The ERCOT Experience with Integrating Renewables

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See footnotes at end of text.

In a mild evening around 9 p.m. on March 31, 2017, instantaneous wind generation set a new record in the Electric Reliability Council of Texas (ERCOT): 16,141 megawatts (about 85% of installed wind capacity), accounting for 39.5% of total electricity demand at that moment. One week earlier on March 23rd, wind penetration had reached 50% market share at 3:50 a.m., but only with 14,391 megawatts (MW) of wind generation as load was much lower at that time. These record-high generation and penetration numbers are impressive. However, it is important to emphasize that high wind generation/penetration often happen in shoulder (non-peak demand) seasons, and non-peak hours of the day. Average annual capacity factor for wind has been swinging between 31% and 35% between 2011 and 2016. It is also worth noting that these high wind penetration numbers benefit from the state's Competitive Renewable Energy Zone (CREZ) initiative that induced the investment of $6.8 billion in nearly 3,600-miles of new transmission lines with roughly 18,000-MW of capacity to accommodate abundant wind resources of West Texas. The cost of CREZ lines is socialized across all customers in ERCOT footprint.[1]

Although wind has been the dominant story in Texas, ERCOT, in its latest long-term system assessment, has forecasted a range of 14.5 gigawatts (GW) to 28.1 GW of solar generation capacity to be added by 2031 depending on the scenario, mostly at the expense of coal and natural gas retirements. These forecasted numbers are quite large but current solar capacity, including those in the pipeline to be built over the next 4 to 5 years, is only about 2.5 GW.

INCREASING RENEWABLES AND EVOLVING OPERATIONAL ADJUSTMENTS

As the share of renewables in the system continues to increase, the grid operator needs to address new operational challenges. ERCOT recently added a new "Reliability Risk Desk" in its control room (which went live in January 2017) to address these evolving risks to grid operation, including renewable energy forecast errors, net load ramps, low inertia, and need for variable ancillary services.

Wind generation predictability is important for least-cost reliable system operations. Short-term wind forecasts have been improving but there are still noticeable errors, particularly in shoulder months when wind penetration is higher. Between 2012 and 2015, average day-ahead wind forecast errors have improved from 8.8% to 6.8% for the off-peak season (October to May) and from 8% to 5% for the peak season (June to September). Hourly forecasts errors have been lower historically but have also improved from 6.1% to 4.3% for the off-peak season, and from 5.2% to 3.4% for the peak season.[2]

Nonetheless, these forecast errors translate into several hundred MWs of discrepancy. Given that total installed wind capacity in ERCOT will reach 25.5 GW by 2019, the errors in thousands of megawatts are likely to become more routine unless forecasts continue to improve. Other generators (often gas or coal-fired) have to be available to either ramp up (when the wind generation is less than forecasted) or ramp down (when the wind generation is more than forecasted). Such ancillary services have a cost; but, the average cost per MWh of load has been in the range of $1 to $1.50 between 2012 and 2016 as compared to $2.4 in 2011, an extreme weather year. These costs are small relative to energy prices that averaged $25-30/MWh between 2012 and 2016 versus $48 in 2011. Hence, we will not focus on the drivers of ancillary costs in this brief note.

IMPACTS OF INCREASING RENEWABLES GENERATION ON THE ERCOT MARKET

One would expect increasing share of wind generation to put downward pressure on financial viability of thermal generators because wind displaces MWhs supplied by these generators, suppresses wholesale energy prices, or, often both. In both competitive and regulated markets, system operators accommodate intermittent wind when it is available subject to reliability constraints. Even without any requirements, wind would displace thermal generators in the dispatch merit order since it has low operating and no fuel cost. This change in merit order could result in lower market prices. Furthermore, wind generators sometimes bid negative prices in order to get dispatched and to collect federal production tax credits (PTC), which lowers market clearing prices further. Such price distortions can be observed more frequently in nodal markets at various nodes but could also impact average system prices. Indeed, average wholesale prices in ERCOT have decreased from $45/MWh in 2011 to $22/MWh in 2016 as wind penetration has increased from 9% to 16% (Figure 1). The low energy prices and threat of market share loss raised concerns of revenue adequacy among existing thermal generators.

