This is the pre-published version published in
Journal of Energy Markets, available online at:
https://doi.org/10.21314/JEM.2018.188.

Electricity market prices for day-ahead ancillary services and energy: Texas

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JEL Codes: D44, D47, G13, G14, Q41

Keywords: Electricity prices, Day-ahead market, Ancillary Services, Texas, ERCOT

This is the pre-published version published in Journal of Energy Markets, available online at: https://doi.org/10.21314/JEM.2018.188.

Abstract

Applying a regression-based approach to a large sample of hourly observations for the 7-year period of January 1, 2011 to December 30, 2017, we explore determinants of day-ahead market (DAM) prices for ancillary services (AS) and energy in the Electricity Reliability Council of Texas (ERCOT). For each GW increase in responsive reserves (RRS) or non-spinning reserves (NSRS) procurement quantities, we estimate price increases of about \$3.47 per MW per hour and \$5.63 per MW per hour, respectively; while the cost of an additional 1-GW of regulation up (REGUP) and regulation down (REGDN) is a much higher \$17 per MW per hour and \$31 per MW per hour, respectively. A \$1/MWh increase in the DAM energy price tends to increase RRS and REGUP prices by nearly \$1 per MW per hour, about twice the estimated impact for NSRS that is not necessarily on-line when selected. The participation of interruptible loads to provide RRS reduces the RRS price, and this impact increased nearly six-fold from the first to the second half of our sample time period. An increase in wind generation tends to decrease AS prices because it reduces the DAM energy price via the merit-order effect. Hence, Texas' wind generation expansion has not raised ERCOT's AS prices in our sample period characterized by stable AS requirement and declining natural gas prices. Going forward, however, Texas could face AS cost escalation due to the high REGUP and REGDN prices,

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should ERCOT’s requirement and procurement of those services increase due to rising renewable production.

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1. Introduction

In a network designed to satisfy the electricity needs of energy consumers, supply and demand must balance in real time to maintain system reliability and frequency. This poses a challenge to a system operator due to random fluctuations in system load, unexpected changes in generation output (e.g., intermittent renewable energy sources), errors in forecasting demand and generation, unexpected mechanical failures of generation or transmission assets, and limited ability to economically store electricity in a network dominated by thermal resources. As a result, procurement of various ancillary services (AS) by a system operator is necessary to resolve a network's inevitable fluctuating demand-supply imbalances occurring between updates of the economic dispatch set-points of generators (Stoft, 2002).[1]

As competitive wholesale electricity markets have evolved, attention has focused on: (a) establishing performance standards for AS resources, (b) the design of competitive markets for the procurement of AS, and (c) determining the optimal levels of AS requirements (Oren, 2002). Increasing dependence on randomly intermittent and as-available renewable resources like solar and wind may increase a network's AS needs, sparking investigations on how such needs may be met in the

[1] The Federal Energy Regulatory Commission (FERC) defines AS as services "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." See FERC Orders 888, 889, and 2000.

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future (GE Energy, 2008; ERCOT, 2013; Exeter Associates and GE Energy, 2012; National Renewable Energy Laboratory, 2011a; National Renewable Energy Laboratory, 2011b; Andrade et al, 2017).

The primary objective of this paper is to empirically characterize, via a regression-based approach, the AS prices' data generating process (DGP) in a competitive market. This characterization is useful and relevant for the following reasons. First, there has been little attention devoted to the market price behavior of AS, notwithstanding a review of historical prices in U.S. markets by Argonne National Laboratory (2016) and periodic analyses performed by the independent market monitor of the Electric Reliability Council of Texas (ERCOT) (Potomac Economics, 2018). Second, a network's AS costs are non-trivial, at least in the aggregate,[2] and ultimately borne by consumers due to load-serving entities' pass-through of such costs that move with the AS prices. Finally, little is known regarding how AS prices may vary with a network's dependence upon renewable generation, unlike the well-documented merit-order effects of renewable generation on day-ahead market (DAM) and real-time market (RTM) energy prices (e.g., Woo et

[2] Based on Argonne National Laboratory (2016, p. 34), the annual market revenues for regulation service added across the California (CAISO), Mid-West (MISO), PJM, and Southwest Power Pool (SPP) markets in 2014 was about $383 million. For spinning or responsive reserves, the total was $139 in that year for those markets. The annual market revenue for non-spinning reserves in those markets in 2014 totaled $36 million.

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al., 2011, 2015, 2016a, 2017, 2018; Zarnikau, et al., 2016; and the extensive references thereof).

We exploit the interdependence of AS and energy markets to develop a model of price regressions to analyze hourly data obtained from ERCOT. ERCOT serves 85% of the electrical needs of the largest electricity-consuming state in the U.S. and accounts for over 9% of the nation's total electricity generation.[3] Moreover, ERCOT is repeatedly cited as North America's most successful attempt to introduce competition in both generation and retail segments of the power industry (Distributed Energy Financial Group, 2015). Finally, Texas has greatly increased its dependence upon intermittent renewable energy generation over the time period studied here.

Our comprehensive analysis of ERCOT's DAM energy and AS prices finds:

- ERCOT's DAM energy price moves with such fundamental drivers as natural gas price, system load, nuclear generation, wind generation, and AS requirements. In particular, it declines with nuclear and wind generation but increases with the other drivers.
- Because of market interdependence between AS and energy, ERCOT's AS prices increase with the DAM energy price. They also increase with ERCOT's

[3] Generation in ERCOT was 375,890 GWh in 2017, as reported to NERC: http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx. Total U.S. generation at utility-scale facilities was 4,014,804 GWh in that year, according to the U.S. Department of Energy's Energy Information Administration: http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_1.

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AS demands measured by the procurement quantities but decrease with ERCOT’s AS supplies as measured by the offer quantities.

- A $1/MWh increase in the DAM energy price tends to increase the responsive reserve (RRS) and regulation up (REGUP) prices by nearly $1 per MW per hour, indicating market efficiency that results from the arbitrage behavior and co-optimization among generating units that provide RRS and REGUP services and can also supply DAM energy.
- A $1/MWh increase in the DAM energy price tends to raise the NSRS price by a lesser amount of about $0.44 MW per hour, reflecting that providers of this service are not necessarily on-line and burning fuel, and thus incur lower costs to provide NSRS.
- The per MW per hour price of acquiring additional REGUP and regulation down (REGDN) services is considerably more expensive than RRS or NSRS, reflecting that few generation and load resources can respond fast enough to system changes to qualify as REGUP and REGDN providers.
- Rising share of RRS provided by load resources tends to reduce the RRS price because ERCOT’s interruptible loads often offer demand reductions at zero prices, thereby raising their likelihood of being awarded.

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Taken together, the above findings suggest that large-scale renewable energy development in Texas has not increased ERCOT's AS prices during our sample period. Nor has it increased ERCOT's AS procurement costs, thanks to ERCOT's stable AS requirements and procurements. Further, ERCOT's success in facilitating the participation of load resources into the market for RRS has proven successful in constraining the market prices of that service, lending support to FERC's actions to ensure load resources' opportunity to participate in AS markets in other regions of the U.S. Going forward, however, there is a potential risk for AS cost escalation in Texas because of the high per MW cost for additional REGUP and REGDN procurement which may rise in response to the state's further expansion of wind energy development.

This paper makes the following contributions to the literature of electricity market price behavior. First, to the best of our knowledge, it is the first detailed regression analysis of AS prices in ERCOT's DAM environment. Second, the analysis is comprehensive, encompassing all of ERCOT's day-ahead products: energy, RRS, NRRS, REGUP and REGDN. Finally, its parsimonious and easy-to-understand regression specification is general, equally applicable to other regional grids with data availability similar to ERCOT's (e.g., California, New York, New England and PJM).

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The paper proceeds as follows. Section 2 provides an overview of the ERCOT market and explains the determination of AS requirements, obligations, and procurement. It also describes our data sample and proposes our regression specification. Section 3 presents the regression results. Section 4 discusses these results. Section 5 contains our conclusions.

2. Materials and methods

2.1 Why ERCOT?

ERCOT presents an interesting setting for analyzing the AS market price behavior because formal markets for both energy and AS have been established to foster competition, the markets are of significant size, and Texas leads the nation in electricity generation from wind farms. Increased generation from intermittent renewable energy sources, such has wind, has prompted concerns that the state's need for AS may increase in the future, perhaps raising the cost of maintaining adequate AS. Consequently, an examination of how growing wind generation has affected market prices of AS in Texas can inform other markets with large-scale renewable energy development.

