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Texas's operating reserve demand curve's generation investment incentive

Zarnikau[a,b,*], S. Zhu[b], C.K. Woo[c], C.H. Tsai[d]

[a] Department of Economics, University of Texas at Austin, 2225 Speedway, Austin, TX 78712, USA

[b] Frontier Energy, 1515 S. Capital of Texas Highway, Suite 110, Austin, TX 78746, USA

[c] Department of Asian and Policy Studies, Education University of Hong Kong, 10 Lo Ping Road, Tai Po, New Territories, Hong Kong

[d] MISO, 2985 Ames Crossing Road, Eagan, MN 55121, USA

[*] Corresponding author

Email addresses: jayz@utexas.edu (J. Zarnikau), zss@frontierenergy.com (S. Zhu), chiwoo@euduhk.hk (C.K. Woo), ctsai@misoenergy.org (C.H. Tsai)

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Abstract

Faced with reserve margin projections well below the adopted target of 13.75% of the system peak forecast, the Public Utility Commission of Texas on 01/17/2019 ordered the state's grid operator, the Electric Reliability Council of Texas, to "right shift" the operating reserve demand curve (ORDC) to increase generators' revenue from energy sales in ERCOT's real-time market (RTM). Using a large sample of 15-minute data for the backcast period of 01/01/2015 through 12/31/2018, we calculate the ORDC shift's impact on RTM prices and investment incentives for natural-gas-fired generation (NGFG). Had the ORDC shift been in effect in the backcast period, the resulting RTM price increases in 2018 could suffice to justify NGFG investment, though not in the prior years of 2015, 2016 and 2017. While the actual ORDC shift occurred on 03/01/2019 had a large impact on RTM prices in the ensuing six-month period of March – August 2019, Texas's planned renewable generation is expected to erode NGFG's operating profit, thus diminishing the ORDC's investment incentive over time. Hence, Texas's energy-only market design will likely need further refinements to solve the missing money problem of inadequate NGFG investment incentive.

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1. Introduction

This paper explores Professor Paul Joskow's insightful observation: "Revenue adequacy has emerged as a problem in many organized wholesale electricity markets and has been of growing concern in liberalized electricity markets in the U.S. and Europe. The revenue adequacy or 'missing money' problem arises when the expected net revenues from sales of energy and ancillary services at market prices provide inadequate incentives for merchant investors in new generating capacity or equivalent demand-side resources to invest in sufficient new capacity to match administrative reliability criteria at the system and individual load serving entity levels" (Joskow, 2013, p.i).

The missing money problem stems from the global trend documented by Sioshansi (2013) of market restructuring to introduce wholesale competition in electricity generation. Despite occasionally large spikes, wholesale market prices may not suffice to justify the generation investment necessary for a grid's reliable operation (Neuhof and De Vries, 2004; Wangensteen et al., 2005; Roques et al., 2005; Newbery, 2010; Milstein and Tishler, 2012; Brattle Group, 2012). To remedy the missing money problem, capacity markets were introduced in the late 1990s in the U.S. restructured markets of New York, PJM, and New England (Spees et al., 2013). In contrast, Texas continues to use an energy-only market design with a high price cap of $9,000/MWh since June 2015 to provide generation investment incentives (Zarnikau et al., 2019).

Many countries see large-scale development of wind and solar generation, a critical component of the pathway of deep de-carbonization to mitigate global warming (Williams et al., 2012). This development will likely continue because of renewable resource abundance (Hoogwijk et al., 2004; Lu et al., 2009) and government policies

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such as easy and low-cost transmission access, financial incentives (e.g., feed-in-tariffs, government loans and grants, and tax credits), and quota programs (e.g., renewable portfolio standards, cap-and-trade programs for carbon emissions certificates, and renewable-energy credits) (Haas et al., 2008; Barroso et al., 2010; Alagappan et al. 2011; Zarnikau, 2011; Yatchew and Baziliauskas, 2011; Green and Yatchew, 2012).

Thanks to its zero fuel cost, wind generation displaces thermal generation in an electricity grid's least cost-dispatch and reduces the grid's wholesale market prices (European Wind Energy Association, 2010). Its price reduction (*aka* merit order) effect has been demonstrated through model simulation (e.g., Morales and Conejo, 2011; Traber and Kemfert, 2011, 2012), as well as regression analyses for Spain (Gelabert et al., 2011; Gil et al., 2012), Germany (Sensfuß et al., 2008), Denmark (Munksgaard and Morthorst, 2008; Jacobsen and Zvingilaite, 2010), Australia (Cutler et al., 2011), Texas (Woo et al., 2011; Tsai and Eryilmaz, 2018; Zarnikau et al., 2016, 2019), PJM (Gil and Lin, 2013), the Pacific Northwest (Woo et al., 2013), and California (Woo et al., 2016a, 2017a, 2017b, 2018). Wind generation's merit order effect weakens the market-based investment incentives for natural-gas-fired generation (NGFG), as documented by the simulation studies of Traber and Kemfert (2011, 2012), the regression analyses of Woo et al. (2012, 2016b) and Liu et al. (2016), the descriptive assessment of Steggals et al. (2011), and the theoretical exploration of Milstein and Tishler (2011).

