Attachment A

GE Energy

Executive Summary

Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements

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Electric Reliability Council of Texas

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FOREWORD

This document was prepared by General Electric International, Inc. under contract to Electric Reliability Council of Texas, Inc.

Project Manager:

Reigh A. Walling

GE Energy
One River Road
Building 2, Room 618
Schenectady, New York 12345

GE Project Team:

Venkat Banunarayanan
Amanvir Chahal
Lavelle Freeman
Jerry Martinez
Nicholas Miller
Devin Van Zandt
Mark Walling
Reigh Walling

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EXECUTIVE SUMMARY

A fundamental requirement of reliable power system operation is that the amount of power generation must exactly match, on a near-instantaneous basis, the amount of customer load demand. A category of services, called "ancillary services", are procured by the Electric Reliability Council of Texas (ERCOT) power market to facilitate the operation and balancing of the system. ERCOT currently uses several ancillary services to control system frequency and ensure system reliability. In the past, this imbalance might occur due to the variability of load, inaccuracies in the prediction of load levels, or the unplanned loss of resources. Unlike conventional generation, the electrical output of wind generation plants cannot be dispatched[1], but is inherently variable and imprecisely predictable. Thus, addition of wind generation resources increases the amount of variability and unpredictability that must be addressed in system operations. The integration of increasing amounts of wind generation capacity into the ERCOT system inevitably leads to changing requirements for ancillary services procurement.

The ancillary services in the ERCOT nodal market design are:

- *Regulation Service* – is used to maintain the instantaneous balance between load and generation resources.
- *Responsive Reserve Service* – is generation resources held in reserve to address loss of generation resources and unexpected large changes in generation requirements.
- *Non-Spinning Reserve Service* – are generation resources that can come on line with short (presently thirty minute) notice to compensate for load forecast errors.
- *Replacement Reserves* – are used to commit additional capacity based on forecasted load, either for load balance or congestion.

ERCOT has commissioned GE Energy to perform an intensive study of ancillary services requirements for the system to accommodate large-scale expansion of wind generation capacity. AWS Truewind, LLC, (AWST) was a major co-contributor to the study. The results provide the information needed to guide ERCOT and the PUCT in evaluating the reliability implications of large-scale wind generation penetration, and to develop the procedures and protocols for ancillary services procurement needed to strike the proper balance between system reliability and economic operation of the system.

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[1] Wind generation can be "turned down", or curtailed, from its potential output, but cannot be increased beyond the power level provided by the existing wind velocity. Curtailment "spills" non-recoverable energy., thus curtailment on a continuous basis to render a wind plant equally dispatchable as a conventional plant is not practical. Where appropriate wind plant controls are installed, wind plant turndown can potentially be used to provide regulation service in certain circumstances.

The specific objectives of this study are to:

1. Quantitatively assess the impact of various wind development scenarios on the levels of ancillary services required.
2. Evaluate the methodology used by ERCOT to determine the amount of ancillary services required, and recommend improvements to that methodology where appropriate.
3. Estimate the impact of wind generation on the costs to procure ancillary services.
4. Identify changes to current procedures or new procedures required for operations with impending severe weather conditions.

Study Approach

The study focuses on five wind penetration scenarios that have been defined by ERCOT, ranging from zero to 15,000 MW of wind capacity. Although this 15,000 MW level of wind generation will take several years to develop, and the present wind capacity is on the order of 5,000 MW, these wind scenarios are applied to a system model representing 2008 load levels and generation composition for consistency. The 15,000 MW of wind generation applied to the 2008 loading results in a 23% penetration on a nameplate wind generation capacity to peak load basis. This is equivalent in terms of wind penetration to 18,456 MW of wind generation applied to the forecast 2017 system load.

The allocation of wind generation capacity by Competitive Renewable Energy Zones (CREZ) was defined by ERCOT. Table 1 lists these allocations, and Figure 1 shows the geographic locations of the CREZs. Wind generation profiles, on a one-minute resolution, were produced by AWST for a two-year period based on the meteorological conditions present in the years 2005 and 2006. Day-ahead wind generation forecasts, with hourly resolution, were also synthesized by AWST for the same period. ERCOT provided system load history, with one-minute resolution for the same two years, as well as day-ahead hourly load forecasts. Thus the wind and load were described by fully synchronized data. The load and load forecast data were scaled up to reflect 2007 and 2008 levels.

The study performs sequential time-series modeling of the wind and load behaviors, as well as the processes used to forecast both wind and load. Extensive statistical analyses are used to characterize the wind and load variability. Detailed modeling is performed of ancillary service deployments to determine both the amount of ancillary service required to be procured as a function of wind penetration, and to assess the suitability of procurement procedures. System-wide power production simulation is performed to determine the ability of the system to provide ancillary services, as well as to estimate the costs of these services.

The impacts of wind generation on ancillary service requirements cannot be evaluated by examining wind generation output characteristics independently from the simultaneous behavior of the load. Factors causing inaccuracy in wind forecasting may also affect load forecasting (e.g., arrival time of a cold front). Operationally, the dispatchable generation output must conform to the characteristics of the *net load*, defined as the aggregate customer load demand minus the aggregate wind generation output. The fundamental approach of this study is to analyze the **net load** variability and the resulting impacts on ancillary services requirements brought on by increasing penetrations of wind generation.

