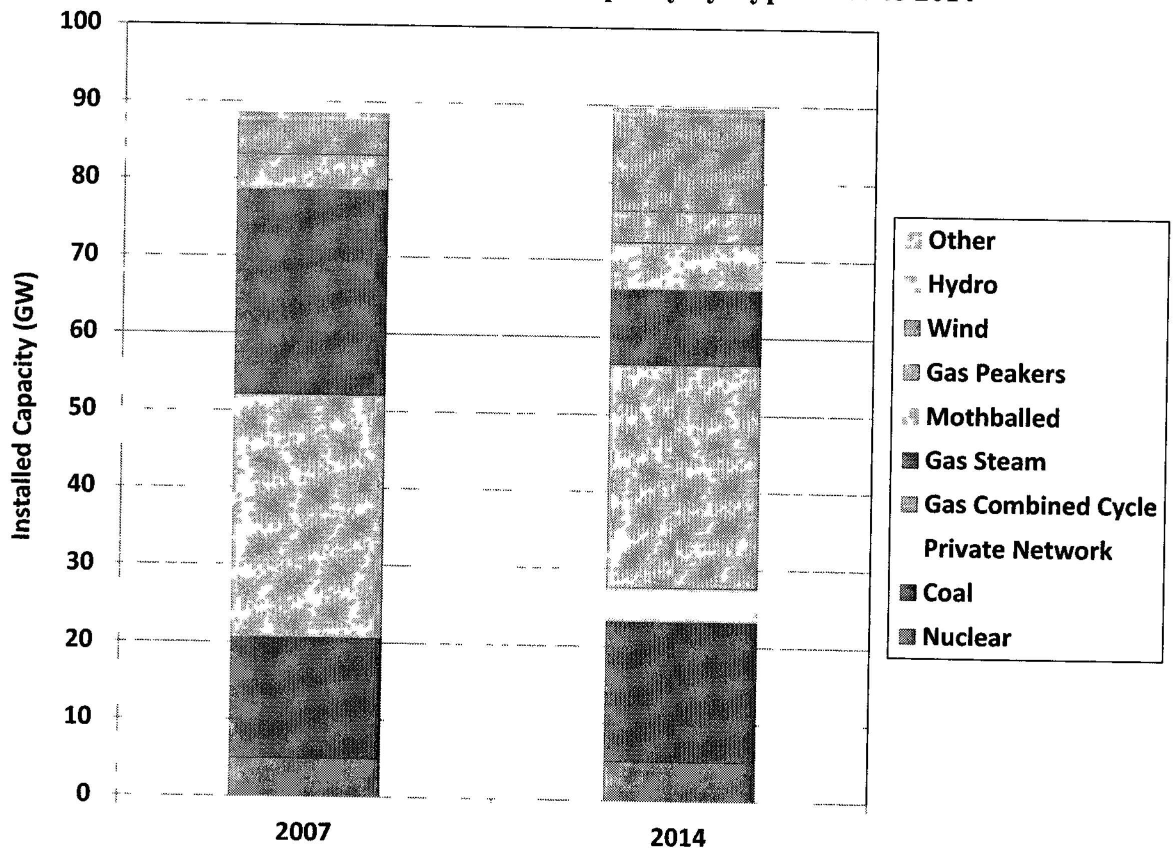
By comparing the current mix of installed generation capacity to that in 2007, as shown in Figure 55, the effects of longer term trends can be seen. Over these seven years, more new wind and coal generation has been added than any other type of capacity.[9] The sizable additions in these two categories have been more than offset by retirements of old natural gas-fired steam units. Nonetheless, the resulting installed capacity in 2014 was 1 GW more than in 2007. Comparatively, peak load in 2014 was greater than the 2007 peak load by more than 4 GW.

Figure 55: Installed Capacity by Type: 2007 to 2014

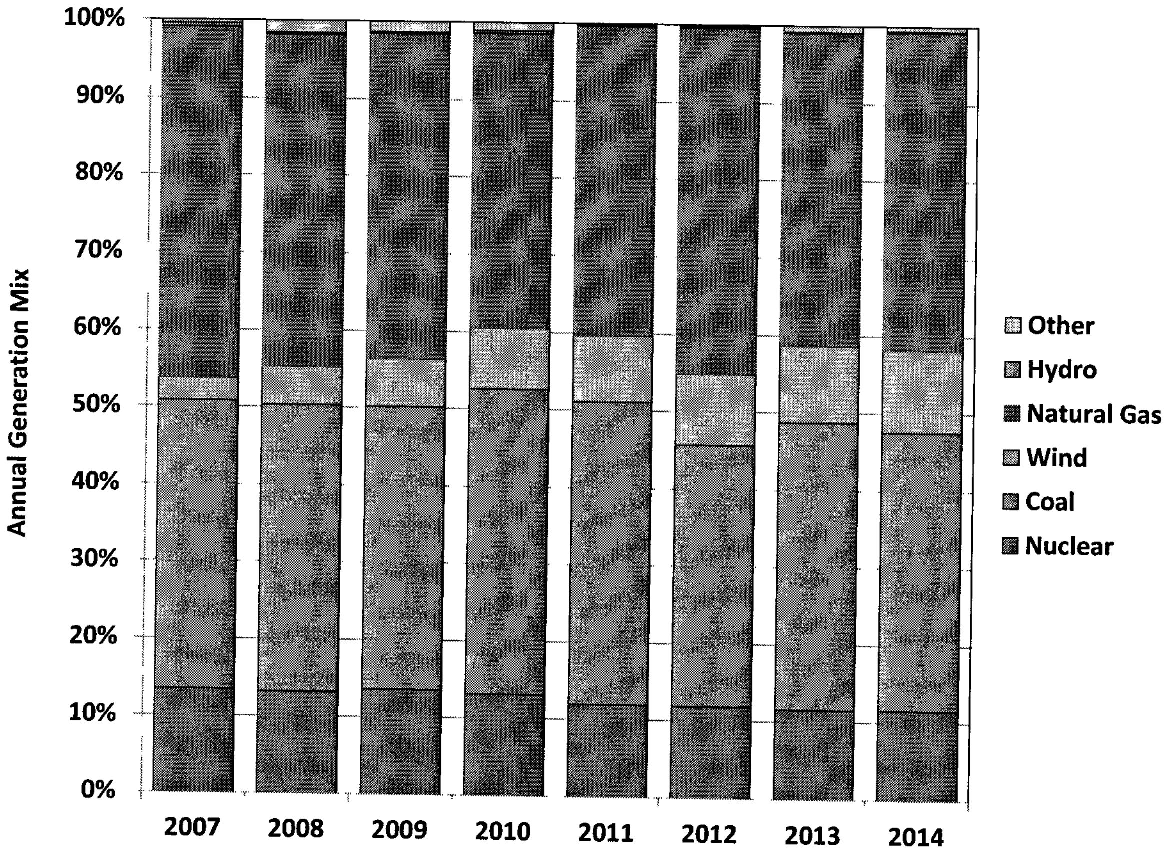


The shifting contribution of coal and wind generation is evident in Figure 56, which shows the percentage of annual generation from each fuel type for the years 2007 through 2014. The generation share from wind has increased every year, reaching 11 percent of the annual generation requirement in 2014, up from 3 percent in 2007. During the same period the percentage of generation provided by natural gas has ranged from a high of 45 percent in 2007 to

[9] Wind capacity is shown at its full installed capacity in this chart.

a low of 38 percent in 2010. In 2014 the percentage of generation from natural gas was 41 percent, which was a very slight increase from the 2013 level.[10] Similarly, the percentage of generation produced by coal units ranged from a high of 40 percent in 2010 to a low of 34 percent in 2012. The percentage of generation from coal was 36 percent in 2014, a small decrease from 37 percent in 2013.

Figure 56: Annual Generation Mix



While coal/lignite and nuclear plants operate primarily as base load units in ERCOT, it is the reliance on natural gas resources that drives the high correlation between real-time energy prices and the price of natural gas fuel. There is approximately 23.4 GW of coal and nuclear generation in ERCOT. Generally, when ERCOT load is above this level, natural gas resources will be on the margin and set the real-time energy spot price.

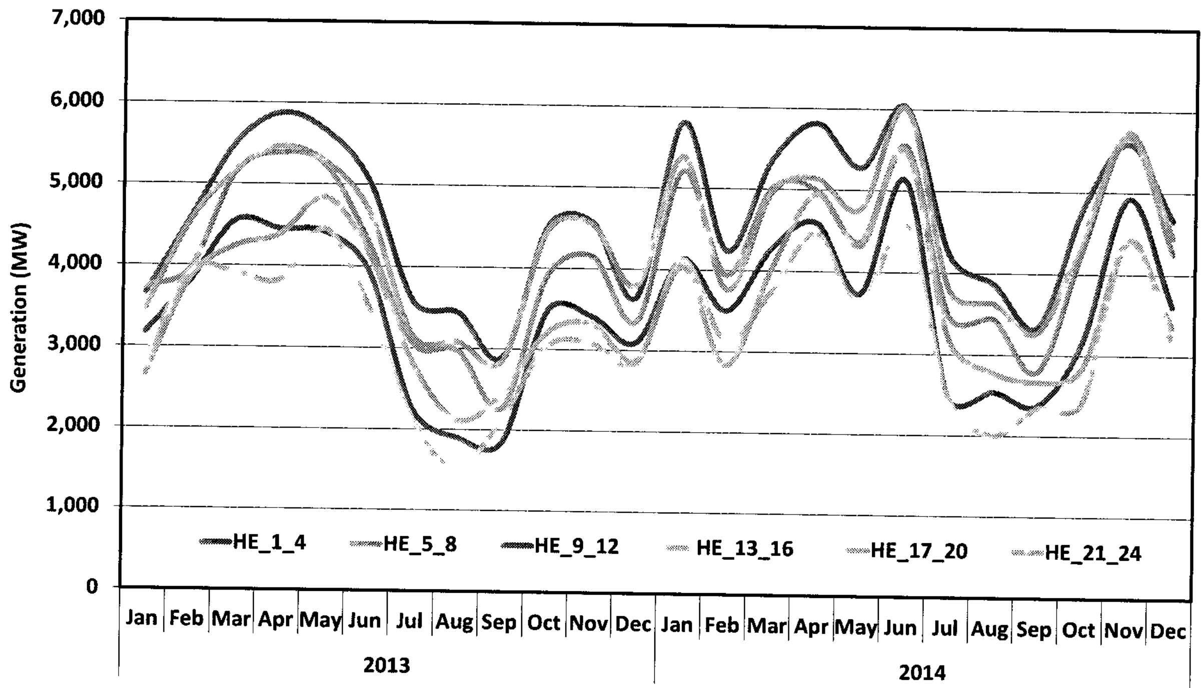
10 Natural gas provided 40.5 percent of total generation in 2013, and 41.1 percent in 2014.

The generation mix in 2012 remains notable due to the reduced share of coal generation. For the first time the combination of coal and nuclear units provided less than 50 percent of the annual energy requirements. The reduced contribution from coal in 2012 was directly related to relatively low natural gas prices experienced that year. Low natural gas prices allow efficient gas units to produce electricity at lower costs than most coal units in ERCOT, leading to the noticeable displacement of coal observed in 2012. As natural gas prices increased in 2013 and 2014 the amount of coal displacement has decreased and the generation share from coal has increased.

1. Wind Generation

The amount of wind generation installed in ERCOT exceeded 12 GW by the end of 2014. Although the large majority of wind generation is located in the West zone, more than 3 GW of wind generation has been located in the South zone. Additionally, a private transmission line that went into service in late 2010 allows another nearly 1 GW of West zone wind to be delivered directly to the South zone. This subsection will more fully describe the characteristics of wind generation in ERCOT.

Figure 57: Average Wind Production



The average profile of wind production is negatively correlated with the load profile, with the highest wind production occurring during non-summer months, and predominately during off-peak hours. Figure 57 shows average wind production for each month in 2013 and 2014, with the average production in each month shown separately in four hour blocks.

The completion of the CREZ lines in late 2013 eliminated what had been a longstanding constraint limiting the export of wind from the West zone. There continue to be localized constraints limiting wind generation at certain locations.

Examining wind generation in total masks the different wind profiles that exist for locations across ERCOT. Wind developers have more recently been attracted to site facilities along the Gulf Coast of Texas due to the higher correlation of winds with electricity demands. The differences in output for wind units located in the coastal area of the South zone and those located elsewhere in ERCOT are compared below.

Figure 58: Summer Wind Production vs. Load

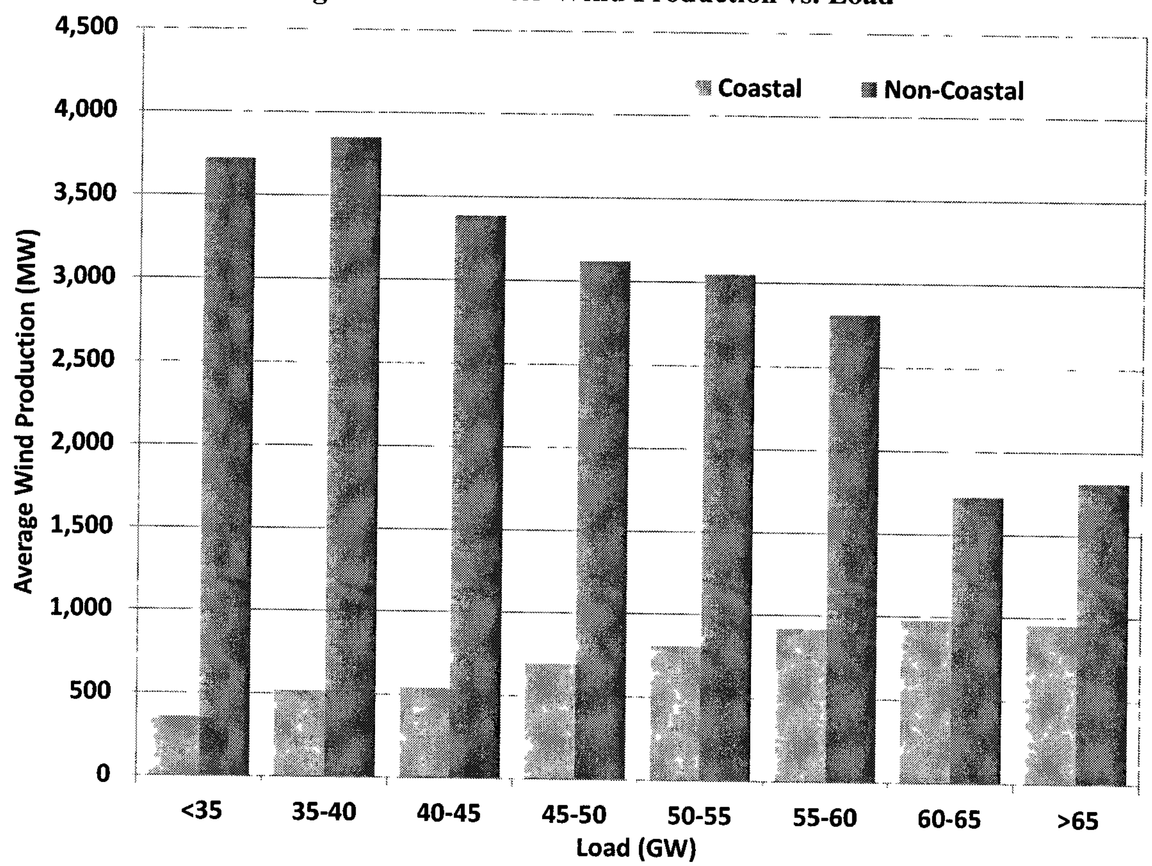
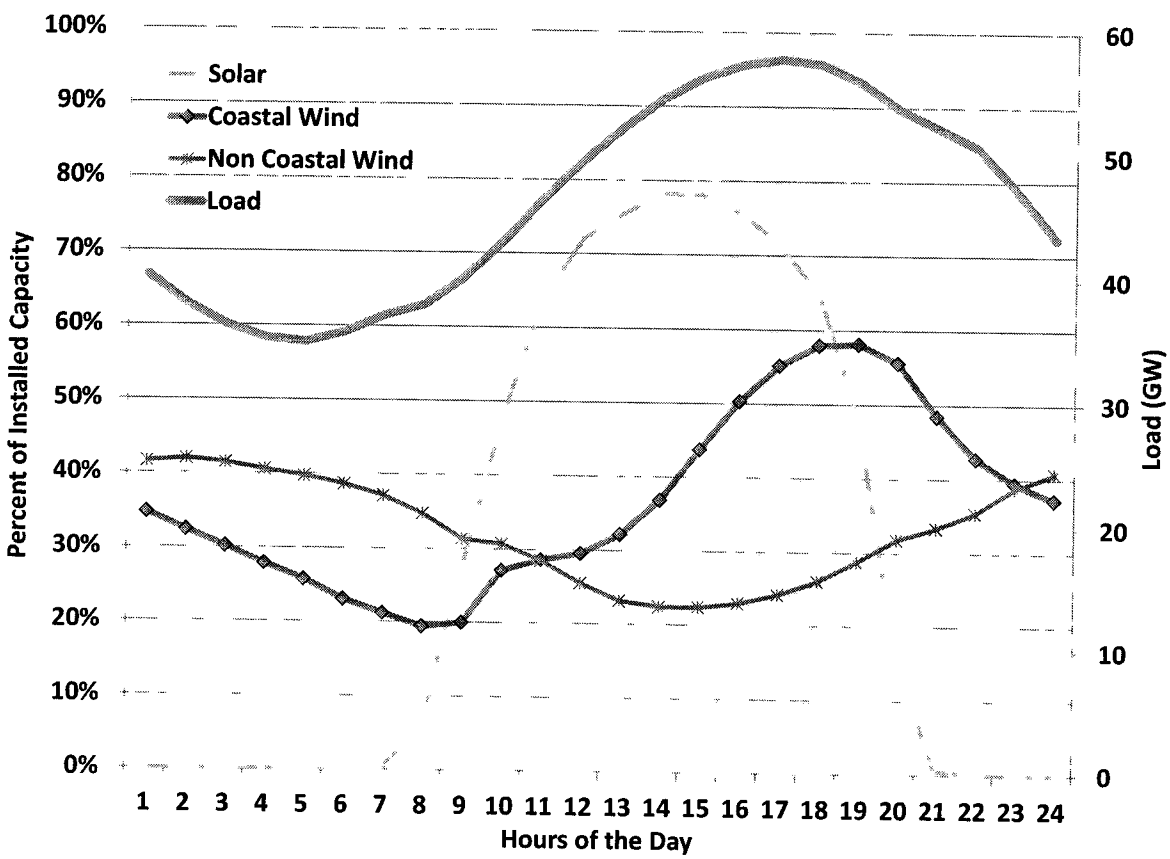


Figure 58 presents data for the summer months of June through August, comparing the average output for wind generators located in coastal and non-coastal areas in ERCOT across various load levels. It shows a strong negative relationship between non-coastal wind output and increasing load levels. It further shows that the output from wind generators located in the coastal area of the South zone is much more highly correlated with peak electricity demand.