ERCOT has undergone gradual restructuring since the mid-1990s (Zarnikau, 2005). Legislation enacted in 1995 required the Public Utility Commission of Texas to establish rules to foster wholesale competition and create an ISO to ensure

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non-discriminatory access to the transmission network. Sweeping reforms were introduced through Senate Bill 7 in 1999, allowing customers of the investor-owned utilities within ERCOT to choose among competitive retail electric providers (REPs) for a retail supply of electricity beginning on January 1, 2002. Senate Bill 7 also enhanced the ISO's centralized control over the wholesale market, replacing ten control centers formerly operated by various utilities. This led to the establishment of a formal DAM for AS and a real-time market (RTM) for balancing energy.

An important structural change to the ERCOT market was completed on December 1, 2010: the introduction of a nodal market structure (Zarnikau et al, 2014a). The DAM was expanded from merely a market for the procurement of operating reserves to also include energy. Similar to the DAM energy markets elsewhere (e.g., PJM, New York, New England, and California), ERCOT’s DAM matches day-ahead forward energy bids and offers (Zarnikau, et al, 2014b). Hourly market-clearing DAM energy prices used to settle DAM transactions result from a least-cost dispatch that co-optimizes energy generation with AS and congestion revenue rights.

Supply offers and bids begin at 6 a.m. and end at 10 a.m. on day *t*-1 for ERCOT’s day-ahead price determination. DAM is normally executed between 10 a.m. and 1:30 p.m., and prices for the following day are set around 2 p.m., though prices

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may be updated by 6 p.m. after any needed reliability unit commitment activities are completed.[4] As actual wind generation and total energy demand on day *t* are not known on day *t*-1, the DAM energy prices for energy and AS depend, in part, on forecasts of wind generation and load made on day *t*-1 in the 6 to 10 a.m. window.

There is presently no "capacity market" in ERCOT to maintain a target reserve margin. Consequently, ERCOT relies on market forces to achieve reliability and resource adequacy. To encourage investment in generation capacity, the offer cap on wholesale market prices was raised to $3,000 per MWh at the start of the nodal market on December 1, 2010. The cap was further increased to $4,500 per MWh effective August 2012, $5,000 per MWh on June 1, 2013, $7,000 per MWh on June 1, 2014, and $9,000 per MWh on June 1, 2015. ERCOT's DAM energy prices, however, have seldom reached the caps since the nodal market's establishment.

Texas has the most wind generation in the United States, thanks to its enormous resource potential, establishment of policy targets and a system of tradable Renewable Energy Credits (RECs), federal tax credits, and ERCOT's favourable market rules (Zarnikau, 2011). The completion of Competitive Renewable Energy Zone transmission in January 2014 resulted in 3,600 circuit-miles of 345kV transmission line to increase export capability to accommodate approximately 11GW additional for a

[4] See ERCOT training module, Module 2: Day-Ahead Operations, available at: http://www.ercot.com/content/wcm/training_courses/58/GEN101_M2_Jan2010.pdf

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total of 18.5GW of renewable capacity, further fully unlocking the wind potential in West Texas. The intermittent nature of wind generation resources has presented operational challenges to ERCOT, and the establishment of new market rules was necessary in order to accommodate this non-dispatchable intermittent resource. Additionally, ERCOT has been improving its ability to accurately forecast wind generation output.

2.2 Ancillary services in ERCOT

As summarized in Table 1, ERCOT presently procures four types of system-wide operating reserves: REGUP, REGDN, RRS and NSRS, similar to the system operators elsewhere (e.g., California, New York, New England and PJM).

REGUP and REGDN capacities balance small fluctuations in supply and demand in real time to maintain system frequency close to 60Hz. These services are primarily provided by generators with Automatic Generation Control (AGC) or the equivalent. Resources providing regulation services must respond every four seconds, either increasing or decreasing output to address gaps between supply and demand, and must comply with ERCOT instructions within five minutes.

Similar to the spinning reserves maintained in many other electricity markets, RRS restores the balance between generation and load after the sudden forced outage of a major generator or transmission line or some other major shock to the electrical

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system (e.g., an unexpectedly large drop of wind speed in West Texas where most of the state's wind farms reside). The dispatcher must therefore have RRS available to prevent an unacceptable drop in system frequency.

RRS can be provided by unloaded generation resources that are on-line but not generating at full capacity and can therefore increase their output quickly to provide additional capacity to the system. As with generation resources providing REGUP and REGDN, generators providing RRS must be responsive to automated ERCOT instructions, via AGC that translates instructions into adjustment of prime mover and electrical output. In addition, properly qualified load resources can provide RRS. Nearly half of ERCOT's RRS requirements are met by load resources equipped with under-frequency relays that instantaneously curtail load when frequency drops to 59.7 Hz. Resources providing this service must also be able to respond to verbal dispatch instructions. Requirements for RRS are calculated in four-hour blocks on the basis of forecasted load and wind patterns. During the sample period, load resources were permitted to provide no more than 50% of RRS requirements, thus ensuring sufficient generation resources to maintain adequate inertia on the system, though the limit was subsequently raised to 60% effective May 31, 2018.[5]

[5] See ERCOT "Percent Change in Load-Provided Responsive Reserve" at http://ercot.com/mktinfo

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NSRS ensures sufficient capacity to cover large forecast errors or replace deployed RRS. While resources providing RRS must increase output in compliance with ERCOT instructions within 10 minutes, resources providing NSRS must comply within 30 minutes. NSRS may be provided by generation units that are offline, as long as they are able to start up and increase their output to the target level within a predefined period of time, usually 10 to 30 minutes. Small amounts of NSRS have historically been provided by load resources.

ERCOT establishes hourly requirements for each operating reserve depicted in Fig. 1. Requirements changed greatly when the nodal market was introduced in Dec. 1, 2010 and generation prices started to be calculated each 5 minutes (at most), rather than each 15 minutes. In particular, the need for REGUP and REGDN was reduced accordingly, mirroring the shorter time between a security-constrained economic dispatch solution and the start of an operating period, which is presumed to decrease short-term forecasting errors. In light of the confounding structural changes that accompanied the introduction of the nodal market, the AS prices and procurements during the zonal market period will not be considered in this analysis.

For REGUP, requirements can change from hour to hour, depending upon historical wind generation and other factors. At the start of the nodal market, regulation requirements were set based on an examination of changes in net load

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(demand minus wind generation) the same month of the previous year and the past 30 days prior to the time of a study, and refinements were applied in February 2011.[6] Considerable changes to the method used to set minimum regulation requirements were made on January 1, 2016 which resulted in lower requirements.[7] A small change to the relationship between wind generation and regulation requirements was implemented at the beginning of 2014.[8] The discussion for REGDN is entirely analogous and hence omitted for brevity.

RRS requirements change less often than other AS. RRS requirements were historically nearly always 2,300 MW, were raised to 2,800 MW on April 1, 2012,[9] and since June 1, 2015 have based on variable hourly needs.

While initially set at a fixed hourly amount, NSRS requirements were based on the largest unit planned to be in operation for periods of projected higher risk through most of the zonal market period. This was changed to 1,500 MW per hour beginning April 1, 2012.[10] Subsequently, the system requirement for NSRS was determined by first calculating the 95th percentile of net load uncertainty from both

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[6] 2010-2011 Ancillary Service Methodology, presentation to ERCOT Board of Directors, 20 July, 2010.
[7] Item 9: 2016 Methodology for Determining Minimum Ancillary Service Requirements, ERCOT Board of Directors, Dec. 8, 2015.
[8] Item 8: Proposed Changes for the 2014 Methodology for Determining Minimum Ancillary Service Requirements, ERCOT Board of Directors, Dec. 2013.
[9] Item 9: 2012 Ancillary Services Methodology Recommendation, Memo from John Dumas to ERCOT Board of Directors, Feb. 21, 2012.
[10] Item 9: 2012 Ancillary Services Methodology Recommendation, Memo from John Dumas to ERCOT Board of Directors, Feb. 21, 2012.

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the previous 30 days and the same month of the previous year.[11] ERCOT would then subtract the REGUP requirement from this 95th percentile to obtain the NSRS requirement. In 2016, the formula was altered to remove consideration of net load uncertainty during the previous 30 days, and to instead consider net load uncertainty in the same month of the previous three years.[12] During the hours of 7 a.m. through 10 p.m. Central time, ERCOT also applies a minimum NSRS requirement equal to the largest single unit in the system. Generally, an improvement in ERCOT's accuracy in predicting next-day load and wind generation levels reduces ERCOT's requirements for this service.