Table 1 - Wind Capacity Allocation by CREZ

	Wind Development Scenario			
CREZ Zone	**5000 MW**	**10,000 MW (1)**	**10,000 MW (2)**	**15,000 MW**
none	120	120	120	120
2	60	1,560	1,560	2,340
4	0	1,500	0	0
5	355	1,355	1,355	1,355
6	400.5	400.5	400.5	1,278.3
7	65	65	65	97.5
9	814	1,314	1,314	1,971
10	2,464.5	2,964.5	2,964.5	4,446.8
12	400	400	400	600
14	160	160	160	240
15	60	60	60	90
19	101	101	101	211.5
24	0	0	1,500	2,250

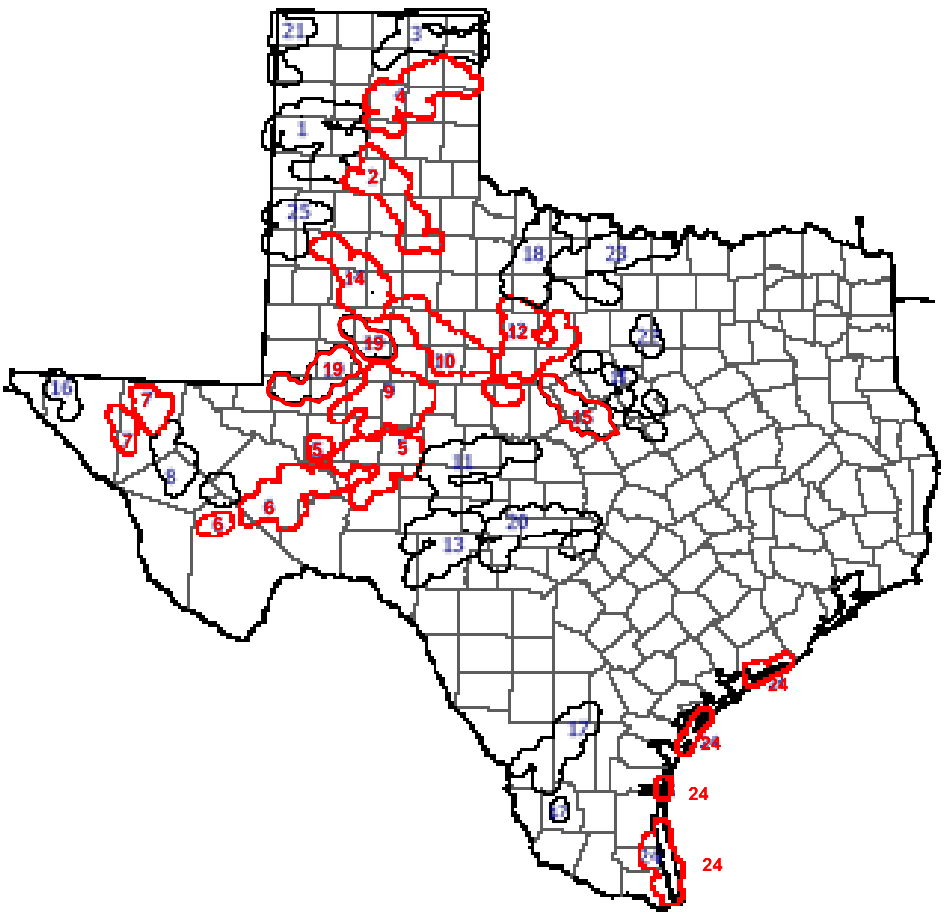

Figure 1 - CREZ map, zones included in the study are shown in red.

The key assumptions in this study are:

- Transmission constraints are ignored. Policy is to develop transmission to support the wind generation additions, so today's transmission constraints are not necessarily relevant to the future.
- The make-up of the non-wind generation fleet in ERCOT (i.e., the percentages comprising single cycle gas turbines, coal, nuclear, etc.) is assumed to remain the same as it is today.

Other assumptions are documented in the main report.

Net Load Variability

Wind generation in Texas has a diurnal component of variation that tends to be anti-correlated, or out-of-phase, with the daily load curve. Wind generation output tends to be the greatest at night and least in the daytime, with wind generation tending to drop sharply in the morning when load is rising quickly, and increase sharply in the evening when load is dropping. The inverse-phase relationship appears to be stronger in the summer than during other seasons. The winter afternoon load rise tends to coincide with a general increase in wind production, but there are times when wind is also ramping down in this period. Figure 2 illustrates the cyclic patterns of load, wind generation, and net load for the month of April.

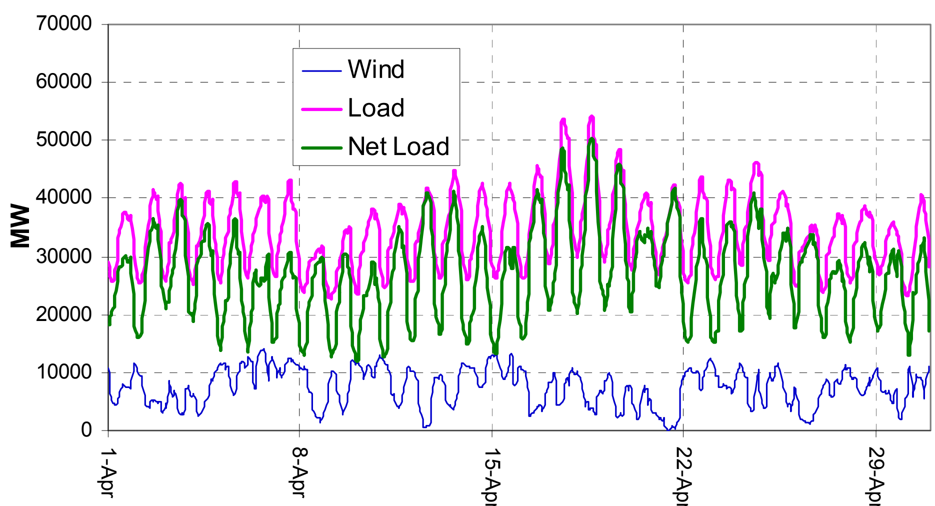

Figure 2- Load, 15 GW of wind generation, and net load for April of study year

The variability of net load is much less than the sum of the variabilities of load and wind generation considered in isolation. Net load variability increases linearly with wind generation capacity. For longer time spans (more than five minutes), net load variability is primarily driven by the long term ramp, but in shorter time spans there is an incremental component due to stochastic variation. With the same wind generating capacity, the incremental variability due to wind increases as the time span becomes longer, but appears to taper off, and appears to saturate at longer timeframes as shown in Figure 3.