The growing numbers of solar generation facilities in ERCOT also have an expected generation profile highly correlated with peak summer loads. Figure 59 below compares average summertime (June through August) hourly loads with observed output from solar and wind resources. Generation output is expressed as a ratio of actual output divided by installed capacity. The total installed capacity of solar generation is much smaller than that of wind generation. However, its production as a percentage of installed capacity is the highest, nearing 80 percent in the early afternoon, and producing more than 60 percent of its installed capacity during peak load hours.

Figure 59: Summer Renewable Production



The contrast between coastal wind and non-coastal wind is also clearly displayed in Figure 59. Coastal wind produced greater than 50 percent of its installed capacity during summer peak hours while output from non-coastal wind was between 20 and 30 percent during summer peak hours.

Figure 60: Wind Production and Curtailment

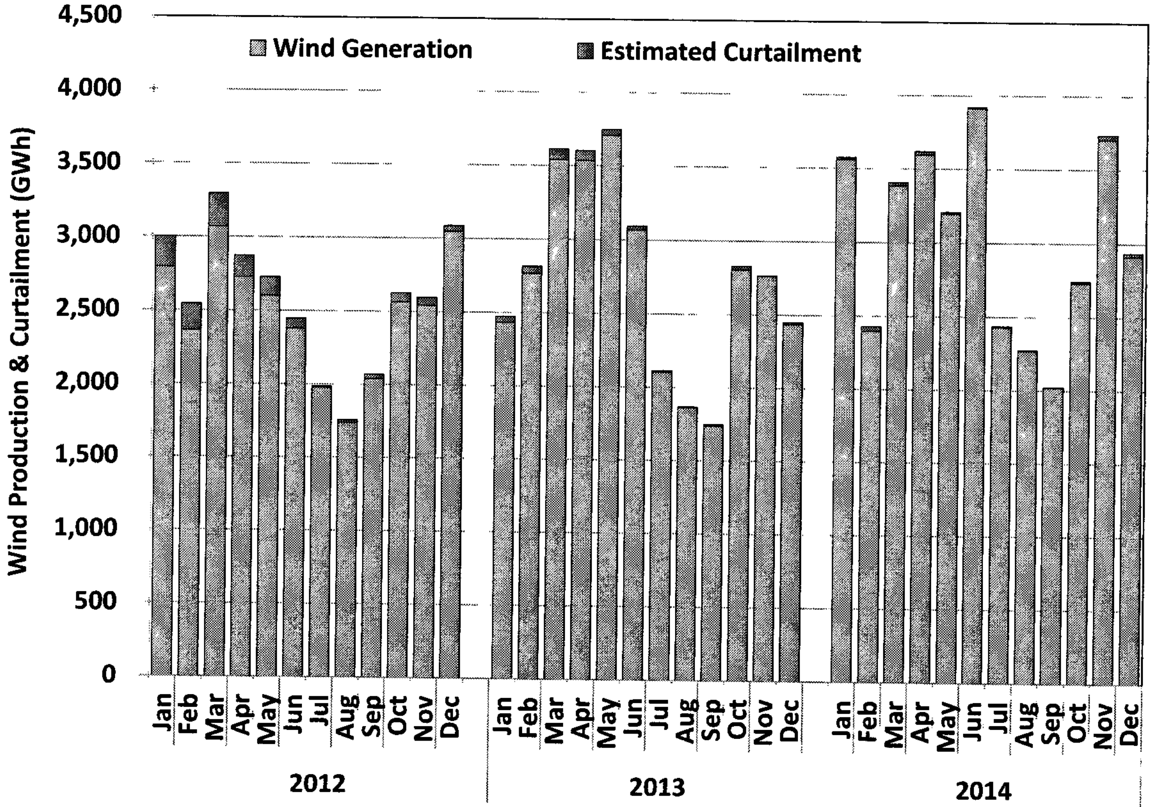
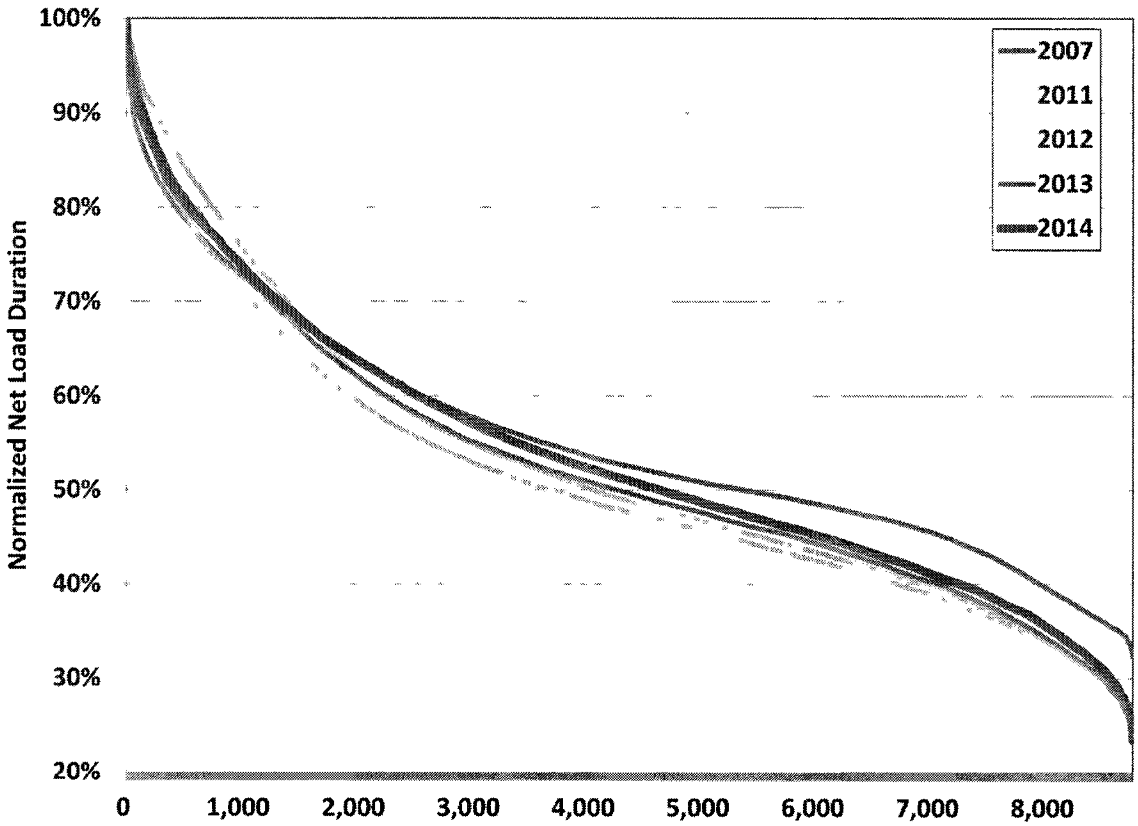


Figure 60 shows the wind production and estimated curtailment quantities for each month of 2012 through 2014. This figure reveals that the total production from wind resources continued to increase and the quantity of curtailments was reduced in 2014. The volume of wind actually produced was estimated as 99.5 percent of the total available wind in 2014, up slightly from 98.9 percent in 2013 and 96 percent in 2012.

Increasing levels of wind resources in ERCOT also has important implications for the net load duration curve faced by the non-wind fleet of resources. Net load is defined as the system load minus wind production. Figure 61 shows the net load duration curves for the years 2011 through 2014, normalized as a percentage of peak load, and including 2007 as a point of reference.

Figure 61: Net Load Duration Curves

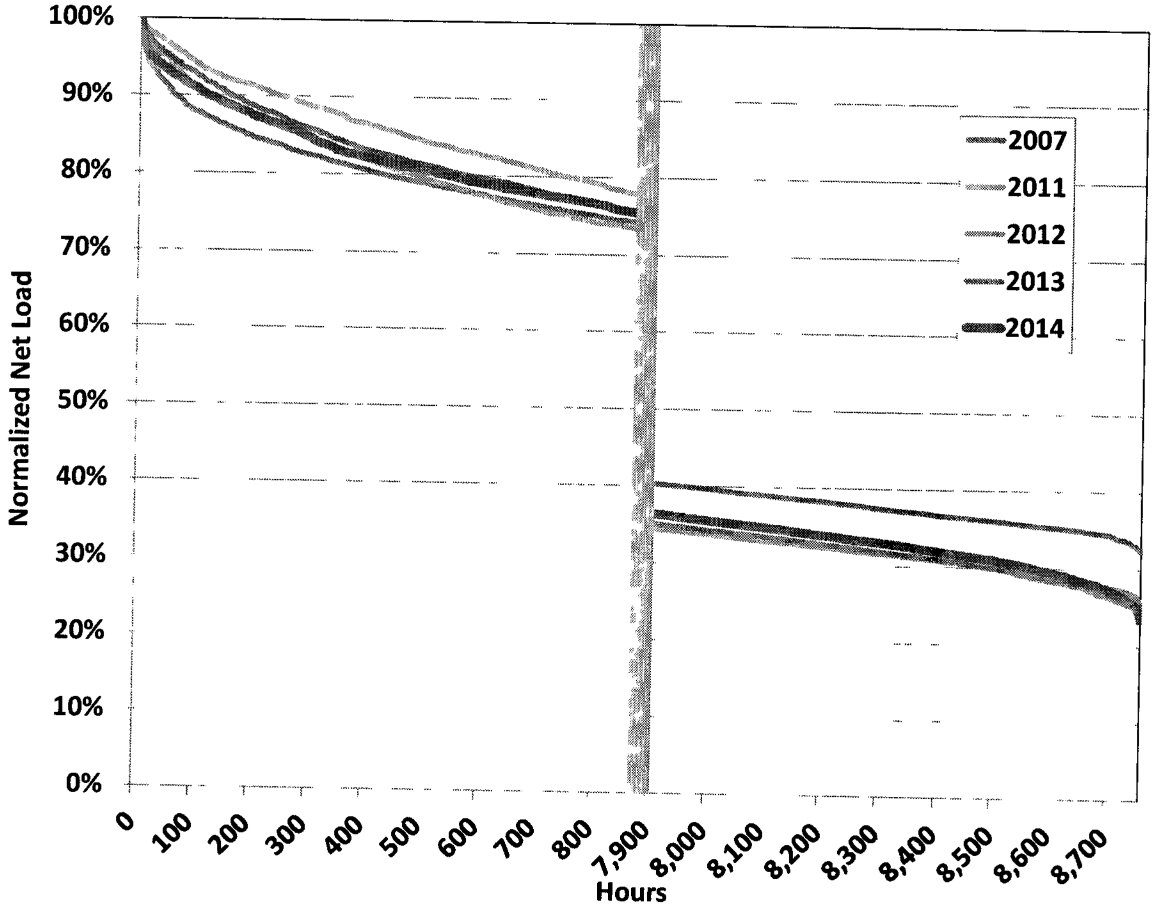


This figure shows the reduction of remaining energy available for non-wind units to serve during most hours of the year, even after factoring in several years of load growth. The impact of wind on the highest net load values is much smaller. Wind generation erodes the amount of energy available to be served by baseload coal units, while doing very little to reduce the amount capacity necessary to reliably serve peak load.

Even with the increased development activity in the coastal area of the South zone, nearly 80 percent of the wind resources in the ERCOT region are located in West Texas. The wind profiles in this area are such that most of the wind production occurs during off-peak hours or other times of relatively low system demand. This profile results in only modest reductions of the net load relative to the actual load during the hours of highest demand, but much more significant reductions in the net load relative to the actual load in the other hours of the year.

Focusing on the left side of the net load duration curve shown in Figure 62, the difference between peak net load and the 95th percentile of net load has averaged 12 GW the past three years.

Figure 62: Top and Bottom Ten Percent of Net Load



On the right side of the net load duration curve, the minimum net load has dropped from approximately 20 GW in 2007 to below 16 GW last year, even with sizable growth in total annual load. This continues to put operational pressure on the 23.5 GW of nuclear and coal-fired generation currently installed in ERCOT.

Thus, although the peak net load and reserve margin requirements are projected to continue to increase and create an increasing need for non-wind capacity to meet net load and reliability requirements, the non-wind fleet can expect to operate for fewer hours as wind penetration continues to increase. This outlook further reinforces the importance of efficient energy pricing during peak demand conditions and other times of system stress, particularly within the context of the ERCOT energy-only market design.

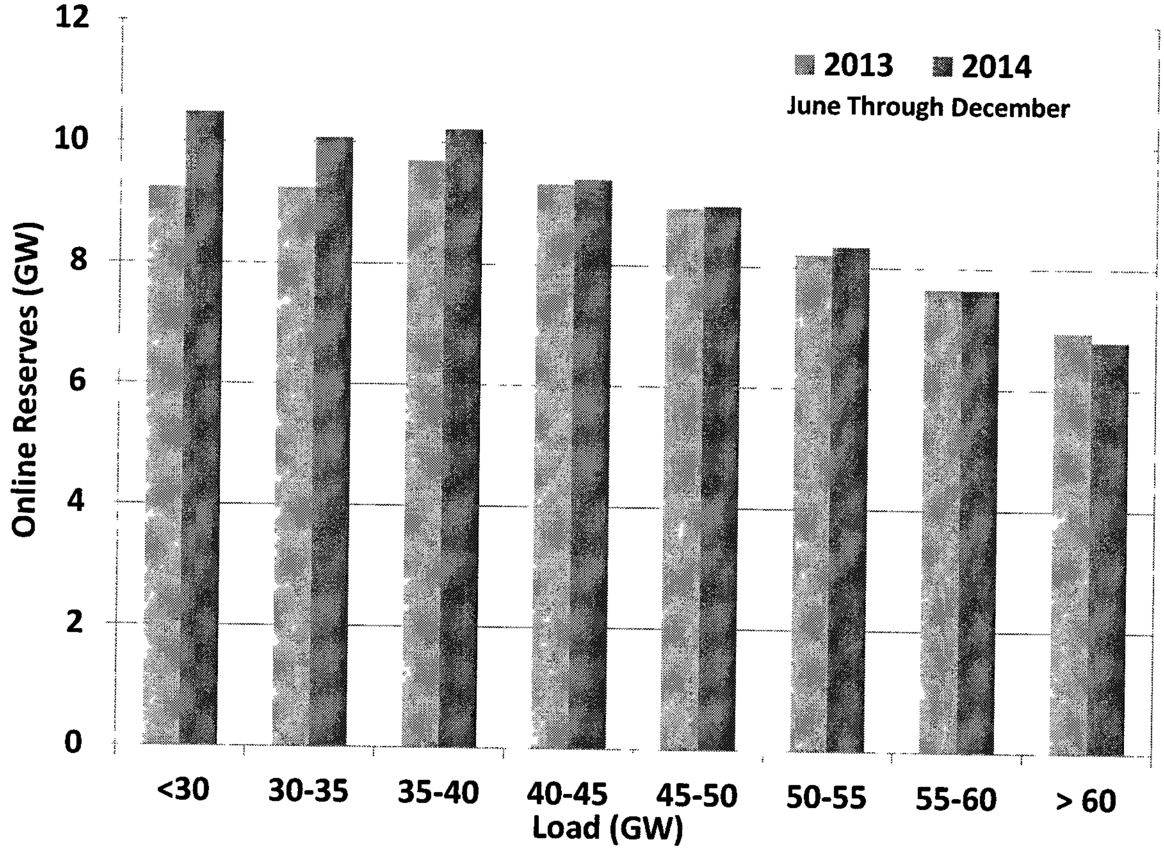
2. Generator Commitments

One of the important characteristics of any electricity market is the extent to which it results in the efficient commitment of generating resources. Under-commitment can cause apparent shortages in the real-time market and inefficiently high energy prices; while over-commitment can result in excessive start-up costs, uplift charges, and inefficiently low energy prices.