Continued expansion of renewable generation likely discourages NGFG investments necessary for an electricity grid's reliable operation, highlighting the difficulty in solving the missing money problem faced by the grid's operator, regulator, market participants, and other stakeholders. Persistently low market prices also accelerate

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retirement of old generation units with relatively high fuel and O&M costs. Our paper's primary focus is new plant construction, reflecting our research interest in the missing money problem as stated by Professor Joskow.

Concern over the missing money problem in Texas has recently intensified, owing to the projected reserve margin of 7.4% for the summer of 2019, which is well below the adopted target of 13.75% of the system peak demand forecast.[1] The gap between the projected and target reserves has been widening in the past five years, despite the effort by the state's grid operator, the Electric Reliability Council of Texas (ERCOT), to revise its real-time market's (RTM's) energy price determination.

In June 2014, ERCOT implemented its operating reserve demand curve (ORDC), yielding a price adder to increase the ERCOT's RTM prices during periods of low operating reserves (ERCOT, 2013, 2014; Bajo-Buenestado, 2017). The ORDC provided $750 million in revenues to generators in 2018, an amount viewed by some policy makers as insufficient in ERCOT's RTM with about $9 to $14 billion of energy sales. On 01/17/2019, the Public Utility Commission of Texas (PUCT) ordered ERCOT to "right shift" the ORDC to increase the RTM price adder's size and frequency, hoping to reverse Texas's trend of sinking reserve margin (Walker, 2019).

Using a large sample of 15-minute data for the period of 01/01/2015 – 12/31/2018, this paper uses backcasting to document the PUCT order's effectiveness in solving Texas's missing money problem. It finds that the mandated ORDC shift could indeed

[1] Texas's declining reserve margin problem is partly related to recent closures of aging coal plants (http://www.ercot.com/gridinfo/resource).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. This is because 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 its merit order effect.

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have a very significant impact on RTM prices, particularly in a low reserve margin year like 2018. Moreover, the actual ORDC shift occurred on 03/01/2019 had a large impact on RTM prices in the ensuing six-month period of March – August 2019. Given the low planning reserve margins anticipated over the next few years, the ORDC shift serves to encourage new plant construction and delay old plant retirement. In the longer term, however, continued renewable energy development's merit order effect is expected to suppress ERCOT's RTM prices. In short, the ORDC shift's effectiveness will likely diminish over time, implying that Texas's energy-only market design may need further refinements to solve Texas's missing money problem.

This paper's main contribution is a detailed determination of the PUCT order's effectiveness in solving Texas's missing money problem. To the best of our knowledge, it is new, meaningfully informing the ongoing debate on the ORDC's usefulness (Bajo-Buenestado, 2017; Wakeland, 2018; Walker, 2019). Its real-world significance and policy relevance are obvious, underscored by Texas's low reserve margin projection in the near term and large scale renewable energy development in the longer term.

The rest of this paper proceeds as follows. Section 2 justifies our geographic focus of ERCOT and presents our approach. Section 3 reports our empirical results that are discussed in Section 4. Section 5 concludes and highlights the paper's policy implication.

2. Materials and methods

2.1 Why 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 independent system operator in the U.S. that uses an energy-only market design to implement wholesale competition. Further, Texas leads the U.S. in wind generation development, with an installed capacity of 22 GW in 2019 and an expected addition of 14 GW by 2021.[2] While Texas's solar generation lags California's, it has been growing rapidly from ~0.09% in 2014 to ~0.86% in 2018 of the state's total generation.[3] Additional details about ERCOT's system characteristics are available in Zarnikau et al. (2019).

ERCOT's nodal price determination is based on the theory of locational marginal pricing (Stoft, 2002; Zarnikau et al., 2014). It uses a real-time security-constrained economic dispatch (SCED) that simultaneously manages energy, system power balance and network congestion, yielding new nodal prices every 5 minutes or less. As part of this process, ERCOT deploys operating reserves procured on the prior day to control frequency and resolve potential reliability issues. In obeisance to ERCOT's "peaker-net-margin" (PNM) calculation mandated by the PUCT, we use ERCOT's published 15-minute RTM Hub average prices based on the 5-minute nodal prices.[4]

Texas's energy-only market design aims to use market forces to induce generation investments necessary to support a reliable system. Market forces alone are projected to yield an "economically optimal" reserve margin of 9% and a "market equilibrium" reserve margin of 10.25% that incorporates the ORDC price adder's investment incentive