Load-Serving Entities (LSEs) are assigned AS obligations based on their share of load the same hour of the previous day. If the LSE served 10% of the load at 2-3 p.m. yesterday, they have an obligation for 10% of each operating reserve AS at 2-3 p.m. today. With advanced notice to ERCOT before the DAM's price determination, LSEs can self-arrange to meet part or all of their AS obligation. They can use their own generating capacity or interruptible load, or acquire it through a market outside

[11] Net load is defined as total load minus wind generation, and net load uncertainty is defined as the difference between the realized net load and forecast net load. Solar generation was also included in this definition beginning in January 2017. See Item 9: 2017 Methodology for Determining Minimum Ancillary Service Requirements, ERCOT Board of Directors, Dec. 13, 2016.
[12] Item 9: 2016 Methodology for Determining Minimum Ancillary Service Requirements, ERCOT Board of Directors, Dec. 8, 2015.

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of the DAM. Trades among market participants are common. Figs. 2-4 indicate the percentage of AS obligations which are self-arranged for REGUP, RRS, and NSRS. [13]

Many of the larger LSEs that also have generation assets seek to fully hedge (i.e., fully self-arrange) and thus avoid their risk exposure to the DAM's AS price volatilities. The rural electric coops contend that they may encounter federal tax problems if they profit from trading activities unrelated to satisfying the energy needs of their customers.[14] Consequently, some cooperatives may avoid using the DAM to sell any AS. During the zonal market period, NSRS was typically fully self-arranged, so that there was no market for this operating reserve. However, this has become unusual, following some market changes.

Whatever portion of an LSE's obligation is not self-arranged is procured on behalf of the LSE by ERCOT through the DAM.[15] These quantities are indicated in Fig. 5. The DAM is an hourly market for both energy and AS, whose prices are determined between 10:00am and 1:30pm for the 24 hours of the following day. ERCOT bills the LSE for the cost of procuring AS on the LSE's behalf at a single market clearing price of capacity (MCPC) for each AS for each hour.

[13] Per ERCOT Nodal Protocol Section 4.4.7.1.1, a scheduling entity (QSE) may submit a negative Self-Arranged Ancillary Service Quantity in the DAM, and ERCOT shall procure all negative Self-Arranged AS submitted by a QSE.

[14] See various statements and testimony filed in PUCT Docket No. 31540: Proceeding to Consider Protocols to Implement a Nodal Market in the Electric Reliability Council of Texas Pursuant to PUC Subst. R. 25.501.

[15] In certain ERCOT systems and databases, the amounts procured are referred to as the amount awarded. Certain ancillary services which are not acquired through the DAM (e.g., black start and voltage support), and shall be ignored here.

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Generation and load resources supplying AS and energy are co-optimized in the DAM. Thus a resource offered to the DAM will end up, if selected or awarded, providing AS or energy, depending upon where it has the most value. But, not all resources are qualified to provide all types of AS. A resource that responds slowly will not be selected to provide a service that requires a fast response, such as REGUP.

There is often an over-abundance of load resources to provide RRS at $0/MW in hopes of ensuring their offer is accepted. These resources have negligible deployment costs and count on generators to set the market clearing price. Formerly, load resources were allowed to offer capacity at negative prices, leading to occasional negative market-clearing prices. Negative-price bidding by load is no longer allowed.[16]

Contrary to the expectations of many, it has been asserted that the quantity of AS required by the ERCOT system operator has declined very slightly in recent years, despite a large increase in wind generation (Potomac Economics, 2018, p. 37).[17] This may, in large part, be due to improvements in ERCOT's near-term forecasts of load and wind generation and a multitude of changes in the ERCOT Protocols (Andrade et al., 2017). As suggested by Fig. 6, there has been a slight decrease in AS requirements

[16] See the background materials for NPRR 150: Responsive Reserve Service Offer Floor, 2008; and Nodal Protocol Section 4.4.7.2.1 (2). Available from www.ercot.com.
[17] As noted by Potomac Economics, total AS requirements were 5,300 MW in 2015, 4,900 MW in 2016, and 4,800 MW in 2018.

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from January 1, 2010 to December 31, 2017, as suggested by the negative slope coefficient in the trend line regression equation presented in the figure.

The amounts of AS procured or awarded through the DAM may have declined or increased, depending on the period selected (Tsai, 2018). Fig. 7 suggests a slight increase in total AS procured or awarded through the DAM in the period since the beginning of 2011. Changes in the procurement amounts may be explained by changes in requirements and changes in the self-arrangement of AS, as noted in the following section.

The market-clearing prices of AS have generally declined. But how have the changes in the AS market prices been affected by the changes in the quantities procured through the DAM, fluctuations in natural gas prices, and other factors? This question is explored in the following sections.

2.3 Data

Obtained from the ERCOT website and through public data requests to ERCOT, our sample contains hourly data from January 1, 2011 to December 30, 2017 for the following variables used in our price regressions described below:

- Generation (MWh) by fuel type for baseload nuclear power plants and wind farms for the ERCOT system.

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- Hourly quantities required by ERCOT, offered to the DAM, and procured through the DAM of each ancillary service (RRS, NSRS, REGUP and REGDN) in each hour (GW in each hour).[18]
- Hourly market-clearing price ($ per MW) of each ancillary service, as well as the price of energy ($/MWh) procured (i.e., awarded) through the DAM.
- For RRS, the percentage or share of the required quantity that was provided by interruptible load resources.
- The system-wide forecast of load for each hour of the following day made available by ERCOT at the market at the start of each day's DAM process.
- The system-wide forecast of wind generation for each hour of the following day made available by ERCOT to the market at the start of each day's DAM procurement process.

Additionally, the price of natural gas at the Henry Hub was obtained from the US DOE Energy Information Agency. Daily values were repeated for each hour of a day, and prices for days in which no trading took place (i.e., weekdays and holidays) were based on prices for the prior trading day.

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[18] Some of our calculations may omit the small amounts that ERCOT procures through "supplemental auctions" for AS. ERCOT has implemented SASMs (supplemental auctions) 391 times since the start of the nodal market. See ERCOT (2018). ERCOT reports quantities in MW. The values in MW were converted to values in GW, so that the coefficient estimates could be better illuminated.

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Our sample period closely matches the initiation of nodal pricing and the DAM on December 1, 2010. It begins January 1, 2011 because coherent price data reflecting the new markets and zones were unavailable for December 2010. It ends on December 31, 2017, reflecting the data supplied to us by ERCOT at the time of our writing.

Figure 8 displays the pattern of AS prices over time. Simple trend analysis suggests a small decline in the prices of each AS over the period considered in this analysis. Yet, simple trends are rather meaningless due to the large spikes indicated in this figure.

2.4 Price regressions

Our regression setup reflects that the day-ahead markets for energy and AS are interdependent because: (a) many generation resources can offer energy or AS, or both into DAM; and (b) resources are assigned to provide energy or AS through ERCOT's co-optimization routine. It also recognizes that DAM energy prices are mainly driven by such fundamental drivers as natural gas price, nuclear generation, and day-ahead forecast of system load and wind generation (Woo, et al., 2011; Zarnikau et al., 2014a, 2016).

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Let P_{jht} be the price for market j (= 1 for DAM, 2 for RRS, 3 for NSRS, 4 for REGUP and 5 for REGDN) in hour h (= 1, …, 24) on day t (= 01/01/2011, …, 12/30/2017). For the DAM energy price, the regression with random error ε_{1ht} is:[19]

$$P_{1ht} = \theta_{ht} + \theta_G G_t + \theta_N N_{ht} + \theta_D D_{ht} + \theta_W W_{ht} + \sum_{j=2}^{5} \theta_{Yj} Y_{jht} + \varepsilon_{1ht}. \quad (1)$$

In Eq. (1), coefficient θ_{ht} is a time-varying intercept that captures the fixed effects of hour-of-day and month-of-year. Coefficient $\theta_G > 0$ is the market-based heat rate that measures the DAM energy price increase due to a \$1/MMBtu increase in the natural gas price G_t (Woo et al., 2016b). Coefficient $\theta_N < 0$ is the marginal price effect of baseload nuclear generation N_{ht}. Coefficients $\theta_D > 0$ aims to capture the marginal price effect of ERCOT's day-ahead load forecast D_{ht}. Coefficient $\theta_W < 0$ measures the price-reduction (or merit-order) effect of the day-ahead forecast of wind generation W_{ht}. We do not consider other renewable generation types such as solar because of its small presence in Texas until recently and the absence reliable data throughout the timeframe of this analysis.