The ERCOT market does not include a centralized unit commitment process. The decision to start-up or shut-down a generator is made by the market participant. ERCOT's day-ahead market outcomes help to inform these decisions, but it is important to note that ERCOT's day-ahead market is only financially binding. That is, although a generator's offer to sell is selected (cleared) in the day-ahead market there is no corresponding requirement to actually start that unit. Nonetheless, the generator will be financially responsible for replacing its offered capacity if it does not start the unit.

The following figure compares the amount of on-line reserves in 2014 and 2013. The amount of on-line reserves is equal to the amount of the capacity committed in excess of expected demand. Figure 63 displays available online reserves aggregated by total system load levels and shows the expected pattern of declining reserves as system load increases. Further, at all but the very highest system loads, there were more online reserves in 2014 than in 2013. This indicates that more capacity was online during 2014.

Figure 63: Average On-line Reserves



Two possible explanations for the increase in capacity commitments in 2014 are: (1) response to the increased payment made to online reserves with the implementation of ORDC on June 1, and (2) increased hedging behavior by entities wanting to avoid potential exposure to $7,000 per MWh prices resulting from the higher system-wide offer cap.

Once ERCOT assesses the unit commitments resulting from the day-ahead market, additional capacity commitments are made, if needed, using a reliability unit commitment process that executes both on a day-ahead and hour-ahead basis. These additional unit commitments may be made for one of two reasons. Either additional capacity is required to ensure forecasted total demand will be met, or a specific generator is required to resolve transmission congestion.

Figure 64: Frequency of Reliability Unit Commitments

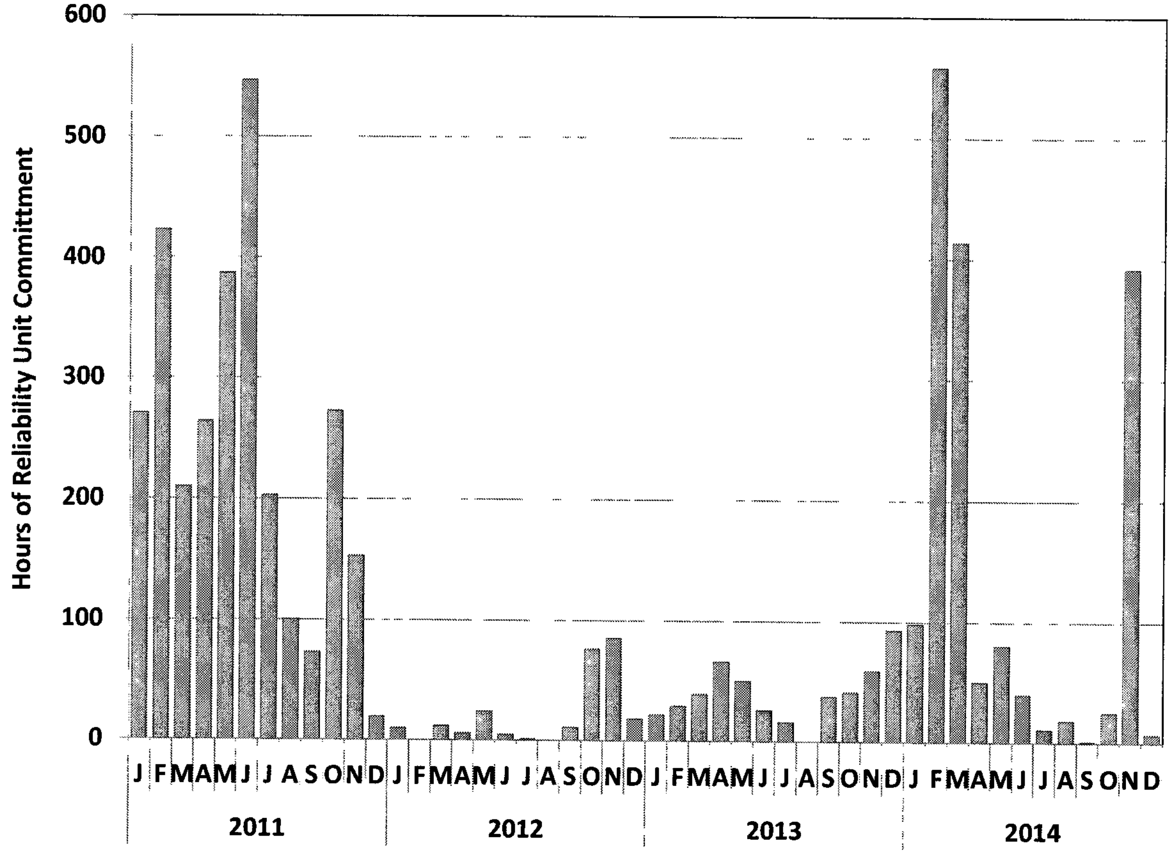


Figure 64 summarizes, by month, the number of hours with units committed via the reliability unit commitment process. There was increased reliance on the reliability unit commitment process in 2014. During 2014, the number of hours with at least one unit receiving a reliability unit commitment instruction was 19 percent. The increase was noticeable given the relatively low occurrences in 2012 and 2013 when the number of hours with at least one unit receiving a reliability unit commitment instruction was 3 percent and 5 percent, respectively. During 2011, approximately one third of the hours had at least one unit committed by ERCOT through the reliability unit commitment process.

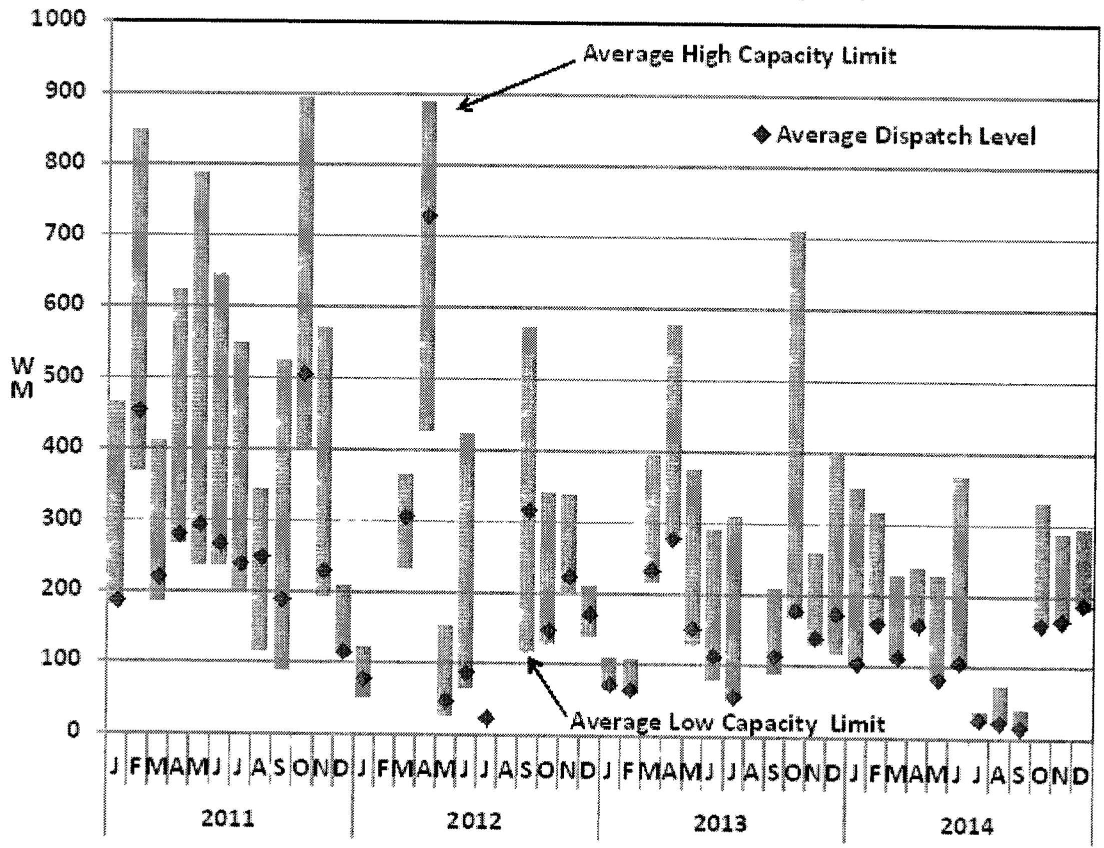
One cause for the increase in reliability unit commitment activity in 2014 was related to maintaining reliable service in the Rio Grande Valley. Almost half (47 percent) of the hours with at least one unit receiving a reliability unit commitment instruction in 2014 were related to conditions in the Valley. Another reason for the increase in 2014 was due to the more extreme weather conditions during the winter (January through March). Natural gas curtailments to power plants are more common as the temperature drops. In these situations it is not unusual for ERCOT to use the reliability unit commitment process to ensure generation capacity using fuel-oil is available.

The low number of hours in 2012 and 2013 can be attributed, in part, to the less extreme weather and resulting lower load levels experienced. There also was an operational change midway through 2011 which contributed to the reduced frequency of reliability unit commitments. During the initial months of operating the nodal market, it was common for ERCOT to commit units that were providing non-spin reserves if they were needed to resolve congestion. This practice was greatly reduced starting in July 2011.

The majority of reliability unit commitment instructions are to resolve localized transmission constraints. Less than 18 percent of the unit hours of RUC instructions in 2014 were for system-wide capacity requirements and these hours were primarily during the period from January through March.

The next analysis compares the average dispatched output of the reliability committed units with their operational limits. Figure 65 below shows that the quantity of reliability unit commitment generation decreased in 2014; even though, as previously described, the frequency of reliability unit commitment increased in 2014.

Figure 65: Reliability Unit Commitment Capacity



There was less variation in the average quantity of reliability committed capacity in 2014. The average quantity dispatched was generally between 100 and 200 MW for all but the summer months.

Factors contributing to the high average capacity in October 2013 included an unseasonably warm day leading to system-wide capacity deficiency and localized generation requirements because of North to Houston and Valley import transmission constraints. April 2013 capacity needs were primarily in the Dallas-Fort Worth area for voltage support. The large amounts of reliability unit committed capacity in April 2012 were related to brief generator outages resulting in reactive power deficiencies in the Dallas-Fort Worth area. This was similar to the situation that existed during October 2011. The larger quantity of committed capacity in February 2011 was a result of ERCOT operator action taken to attempt to ensure overall capacity adequacy during both the extreme cold weather event that occurred early in the month, and a subsequent bout of cold weather that occurred one week later.

C. Demand Response Capability

Demand response is a term that broadly refers to actions that can be taken by end users of electricity to reduce load in response to instructions from ERCOT or in response to certain market or system conditions. The ERCOT market allows participants with demand-response capability to provide energy and reserves in a manner similar to a generating resource. The ERCOT Protocols allow for loads to actively participate in the ERCOT-administered markets as load resources. A second way that loads may participate is through ERCOT-dispatched reliability programs, including Emergency Response Service and legislatively-mandated demand response programs administered by transmission providers. Additionally, loads may self-dispatch by adjusting consumption in response to energy prices or by reducing consumption during specific hours to lower transmission charges. Unlike active participation in ERCOT-administered markets, self-dispatch by demand is not directly tracked by ERCOT.

1. Reserve Markets

ERCOT allows qualified load resources to offer responsive reserves into the day-ahead ancillary services markets. Those providing responsive reserves have high set under-frequency relay equipment. This equipment enables the load to be automatically tripped when the frequency falls below 59.7 Hz, which will typically occur only a few times in each year. As of December 2014, approximately 3,154 MW of capability were qualified as Load Resources.

Figure 66 shows the amount of responsive reserves provided from load resources on a daily basis in 2014. The high level of participation by demand response in the ancillary service markets sets ERCOT apart from other operating electricity markets. For reliability reasons the maximum amount of responsive reserves that can be provided by load resources is limited to 50 percent of the total, or 1,400 MW. The fifty percent limit has been maintained even as the total amount of responsive reserves increased from 2,300 MW to 2,800 MW in April of 2012.

Figure 66: Daily Average of Responsive Reserves Provided by Load Resources

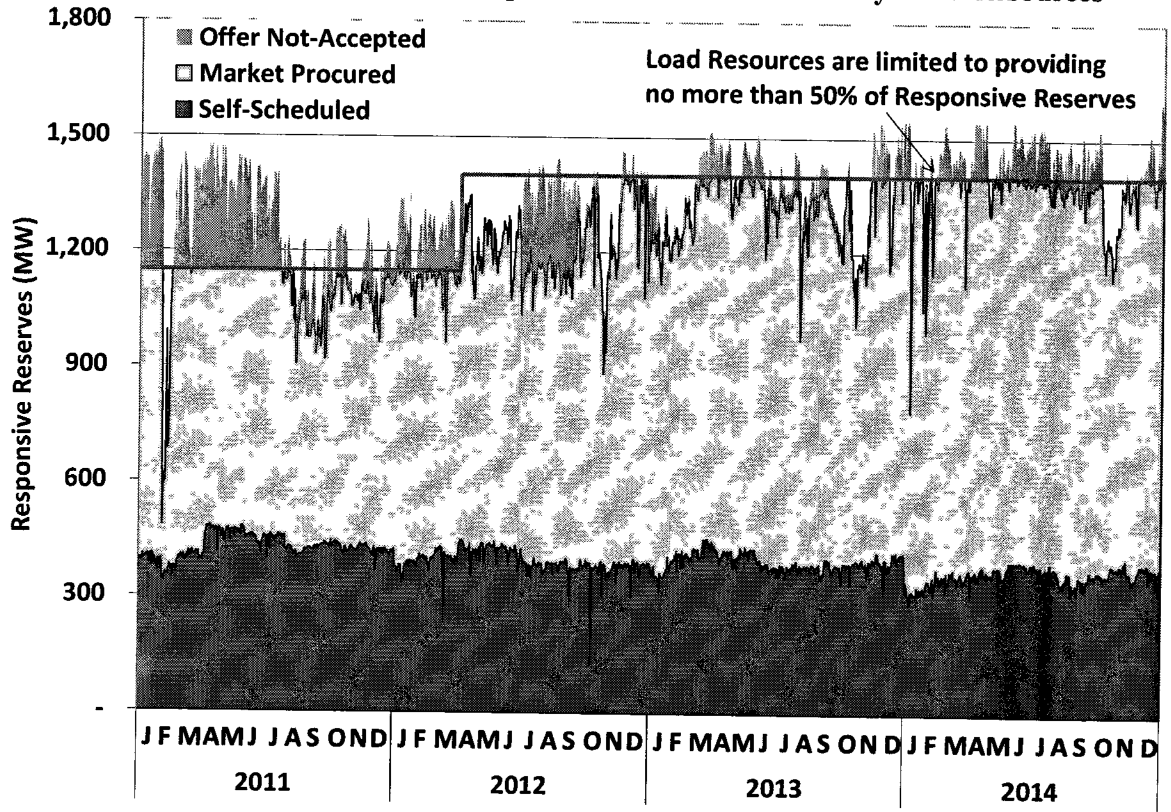


Figure 66 shows amounts of responsive reserves that were either self-scheduled or offered by load resources. The quantity of offers submitted by load resources exceeds the 50 percent limit most of the time. Times when this is not the case generally correspond with periods of expected high real-time prices. Since load resources provide capacity by reducing their consumption, they have to actually be consuming energy to be eligible to provide the capacity service. During periods of expected high prices the price paid for the energy can exceed the value received from providing responsive reserves. Noticeable reductions can be seen in February 2011 and the summer months of 2011. Reductions in the amount of offers are also observed every year around October, which generally reflect the lack of availability of load resources due to annual maintenance at some of the larger load resource facilities.

ERCOT Protocols permit load resources to provide non-spinning reserves and regulation services, but for a variety of reasons there has been minimal participation by load resources.

2. Reliability Programs

There are two main reliability programs in which demand can participate in ERCOT, Emergency Response Service and transmission provider load management programs. The Emergency Response Service (ERS) product is defined by PUCT Rule enacted in March of 2012. It replaced a previously defined emergency load service that was created in 2007. As originally conceived in 2007, the program would have ERCOT procure 500 to 1000 MW of load that would submit to being curtailed during emergency conditions, just prior to the forced curtailment of firm load. Although $20 million was initially allocated to fund this procurement, less than 500 MW of loads offered to be included.

