

Figure 6-49 – Relative total annual cost of procured regulation, based on state-of-the-art wind generation forecast used in day-ahead unit commitment.

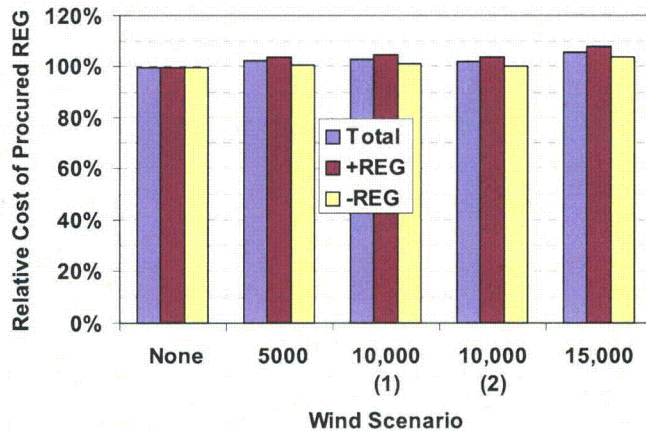


Figure 6-50 - Relative total annual cost of procured regulation, based on a perfect wind generation forecast used in day-ahead unit commitment.

Table 6-6 summarizes the total regulation costs for each wind generation capacity scenario, and shows results for both the “state-of-the-art” and perfect wind forecasts used in day-ahead unit commitment. Figure 6-51 shows the incremental cost of regulation per MWh of wind energy produced.

The incremental costs of regulation appear volatile, subject to differences in sign due to differences in forecast accuracy. The fact is, however, that the incremental per MWh regulation costs are small in all cases and the changes are not of practical significance.

Table 6-6 – Summary of Total Regulation Costs

Wind Capacity (MW)	Reg-Up Cost (\$MM)	Reg-Down Cost (\$MM)	Total Reg. Cost (\$MM)	Total Wind Generation (MWh)	Inc. Cost of Regulation (\$/MWh)
0	\$66.88	\$72.21	\$139.09	0	
State of Art Wind Generation Forecast					
5,000	\$67.90	\$73.21	\$141.11	17,940,311	\$0.112
10,000 (1)	\$71.22	\$78.14	\$149.35	37,037,236	\$0.277
10,000 (2)	\$70.12	\$76.21	\$146.33	36,180,453	\$0.200
15,000	\$61.44	\$67.94	\$129.37	53,933,379	-\$0.180
Perfect Wind Generation Forecast					
5,000	\$69.54	\$72.76	\$139.09	17,940,311	\$0.179
10,000 (1)	\$70.12	\$72.93	\$142.30	37,037,236	\$0.107
10,000 (2)	\$69.36	\$72.49	\$143.05	36,180,453	\$0.076
15,000	\$72.01	\$74.83	\$141.85	53,933,379	\$0.144

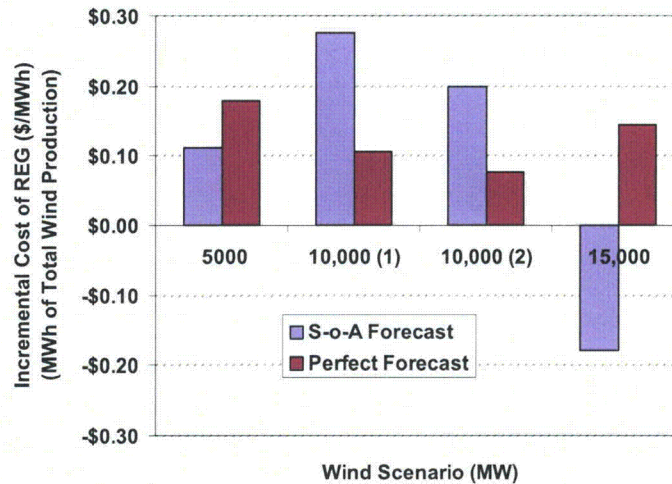
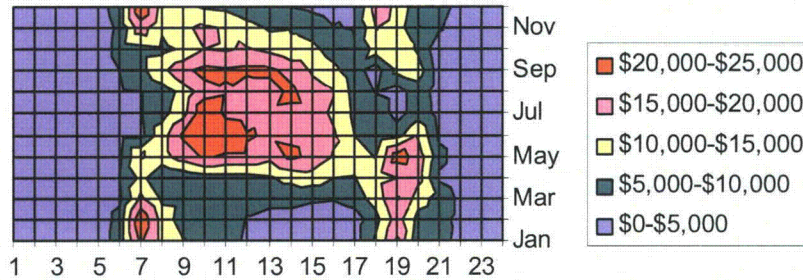


Figure 6-51 – Incremental cost of regulation, relative to the no-wind scenario, per MWh of wind energy produced.

6.5.3. Temporal Characteristics of Regulation Costs

Changes in the costs of regulation, due to wind generation capacity increases, are not uniform across the year. Figure 6-52 show costs of up-regulation by hour of day and month of year for the load-alone and 15,000 MW wind generation capacity scenarios. The differential cost, in percentage of the load-alone value, is shown in Figure 6-53. Similar plots for down-regulation are shown in Figure 6-54 and Figure 6-55. All of these plots assume that a state-of-the-art wind generation forecast is used in the day-ahead unit commitment. This analysis was also performed assuming a perfect forecast, and the resulting plots are provided in Appendix G.

a)



b)

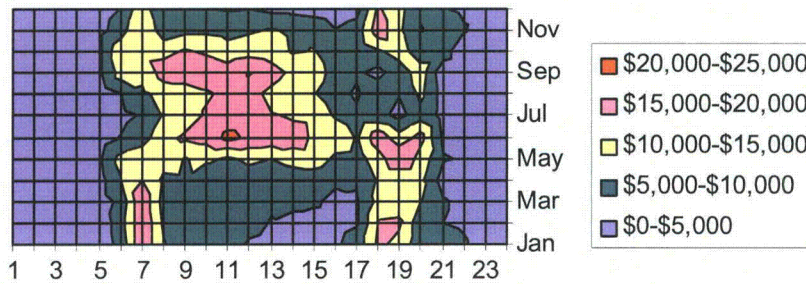


Figure 6-52 – Costs of up-regulation (average \$/hr) by hour of day and month of year for the scenarios with load alone (a) and with 15,000 MW of wind generation capacity (b).

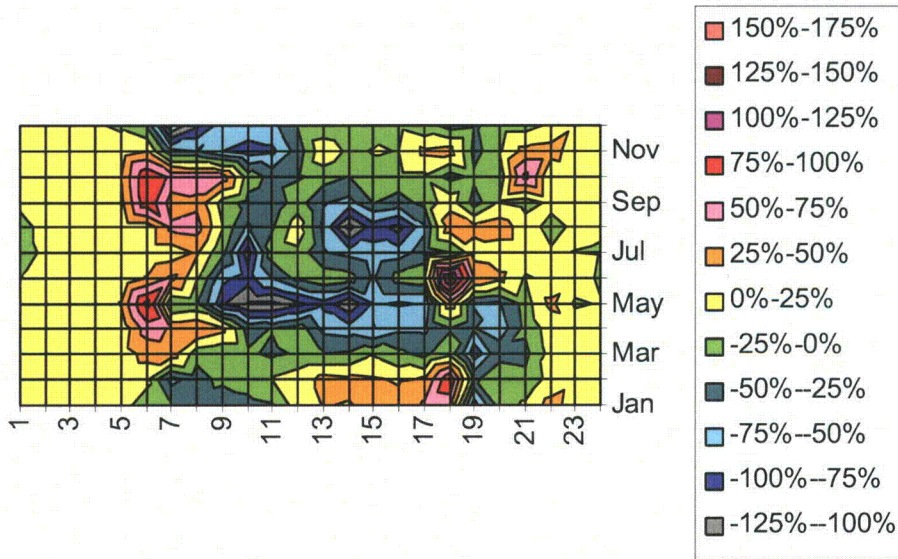
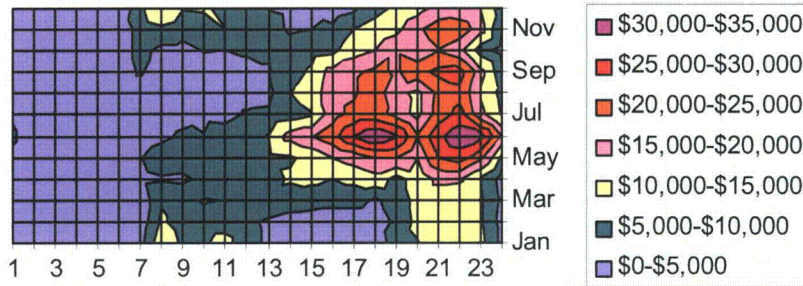


Figure 6-53 – Change in average up-regulation costs, by hour of day and month of year, from the load-alone scenario to the 15,000 MW wind generation capacity scenario. The percentage base is the respective hour and month up-regulation cost for the load-alone scenario.

a)



b)

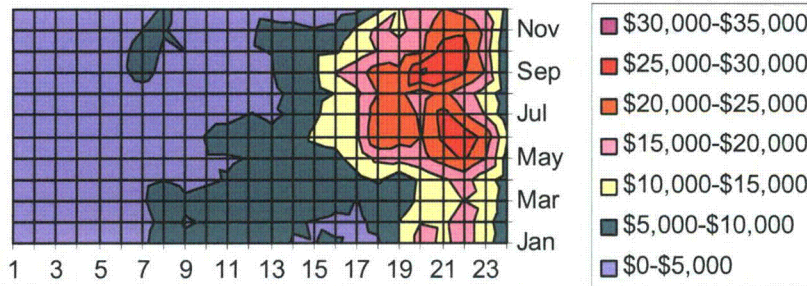


Figure 6-54 - Costs of down-regulation (average \$/hr) by hour of day and month of year for the scenarios with load alone (a) and with 15,000 MW of wind generation capacity (b).

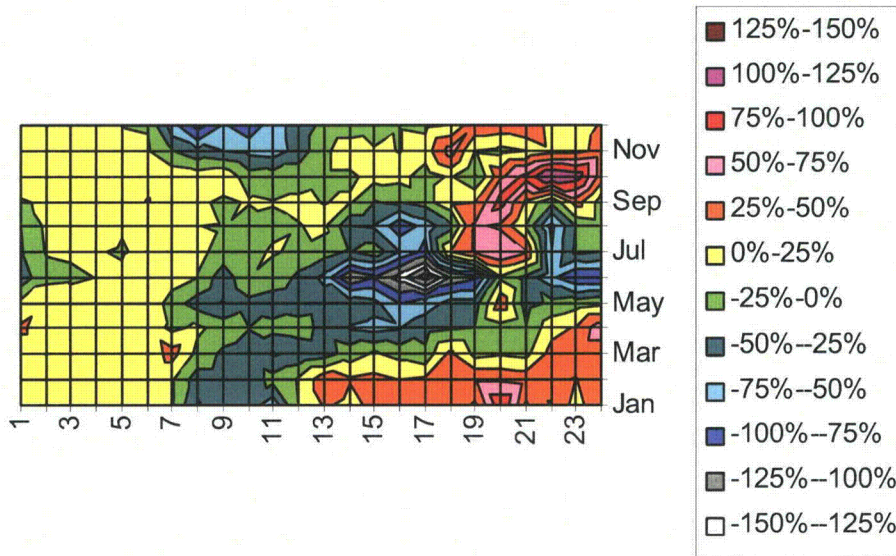


Figure 6-55 - Change in average down-regulation costs, by hour of day and month of year, from the load-alone scenario to the 15,000 MW wind generation capacity scenario. The percentage base is the respective hour and month down-regulation cost for the load-alone scenario.

6.6. Alternatives to Meet Regulation Requirements

There are various means to obtain sufficient regulation range when the economic dispatch does not inherently provide enough. These are:

- Adjust the dispatch of non-wind generation. For example, to increase down-regulation range, a unit can be de-committed and the remaining units dispatched to a higher level to provide more range to their lower limits.
- Allow wind generation units to participate in the regulation market, particularly down-regulation. Because wind units are subject to un-ordered power changes, the definitions and rules of regulation would need to be adapted, and perhaps a unique regulation service defined specifically for wind generation.

Require up-ramp limits on wind generation for the affected hours. Some wind plant control systems already provide this function.

7. EXTREME WEATHER

ERCOT's present ancillary services protocols define extreme weather on the basis of unusually hot or cold weather in the major Texas load areas. This temperature-based definition is relevant to load, but a system with high wind penetration is also stressed by severe changes in wind generation output due to different types of extreme weather.

In this section, the propensity of the system to experience unusually large and rapid changes of net load, due to wind variations, is explored using two different approaches; one based on meteorological analysis and the other based on outlier analysis of the modeled wind generation data. The information derived from the analysis of extreme wind generation changes is used later in Section 8 to define requirements for the responsive reserve and non-spinning reserve ancillary services.

7.1. Meteorological Analysis

As a key part of the analysis of extreme weather, with respect to wind generation output changes, AWS Truewind (AWST) was tasked to perform an analysis of extreme wind generation changes in Texas and the underlying meteorological basis. Their report is included, in entirety, as Appendix H. In this main body of the study report, key findings of the AWST work are briefly summarized.

The concentration of AWST's work was on analysis of historic events causing more than a 200 MW change in wind generation output over a thirty minute period. Thirty minutes was chosen as a criterion because ERCOT presently requires that units bidding into the Non-Spinning Reserve Service be able to start in thirty minutes. The 200 MW change is on a base of 970 MW of wind generation capacity located at a limited number of sites for which ERCOT could provide historical minute-by-minute wind generation data from 2005 and 2006. Thus, the changes constitute more than 20% change of the somewhat limited sampling of wind generation sites.

Both increases and decreases in wind generation output were considered. Extreme wind generation decreases are more operationally significant to the power system. However, increases in wind velocity can also cause sharp decreases in wind generation output due to wind turbines going into high-wind cutout. Thus, rapid wind velocity increase incidents are equally significant.

7.1.1. Underlying Weather Phenomena

For the extreme wind generation change events identified by AWST, the underlying causes were determined by evaluation of available meteorological observations. Several weather phenomena are identified in AWST's report as causes for significant wind changes:

- **Frontal system, trough, or dry line.** These fronts can extend for over 600 miles, and the frontal line can advance with speeds in excess of 34 mph. These fronts typically cause a rapid increase of wind speed, followed by a slower decay of wind speed.
- **Thunderstorms and convection-induced outflow.** These storms are generally more local in extent, and can move with considerable speed. They can form rapidly and are sometimes difficult to predict.
- **Low-level jets** are a common weather feature in Texas, and can form due to radiational cooling at sunset, or due to a cold front.¹
- **Weakening pressure gradients** cause rapid decrease of wind speed over a potentially large area.
- **Strengthening pressure gradients**, developing high winds that can potentially cause widespread wind turbine cutouts.

7.1.2. Probability and Predictability of Wind Events

AWST's analysis of wind events in Texas is summarized in Table 7-1. In this table, "Ramp up/Ramp down" indicates the number of events in the actual wind plant output data where wind generation output change up or down at least 20% of capacity in thirty minutes. Note that this is for a limited number of wind generation sites, and this sampling does not have the geographic diversity of the CREZ scenarios. The typical events per year is the number of times per year that the given weather event can be expected to occur, but not necessarily with any particular severity.

7.1.3. Extrapolation to the 15,000 MW Scenario

AWST used the historic weather analysis, along with the geographic descriptions of the CREZs and the proposed wind generation capacities in each CREZ, to make an informed estimate of maximum wind generation change events in the 15,000 MW wind generation scenario. The results of this extrapolation are shown in Table 7-2. In this table, the column marked "CREZs affected" indicate the estimated worst-case scenario of adjacent CREZs that could be involved simultaneously in each type of event. The aggregate capacity is the capacity of wind generation in each of the affected CREZs for the 15,000 MW wind generation capacity scenario.

¹ Investigation of large ramp events detected no direct evidence of the involvement of low-level jets as a significant cause. Given the lack of observations needed to directly detect the presence of a low-level jet near a wind farm, at best we can infer the potential for low-level jets since there is only one station in Texas that continuously measures the vertical wind profile in the lower boundary layer. Low-level jets, while potentially significant to the variability of a specific plant, may not be as important to the aggregate production.

Table 7-1 - Summary of weather phenomena associated with ramp events²

	Ramp up/Ramp down	Typical Events per year	Preferred time of day/season	Forecast Lead Time
Frontal Passage	12/3	Around 50	Winter, followed by Spring or Fall, no preference for time of day, although pre-frontal convection usually occurs during evening.	Can usually be forecast days in advance with better accuracy of timing as event approaches. More precise frontal timing can be accurately forecast with a few hours lead time on a given day. Within 2-5 hours of anticipated frontal passage they can be forecast to perhaps within 30 minutes.
Dry Line	4/0	40-50	Spring, Summer. The dryline generally advances east by day, retreats by night	Dry line formation can typically be anticipated a day or so in advance. When formed, dry line passage can be forecast on the local scale a few to several hours in advance.
Troughs	5/1	Around 50	Anytime, no strong seasonal preference, no hourly dependency	Similar to frontal passages, above.
Weakening Pressure Gradient	0/14	80/100	Anytime, no strong seasonal preference, no hourly dependency	Large scale gradients similar to "fronts"; smaller scale gradients related to small scale pressure couplets similar to "convection".
Convective Outflow	14/5	40-60 days in the project area at a given point. Can have multiple outflows from one event.	Spring or Summer, afternoon and evening	Occurrence can be "nowcast" using current data, with a few hours lead. Individual outflows perhaps 20-30 minutes in advance of arrival at a particular site. Probabilities in a region may be forecast a few (2-3) days in advance with good confidence
Stabilization	0/1	unknown	Around sunset	Can be anticipated perhaps a day or two in advance for probabilities.
High Wind	1/1	1	Anytime, preference for cold season	A few hours to several days

² From AWS Truewind Report, *Analysis of West Texas Wind Plant Ramp-up and Ramp-down Events*, included as Appendix H to this report.

Convective events can range from an isolated thunderstorm to a large cluster of storms. While a single storm can be of devastating potential to a small number of wind turbines, the impact on ERCOT-wide wind generation impact cannot be large. A cluster of thunderstorms can affect wind generation sites over a moderate area. AWST estimates that a single such event could affect CREZ 5 and 9 within a thirty-minute period. Severe events can be expected two to four times per year. Fronts and troughs can affect a wider area. The most widespread wind generation impact can be caused by strengthening of pressure gradients between weather systems. The resulting high winds can potentially result in widespread wind turbine cutouts. Such a phenomenon was responsible for the February 24, 2007 event causing rapid wind generation output changes in ERCOT. For the 15,000 MW scenario, AWST conceived a worst-case scenario of this phenomenon affecting nine different CREZs. Given an event of similar severity as the February 24, 2007 event in the 15,000 MW scenario, AWST forecasts that a 2836 MW drop in wind generation could occur over a thirty-minute period. Events of this severity can be expected less often than once per year; AWST estimates a mean recurrence of once in three to five years. . As indicated in Table 7-1, these events can generally be predicted several days in advance.

Table 7-2 - Extreme Events Summary: 15,000 GW Scenario³

Weather Event	CREZs Affected	Aggregate Rated Capacity (MW)	Maximum 30-Minute Ramp (MW)	Frequency (# times approaching max ramp per year)
Convective	5, 9	3251	+1300	2 - 4
Frontal/dry line/trough	5, 6, 9	4529	+1324	2 - 4
Weak gradient	5, 6, 9	4529	-1313	2 - 4
High Wind	2, 4, 5, 6, 7, 9, 10, 12, 14	12,329	-2836	< 1

7.2. Analysis of Modeled Wind and Net Load Data

Large rates of change in wind generation output and net load were identified in the modeled scenario data and analyzed to provide indications of the severity and frequency of occurrence of extreme changes.

7.2.1. Wind Generation Diversity

Similar to the way system load exhibits diversity, the variations of the wind generation portfolio are mitigated by spatial diversity. In Table 7-3, the maximum one-hour drop in

³ *Ibid.*

wind generation output for each scenario is compared with the sum of the non-coincident maximum drops for all the wind sites⁴. The ratio is a coincidence factor. Note that this coincidence factor decreases as the total wind generation capacity increases, due to greater diversity. The second 10,000 MW scenario has a smaller coincidence factor than the first because it has 1,500 MW of capacity in CREZ 24 (South Texas Coast) substitute for the same capacity in CREZ 4 (Panhandle), again, illustrating the value of geographic diversity of the wind generation assets.

Table 7-3 – Coincidence of Wind Generation Output Drops

	Wind Generation Capacity Scenario			
	5,000 MW	10,000 MW (1)	10,000 MW (2)	15,000 MW
Observed max drop for scenario	-1507	-2418	-2242	-3340
Sum of max drops for all sites	-2418	-4979	-4883	-7320
Coincidence factor	0.62	0.49	0.46	0.46

On January 28, 2006, a significant wind generation drop event was observed in ERCOT. Because this is the year on which the study year data were based, the models used to derive the wind generation model reflect the meteorological phenomena that occurred on that date. Figure 7-1 and Figure 7-2 plot the modeled wind generation output for the 15,000 MW capacity scenario, as a function of time, for this date. Figure 7-1 shows wind plant output aggregated by CREZ. Because this event was the result of frontal activity, it affected a number of CREZs in West Texas over a short period of time. CREZ 9 and 10 had the steepest drops. CREZ 24, in South Texas, actually had an increase of wind output for the same period as the West Texas CREZs were dropping, providing partial mitigation. A key observation is that, although this was a severe event, the aggregate effect of such an event is a fast ramp of power, not an abrupt drop such as occurs with the trip of a large thermal generating unit. In Figure 7-2, the modeled outputs of sites in CREZ 10 are plotted. For sites within a CREZ, the output drops for a severe weather event are a near-simultaneous ramp-down.

⁴ Individual actual wind plant sites plus hypothesized sites identified by AWS Truewind for use in constructing the wind generation scenarios.

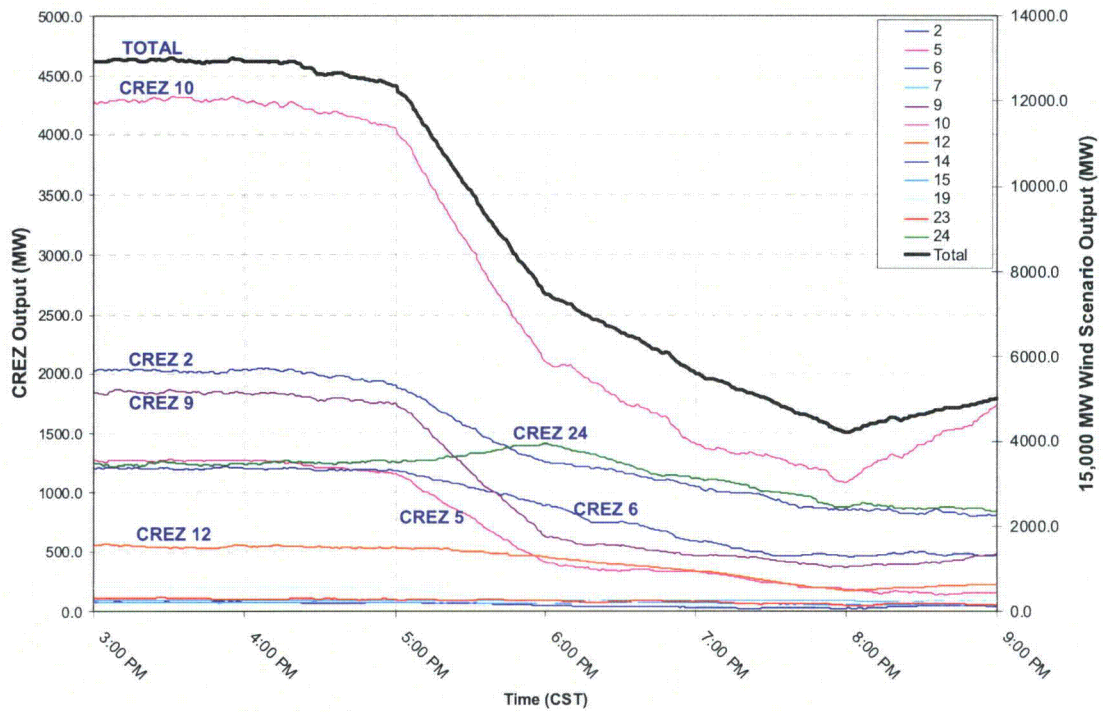


Figure 7-1 – Aggregate CREZ outputs for wind ramp-down event of January 28, 2006.

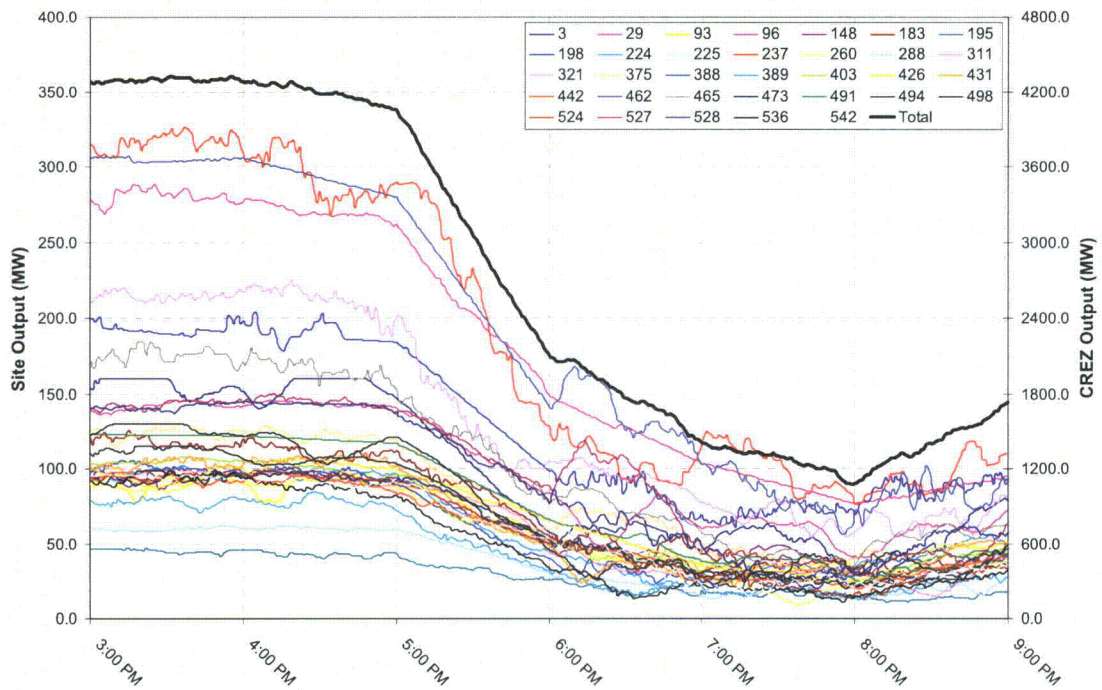


Figure 7-2 - Aggregate wind plant outputs in CREZ 10 for wind ramp-down event of January 28, 2006.

7.2.2. State Transition Matrices

Changes of wind generation output, from one 15-minute period to the next for the entire study year, were processed to define the state transition matrix shown in Table 7-4. This state transition matrix is for the 15,000 MW wind generation capacity scenario. Rows in this matrix indicate the level of average wind generation output at any given period, and columns indicate the average output at the next 15-minute period. Elements in the matrix indicate the probability that the wind generation output will change from the value given by the row to the value indicated by the column.

The elements of the diagonal of this matrix, highlighted in yellow, indicate an average probability of more than 85% that the generation output will remain nearly the same (within the same band of 10% width). Wind generation output is actually most stable when the portfolio is operating close to the maximum capacity. At operating points greater than 80% of capacity, the probability of the wind remaining in the same band is more than 90%.

The elements highlighted in green are the probabilities of the wind generation output increasing to the next higher band, and the elements highlighted in blue indicate probability of dropping to the next lower band. The average probability of the wind generation output decreasing by one 10% band in fifteen minutes are less than seven percent. Changes of more than one band are less frequent than once in 5,000 hours.

Table 7-4 – Fifteen-Minute State Transition Matrix – 15,000 MW Scenario

		Next State (Output, % rated capacity)									
		0-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91-100%
Current State (Output)	0-10%	0.8386	0.1614	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	11-20%	0.0225	0.8602	0.1173	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	21-30%	0.0000	0.0486	0.8445	0.1069	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	31-40%	0.0000	0.0000	0.0598	0.8232	0.1170	0.0000	0.0000	0.0000	0.0000	0.0000
	41-50%	0.0000	0.0000	0.0000	0.0655	0.8176	0.1169	0.0000	0.0000	0.0000	0.0000
	51-60%	0.0000	0.0000	0.0000	0.0000	0.0667	0.8079	0.1253	0.0000	0.0000	0.0000
	61-70%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0641	0.8495	0.0864	0.0000	0.0000
	71-80%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0514	0.8701	0.0785	0.0000
	81-90%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0516	0.9134	0.0350
	91-100%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0791	0.9209

A similar state transition matrix, for changes in 30-minute periods, is shown in Table 7-5. There is an 80% probability that the wind generation output will remain within ±750 MW of the current output. The probability of a 3000 MW (20% of capacity) decrease is small. When the wind generation portfolio is operating at an aggregate output of 60%-70% of capacity (9,000 MW to 10,500 MW), there is one chance in more than 900 that wind generation will drop by more than 3000 MW in the next half hour. At other operating

points, the probability is too small to be indicated by the decimal places carried in the matrix.

Table 7-5 – Thirty-Minute State Transition Matrix – 15,000 MW Scenario

		Next State (Output, % rated capacity)									
		0-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91-100%
Current State (Output)	0-10%	0.8139	0.1861	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	11-20%	0.0199	0.8094	0.1707	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	21-30%	0.0000	0.0595	0.7698	0.1699	0.0008	0.0000	0.0000	0.0000	0.0000	0.0000
	31-40%	0.0000	0.0000	0.0820	0.7324	0.1835	0.0021	0.0000	0.0000	0.0000	0.0000
	41-50%	0.0000	0.0000	0.0000	0.0916	0.7247	0.1832	0.0005	0.0000	0.0000	0.0000
	51-60%	0.0000	0.0000	0.0000	0.0000	0.0939	0.7209	0.1847	0.0005	0.0000	0.0000
	61-70%	0.0000	0.0000	0.0000	0.0000	0.0011	0.0879	0.7840	0.1270	0.0000	0.0000
	71-80%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0013	0.0583	0.8362	0.1042	0.0000
	81-90%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0477	0.9019	0.0503
	91-100%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0658	0.9342

Table 7-6 shows a one-hour state transition matrix for the 15,000 MW wind generation capacity scenario. The average persistence of the wind generation output, the probability of remaining within the same 1500 MW-wide band of the current output, drops to 66%. Persistence, however is significantly greater at the upper and lower end of the power output range. The probability of a -1,500 MW change is less than 18%.

Table 7-6 – One-Hour State Transition Matrix – 15,000 MW Scenario

		Next State (Output, % rated capacity)									
		0-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91-100%
Current State (Output)	0-10%	0.7244	0.2742	0.0014	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	11-20%	0.0590	0.6881	0.2419	0.0103	0.0007	0.0000	0.0000	0.0000	0.0000	0.0000
	21-30%	0.0000	0.1398	0.6106	0.2250	0.0246	0.0000	0.0000	0.0000	0.0000	0.0000
	31-40%	0.0000	0.0043	0.1845	0.5527	0.2355	0.0221	0.0009	0.0000	0.0000	0.0000
	41-50%	0.0000	0.0000	0.0066	0.1915	0.5315	0.2357	0.0347	0.0000	0.0000	0.0000
	51-60%	0.0000	0.0000	0.0000	0.0161	0.1847	0.5432	0.2390	0.0171	0.0000	0.0000
	61-70%	0.0000	0.0000	0.0000	0.0000	0.0149	0.1943	0.5934	0.1890	0.0085	0.0000
	71-80%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0039	0.1399	0.7242	0.1320	0.0000
	81-90%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0077	0.1231	0.8077	0.0615
	91-100%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0286	0.1429	0.8286

7.2.3. Extrema Analysis

Figure 7-3 shows the frequency distribution of wind generation output 30-minute deltas (changes). Superimposed is a normal distribution curve, for reference. Note that this curve is slightly skewed to the positive direction, indicating the propensity for wind generation output to rise faster than it declines. Wind generation output deltas for fifteen minutes and one hour are included in Appendix I.