[2] See ERCOT Monthly Operational Overview (April 2019). http://www.ercot.com/content/wcm/key_documents_lists/27311/ERCOT_Monthly_Operational_Overview_201904.pdf (accessed August 31, 2019).
[3] Texas's solar generation's installed capacity is 1.9 GW in 2019 and is projected to reach 8.9 GW by 2021. *Ibid*.
[4] Per ERCOT Nodal Protocols 4.4.11.1 Scarcity Pricing Mechanism, the Real-Time Energy Price (RTEP) shall be measured as the ERCOT Hub Average 345 kV Hub price. ERCOT Nodal Protocols 3.5.2.6 defines the calculation of the ERCOT Hub Average 345 kV Hub price. Details of the PNM are also available at: http://www.ercot.com/content/meetings/board/keydocs/2013/1119/5_Independent_Market_Monitor_Report_-_November_2013.pdf

(Brattle Group, 2018a). These margin estimates are below the 17.6% target under the traditional loss-of-load expectation standard of 1-in-10-years (Northbridge, 2017). ERCOT's adopted reserve margin target of 13.75%, however, is more the result of judgement and compromise than any strict economic or engineering criteria.

2.2 Theory

2.2.1 Why ORDC?

ERCOT's ORDC implements scarcity pricing. It is also viewed as a means to overcome some of ERCOT's observed inefficiencies resulting from the existing absence of co-optimization of real-time energy and ancillary services.[5] While encouraging the demand side to curtail consumption, high prices during periods of low operating reserves incent generators to make their resources available to maintain system reliability (Hogan, 2013). The importance of the ORDC's impact on Texas's NGFG investments is further underscored by an electricity grid's rising need for NGFG's flexible capacity to integrate an increasing amount of intermittent solar and wind resources (National Renewable Energy Laboratory, 2011).

Unlike PJM's ORDC which is 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). Figure 1 illustrates the relationship between available operating reserves and the ORDC price adder. This adder will raise ERCOT's nodal prices to the value of loss of load (VOLL) when ERCOT's total available reserves are

[5] Presently, ancillary services are procured in ERCOT's day-ahead market. If the market value of ancillary services changes between the day-ahead period and real-time due to a change in market conditions, the price of ancillary services procured through ERCOT's formal market does not change. Further, a change in the value of ancillary services between day-ahead and real-time will not affect the value of real-time energy. The ORDC can compensate for this, to some degree, by raising real-time energy prices when the actual quantity of available reserves dwindles.

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less than the minimum reserve level (MRL) of 2,000 MW.[6] The ORDC adder rapidly declines to \$0/MWh as the level of available reserves approaches 5,000 MW.[7] There is some "cushion" built into this calculation, since a level of reserves of 2,000 MW would trigger emergency alerts, though not rolling blackouts.

At operating reserve levels below the 2,000 MW MRL, the ORDC price adder is the VOLL times the loss-of-load probability (LOLP) of a system emergency within one hour. As a result, the LOLP calculation is a function of ERCOT's accuracy in forecasting the level of hour-ahead reserves.[8] The adder declines to \$0/MWh when ERCOT's available reserve level approaches 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 standard deviation of the hour-ahead errors in forecasting the level of available reserves. To calculate the ORDC adder for a given SCED interval, ERCOT first identifies the amount of real-time operating reserves available in that SCED interval. Next, it calculates the LOLP based on the probability that operating reserves may fall below the MRL of 2,000 MW within one hour.

When ERCOT first implemented the ORDC in June 2014, it right-shifted the curve by 1,000 MW to reflect risk aversion to lost load (Brattle Group, 2018a, p.v). As

[6] The measurement of available reserves uses real-time telemetry readings on potential resources through the system to infer the remaining capacity available from partially-loaded generating units, generation and load resources awarded to provide operating reserves through ERCOT's day-ahead market (DAM), generation and load resources self-arranged to provide operating reserves by LSEs, the status of direct current ties between ERCOT and neighboring reliability councils, and other potential resources identified in commercial operating plans submitted to ERCOT by scheduling entities.
[7] Historically, there were 24 ORDCs per year by season and time-of-day period. This was changed to four seasonal curves based on PUCT's January 2019 order.
[8] The "operating reserve forecast error" might result from errors in forecasts of system load, errors in projections of wind generation, solar energy performance, generator outages, and a variety of other factors.

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ERCOT's reserve margin declined in recent years, a further "shift" was repeatedly proposed to maintain adequate generating capacity in the operating reserve market (ERCOT Supply Analysis Working Group, 2015; Hogan and Pope, 2017; Northbridge, 2017; Excelon, 2017, 2018; Brattle Group, 2018b; Wakeland, 2018).

On 01/17/2019, the PUCT ordered a "right shift" in the ORDC by 0.25 σ, which was implemented on 03/01/2019. A shift of an additional 0.25 σ is scheduled for early 2020. Figure 2 illustrates the price effects of these ORDC shifts. The ORDC will be replaced by demand curves for ancillary services after ERCOT's market revisions expected to occur by 2023 to include ancillary services in the RTM and co-optimize resources in real-time.