Several program changes have been implemented over the years, so that now almost $50 million is spent annually to procure, on average, slightly less than 800 MW. The amount of ERS procured ranged from 600 to 1000MW across the various periods in the 2014 program year. Beginning with the auction covering the first period of program year 2014 (February 1 – May 31) the program was modified from a pay as bid auction to a clearing price auction, increasing participation and providing a clearer incentive to load to submit offers based on their costs to curtail, including opportunity cost. ERS was deployed only once in 2014. The time weighted average price paid in 2014 to providers of ERS service was $7.15 per MWh. As a point of comparison, the average paid to providers of responsive reserve service was $14.22 per MWh.

Beyond ERS there are slightly more than 200 MW of load participating in load management programs administered by transmission providers. Energy efficiency and peak load reduction programs are required under state law and PUCT rule and most commonly take the form of load management, where participants allow electricity to selected appliances (typically air conditioners) to be curtailed. These curtailments are actually controlled by ERCOT and occur during EEA Level 2.

3. Self-dispatch

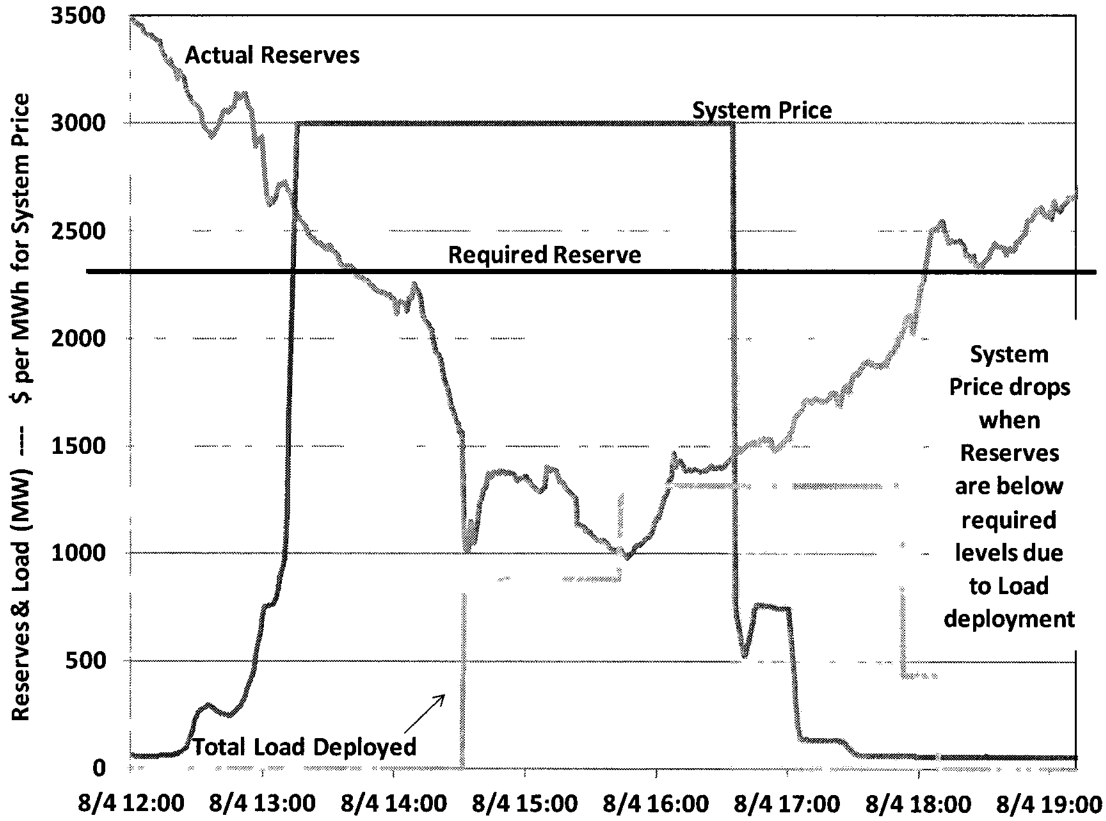
In addition to active participation in the ERCOT market and ERCOT-dispatched reliability programs; loads in ERCOT can observe system conditions and reduce consumption accordingly. This response comes in two main forms. The first is by participating in programs administered by competitive retailers and/or third parties to provide shared benefits of load reduction with end-use customers. The second is by actions taken specifically to avoid the allocation of transmission costs. Of these two methods, the more significant are actions taken specifically to avoid the allocation of transmission costs.

Transmission costs have for decades been allocated to all loads in ERCOT on the basis of load contribution to the highest 15-minute system demand during each of the four months, June – September. This allocation mechanism is routinely referred to as four coincident peak, or 4CP. Over the last three years these transmission costs have risen by more than 60 percent, thus significantly increasing an already substantial incentive to reduce load during probable peak intervals in the summer. It is estimated that over 800MW of load is actively pursuing reduction during these intervals.

Pricing During Load Deployments

During times when there are shortages of supply offers available for dispatch and Responsive Reserves are deployed, that is, converted to energy as one of the last steps taken before shedding firm load, the value of the foregone reserves – which is much higher than the marginal cost of the most expensive online generator – should be reflected in energy prices to achieve efficient economic signals governing investment in generation, demand response, and transmission. Unfortunately, ERCOT's dispatch software does not recognize that load has been curtailed, and computes prices based on supplying only the remaining load. A good example of this situation occurred on August 4, 2011. Figure 67 displays available reserves and the system price for that afternoon and shows that even though reserves were below required levels, system prices dropped to $60 per MWh. At this level, prices are being set based on supply offers and do not reflect the value of the load that is being curtailed to reliably serve the remaining system demand.

Figure 67: Pricing During Load Deployments



In 2014 ERCOT took the first step toward including the actions taken by load during the real-time energy market. The first phase of "Loads in SCED" allows those controllable loads that can respond to 5-minute dispatch instructions to specify the price at which they no longer wish to consume. This change was implemented in June of 2014. Although an important first step, there are very few loads that can respond to price in this manner.

We recommend that ERCOT implement system changes that will ensure that all demand response that is actively deployed by ERCOT be able to set the price at the value of load at times when such deployments are necessary to reliably serve the remaining system demand. This includes load resources and ERS providers being deployed for the services they contracted to provide or when firm load is involuntarily curtailed. It may be possible to integrate load bids and emergency resources in the real-time dispatch software and allow them to set prices when they are effectively marginal. Alternatively, it may be adequate to address this concern through administrative shortage pricing rules.

V. RESOURCE ADEQUACY

One of the primary functions of the wholesale electricity market is to provide economic signals that will facilitate the investment needed to maintain a set of resources that are adequate to satisfy the system's demands and reliability needs. This section begins with an evaluation of these economic signals by estimating the "net revenue" resources received from ERCOT real-time and ancillary services markets. Next, the effectiveness of the Scarcity Pricing Mechanism is reviewed. The current estimate of planning reserve margins for ERCOT and other regions are presented, followed by a description of the factors necessary to ensure resource adequacy in an energy-only market design. The section concludes with a discussion of the impacts of the Operating Reserve Demand Curve implemented last year.

A. Net Revenue Analysis

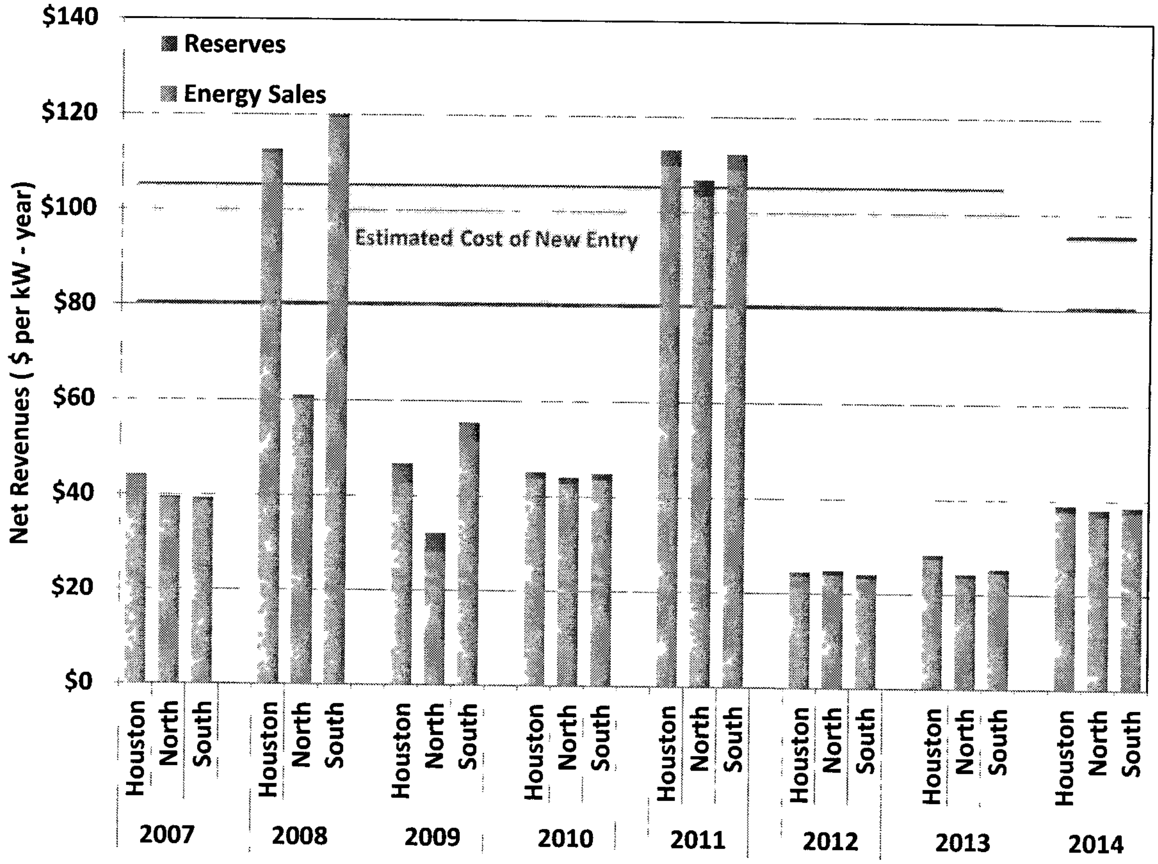
Net revenue is calculated by determining the total revenue that could have been earned by a generating unit less its variable production costs. Put another way, it is the revenue in excess of short-run operating costs that is available to recover a unit's fixed and capital costs, including a return on the investment. Net revenues from the real-time energy and ancillary services markets provide economic signals that help inform suppliers' decisions to invest in new generation or retire existing generation. Although most suppliers are likely to receive the bulk of their revenues through bilateral contracts, the spot prices produced in the real-time energy market should drive bilateral energy prices over time and thus are appropriate to use for this evaluation. It is important to note that this net revenue calculation is a look back at the estimated contribution based on actual market outcomes. Suppliers will typically base their investment decisions on their expectations of future electricity prices. Although expectations of future prices should be informed by history, they will also factor in the likelihood of shortage pricing conditions that could be very different than what actually occurred.

The energy net revenues are computed based on the generation-weighted settlement point prices from the real-time energy market. Weighting the energy values in this way facilitates comparisons between geographic zones, but will mask what could be very high values for a specific generator location. This analysis does not consider any payments for potential reliability unit commitment actions. The analysis necessitates reliance on simplifying assumptions that can lead to over-estimates of the profitability of operating in the wholesale market. Start-up costs and minimum running times are not accounted for in the net revenue analysis. Ramping restrictions, which can prevent generators from profiting during brief price spikes, are also excluded. But despite these limitations, the net revenue analysis provides a useful summary of signals for investment in the wholesale market.

For purposes of this analysis, the following assumptions were used for natural gas units: heat rates of 7 MMBtu per MWh for a combined cycle unit, 10.5 MMBtu per MWh for a combustion turbine, and $4 per MWh in variable operating and maintenance costs. Variable costs (fuel and O&M) were assumed to be $24 per MWh for the coal unit and $8 per MWh for the nuclear. A total outage rate (planned and forced) of 10 percent was assumed for each technology.

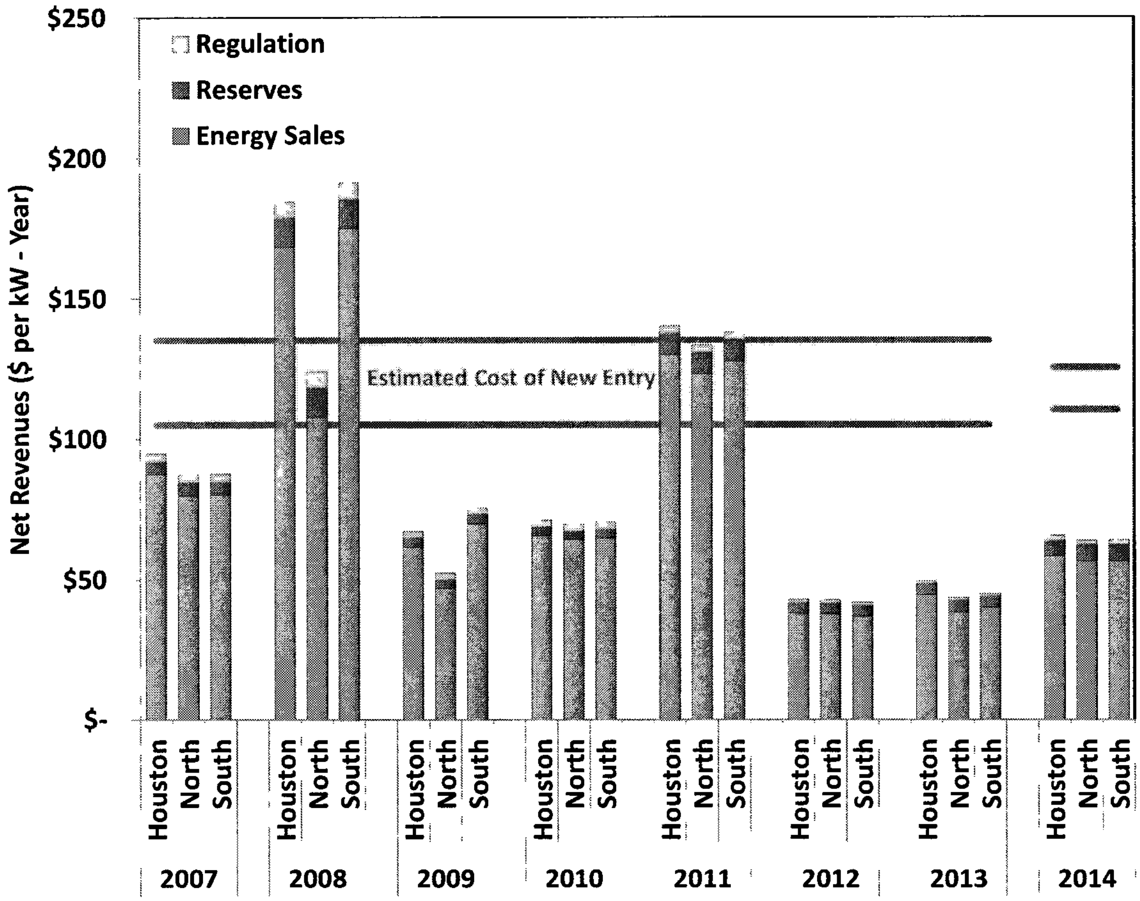
The next two figures provide an historical perspective of the net revenues available to support new natural gas combustion turbine (Figure 68) and combined cycle generation (Figure 69).

Figure 68: Combustion Turbine Net Revenues



Based on updated estimates of investment costs for new units,[11] the net revenue required to satisfy the annual fixed costs (including capital carrying costs) of a new gas turbine unit ranges from $80 to $95 per kW-year. The updated estimates of annual fixed costs have been reduced to reflect lower power plant equipment costs and further reduced to reflect Texas-specific construction costs. The net revenue in 2014 for a new gas turbine was calculated to be approximately $37 per kW-year, below the estimated cost of new gas turbine generation.

