discussion

Table 1 suggests that the impact of changing the ORDC on market prices would have been enourmous in a year such as 2018, notwithstanding that the impact would have been rather benign in years like 2016 or 2017. The tremendous uncertainty in the impacts lead us to infer that it is very difficult to predict how changes to ERCOT's ORDC will actually impact the state's RTM market prices and incentives for plant retention and new capacity.

It seems plausible that the prices produced by SCED will continue on their downward trend, absent an increase in the price of natural gas. This is because renewable generation tends to depresses wholesale market prices via its merit-order effect. A review of planned resource additions for the ERCOT market suggests that Texas's wind and solar generation is likely to increase, resulting in low market prices that may persist in future years during periods when there is no scarcity of capacity. In our studies, we find that each additional GWh of wind energy generation lowers market-wide prices by $1.6/MWh (Zarnikau et al, 2019b) to $1.8/MWh (Zarnikau et al, 2019a). Our earlier research found larger impacts of wind generation on prices (Zarnikau et al, 2016; Woo et al, 2011a; Woo et al, 2011b). Thus, it is unclear whether increased ORDC adders will be able to adequately counter the renewable generation's merit order effect in the long-run.

6. Conclusions

Arguably, ERCOT will soon no longer have an "energy-only" market structure purely based on market forces. Its ORDC mechanism is increasingly used to ensure resource adequacy.

It is quite plausible that an energy-only market will result in reserve margins which are adequate from an economic perspective, which considers the cost that consumers are willing and able to pay for electricity and the cost of resource additions. Consequently, we have some sympathy for proponents of "letting the market work." But, market forces alone may be insufficient to achieve a "politically-acceptable" level of resource adequacy. Accepting the loss-of-load expection associated with a market equilibrium level of reliability (perhaps a 12.5% reserve margin and 0.5 loss-of-load events per year) or with an economically-optimal level (perhaps 9% with 0.8 loss-of-load events per year) will make a risk-averse policy-maker or regulator uncomfortable – particularly when the media is likely to blame the regulator for any reliability problems. Moreover, the economically-optimal or market equilibrium levels of reliability are long-term equilibrium values, and year-to-year deviations from those values are inevitable, due to the time required to construct generating capacity, the lumpiness in the size of generation power plants, and near-term market conditions. Thus a projected reserve margin for the summer of 2019 of a mere 7.4% has prompted a bold response from Texas' policy makers and regulators.

Will a shift in the ORDC curve prove sufficient to ensure higher levels of resource adequacy? Had the redesigned curves been in effect in 2018, it might have been effective in delaying some coal plant closures and attracting additional investment in generating capacity. Yet, the impacts of the redesigned curve on prices in 2017 would be been only about 20% of what they would have been in 2018. Back casts suggest that the year-to-year variation in ORDC payments will be very great. The ORDC's impact over the next couple years could be even greater than a redesigned curve's impact would have been in 2018, given the projected slim planning reserves. Yet, the volatility in the ORDC's impact will continue to make investment in the ERCOT market quite a gamble.

Thus, it is time to get out the duct tape to patch-up the ERCOT market as low market prices persist in the face of continued growth in renewable energy generation and political resistance to establishing a capacity market or resource adequacy requirements.

The actions taken to ensure resource adequacy in ERCOT may prove instructive to the design and redesign of other markets.