However, there are other factors to consider. First, during the same period (2011-2016), the price of natural gas, which has fueled consistently more than 40% of generation in ERCOT and has been the marginal fuel setting the market clearing prices at many nodes most of the time, has been very low (Figure 1). Except for 2014, the annual average natural gas Henry Hub spot price was below $4 per million Btu (MMBtu) and was below $3/MMBtu in 2012, 2015 and 2016. Second, unlike many parts of the country, load growth in ERCOT has been robust. Electricity consumption in ERCOT grew almost 28 million MWh between 2012 and 2016.[3] Wind generation grew more than 23 million MWh over the same period. As such, thermal generators did not have to reduce generation to accommodate wind. Indeed, between 2012 and 2016, coal and natural gas plants consistently generated about 255 to 265 million MWhs of energy every year. Still, it is possible for individual units to have experienced a drop in generation depending on their location on the grid relative to high load growth areas and wind farms. In other markets where load growth is stagnant or even negative, increasing wind penetration would displace MWhs from existing thermal generators.

Overall, differentiating the effects of subsidized, low-operating-cost wind, cheap natural gas, and load growth on ERCOT wholesale energy prices is a non-trivial exercise; but we offer some statistics that support the expectations discussed above with some important qualifications.[4]

First, in Figure 2 and Figure 3, we illustrate the level of wind penetration in percentage of total load at different hours of the day during the peak season (June to September) and the off-peak, or shoulder, season (October to May) between 2011 and 2016. In general, we observe a similar pattern: wind penetration is low (below 10%) during peak hours (between 12 p.m. and 6 p.m.) and higher during off-peak hours, in both peak and shoulder seasons. However, as the installed wind capacity doubled from 9 GW in 2011 to 18.9 GW in 2016, and CREZ lines are completed, we observe that the number of higher wind penetration hours (above 20%) began to increase, and also to migrate, albeit in a limited fashion, from off-peak to peak hours in a day, and from shoulder to peak months in a year.

Second, we are interested in how market clearing energy prices change at different levels of wind penetration. For illustrative purposes, we graph the distribution of ERCOT-average hourly prices at peak hours during the peak season (Figure 4), and the price distribution at off-peak hours during the shoulder season (Figure 5). Increasing wind penetration has limited impact on market prices during peak hours and peak months (Figure 4) when wind penetration is usually below 20%. There was noticeable difference between the median of the two price distribution curves in early years (from 2011 to 2013). However the completion of CREZ lines helped to mitigate negative prices and helped nodal price convergence. In each year from 2014 to 2016, the two price distribution curves do not differ significantly. On the other

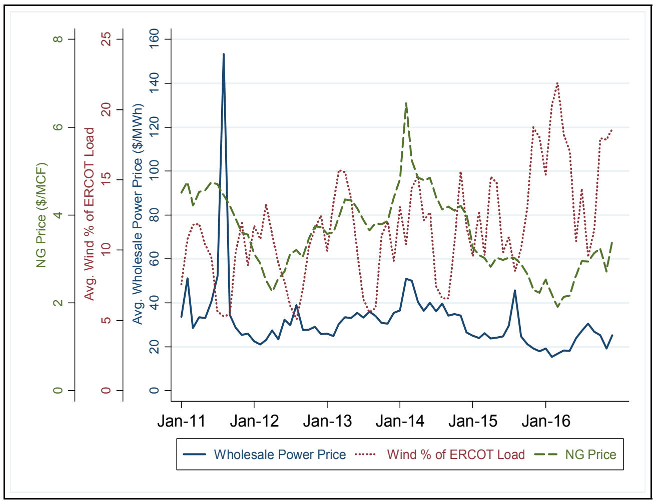

Figure 1: ERCOT Monthly Average Wholesale Energy Price, Wind Penetration and Henry Hub Natural Gas Price (2011 to 2016)

Data sources: ERCOT for hourly Day-Ahead energy price, hourly load, and wind generation output; U.S. EIA for daily natural gas Henry Hub spot price.