Eq. (1) uses $\{Y_{jht}\}$ to capture the effects of ERCOT's reliability-driven AS requirements on the DAM energy price, thus recognizing the ERCOT DAM's energy-AS interdependence ignored by prior price regression analyses for Texas (Woo

[19] We do not use the double-log specification because of the presence of zero and negative prices, whose natural log are missing values that cause data gaps in our regression analysis. The values of all quantity variables representing generation and load were converted from MWh values to GWh values, so that the coefficients associated with some of the variables could be better illuminated and all of these variables could be represented in the same units.

et al., 2011; Zarnikau et al., 2014a, 2016). We expect $\{\theta_j\}$ to be positive because prices tend to increase as more AS are required.

Let Q_{jht} = ERCOT's AS procurement quantity of type j (= 2, 3, 4, 5) in hour h on day t, S_{ht} = portion of RRS of Q_{2ht} provided by load resources, and Z_{jth} = total AS offer j in hour h on day t. To allay concerns of estimation bias due to endogenous regressors, we reason that $\{Q_{jht}\}$are pre-determined variables that measure the AS procurement amounts based on ERCOT's reliability requirements less the LSEs' total self-arranged amounts known to ERCOT before its calculation of the DAM's AS prices. We similarly reason that $\{Z_{jht}\}$ are pre-determined variables, as they are made prior to ERCOT's AS price determination.[20]

Reflecting the energy-AS markets' interdependence and the pre-determined nature of $\{Q_{jht}\}$, S_{ht} and $\{Z_{jht}\}$, our postulated AS price regressions with random errors ε_{jht} are:

$$P_{2ht} = \alpha + \alpha_1 P_{1ht} + \alpha_2 Q_{2ht} + \alpha_S S_{ht} + \lambda_2 Z_{2ht} + \varepsilon_{2ht}\,; \tag{2}$$

$$P_{3ht} = \beta + \beta_1 P_{1ht} + \beta_3 Q_{3ht} + \lambda_3 Z_{3ht} + \varepsilon_{3ht}\,; \tag{3}$$

$$P_{4ht} = \gamma + \gamma_1 P_{1ht} + \gamma_4 Q_{4ht} + \lambda_4 Z_{4ht} + \varepsilon_{4ht}\,; \tag{4}$$

$$P_{5ht} = \phi + \phi_1 P_{1ht} + \phi_5 Q_{5ht} + \lambda_5 Z_{5ht} + \varepsilon_{5ht}\,. \tag{5}$$

[20] This model does not use self-procured AS quantities as additional regressors because these quantities are endogenously determined by a load-serving entity with self-arrangement capability based on its least-cost offer decisions. In particular, it will buy from the AS market when the AS price is below the per MW cost of self-arrangement. Thus, even if the self-procured AS quantities should have appeared in the model, the DAM energy and AS prices would move with the fundamental drivers and AS procurements according to the price regressions postulated here.

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Coefficient α in Eq.(2) is the intercept. Coefficient $\alpha_1 > 0$ measures the DAM energy price's effect on the RRS price.[21] Hence, the change in a fundamental driver that alters the DAM energy price also impacts the RRS price. For example, $\theta_G\,\alpha_1$ is the RRS price effect of an increase in the natural gas price. Coefficient α_2 captures the demand-side price effect of Q_{2ht}. Finally, Eq. (2) uses coefficient $\lambda_2 < 0$ to measure the supply-side effect of hourly total RSS offer Z_{2ht} on the RRS price. As the interpretation of the remaining AS price regression is entirely analogous, it is omitted for brevity.

We tested a number of alternative models which included dummy variables to represent relevant changes in market rules and modifications to the formulas used by ERCOT to calculate AS requirements, but concluded that the effects of these changes were already reflected in $\{Q_{jht}\}$, leading to these dummy variables' statistical insignificance.

Thanks to market interdependence, the random errors in Eqs. (1) to (5) are contemporaneously correlated. As the hourly price data are likely serially correlated, we assume that the random errors follow an AR(n) process, whose order n is to be determined empirically. The endogenous DAM energy price appears as a regressor in Eqs. (2) to (4). Thus, Eqs. (1) to (5) form a system of simultaneous regressions, which

[21] Under the efficient market hypothesis (EMH), we expect α_1 to equal one based on the arbitrage behavior of suppliers. EROCT's reliability and operation constraints, however, imply that the EMH is unlikely to hold for all AS products.

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can be readily estimated using the iterated three-stage-least square (IT3SLS) technique in PROC MODEL of SAS software.

2.5 Data description

Table 2 reports the descriptive statistics and price correlations of the variables used in our price regressions. All data series are found to be stationary at the 1% significance level based on the Phillip-Perron unit-root test (Phillips and Perron, 1988), obviating concerns of spurious regressions due to non-stationary data that follow a random walk (Granger and Newbold, 1974).

It is noteworthy that RRS prices tend to be greater than the prices of REGUP, since REGUP has stricter performance requirements. Some of the reasons explaining differences in the relative average prices of the two products include: [22]

- ERCOT requires much more RRS than REGUP (~2800 MW for RRS versus ~300 MW of REGUP).
- Generating units are limited in how much RRS they can provide. Historically, this limit was no more than 20% of a unit's maximum capacity.
- While generation capacity providing RRS is required to be frequency-responsive, REGUP capacity is not required to have that capability.

The data series in Table 2 are volatile, with large standard deviations and wide

[22] These explanations were provided through correspondence with Beth Garza of Potomac Economics.

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ranges defined by the series' minimum and maximum values. The DAM energy price is highly correlated with the RRS, NSRS and REGUP prices (r > 0.71), though not with the REGDN price (r = 0.24). The positive correlation coefficients (r > 0.79) for the market prices of RRS, NSRS, and REGUP suggest that these three market prices tend to move in tandem, thus affirming their inter-dependence. However, the positive correlations of the REGDN price with the DAM energy and other AS prices are weak (r < 0.29), presaging an empirical challenge in modeling REGDN price movements. Happily, the regressions results reported in Table 3 demonstrate that the challenge is an unwarranted concern.

DAM energy prices are positively correlated with the natural gas prices and system loads but they are negatively correlated with wind generation output levels. Further, RRS, REGUP, and REGDN prices are negatively correlated with AS offers. Still further, RRS prices are negatively correlated with the shares of RRS met by load resources.

Many of the remaining correlation coefficients in Table 2 fail to attain their expected signs, thus motivating our estimation of the price regressions given by Eqs. (1) – (5) that controls for the effects of confounding variables and yields the generally reasonable empirics reported in the section below.

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3. Results

Table 3 presents our IT3SLS regression results. The five price regressions have adjusted R^2 that range from 0.36 for REGDN to 0.93 for RRS, indicating their eminently reasonable fit with the voluminous and noisy price data. The empirically determined AR order is $n = 3$ because the parameter estimates for $n > 3$ are all close to zero with dwindling statistical significance.[23] The estimated price regressions are empirically plausible because all coefficient estimates in Table 3 have the expected signs and they are mostly (17 out of 21) highly significant (p-value < 0.01).[24]

Focusing on the DAM energy price regression, we find that a $1/MMBtu increase in natural gas price tends to increase the DAM energy price by about $10.4/MWh, statistically close to a new combustion turbine's engineering heat rate of about 9 MMBtu/MWh. This makes sense as Texas is a thermal system whose marginal fuel is natural gas with combustion turbines being the marginal resource at high demand levels.

The remaining coefficient estimates indicate that a 1-GW increase in system load would raise the DAM energy price by $2.67/MWh on average, while the same GW increase in wind generation would cause a DAM price decrease by $1.85/MWh

[23] As an additional check, we assume AR(4) errors to re-estimate the price regression system, yielding results that are virtually identical to those shown in Table 2.

[24] Of the four coefficient estimates in the DAM energy price regression that are insignificant at the 1% level, three are significant at the 5% level. The estimate for nuclear generation, however, is highly insignificant (p-value > 0.1).

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on average. Nuclear generation's estimated price effect is statistically insignificant (p-value > 0.1), with a size half of wind generation's. The difference in magnitude between the effects of wind and nuclear generation on prices may be due to differences in their temporal profiles. As expected, the DAM energy price increases with ERCOT's AS requirements: a 1-GW increase's estimated price effect is over $20/MW/hr for the REGUP requirement and $1.69/MW/hr to $3.62/MW/hr for the other three AS requirements.

Turning our attention to the AS price regressions, we find that a $1/MWh increase in the DAM energy price tends to raise the RRS and REGUP prices by about a corresponding amount, nearly $1 per MW per hour, though much less for the NSRS and REGDN prices. The RRS price tends to decline with the share of RRS supplied by load resources.