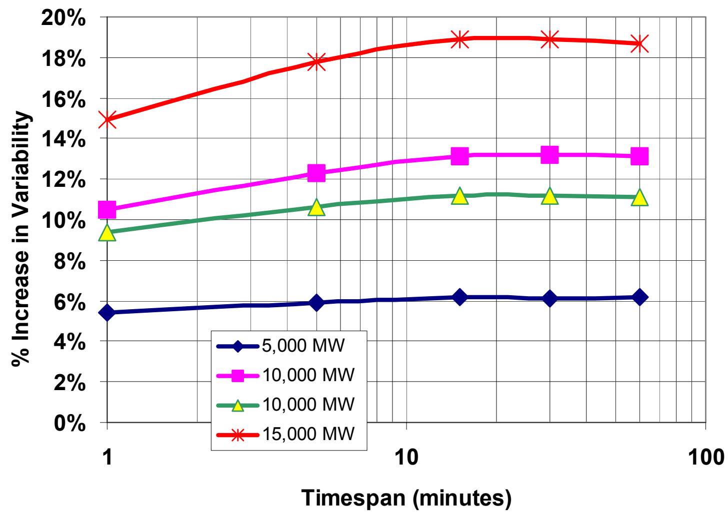

Figure 3 - - Increase in variability, relative to load alone, due to wind generation capacity as a function of time span

Wind generation tends to have a greater overall impact on variability in the summer, late spring and early fall, but variations in winter and early spring tend to be more operationally significant due to the low net load levels. The instantaneous wind generation penetration reaches 57% of served load during low-load periods with high wind, when the wind generation capacity reaches 15,000 MW. The minimum net load, served by the non-wind generation, is reduced by 56% during this period.

Net Load Predictability

The impact of wind on the accuracy of day-ahead prediction was studied by comparing net load forecast error under the various wind generation scenarios with day-ahead load forecast errors. Predictability was analyzed by time-of-year and time-of-day using various statistical techniques.

The results revealed that, load and wind generation forecast errors are virtually independent; they do not systematically coincide or reinforce each other. It is unlikely for the most severe load and wind errors to occur in the same hour.

Net load forecast accuracy decreases with increasing wind penetration, as shown by the increasing error metrics in Figure 4. The larger wind forecast errors tend to be under-forecast errors, which skew the frequency distribution of the net load in the direction of generation over-commitment, as shown in Figure 5. This results in an operating cost penalty, in contrast to under-under-forecast errors which result in decreased system security.

Extreme net-load forecast errors tend to be larger in non-summer months, than summer months. Across all seasons, during the morning load rise hours, net load tends to be generally over-forecasted relative to load alone. With wind generation, late evening hours tend to have lower net load forecast accuracy (relative to load-alone forecast accuracy) and incrementally larger extreme net load under-forecast errors, which may lead to under-commitment of resources. However, these are typically the hours of the day when resource needs are low. During afternoon to early evening (peak) hours during summer and fall, there are incrementally larger net load under-forecast errors with wind generation. The size of these errors, relative to load errors, are such that they may potentially lead to under-commitment of resources during peak load times when they are most needed.

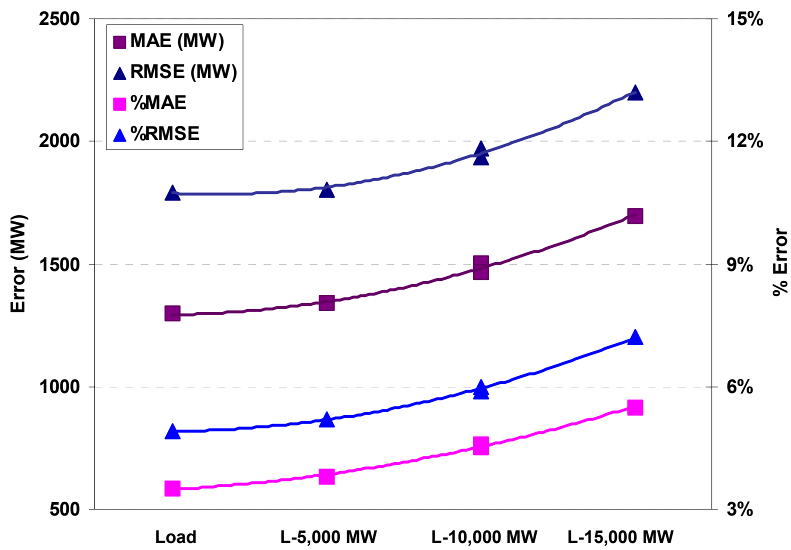

Figure 4 - Trend in net load forecast error (MAE is mean absolute error, and RMSE is root-mean-square error, which tends to accentuate large error values.