Power system operations, however, are predominately focused on managing the extreme events rather than the average system behavior. Figure 7-4 and Table 7-7 focus on the

negative fringes of the wind delta distribution; indicating the frequency of large drops in wind generation output in thirty-minute periods. The focus of the analysis on the thirty-minute change is based on ERCOT’s present ancillary services practices. Responsive Reserve Service (RRS) is used as the backstop to extreme change events exceeding the procured regulation service. For unanticipated changes over a longer period, Non-Spinning Reserve Service (NSRS) units can be placed in service. The startup time for NSRS units is defined as thirty minutes. Changes in less than thirty minutes are assumed to drive RRS requirements, unless the start-up time requirement for NSRS is shortened. Appendix I contains plots similar to Figure 7-4 for 15-minute and one-hour changes.

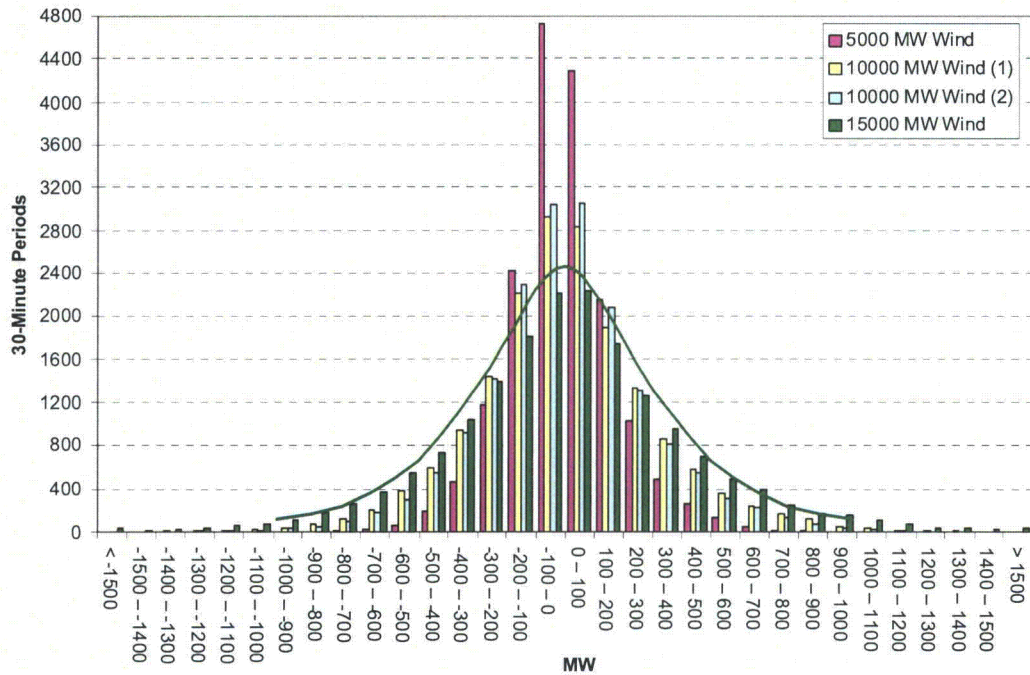


Figure 7-3 – Frequency distribution of 30-minute wind generation output deltas.

Table 7-7 – Extreme 30-Minute Wind Generation Output Drops

	5000 MW Wind	10,000 MW Wind (1)	10,000 MW Wind (2)	15,000 MW Wind
Max Pos Delta	1079	1611	1629	2370
Max Neg Delta	-1167	-2053	-1771	-2563
No. Drops > 1000 MW	5	63	36	249
No. Drops > 2300 MW	0	0	0	3

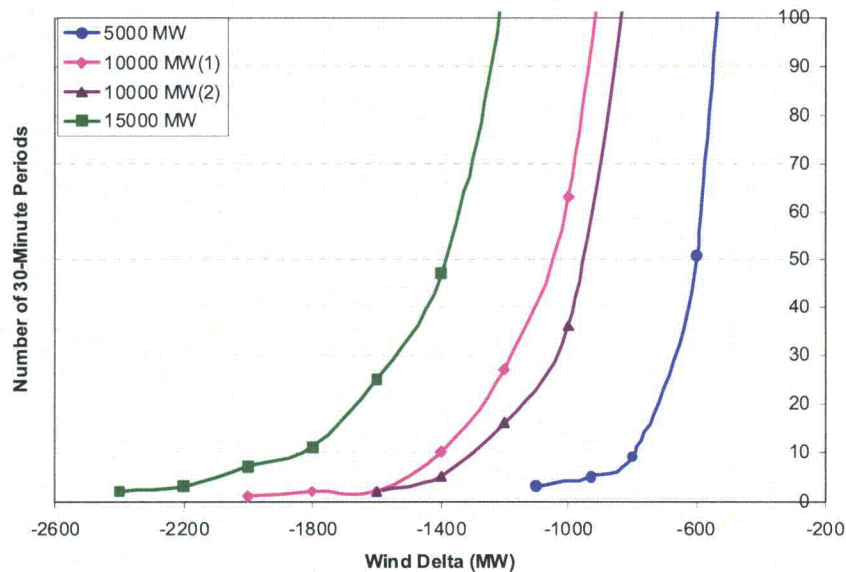


Figure 7-4 – Number of 30-minute periods where wind generation output drops are more severe than the x-axis value.

At the same time that wind changes, however, system load is also changing. The salient impact on the system is defined by the change in net load. Figure 7-5 shows the cumulative frequency of extreme thirty-minute increases in net load, and Table 7-8 provides related statistics. Appendix I shows similar plots for extreme 15-minute and one-hour net load rises. The vertical dashed line in Figure 7-5 indicates the maximum thirty-minute increase for load alone, 3101 MW. Of particular operational significance is that the frequency of exceeding this threshold increases nonlinearly with addition of wind generation capacity. Figure 7-6 plots this increase in frequency as a function of wind generation capacity. Although it is statistically risky to fixate on the absolute extrema (worst case) from a limited data set of one year, there is also an apparent non-linear increase in worst-case net load thirty-minute deltas with increasing wind generation capacity.

Although statistically defined metrics of the wind generation impact on net load, such as mean values, standard deviations, etc., vary linearly with wind penetration, it is observed that the severity and frequency of extreme conditions increase at a much faster rate.

Table 7-8 – Extreme 30-Minute Net Load Increases

	Load-alone	L-5000 MW Wind (1)	L-10,000 MW Wind (1)	L-10,000 MW Wind (2)	L-15,000 MW Wind
Max Pos Delta	3101	3271	3928	3805	4502
Max Neg Delta	-2756	-3138	-3360	-3300	-3612
No. Rises > 1000 MW	2557	2769	2986	2916	3092
No. Rises > 2300 MW	78	114	191	168	289

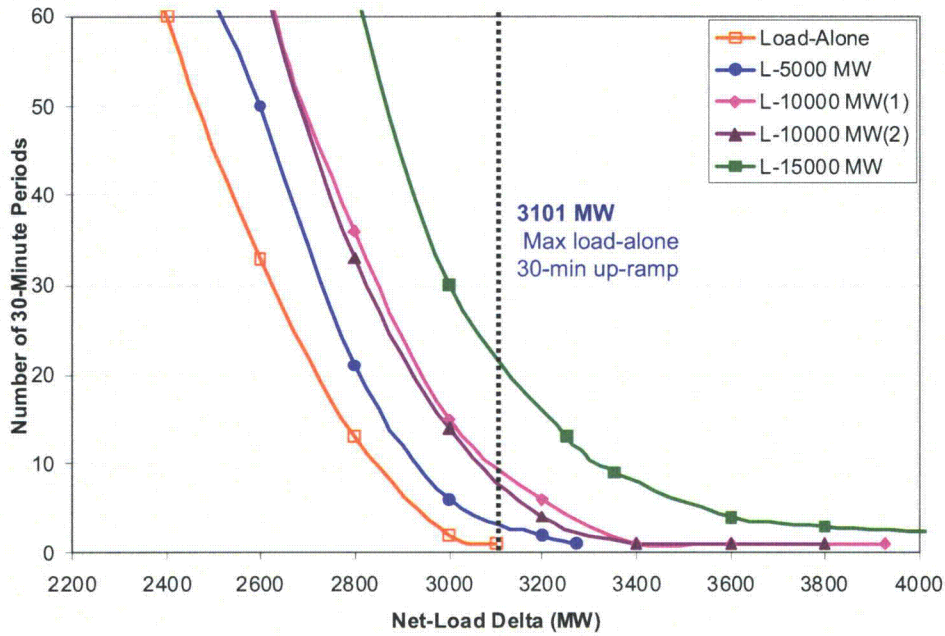


Figure 7-5 - Number of 30-minute periods where net load increase exceeds x-axis value.

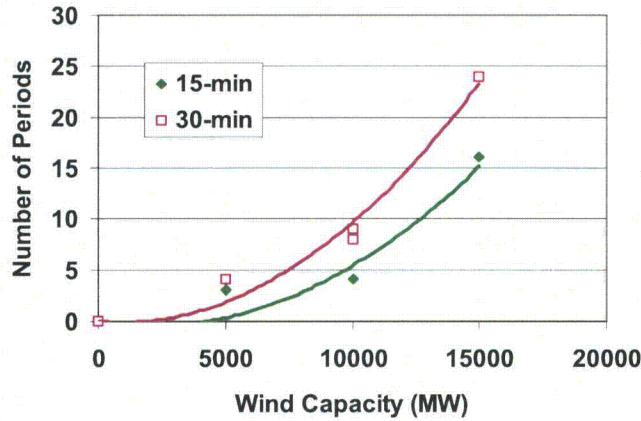


Figure 7-6 – Number of periods where the net load increase, over 15 and 30 minute periods, are greater than the worst case for load alone.

These results clearly show that the extreme changes in net load are less severe than the extreme changes in its components: wind generation output and system load. For example, the extreme 30-minute change decrease wind generation output, for the 15,000 MW wind scenario, is 2563 MW. The maximum 30-minute increase in system load is 3101 MW, yet the largest increase in net load for this scenario is 4502 MW, which is less than 80% of the sum of the component extrema.

7.2.4. Temporal Characterization of Extrema

The timing of the maximum thirty-minute decreases in wind generation output, for the 15,000 MW wind generation capacity scenario, is plotted in Figure 7-7. The most severe decreases tend to be in the morning, and in the evening in winter, spring, and fall. The morning decreases of wind coincide with load pickup, shown in Figure 7-8, compounding the increase in net load rise as shown in Figure 7-9. The severe evening wind generation output drops tend to offset load drops in the summer. However, in the winter, there is a load rise in the evening that is aggravated by the wind generation drops.

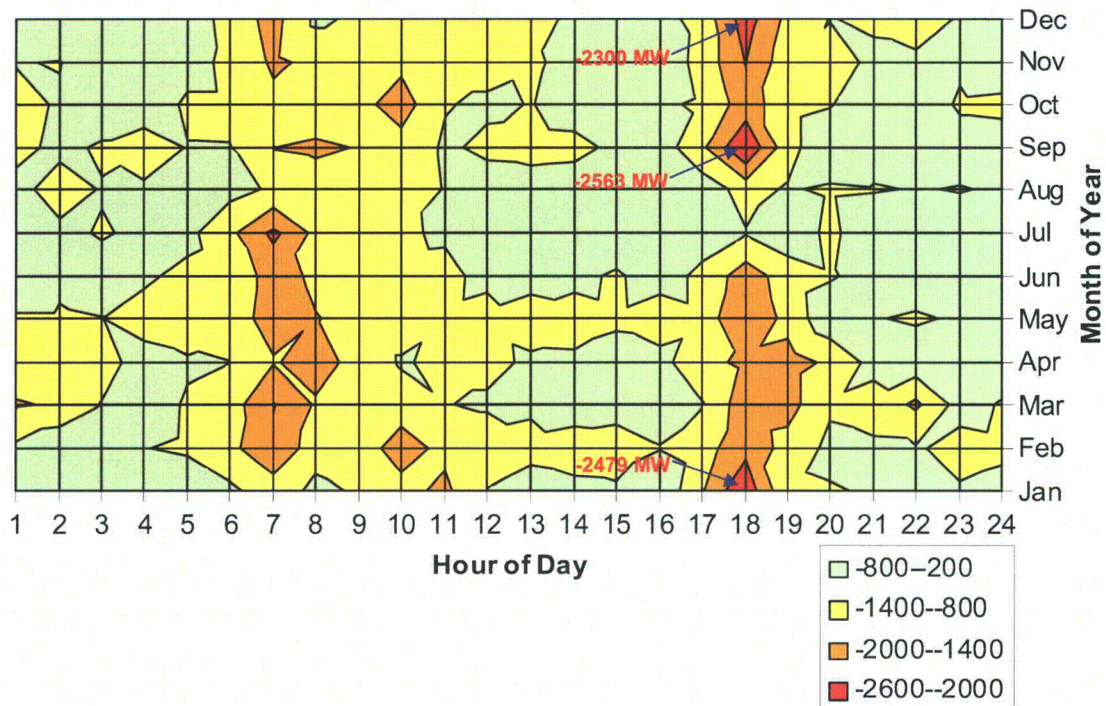


Figure 7-7 – Timing of extreme 30-minute decreases in wind generation output for the 15,000 MW wind generation capacity scenario.

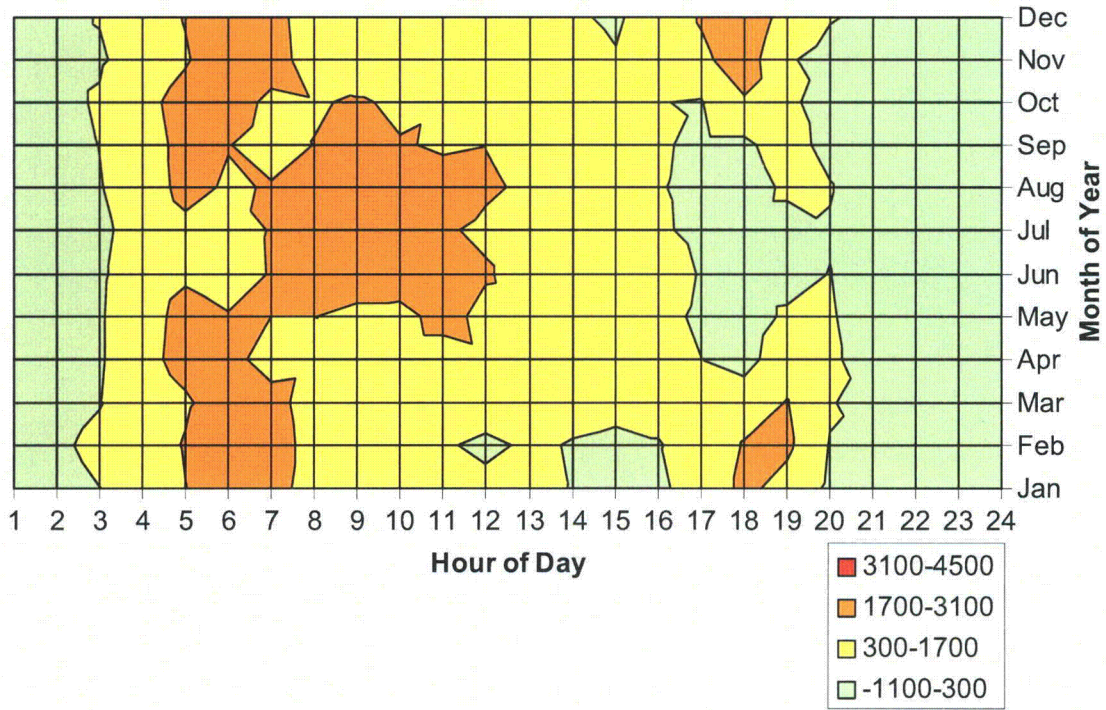


Figure 7-8 - Timing of extreme 30-minute increases in load.

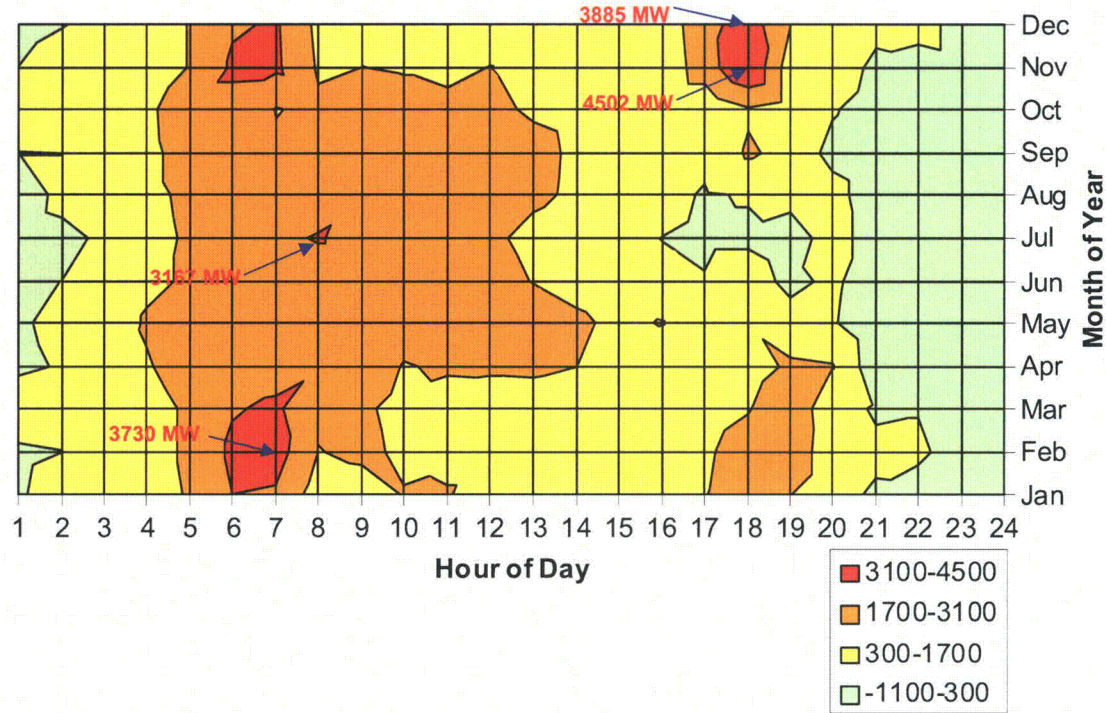


Figure 7-9 - Timing of extreme 30-minute increases in net load for the 15,000 MW wind generation capacity scenario.

8. RESPONSIVE AND NON-SPIN RESERVE SERVICES

ERCOT's present operating practice is to procure sufficient regulation to cover 98.8 percent of changes in net system load. When changes occur that are beyond the regulation procurement, the Responsive Reserve Service (RRS) is called upon to maintain system frequency. RRS is also used to cover generation plant trips, and the present amount of RRS procured, 2300 MW, is based on near-simultaneous trips of the two largest generating units in ERCOT. Thus, RRS has been employed both for load changes 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 units are of insignificant size with respect to the whole ERCOT system. While entire wind plants can trip, e.g., due to an interconnection substation fault, the capacity rating of an individual wind plant is much less than the largest thermal power plant units. Wind plants are becoming ever larger, but the practical aspects of collector system design will tend to cause future "mega-plants" to have multiple interconnections to the transmission system and are thus not prone to single-contingencies. 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 positive load change, despite the fact that they are 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.

8.1. 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.

The detailed system reliability study required to determine the RRS needed is beyond the scope of this study, but this study provides ample characterization of wind generation variability needed to support such an investigation. Unlike thermal generation trips, which are essentially uniform in probability throughout the year¹, 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. Information provided in previous sections provide a great deal of information to guide establishment of standing temporal patterns of RRS requirements. In addition to standing patterns, the RRS procurement should be adjusted for periods of specific risk, as discussed later in Subsection 8.3.

Presently, ERCOT allows 50% of the RRS to be provided by Loads Acting As Reserves (LAARS). The willingness of loads to accept an interruptible service depends on the frequency that they are called upon. This factor needs to be considered in determining the appropriate proportion of LAARS in the RRS with high wind penetration.

8.2. Tradeoffs Between RRS and NSRS

Generating plant trips, causing imbalances exceeding the regulation range, must necessarily be compensated by RRS. 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. ERCOT presently has an NSRS startup time requirement of thirty minutes. Other operating areas have shorter startup times for non-spinning reserves, often ten or fifteen minutes. There are thermal generating technologies, typically single-cycle gas turbines and reciprocating engines, that can easily achieve these faster starting times. In addition, demand response can be a very effective tool in achieving a rapid correction of unanticipated generation shortfalls.

¹ The largest thermal units presently defining RRS needs are base-load units which are almost always on line.

There is an inherent tradeoff between the amount of RRS required and the NSRS startup time. 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.

8.3. 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.

9. CONCLUSIONS

9.1. General Observations

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.

9.2. Summary of Findings

9.2.1. Variability of Net Load

- 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. The inverse-phase relationship appears to be stronger in the summer than during other seasons.
- Wind generation tends to drop sharply in the morning when load is rising quickly, and increase sharply in the evening when load is dropping. 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.
- 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. The 15,000 MW of wind generation capacity is 23% of the peak system load.
- The variability of net load (served load minus wind generation) is much less than the sum of the variabilities of load and wind generation considered in isolation. This is true for both extreme values as well as mean values. Nevertheless, the incremental variability of net load at high wind penetrations is substantial.
- Both wind generation and load are affected by the same weather-related phenomena. Correct analysis of net load variability requires use of time-synchronized wind generation and load data.
- 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 may be more operationally significant due to the low net load levels. When segregated by load level, variability is relatively constant, with a tendency to be somewhat greater during mid-range load levels than high and low load levels.
- Net load variability increases linearly with wind generation capacity. The number and size of large and extreme changes from one time period to the next also increase with wind generation, but tend to grow faster than a linear rate.
- 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. The impact of the non-random ramp component can be seen in the frequency plots which become increasingly triangular in longer timeframes. 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.

9.2.2. Predictability of Wind Generation and Net Load

- Load and wind generation forecast errors are virtually independent; they do not systematically coincide or reinforce each other. It is improbable for the most severe load and wind errors to occur in the same hour.
- Net load forecast accuracy decreases with increasing wind penetration. 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. 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.

9.2.3. Regulation Requirements

- The overall tendency is for average up and down regulation deployments to increase 18 MW with 15,000 MW of wind generation capacity. The 98.8th percentiles of deployment, however, increase 54 MW (23%) for up-regulation and 48 MW (20%) for down-regulation.
- 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.

- Of the two 10,000 wind generation capacity scenarios investigated, the scenario with wind sites in coastal South Texas in place of 1,500 MW of capacity in the Panhandle required somewhat less regulation.
- 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 incremental impact of wind generation on regulation requirements is greatest when the wind generation output is at about half of the installed capacity.

9.2.4. Regulation Procurement Methodology

- 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.

9.2.5. 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. 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 $-\$0.18/\text{MWh}$ to $+\$0.27/\text{MWh}$, depending on the wind capacity scenario and wind forecast accuracy assumptions.

9.2.6. Extreme Weather

- Geographic diversity of the wind generation limits the rate at which wind generation output can change. Extreme changes in wind occur as rapid ramps, not as abrupt changes like occurs for a conventional power plant trip.
- Extreme wind generation output changes are almost always due to predictable weather phenomena.
- The frequency and severity of extreme short-term (15 minute to one hour) wind generation output changes increases at a faster than linear rate with increasing wind generation capacity.
- 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 in 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 15000 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. This maximum net load rise is less than 80% of the sum of the maximum load rise and the maximum wind generation decrease (absolute value).
- Large, abrupt increases in net load are more likely in the morning, and in the evening during winter.

9.2.7. Impacts of Wind Generation on Energy Production

Indirectly related to ancillary services, *per se*, but as a by-product of the economic production simulations performed to determine availability and costs of ancillary services, a number of observations were made:

- Energy production from wind tends to be offset primarily by reduction in production from combined-cycle natural gas plants.
- For the maximum wind penetration studied (15,000 MW capacity), combined cycle plant commitment and dispatch levels are reduced to near zero during the overnight hours having high wind levels. Even coal plants see significant turn-downs in these periods.

- In general, as the wind generation penetration increases, it displaces the higher cost thermal generation and tends to reduce the overall spot price of energy.
- Wind generation decreases total system energy production cost, per MWh of wind energy produced, by \$53/MWh to \$55/MWh for the 5,000 MW through 15,000 MW wind generation capacity scenarios.
- The accuracy and utilization of day-ahead wind generation output forecasts has significant impact on spot prices. Compared to the present “state-of-the-art” wind forecast accuracy, a perfect forecast tends to raise spot 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.

9.3. Other Observations

Beyond the information developed from this study, it has been observed that economic factors, plus the inherent maneuverability of wind generation plants, can result in rapid wind generation changes that become operational problems. Modern wind plants can intentionally change their power production very rapidly anywhere between near zero and the maximum possible for the existing wind conditions. There is little to no incremental costs associated with starting and stopping wind plants, beyond the obvious energy revenue costs. Consequently, price signals to reduce or increase wind plant output can and will be acted upon much faster than for thermal plants. Recent events, both within ERCOT and elsewhere, involving swings of prices into the negative domain and back, have demonstrated that this agility can cause some surprising and undesirable behavior. On the other hand, this high level of agility also presents an opportunity for creative applications to make the system both more reliable and economic.

A recent operational incident in ERCOT resulted in dropping of interruptible loads (LAARs). Wind generation ramping was a contributor to this event, which coincided with a sharp load rise and issues with dispatched generation. The wind generation change was forecast, but the ERCOT operating procedures had not been revised to employ the wind forecast at that time.

9.4. 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 errors 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.

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**APPENDIX B - AWS TRUEWIND REPORT:
*WIND GENERATION AND FORECASTING PROFILES***



A Report to
GE Energy Consulting

WIND GENERATION AND FORECASTING PROFILES

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A REPORT ON THE CREATION OF WIND GENERATION AND FORECASTING PROFILES FOR TEXAS

1 INTRODUCTION

As input to a study of the ancillary services requirements for wind generation in Texas performed by GE Energy consulting for the Electric Reliability Council of Texas (ERCOT), AWS Truewind produced model-derived wind plant output and forecast data for two continuous years, 2005-2006. Four sets of data were produced: one-hour plant output, one-hour forecasts looking four hours ahead, one-hour forecasts looking one day ahead, and one-minute output. The data were generated for each of 716 project sites in 25 Competitive Renewable Energy Zones (CREZs) selected by AWS Truewind in a previous project.¹ This report describes the methods used to generate the data.

2 METHODS

The methods used to generate the wind data were adapted from those developed in previous projects to assess the impacts of wind generation on the New York, North and South Dakota, and California power grids.²

2.1 Hourly Wind Generation Profiles

For each wind project site identified in the previous project, AWS Truewind created two historical years (2005-2006) of hourly simulated wind generation data. The procedure was very similar to that used in the previous project. The main difference was the time period for which the data were produced (two continuous years rather than 366 days sampled from a 15-year period).

In the first stage of the process, the MASS model, a numerical atmospheric simulation model that is part of AWS Truewind's MesoMap system, was run in continuous one-month blocks throughout the period. The initial conditions and lateral boundary conditions for the simulations were taken from the NCAR/NCEP reanalysis data set, a global, gridded data base of historical weather conditions every 6 hours for the past 60 years. Additional data for the simulations were obtained from rawinsonde (instrumented balloon) observations. The simulations were performed in a nested grid configuration, with the innermost grid having a horizontal spacing of 10 km.

During the simulations, hourly samples of wind speed, direction, temperature, pressure, and other atmospheric parameters were stored for each grid cell at 25 heights from the surface to the top of the atmosphere. The wind, temperature, pressure, and turbulent kinetic energy (TKE) were then interpolated to the location of each project site and the presumed 80 m hub height of the turbines.

¹ AWS Truewind, LLC, "Wind Generation Assessment," Report to ERCOT, January 2007.

² See, e.g., GE Power Systems Energy Consulting, "The Effects of Integrating Wind Power on Transmission Planning, Reliability, and Operations," Report to the New York State Energy Research and Development Authority, Appendix A (2005). The Dakotas work was performed in conjunction with ABB for the Western Area Power Administration. The California work is being performed for GE and the California Energy Commission.

The wind speed, direction, and temperature data were then converted to plant output. The method accounted for variations in speed, air density, wake loss (as a function of direction), and other losses (such as electrical losses), as well as random fluctuations related to turbulence. For each site, the following steps were carried out:

- The diurnal average speeds were adjusted to match observed patterns at 11 tall towers in the state.
- A direction-dependent loss factor was then subtracted from the speed in each hour to represent the effect of wake interference between turbines as well as other, non-direction-dependent losses such as blade soiling. The loss factor ranged from 4% to 9% depending on the direction of the wind relative to the prevailing (most frequent) direction.
- The speed was adjusted up or down by a random factor related to the turbulent kinetic energy (TKE) predicted by the model for that hour. The TKE is a measure of the gustiness of the wind, and, thus, this adjustment allowed the output to fluctuate according to how gusty the conditions were expected to be.
- The speed was transformed to power using a generic power curve, which had been adjusted to the predicted air density for each hour. The power curve was a composite of three leading turbine power curves chosen to match the IEC class of the site.³ The turbine models for each class were as follows:

Class I (>8.5 m/s): GE 1.5sl, Vestas V80, Gamesa G80

Class II (7.5-8.5): GE 1.5sle, Vestas V82, Gamesa G87

Class III (<7.5 m/s): GE 1.5xle, Vestas V100, Gamesa G90

(The speed ranges are defined for the standard sea-level air density of 1.225 kg/m³.)

- The output was adjusted by a random loss factor ranging from 0% to 8%, with an average of 4%, representing fluctuations in losses associated with turbine down time. The combined wake and non-wake losses averaged about 14% for all projects and ranged from 12% to 16%.

The output data were provided to GE Energy Consulting in one comma-delimited file for each CREZ. Within each file, a time series of data was provided for each project site in the CREZ. This approach allowed GE Energy Consulting to select any number of sites in a CREZ, up to the maximum, to create a variety of wind generation scenarios.

2.2 Next-Day and Four-Hour Forecasts

After producing the hourly generation data, AWS Truewind simulated forecasts for the existing and future wind project sites. The aim was to reproduce the dynamic behavior and error patterns of state-of-the-art wind forecasts. Two types of forecasts were provided: four-hour-ahead and next-day forecasts. Four-hour-ahead forecasts are defined as the predicted generation from 2.75

³ Turbines are designed for sites that fall within a range of wind conditions defined by the IEC class. At a standard sea-level air density of 1.225 kg/m³, a site is Class I if its mean speed exceeds 8.5 m/s, Class II if it exceeds 7.5 m/s, and Class III if it is below 7.5 m/s. The speed threshold is adjusted according to the air density: a lower air density means the speed threshold for a particular IEC class can be increased, so that, for example, a Class II turbine could be used at a site that, at standard density, would be Class I.

hours to 3.75 hours after the time of delivery of the forecast, which is 15 minutes after every hour. Day-ahead forecasts are defined to occur early in the morning and cover from midnight to midnight of the following day, in one-hour intervals.

Normally, mesoscale numerical weather modeling would be a key input for wind forecasts. However, since such modeling was already employed to simulate the “actual” generation, it was necessary to apply a purely statistical model to reproduce the error patterns and dynamic behavior of real forecasts. Otherwise, the forecasts would appear to be too good.

For each time horizon, we derived from forecast performance data in other regions a set of error distributions as a function of forecasted generation and previous forecast error.⁴ Following a Markov chain approach, the statistical model stepped through time, drawing randomly from the error distributions to construct a forecast based on the simulated generation. Finally, a bias correction was applied to ensure accurate prediction of the mean.

2.3 One-Minute Plant Output

In the final task, AWS Truewind simulated one-minute plant output data for the two-year period for the same sites. To produce the data, AWS Truewind employed a computer program to sample four-hour windows of historical one-minute data from existing wind projects. The source of the samples was two years of one-minute plant output data provided by ERCOT for 17 substations serving seven Texas wind projects.⁵ The program removed one-hour trends from the data and added the residuals to the simulated hourly output for each site. It did not allow the same window of residuals to be applied to two different sites in the same time period, as this would have resulted in perfect correlation of the one-minute fluctuations between those sites, whereas in reality one-minute fluctuations between wind projects are entirely uncorrelated. The program excluded from the training data one-minute changes greater than 5% of the plant rated capacity, as they correspond to plant outages, curtailments, and restarts unrelated to the wind. (Such events are discussed in section 3.4.)

3 RESULTS AND VERIFICATION

3.1 Representativeness of 2005-2006

The first question we addressed was whether the mean wind resource for the two-year period was typical. We obtained hourly wind speed measurements from four National Weather Service (NWS) stations in northern and central Texas (Amarillo, Abilene, Lubbock, and Midland) and one (Corpus Christi) on the southern Texas coast. These stations are fairly representative of the wind climate where most Texas wind projects have been built or proposed. We found the average speeds at each station for 2005 and 2006, and compared those values with the average speeds from July 1996 to June 2007.

⁴ Although AWS Truewind has provided forecasts for wind projects in Texas, confidentiality agreements prevented the use of these data to define the probability distributions for this study. Instead, we relied on forecasts generated for several California wind projects.