To see the ORDC's investment incentive, consider the per MW-year profit of a new generation unit: π = annual sum of $\{\pi_{jt}\}$, where

$$\pi_{jt} = \max(P_{jt} - VC_{jt}, 0) \times \alpha_{jt} \tag{1}$$

is the per MWh operating profit ("profit" for short hereafter) at RTM price P_{jt} (\$/MWh) and per MWh variable cost VC_{jt} (\$/MWh) in 15-minute time interval $j = 1, \ldots, 96$ on day $t = 1, \ldots, 365$ for a given calendar year. To account for the unit's availability, α_{jt} is a binary indicator that equals 1 if the unit is available and 0, otherwise.[9]

For a NGFG unit, an estimate for VC_{jt} is:

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[9] The backcast results reported in Section 3 below assume $\alpha_{jt} = 1$ because they are based on the *ex post* data that portray generation units' actual availability in the backcast years. That said, the new unit may be unavailable in the high price hours due to a forced outage or in the low price hours due to a planned outage caused by scheduled maintenance. As the unit is unprofitable in the low price hours, accounting for the unit's forced outage rate $\alpha = \mathrm{E}(\alpha_{jt}) \approx 5\%$ in the high price hours entails adjusting the per MWh profit backcasts in Table 2 by an availability factor of $(1 - \alpha)$. For a new CCGT or CT, $(1 - \alpha) \approx 0.95$ (Woo and Zarnikau, 2019), implying that the adjustment does not materially affect our assessment of investment incentives based on Table 2.

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$$VC_{jt} = HR \times F_t + C_{jt}, \tag{2}$$

where HR = engineering-based heat rate (MMBtu/MWh) of the unit, F_t = natural gas price ($/MMBtu) on day t,[10] and C_{jt} = per MWh variable O&M cost ($/MWh), which is often assumed to a time-invariant number.

Let K = cost of new entry (CONE) = per MW-year fixed cost for a new unit's O&M and returns on and of investment. When $(\pi - K) < 0$, an independent power producer faces a missing money problem and is unwilling to make a generation investment.[11] As systematically increasing P_{jt} enlarges π, the PUCT order aims to increase ERCOT's ORDC price adder, thereby reversing the state's trend of shrinking reserve margin (Walker, 2019).

The PUCT uses the "peaker-net-margin" (PNM = annual sum of operating profits per MW of peaker capacity) to provide a crude measure of the annual margin earned by a peaking unit.[12] ERCOT estimates the PNM on an ongoing basis under the assumption of HR = 10 MMBtu per MWh and C_{jt} = 0. If the PNM estimate exceeds the CONE estimate, the missing money problem is deemed absent.

ERCOT's current CONE estimate is $105,000/MW-year based on values calculated for other markets.[13] As evident from Figure 3, the PNM failed to meet this CONE threshold in the years 2014 through 2018. However, the same cannot be said for the period of 01/01/2019 to 09/10/2019, chiefly because the ORDC shift occurred on

[10] For our backcasting exercise, F_t is proxied by the readily available and widely used Louisiana's Henry Hub price that closely matches Texas's citygate prices.
[11] For easy exposition of our empirical results presented in Tables 2 and 3, we convert $(\pi - K) < 0$ to $(\gamma - \delta) < 0$, where $\gamma = \pi \div 8760$ hours and $\delta = K \div 8760$ hours.
[12] PUCT Subst. R. §25.505. https://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.505/25.505.pdf (accessed 08/31/2019)
[13] ERCOT is presently contemplating the sponsorship of a Texas-specific study to incorporate factors specific to the state.

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03/01/2019 and Texas's 2019 summer was hotter than expected. The resulting RTM price spikes caused the PNM to reach $119,100/MW-year on 09/10/2019.

In addition to ERCOT's PNM calculation, the PUCT's market monitor, Potomac Economics, includes in its 2018 annual State of the Market report's net revenue calculations that assume: (a) HR = 7 MMBtu/MWh for a combined cycle gas turbine (CCGT) and HR = 10.5 MMBtu/MWh for a combustion turbine (CT); (b) C_{jt} = $4/MWh; (c) a total outage rate (planned and forced) of 10%; and (d) the unit, if available, produces energy in any hour for which it is profitable and sells reserves and regulation in all other hours (Potomac Economics, 2019). Its net revenue estimates for 2018 are $72,000 to $78,000 per MW-year for a CCGT and $52,000 to $56,000 per MW-year for a CT, insufficient to cover a new CCGT's fixed cost of $110,000 to $125,000 per MW-year and a new CT's fixed cost of $80,000 to $95,000 per MW-year (Potomac Economics, 2019, pp.112-113).

2.3 Analysis plan

Our analysis plan has two parts. Part 1 is a backcast of the ORDC price adders, had the shift taken place years earlier. Part 2 calculates a generation unit's average per MWh profit γ = annual mean of $\{\pi_{jt}\}$. The unit is assumed to be a CCGT with HR = 7 MMBtu/MWh or a CT with HR = 9 MMBtu/MWh (Woo et al., 2016b) or 10.5 MMBtu/MWh (Potomac Economics, 2019, p.112). The backcast profit calculations include the $4/MWh O&M cost assumed by Potomac Economics (2019). However, they do not consider the revenue opportunities in ERCOT's ancillary services market, as the ORDC shift's primary impact is the price adder increases in a backcast setting.