Figure 69: Combined Cycle Net Revenues



For a new combined cycle gas unit, the updated estimate of net revenue requirement is approximately $110 to $125 per kW-year, also reflecting lower power plant equipment costs and

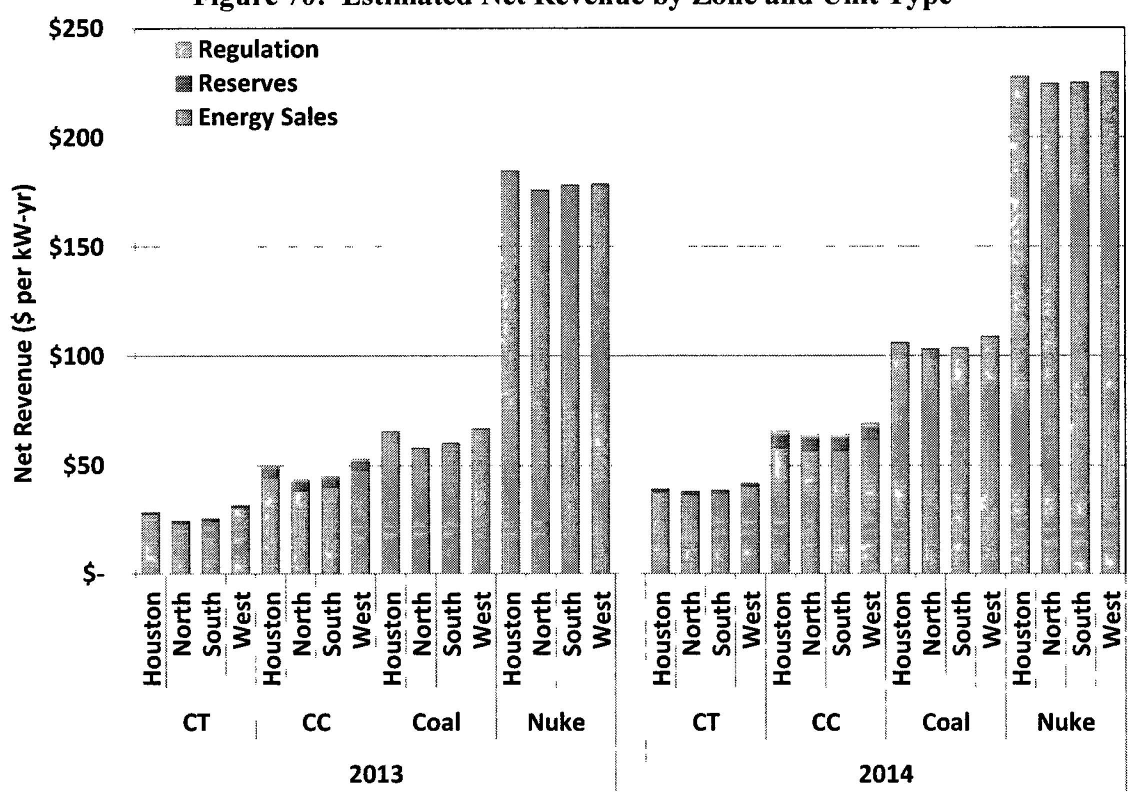
[11] Estimated annual fixed costs are derived from the EIA estimates released April 12, 2013 available here: http://www.eia.gov/forecasts/capitalcost/.

further reduced to reflect Texas-specific construction costs. The net revenue in 2014 for a new combined cycle unit was calculated to be approximately $57 per kW-year, also below the estimated cost of new combined cycle generation.

Even though net revenues for the Houston and South zones in 2008 may have appeared to be sufficient to support new natural gas-fired generation, the higher prices actually resulted from extremely inefficient transmission congestion management and inefficient pricing mechanisms associated with the deployment of non-spinning reserves, thereby contributing to higher than warranted net revenues. Discounting the effect that the 2008 results would have had on forward price signals, 2011 has been the only year with net revenues that would have been sufficient to support either new gas turbine or combined cycle generation.

Figure 70 expands the net revenue analysis to include coal and nuclear generation in addition to natural gas-fired combustion turbine and combined-cycle generation. Estimated net revenues for the four types of generation are compared below for 2013 and 2014.

Figure 70: Estimated Net Revenue by Zone and Unit Type



For the natural gas units, net revenue is calculated by assuming the unit will produce energy in any hour for which it is profitable and by assuming it will be available to sell reserves and regulation in all other hours. For coal and nuclear technologies, net revenue is calculated solely from producing energy.

Overall, the net revenues in 2014 were higher than those in 2013 and 2012, and all three years were much lower than in 2011. This is not surprising given shortages have been very infrequent over the past three years. Shortage pricing plays a pivotal role in providing investment incentives in an energy-only market like ERCOT. In order to provide adequate incentives, some years must exhibit an extraordinary number of shortages and net revenues that are multiples of annual net revenues needed to support investment.

As previously described, the 2014 net revenue for the natural gas-fired technologies was somewhat higher than 2013 levels, primarily because of higher gas prices during the first quarter of 2014. Net revenues for coal and nuclear technologies increased by larger amounts from 2013 to 2014 because they benefit from the increase in natural gas prices.

Despite these increases, the net revenues produced by the ERCOT markets in 2014 were lower than the annualized cost of investing in any of these new technologies.

- For a new coal unit, the estimated net revenue requirement is approximately $265 to $310 per kW-year. The net revenue in 2014 for a new coal unit was calculated to be approximately $105 per kW-year.
- For a new nuclear unit, the estimated net revenue requirement is approximately $450 to $585 per kW-year. The net revenue in 2014 for a new nuclear unit was calculated to be approximately $227 per kW-year.

Prior to 2005, net revenues were well below the levels necessary to justify new investment in coal and nuclear generation. Higher natural gas prices from 2005 through 2008 resulted in sustained energy prices high enough to support new entry for these technologies. The production costs of coal and nuclear units did not change significantly over this period, leading to a dramatic rise in net revenues. However, natural gas prices peaked in 2008, resulting in reduced net revenues for coal and nuclear technologies since then. Even with the higher energy prices experienced in 2011, net revenues for these technologies were calculated to be less than the estimated cost of new entry. Very low natural gas prices and few occurrences of shortage pricing during 2012 resulted in calculated net revenue for coal and nuclear to be well below the estimated cost of new entry. Although natural gas prices increased in 2013, the calculated net revenue for coal and nuclear technologies was less than the estimated cost of new entry. Similarly, net revenue for coal and nuclear technologies in 2014 was again less than the estimated cost of new entry.

The net revenues in 2014 were higher than those in 2013 and 2012, and all three years were much lower than in 2011. These results indicate that during 2014 the ERCOT markets would not have provided sufficient revenues to support profitable investment in any of the types of generation technology evaluated. Therefore, it may seem inconsistent with these results that new generation continues to be added in the ERCOT market. This can be explained by the following factors:

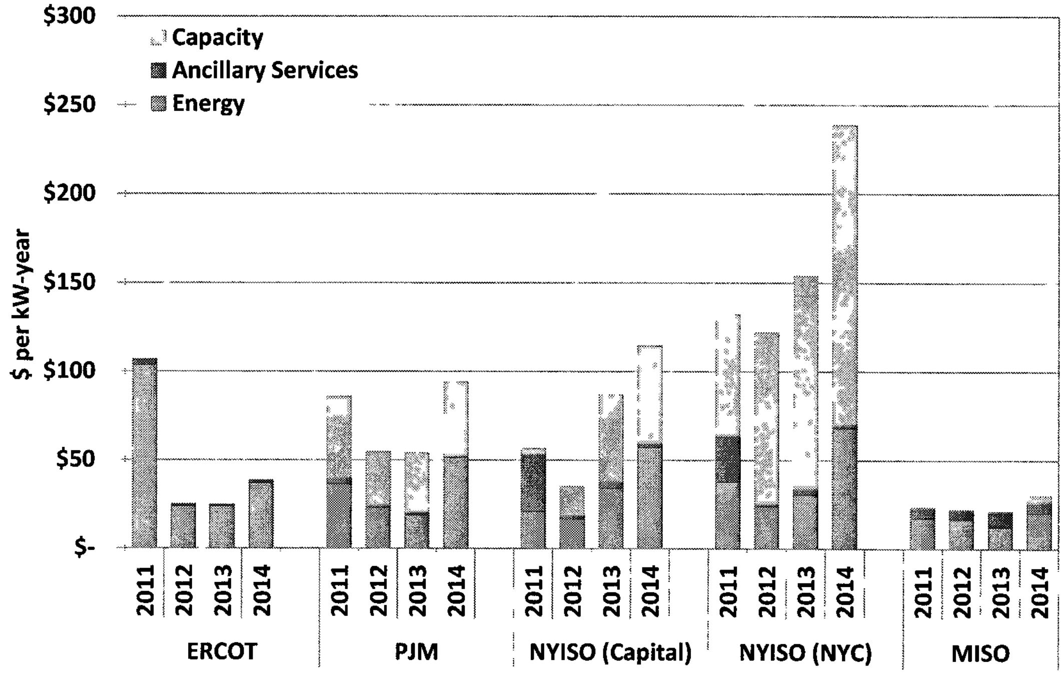
First, the net revenues in any one year may be higher or lower than an investor would require over the long term. In 2014, the net revenues were substantially lower than the cost of entry because shortages were much less frequent than would be expected over the long-term. Shortage revenues play a pivotal role in motivating investment in an energy only market like ERCOT. Hence, in some years the shortage pricing will be frequent and net revenues may substantially exceed the cost of entry, while in most others it will be less frequent and net revenue will be less than the cost of entry.

Second, the costs of new entry used in this report are generic and reflective of the costs of new resources on a new, undeveloped greenfield site. They have been reduced somewhat to reflect the lower costs of construction in Texas. However, companies may have opportunities to build generation at much lower cost than these estimates; either by having access to lower equipment costs, possibly through large, long-term supply agreements, or by adding generation to existing sites, or some combination of both.

Third, in addition to the equipment cost, financing structures and costs can vary greatly between suppliers. Again, the net revenue analysis assumes generic financing costs that a specific supplier may be able to improve on. The only revenues considered in the net revenue calculation are those that came directly from the ERCOT real-time energy and ancillary services markets in a specific year. Suppliers will develop their own view of future expected revenue which may include a power sales contract for some amount of the output. A long-term power sales contract could provide them with more revenue certainly than is available by relying completely on the ERCOT wholesale market. Given the level to which prices will rise under shortage conditions, small differences in expectations about the frequency of shortage pricing can greatly influence revenue expectations.

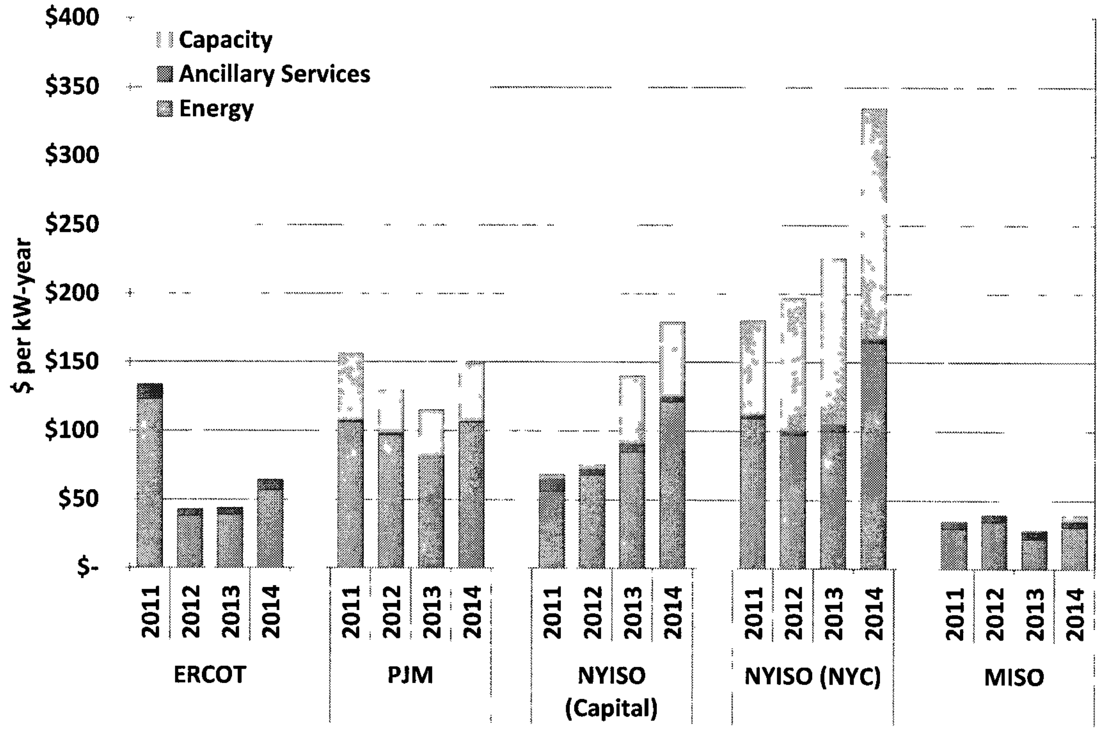
To provide additional context for the net revenue results presented in this subsection, the net revenue in the ERCOT market for two types of natural gas-fired technologies are compared with the net revenue that those technologies could expect in other wholesale markets with centrally cleared capacity markets. The technologies are differentiated by assumed heat rate; 7,000 MMBtu per MWh for combined cycle and 10,500 MMBtu per MWh for simple-cycle combustion turbine. The next two figures compare estimates of net revenue for two types of natural gas generators for the ERCOT North zone, PJM, two locations within the New York ISO, and the Midcontinent ISO. Most of these locations are central locations with the exception of New York City, which is significantly affected by congestion. Figure 71provides a comparison of net revenues for a combustion turbine and Figure 72 provides the same comparison for a combined cycle unit.

Figure 71: Combustion Turbine Net Revenue Comparison between Markets



The figures include estimates of net revenue from energy, reserves and regulation, and capacity. ERCOT does not have a capacity market, and thus, does not have any net revenue from capacity sales. The nascent capacity market in MISO contributed a small amount to net revenues in 2014. Net revenues for all other regions are calculated for central locations. However, there are load pockets within each market where net revenue and the cost of new investment may be higher. The NYC zone of NYISO is presented as an example of much higher value in a load pocket. Thus, even if new investment is not generally profitable in a market, it may be economic in certain areas. Finally, resource investments are driven primarily by forward price expectations, so historical net revenue analyses do not provide a complete picture of the future pricing expectations that will spur new investment.

Figure 72: Combined Cycle Net Revenue Comparison Between Markets



Both figures indicate that across all markets net revenues increased in 2014. The increases were more noticeable in PJM and NYISO, primarily due to higher energy revenues as a result of the extreme winter weather experienced in those regions early in 2014.

Over the long-run, markets should provide sufficient net revenue to allow generation owners to receive a return of, and on an investment in a new generating unit when that unit is needed. In the short-run, if the net revenues produced by the market are not sufficient to justify entry, then one or more of these conditions exist:

- New capacity is not needed because there is sufficient generation already available;
- Load levels, and thus energy prices, are temporarily low due to mild weather or economic conditions;
- Market rules or operational practices are causing revenues to be reduced inefficiently; or
- Market rules are not sufficiently linked in short-term operations to ensure long-term resource adequacy objectives are met.

Likewise, the opposite would be true if the markets provide excessive net revenues in the short-run. The persistence of excessive net revenues in the presence of a capacity surplus is an indication of competitive issues or market design flaws.

In an energy only market, net revenues are expected to be less than required to support new investment in most years. However, in the small number of years that are much worse than normal, the sharp increase in the frequency of shortage pricing should cause the net revenues in that year to be multiples of the annual level required to support investment. This pattern over the long run must create an expectation that net revenues, on average, will support new investments.

B. Effectiveness of the Scarcity Pricing Mechanism

The Public Utility Commission of Texas (PUCT) adopted rules in 2006 that define the parameters of an energy-only market. These rules included a Scarcity Pricing Mechanism (SPM) that increased the system-wide offer cap in multiple steps until it reached $3,000 per MWh shortly after the implementation of the nodal market. In accordance with the IMM's charge to conduct an annual review,[12] this subsection assesses the SPM in 2014 under ERCOT's energy-only market structure.

Revisions to 16 TEX. ADMIN. CODE § 25.505 were adopted in 2012 that specified the following increases to the system-wide offer cap:

- $5,000 per MWh beginning on June 1, 2013,
- $7,000 per MWh beginning on June 1, 2014, and
- $9,000 per MWh beginning on June 1, 2015.