The demand-side effects of a 1-GW increase in ERCOT's AS procurements are $3.49/MW/hr for RRS, $5.63/MW/hr for NSRS, $17/MW/hr for REGUP and $31/MW/hr for REGDN. The supply-side effects of a 1-GW increase in AS offers are AS price reductions of $1.29/MW/hr for NSRS to $4.56/MW/hr for REGUP.

As correctly noted by a reviewer, one might expect many of relationships among these variables to evolve over this long seven-year period, as the market has evolved. Since we could not identify any obvious point of structural change in this

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market during the time period analyzed, we simply divide the estimation in period in half. Thus period 1 encompasses January 1, 2011 to June 30, 2013 and period 2 covers July 1, 2013 to December 30, 2017. Indeed, some of the relationships significantly changed between these two time periods, as noted in Table 4. The impact of the day-ahead load forecast on DAM energy prices has declined. The impact of the DAM energy price on the price of REGDN has gone from positive to negative. The price reductions effect on RRS from a one percent increase in the share of RRS provided by interruptible loads increased by nearly six-fold from the first period to the second. Chow tests for subsample stability confirm the presence of some structural changes between these two periods. Yet, it is noteworthy that the effect of the wind generation forecast on DAM prices did not change significantly at the 5% level of statistical significance; nor were the changes in the coefficients on the gas price and nuclear generation variables significant.

4. Discussion

The empirics reported in Section 3 have important implications for generation investments and electricity bills. Specifically, the DAM price regression’s coefficient estimate for wind generation affirms the order merit effect that weakens the investment incentive for natural-gas-fired generation but helps reduce electricity bills

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(Liu et al., 2016; Woo et al., 2012, 2016b). If rising wind generation also increases ERCOT's AS requirements, its order merit effect on the DAM energy price diminishes.

The AS regressions' coefficient estimates suggest that rising wind generation tends to reduce AS prices because of its merit order effect on the DAM energy price, which in turn causes the AS prices to decline. To be sure, if rising wind generation also increases in ERCOT's AS procurement quantity, it shrinks these AS price declines. A substantive question thus arises: have ERCOT's AS procurements been rising in light of the rapid wind generation development in Texas?

The answer appears to be negative based on Fig. 7 which indicates that procurement quantities have remained quite stable albeit the wind generation capacity expansion in the last decade. This stability may be due partly to ERCOT's improved accuracy in forecasting wind generation and total system generation and due to a variety of protocol changes (Andrade et al., 2017). Declining natural gas prices that cut the DAM energy prices also contribute to ERCOT's stable AS prices.

Notwithstanding the above findings, we would be remiss had we failed to acknowledge the potential risk that ERCOT's AS cost *could* escalate in the future. This risk can be attributed to the very high marginal procurement cost of REGUP and REGDN that are used to counter the rapid fluctuations in intermittent generation

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resource such as wind. Furthermore, 4GW of coal capacity was retired in early 2018, which may also resulted in decreases in AS offer quantities and hence amplify potential risk of AS cost escalation.[25]

5. Conclusions

Based on an econometric analysis of AS prices set in ERCOT's DAM from January 1, 2011 to December 30, 2017, we find that:

- ERCOT's requirements for AS have proven remarkably stable over the seven years examined here, despite a large expansion in wind generation capacity. In the 2011 to 2017 period, a very slight negative trend in requirements may be seen, contrary to early predictions that increased dependence upon intermittent renewable energy generation would prompt increases in ERCOT's AS requirements.
- The pattern of the quantities of AS procured via ERCOT's formal market for AS mirrors the pattern exhibited by requirements, though the values are smaller due to the ability of some LSEs to self-arrange their obligations. Thus, the quantities procured through the DAM have also proven quite stable.

[25] For instance, average DAM market clearing price of REGUP has increased to $320 / MW per hour in July 2018. Average REGDN price also increased to $290 / MW per hour. This price spike in AS may reflect the tight AS supply condition. Interestingly, DAM average energy price stayed below $35/MWh, except in few hours in which the price skyrocketed and exceeded $1,000/MWh due to extreme high demand and low wind production.

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- The marginal cost of acquiring additional REGUP and REGDN capacity through ERCOT's DAM is quite high on average (despite the low average cost of these services), after controlling for the effects of other variables. This suggests that any increase in the requirements for these services may come at a high cost. The need for these services are sensitive to the levels of wind generation and forecasting error.
- We also find that the markets for RRS and REGUP are efficient, in the sense that a one-unit increase in DAM energy prices tends to increase RRS and REGUP prices by roughly one unit. This would be expected in an efficient market where resource are co-optimized, since generating units that set the market-clearing prices of RRS and REGUP could alternatively be used to provide energy.
- However, an increase in DAM energy prices will lead to a lesser increase in NSRS prices, reflecting that providers of this service are not necessarily on-line and burning fuel, and thus incur lower costs to provide this service.
- Increases in the share of RRS provided by load resources lead to lower prices for RRS because interruptible loads offer their demand reduction capacity at very low prices into the market for RRS. Hence, an increase in load participation can reduce the RRS market prices, which are typically set by generating units, in a

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manner similar to how increased baseload generation can reduce energy prices via a merit order effect.

In summary, our documentation of the market price behavior of ERCOT's DAM energy and AS prices suggests that wind energy development has reduced these prices in the last seven years, without materially raising ERCOT's AS requirement and procurement. Additional data collection and analysis in the coming years will tell whether this suggestion's empirical validity will continue to hold in the future.

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This is the pre-published version published in Journal of Energy Markets, available online at: https://doi.org/10.21314/JEM.2018.188.

Table 1. Summary of operating reserve AS required by ERCOT

Product	Description
Regulation-Up (REGUP)	Must immediately increase generation output (or reduce demand, if a load resource) in response to automated signals to balance real-time demand and resources.
Regulation-Down (REGDN)	Must immediately decrease generation output (or increase demand, if a load resource) in response to automated signals to balance real-time demand and resources.
Responsive Reserves (RRS)	Each resource providing RRS must be on-line, frequency responsive based on governor action, and fully responsive to any automated or verbal dispatch instructions from ERCOT within ten minutes. Load resource providing RRS must immediately respond when system frequency drops below 59.7 Hz, and must be able to maintain the scheduled level of deployment for the period of the service commitment.
Non-spinning Reserves (NSRS)	Each resource providing NSRS must be capable of being synchronized and ramped to its schedule for NSRS within 30 minutes. Non-Spin may only be provided from capacity that is not fulfilling any other energy or capacity commitment.

Source: The authors' interpretation of requirements within ERCOT's Protocols.

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Table 2. Descriptive statistics and price correlations; January 1, 2011 to December 30, 2017; sample size = 60,801 hourly observations; all data series are found to be stationary at the 1% level based on the Phillip-Perron unit-root test.

Variable: Definition	Descriptive statistics					Price correlation coefficients			
	Mean	Standard deviation	Minimum	Maximum	P_{1ht}	P_{2ht}	P_{3ht}	P_{4ht}	P_{5ht}
P_{1ht}: DAM energy price ($/MWh) in hour *h* on day *t*	31.817	55.090	1.188	2636		0.952	0.707	0.893	0.235
P_{2ht}: RRS price ($/MW/hr) in hour *h* on day *t*	12.690	56.060	0.450	3000	0.953		0.790	0.931	0.284
P_{3ht}: NSRS price ($/MW/hr) in hour *h* on day *t*	5.288	32.230	0.010	3000	0.707	0.790		0.741	0.190
P_{4ht}: REGUP price ($/MW/hr) in hour *h* on day *t*	11.206	58.898	0.010	4999	0.893	0.931	0.741		0.278
P_{5ht}: REGDN price ($/MW/hr) in hour *h* on day *t*	6.398	8.980	0	593	0.235	0.283	0.190	0.278	
G_t: Henry Hub natural gas price ($/MMBtu) on day *t*	3.275	0.828	1.450	8.15	0.157	0.064	0.047	0.066	0.159
N_{ht}: Nuclear generation (GWh) in hour *h* on day *t*	4.491	0.795	0	7.590	0.030	0.022	0.023	0.020	-0.069
D_{ht}: Day-ahead system load forecast (GWh) in hour *h* on day *t*	38.839	9.312	20.842	70.676	0.272	0.174	0.183	0.152	-0.192