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2.3.1 Profit effects of the PUCT order

To understand the impact of ERCOT's revised ORDC on market prices, we perform a backcast of the ORDC adders in 2015, 2016, 2017, and 2018 that would have occurred, had the ORDC been shifted by 0.25 σ and 0.5 σ in those years. We perform this calculation for every SCED interval within these four years. We then use the revised adders to raise ERCOT's 15-minute RTM energy prices (i.e., backcast RTM prices = actual RTM prices – actual ORDC adders + backcast ORDC adders).

Our backcasting entails the following steps:

(1) Collect the necessary input data from ERCOT.

(2) Set up a spreadsheet to perform the price adder backcasts based on ERCOT's formulae (ERCOT, 2013).

(3) Validate 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.

The actual reserve margins in the backcast years are far above the levels anticipated in 2019 and 2020. For example, the actual reserve margin in the summer of 2018 is 11% and 17% in 2017. Consequently, our backcasts for those years likely underestimate the impact of the ORDC shift in a year of tight reserve margins expected in 2019 and 2020.

After backcasting the 15-minute price adders that increase the RTM prices for each of the three σ values of 1.0, 1.25 and 1.5, we calculate: γ_1 = annual average of the

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per MWh profits (\$/MWh) of a CCGT; and γ_2 = annual average profit (\$/MWh) of the per MWh profits of a CT. Based on Texas's per MW-year fixed costs (Brattle Group, 2018a, p.17), we also calculate: δ_1 = CCGT's per MWh fixed cost of \$10.78 (= \$94,500/MW-year ÷ 8,760 hours); and δ_2 = CT's per MWh fixed cost of \$10.10 (= \$88,500/MW-year ÷ 8,760 hours).[14] If $\gamma_g > \delta_g$ for g = 1, 2 at σ = 1.25 (or 1.50) for the backcast period, we infer that the PUCT order is deemed effective in solving Texas's missing money problem.

3. Results

Table 1 reports the PUCT order's financial effects. Based on the actual ORDC adders at σ = 1, ERCOT's total electricity cost (= annual sum of the 15-minute system demands at the RTM prices) was \$14.24 billion in 2018, of which \$0.75 billion or 5.3% was due to the ORDC. Shifting the ORDC by 0.25 σ would have increased the total ORDC collection in 2018 to \$2.11 billion, a \$1.36 billion or 180% increase from the actual ORDC collection, leading to a 9.5% increase (\$1.36B/\$14.24B = 9.5%) in total electricity cost for 2018. Shifting the ORDC curve by 0.5 σ would have increased the total ORDC collection to \$3.25 billion, a whopping \$2.5 billion or 332% increase from the actual ORDC collection, resulting in a 17.6% increase (\$2.5B/\$14.24B = 17.6%) in total electricity cost for 2018. However, the impacts on total ORDC collections in 2016 and 2017 would have been modest, less than \$0.6 billion.

[14] The per MWh fixed costs can also be based on ERCOT's CONE of \$105,000/MW-year and Potomac Economics' per MW-year estimates of \$110,000 to \$125,000 per MW-year for a new CCGT and \$80,000 to \$95,000 per MW-year for a new CT. Using these alternative per MW-year cost estimates do not qualitatively change our findings developed from Tables 2 and 3 on the ORDC shift's effectiveness in solving Texas's missing money problem.

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Table 2 reports each generation technology's annual averages of RTM prices and per MWh profits. At $\sigma = 1$ for the case of no ORDC shifting, Panel A indicates that these average profits are less than the per MWh fixed costs, suggesting insufficient investment incentives for new plant construction in all four backcast years. At $\sigma = 1.25$ for the case of a 0.25 σ ORDC shift, Panel B indicates sufficient investment incentives for 2018 CCGT only. At $\sigma = 1.5$ for the case of a 0.5 σ ORDC shift, Panel C shows sufficient investment incentives for both CCGT and CT in 2018 only. In summary, the PUCT order's effectiveness in solving the missing problem is only found for the low reserve margin year of 2018.

Based on Table 2, an increase in RTM prices of 9.5% for $\sigma = 1.25$ or 17.6% for $\sigma = 1.5$ in 2018 seems sufficient to incent a coal plant owner to continue to operate the asset. This is because (a) a new plant's per MWh costs include fuel and O&M and returns on and of investment; and (b) an old plant's per MWh costs include fuel and O&M. As (a) typically exceeds (b), sufficient investment incentive for a new plant implies sufficient retention incentive for an old plant.

The far smaller impact in 2016 or 2017 in Table 2 might have made little difference to a coal plant owner. The higher impacts in 2018 were due to the tight reserve margin in that year, partly driven by retirement of three large coal plants. As 2020 is likely to continue to see a reserve margin below 2018's value, the near-term impact of a shift in the ORDC would strengthen after the 0.5 σ shift's implementation. This suggests that the PUCT's order will likely succeed in discouraging further plant retirements over the next couple years.