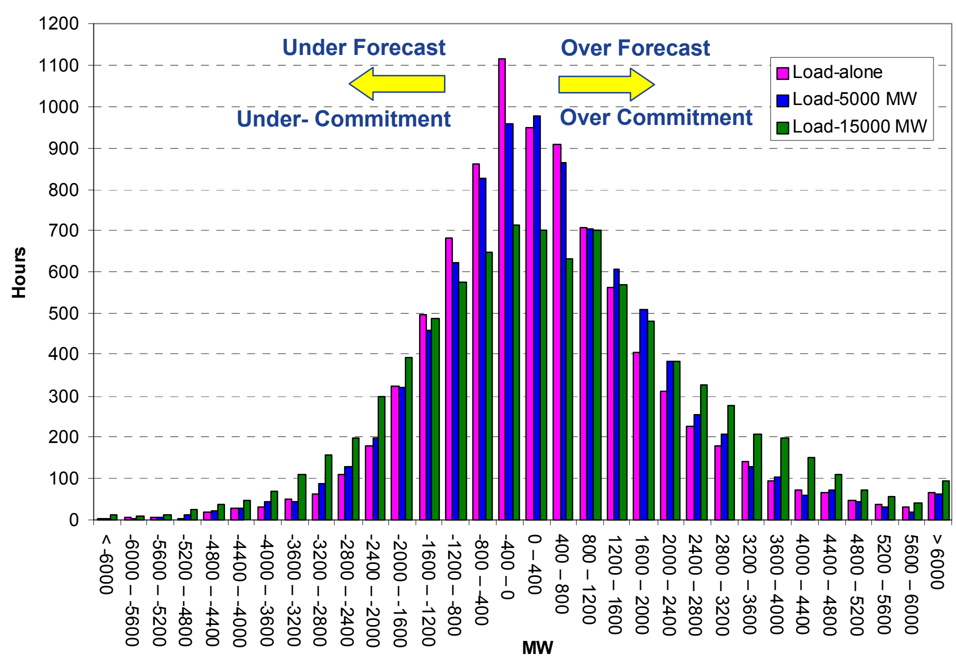

Figure 5 - Distribution of net load forecast errors over the study year

Impacts of Wind on System Energy Production

Economic simulation was performed of the ERCOT system in order to determine the operational impact of various levels of wind generation on the balance of the system generation. Production simulation, using the GE MAPS program, revealed the changes in the hourly spot prices, or marginal cost of energy, and the hourly value, or opportunity cost, of spinning reserves for each of the wind penetration scenarios. Economic simulation was also used to examine the influence of wind generation output forecasts on operating costs.

Results show that increased wind energy production is primarily offset by decrease in total annual production of combined-cycle gas turbine plants (assuming constant system load). For every 1000 MWh of wind generation, combined-cycle plant energy output drops approximately 800 MWh. The annual energy outputs, by generation type, are shown in Figure 6. Nuclear and hydro units are not shown as their annual outputs are virtually unaffected.

During light load periods with high wind levels in the 15,000 MW wind generation capacity scenario, combined cycle plant commitment and dispatch levels are reduced to near zero during the overnight hours. Even coal plants see significant turn-downs in these periods.

The decrease in total system energy production cost, per MWh of wind energy produced, remains nearly constant between $53/MWh and $55/MWh for the 5,000 MW through 15,000 MW wind generation capacity scenarios.

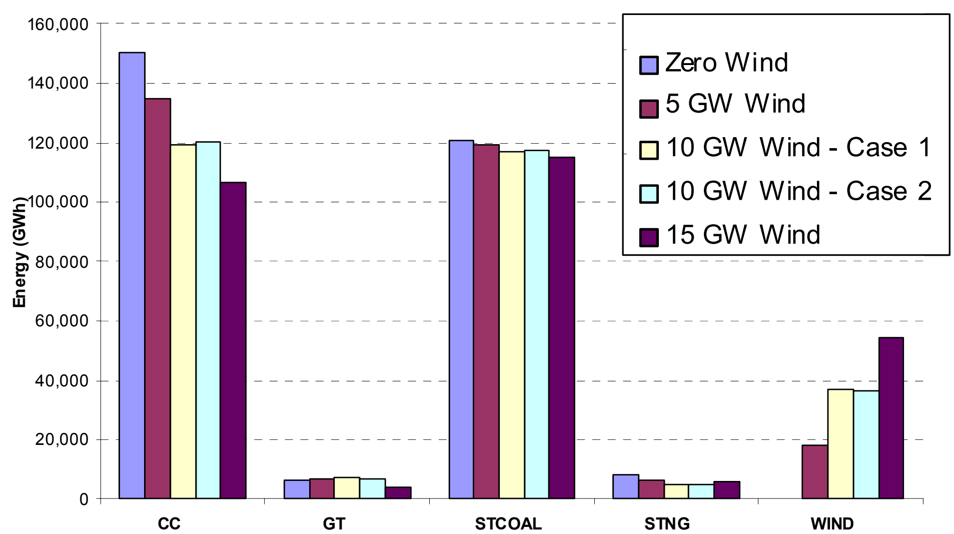

Figure 6 - - Generation by type.