⁵ The files provided by ERCOT contained data for 32 substations. However, 17 of these did not have valid data. Of the remaining 15 substations, several represented different parts of the same project.

The results, shown in Table 1, indicate that 2005 was well below normal (as defined by the 1996-2007 average) at all stations, whereas 2006 was slightly above normal at all stations except Midland. The average for the two years ranges from 3.9% below the 1996-2007 average to 0.3% above normal. If the stations are plotted on a map, it is apparent that the degree of departure from normal conditions depends on latitude. The station farthest north, Amarillo, experienced the closest to normal conditions in 2005-2006; Lubbock, which is the next station to the south of Amarillo, was below normal by 1.6%, whereas all the other stations were at least 2% below normal. Most existing wind projects are located in two clusters, one between Midland and Abilene and the other south of Midland. For these projects, 2005 in particular was a rather poor wind year, with mean speeds more than 5% below the 1996-2007 average.

Table 1. Annual mean wind speeds in meters per second (m/s) for representative National Weather Service stations in Texas.

<i>Weather Station</i>	<i>2005</i>	<i>2006</i>	<i>2005-2006 Average</i>	<i>1996-2007 Average</i>	<i>Difference</i>
Abilene	4.59	4.94	4.77	4.86	-2.0%
Amarillo	5.54	5.79	5.67	5.65	0.3%
Corpus Christi	4.73	5.11	4.92	5.05	-2.5%
Lubbock	5.10	5.38	5.24	5.32	-1.6%
Midland	4.54	4.68	4.61	4.80	-3.9%

3.2 Hourly Wind Generation Profiles

Figure 1 presents typical examples of the simulated hourly wind generation data superimposed on the concurrent actual generation for a wind project at the same location. Although there are discrepancies, which may be caused by such factors as the finite mesoscale grid resolution and possible curtailments or low availability of the wind project,⁶ the simulated and actual generation exhibit similar behavior. Similar results are found for other projects and months. For the seven projects for which data were available, the r^2 correlation coefficient between actual and predicted generation ranged from 0.35 to 0.6.⁷

⁶ We noted that the average capacity factor of some of the seven wind projects was relatively low in 2005-2006. The average for the two years was 0.35, whereas for the same sites and period, the simulated net capacity factor averages 0.42. The difference may be indicative of performance problems at some projects, such as low availability, or transmission curtailments, as well as the use of different turbine models.

⁷ These results and others presented in this section are for 2005. Similar results were obtained for 2006.

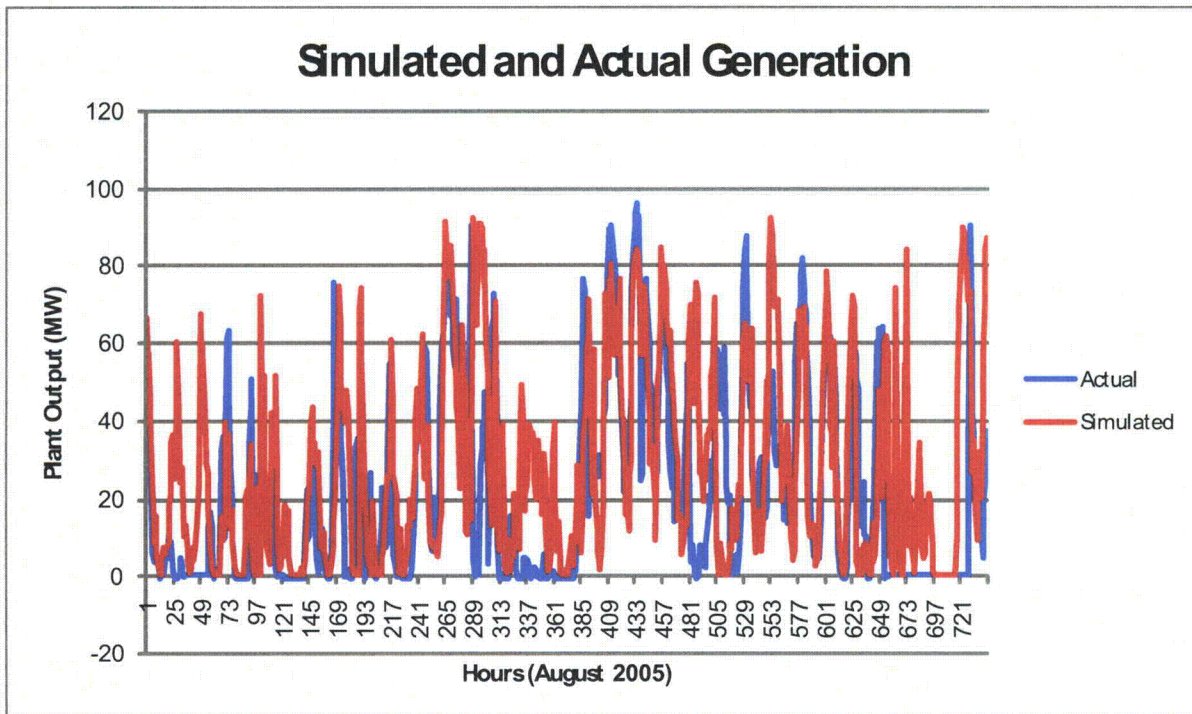
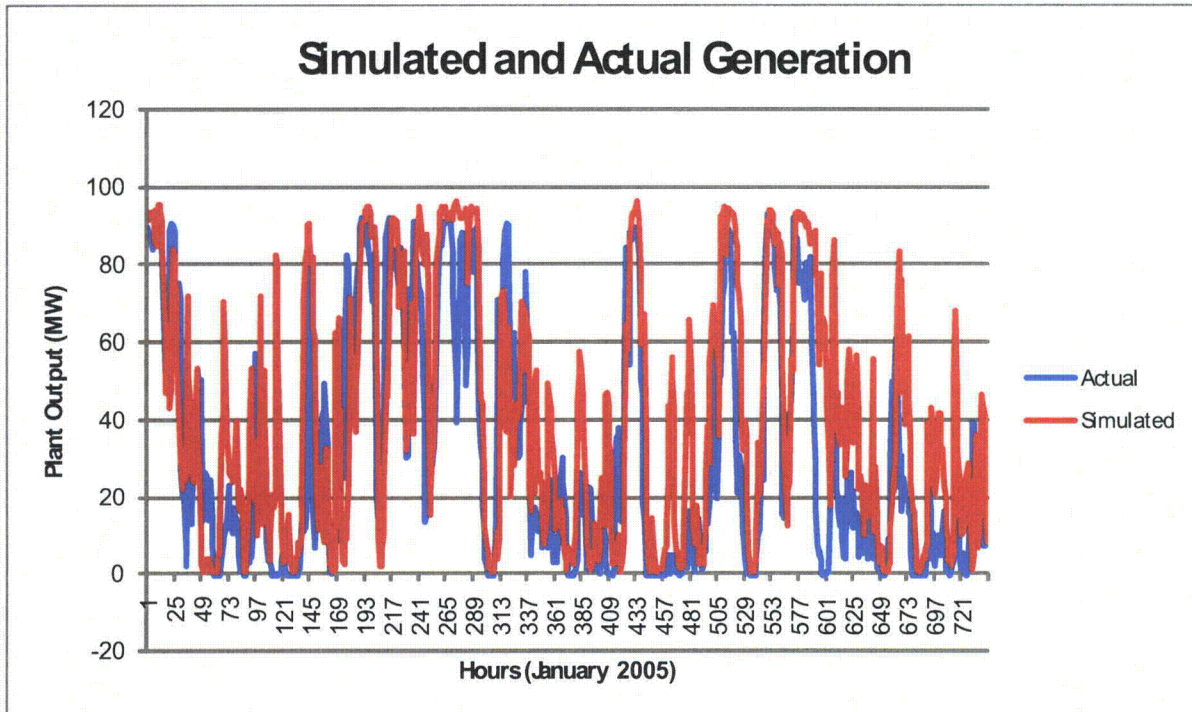


Figure 1. Comparison of actual and simulated hourly wind generation for a wind project in Texas for (a) January 2005 and (b) August 2005.

Another measure of the similarity of the actual and simulated wind generation is the rate of change of plant output. This is relevant for the analysis of ancillary services such as load following, which requires generation to respond to changing net load. Figure 2 compares the simulated and actual mean absolute deviation (normalized to the annual average output) averaged over the seven projects for time lapses of one to nine hours. The two curves follow very similar trajectories.

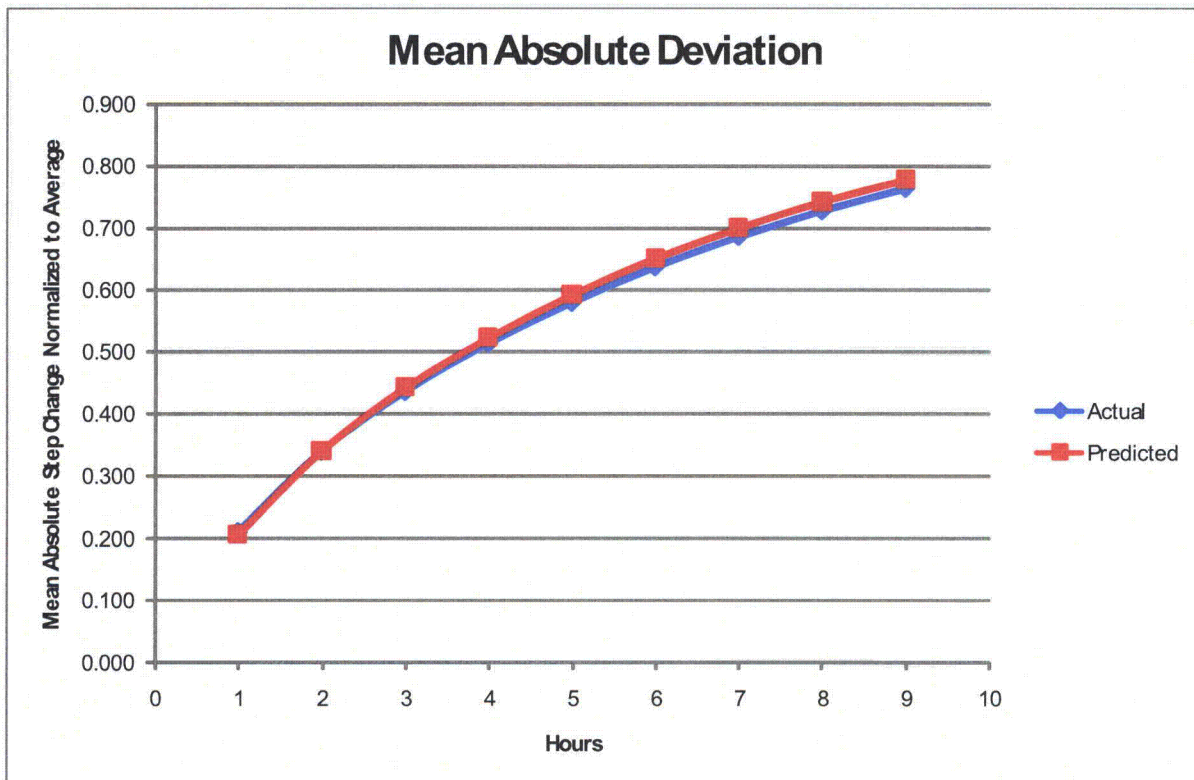


Figure 2. Relationship between the mean absolute change of the simulated and actual generation in 2005, averaged over seven wind projects, and the time lapse in hours.

Figure 3 illustrates the distribution of simulated and actual one-hour step changes in 2005 for the seven projects. This allows both small and large step changes to be compared in detail. Overall, the two patterns are very similar. The frequency of changes less than ± 0.1 (i.e., less than 10% of the average annual output) is slightly greater for the real projects than for the simulated projects, a difference that is made up by a slightly smaller frequency of changes between ± 0.3 and ± 0.1 . Such differences have little significance for ancillary services, however. Of greater interest are the large changes, greater than, say, ± 0.9 , which, for an average capacity factor of 40%, corresponds to about 36% of rated capacity. Overall, the actual projects exhibit a slightly greater chance of a large step change than the simulated projects. The total frequency for changes greater than 0.9 is 2.75%, according to the actual data, compared to 2.17% for the simulated data.

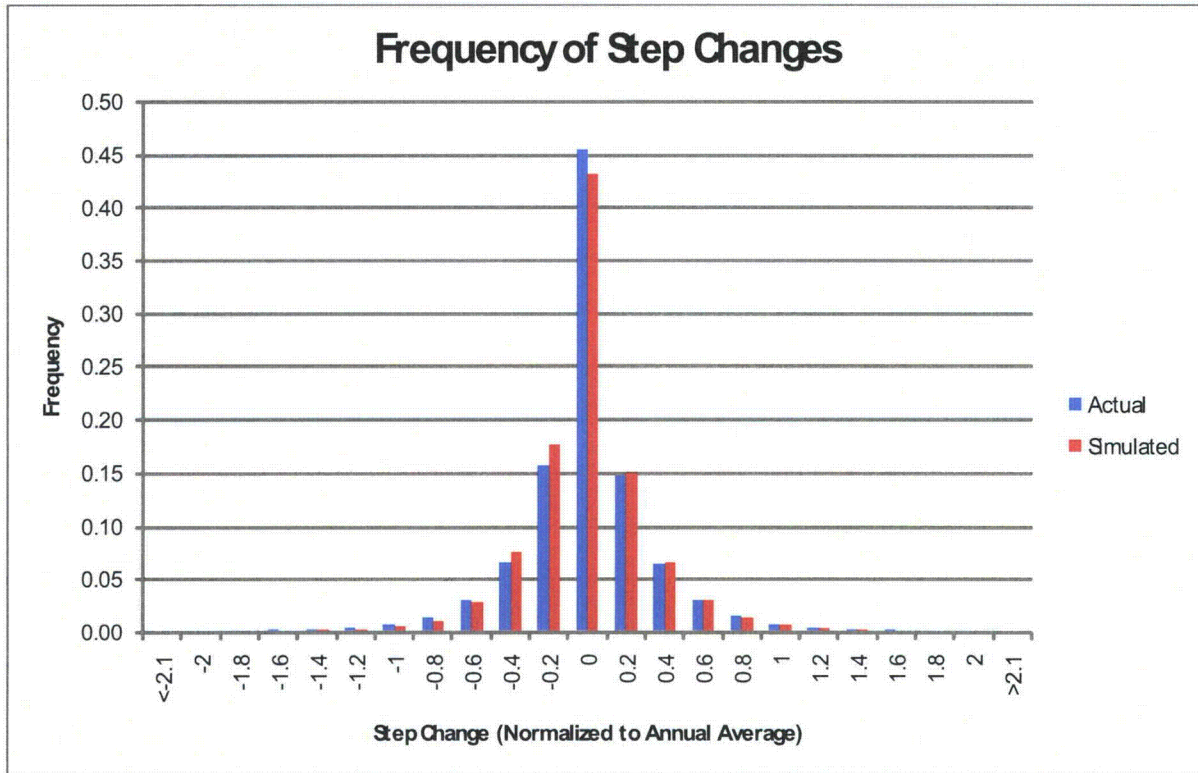


Figure 3. Frequency of one-hour step changes for the ensemble of seven projects and corresponding simulated projects. The step changes are normalized to the average annual output of the projects.

The largest actual one-hour change in 2005 was a drop of 4.5 times the annual average output, whereas in the simulated data, the largest drop was 2.1 times the annual average. However, we suspect that such large changes in the observed output are caused by plant or grid outages or mandated curtailments rather than by fluctuations in the wind. The largest single proportionate drop in 2005 was observed at a substation where the reported output fell from 38 MW to 1 MW in two minutes. This represents almost certainly a forced shutdown. The pattern of output at such times is clearly indicative of partial or complete outages, curtailments, and restarts. One example is shown in Figure 4.

For the aggregated plant output, which is not very sensitive to anomalous events at individual projects, the simulations appear to capture the frequency and magnitude of step changes very well. The largest observed step change in aggregated output in 2005 was 1.13 times the annual average output; for the simulated data, it is 1.10.

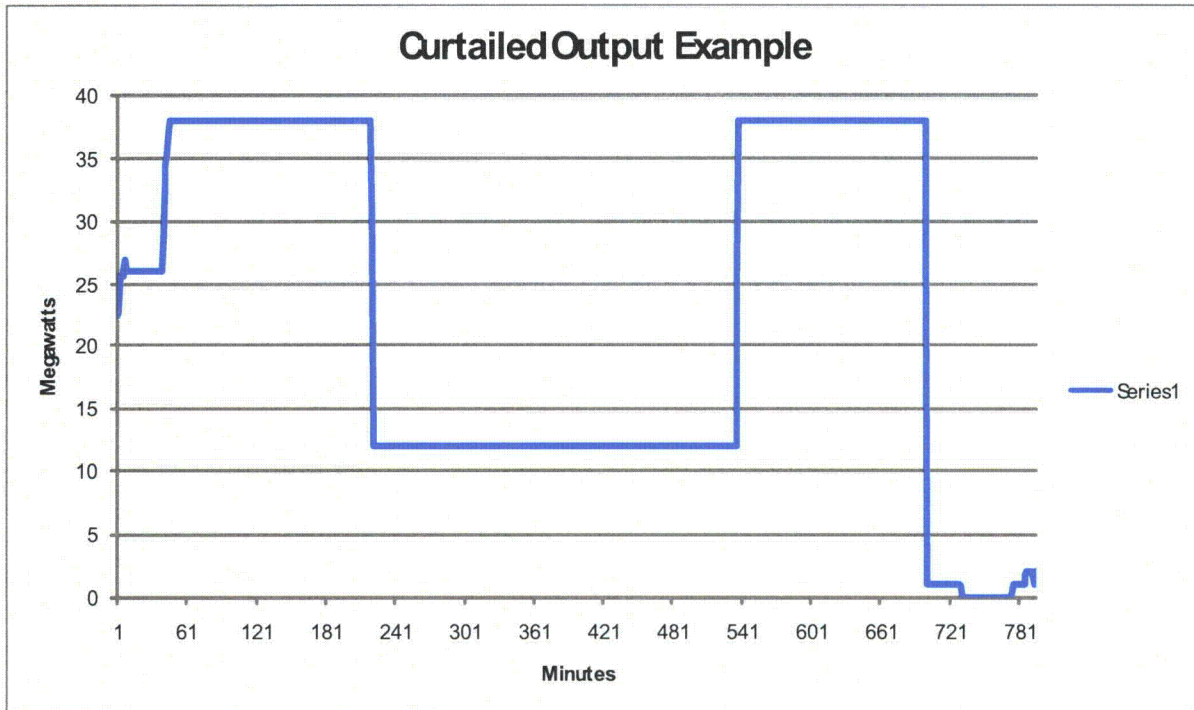


Figure 4. An example of a wind project whose output has been partially curtailed. Such curtailments may be due to a grid capacity constraint or the outage of a string of turbines. At the end of the period, it appears the plant is completely shut down.

Another important aspect of the behavior of wind projects is the time correlation of the output of different projects. If output variations are highly correlated between projects, then there is little proportionate reduction in the variability of the aggregated output; in other words, the geographic diversity benefit is small. Conversely, a small degree of correlation between projects confers a large diversity benefit.

To determine if the simulated data faithfully capture such correlations, we compared the observed and simulated correlation coefficients (r values) of the seven projects. Tables 2 and 3 present the actual and simulated correlations between the projects. Figure 5 shows the correlations between one of the seven and each of the other six. The correlation coefficients agree well, with the exception of project no. 2, whose actual output is not as well correlated with that of the other projects as the simulated output.

Table 2. Correlation coefficients of hourly average observed plant output for seven wind projects

	1	2	3	4	5	6	7
1	1.00	0.14	0.58	0.54	0.74	0.80	0.49
2		1.00	0.01	0.15	0.16	0.14	0.04
3			1.00	0.78	0.57	0.61	0.83
4				1.00	0.53	0.54	0.80
5					1.00	0.89	0.47
6						1.00	0.49
7							1.00

Table 3. Correlation coefficients of hourly average simulated plant output for seven wind projects

	1	2	3	4	5	6	7
1	1.00	0.26	0.55	0.54	0.77	0.78	0.52
2		1.00	0.20	0.25	0.25	0.23	0.22
3			1.00	0.87	0.63	0.57	0.79
4				1.00	0.60	0.52	0.79
5					1.00	0.93	0.53
6						1.00	0.50
7							1.00

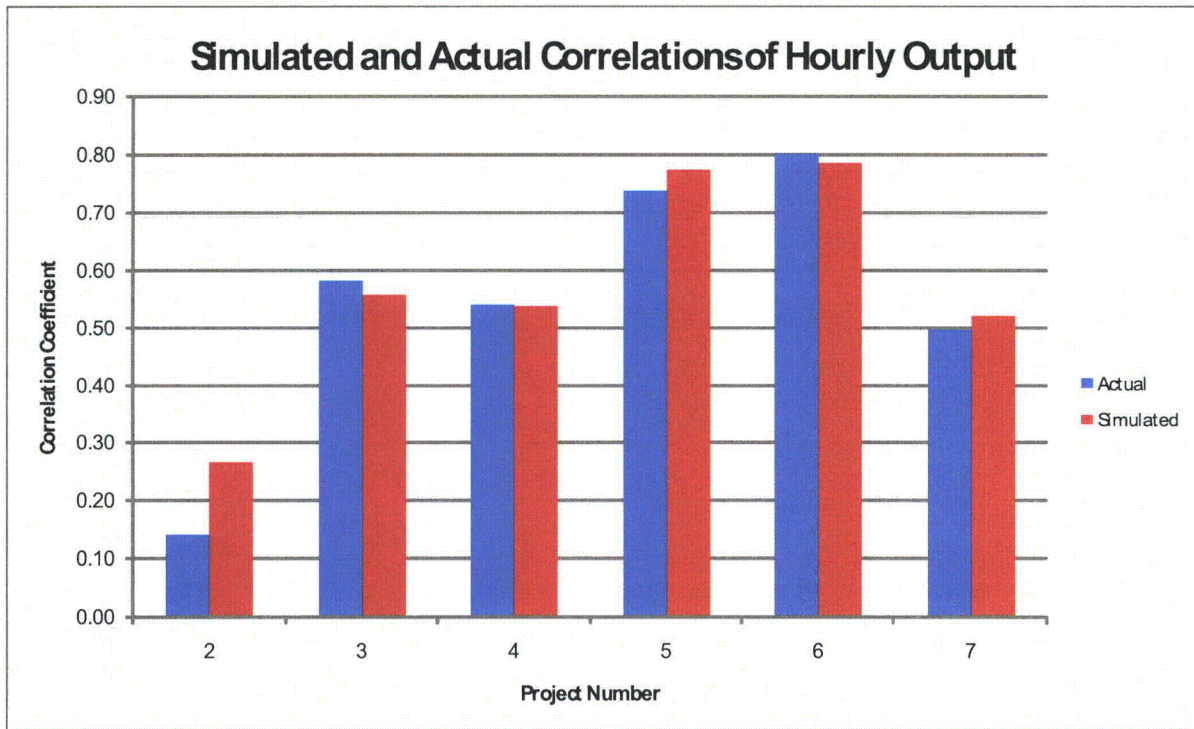


Figure 5. Correlation coefficients between the hourly average output in 2005 of wind plant no. 1 with each of the other six projects.

The seasonal and diurnal patterns of generation influence the capacity value of wind (the reliable output during peak load periods) as well as average transmission flows and the mix of non-wind electricity generation sources. Figure 6 compares the simulated and actual diurnal average plant output for one of the seven projects. The curves, which are typical for Texas projects,⁸ agree closely. Figure 7 compares the simulated and actual monthly averages for the same project for the 24 months starting January 2005. The two curves clearly follow a very similar pattern, although there are some discrepancies, most notably the surge in plant output observed in June,

⁸ In Texas, as in most other regions, the output of a wind project – assuming a turbine hub height of around 60 m or greater – is typically at a maximum at night because of the decoupling of the surface layer from the upper atmosphere under thermally stable, nighttime conditions.

2005, which is only partly matched by an increase in the simulated generation. These discrepancies follow no apparent pattern.

On the basis of these comparisons, we conclude that the model reproduces the dynamic behavior of wind plants in Texas with acceptable accuracy. It is not expected that the simulated winds will match the actual exactly at any given time or place. Some of the discrepancies we have noted may be caused by limitations in the numerical weather modeling, such as the finite grid resolution. Others may be caused by differences in the assumed turbine models or problems with the wind plant performance (including low availability, curtailments and outages). Considering that the dynamic behavior is realistic and the mean seasonal and diurnal patterns are captured reasonably well, the data appear to provide a solid basis for the hourly grid impact simulations.

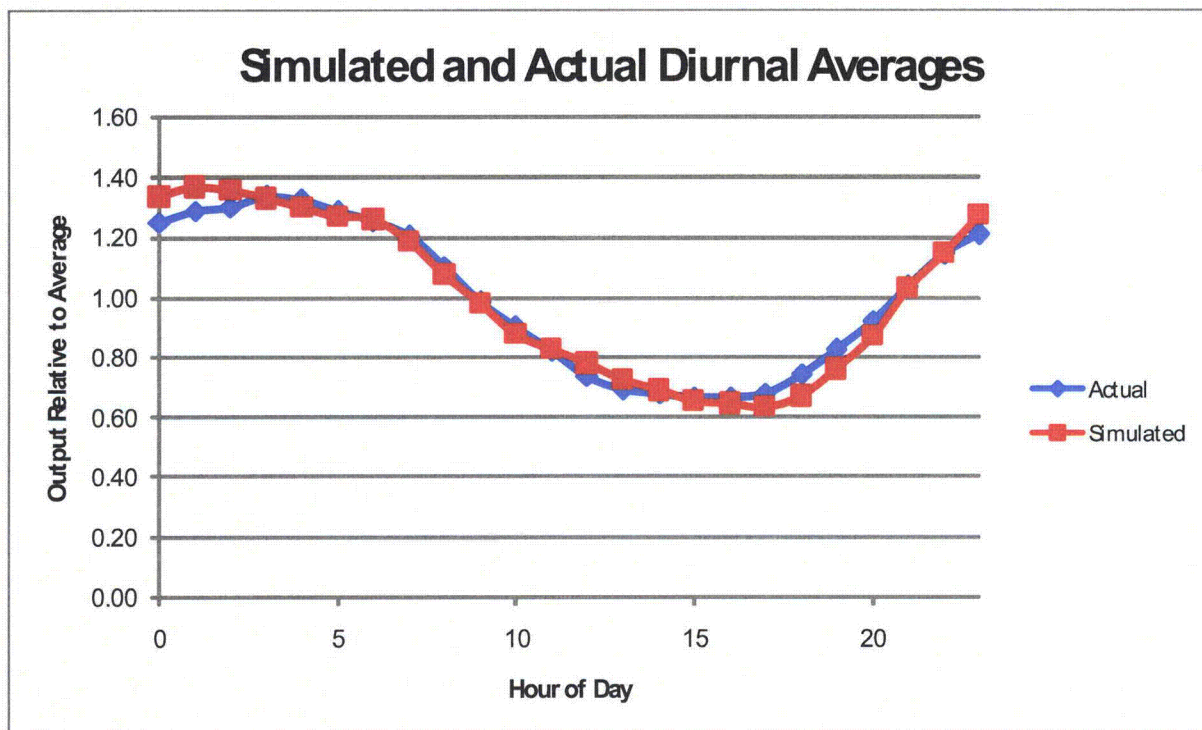


Figure 6. Comparison of the simulated and actual average output in 2005 as a function of time of day, for one project.

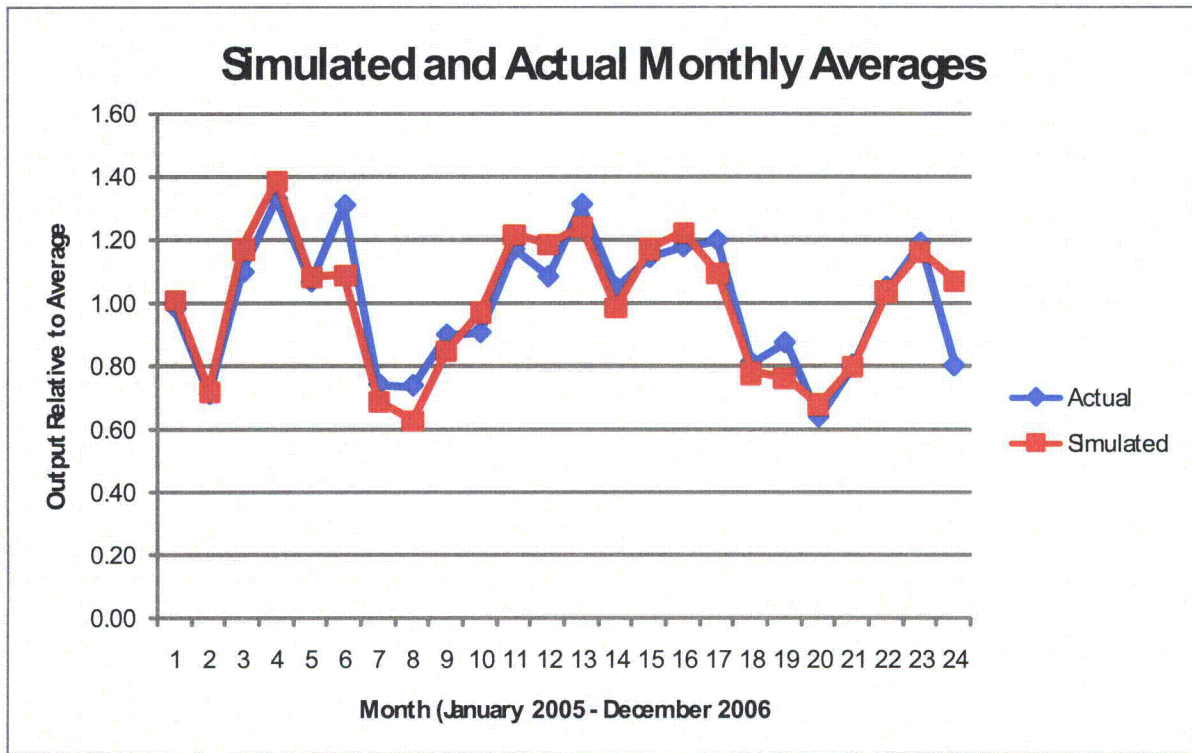


Figure 7. Comparison of the simulated and actual monthly average output in 2005-2006 for one project.

3.3 Forecasts

Figure 8 presents an example of both next-day and four-hour forecasts for a two-week period in January 2005, for a site in west-central Texas. The “actual” generation in this case is that simulated by the AWS Truewind model. Although the forecasts follow the actual to a considerable degree, there are significant errors in some hours. These errors tend to be larger for the next-day forecasts than for the four-hour forecast. Such discrepancies are normal for wind forecasts, since weather forecasting models do not have perfect prediction accuracy, and errors tend to grow with the forecast time horizon.

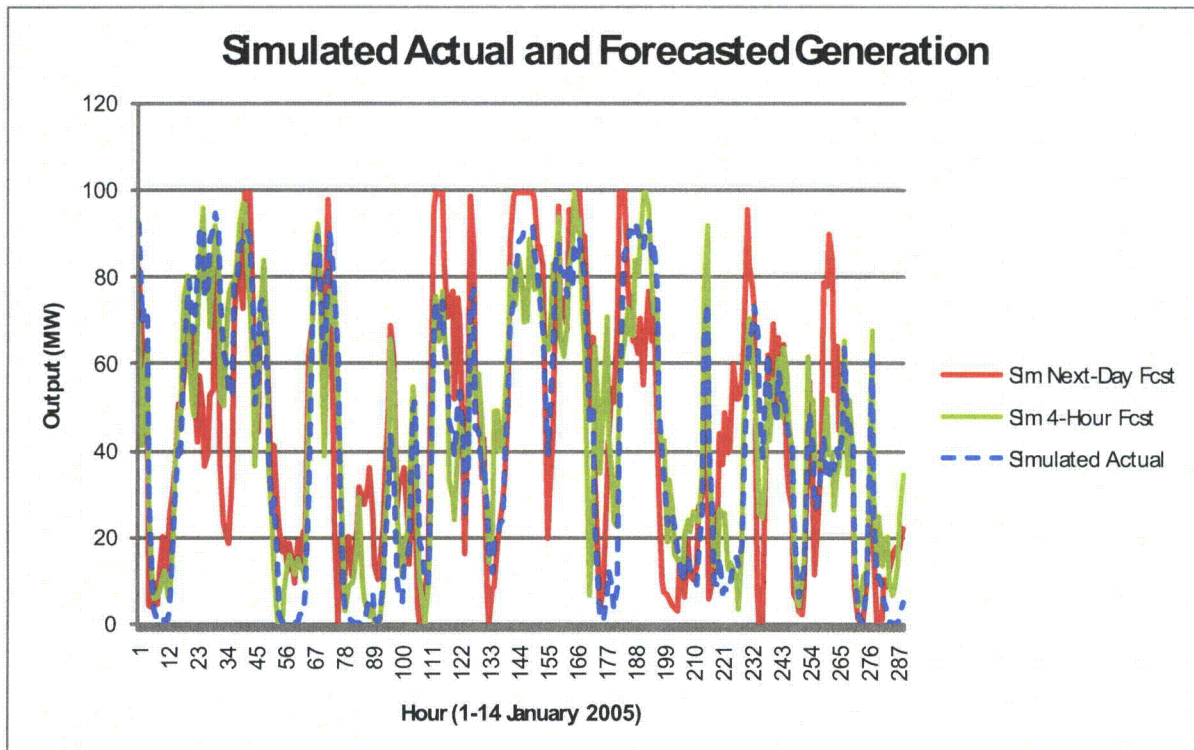


Figure 8. Typical four-hour and next-day wind forecasts for a two-week period in January 2005, compared to the simulated “actual” generation, for a site in west-central Texas.