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To better understand Texas's missing money problem, consider Table 3 that reports the average per MWh profits, which are above a CCGT's and a CT's fixed cost in the six-month period of March – August 2019. This is because: (a) the ORDC's 0.25 σ shift occurred on 03/01/2019 and raised the period's RTM prices; and (b) the six-month period's high RTM prices are also attributable to lower reserve margin caused by Texas's hotter than expected summer in 2019.

Notwithstanding the ORDC shift's near-term effects, the RTM prices produced by SCED will likely continue on their downward trend, absent an increase in the price of natural gas. This is because renewable generation tends to depress 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 will likely increase, resulting in low RTM prices that may persist in future years with abundant capacity.[15] 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.

4. Discussion

Based on the backcast results for 2015-2018 and actual results for the six-month period in 2019, we infer that the PUCT order of shifting the ORDC is likely successful in in addressing Texas's missing money problem in the next 2-3 years when the future reserve levels are similar or lower than those experienced in 2018. However, a long-term challenge remains for two reasons. First, Texas's planned solar and wind generation development will continue to dampen prices through their merit order effects. Second, the

[15] We have recently found that each additional GWh of wind energy generation lowers market-wide prices by \$1.8/MWh (Zarnikau et al, 2019). Our earlier research indicates larger price impacts of wind generation (Woo et al, 2011a; Zarnikau et al, 2016).

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level of reserves likely rises, if short-term effect of ORDC redesign indeed incentivizes new capacity's market entry.

Future efforts to improve Texas's reserve margin might involve encouraging additional demand response (DR). Barriers to the further provision of DR by participants in ERCOT's competitive wholesale and retail markets might be removed, or ERCOT's Emergency Response Service could be expanded. As the incremental DR does not enter the ORDC adder's calculation, it does not reduce the ORDC's generation investment incentives.

Another alternative would focus on improving the price signals provided to residential and small commercial customers in the competitive retail market. Designed before deployment of advanced metering systems, demand-related costs such as the cost of providing transmission and distribution service are presently recovered through volumetric delivery charges on residential and small commercial customers. Demand charges or time-differentiated energy charges for the recovery of transmission and distribution costs might send a better price signal to smaller consumers and reduce usage coincident with annual peaks.

Despite the evidence presented herein suggesting that the incentives for NGFG investment have been inadequate in the years prior to 2018, Potomac Economics (2019, p.77) reported that 670 MW of new CTs came on line in 2018. Various explanations have been offered for this apparent contradiction:

- Some independent power producers (IPPs) are confident that the economics of power plant investment in ERCOT will improve beyond what our empirics have portrayed, apparently encouraged by policy actions by the state to shift the ORDC curve.

- New NGFG has become more fuel-efficient, making it more profitable than assumed here. To wit, CTs with heat rates close to 8.0 MMBtu/MWh are now commercially-available.[16]
- Some IPPs might foresee higher ancillary services revenues from NGFG in the future, as ERCOT's reliance on intermittent renewables continues to increase (Kleit and Michaels, 2013).
- Investing in a physical asset such as NGFG may have some hedging benefits to particular retailers.

5. Conclusions and policy implications

To achieve Texas's adopted reserve target by ensuring adequate incentive for generation investment, ERCOT has implemented several measures to raise its RTM prices, including a high price cap of $9,000/MWh and the ORDC price adder to account for reserve scarcity. Nonetheless, owing to relatively stable natural gas price and significant development of renewable resources, ERCOT's RTM prices rarely hit the $9,000/MWh cap. Sustained low energy prices disallow full cost recovery by existing generation plants and discourage new plant construction, causing the unwelcome trend of shrinking reserve margins.

Recent changes in the ORDC calculation may address this problem, if the next few years have reserve margins at or below the levels experienced in 2018 and 2019. Yet, the impacts are difficult to forecast, since the ORDC adder is highly sensitive to the levels of available operating reserves. In the longer run, we doubt revisions of the ORDC will provide an adequate solution. This is because the growth of solar and wind energy

[16] See: https://www.ge.com/power/gas/gas-turbines/7ha; and https://new.siemens.com/global/en/products/energy/power-generation/gas-turbines/sgt5-9000hl.html

generation in Texas that is rich in renewable energy potential tends to constrain RTM prices through their merit-order effects.

Our findings' policy implication is that Texas's energy-only market design may need refinements based on a consideration of the mechanisms discussed by Woo and Zanikau (2019), potentially including capacity market, resource adequacy requirement, and reliability differentiation. Selecting an appropriate mechanism with wide acceptance by stakeholders of Texas's electricity sector, however, is a challenging task, one that is well beyond the intent and scope of this paper.

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Table 1. ORDC payments to generators ($Billion)

Variable	2015	2016	2017	2018
Actual energy Cost	9.63	8.91	11.03	14.24
Actual ORDC payment	0.49	0.1	0.09	0.75
Backcast ORDC payment with a 0.25 σ shift	1	0.32	0.29	2.11
Backcast ORDC with a 0.5 σ shift	1.57	0.55	0.51	3.25

Note: The actual energy cost and ORDC payments are based on the recorded RTM energy prices and sales. The backcast ORDC payments are based on the ORDC price adders that would have occurred had the ORDC shift been in place.