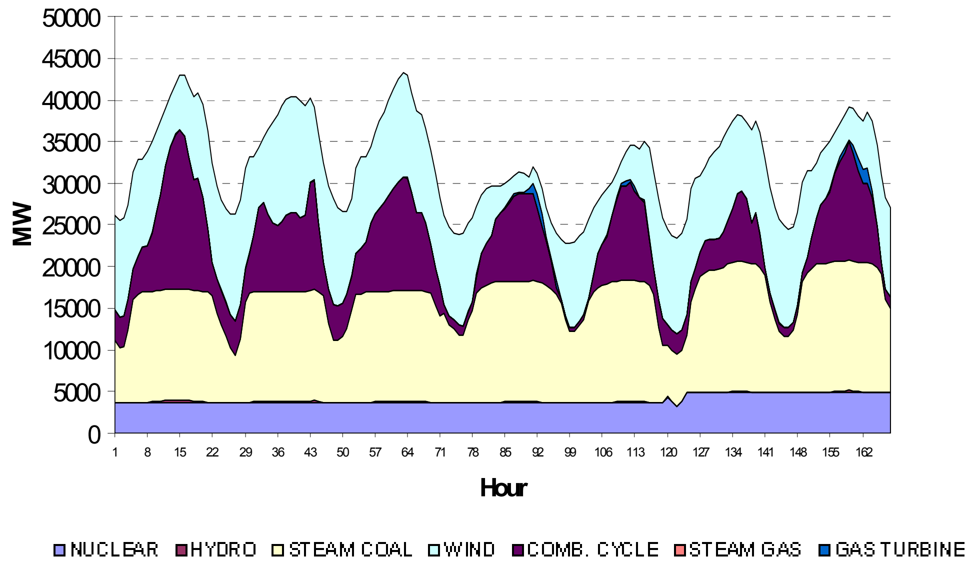

Figure 7 - Dispatch for peak wind generation output week, 15 GW wind generation capacity scenario.

In general, as the wind generation penetration increases, it displaces the higher cost thermal generation and reduces the overall spot price of energy. In some cases the spot prices are slightly higher due to the imperfections in the state-of-the-art forecast used.

Results of the MAPS simulations showed that the accuracy and utilization of day-ahead wind generation output forecasts has significant impact spot prices. Compared to the present “state-of-the-art” wind forecast accuracy, a perfect forecast would raise the prices for nearly all hours. If wind forecasting is totally ignored in the day-ahead unit commitment, spot prices are decreased dramatically due to over-commitment of thermal units.

Regulation Service Requirements

The incremental regulation requirements due to wind generation are highly correlated to the multi-hour ramp rate of wind generation. This ramping impact is more significant to regulation than the increase in stochastic “noise”. The overall tendency is for average up- and down-regulation deployments to increase linearly with wind generation capacity, reaching 18 MW with 15,000 MW of wind. The 98.8th percentiles of deployment, however, increase 54 MW (23%) for up-regulation and 48 MW (20%) for down-regulation. Figure 8 shows the frequency distribution of changes in hourly maximum regulation deployments between the zero wind and 15,000 MW wind scenarios.

Regulation deployment changes, due to wind, vary greatly for different times of day and seasons. The impact of wind generation on up-regulation procurement is greatest in the summer mornings and evenings all year. Between zero wind and 15,000 MW of wind generation capacity, up-regulation in the evening (1800) increases 65%. On a percentage increase basis, the overnight hours have a large regulation increase 52% over the small amount required without wind. The period with the greatest regulation requirements for load alone (zero wind), mornings, has an increase of 26% when 15,000 MW of wind is added to the system. Down-regulation procurement requirements are increased in the evening all year, increasing 32% between the zero wind and 15,000 MW scenarios. The variation of regulation requirements with wind penetration, for selected critical time periods, are shown in Figure 9.

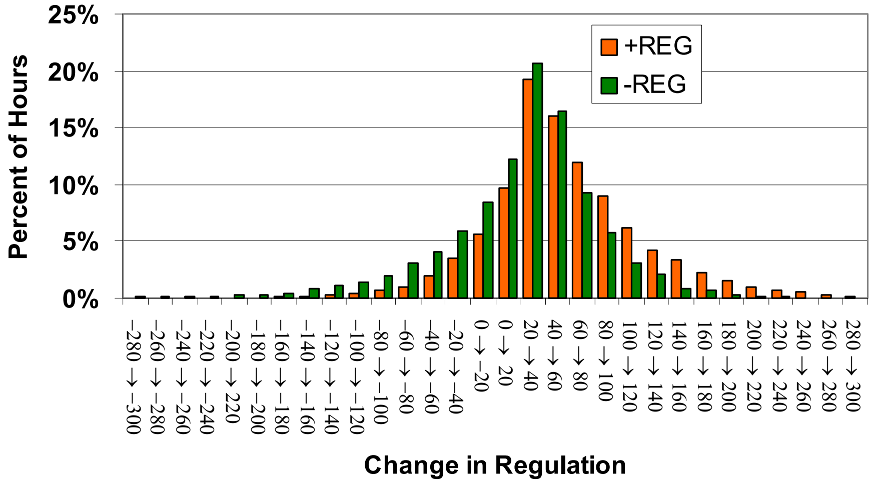

Figure 8 - Frequency distribution of changes in hourly maximum regulation deployments between the 15,000 MW wind scenario and the zero wind scenario.

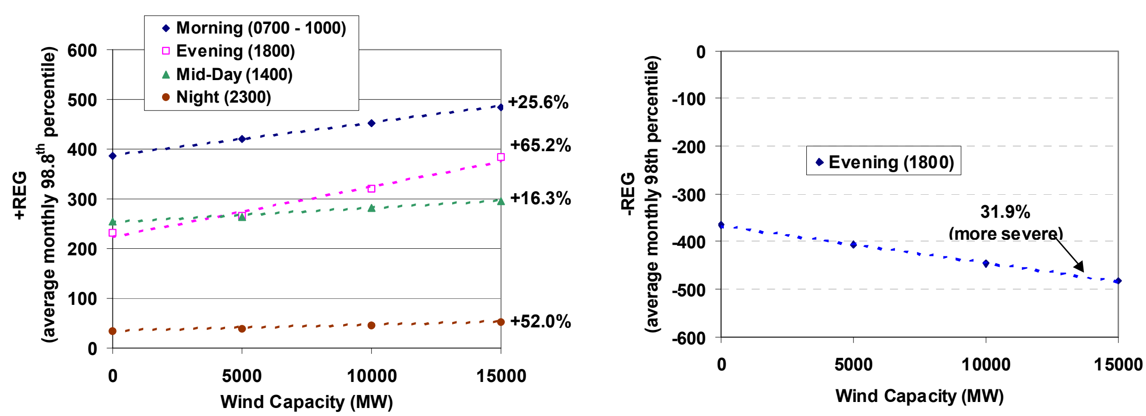

Figure 9- Up-regulation (left) and down-regulation (right) deployment (average 98.8th percentile) as a function of wind generation capacity. (Down regulation is plotted as a negative value.)