The error characteristics of these simulated forecasts are similar to those of actual state-of-the-art forecasts. The statistical model used to create the forecasts was based on eWind forecasts for southern California wind projects, as sufficient forecasting data for Texas projects were not available. As noted earlier, it was necessary to employ a statistical model rather than a standard weather forecasting model (which would be used in real forecasts) because such a weather model was already used to simulate the “actual” output of the Texas wind projects. Were the same type of model to be used, the forecasts and actual generation would be too similar, resulting in much smaller errors than are typically encountered in real forecasts. The statistical model gets around this problem by mimicking the error patterns.

In 2005, the mean absolute deviation (MAD) of four-hour eWind forecasts averaged 9.2% of rated capacity at both Tehachapi and San Gorgonio passes; for next-day forecasts the range was 13.1% to 16.1%. A comparable level of next-day forecast performance was achieved in a 12-month wind forecasting test conducted in Texas by the Electric Power Research Institute (EPRI).⁹ For the 75-MW project that was the subject of that test, the MAD of AWS Truewind’s forecasts averaged 17.5%. In the present study, the MAD for Texas forecasts averaged 11.4% and 16.7% for four-hour and next-day forecasts, respectively, in CREZ 1. Thus, the errors for both the actual and synthesized forecasts in Texas were somewhat larger than the errors of the California forecasts. This difference arises because the Texas forecasts were for individual

⁹ Electric Power Research Institute, “Texas Wind Energy Forecasting System Development and Testing: Phase 2: 12-Month Testing,” Report #1008033, August 2004.

projects, whereas the California forecasts were numerous projects totaling hundreds of megawatts in each resource area. Forecast errors generally decrease with larger numbers of projects. For example, for a sample of eight projects in CREZ 1, the MAD for next-day forecasts is 14.1%.

We did not account for potential improvements in wind forecasts. Significant improvements are possible, particularly with the advent of new remote sensing platforms (including satellites) that can provide more precise and high-resolution weather data for forecasting models.

3.4 One-Minute Plant Output

Figure 9 presents a typical one-minute sample of simulated plant output data for a single site overlaid on the simulated hourly data for the same site. The sample shows the wide deviations that can occur within an hour due to the passage of weather fronts and turbulent fluctuations in wind speed. Figure 10 shows the same extracted from actual data for an existing wind project.

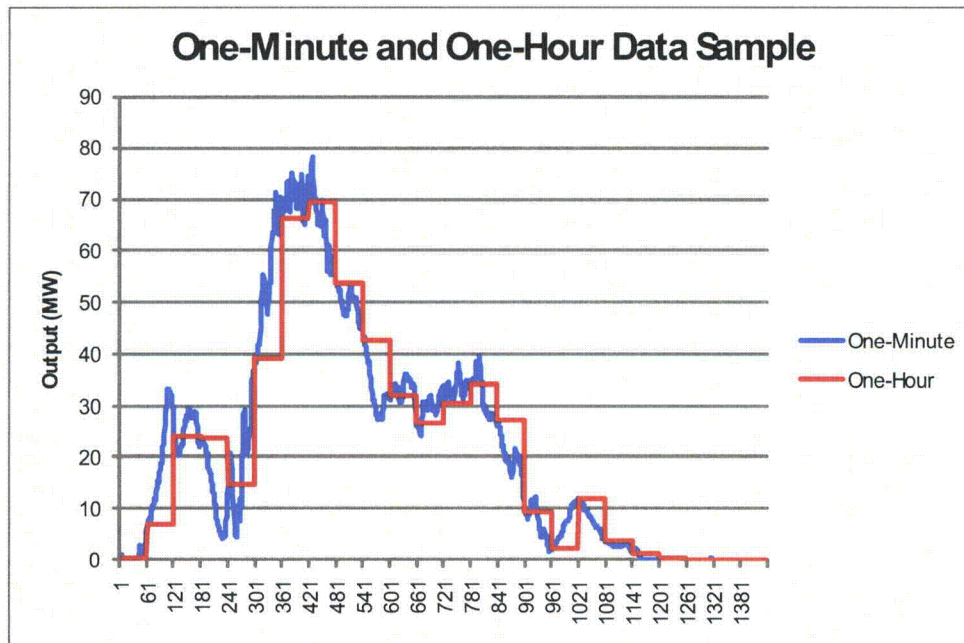


Figure 9. Sample of one-minute data for a single wind project site, overlaid on the corresponding one-hour data, for a 24-hour period beginning 6 PM on October 13, 2005.

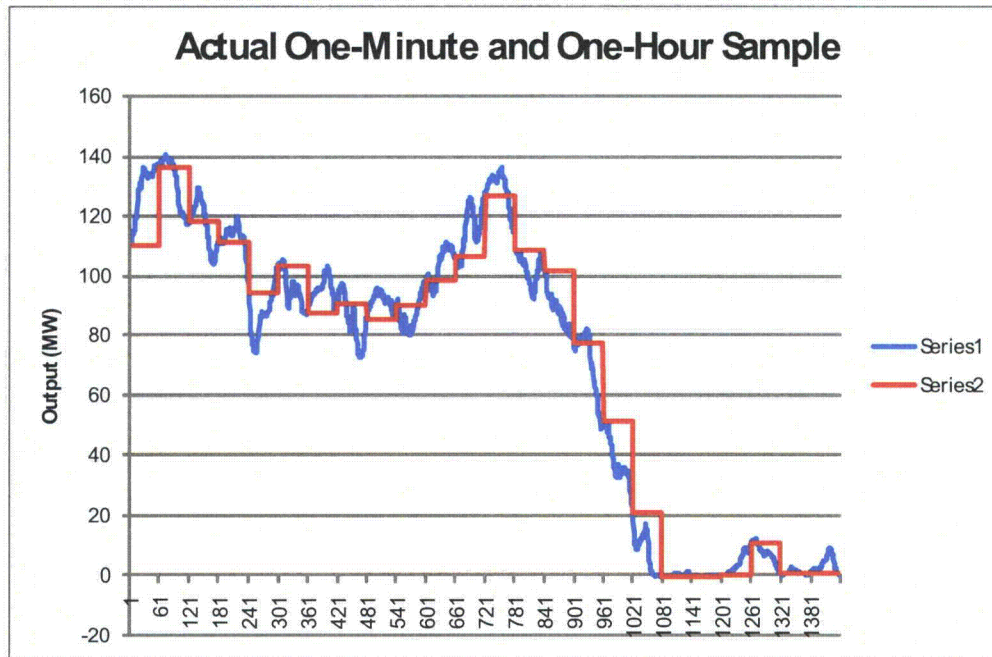


Figure 10. Sample of one-minute data for a single wind project site, overlaid on the corresponding one-hour data, for a 24-hour period beginning 6 PM on August 13, 2005.

Figure 11 compares the distribution of step changes of one-minute plant output for an existing project in Texas and for the simulated data for the same location. As with the one-hour step changes, the distributions are superficially very similar. A closer examination shows that the actual plant output rose or dropped in one minute by amounts greater than 5% of the rated capacity of the project much more often than a normal distribution of changes would allow.¹⁰ In the largest such change at this project, the output increased from zero to 80.5 MW in one minute. Almost certainly this indicates the restoration of the grid connection after an outage or curtailment rather than a surge of production caused by a project-wide wind gust. Analysis of the output data suggests that almost one-minute step changes greater than 5% of rated capacity are not caused by wind fluctuations but by some other factor, such as strings of turbines going on or off line. Such events were therefore excluded from the training sample in creating the one-minute wind output data, as described in section 2.3.

¹⁰ At this project, the standard deviation of step changes, as a fraction of rated capacity, is about 0.9%. A 5% change is therefore more than 5 standard deviations. The probability of such an event occurring by chance, assuming a normal distribution of changes, is about 1×10^{-7} , implying one such event in 20 years. Approximately 1300 such changes were actually observed at this project in 2005.

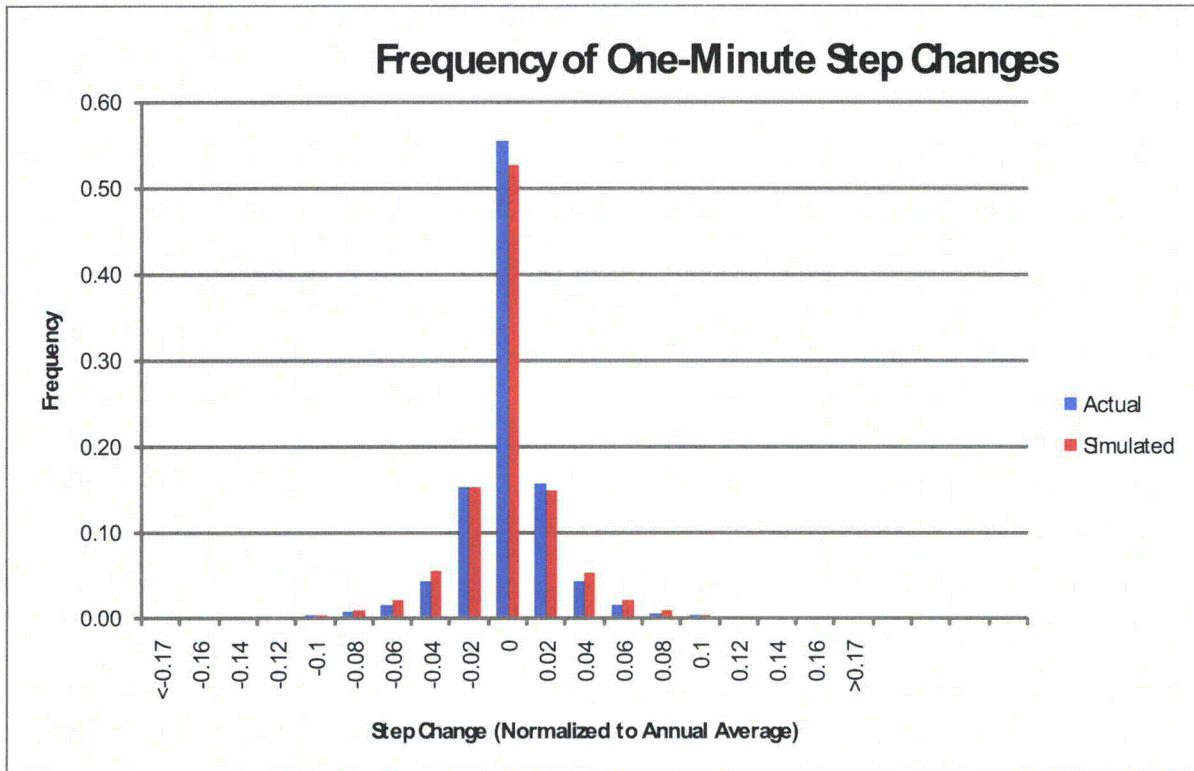


Figure 11. Frequency distribution of step changes of simulated and actual one-minute output for a single wind project.

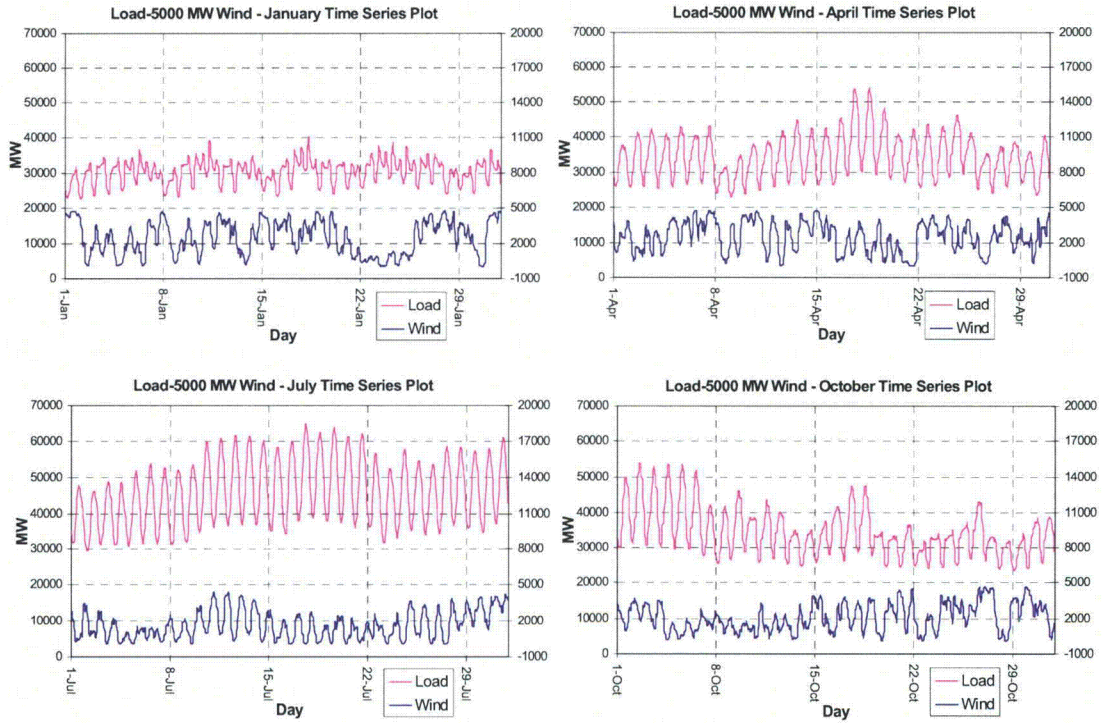
4 CONCLUSIONS

AWS Truwind employed its MesoMap system and a variety of other tools to produce data files characterizing the hourly output of up to 4000 MW of capacity in each of 25 CREZs for two continuous historical years. The simulated output values were adjusted to match observed diurnal patterns using tall tower data obtained by AWS Truwind from various parts of the state. AWS Truwind also simulated next-day and four-hour forecasts, as well as one-minute plant output data, for the same sites and time period. The results have been verified through comparisons with one-minute data from existing wind projects as well as other sources of information. In general, the seasonal and diurnal patterns, rates of change, and distributions of step changes match the behavior of existing wind projects very well, and the accuracy of the simulated forecasts is consistent with actual forecasts in California and Texas. The data therefore appear to provide a sound basis for the study of ancillary service requirements for wind energy projects in Texas.

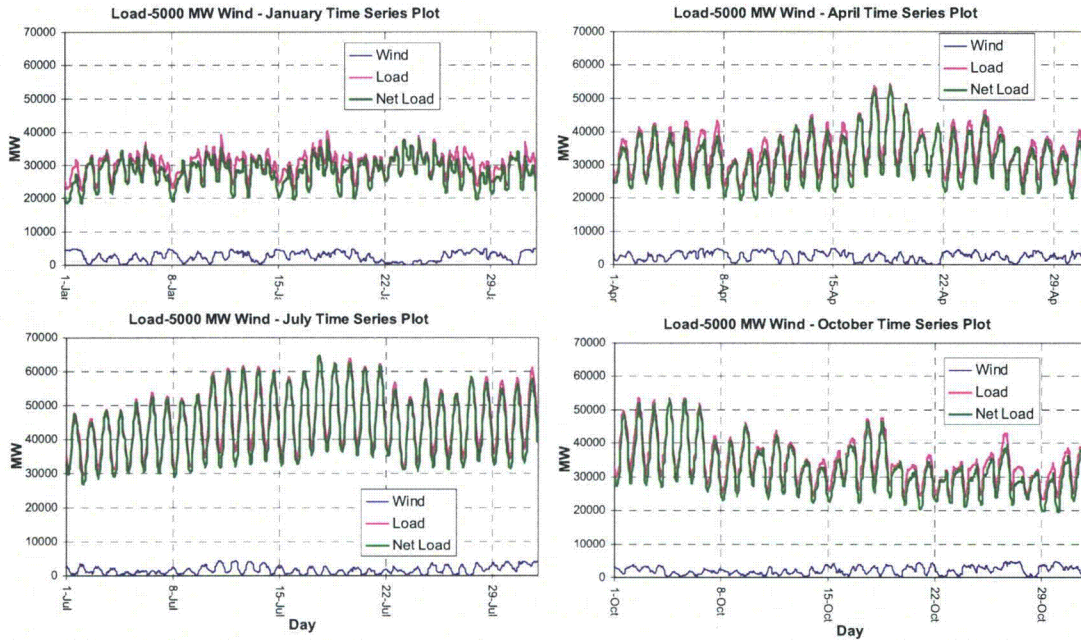
APPENDIX C – SUPPLEMENTAL VARIABILITY PLOTS

C.1 Time Series Plots and Average Daily Profiles

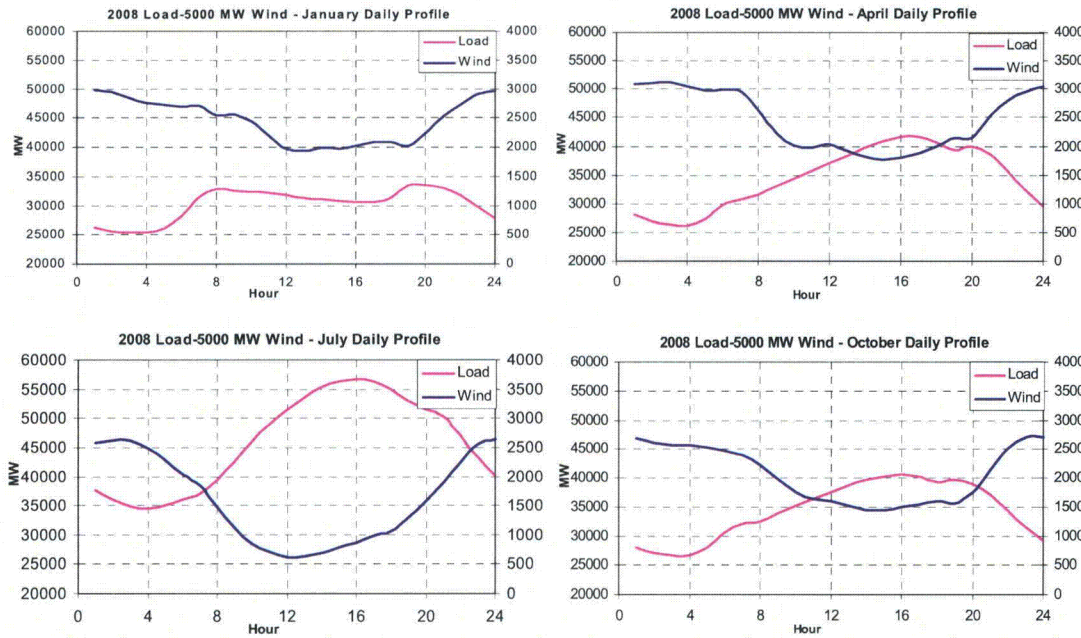
Load-5000 MW of Wind Capacity (Study Year) Time Series Plots



Appendices



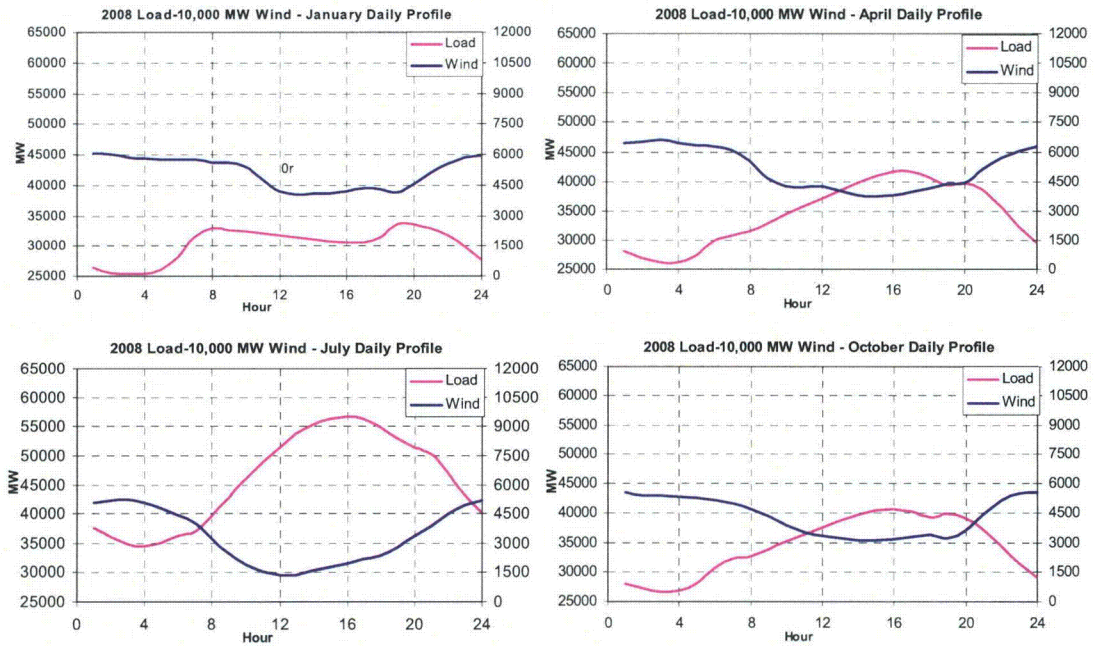
Average Daily Profiles



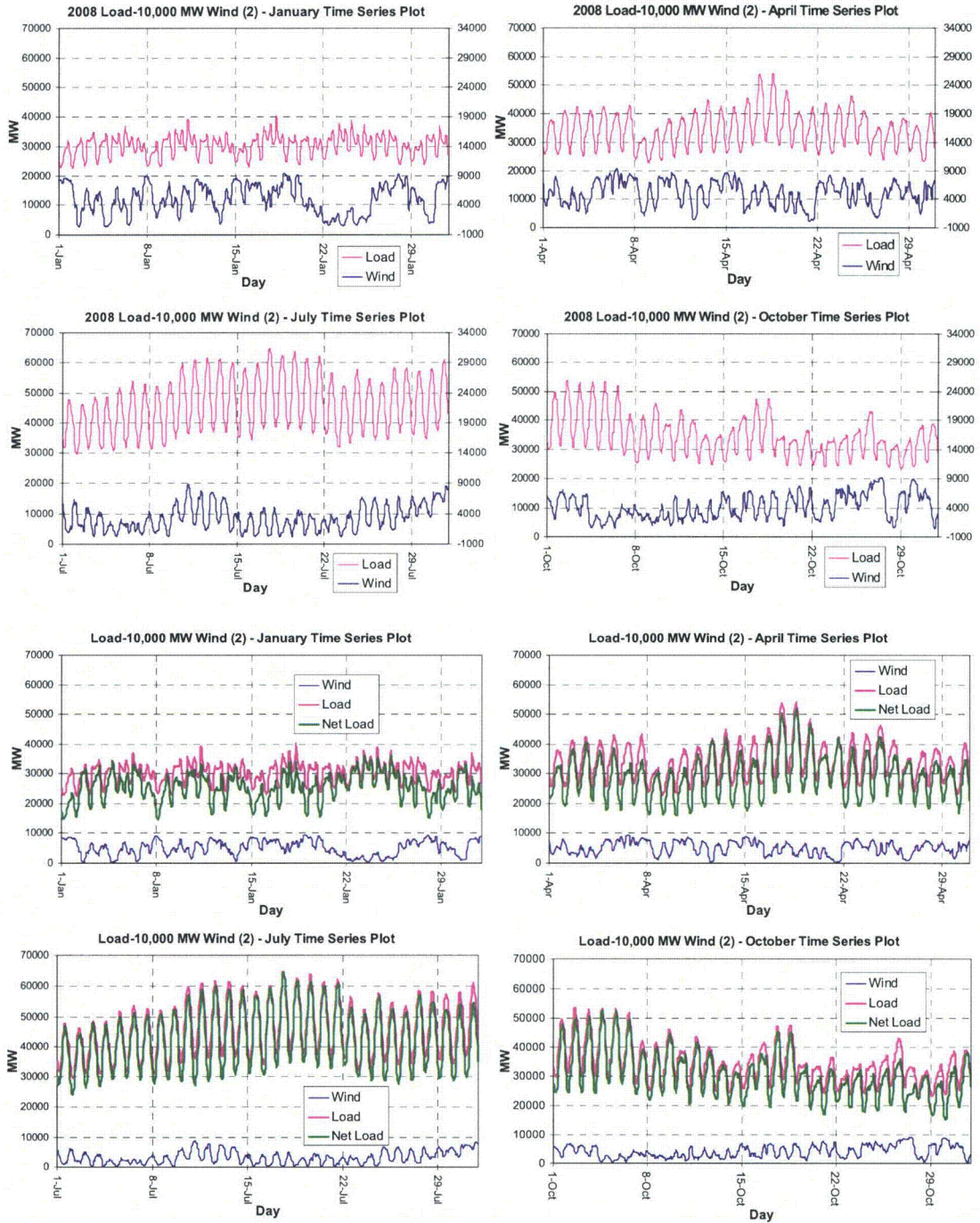
Load-10,000 MW of Wind Capacity, Case 1 (Study Year) Time Series Plots



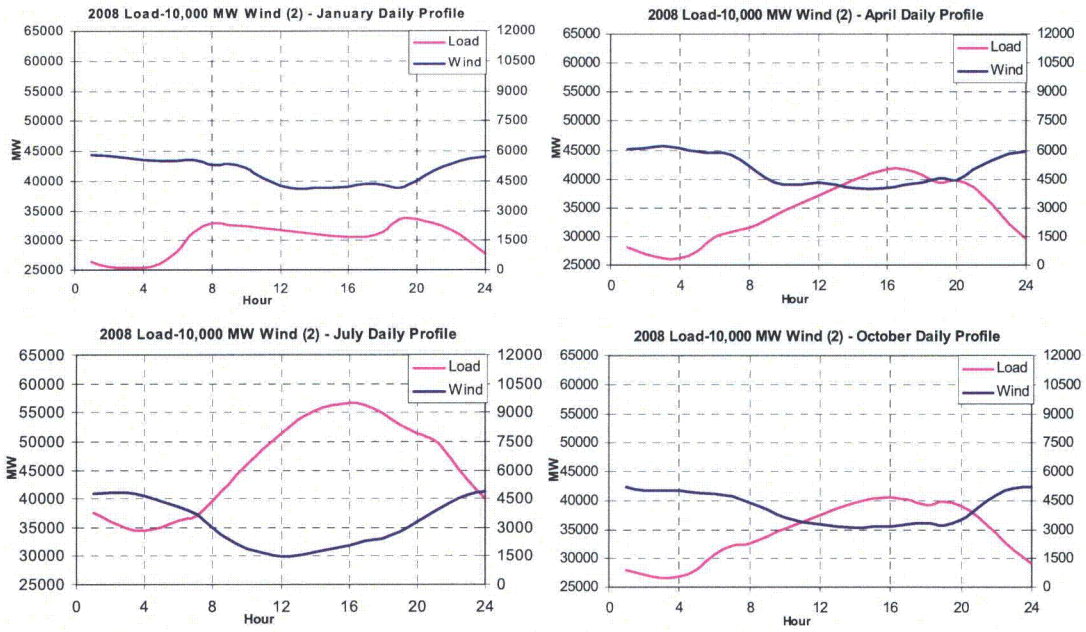
Average Daily Profiles



Load-10,000 MW of Wind Capacity, Case 2 (Study Year) Time Series Plots



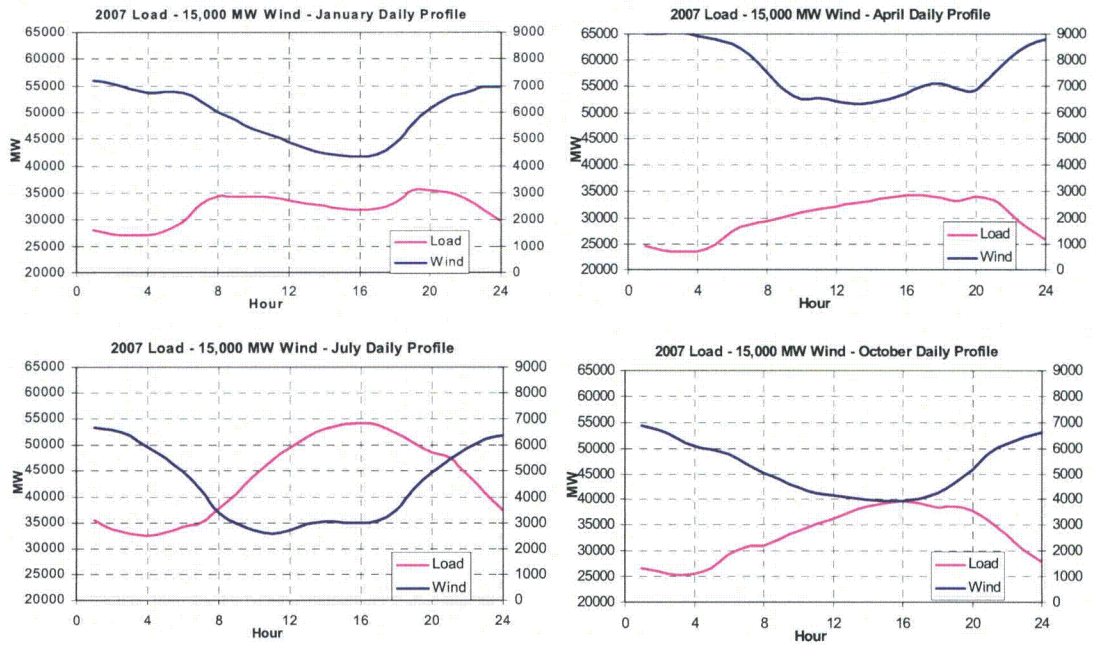
Average Daily Profiles



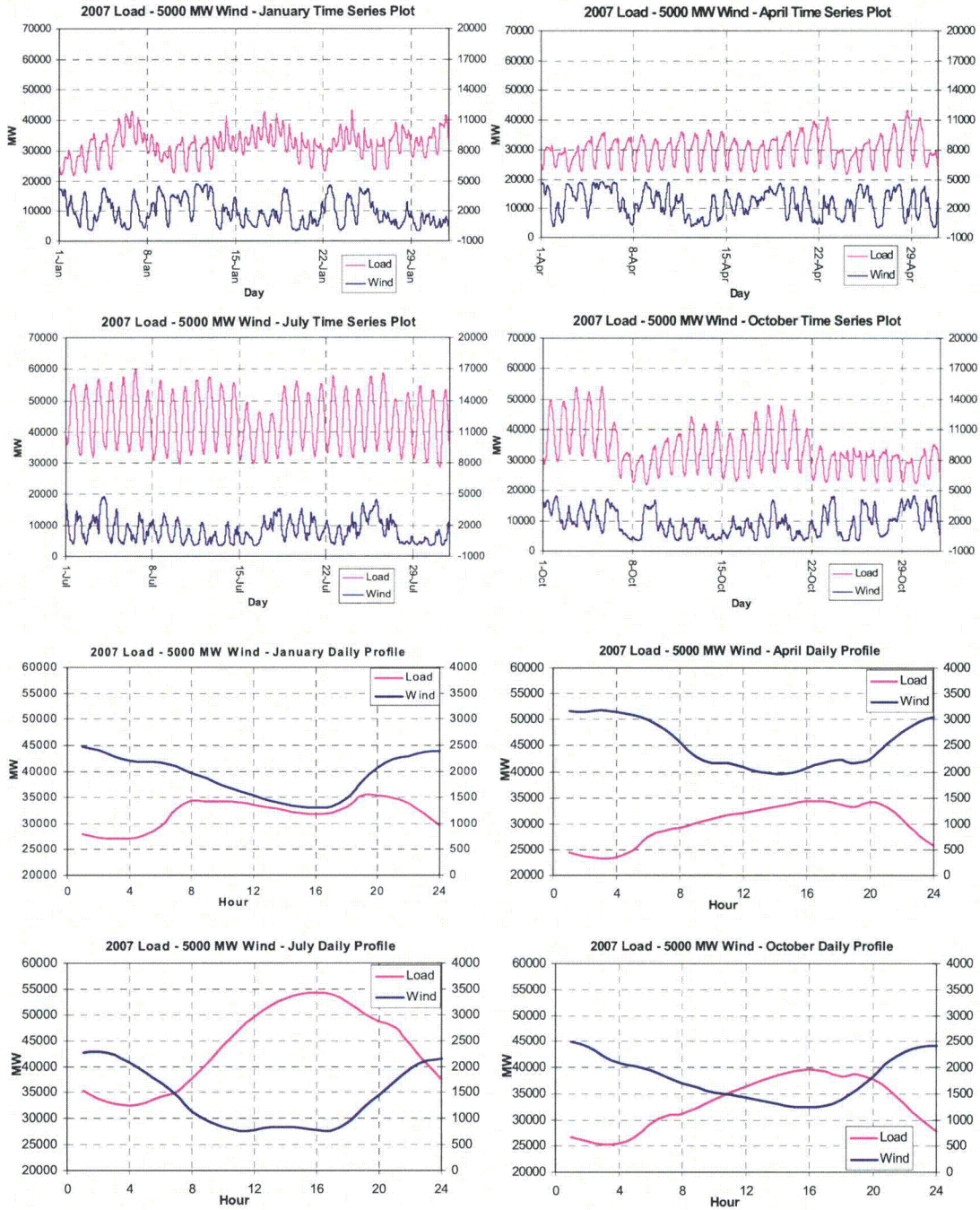
Load-15,000 MW of Wind Capacity, (Study Year) Time Series Plots