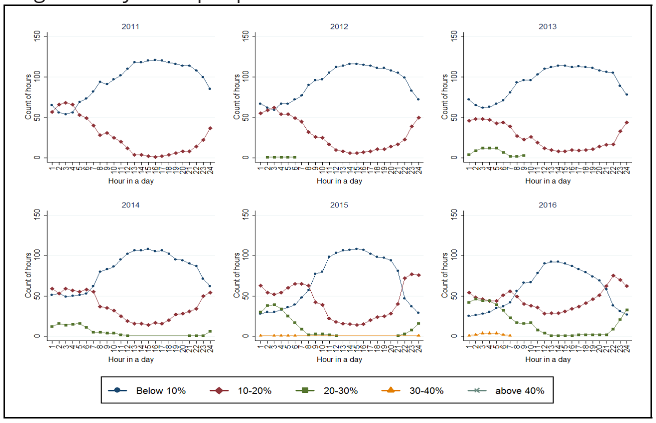

Figure 2: ERCOT wind penetration at different hours in a day (Peak season, June to September)

Data sources: ERCOT

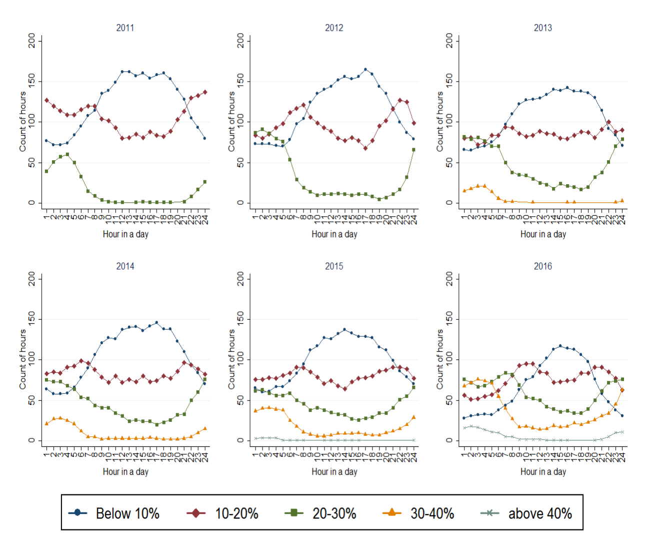

Figure 3: ERCOT wind penetration at different hours in a day (Shoulder season, October to May).

Data sources: ERCOT

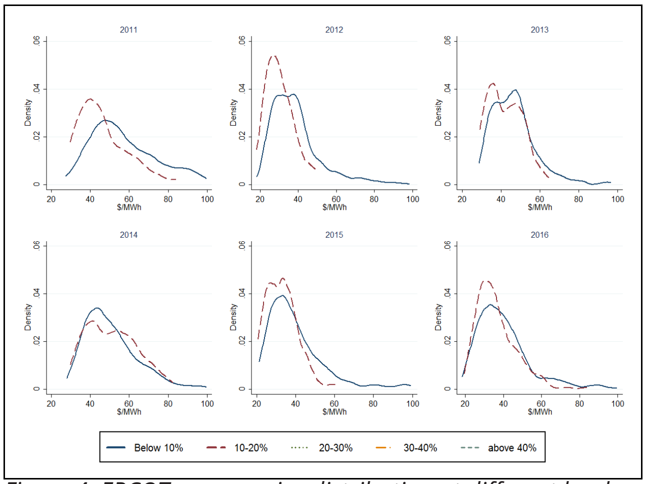

Figure 4: ERCOT energy price distribution at different levels of wind penetration - Peak hours (12 p.m. – 6 p.m.) during the peak season (June to September).