Regulation Service Procurement

By and large, the present ERCOT regulation procurement methodology continues to be adequate with a large penetration of wind capacity in the system, from the standpoint of procuring sufficient regulation service. Procurements continue to cover 98.6% to 98.8% of the deployment requirements, as planned for in the methodology. There are no periods where the wind generation causes a significant increase in under-procurement frequency.

The average and root-mean square measures of under-procurement magnitudes, the amount of regulation required that exceeds the amount procured, increase on a MW basis with wind capacity. However, when viewed relative to the amount of regulation procured, the under-deployment magnitude remains the same for up-regulation and decreases for down-regulation.

The study assessed steady-state levels of wind generation penetration. The present regulation procurement methodology may maintain accuracy when there are large year-to-year increases in wind generation capacity. An improved approach to factor in this growth has been detailed in the report.

Incorporation of day-ahead wind forecast information into the regulation procurement methodology may also be able to reduce the amount of regulation procured, while retaining the accuracy of procurement. These improvements require a break from the current practice of procuring a constant amount of regulation service for a given hour of day for a month. Adjustments can be made to the regulation procured based on the forecast wind generation ramp rate and forecast wind variability.

Regulation Availability and Cost

There appears to be sufficient up-regulation range available for all hours with all of the wind generation scenarios investigated. There are a limited number of hours per year, at wind generation capacities greater than 10,000 MW, when there is insufficient maneuverability of committed generation to meet down-regulation requirements. An example of down-regulation inadequacy, assuming strictly economic unit commitment and dispatch, is shown in Figure 10. There are various ways that the down-regulation can be provided, including modification of unit commitment and dispatch for these periods.

The total regulation service procured in a year increases with wind generation capacity. However, increased wind capacity tends to reduce the per-MWh costs for non-wind generating units to provide regulation service. The increased requirement for regulation service is more or less offset by the decreasing per-MWh price, yielding a cost of regulation per MWh of wind generation that is very small, ranging between –\$0.18/MWh to +\$0.27/MWh, depending on the wind capacity scenario and wind forecast accuracy assumptions.

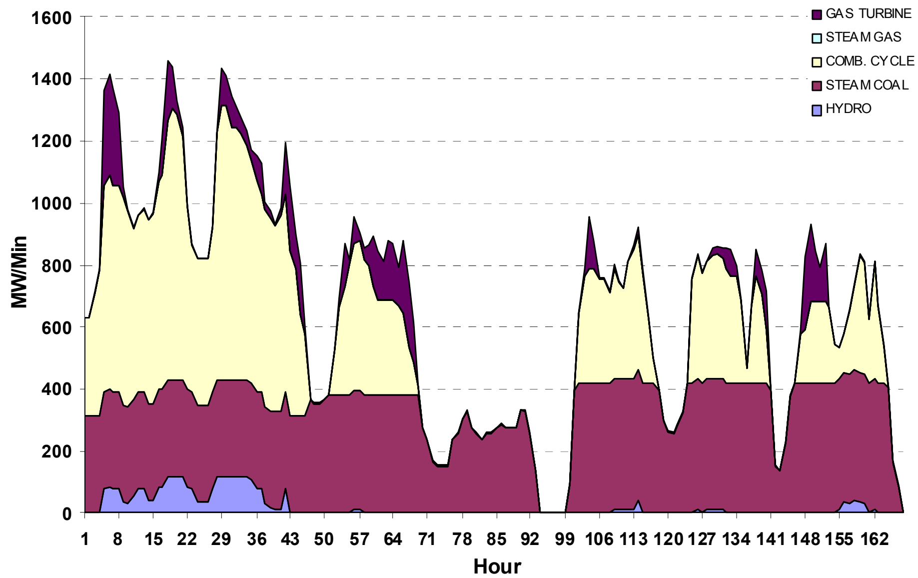

Figure 10 - Regulation ramping capacity provided, by generation unit type, for the minimum-load week in the 15,000 MW wind generation capacity scenario.

Extreme Weather Events

Geographic diversity of the wind generation limits the rate at which aggregate wind generation output can change. Extreme changes in wind occur as rapid ramps, not as abrupt changes that occur for a conventional power plant trip. Extreme wind generation output changes are almost always due to predictable weather phenomena, and are more likely to occur in the morning, and in the evening during winter.

The frequency and severity of extreme short-term (15 minute to one hour) wind generation output changes increase at a faster than linear rate with increasing wind generation capacity, as shown in Figure 11.