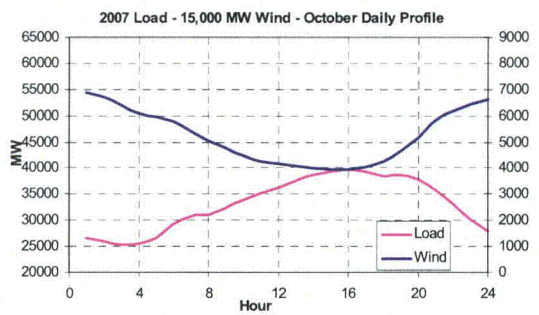
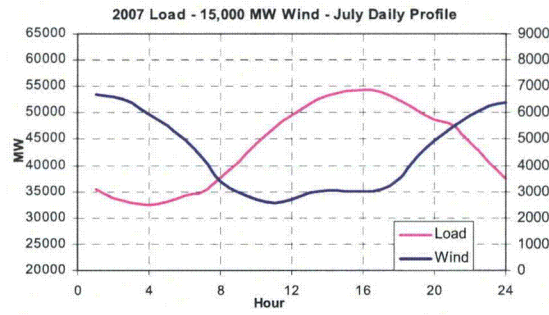
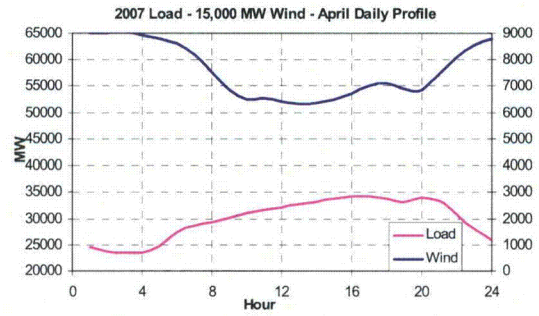
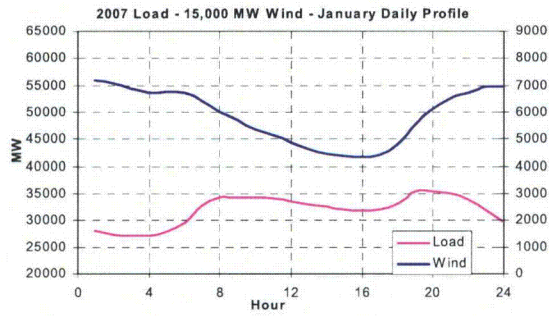
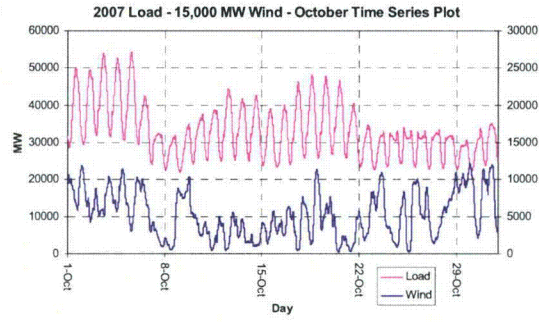
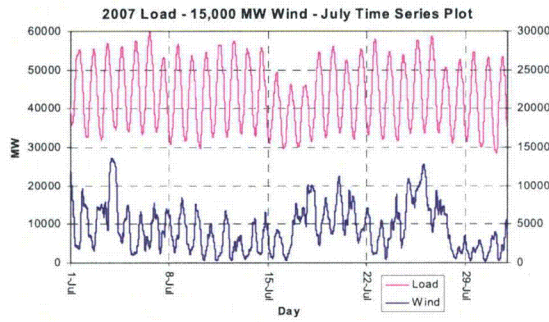
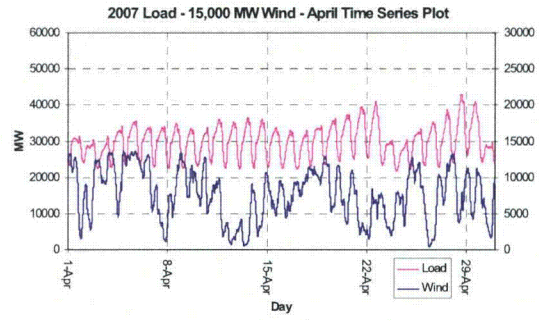
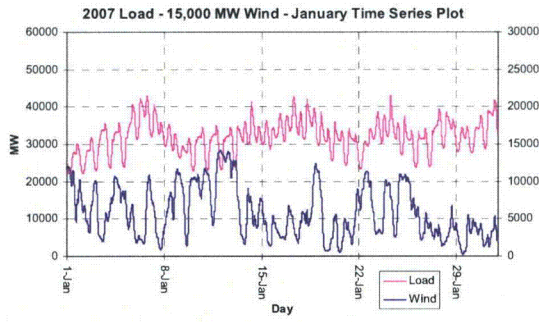
Average Daily Profiles



Load-5000 MW of Wind Capacity (Previous Year)



Appendices



C.2 Frequency Distribution of Deltas

One-Minute Load-Wind Variability – Summary

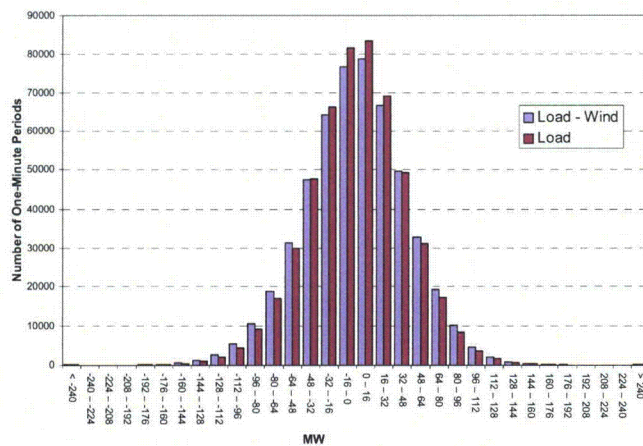
From Study Year Data

Case	Penetration	$\sigma_{\text{Load-Wind Delta (MW)}}$	Max. Negative Load-Wind Delta (MW)	Max. Positive Load-Wind Delta (MW)	No. Deltas > 2.5 (load) σ (-/+)	σ % Increase with Wind
Base Case: Study Year Load w/ no Wind	0%	43.22	-513.7	491.6	4696 / 3805	--
Study Year Load w/ 5000 MW Wind	7.6%	45.56	-526.6	507.2	6181 / 4807	5.4%
Study Year Load w/ 10,000 MW Wind (1)	15.3%	47.74	-534.0	529.3	7635 / 6041	10.5%
Study Year Load w/ 10,000 MW Wind (2)	15.3%	47.27	-536.7	520.4	7350 / 5757	9.4%
Study Year Load w/ 15,000 MW Wind	22.9%	49.67	-552.6	538.3	9277 / 7408	14.9%

From Prev. Year Data

Case	Penetration	$\sigma_{\text{Load-Wind Delta (MW)}}$	Max. Negative Load-Wind Delta (MW)	Max. Positive Load-Wind Delta (MW)	No. Deltas > 2.5 (load) σ (-/+)	σ % Increase with Wind
Base Case: Year 1 Load w/ no Wind	0%	42.81	-519.4	518.3	4511 / 3976	--
Year 1 Load w/ 5000 MW Wind	8%	45.00	-526.2	541.5	5949 / 4772	5.1%
Year 1 Load w/ 10,000 MW Wind (1)	16.0%	47.07	-527.0	562.4	7397 / 5887	10.0%
Year 1 Load w/ 10,000 MW Wind (2)	16.0%	46.60	-521.2	557.3	7071 / 5635	8.9%
Year 1 Load w/ 15,000 MW Wind	24.0%	48.81	-521.5	561.7	8924 / 7110	14.0%

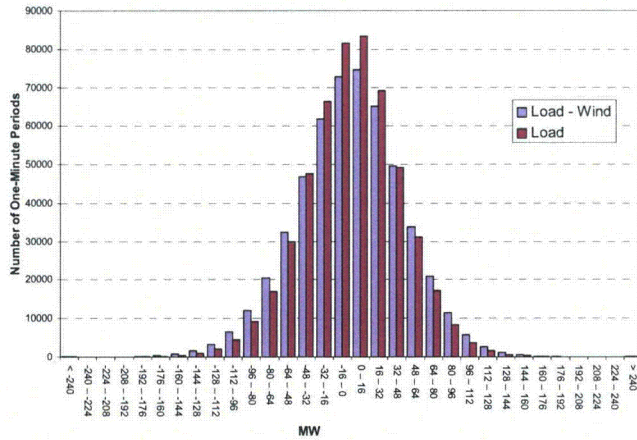
One-Minute Load-Wind Variability – 5000 MW



Statistical Summary

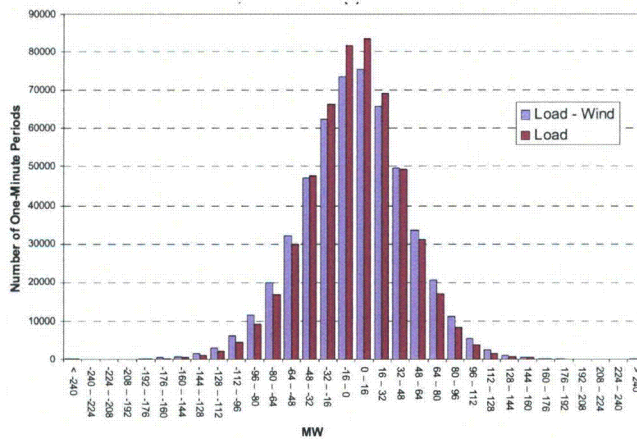
	Load-alone (MW)	With Wind (MW)
Mean (-/+ Deltas)	-34.0 / 33.3	-36.0 / 35.2
Sigma (Delta)	43.22	45.56
Min. Delta	-513.7	-526.6
Max. Delta	491.6	507.2

One-Minute Load-Wind Variability – 10,000 MW - 1



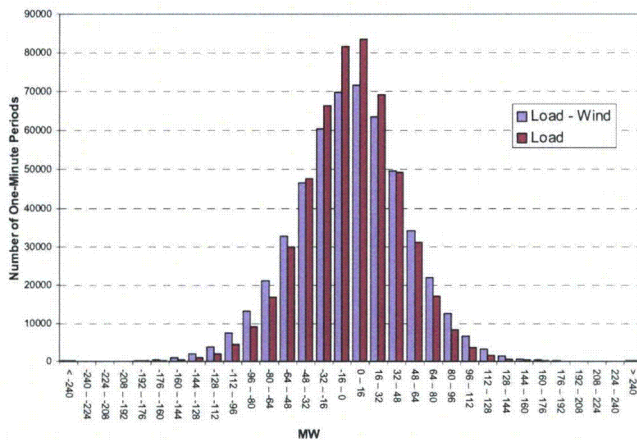
	Load-alone (MW)	With Wind (MW)
Mean (-/+ Deltas)	-34.0 / 33.3	
Sigma (Delta)	43.22	47.74
Min. Delta	-513.7	-534.0
Max. Delta	491.6	529.3

One-Minute Load-Wind Variability – 10,000 MW - 2



	Load-alone (MW)	With Wind (MW)
Mean (-/+ Deltas)	-34.0 / 33.3	
Sigma (Delta)	43.22	47.27
Min. Delta	-513.7	-536.7
Max. Delta	491.6	520.4

One-Minute Load-Wind Variability – 15,000 MW



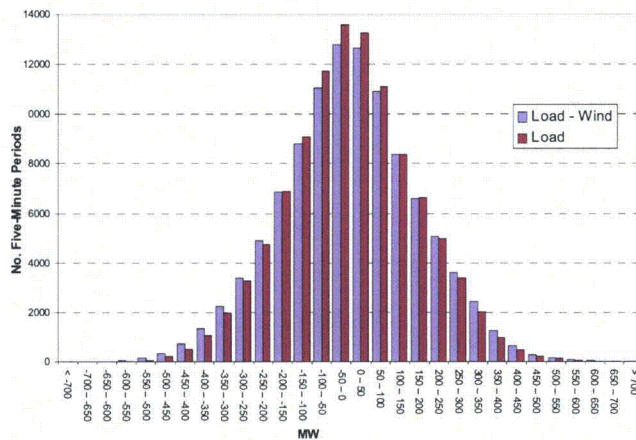
	Load-alone (MW)	With Wind (MW)
Mean (-/+ Deltas)	-34.0 / 33.3	
Sigma (Delta)	43.22	49.67
Min. Delta	-513.7	-552.6
Max. Delta	491.6	538.3

Five-Minute Load-Wind Variability – Summary

From Study Year Data						
Case	Penetration	$\sigma_{\text{Load-Wind}}$ (MW)	Max. Negative Load-Wind Delta (MW)	Max. Positive Load-Wind Delta (MW)	No. Deltas > 2.5 (load) σ (-/+)	σ % Increase with Wind
Base Case: Study Year Load w/ no Wind	0%	167.39	-881.2	958.8	621 / 787	--
Study Year Load w/ 5000 MW Wind	7.6%	177.29	-916.6	988.9	1007 / 977	5.9%
Study Year Load w/ 10,000 MW Wind (1)	15.3%	188.01	-951.1	992.1	1482 / 1368	12.3%
Study Year Load w/ 10,000 MW Wind (2)	15.3%	185.17	-938.3	1002.4	1353 / 1273	10.6%
Study Year Load w/ 15,000 MW Wind	22.9%	197.12	-948.2	1022.2	1970 / 1856	17.8%

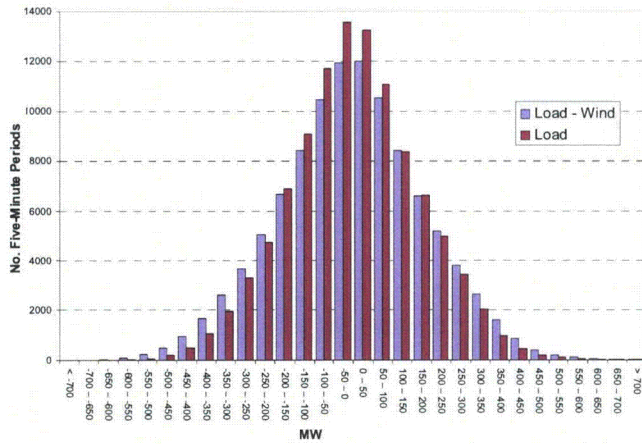
From Prev. Year Data						
Case	Penetration	$\sigma_{\text{Load-Wind}}$ (MW)	Max. Negative Load-Wind Delta (MW)	Max. Positive Load-Wind Delta (MW)	No. Deltas > 2.5 (load) σ (-/+)	σ % Increase with Wind
Base Case: Year 1 Load w/ no Wind	0%	165.61	-900.9	858.3	644 / 860	--
Year 1 Load w/ 5000 MW Wind	8%	174.68	-935.6	876.2	1068 / 1025	5.5%
Year 1 Load w/ 10,000 MW Wind (1)	16.0%	184.84	-987.3	941.2	1515 / 1413	11.6%
Year 1 Load w/ 10,000 MW Wind (2)	16.0%	182.05	-963.5	878.3	1409 / 1286	9.9%
Year 1 Load w/ 15,000 MW Wind	24.0%	193.04	-958.5	991.9	1993 / 1769	16.6%

Five -Minute Load-Wind Variability – 5000 MW



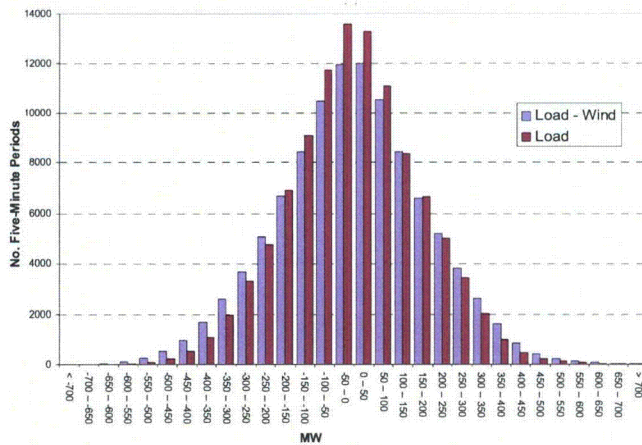
	Load-alone (MW)	With Wind (MW)
Mean (-/+ Deltas)		
Sigma (Delta)	167.39	177.29
Min. Delta	-881.2	-916.6
Max. Delta	958.8	988.9

Five -Minute Load-Wind Variability – 10,000 MW (1)



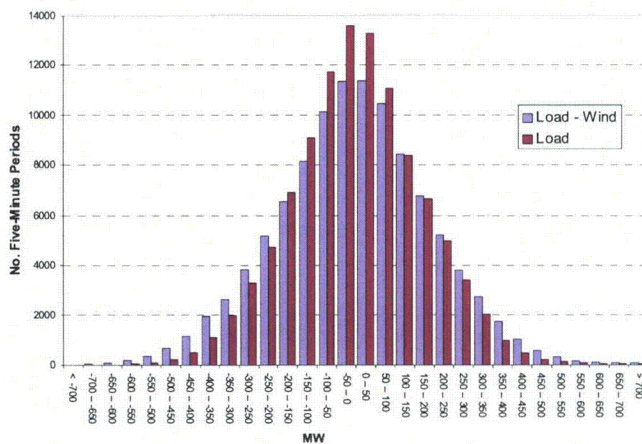
	Load-alone (MW)	With Wind (MW)
Mean (-/+ Deltas)		
Sigma (Delta)	167.39	188.01
Min. Delta	-881.2	-951.1
Max. Delta	958.8	992.1

Five -Minute Load-Wind Variability – 10,000 MW (2)



	Load-alone (MW)	With Wind (MW)
Mean (-/+ Deltas)		
Sigma (Delta)	167.39	185.17
Min. Delta	-881.2	-938.3
Max. Delta	958.8	1002.4

Five -Minute Load-Wind Variability – 15,000 MW



	Load-alone (MW)	With Wind (MW)
Mean (-/+ Deltas)		
Sigma (Delta)	167.39	197.12
Min. Delta	-881.2	-948.2
Max. Delta	958.8	1022.2

Fifteen-Minute Load-Wind Variability – Summary

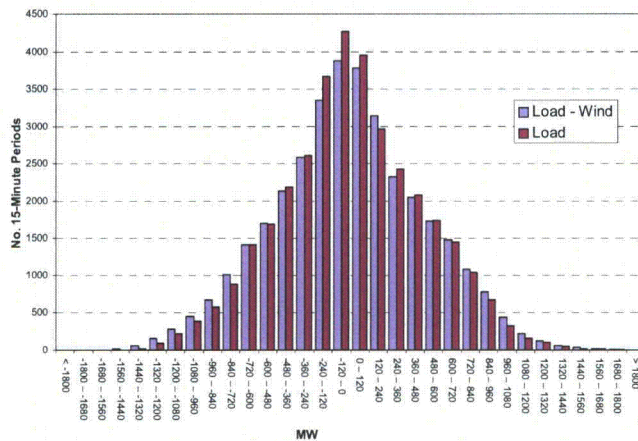
From Study Year Data

Case	Penetration	$\sigma_{\text{Load-Wind Delta (MW)}}$	Max. Negative Load-Wind Delta (MW)	Max. Positive Load-Wind Delta (MW)	No. Deltas > 2.5 (load) σ (-/+)	σ % Increase with Wind
Base Case: Study Year Load w/ no Wind	0%	467.06	-1587.5	1863.2	161 / 238	--
Study Year Load w/ 5000 MW Wind	7.6%	496.09	-1809.3	1943.7	316 / 306	6.2%
Study Year Load w/ 10,000 MW Wind (1)	15.3%	528.46	-1906.8	2143.5	476 / 456	13.1%
Study Year Load w/ 10,000 MW Wind (2)	15.3%	519.56	-1880.5	2087.9	444 / 414	11.2%
Study Year Load w/ 15,000 MW Wind	22.9%	555.50	-2036.7	2433.5	679 / 645	18.9%

From Prev. Year Data

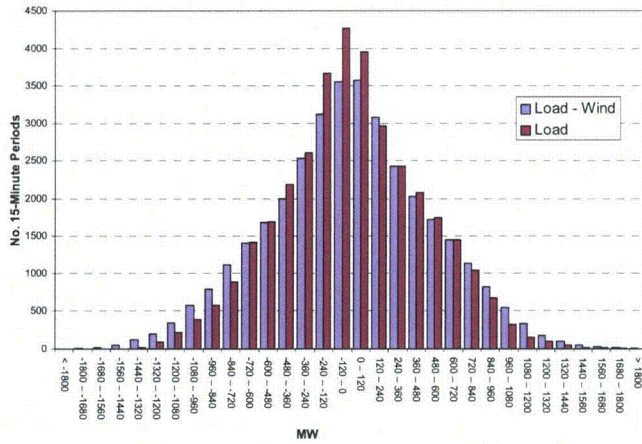
Case	Penetration	$\sigma_{\text{Load-Wind Delta (MW)}}$	Max. Negative Load-Wind Delta (MW)	Max. Positive Load-Wind Delta (MW)	No. Deltas > 2.5 (load) σ (-/+)	σ % Increase with Wind
Base Case: Year 1 Load w/ no Wind	0%	463.62	-1555.7	1664.0	161 / 258	--
Year 1 Load w/ 5000 MW Wind	8%	489.95	-1686.2	1777.5	342 / 314	5.7%
Year 1 Load w/ 10,000 MW Wind (1)	16.0%	520.59	-1740.8	1979.3	510 / 429	12.3%
Year 1 Load w/ 10,000 MW Wind (2)	16.0%	511.82	-1732.3	1855.0	471 / 398	10.4%
Year 1 Load w/ 15,000 MW Wind	24.0%	544.73	-1876.0	2158.9	712 / 597	17.5%

Fifteen -Minute Load-Wind Variability – 5000 MW



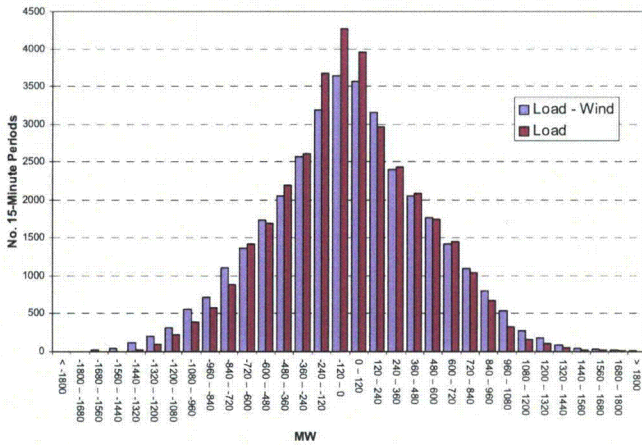
	Load-alone (MW)	With Wind (MW)
Mean (-/+ Deltas)		
Sigma (Delta)	467.06	496.09
Min. Delta	-1587.5	-1809.3
Max. Delta	1863.2	1943.7

Fifteen -Minute Load-Wind Variability – 10,000 MW (1)



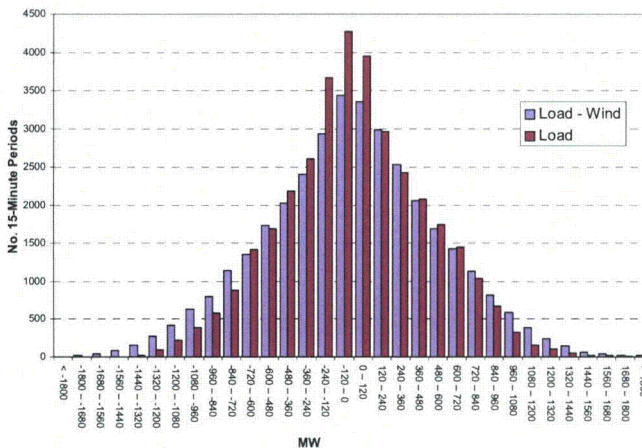
	Load-alone (MW)	With Wind (MW)
Mean (-/+ Deltas)		
Sigma (Delta)	467.06	528.46
Min. Delta	-1587.5	-1906.8
Max. Delta	1863.2	2143.5

Fifteen -Minute Load-Wind Variability – 10,000 MW (2)



	Load-alone (MW)	With Wind (MW)
Mean (-/+ Deltas)		
Sigma (Delta)	467.06	519.56
Min. Delta	-1587.5	-1880.5
Max. Delta	1863.2	2087.9

Fifteen -Minute Load-Wind Variability – 15,000 MW



	Load-alone (MW)	With Wind (MW)
Mean (-/+ Deltas)		
Sigma (Delta)	467.06	555.50
Min. Delta	-1587.5	-2036.7
Max. Delta	1863.2	2433.5

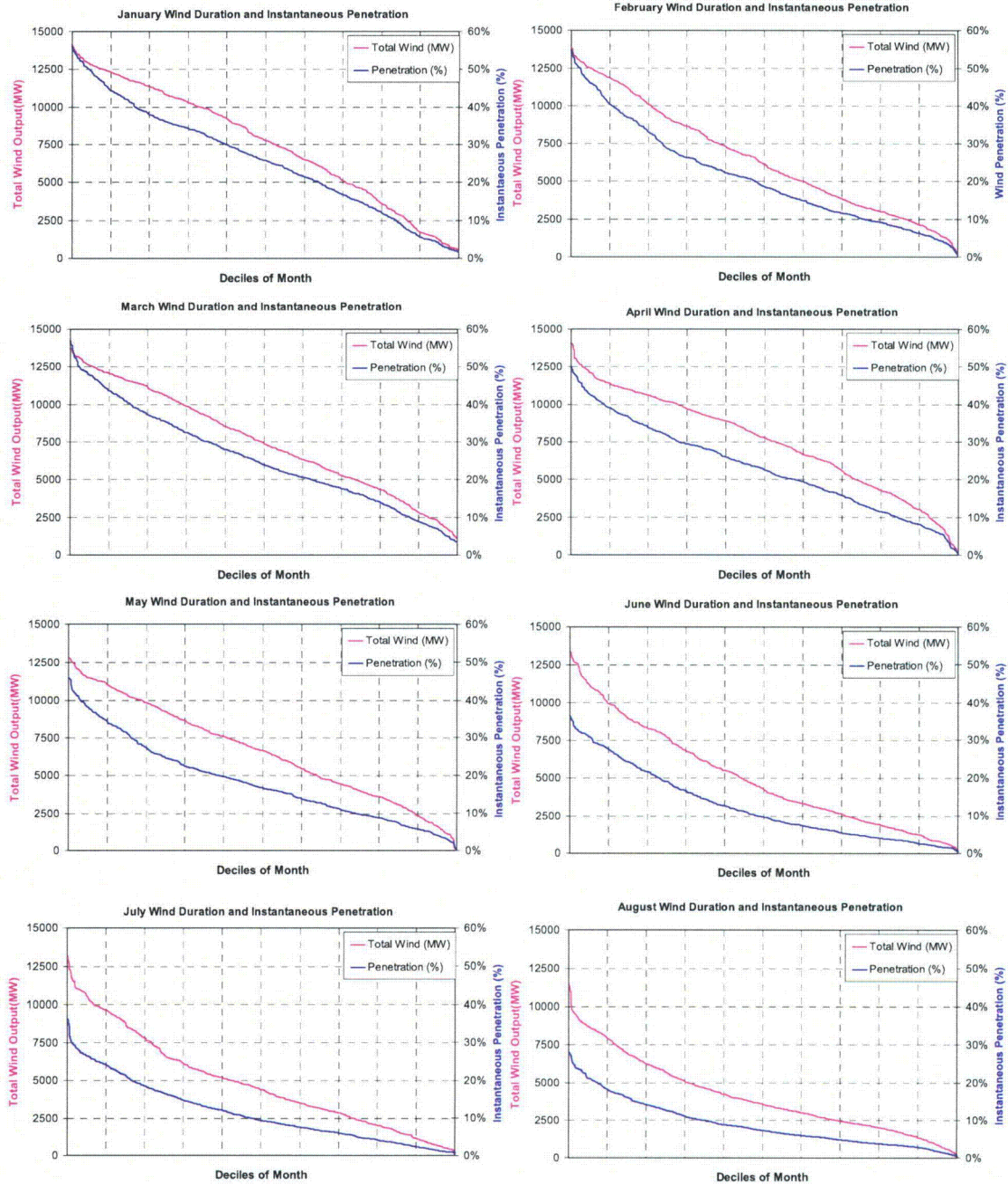
Thirty-Minute Load-Wind Variability – Summary

From Study Year Data

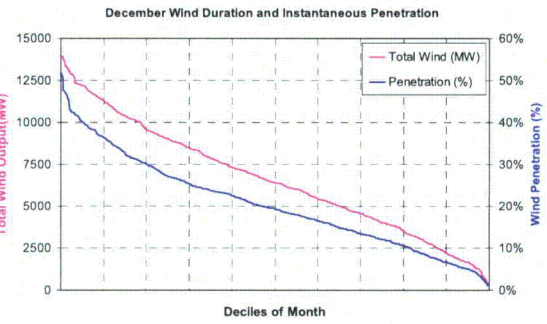
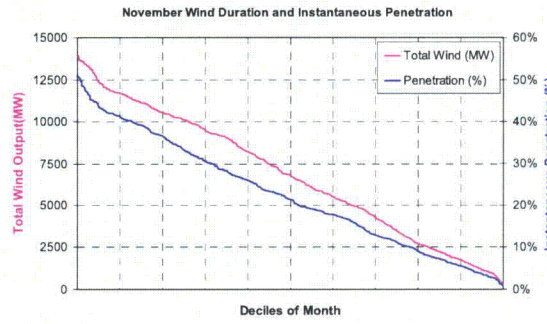
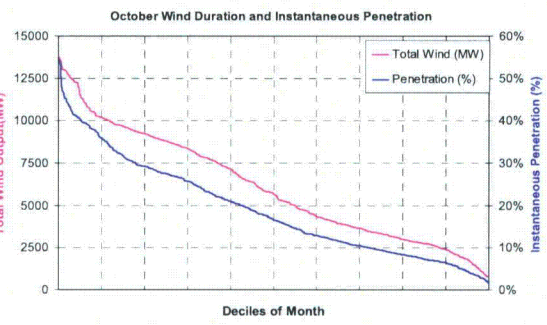
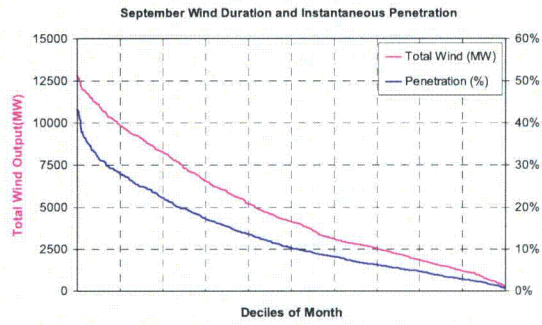
Case	Penetration	$\sigma_{\text{Load-Wind}}$ Delta (MW)	Max. Negative Load-Wind Delta (MW)	Max. Positive Load-Wind Delta (MW)	No. Deltas > 2.5 (load) σ (-/+)	σ % Increase with Wind
Base Case: Study Year Load w/ no Wind	0%	911	-2756	3101	71 / 80	–
Study Year Load w/ 5000 MW Wind	7.6%	967	-3138	3271	173 / 122	6.1%
Study Year Load w/ 10,000 MW Wind (1)	15.3%	1031	-3360	3928	249 / 209	13.1%
Study Year Load w/ 10,000 MW Wind (2)	15.3%	1013	-3300	3805	226 / 180	11.2%
Study Year Load w/ 15,000 MW Wind	22.9%	1083	-3612	4502	337 / 305	18.9%