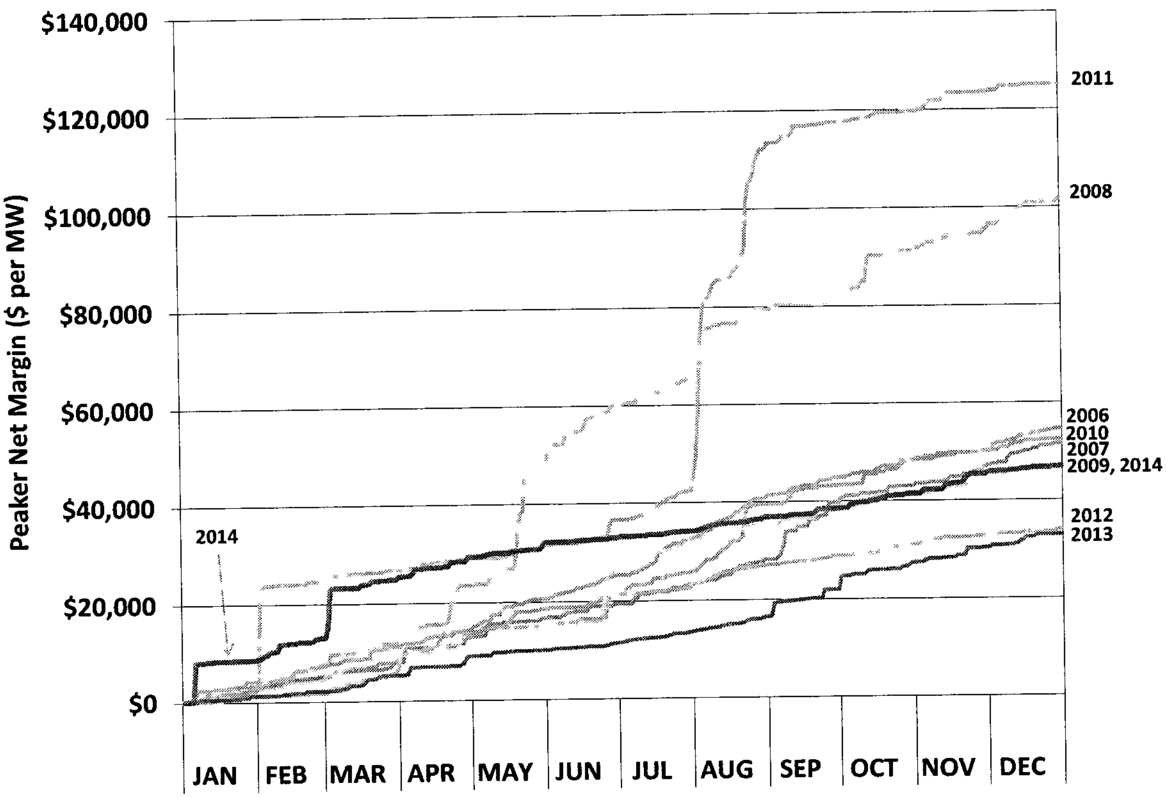
As shown in Figure 16 on page 16, there have been very brief periods when energy prices rose to the cap since the system-wide offer cap was increased to greater than $3,000 per MWh.

The SPM includes a provision termed the Peaker Net Margin (PNM) that is designed to provide a fail-safe pricing measure, which if exceeded would result in reducing the system-wide offer cap. PNM also serves as a simplified measure of the annual net revenue of a hypothetical

12 *See* 16 TEX. ADMIN. CODE § 25.505(g)(6)(D).

peaking unit.[13] Under the current rule, if the PNM for a year reaches a cumulative total of $300,000 per MW, the system-wide offer cap is then reduced to the higher of $2,000 per MWh or 50 times the daily natural gas price index.[14] Figure 73 shows the cumulative PNM results for each year from 2006 through 2014 and shows that PNM in 2014 was similar to the level of 2009.

Figure 73: Peaker Net Margin



As previously described, the net revenue required to satisfy the reduced estimates of the annual fixed costs (including capital carrying costs) of a new gas turbine unit ranges from $75,000 to $90,000 per MW-year. Thus, as shown in Figure 73 and consistent with the previous findings in this section relating to net revenue, the PNM was slightly below the levels estimated to support new entry in 2014.

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13 The proxy combustion turbine in the Peaker Net Margin calculation assumes a heat rate of 10 MMBtu per MWh and includes no other variable operating costs or startup costs.

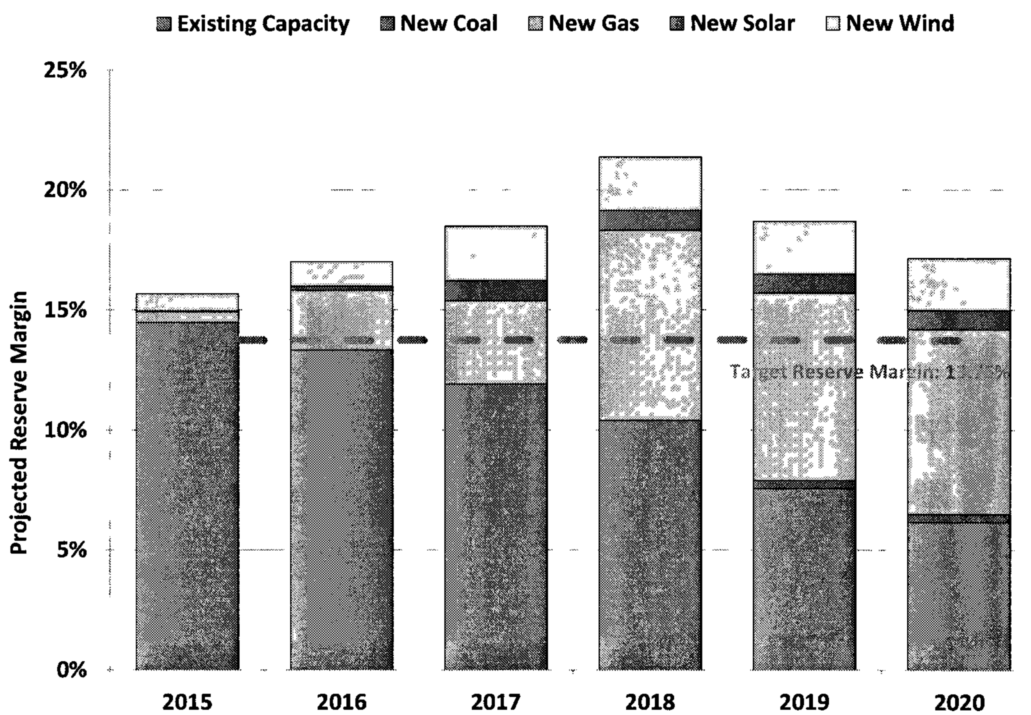
14 For 2014 and each subsequent year, ERCOT shall set the PNM threshold at three times the cost of new entry of new generation plants. The PNM threshold for 2014 and each subsequent year will be set to $315,000 per MW-year based on the analysis prepared by Brattle dated June 1, 2012, unless there is a change identified in the cost of new entry of new generation plants.

Considering the purpose for which the PNM was initially defined, that is to provide a "circuit breaker" trigger for lowering the system-wide offer cap, it has not approached levels that would dictate a needed reduction in the system wide offer cap.

C. Planning Reserve Margin

The prior subsection discusses and evaluates the economic signals produced by the ERCOT markets to facilitate efficient decisions by suppliers to maintain an adequate base of resources. This subsection summarizes and discusses the current level of capacity in ERCOT, as well as the long-term need for capacity in ERCOT. The figure below shows ERCOT's projection of reserve margins developed prior to the summer of 2015.

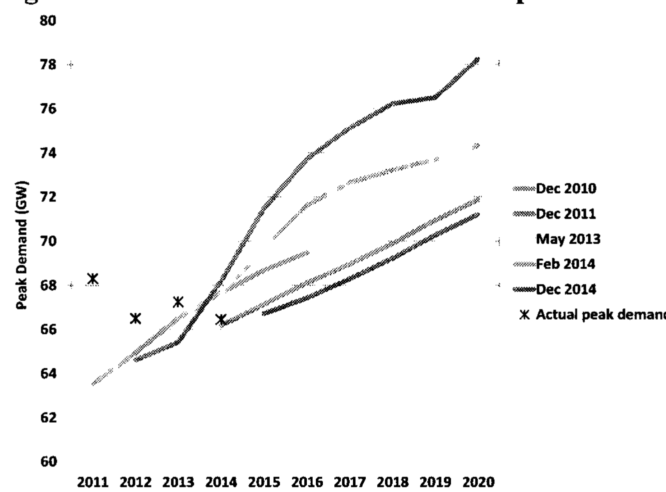
Figure 74: Projected Reserve Margins



Source: ERCOT Capacity Demand Reserve Reports / 2015 from December 2014 and 2016-2020 from May 2015

Figure 74 above indicates that the region will have a 15.7 percent reserve margin heading into the summer of 2015. Reserve margins are now expected to exceed the target level of 13.75 percent for the next several years. These projections are higher than those developed last year. Further, this outlook is very different than in 2013, when reserve margins were expected to be below the target level of 13.75 percent for the foreseeable future. In 2013 the expected reserve margin for 2016 was 10.4 percent, much lower than the current expectation for 2016 of 17 percent. This increase in expected reserve margin is not due to an increase in available generating resources, but rather to ERCOT's revised long-term load forecasting methodology and resulting reduction in the forecasted peak demand. The quantity of available resources expected in 2016 as shown in the May 2013 Capacity Demand Report (CDR) is nearly identical to the quantity of resources shown in the May 2015 CDR. Although the total expected capacity of resources has not changed between the two CDRs, the mix has changed. Almost 1,700 MW of increased wind capacity expected in 2016 has been offset by reductions in the total capacity expected from natural gas and coal.

Figure 75: Peak Demand Forecast Comparison



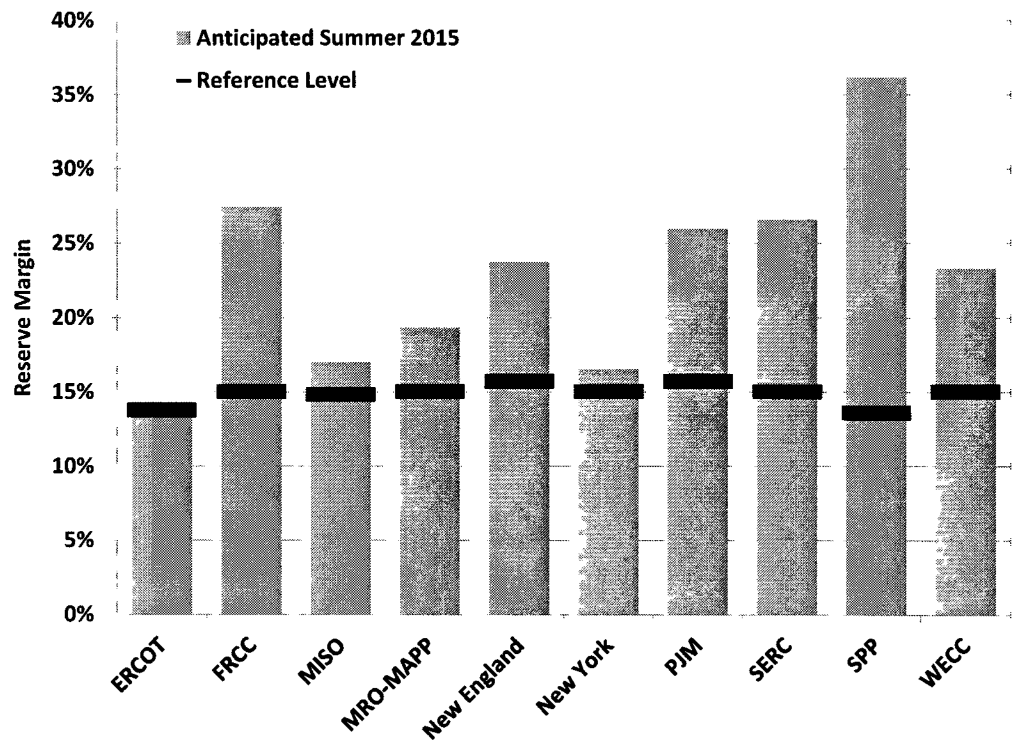
The figure to the right presents a comparison of ERCOT's peak demand forecasts from recent CDR reports. Comparing the May 2013 forecast with the December 2014 forecast, the difference in peak demand expected in 2016 is greater than 4,000 MW.

Looking beyond 2016, several new additions have been announced that meet the requirements for being included in the CDR. The bulk of this new capacity is from new gas units (greater than 5 GW) sited at locations across the ERCOT region. Wind additions are also projected to continue, with 1.5 GW of capacity shown in the CDR representing nearly 10 GW of installed wind capacity. Rounding out the additions is more than 500 MW of solar capacity.

To compare the situation in ERCOT with other regions, Figure 76 provides the anticipated reserve margins for the North American Electric Reliability Council (NERC) regions in the

United States for the summer of 2015, as of the most recent NERC report in November 2014.[15] Figure 76 shows that required, or reference level reserve margins center around 15 percent across other regions. These regions run the gamut from traditional bundled, regulated utility service territories to fully competitive, centrally operated wholesale markets. There are large differences in the level of planning reserves expected for the summer of 2015. However, reserve margins are lower in nearly every region this year compared to last. ERCOT is unique in that its anticipated reserve margin remains very close to its target level. Even with the forecasted additions, ERCOT is projected to sustain lower reserve margins than many other regions. This makes it important to ensure that the ERCOT market is designed to provide adequate economic signals to remain near this target, which is discussed below

Figure 76: Reserve Margins in Other Regions



15 Data from NERC 2014 Long-Term Reliability Assessment (November 2014) available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA_ERATTA.pdf. For the most recent projected reserve margins for ERCOT, please see Figure 74 and the associated discussion supra.

D. Ensuring Resource Adequacy

One of the primary goals of an efficient and effective electricity market is to ensure that, over the long term, there is an adequate supply of resources to meet customer demand plus any required installed or planning reserves. In a region like ERCOT, where customer requirements for electricity are continually increasing, even with growing demand response efforts, maintaining adequate supply requires capacity additions. To incent these additions the market design must provide revenues such that the marginal resource receives revenues sufficient to make that resource economic. In this context, "economic" includes both a return of, and on capital investment.

Generators earn revenues from three sources: energy prices during non-scarcity, energy prices during scarcity and capacity payments. The capacity payments generators receive in ERCOT are related to the provision of ancillary services. As discussed in the net revenue subsection, ancillary service payments are a small contributor: $5 - $10 per kW-year. Setting them aside, generator revenue in ERCOT is overwhelmingly derived from energy prices under both scarcity and non-scarcity conditions.

Expectations for energy pricing under non-scarcity conditions are the same regardless of whether payments for capacity exist. In ERCOT, with no capacity payments available, the amount a generator may receive from energy pricing under shortage conditions must be large enough to provide the necessary incentives for new capacity additions. This will occur when energy prices are allowed to rise substantially at times when the available supply is insufficient to simultaneously meet both energy and minimum operating reserve requirements.

Ideally, energy and reserve prices during shortages should reflect the diminished system reliability under these conditions, which is equal to the increased probability of "losing" load times the value of the lost load. Allowing energy prices to rise during shortages mirrors the outcome expected if loads were able to actively specify the quantity of electricity they wanted and the price they would be willing to pay. The energy-only market design relies exclusively on these relatively infrequent occurrences of high prices to provide the appropriate price signal for demand response and new investment, when required. In this way, energy-only markets can provide price signals that will sustain a portfolio of resources to be used in real time to satisfy the needs of the system. However, this portfolio may produce a planning reserve margin that is less than the planning reserve target.

As a general principle, competitive and efficient market prices should be consistent with the marginal cost of the marginal action taken to satisfy the market's demand. In the vast majority of hours, the marginal cost of the marginal action is associated with the dispatch of the last generator required to meet demand. It is appropriate and efficient in these hours for this generator to "set the price." However, this is not true under shortage conditions. When the system is in shortage, the demand for energy and minimum operating reserves cannot be satisfied with the available resources, which will cause the system operator to take one or more of the following actions:

- Sacrifice a portion of the operating reserves by dispatching them for energy;
- Voluntarily curtail load through demand response programs;
- Curtail exports or make emergency imports; or
- Involuntarily curtail load.

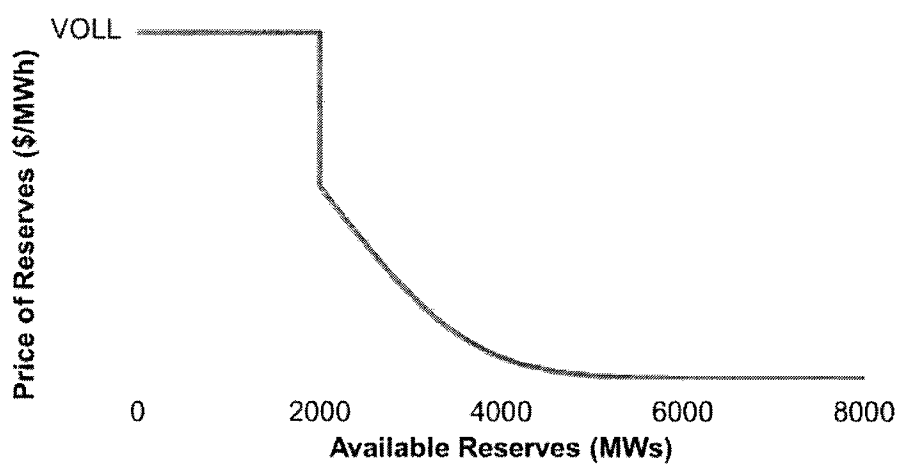
A market design that adheres to the pricing principles stated above will set prices that reflect each of these actions. When there is a shortage of supply in the market, the marginal action first taken by the system operator is generally to sacrifice operating reserves requirements (*i.e.*, dispatch reserves for energy). Diminished operating reserves results in an increased probability of outage, which has a real cost to electricity consumers. In this case, the value of the foregone reserves – which is much higher than the marginal cost of the most expensive online generator – should be reflected in energy prices to achieve efficient economic signals governing investment in generation, demand response, and transmission.