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W_{ht}: Day-ahead wind generation forecast (GWh) in hour *h* on day *t*	4.736	2.882	0.143	28.612	-0.140	-0.053	-0.074	-0.058	0.169
Q_{2ht}: RRS procurement (GW/hr) in hour *h* on day *t*	2.229	0.210	2.146	3.132	-0.061	-0.032	-0.048	-0.045	-0.010
S_{ht}: share of RRS requirement met by load resources in hour *h* on day *t*	0.482	0.037	0.211	0.512	-0.048	-0.059	-0.063	-0.051	0.008
Q_{3ht}: NSRS procurement (GW/hr) in hour *h* on day *t*	1.630	0.328	0.496	2.804	0.014	0.022	0.067	0.021	-0.064
Q_{4ht}: REGUP procurement (GW/hr) in hour *h* on day *t*	0.440	0.146	0.176	1.139	0.078	0.038	0.034	0.075	0.110
Q_{5ht}: REGDN procurement (GW/hr) in hour *h* on day *t*	0.396	0.118	0.156	0.859	0.018	-0.009	-0.006	0.011	0.262
Y_{2ht}: RRS requirement (GW/hr) in hour *h* on day *t*	2.671	0.210	2.146	3.132	-0.090	-0.061	-0.080	-0.067	0.007
Y_{3ht}: NSRS requirement (GW/hr) in hour *h* on day *t*	1.630	0.328	0.496	2.804	0.055	0.054	0.094	0.055	-0.019
Y_{4ht}: REGUP requirement (GW/hr) in hour *h* on day *t*	0.440	0.146	0.176	1.139	0.077	0.037	0.033	0.075	0.111
Y_{5ht}: REGDN requirement (GW/hr) in hour *h* on day *t*	0.396	0.118	0.156	0.859	0.035	0.003	0.004	0.023	0.260

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Z_{2ht}: RRS offer (GW/hr) in hour *h* on day *t*	4.920	0.864	2.910	7.902	-0.019	-0.074	-0.054	-0.053	-0.066
Z_{3ht}: NSRS offer (GW/hr) in hour *h* on day *t*	4.209	1.011	2.343	27.287	0.016	0	0.003	0.009	0.019
Z_{4ht}: REGUP offer (GW/hr) in hour *h* on day *t*	2.088	0.515	0.915	3.771	-0.026	-0.071	-0.056	-0.055	-0.105
Z_{5ht}: REGDN offer (GW/hr) in hour *h* on day *t*	1.722	0.612	0.697	3.704	-0.004	-0.038	-0.024	-0.021	-0.052

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Table 3. IT3SLS results for the four price regressions with AR(n = 3) errors; sample period: January 1, 2011 to December 30, 2017; sample size = 60,801 hourly observations; coefficient estimates in **bold** are significant at the 1% level; all coefficient estimates have the correct sign

Variable: Definition	Eq. (1): P_{1ht} = DAM energy price ($/MWh) in hour h on day t	Eq. (2): P_{2ht} = RRS price ($/MW/hr) in hour h on day t	Eq. (3): P_{3ht} = NSRS price ($/MW/hr) in hour h on day t	Eq. (4): P_{4ht} = REGUP price ($/MW/hr) in hour h on day t	Eq. (5): P_{5ht} = REGDN price ($/MW/hr) in hour h on day t
Adjusted R^2	0.745	0.930	0.623	0.808	0.360
Root mean square error (*RMSE*)	27.92	14.90	19.86	25.94	7.04
G_t: Henry Hub natural gas price ($/MMBtu) on day t	**9.881**				
N_{ht}: Nuclear generation (GWh) in hour h on day t	-0.862				
D_{ht}: Day-ahead load forecast (GWh) in hour h on day t	**2.657**				
W_{ht}: Day-ahead wind generation forecast (GWh) in hour h on day t	**-1.671**				
Y_{2ht}: RRS requirements (GW/hr) in hour h on day t	3.618				
Y_{3ht}: NSRS requirements (GW/hr) in hour h on day t	1.695				
Y_{4ht}: REGUP requirements (GW/hr) in hour h on day t	**20.754**				
Y_{5ht}: REGDN requirements (GW/hr) in hour h on day t	3.021				
P_{1ht}: DAM energy price ($/MWh) in hour h on day t		**0.980**	**0.438**	**0.952**	**0.038**
Q_{2ht}: RRS procurement (GW/hr) in hour h on day t		**3.486**			
S_{ht}: share of RRS requirement met by load resources in hour h on day t		**-14.589**			
Q_{3ht}: NSRS procurement (GW/hr) in hour h on day t			**5.632**		
Q_{4ht}: REGUP procurement (GW/hr) in hour h on day t				**17.044**	

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Q_{5ht}: REGDN procurement (GW/hr) in hour h on day t					**31.343**
Z_{2ht}: RRS offer (GW/hr) in hour h on day t		**-2.266**			
Z_{3ht}: NSRS offer (GW/hr) in hour h on day t			**-1.290**		
Z_{4ht}: REGUP offer (GW/hr) in hour h on day t				**-4.563**	
Z_{5ht}: REGDN offer (GW/hr) in hour h on day t					**-2.393**

Note: For brevity, this table omits the generally-significant time-varying intercept estimates. The AR(n = 3) order is determined by their highly significant (p-value < 0.01) parameter estimates. Increasing n > 3 does not materially change the regression results because the resulting additional AR parameters are close to zero with dwindling statistical significance.

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Table 4. Comparison of IT3SLS results for the four price regressions between the first and second half of the sample period. Sample period 1: January 1, 2011 to June 30, 2013; Sample period 2: July 1, 2013 to December 30, 2017; significant differences in coefficient estimates at the 5% level based on a t-test are in **bold.**

Variable: Definition	Eq. (1): P_{1ht} = DAM energy price ($/MWh) in hour *h* on day *t*	Eq. (2): P_{2ht} = RRS price ($/MW/hr) in hour *h* on day *t*	Eq. (3): P_{3ht} = NSRS price ($/MW/hr) in hour *h* on day *t*	Eq. (4): P_{4ht} = REGUP price ($/MW/hr) in hour *h* on day *t*	Eq. (5): P_{5ht} = REGDN price ($/MW/hr) in hour *h* on day *t*
	Period 1 / Period 2	Period 1 / Period 2	Period 1 / Period 2	Period 1 / Period 2	Period 1 / Period 2
Adjusted R^2	0.755 / 0.716	0.931 / 0.946	0.569 / 0.848	0.928 / 0.431	0.419 / 0.346
Root mean square error (*RMSE*)	41.69 / 15.45	22.86 / 6.39	30.59 / 8.38	23.13 / 28.70	6.67 / 7.47
G_t: Henry Hub natural gas price ($/MMBtu) on day *t*	11.332 / 8.601				
N_{ht}: Nuclear generation (GWh) in hour *h* on day *t*	-1.218 / -1.082				
D_{ht}: Day-ahead load forecast (GWh) in hour *h* on day *t*	**4.548 / 1.941**				
W_{ht}: Day-ahead wind generation forecast (GWh) in hour *h* on day *t*	-2.119 / -1.040				
Y_{2ht}: RRS requirements (GW/hr) in hour *h* on day *t*	-12.048 / 13.642				
Y_{3ht}: NSRS requirements (GW/hr) in hour *h* on day *t*	-0.963 / 0.150				
Y_{4ht}: REGUP requirements (GW/hr) in hour *h* on day *t*	16.9333 / 20.161				
Y_{5ht}: REGDN requirements (GW/hr) in hour *h* on day *t*	4.715 / -1.931				
P_{1ht}: DAM energy price ($/MWh) in hour *h* on day *t*		0.992 / .961	0.411 / 0.626	**0.977 / 0.823**	**0.049 / -0.015**
Q_{2ht}: RRS procurement (GW/hr) in hour *h* on day *t*		**2.015 / 12.03**			
S_{ht}: share of RRS requirement met by load resources in hour *h* on day *t*		**-6.161 / -36.017**			
Q_{3ht}: NSRS procurement (GW/hr) in hour *h* on day *t*			**5.939 / 2.670**		

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Q_{4ht}: REGUP procurement (GW/hr) in hour *h* on day *t*				9.500 / 25.036	
Q_{5ht}: REGDN procurement (GW/hr) in hour *h* on day *t*					21.147 / 42.507
Z_{2ht}: RRS offer (GW/hr) in hour *h* on day *t*		-0.224 / -0.736			
Z_{3ht}: NSRS offer (GW/hr) in hour *h* on day *t*			-0.890 / 0.620		
Z_{4ht}: REGUP offer (GW/hr) in hour *h* on day *t*				**0.050 / -8.665**	
Z_{5ht}: REGDN offer (GW/hr) in hour *h* on day *t*					**-1.422 / -4.974**

Note: For brevity, this table omits the generally-significant time-varying intercept estimates and AR(n = 3) order parameter estimates.