C.3 Cumulative Duration Plots

Wind Generation Instantaneous Penetration

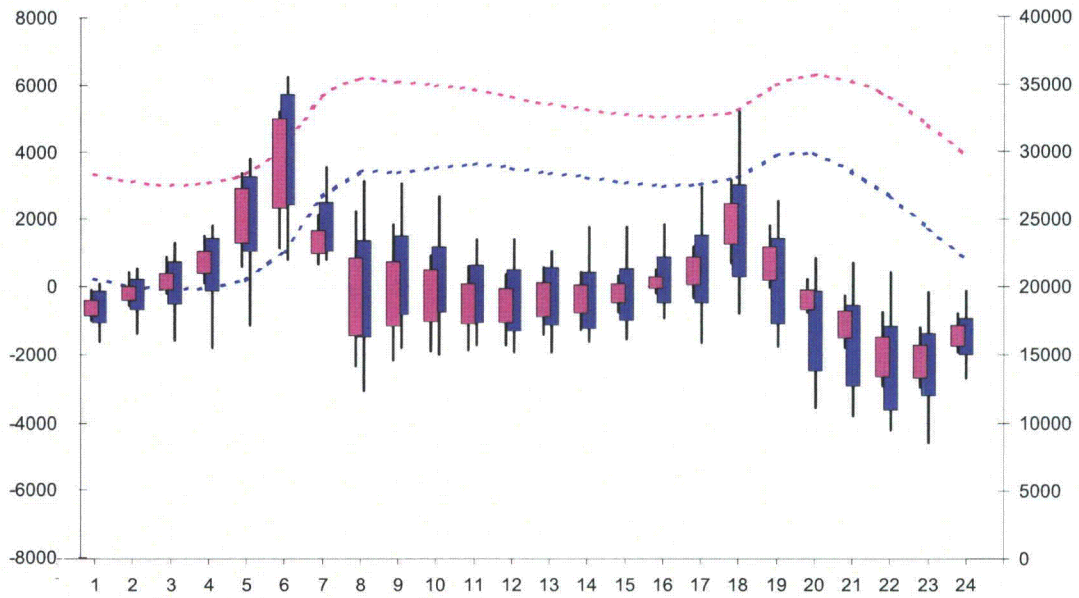


Appendices

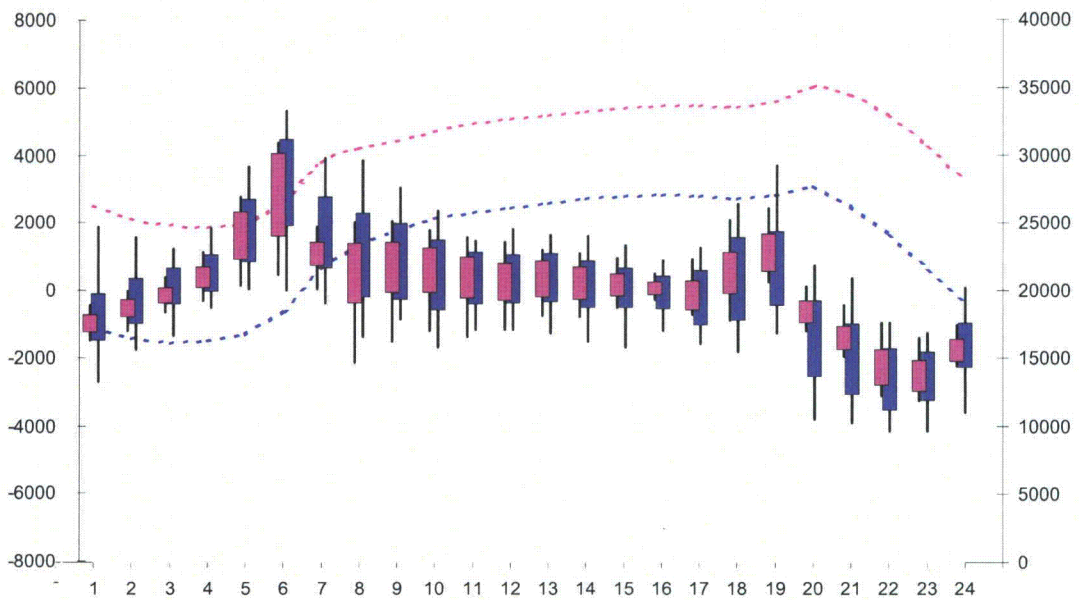


C.4 Variability by Time of Day

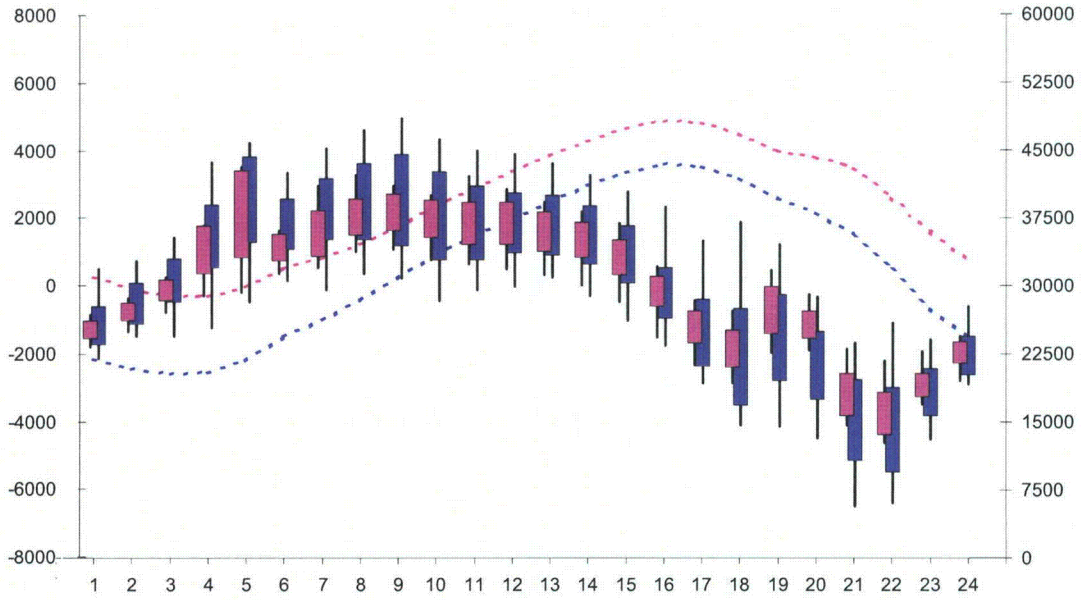
February Average Daily Profiles and Hourly Variability Load and Load-15,000 MW Of Wind Generation



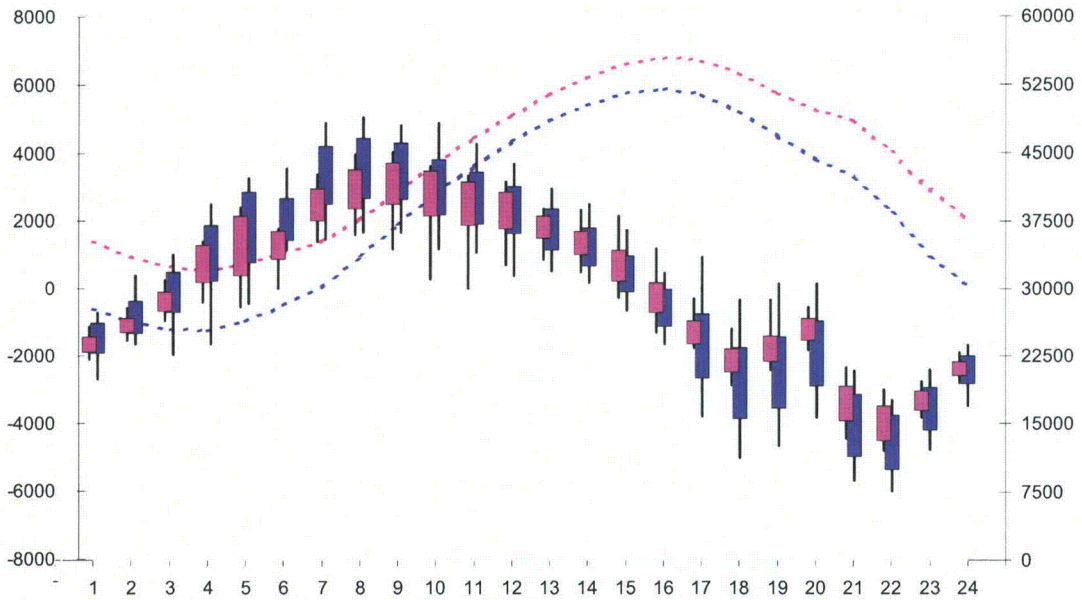
March Average Daily Profiles and Hourly Variability Load and Load-15,000 MW Of Wind Generation



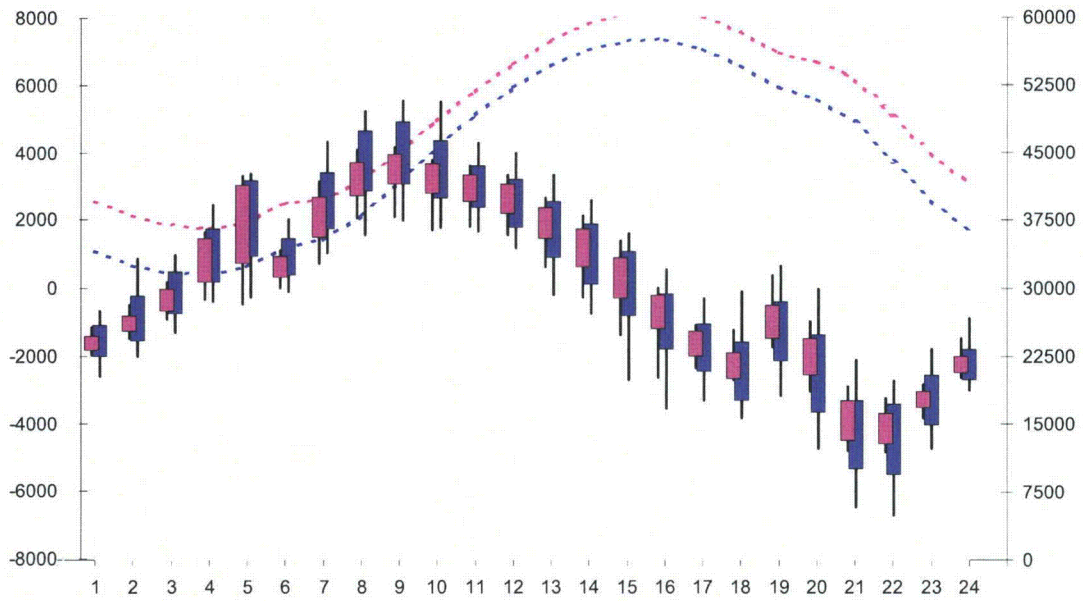
May Average Daily Profiles and Hourly Variability Load and Load-15,000 MW Of Wind Generation



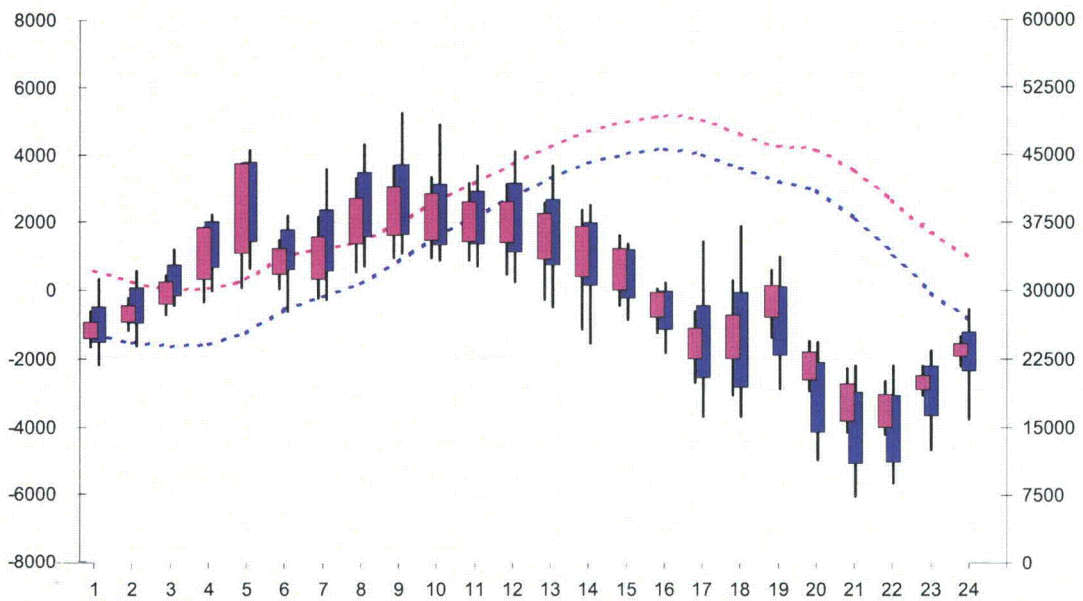
June Average Daily Profiles and Hourly Variability Load and Load-15,000 MW Of Wind Generation



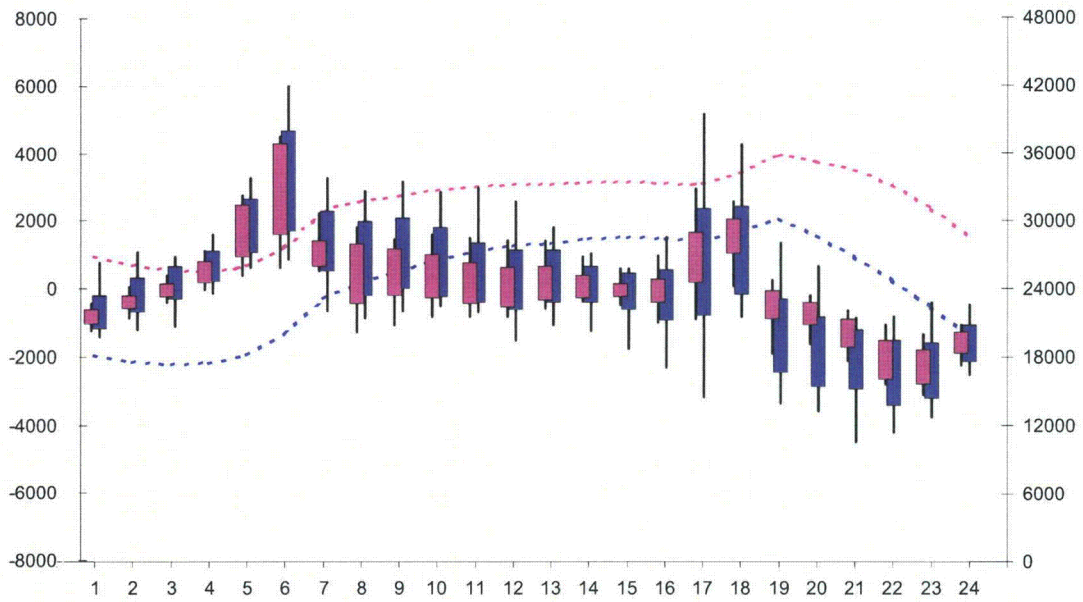
**August Daily Average Profiles and Forecast Errors
(Study Year Load with 15000 MW of Wind)**



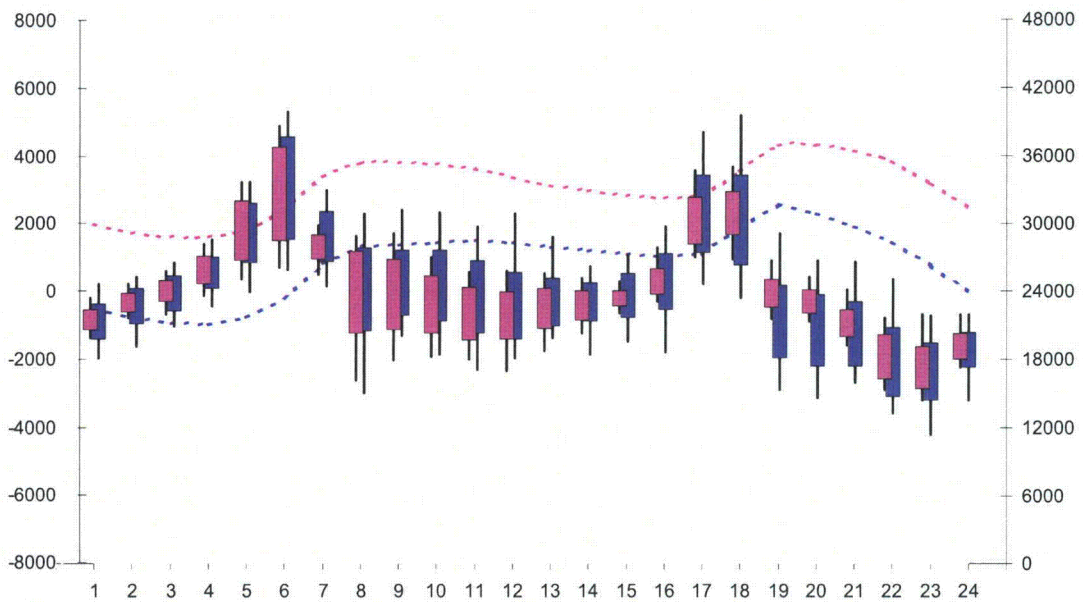
**September Daily Average Profiles and Forecast Errors
(Study Year Load with 15000 MW of Wind)**



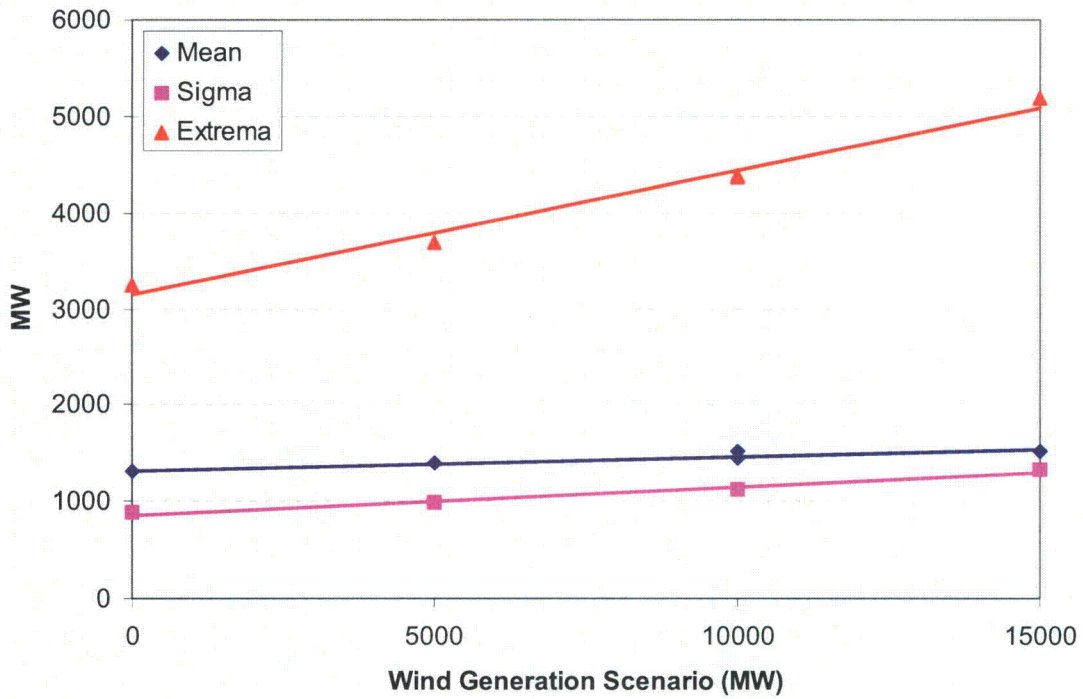
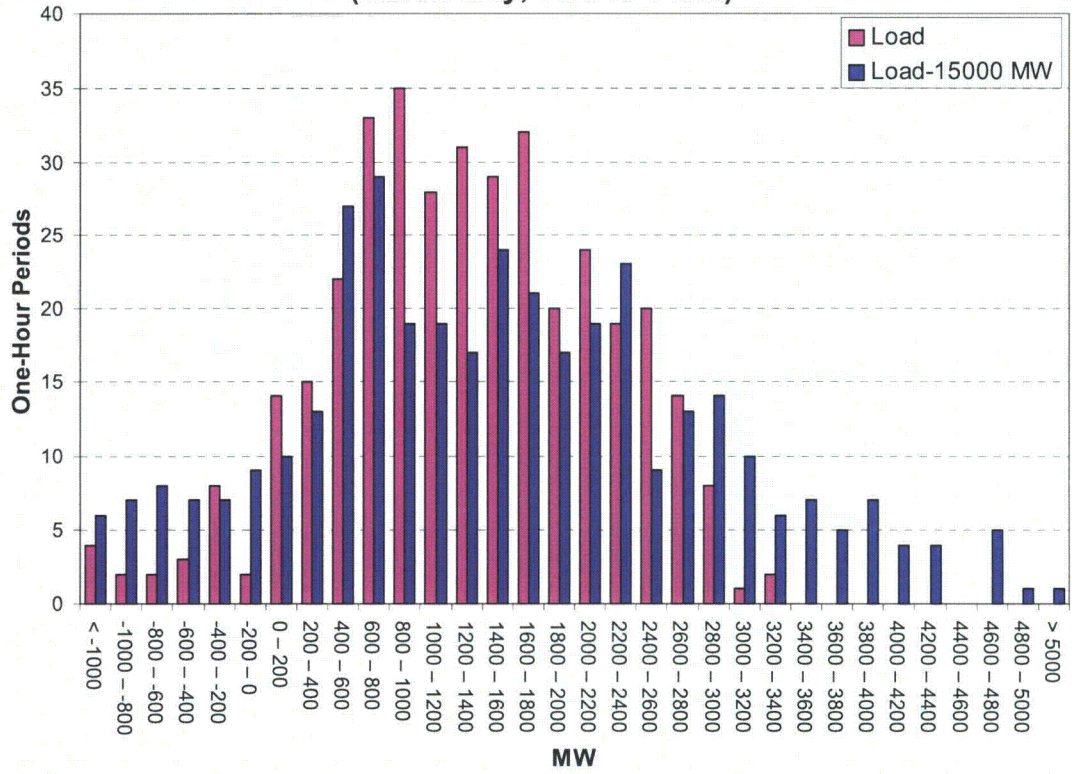
November Daily Average Profiles and Forecast Errors (Study Year Load with 15000 MW of Wind)



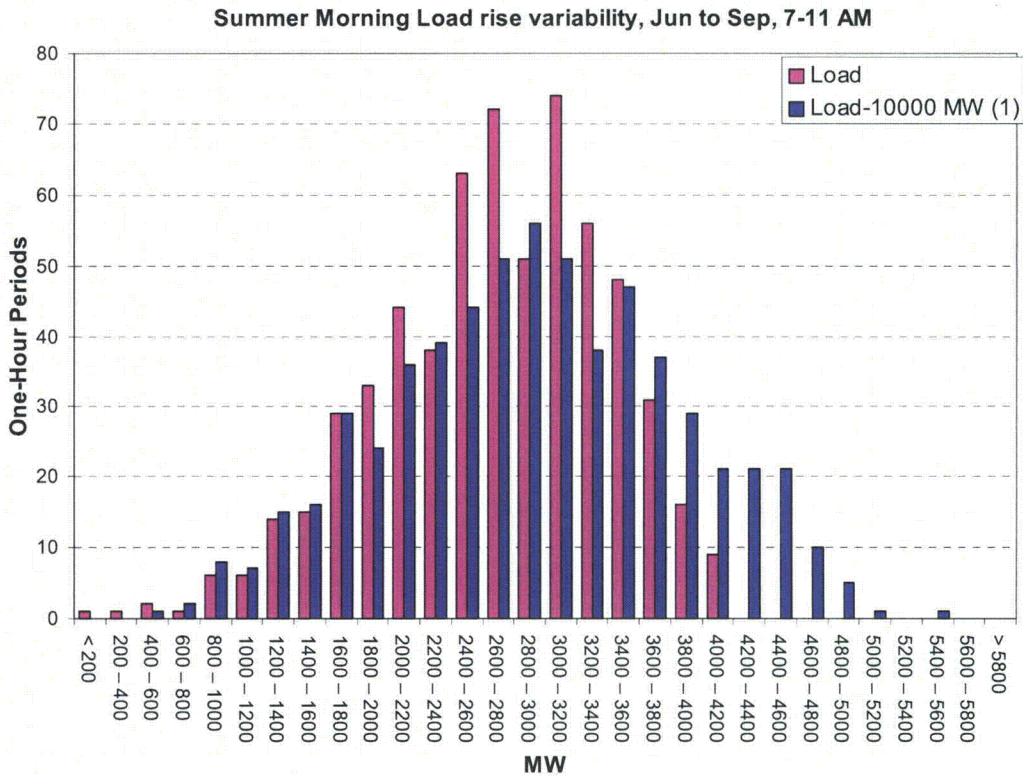
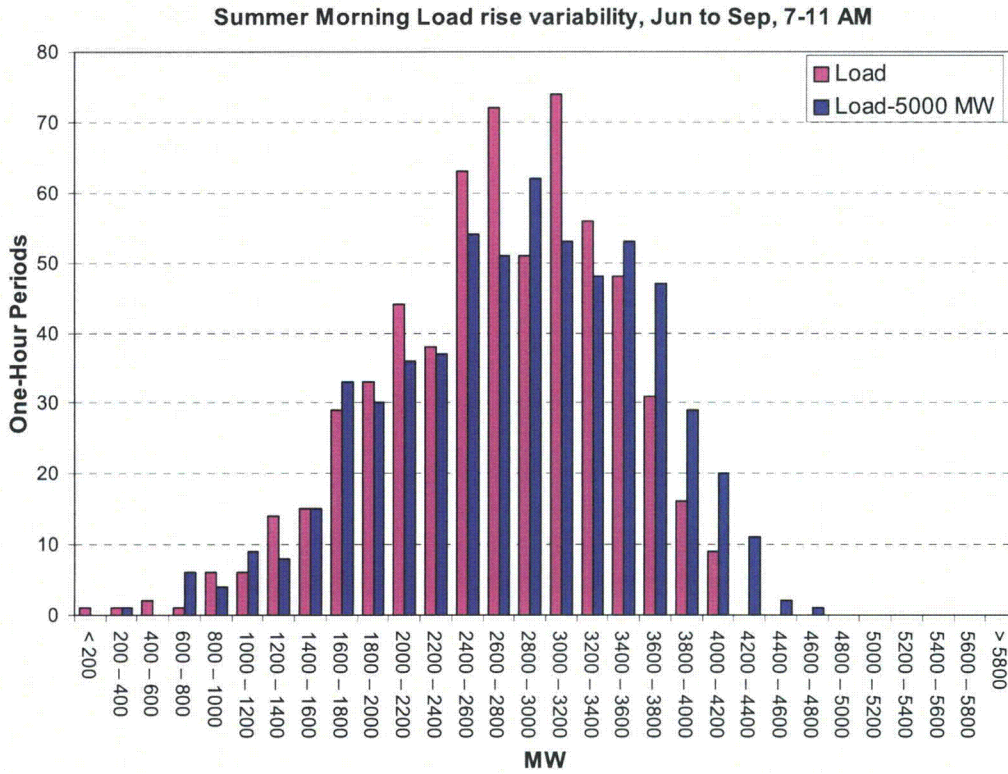
December Daily Average Profiles and Forecast Errors (Study Year Load with 15000 MW of Wind)



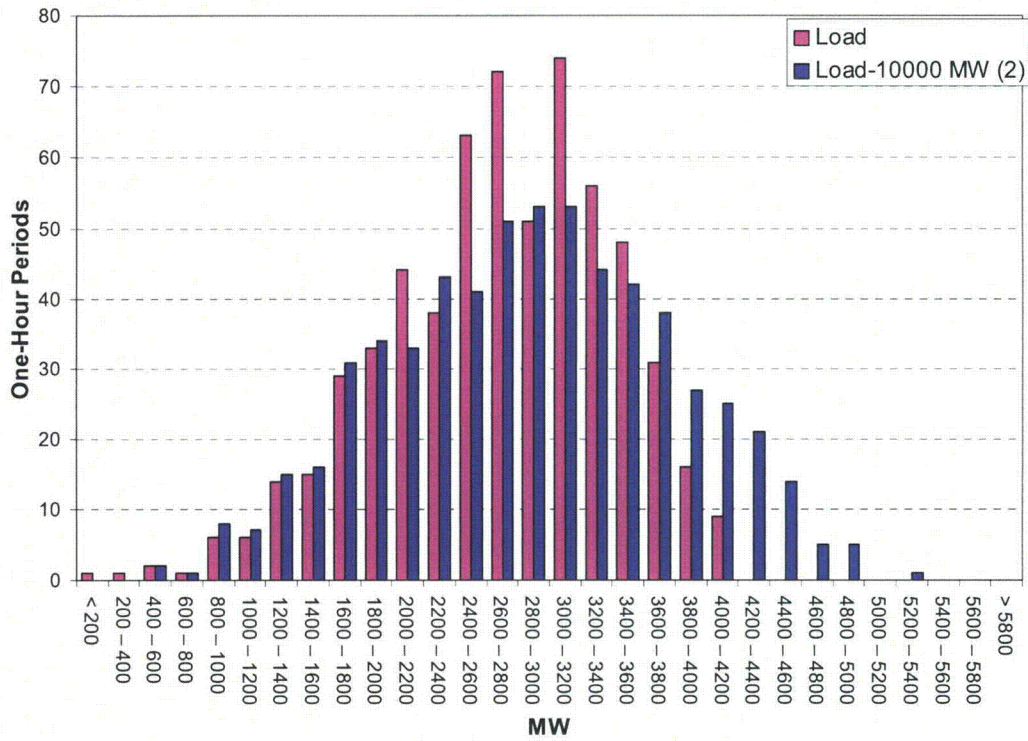
**Variability During Spring Morning Load Rise Periods
(March-May; 7am to 11am)**



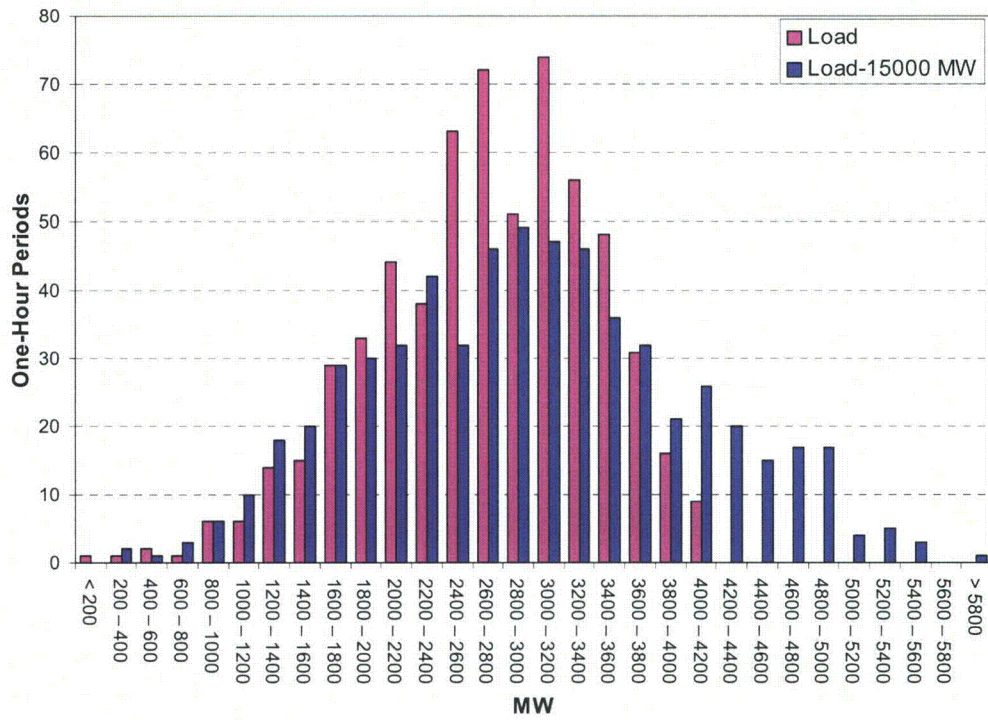
Variability During Summer Morning Load Rise Periods