Faced with reduced levels of generation development activity coupled with increasing loads that result in falling planning reserve margins, the PUCT has devoted considerable effort since 2012 deliberating issues related to resource adequacy. To date, the PUCT continues to support the energy-only nature of the ERCOT market and has directed market modifications to improve ERCOT's shortage pricing based on the demand for operating reserves.

E. Operating Reserve Demand Curve Implementation

The Operating Reserve Demand Curve (ORDC) is a shortage pricing mechanism that reflects the loss of load probability (LOLP) at varying levels of operating reserves multiplied by the value of lost load (VOLL). Selected as an easier to implement alternative to real-time co-optimization of energy and ancillary services, the ORDC provides a new form of shortage pricing for online and offline reserves, as well as energy. As the quantity of reserves decreases, payments will increase. As conceptualized below in Figure 77, once available reserve capacity drops to 2,000 MW, payment for reserve capacity will rise to VOLL, or $9,000 per MWh.

Figure 77: Operating Reserve Demand Curve

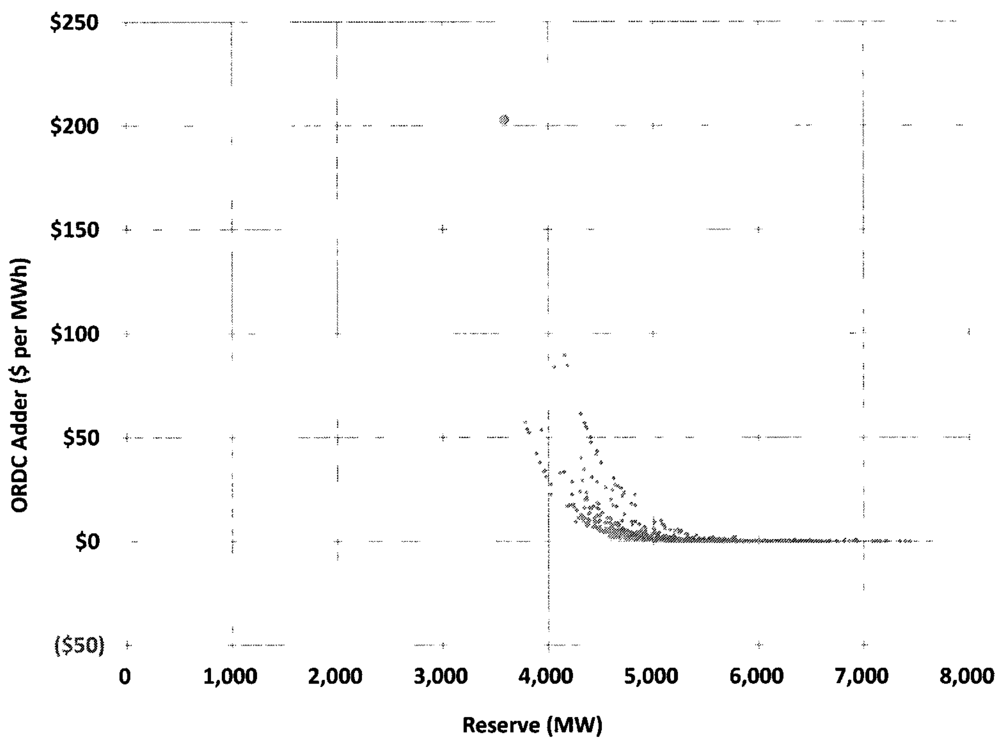


The initial implemetation of ORDC went into effect on June 1, 2014 and included the introduction of real-time reserve on-line and off-line adders. Since real-time co-optimization of energy and ancillary services was not implemented, a mechanism was needed to ensure that resources are indifferent between providing energy and reserves in real-time. This is accomplished using an ancillary service imbalance settlement, with adjustments to the price floors that had previously been in place for the energy associated with capacity providing ancillary services. There is no longer a price floor associated with regulation, responsive reserves, or off-line non spin. The price floor associated with on-line non-spin was reduced to $75 per MWh. The price floor associated with RUC capacity is now set at $1500 per MWh.

The load-weighted real-time energy price for the period of 2014 after ORDC implementation (i.e. after June 1st) was $35.68 per MWh. Of that total, $0.26 per MWh (less than 1 percent) was the on-line reserve adder. The on-line reserve adder includes the off-line adder, which was $0.09 per MWh for this time period.

Figure 78 presents the online reserve adder amount and associated reserve level for every 15 minute settlement period after June 1.

Figure 78: Online Reserve Adder



Although the pricing impacts due to ORDC implementation have so far been very small, the concern remains that prices resulting from ORDC will rise to levels approaching the VOLL when the available reserves are at levels where the LOLP is less than 1.0 and involuntary load curtailment is not imminent. This situation would likely lead to inefficient actions by participants. We will evaluate this concern going forward as the ORDC is fully implemented.

Finally, we continue to recommend that ERCOT implement a system to co-optimize energy and ancillary services because this would improve the efficiency of ERCOT's dispatch, more fully utilize its resources, and allow for improvements in its shortage pricing.

VI. Analysis of Competitive Performance

In this section, market power is evaluated from two perspectives – structural (does market power exist) and behavioral (have attempts been made to exercise it). Market structure is examined by using a pivotal supplier analysis that indicates the frequency with which a supplier was pivotal at higher load levels. This is consistent with observations in prior years. This section also includes a summary of the Voluntary Mitigation Plans in effect during 2014. Market participant conduct is evaluated by reviewing measures of physical and economic withholding. These withholding patterns are further examined relative to the level of demand and the size of each supplier's portfolio.

Based on these analyses, we find the overall performance of the ERCOT wholesale market to be competitive in 2014.

A. Structural Market Power Indicators

The market structure is analyzed by using the Residual Demand Index (RDI), a statistic that measures the percentage of load that could not be satisfied without the resources of the largest supplier. The RDI is used to measure the percentage of load that cannot be served without the resources of the largest supplier, assuming that the market could call upon all committed and quick-start capacity owned by other suppliers.[16] When the RDI is greater than zero, the largest supplier is pivotal (i.e., its resources are needed to satisfy the market demand). When the RDI is less than zero, no single supplier's resources are required to serve the load as long as the resources of its competitors are available.

The RDI is a useful structural indicator of potential market power, although it is important to recognize its limitations. As a structural indicator, it does not illuminate actual supplier behavior to indicate whether a supplier may have exercised market power. The RDI also does not indicate whether it would have been profitable for a pivotal supplier to exercise market power. However,

[16] For the purpose of this analysis, "quick-start" includes off-line simple cycle gas turbines that are flagged as on-line in the current operating plan with a planned generation level of 0 MW that ERCOT has identified as capable of starting-up and reaching full output after receiving a dispatch instruction from the real-time energy market.

it does identify conditions under which a supplier would have the ability to raise prices significantly by withholding resources.

Figure 79 shows the RDI relative to load for all hours in 2014. The trend line indicates a strong positive relationship between load and the RDI. The analysis shown below is done at the QSE level because the largest suppliers that determine the RDI values own a large majority of the resources they are offering. It is possible that they also control other capacity through bilateral arrangements, although we do not know whether this is the case. To the extent that the resources scheduled by the largest QSEs are not controlled by or provide revenue to the QSE, the RDIs will tend to be slightly overstated.

Figure 79: Residual Demand Index

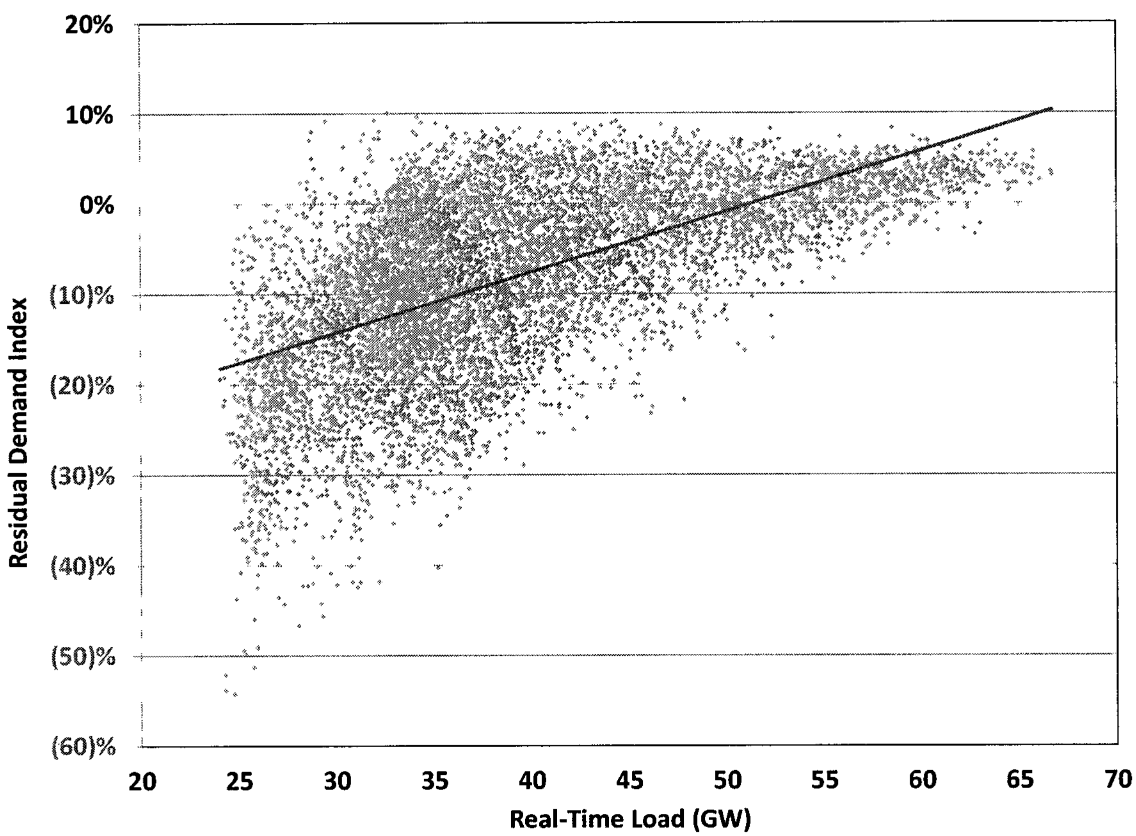
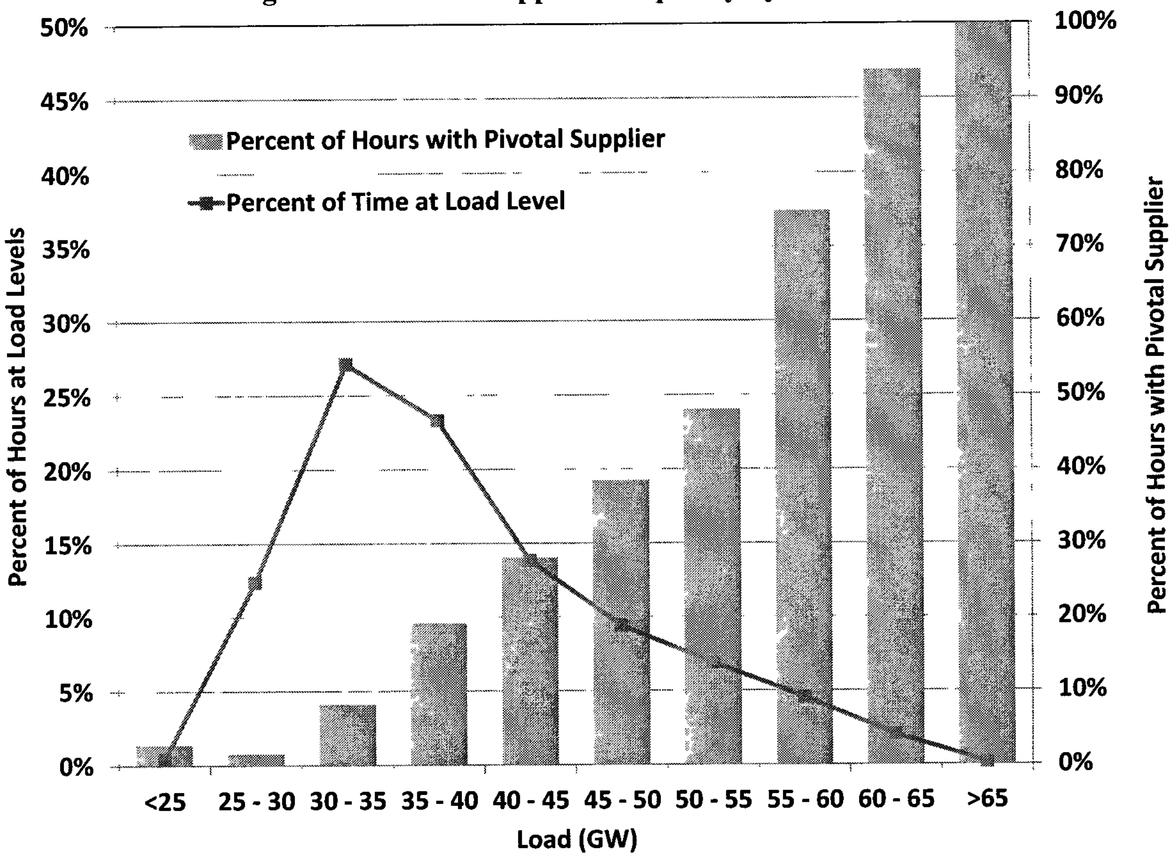


Figure 80 below summarizes the results of the RDI analysis by displaying the percentage of time at each load level there was a pivotal supplier. At loads greater than 65 GW there was a pivotal supplier 100 percent of the time. The figure also displays the percentage of time each load level occurs. By combining these values it can be determined that there was a pivotal supplier in approximately 23 percent of all hours of 2014, which indicates that market power is a potential concern in ERCOT and underscores the need for the current mitigation measures that address it.

Figure 80: Pivotal Supplier Frequency by Load Level



It is important to recognize that inferences regarding market power cannot be made solely from this data. Bilateral contract obligations can affect a supplier's potential market power. For example, a smaller supplier selling energy in the real-time energy market and through short-term bilateral contracts may have a much greater incentive to exercise market power than a larger supplier with substantial long-term sales contracts. The RDI measure shown in the previous figure does not consider the contractual position of the supplier, which can increase a supplier's incentive to exercise market power compared to the load-adjusted capacity assumption made in this analysis.

Voluntary Mitigation Plans

Voluntary Mitigation Plans (VMPs) existed for two market participants – NRG and Calpine – during 2014. Generation owners are motivated to enter into VMPs because adherence to a plan approved by the PUCT constitutes an absolute defense against an allegation of market power abuse through economic withholding with respect to behaviors addressed by the plan. This increased regulatory certainty afforded to a generation owner regarding its energy offers in the ERCOT real-time market must be balanced by appropriate protections against a potential abuse of market power in violation of PURA §39.157(a) and 16 TEX. ADMIN. CODE § 25.503(g)(7).

VMPs should promote competitive outcomes and prevent abuse of market power in the ERCOT real-time energy market through economic withholding. The same restrictions are not required in forward energy markets (e.g., the ERCOT day-ahead market) because the price in forward energy markets is derived from the real-time energy prices. Because the forward energy markets are voluntary and the market rules do not inhibit arbitrage between the forward energy markets and the real-time energy market, competitive outcomes in the real-time energy market serve to discipline the potential abuse of market power in the forward energy markets.

NRG's plan, initially approved in June 2012 and modified in May 2014, allows the company to offer some of its capacity at prices up to the system-wide offer cap. Specifically, up to 12 percent of the difference between the high sustained limit and the low sustained limit for each natural gas-fired unit (5 percent for each coal/lignite unit) may be offered no higher than the higher of $500 per MWh or 50 times the natural gas price. Additionally, up to 3 percent of the difference between the high sustained limit and the low sustained limit for each natural gas-fired unit may be offered no higher than the system-wide offer cap. The amount of capacity covered by these provisions is approximately 500 MW.

Calpine's VMP was approved in March of 2013. Because its generation fleet consists entirely of natural-gas fueled combined cycle units, the details of the Calpine plan are somewhat different than NRG. Calpine may offer up to 10 percent of the dispatchable capacity of its portfolio at prices up to $500 per MWh. Additionally, Calpine may offer up to 5 percent of the dispatchable capacity of its portfolio at prices no higher than the system-wide offer cap. When approved, the amount of capacity covered by these provisions was approximately 500 MW. With recent additions to Calpine's generation fleet its current amount of offer flexibility has increased to approximately 700 MW.

Allowing offers up to these high levels is intended to accommodate potential legitimate fluctuations in marginal cost that may exceed the base offer caps, such as operational risks, short-term fluctuations in fuel costs or availability, or other factors. However, both NRG's and Calpine's VMPs contains a requirement that these offers, if offered in any hour of an operating day, must be offered in the same price/quantity pair for all hours of the operating day. This provision, along with the quantity limitations, significantly reduces the potential that the VMPs will allow market power to be exercised.