Data sources: ERCOT

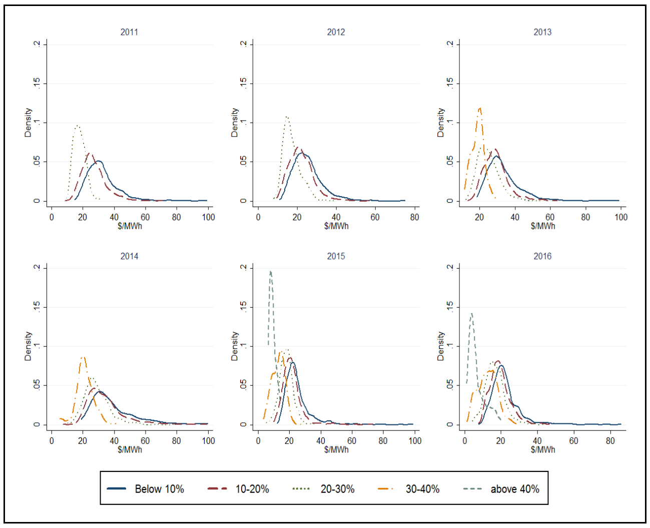

Figure 5: ERCOT energy price distribution at different level of wind penetration – Off-Peak hours (7 p.m. – 11 a.m.) during the shoulder season (October to May)

Data sources: ERCOT

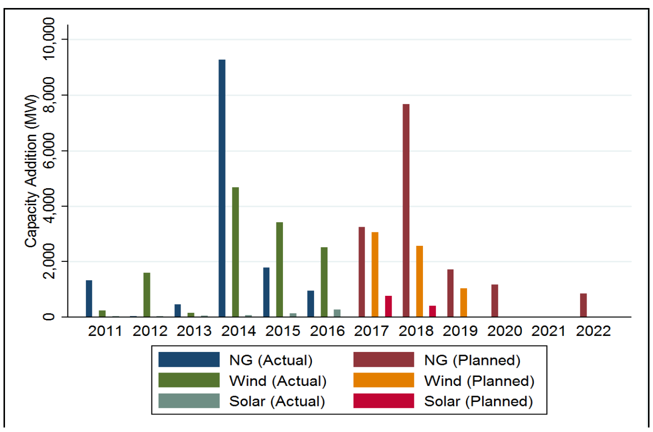

Figure 6: Actual and planned natural gas, wind and solar generation capacity additions in ERCOT (2011 to 2022)

Data source: U.S. EIA Form 860

hand, increasing wind penetration has a larger impact on suppressing market prices during off-peak hours in shoulder seasons (Figure 5), particularly when wind penetration begins to exceed 30%. For example, the median price in 2016 is \$20.9/MWh, \$18.8/MWh, \$16.3/MWh, \$12.7/MWh, and \$4.9/MWh when wind penetration is below 10%, 10-20%, 20-30%, 30-40%, and above 40%, respectively.

Finally, an interesting counterfactual question is: would we have seen higher wholesale energy prices if there was less wind generation? We utilize AURORAxmp, a commercial power market economic dispatch model, to test hypothetical scenarios of having less wind and investigate its impact on energy prices and conventional fossil plants. We first obtain results for a baseline scenario by running hourly economic dispatch of the ERCOT market in 2015 and 2016, without limiting wind generation output. The model yields aggregate wind generation that is within 2% of the actual wind generation reported by ERCOT, and within 0.1% of the actual ERCOT native load, suggesting the model serves as a good representation of the ERCOT wholesale market. We test five scenarios, in which annual wind generation (MWh) is curtailed at 5% increments, starting at 95% of the baseline and finishing with 75% (Table 1).

Reducing wind generation enhances average wholesale price but only slightly (less than \$0.3 per MWh). The effect is smaller in 2016 with lower natural gas price (\$2.39/MMBtu versus \$2.59 in 2015 in real terms). Second, although gas-fired generation increases in all scenarios in both years significantly, coal generation's response is relatively small and can even be negative. In 2015, limiting wind output to 95% or 90% of the baseline generation encourages natural gas to displace coal, while a deeper reduction (85% to 75%) would help both coal and gas generators. In 2016, changes in coal-fired generation fluctuates across scenarios but remains low. Third, additional generation indeed brings significant additional revenue, particularly to natural gas plants. Revenue enhancement is smaller in 2016 owing to lower electricity prices in 2016 although change in gas-fired generation is larger in most scenarios.[5]

BUILDING MORE GAS AND WIND WHEN SOLAR IS READY TO TAKE OFF IN TEXAS?