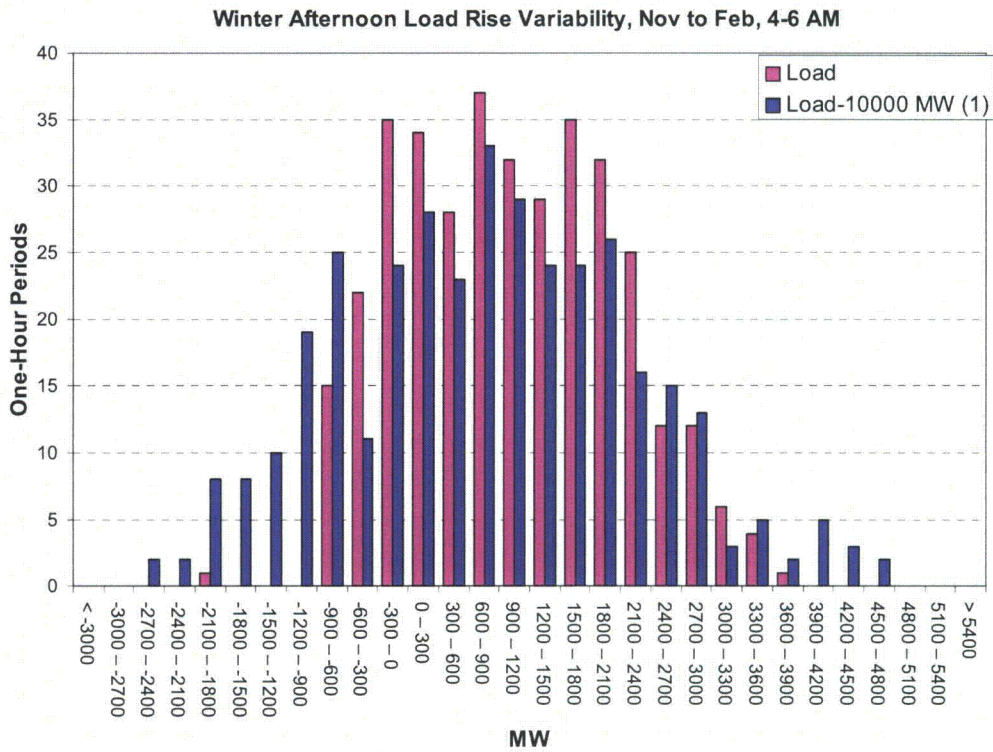
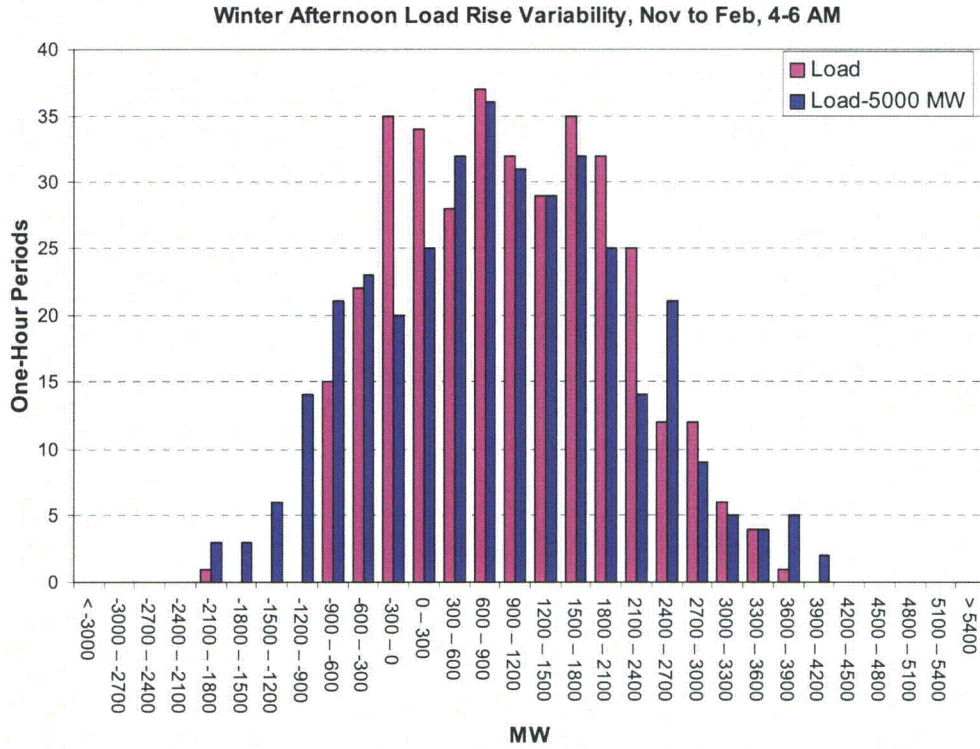
Summer Morning Load rise variability, Jun to Sep, 7-11 AM

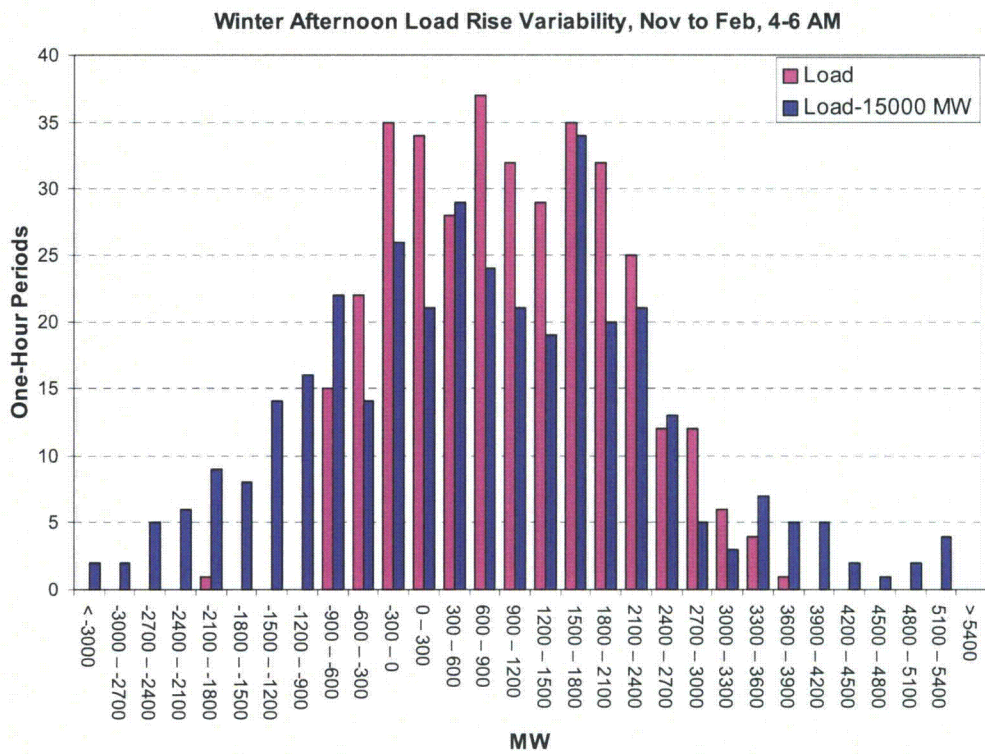
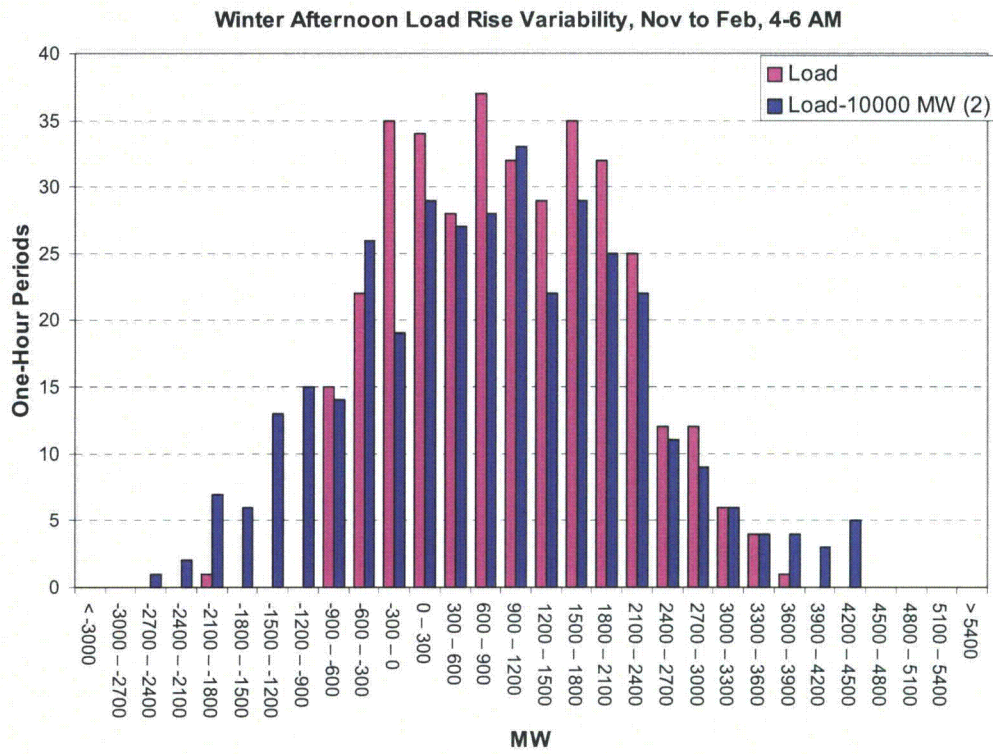


Summer Morning Load rise variability, Jun to Sep, 7-11 AM

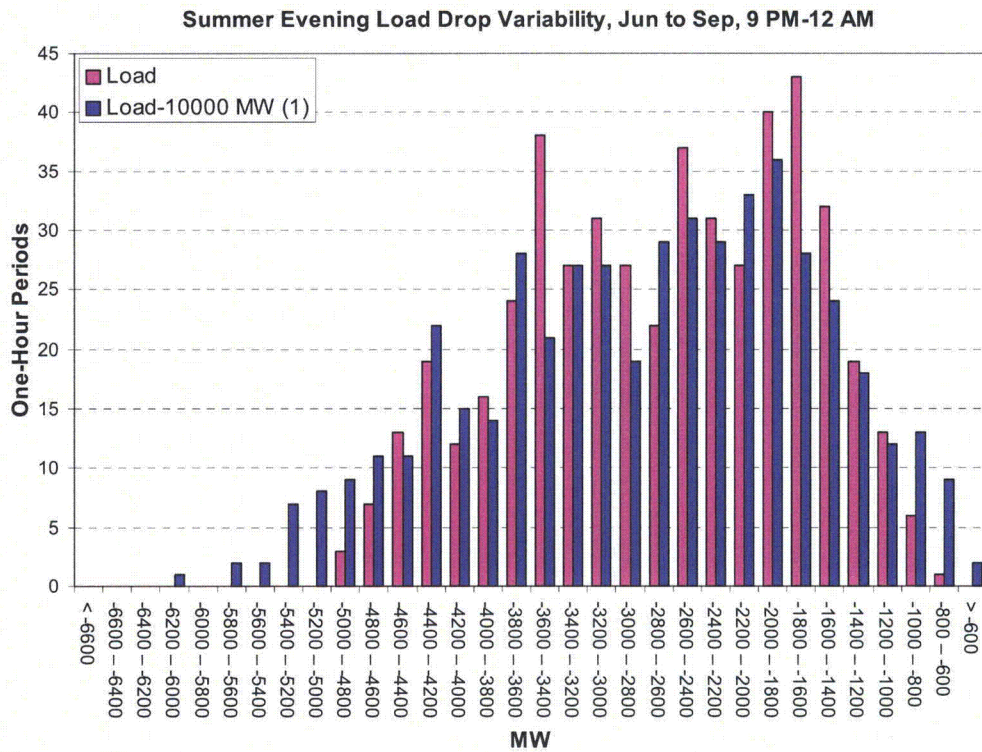
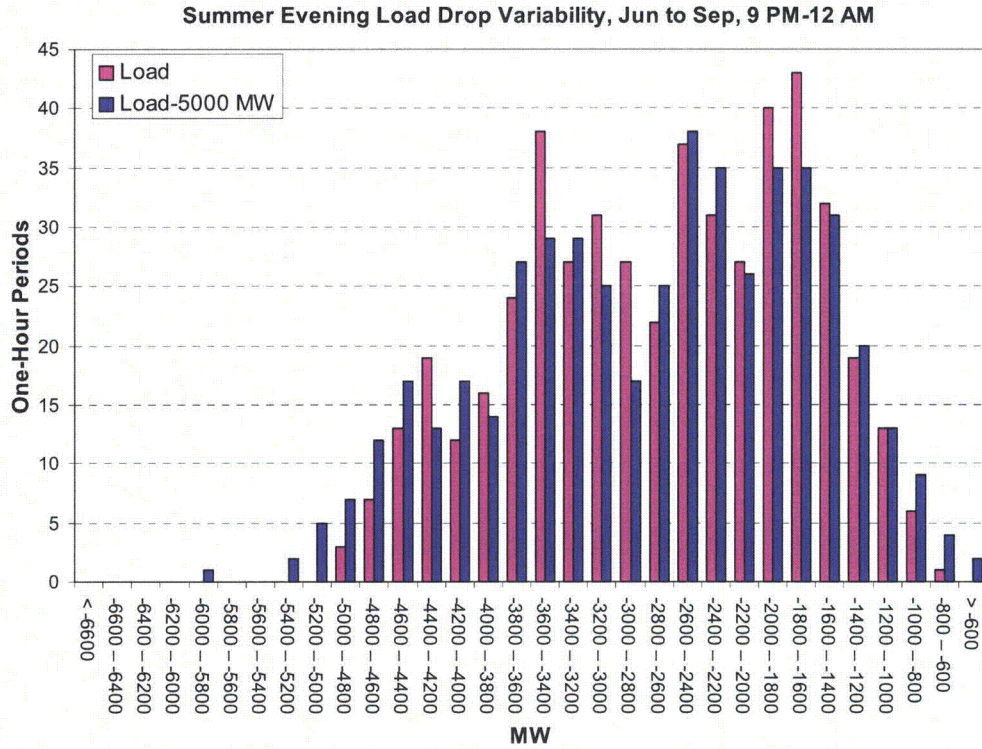


Variability During Winter Afternoon Load Rise Periods

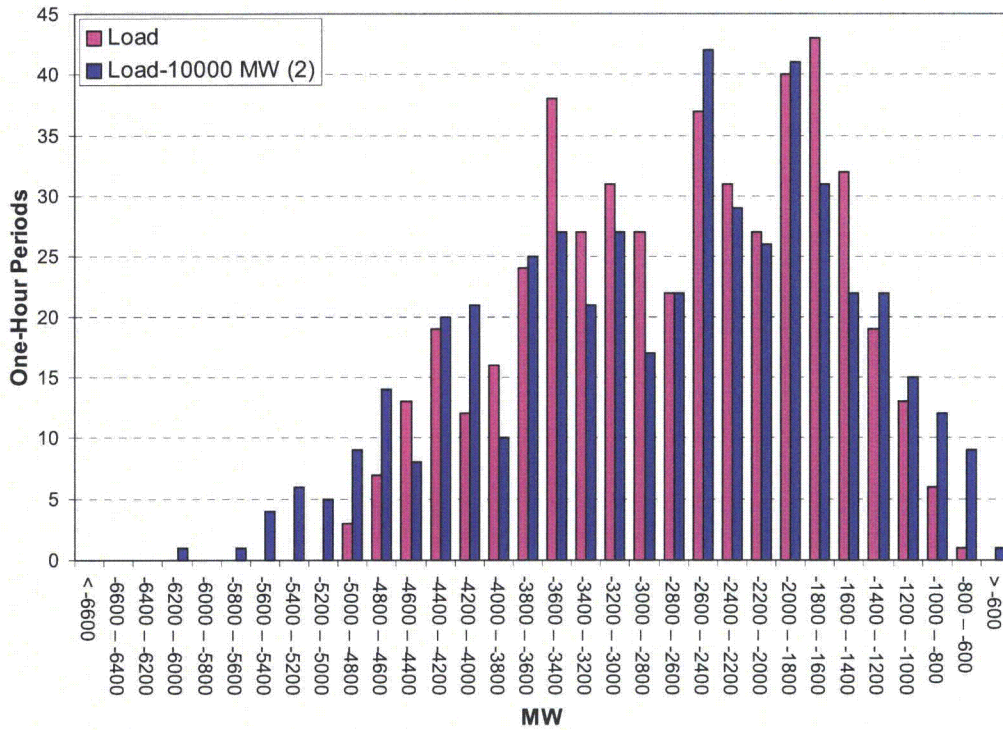




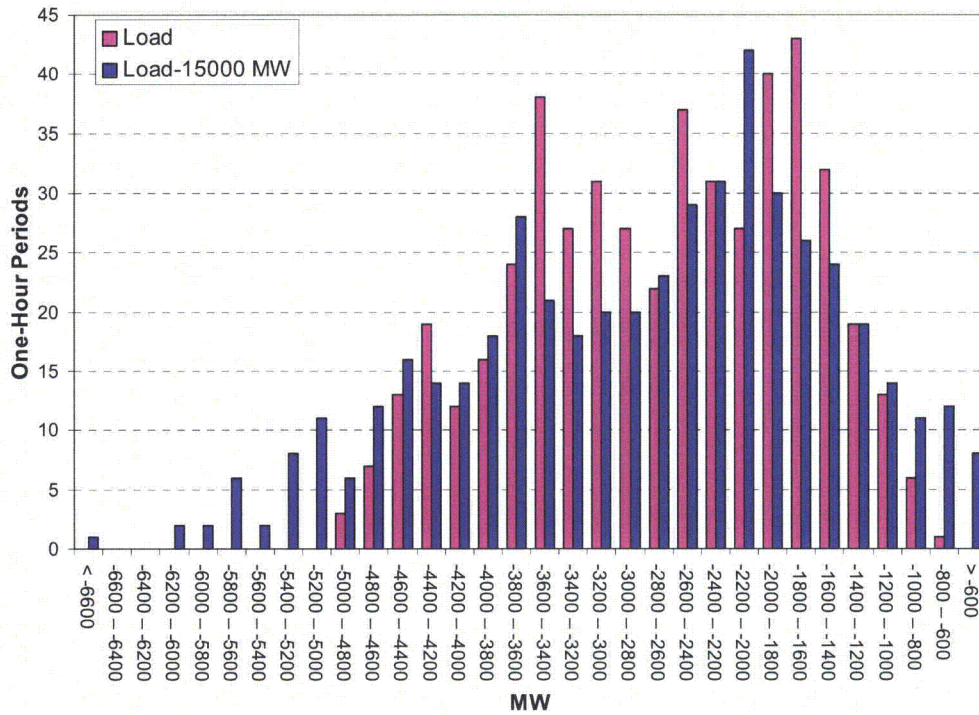
Variability During Summer evening Load Drop Periods



Summer Evening Load Drop Variability, Jun to Sep, 9 PM-12 AM

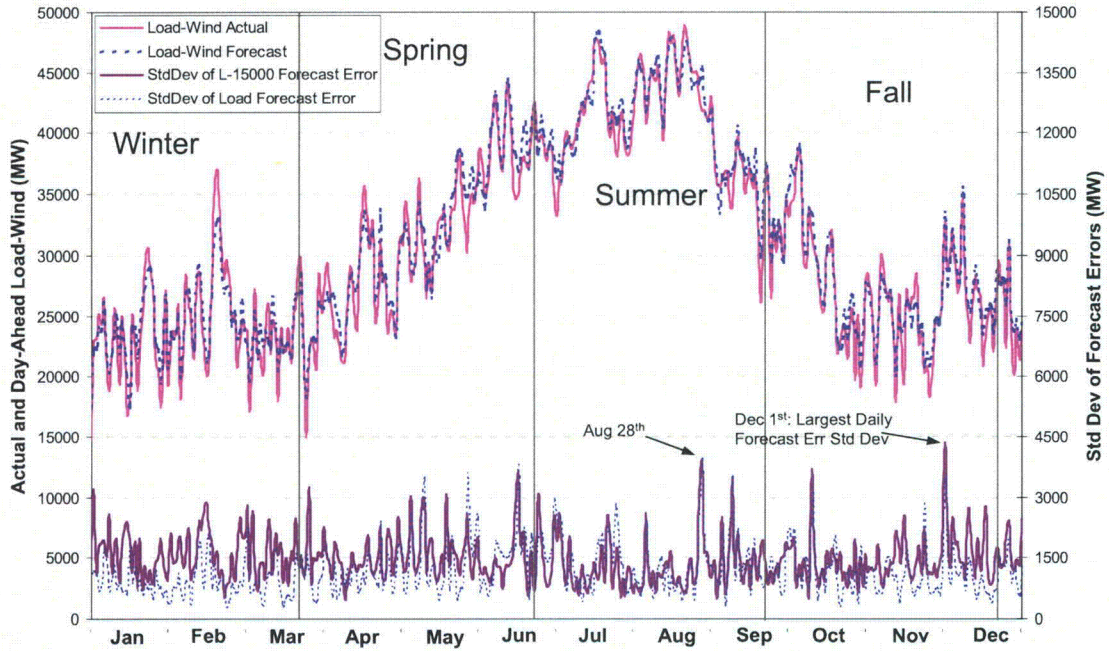


Summer Evening Load Drop Variability, Jun to Sep, 9 PM-12 AM



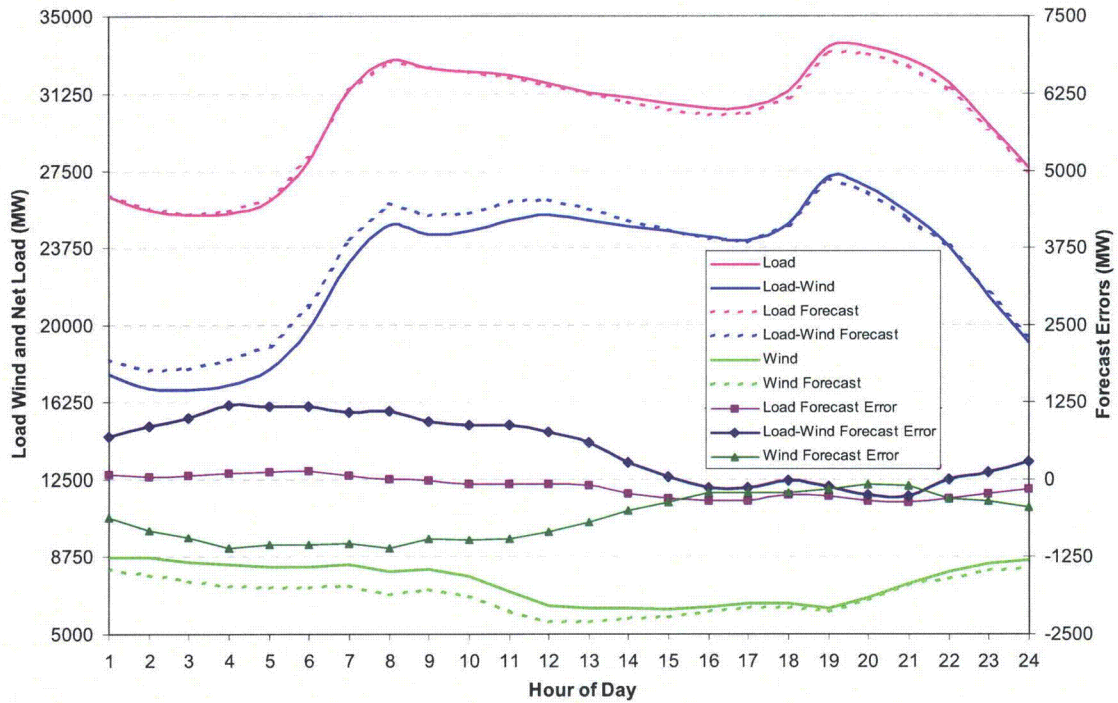
APPENDIX D SUPPLEMENTAL PREDICTABILITY PLOTS

Yearly Average Profiles and Std Dev of Forecast Errors
(Study Year Load with 15000 MW of Wind)

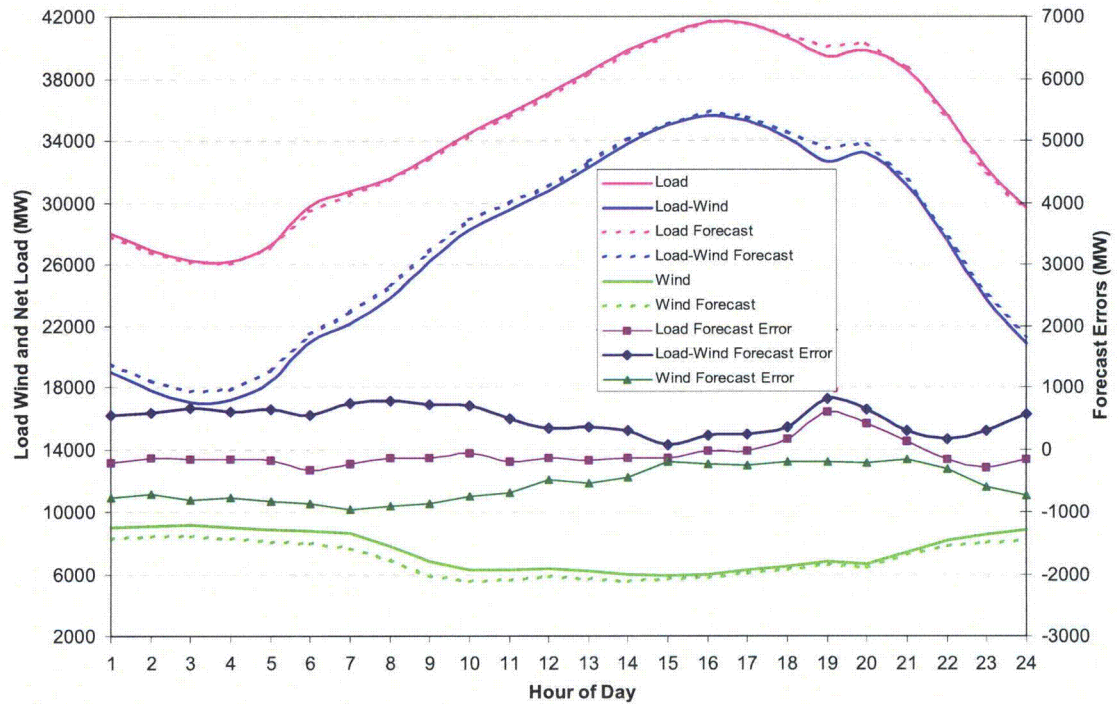


No clear trend in variability of daily forecast errors across the year

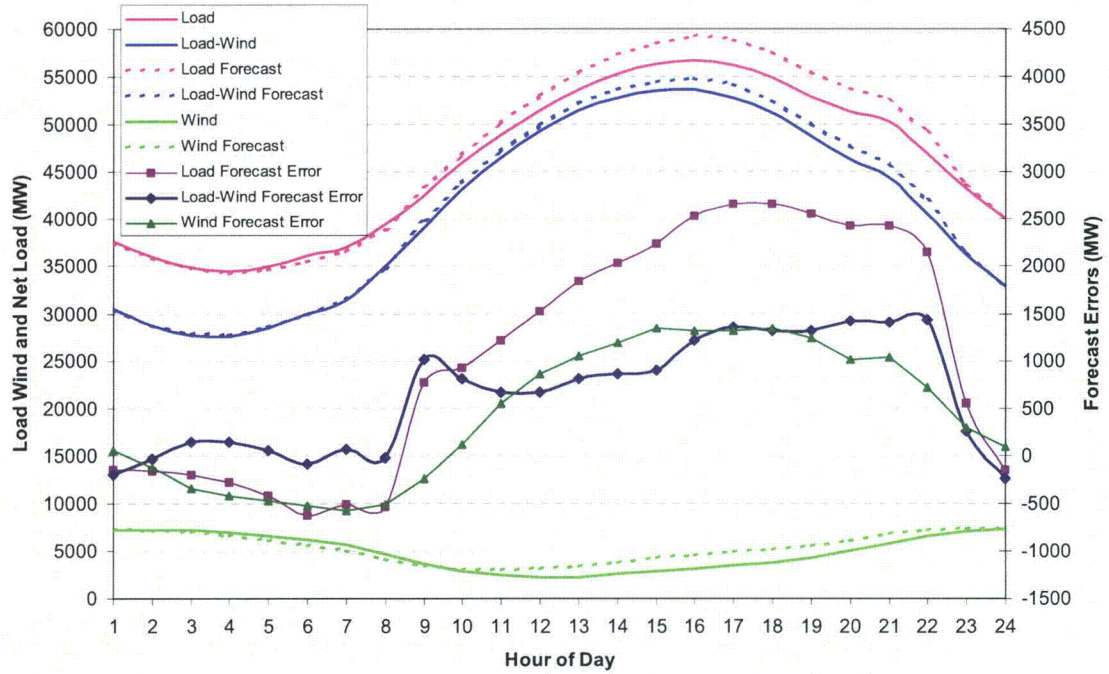
January Daily Average Profiles and Forecast Errors (Study Year Load with 15000 MW of Wind)



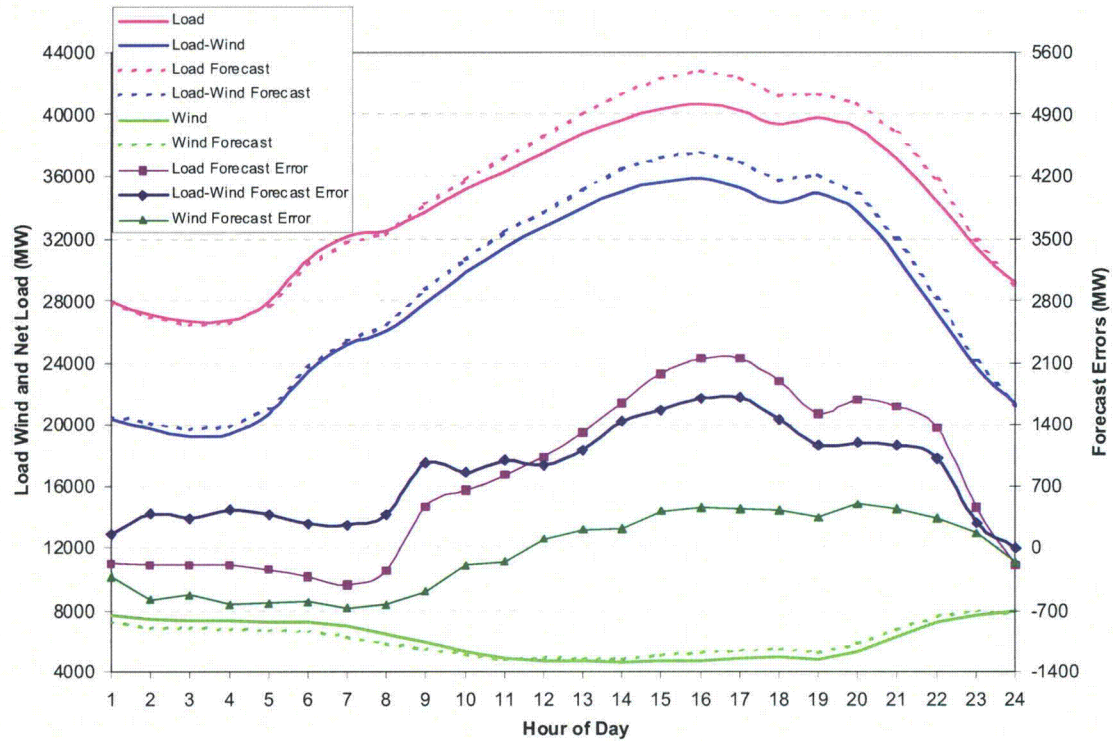
April Daily Average Profiles and Forecast Errors (Study Year Load with 15000 MW of Wind)



July Daily Average Profiles and Forecast Errors (Study Year Load with 15000 MW of Wind)