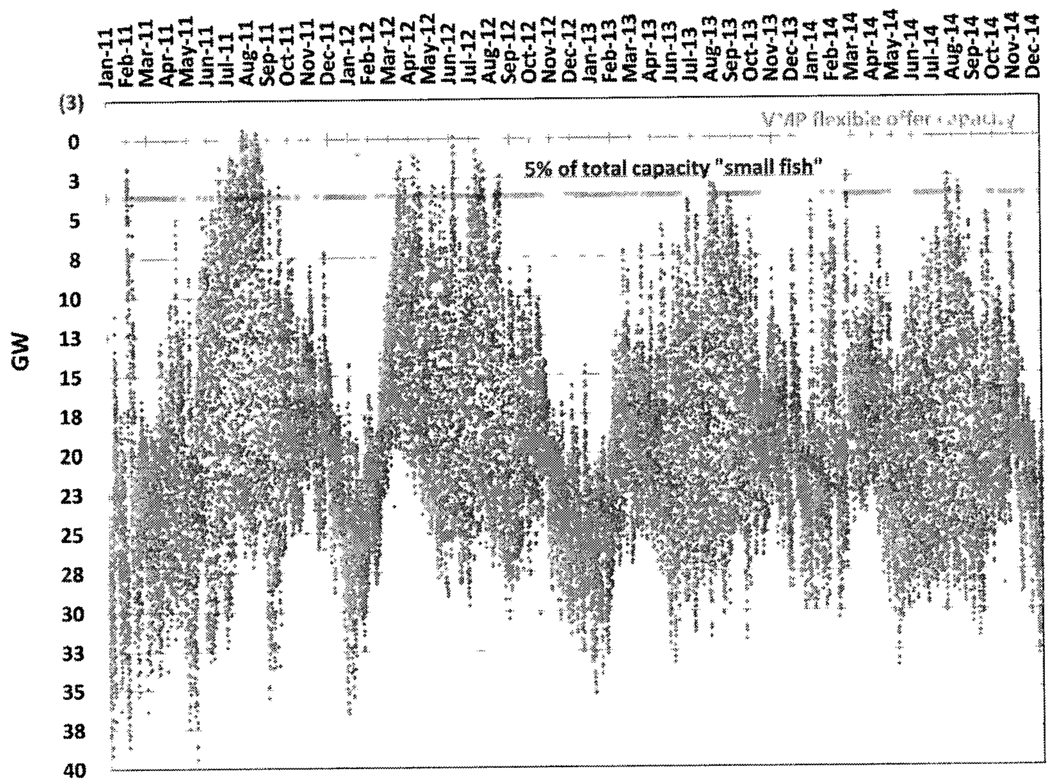
The final key element in these two VMPs is the timing of termination. The approved VMPs for NRG and Calpine may each be terminated after three business days' notice. PURA §39.157(a) defines market power abuses as "practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition..." The exercise of market power may not rise to the level of an abuse of market power if it does not unreasonably impair competition, which would typically involve profitably raising prices significantly above the competitive level for a significant period of time. Thus, although the offer thresholds provided in the VMPs are designed to promote competitive market outcomes, the short termination provision provides additional assurance that any unintended consequences associated with the potential exercise of market power can be addressed in a timely manner rather than persisting and rising to the level of an abuse of market power.

The amount of offer flexibility afforded by the VMPs is small when compared to the offer flexibility that small participants, those with less than 5 percent of total ERCOT capacity, are granted under 16 TEX. ADMIN. CODE § 25.504(c). Although 5 percent of total ERCOT capacity may seem like a small amount, the potential market impacts of a market participant whose size is just under the 5 percent threshold choosing to exercise flexibility and offering a significant portion of their fleet at very high prices could be large.

The figure below shows the amount of surplus capacity available in each hour of every day during 2011, 2012, 2013 and 2014. For this analysis, surplus capacity is defined as online generation plus any offline capacity that was available day ahead, plus DC Tie imports (minus exports), minus responsive reserves provided by generation and regulation up capacity, minus load. Over the past four years there were 13 hours with no surplus capacity, with all but one hour occurring in 2011. These correspond to times when ERCOT was unable to meet load and maintain all operating reserve obligations.

Currently, the 5 percent "small fish" threshold is roughly 4,000 MW, as indicated by the red line in Figure 81. There were 491 hours over the past four years with less than 4,000 MW of surplus capacity.[17] During these times a large "small fish" would have been pivotal and able to increase the market clearing price through its offer, potentially as high as the system-wide offer cap. In contrast, the VMPs granted to NRG and Calpine afford them the flexibility to raise their offers on a combined 1,200 MW of capacity. During the past four years this amount of capacity would have been pivotal in 61 hours.

Figure 81: Surplus Capacity



[17] Surplus capacity was less than 4000 MW for 296 hours in 2011, 154 hours in 2012, 15 hours in 2013, and 26 hours in 2014.

The effects of such actions became much more pronounced after June 21, 2013 when changes to real-time mitigation measures went into effect. These changes narrowed the scope of mitigation addressing the previously discussed issue where mitigation measures were being applied much more broadly than intended or necessary in the ERCOT real-time energy market.[18] Although "small fish" market participants have always been allowed to offer all of their capacity at prices up to the system-wide offer cap, the effect on market outcomes of a large "small fish" offering substantial quantities at high prices became more noticeable after the scope of mitigation was narrowed.

B. Evaluation of Supplier Conduct

The previous subsection presented a structural analysis that supports inferences about potential market power. In this subsection actual participant conduct is evaluated to assess whether market participants have attempted to exercise market power through physical or economic withholding. First examined are unit deratings and forced outages to detect physical withholding, this is followed by an evaluation of "output gap," used to detect economic withholding.

In a single-price auction like the real-time energy market, suppliers may attempt to exercise market power by withholding resources. The purpose of withholding is to cause more expensive resources to set higher market clearing prices, allowing the supplier to profit on its other sales in the real-time energy market. Because forward prices will generally be highly correlated with spot prices, price increases in the real-time energy market can also increase a supplier's profits in the bilateral energy market. The strategy is profitable only if the withholding firm's incremental profit due to higher price is greater than the lost profit from the foregone sales of its withheld capacity.

1. Generation Outages and Deratings

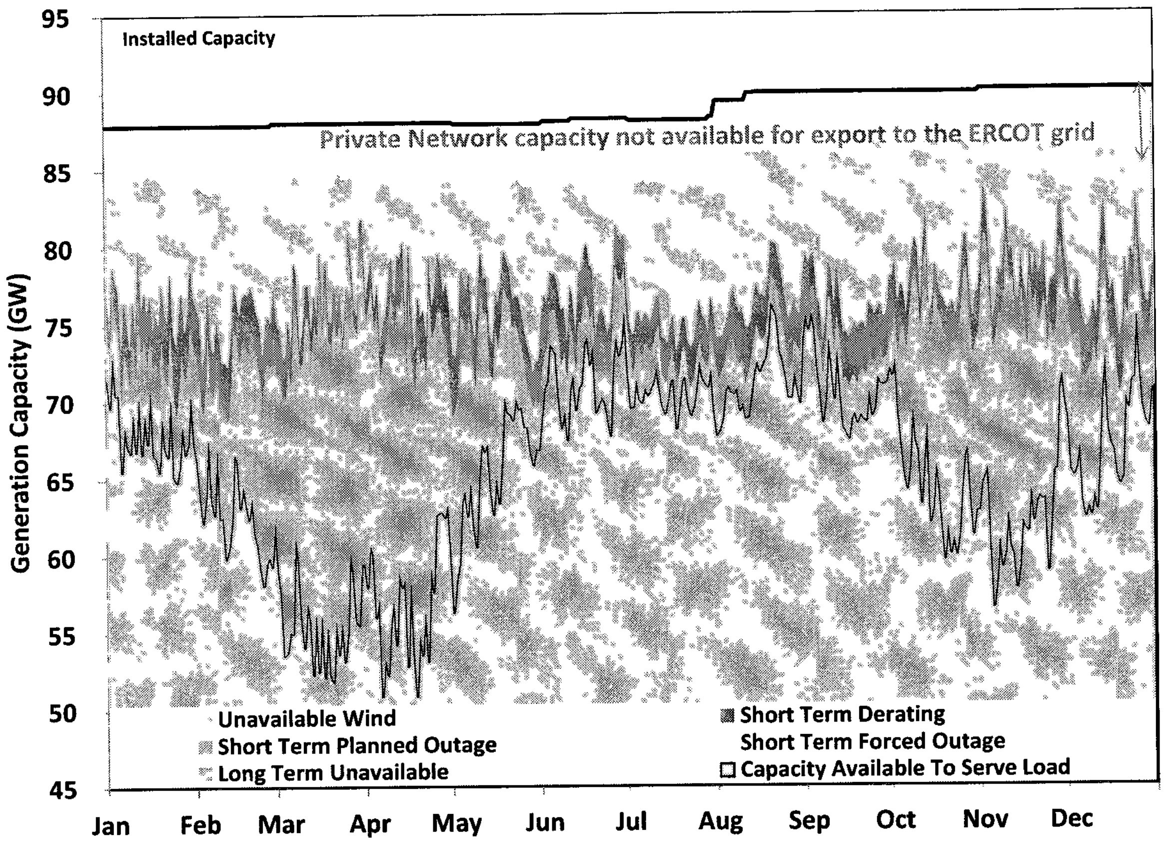
Some portion of installed capability is commonly unavailable because of generator outages and deratings. Due to limitations in outage data, the outage type must be inferred. The outage type can be inferred by cross-referencing unit status information communicated to ERCOT with

[18] Refer to Section I.F. Mitigation at page 22.

scheduled outages. If there is a corresponding scheduled outage, the unit is considered to be on a "planned outage." If not, it is considered to be a "forced outage." The derated capacity is defined as the difference between the summertime maximum capability of a generating resource and its actual capability as communicated to ERCOT on a continuous basis. It is very common for generating capacity to be partially derated (e.g., by 5 to 10 percent) because the resource cannot achieve its installed capability level due to technical or environmental factors (e.g., component equipment failures or ambient temperature conditions). Wind generators rarely produce at their installed capacity rating due to variations in available wind input. Because such a large portion of derated capacity is related to wind generation it is shown separately. In this subsection, long-term and short-term deratings are evaluated.

Figure 82 shows a breakdown of total installed capability for ERCOT on a daily basis during 2014. This analysis includes all in-service and switchable capacity. From the total installed capacity the following are subtracted: (a) capacity from private networks not available for export to the ERCOT grid, (b) wind capacity not available due to the lack of wind input, (c) short-term deratings, (d) short-term planned outages, (e) short-term forced outages, and (e) long-term outages and deratings – greater than 30 days. What remains is the capacity available to serve load.

Figure 82: Reductions in Installed Capability



Outages and deratings of non-wind generators fluctuated between 3 and 30 GW, as shown in Figure 82, while wind unavailability varied between 2 and 12 GW. Short-term planned outages were largest in March and April and small during the summer, which is consistent with expectations. Short-term forced outages also declined during the summer. Short-term deratings peaked during October.

The quantity of long-term (greater than 30 days) unavailable capacity, peaked in March at 3.8 GW, reduced to less than 1 GW during the summer months, and increased to almost 3.5 GW in November. This pattern reflects the choice by some owners to mothball certain generators on a seasonal basis, maintaining the units' operational status only during the high load summer season when more costly units have a higher likelihood of operating.

The next analysis focuses specifically on short-term planned and forced outages and deratings because these classes of outages and deratings are the most likely to be used to physically withhold units in an attempt to raise prices. Figure 83 shows the average magnitude of the outages and deratings lasting less than 30 days for the year and for each month during 2014.

Figure 83: Short-Term Outages and Deratings

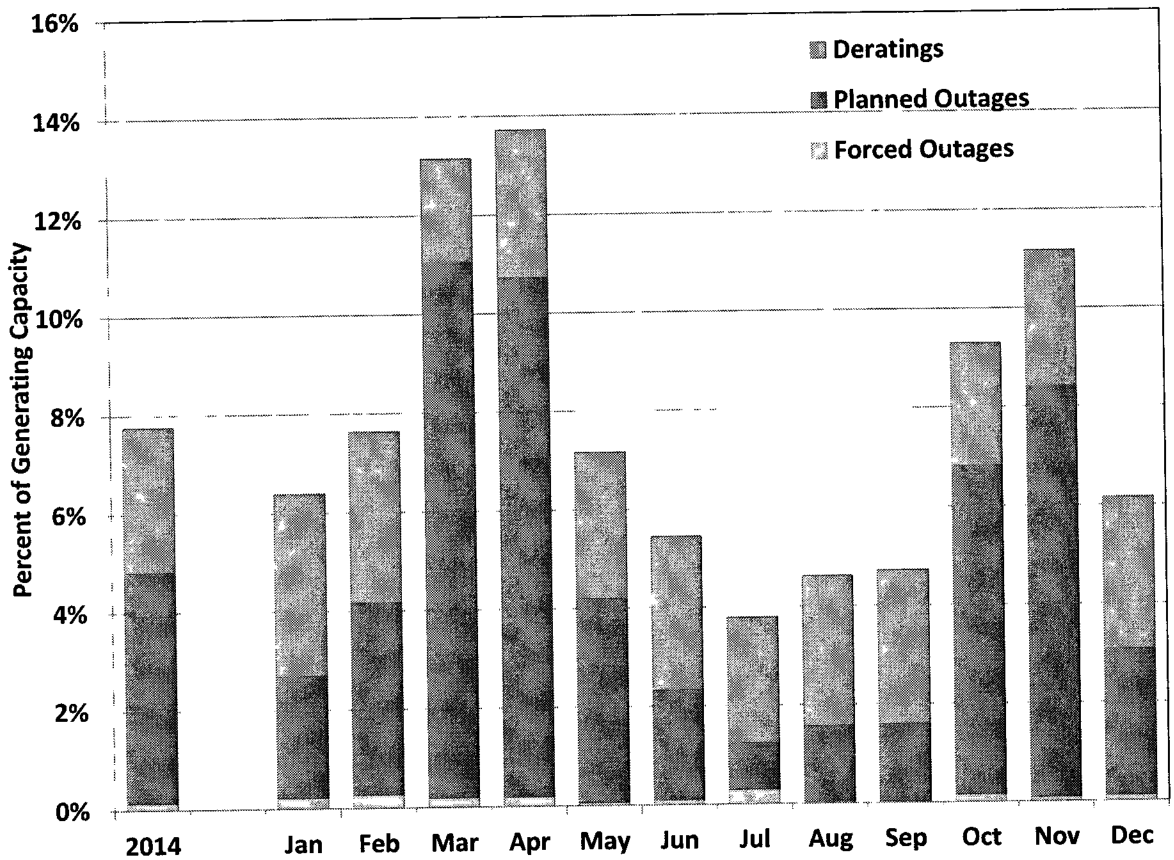


Figure 83 shows that total short-term deratings and outages were as large as 13.7 percent of installed capacity in April, and averaged less than 5 percent during the summer. Most of this fluctuation was due to anticipated planned outages. The amount of capacity unavailable during 2014 averaged 7.8 percent of installed capacity. This is an increase from the 7.0 percent experienced in 2013, and the 5.0 and 6.0 percent experienced in 2012 and 2011. Overall, the fact that outages and deratings are lowest during the summer when load is expected to be highest is consistent with expectations in a competitive market.

2. Evaluation of Potential Physical Withholding

Physical withholding occurs when a participant makes resources unavailable for dispatch that are otherwise physically capable of providing energy and that are economic at prevailing market prices. This can be done either by derating a unit or declaring it as forced out of service. Because generator deratings and forced outages are unavoidable, the goal of the analysis in this subsection is to differentiate justifiable deratings and outages from physical withholding. Physical withholding is tested for by examining deratings and outage data to ascertain whether the data are correlated with conditions under which physical withholding would likely be most profitable.

The RDI results shown in Figure 79 and Figure 80 indicate that the potential for market power abuse rises at higher load levels as the frequency of positive RDI values increases. Hence, if physical withholding is occurring, one would expect to see increased deratings and outages at the highest load levels. Conversely, because competitive prices increase as load increases, deratings and outages in a market performing competitively will tend to decrease as load approaches peak levels. Suppliers that lack market power will take actions to maximize the availability of their resources since their output is generally most profitable in peak periods.

Figure 84 shows the average relationship of short-term deratings and forced outages as a percentage of total installed capacity to real-time load level for large and small suppliers. Portfolio size is important in determining whether individual suppliers have incentives to withhold available resources. Hence, the patterns of outages and deratings of large suppliers can be usefully evaluated by comparing them to the small suppliers' patterns.

Long-term deratings are not included in this analysis because they are unlikely to constitute physical withholding given the cost of such withholding. Wind and private network resources are also excluded from this analysis because of the high variation in the availability of these classes of resources. The large supplier category includes the five largest suppliers in ERCOT. The small supplier category includes the remaining suppliers.