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Table 2. Average RTM prices and average per MWh profits by period and generation technology

Panel A. σ = 1.0 for the base case of no ORDC shift

Period	Average RTM price ($/MWh)	Average per MWh profit		
		CCGT: *HR* = 7 MMBtu/MWh	CT: *HR* = 9 MMBtu/MWh	CT: *HR* = 10.5 MMBtu/MWh
2015	24.18	4.55	3.35	2.97
2016	21.60	3.99	3.13	2.83
2017	24.95	4.88	3.91	3.57
2018	29.66	8.52	7.1	6.54
All years	25.09	5.48	4.37	3.98

Panel B. σ = 1.25 for the case of a 0.25 σ ORDC shift

Period	Average RTM price ($/MWh)	Average per MWh profit		
		CCGT: *HR* = 7 MMBtu/MWh	CT: *HR* = 9 MMBtu/MWh	CT: *HR* = 10.5 MMBtu/MWh
2015	25.13	5.50	4.30	3.92
2016	22.03	4.42	3.56	3.26
2017	25.36	5.29	4.32	3.98
2018	32.01	10.87	9.45	8.89
All years	26.13	6.52	5.41	5.02

Panel C. σ = 1.5 for the case of a 0.5 σ ORDC shift

Period	Average RTM price ($/MWh)	Average per MWh profit		
		CCGT: *HR* = 7 MMBtu/MWh	CT: *HR* = 9 MMBtu/MWh	CT: *HR* = 10.5 MMBtu/MWh
2015	26.23	6.60	5.40	5.02
2016	22.49	4.88	4.02	3.72
2017	25.77	5.70	4.73	4.39
2018	34.03	12.89	11.47	10.91
All years	27.12	7.51	6.40	6.01

Note: The average RTM price is the average of ***all*** 15-minute hub average RTM prices in a given period. The average per MWh profit is the average of ***all*** 15-minute per MWh profits in a given period. A CCGT's fixed cost is $10.78/MWh, below the 2018 average per MWh profits reported in Panels B and C. A CT's fixed cost $10.10/MWh, below the 2018 average per MWh profit reported in Panel C. Adjusting the per MWh profit backcasts by the availability of 0.95 does not alter our assessment of the CCGT's and CT's investment incentive adequacy.

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Table 3. Actual average RTM price and average per MWh profit by generation technology since the actual ORDC's 0.25 σ shift occurred on 03/01/2019 for the ensuing six-month period of March – August 2019

Variable	CCGT: *HR* = 7 MMBtu/MWh	CT: *HR* = 9 MMBtu/MWh	CT: *HR* = 10.5 MMBtu/MWh
Average RTM price ($/MWh)	43.80	43.80	43.80
Average per MWh profit ($/MWh)	25.39	23.96	23.33

Note: The average per MWh profits are found to far exceed a CCGT's fixed cost of $10.78/MWh and a CT's fixed cost of $10.10/MWh.

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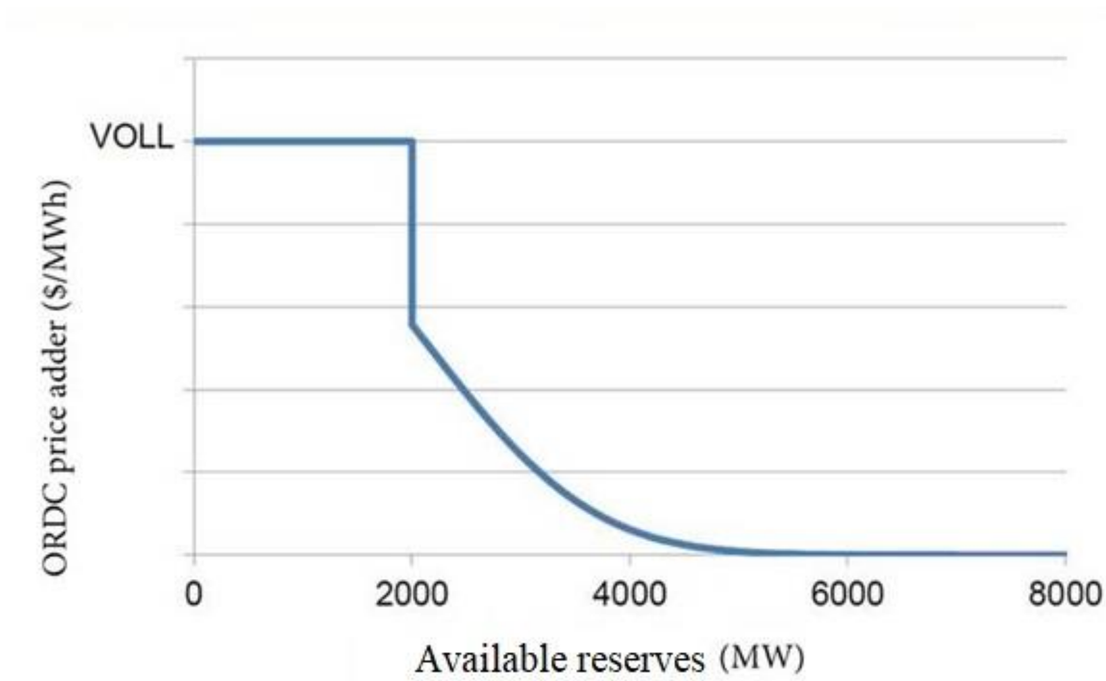