Looking at the suppressed electricity prices of the ERCOT market in recent years and expectations of very large solar builds in Texas, the total capacity of planned new builds in the near future and those units under construction is surprisingly high (Figure 6). The federal PTC is the main driver for wind as it has been for a long time although some local tax benefits have probably played a role.[6] Wind developers are eager to get their projects qualified for PTC before it declines over the next few years and is eliminated in 2020.

However it is rather puzzling that more than 14 GW gas-fired generation capacity are also in the pipeline, with 7.6 GW scheduled to come online in 2018. Given the project development cycles, final investment decisions for these facilities were probably taken several years ago. Several expectations are among the likely drivers of gas plant investments: coal retirements, higher (but not too high) natural gas prices, and load growth. Environmental regulations that threatened coal units might be less of a concern today. Natural gas prices might be climbing somewhat higher than what they were but the forward curve is fairly flat at around $3 for the next few years. The rapid expansion of utility-scale solar on the basis of declining costs have probably surprised many. Still, we may yet see coal retirements, somewhat higher natural gas prices, and less bullish solar expansion. As it stands today, though, sustained low natural gas prices, rapid expansion of solar capacity, which could lower peak prices, and additional wind will continue to stress the long-term functioning of the competitive, energy-only market in ERCOT. Calpine and NRG, two of the largest merchant generators in the country, filed a report on May 10, 2017 with the Public Utility Commission of Texas to recommend "policy and price formation improvements" including scarcity pricing and replacement of "socialized transmission planning" (see footnote 1) in order to address shifts resulting from low natural gas prices and subsidized renewables. This problem is faced by all organized wholesale markets around the country with peculiarities of individual markets and state policies.

	Change in Average Price ($/MWh)		Coal Plants				Natural Gas Plants			
			Generation (Thousands MWh)		Revenue (Million$)		Generation (Thousands MWh)		Revenue (Millions$)	
Scenarios	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016
95% Wind	0.07	-0.02	-472	-104	-8.5	-5.8	2,473	2,508	64.0	32.8
90% Wind	0.12	0.00	-453	476	-7.6	6.9	4,466	4,254	106.5	49. 6
85% Wind	0.18	0.03	80	-278	4.8	-6.5	5,933	7,371	149.9	128.3
80% Wind	0.23	0.02	125	-4	11.7	-6.9	7,892	9,441	203.5	135.4
75% Wind	0.26	0.18	701	698	27.3	18.2	9,308	11,087	244.3	201.5

Note: (1) In this table we report changes in price, generation and revenue from the baseline scenario, in which we did not constraint wind output. (2) All prices and revenues are in real $2014.

Table 1: Hypothetical Wind Constraint Scenarios – Changes from the Baseline Scenario

Footnotes

[1] A report filed with the Public Utility Commission of Texas in May 2017 recommends that "market-reflective policies for transmission investment should be considered as a replacement for Texas socialized transmission planning, which, by building new transmission in advance of scarcity developing, fails to provide the opportunity for markets to respond." http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40000_669_939373.PDF.

[2] For example, see "Wind Forecasting at ERCOT" at http://www.sewind.org/images/fact_sheets/ERCOT_Wind_Forecasting_and_Integration.pdf

[3] We exclude 2011 because load was exceptionally high in that extreme weather year.

[4] We are investigating ERCOT 15-minute data to gain better understanding of wind impacts throughout the seasons and across the grid.

[5] It is important to note that we use the zonal version of AURORAxmp with eight zones. ERCOT is a nodal market with real time price cleared every 15 minutes at various settlement points. Our hourly, zonal modeling runs capture low and negative prices with regional aggregation. It is reasonable to expect that a sub-hourly, nodal analysis would capture more of the low/negative pricing. However, it is also worth noting that the number of 15-minute negative prices has been declining as CREZ lines reduced wind curtailment. On the other hand, increasing wind capacity in the future could potentially surpass the transmission capacity and lead to an increase in negative bidding again as long as PTC remains active.

[6] Texas renewable portfolio standard has not been relevant since mid-2000s when the mandated installed renewable capacity was surpassed.