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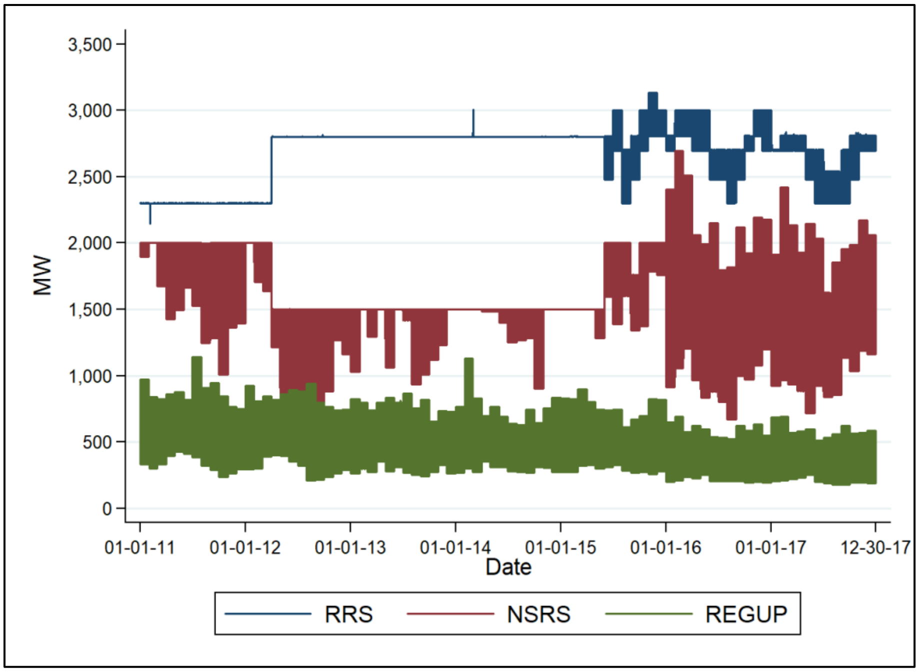

Fig. 1. AS Requirements for REGUP, RRS, and NSRS.

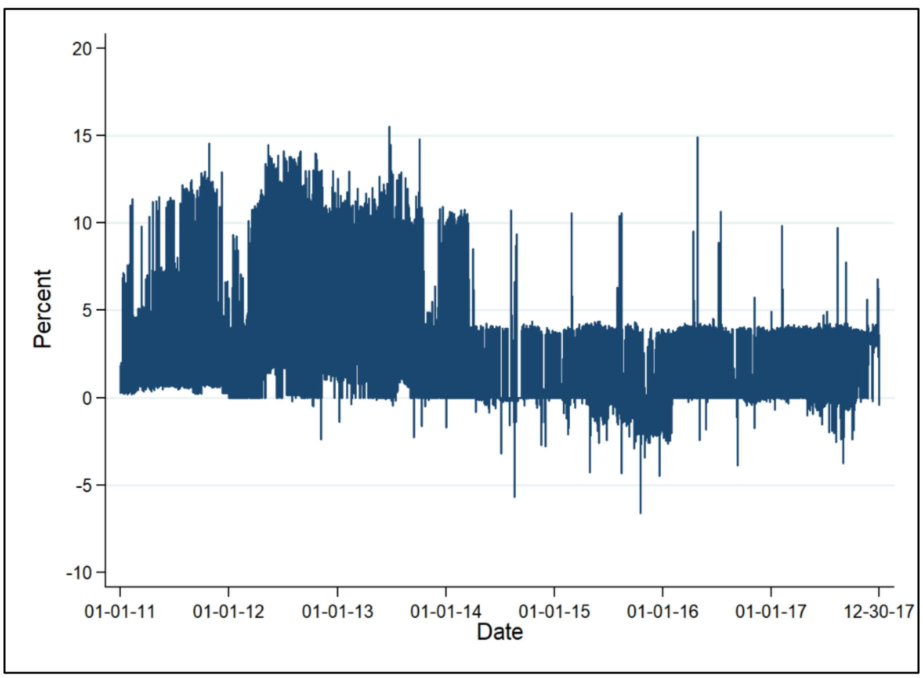

Fig. 2. Self-Arranged REGUP in Percent

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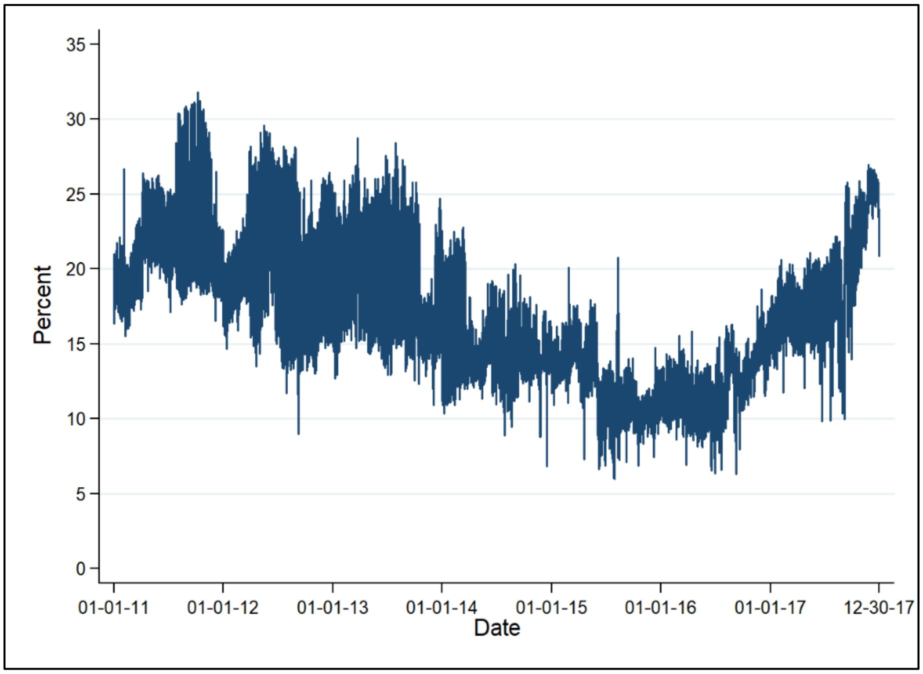