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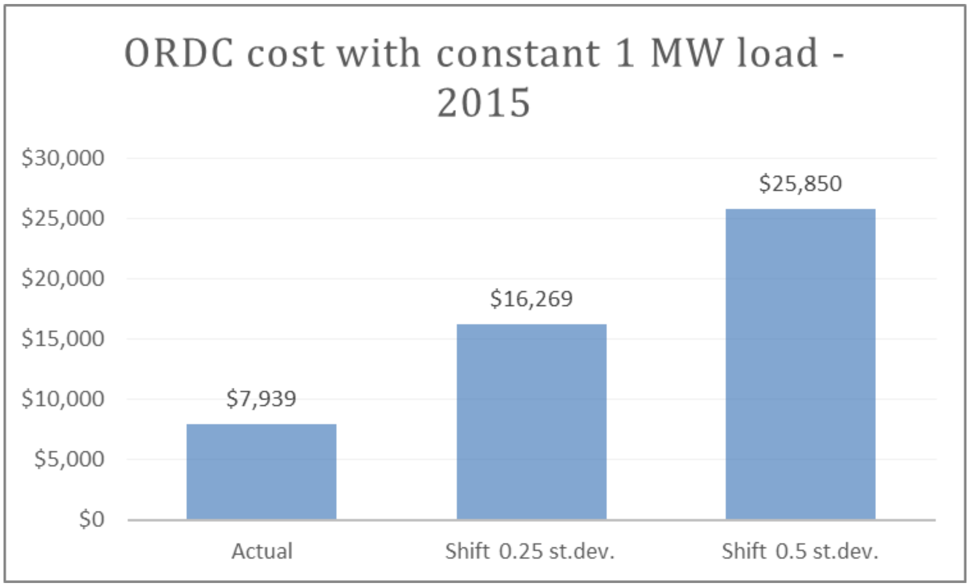
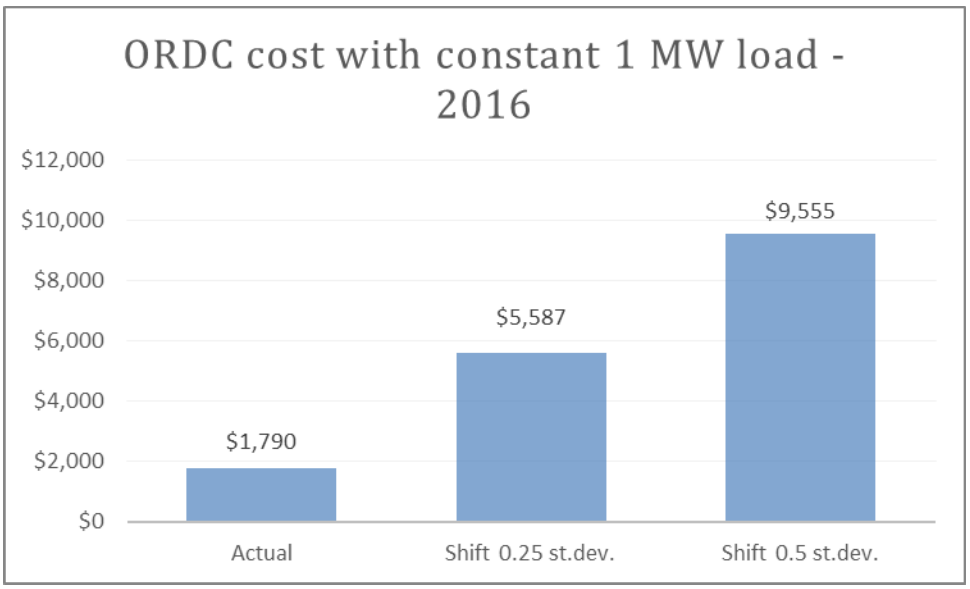
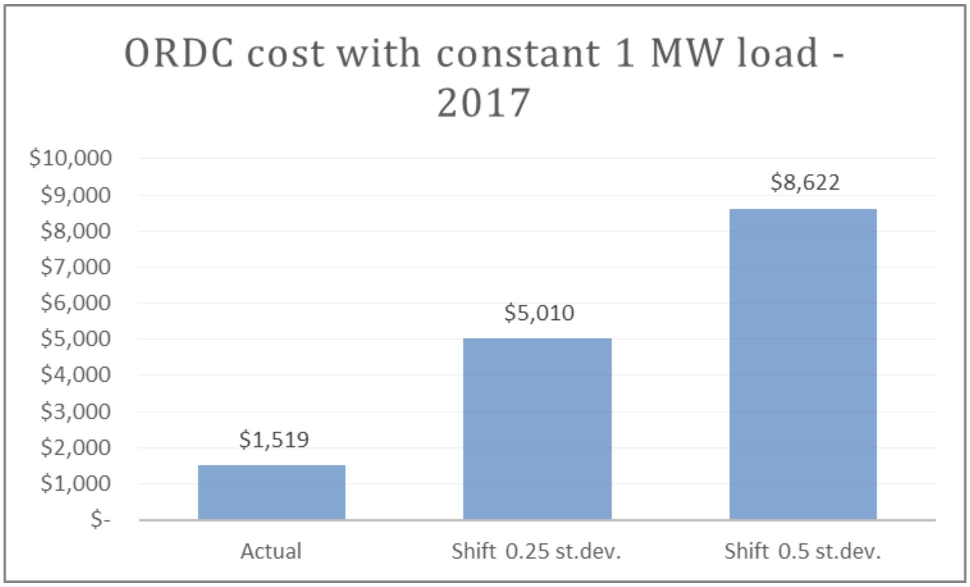
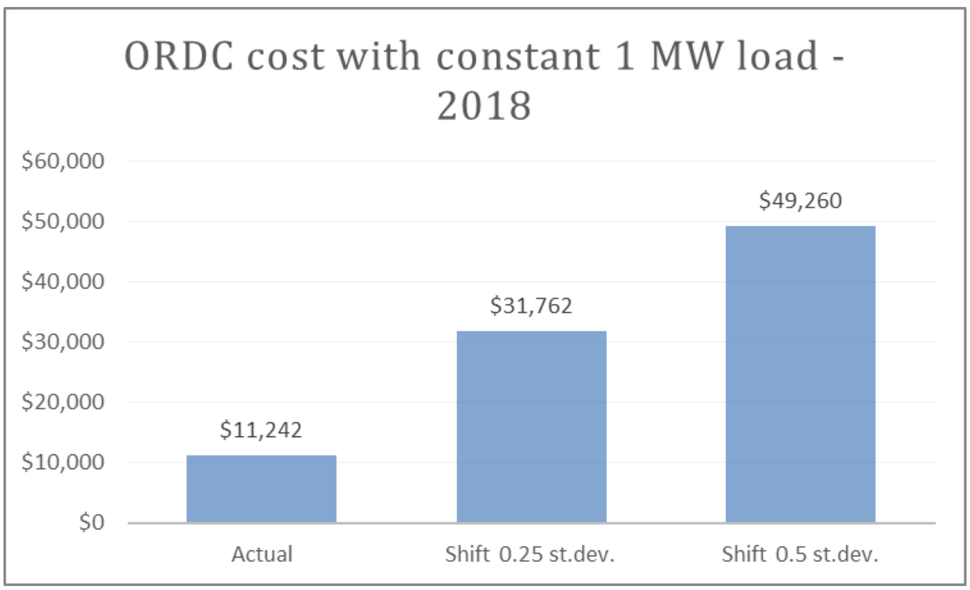
Appendix

Impacts of shifts in the ORDC curve upon ORDC payments by a hypothetical energy consumer with a 1 MW constant load who might pay the wholesale real-time price of energy through a real-time pricing tariff






ORDC cost with constant 1 MW load - 2017
$10,000
$9,000
$8,000
$7,000
$6,000
$5,000
$4,000
$3,000
$2,000
$1,000
$-
$1,519
$5,010
$8,622
Actual
Shift 0.25 st.dev.
Shift 0.5 st.dev.


ORDC cost with constant 1 MW load - 2018
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$0
$11,242
$31,762
$49,260
Actual
Shift 0.25 st.dev.
Shift 0.5 st.dev.