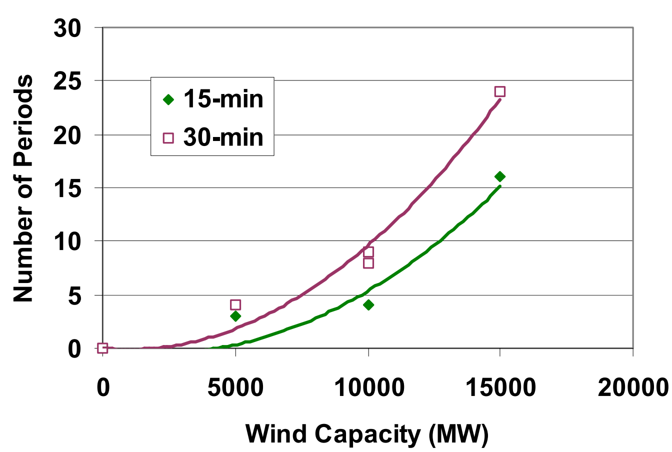

Figure 11 - Number of periods where the net load increase, over 15 and 30 minute periods, are greater than the most-severe net load increase for load alone.

Based on meteorological analysis, the maximum 30-minute drop in wind generation is predicted to be 2836 MW for the 15,000 MW wind generation capacity scenario, with a mean recurrence of once every three to five years. Based on analysis of the modeled wind production data, a 30-minute drop of approximately 2400 MW might occur once per year.

For the 15,000 MW wind scenario, a 30-minute change in net load, greater than the maximum 30-minute change for load alone, occurs approximately 24 times per year. The maximum 30-minute rise in net load is 4502 MW for this wind generation capacity scenario, compared to 3101 MW for load alone.

Responsive and Non-Spin Reserve Services

Responsive Reserve Service (RRS) has been employed by ERCOT for both load changes in excess of regulation procurement, and generation contingencies. These two fundamental needs for RRS, distinct in a system of conventional loads and generation, effectively merge together when non-dispatchable wind generation is added to the system. Individual wind generator unit trips are insignificant to the ERCOT system. Wind generation, however, is subject to uncontrollable output decreases in the same way that system load is subject to uncontrollable increases. Both wind generation decrease and load increase are continuous (i.e., ramping) events, not abrupt changes like generation trips. Thus, wind generation extreme output drops are like a load increase, despite the fact that they constitute a generation "contingency".

Unpredicted load changes, occurring over a period longer than thirty-minutes, can be accommodated by calling up Non-Spinning Reserve Service (NSRS) units. ERCOT does not presently procure NSRS for all hours, but limits this procurement to periods identified as "high risk". ERCOT presently defines "high risk" as periods when "hot weather, cold weather, or uncertain weather is expected, and when amounts of spinning reserve less than 4,600 MW (including that used for RRS) are projected". These criteria are focused on the load behavior. Increased penetration of wind generation, acting as a "negative load", suggests that additional criteria for wind variability need to be included in the high-risk period definition.

RRS Requirements

RRS requirements are driven by system reliability, and must consider the probability and severity of events causing unanticipated changes in generation or load over a short period of time. Because the present ERCOT RRS requirement of 2300 MW is based on loss of the two largest generating units, the present standard is implicitly based on the joint probability of two such trips. Unlike large plant trips, which are discrete events, there is a continuous relationship between the magnitude and probability of unanticipated wind generation output changes, just as there is a similar relationship for load changes.

With significant wind penetration, RRS requirements should be determined considering the joint probabilities of generation trips and unanticipated changes in load and wind generation output. Because load and wind generation changes are fast ramps, their magnitude for determining RRS requirements are relevant only up to the power change that can occur within the time until other resources, such as NSRS or re-dispatch of committed units, can respond.

Wind generation extreme changes are concentrated into particular times of day and seasons. Thus, RRS requirements with high wind penetration should be temporally variable, on an hourly and seasonal basis, to minimize system operating cost while maintaining reliable operation. In addition to standing patterns, the RRS procurement should be adjusted for periods of specific risk.

Tradeoffs Between RRS and NSRS

Fast drops in wind generation output are a fast ramp event more equivalent to an anomalous load rise and RRS need only be procured to cover these events to the degree that they cannot be covered by NSRS. The shorter the NSRS startup time, the smaller the RRS procurement required. It is possible that a change in NSRS startup time requirements could be economically attractive. However, a change of ERCOT's NSRS startup time requirement may be disruptive as existing units participating in the NSRS market are likely to have been configured assuming the present thirty minute startup time. A possible solution is to develop an additional "quick-start non-spinning reserve" service with a shorter startup criterion. Units that are capable can participate in this market, and this will incent future generating unit additions or modifications that permit quick starting.

Periods of Risk

Extreme wind generation changes are generally caused by weather conditions that are forecastable. Although wind generation forecast might not predict the timing and magnitude of events with total precision, forecasters are able to indicate periods of risk when weather conditions are prone to severe wind generation output changes. Therefore, RRS requirements should be adjusted based on forecast risk. ERCOT's present Operating Guides allow RRS to be increased for periods of "extreme conditions". With high wind generation penetration, it is important that identified periods of wind volatility should be included in the definition of extreme conditions.

ERCOT's ancillary services methodology calls for procurement of NSRS for defined system conditions related to month of year and ambient temperature conditions in the large load areas. Wind generation forecast uncertainty needs to be added to this list of conditions where NSRS is required. On a day-ahead basis, the wind forecasters should be able to assess the uncertainty in their forecasts and ERCOT can procure NSRS accordingly.

Because present commitment schedules are based on the mean (50% confidence level) forecast for system load, and both load and wind are subject to forecast error, it is not consistent to use the mean forecast for load and a biased forecast (e.g., 80% confidence level) for wind generation. The system would be more efficiently operated if the mean, unbiased forecast were used for both wind generation and load, and the appropriate reserves procured according to the total uncertainty.