Fig. 3. Self-Arranged RRS in Percent

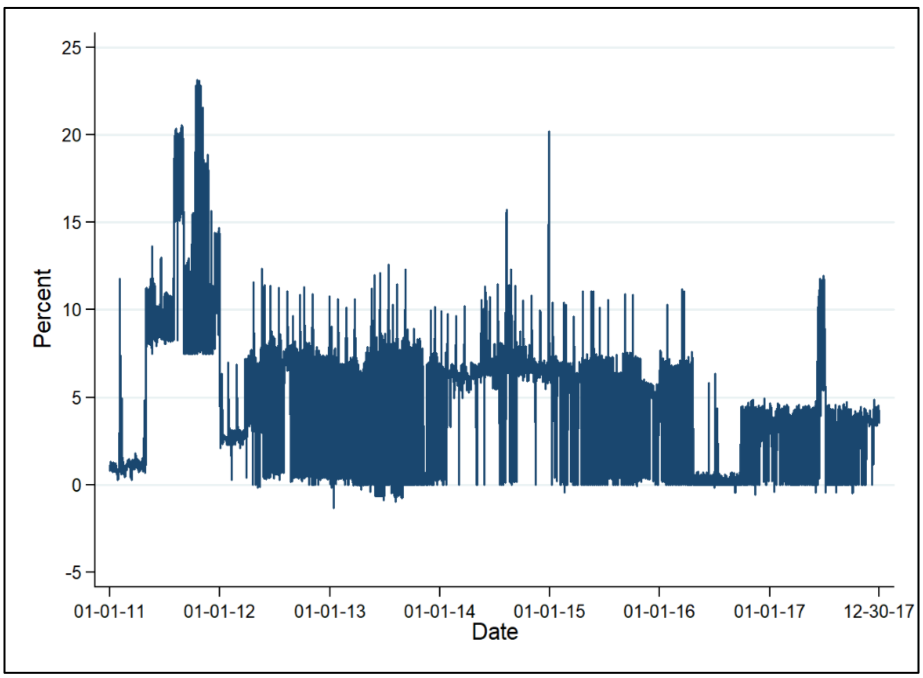

Fig. 4. Self-Arranged NSRS in Percent

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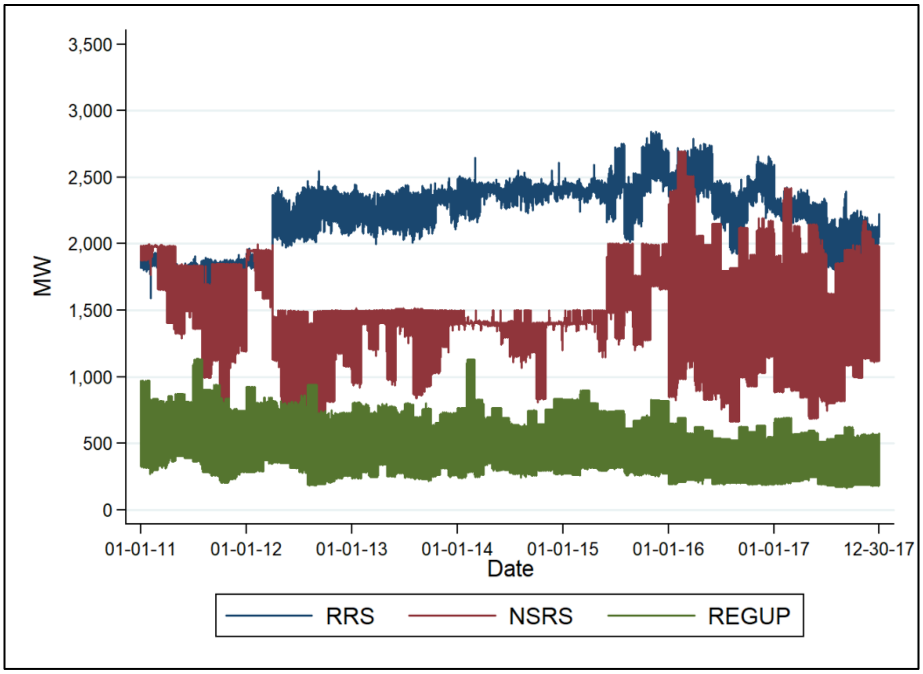

Fig. 5. Quantities of AS procured through the DAM

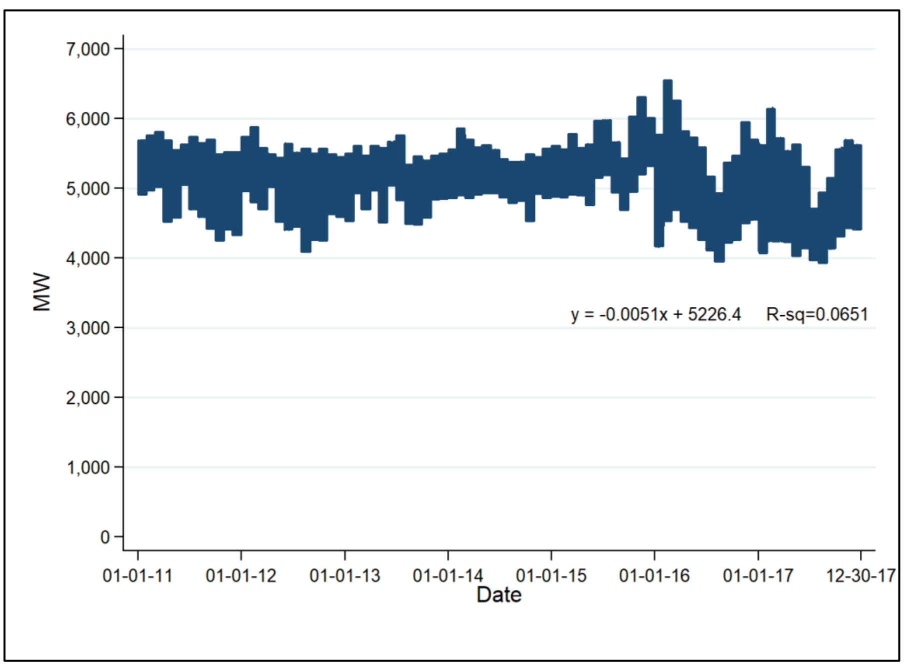

Fig. 6. Total AS (REGUP, REGDN, RRS, and NSRS) Requirements over time

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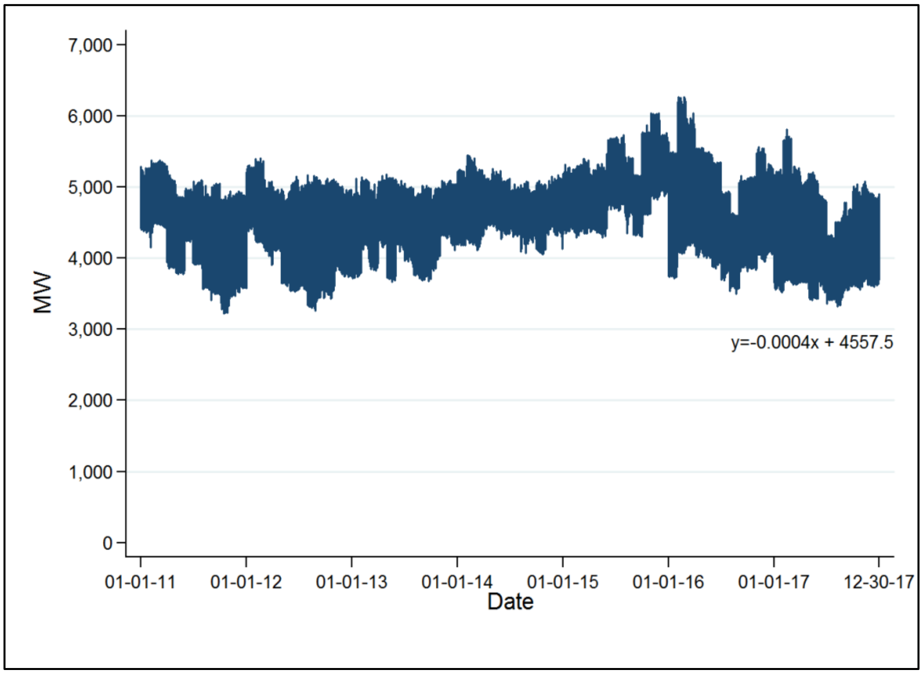

Fig. 7. Procurements of AS (REGUP, REGDN, RRS, and NSRS) through the DAM

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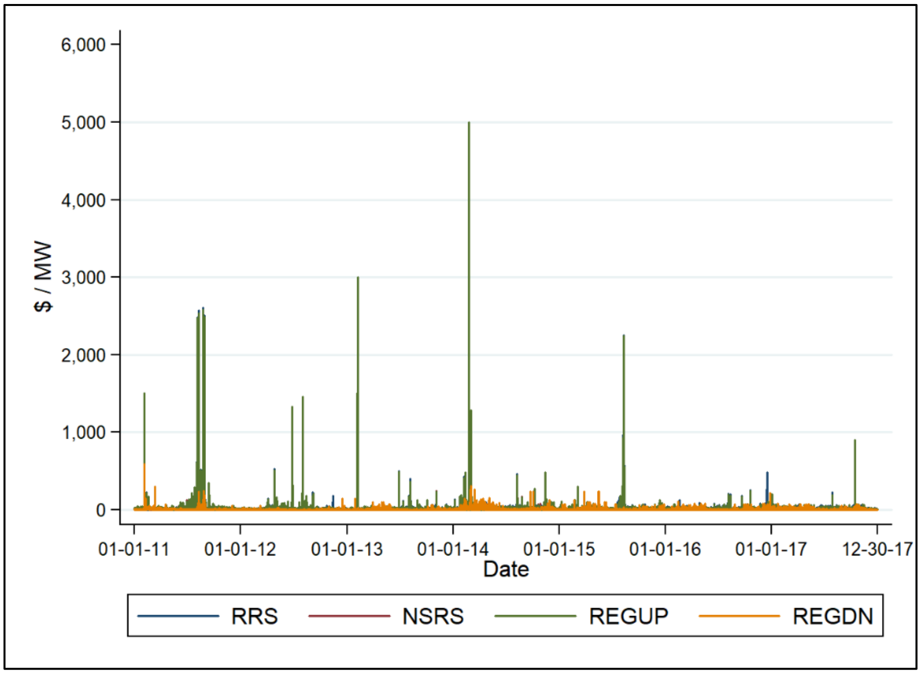

Fig. 8. AS Prices over time