Figure 1. Relationship between ERCOT's available reserves (MW) and ORDC price adder

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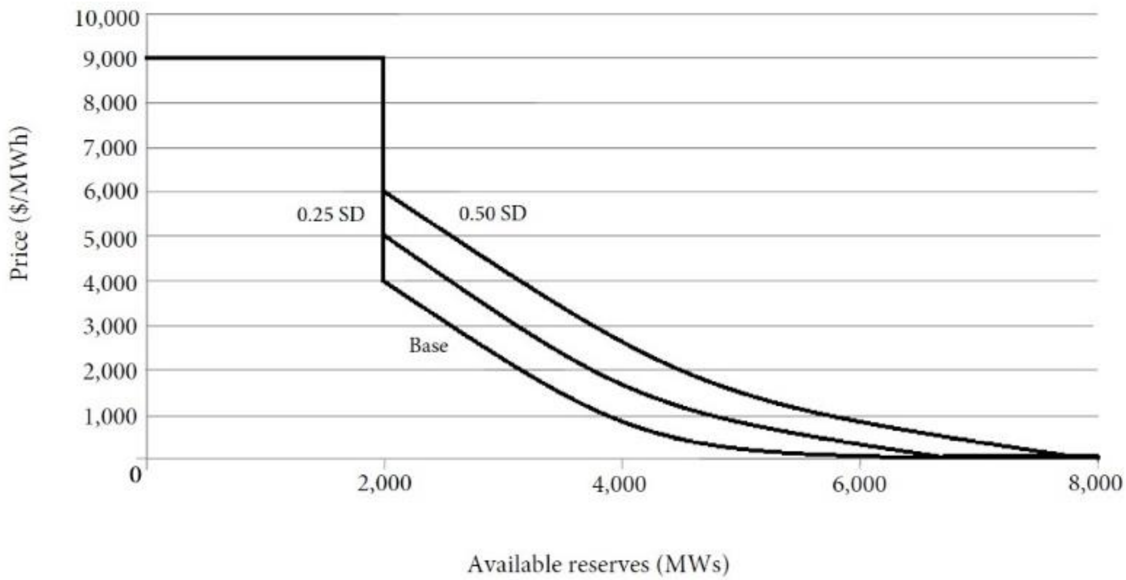

Figure 2. Price effects of increasing $\sigma = 1.0$ (base) to $\sigma = 1.25$ or 1.5, where 0.25 SD and 0.5 SD indicate the incremental standard deviations used for the ORDC shift.

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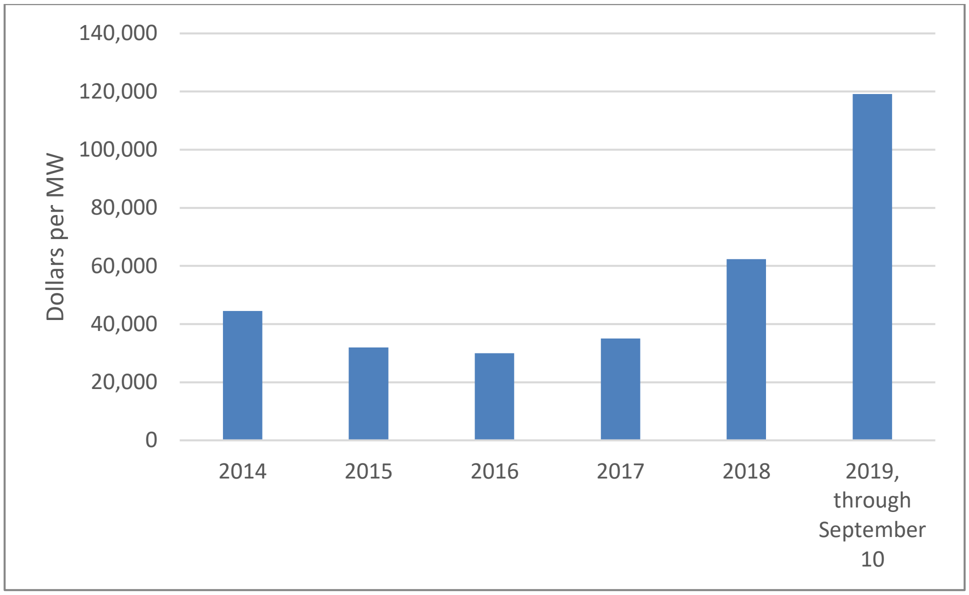

Figure 3. Peaker net margin calculated by ERCOT for recent time periods