General Conclusions

Uncertainty and variability are an inherent part of power system operations; power system infrastructure and operating practices have developed around the requirement to accommodate variability and uncertainty. Addition of wind generation capacity increases both, but does not greatly change their nature. The tools of operation used to address these attributes for load alone are expandable to address the net load resulting from wind generation partially offsetting connected system load.

An overall observation in this study is that through 5,000 MW of wind generation capacity, approximately the level of wind capacity presently in ERCOT, wind generation has limited impact on the system. Its variability barely rises above the inherent variability caused by system loads. At 10,000 MW wind generation capacity, the impacts become more noticeable. By 15,000 MW, the operational issues posed by wind generation will become a significant focus in ERCOT system operations. However, the impacts can be addressed by existing technology and operational attention, without requiring any radical alteration of operations.

While ERCOT's present regulation procurement methodology is adequate in terms of procuring sufficient regulation service, there are improvements that can be made which are expected to reduce the amount of procurement while maintaining sufficiency. Most notable is the inclusion of wind generation forecast information. Also, adjustments are advisable to accommodate year-to-year wind generation capacity growth.

Proper use of wind generation forecasting is of critical importance to reliable and efficient operation of the system. In addition to making efficient unit commitment decisions, wind forecasts allow ancillary services procurements to be adapted to actual conditions. The risks of extreme weather events are generally very predictable, and appropriate operating decisions can be made to pre-emptively reduce their impact.

High penetration of wind generation reduces loading on thermal units while increasing the requirements for these units to provide ancillary services. Beyond ERCOT's present level of wind generation capacity, there will be infrequent periods when unit dispatch and commitment may need to be altered to provide ancillary services. Through the 15,000 MW wind generation capacity scenario investigated, these events become progressively more frequent.

Recommendations

Wind generation forecasts are essential to efficient and secure operation of power systems with large wind power penetration. ERCOT is encouraged to obtain, and integrate into system operations and ancillary services procurement, wind generation forecasts that not only assess the predicted wind generation for each hour, but also the degree of uncertainty in each hour's forecast and a forecast of the expected wind variability on a sub-hourly basis. Wind generation forecast accuracy improves significantly as the time horizon shortens. ERCOT should consider introducing a step between the day-ahead and hour-ahead commitments. The one to six hour ahead timeframe is critical to providing better system reliability and to assure sufficient unit commitment during those periods when the uncertainty of wind forecasts may cause operational problems. Many thermal units can respond to a four-hour ahead schedule adjustment, for example, based on revised load and wind forecasts.

Wind generation has characteristics resembling load, but with a negative sense. ERCOT presently uses a 50% confidence level load forecast in system operations. To be consistent, 50% confidence level (unbiased) wind forecasts should be used as well to calculate the net load forecast to which non-wind generation is committed and dispatched. There is no fundamental difference in the nature and development over time of wind and load forecast errors; both evolve. Although wind forecast error are greater than load forecast errors, on a percentage basis, uncertainty in the wind forecast is more appropriately addressed by procuring ancillary services than by distorting unit commitment. For example, non-spin reserves could be procured to cover the difference between the unbiased wind production forecast and the forecast wind production at a more conservative confidence level. Using a biased forecast would force more dispatchable generation to be committed, removing the operational flexibility to address the wind forecast inaccuracy with less-expensive NSRS instead of what is functionally an increase in spinning reserve.

Conservative levels of responsive and non-spinning reserves, broadly applied over all times, can provide a secure but inefficient system. The risks to system security from large, rapid decreases in wind generation output are not uniformly distributed over time. System efficiency is improved if the procured amount of these reserves is adjusted commensurate with risk factors. Information in this report provides a great deal of information on the general temporal (seasonal and time of day) trends in this risk. These general trends can be used to guide longer-term ancillary service procurement planning (e.g., month ahead). However, day ahead forecasts, and possibly shorter term forecasts, should be used as the basis of ancillary service procurement.

ERCOT should consider introducing a new non-spin reserve service with a startup time of ten to fifteen minutes. This can significantly reduce the amount of responsive reserves needed for identified periods of wind generation drop risk.

The regulation services are presently in amounts that vary over the hours of each day, but with the pattern repeated for all days of the month. Using forecast data, with both wind ramping influence and wind variability (turbulence) considered, the regulation service procurements should be adjusted for each hour on a day-ahead basis.

The results reported here assume that the amount and mix of conventional thermal generation, relative to load growth, will remain constant. It is important that the amount and character of generation capable of delivering ancillary services be tracked. Exit from the market of significant participants could have adverse impacts on the availability and price of ancillary services. A consideration of market design should be providing sufficient incentives to maintain the availability of ancillary services.

The rules and definitions of ancillary services should be continuously reviewed and refined in order to encourage and include a broad range of participants in the competitive ancillary service market. In so far as it is consistent with system reliability, all technologies should be given an opportunity to participate and prove their economic value. This could include load control with sufficient response to provide regulation, energy storage, and wind generation. Wind generation can be very effective in providing down-regulation, when the value of that regulation service exceeds the opportunity value of the wind energy not delivered.

While the pace of wind generation growth in ERCOT is rapid, there is an opportunity for ERCOT to gather data, evaluate potential changes, and implement changes based on real operational data before wind generation capacity reaches the maximum levels investigated in this study. ERCOT is encouraged to collect, analyze, and act on this evolving stream of data. Particular attention should be given to monitoring system operations during periods of low load combined with high wind generation output.

Particular attention should be devoted to thorough analysis of major operational events related to wind generation variability and imprecise predictability. Frequency of such events should be determined and compared to the projections in this study. A meteorological root-cause analysis should be performed for each major event, and reasons for deviations between forecast and actual behavior should be ascertained. As necessary, ancillary services procedures should be updated as actual long-term statistics evolve.