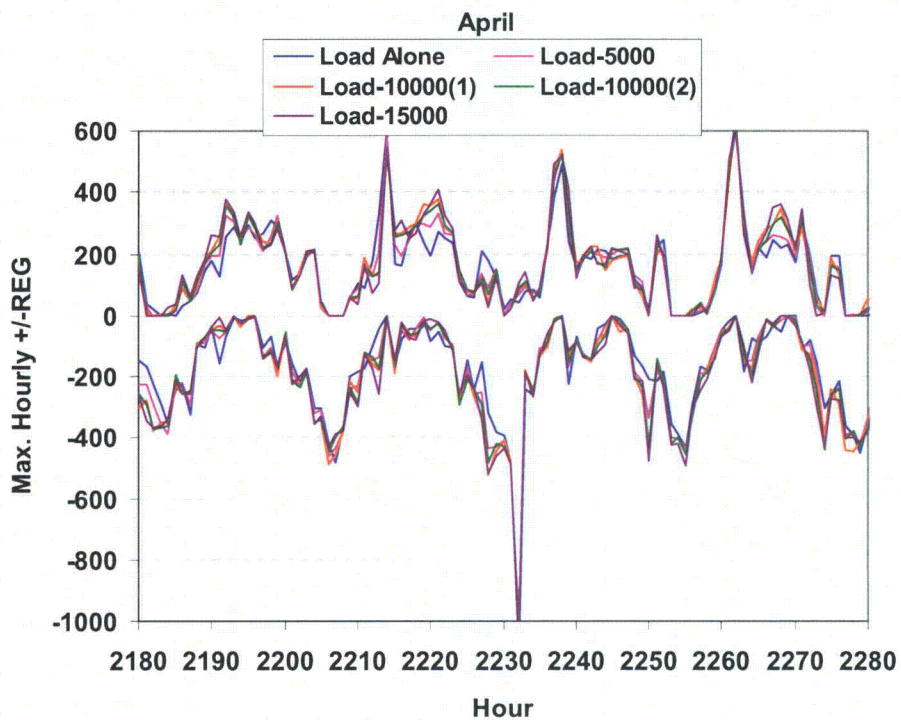
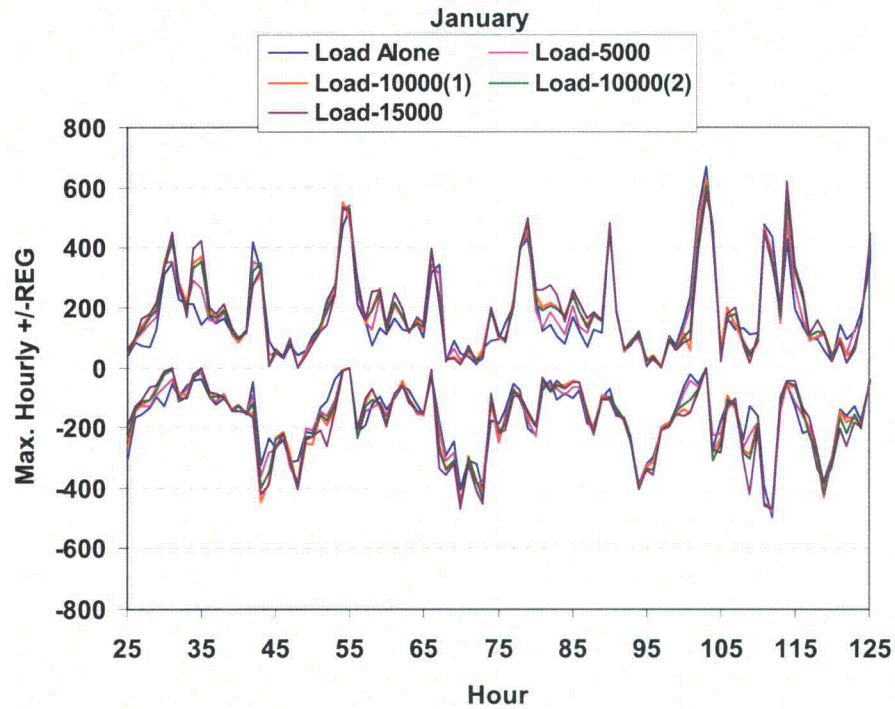


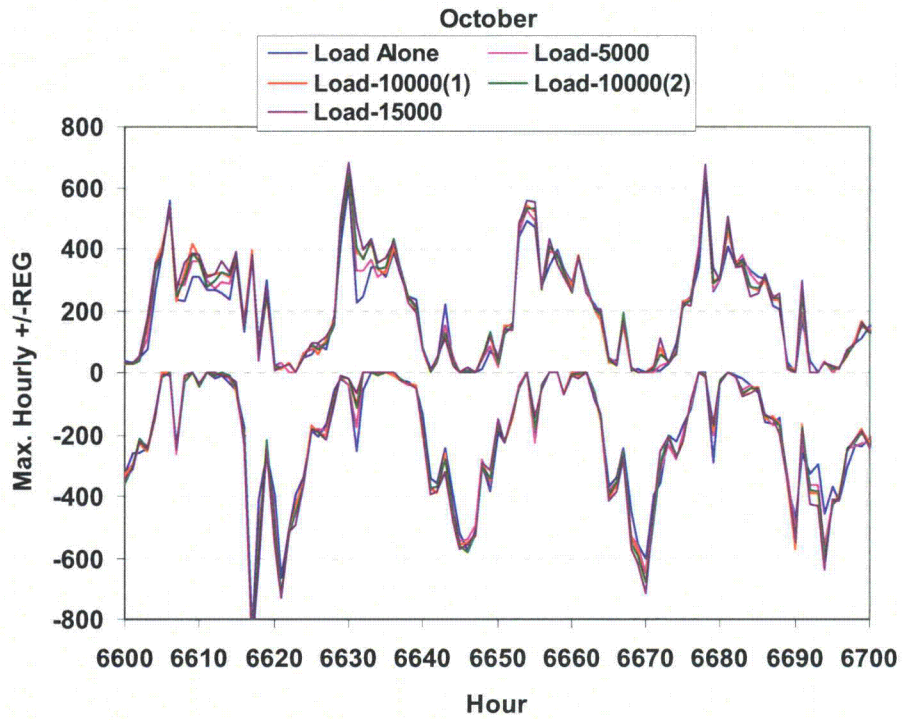
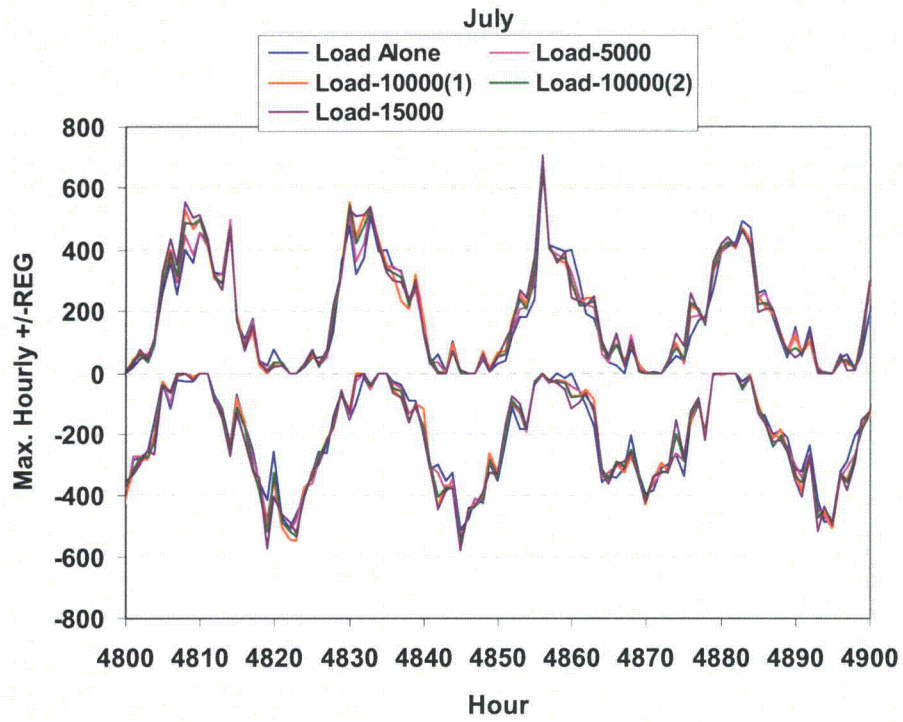
October Daily Average Profiles and Forecast Errors (Study Year Load with 15000 MW of Wind)



APPENDIX E SUPPLEMENTAL REGULATION PLOTS

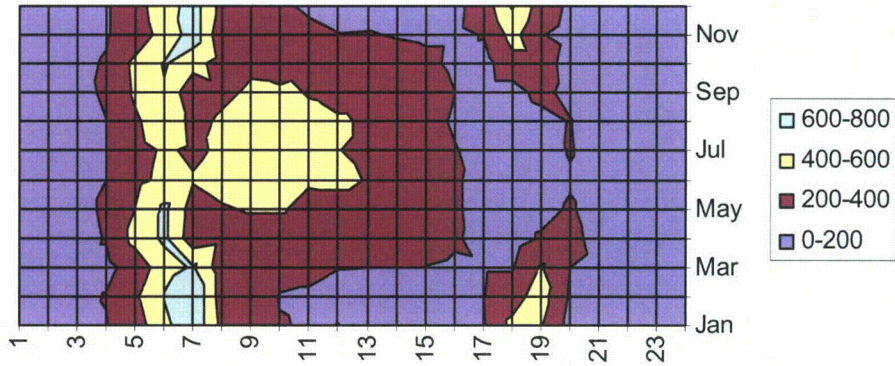
E.1 Maximum Hourly Regulation Deployments (similar to Figure 6-3)



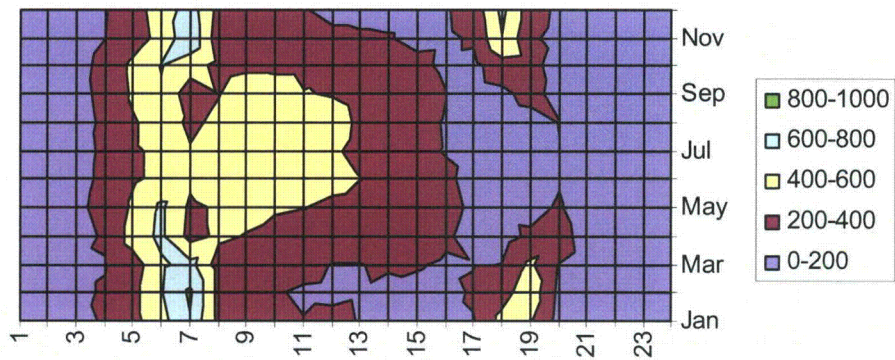


E.2 98.8th Percentile of Regulation Deployments

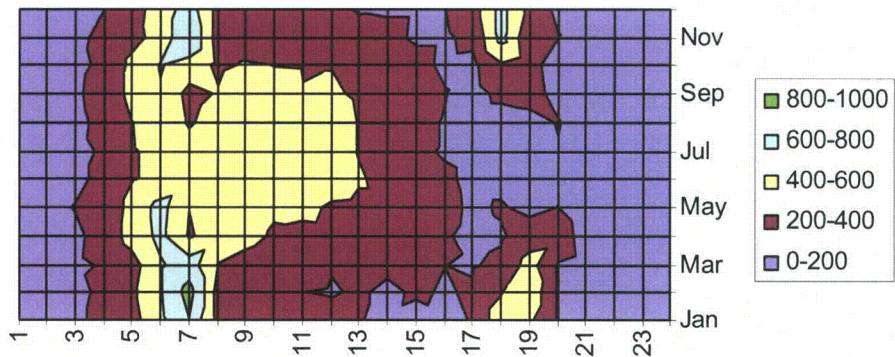
+REG; Load Only



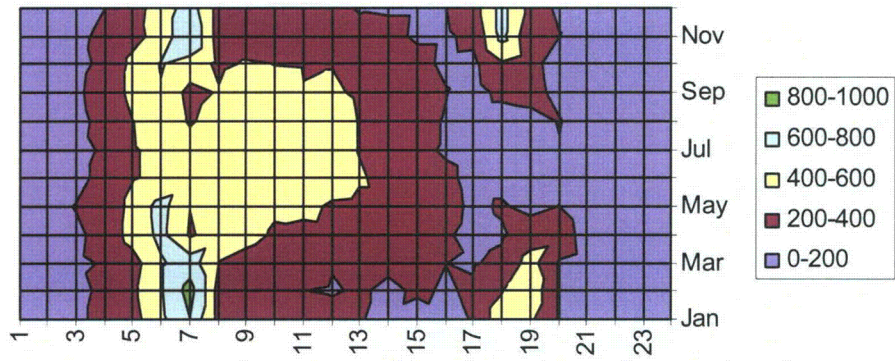
+REG; Load -5,000 MW Wind



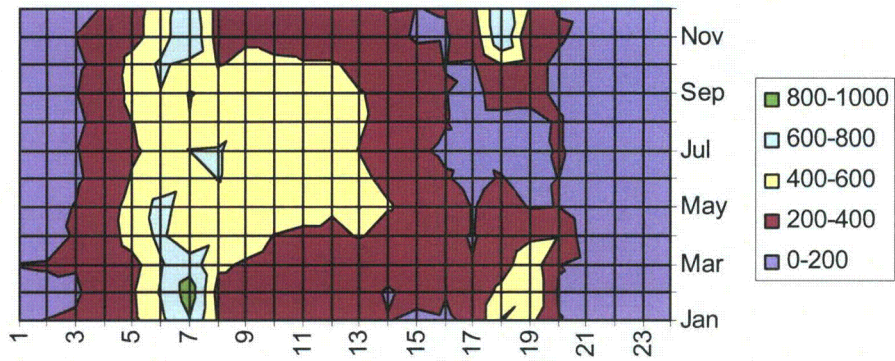
+REG; Load -10,000 MW Wind (Case 1)



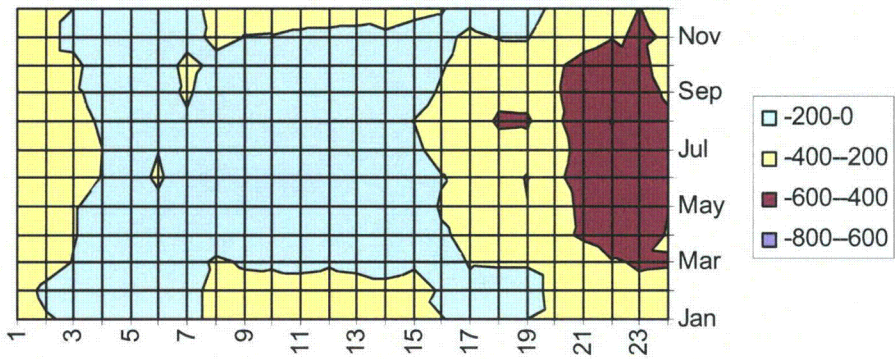
+REG; Load -10,000 MW Wind (Case 2)



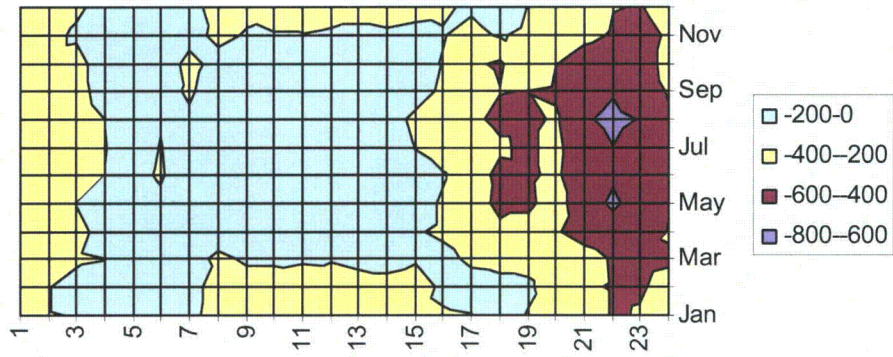
+REG; Load -15,000 MW Wind



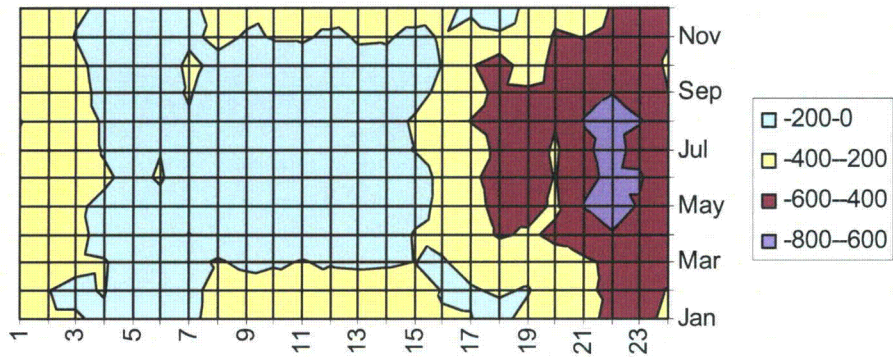
-REG; Load Only



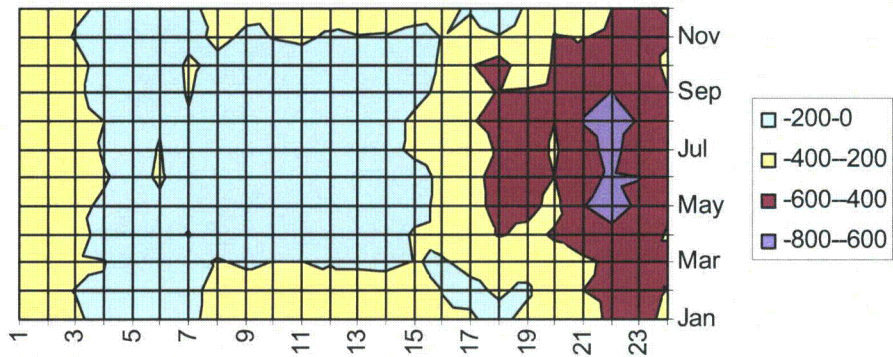
-REG; Load -5,000 MW Wind



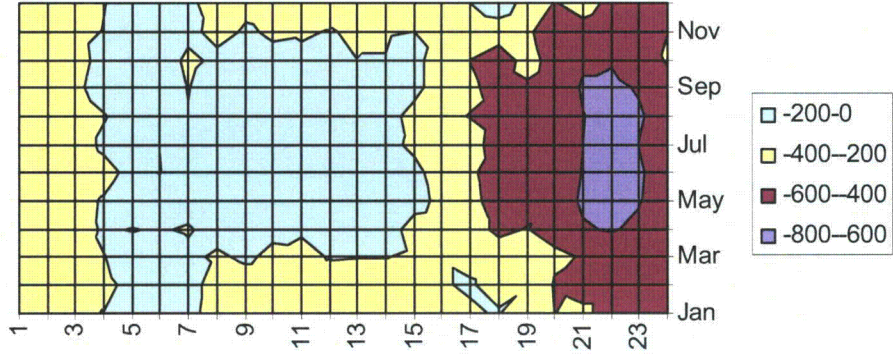
-REG; Load -10,000 MW Wind (Case 1)



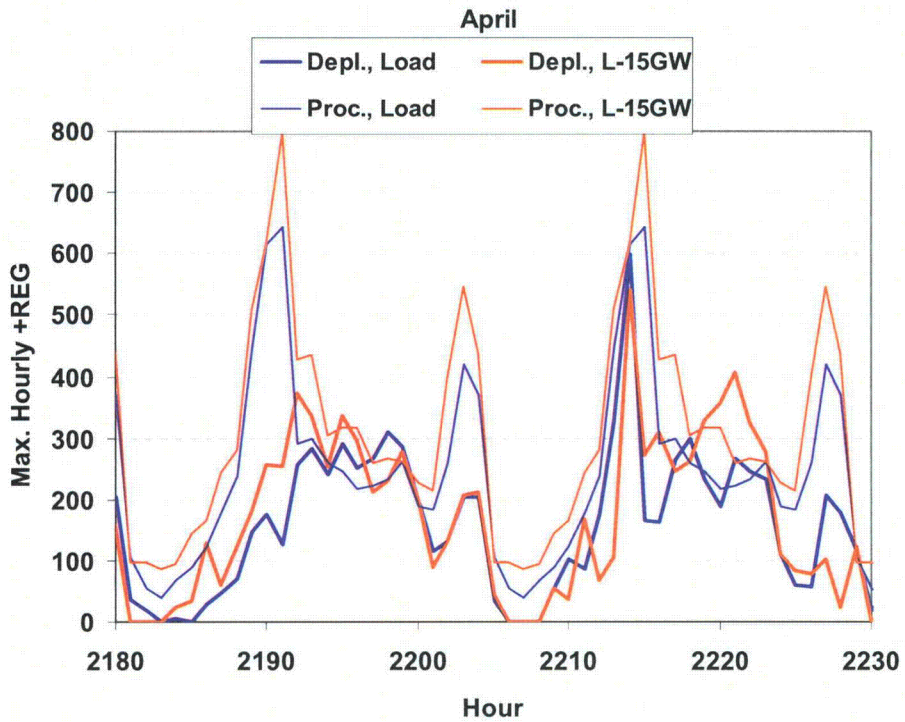
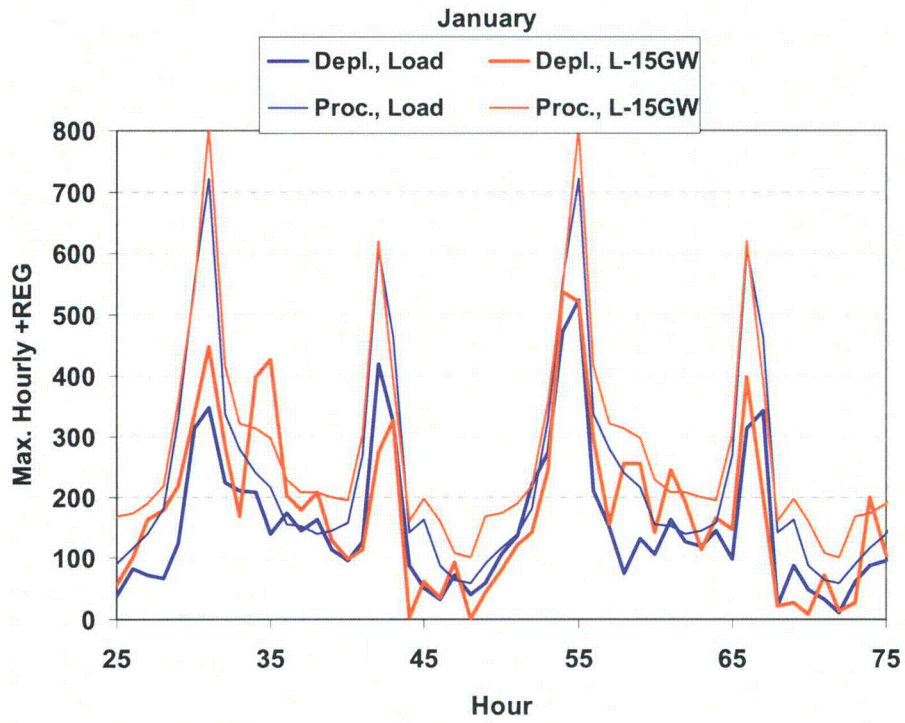
-REG; Load -10,000 MW Wind (Case 2)

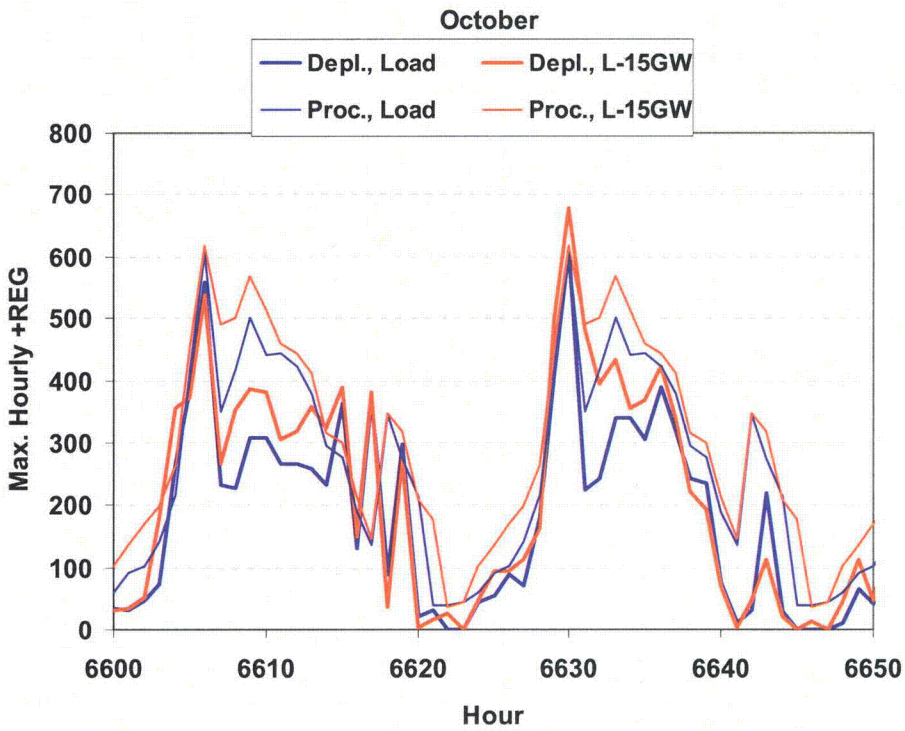
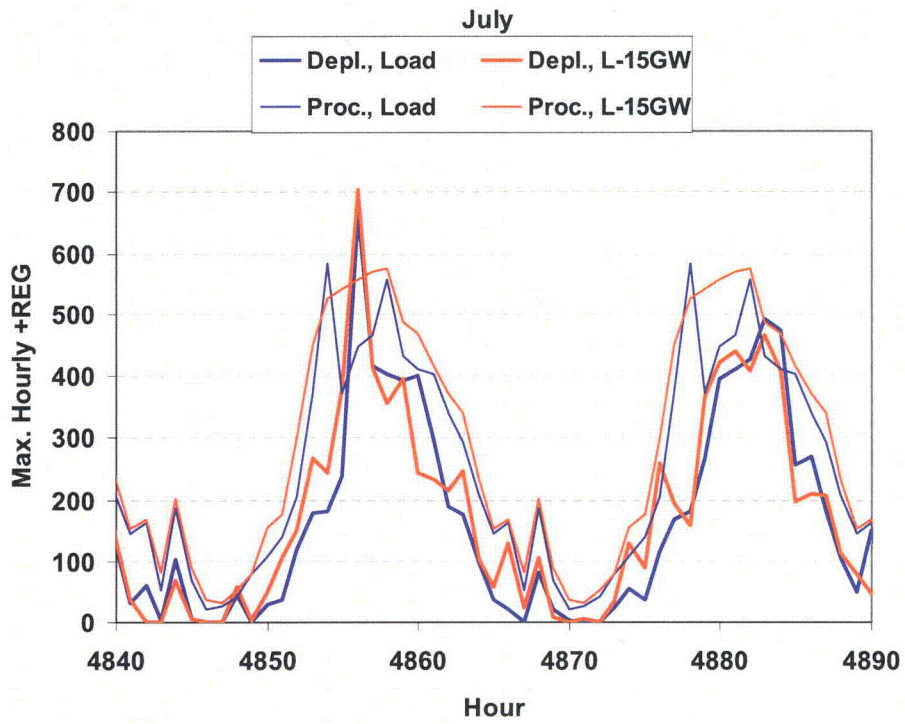


-REG; Load -15,000 MW Wind



E.3 Comparisons of Regulation Procurement and Deployment





APPENDIX F REGULATION ADJUSTMENT FACTORS

Incremental MW Adjustment to Prior-Year Up-Regulation 98.8th Percentile Deployment Values, per 1,000 MW of Incremental Wind Generation Capacity, to Account for Wind Capacity Growth.

	Hour																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	2.8	4.2	3.1	3.7	2.5	0.4	2.3	2.2	4.2	5.9	7.6	5.7	4.7	3.3	2.8	2.3	4.0	8.6	4.2	2.7	1.6	2.7	1.4	1.6
Feb	3.6	4.0	2.9	2.9	1.5	1.8	5.2	3.5	4.9	6.0	5.1	5.2	5.3	4.2	4.3	3.5	3.8	8.6	5.5	1.9	1.4	3.1	1.9	2.2
Mar	5.5	5.3	4.6	4.2	2.6	3.3	7.1	7.9	6.8	5.1	4.2	3.4	2.8	2.6	2.7	2.3	2.9	7.7	6.8	2.1	1.1	3.0	1.5	2.8
Apr	3.1	3.6	5.0	4.0	2.4	2.5	8.5	11.6	10.0	5.6	4.2	3.4	3.2	2.5	2.1	2.1	3.5	9.2	8.2	4.1	1.0	0.8	0.0	1.4
May	3.6	3.3	4.3	4.3	4.2	3.3	8.7	8.8	8.1	5.7	6.0	4.4	3.6	3.8	3.9	4.2	4.7	11.6	5.9	0.6	0.0	1.0	1.4	2.5
Jun	2.3	2.6	3.3	3.7	3.9	2.4	8.5	8.2	6.6	4.5	4.2	3.1	2.5	2.5	0.7	0.2	1.3	7.5	3.3	1.7	0.7	0.3	0.6	1.3
Jul	1.0	2.8	4.1	3.7	3.0	3.2	11.2	10.2	6.5	5.3	3.3	2.2	1.4	0.4	-0.9	-1.3	0.3	3.4	0.9	1.1	0.1	0.0	1.0	1.2
Aug	1.4	3.8	4.5	4.5	2.2	0.9	6.3	6.8	6.6	6.6	3.2	2.6	2.1	1.2	1.4	1.3	1.3	4.6	1.2	0.9	0.7	0.8	1.1	1.3
Sep	3.2	4.0	3.7	3.5	1.8	1.9	6.9	7.7	8.3	6.9	3.5	4.8	3.8	2.3	1.6	1.2	3.0	9.2	3.1	0.9	0.1	0.4	0.8	1.9
Oct	3.4	2.8	2.4	2.2	1.7	1.8	5.0	5.8	6.1	5.9	4.0	5.4	3.2	2.2	1.2	1.7	3.1	6.8	0.8	2.1	0.0	0.2	1.8	2.5
Nov	2.7	3.2	3.6	3.0	2.2	2.3	4.6	5.3	6.9	6.8	5.1	5.6	4.1	3.7	1.8	1.7	5.8	12.8	4.8	3.8	1.0	1.6	2.2	1.4
Dec	2.8	2.4	1.4	2.1	1.2	0.4	2.8	2.7	3.8	4.6	6.8	7.0	6.0	4.4	3.3	3.0	5.0	9.9	4.3	2.6	2.1	4.3	2.0	1.5

Incremental MW Adjustment¹ to Prior-Year Down-Regulation 98.8th Percentile Deployment Values, per 1,000 MW of Incremental Wind Generation Capacity, to Account for Wind Capacity Growth.

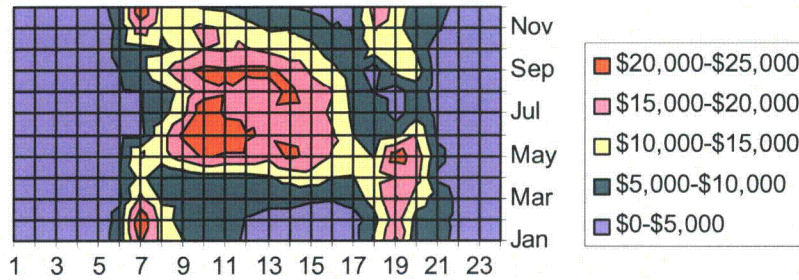
	Hour																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	-1.2	-1.7	-2.2	-2.9	-2.5	-1.0	-0.8	-2.5	0.2	0.5	0.2	-2.4	-4.0	-3.6	-4.0	-3.5	-2.7	-5.1	-7.8	-10.4	-8.4	-5.2	-5.2	-3.6
Feb	-2.7	-3.6	-3.8	-4.4	-3.3	-1.7	-0.5	-2.5	-2.0	-2.3	-2.1	-2.3	-2.8	-3.7	-3.7	-2.6	-2.3	-6.9	-7.2	-10.0	-11.0	-7.3	-7.1	-4.7
Mar	-2.9	-3.8	-3.1	-2.3	-2.2	-2.2	-1.9	-0.9	-0.4	-3.7	-4.0	-2.1	-1.6	-2.3	-3.2	-3.9	-3.2	-6.1	-6.1	-8.3	-9.5	-6.5	-5.2	-3.6
Apr	-4.3	-4.5	-3.4	-3.0	-4.1	-2.8	-2.4	-1.3	-0.6	-2.9	-4.5	-3.3	-1.4	-2.5	-4.1	-4.5	-4.5	-7.3	-7.3	-10.7	-9.5	-7.4	-5.1	-3.0
May	-3.0	-1.6	-2.3	-1.7	-0.4	0.2	-0.4	-0.5	-1.1	-2.4	-3.5	-3.1	-1.8	-2.7	-2.6	-2.5	-3.8	-8.7	-7.5	-11.1	-9.7	-8.2	-5.8	-3.7
Jun	-1.4	-0.1	-1.7	-2.0	-0.5	0.7	1.2	0.7	0.2	0.0	-0.7	-0.9	-1.9	-2.8	-2.9	-2.8	-3.6	-11.0	-8.4	-7.7	-6.5	-5.8	-4.2	-2.7
Jul	-2.6	-1.5	-0.7	0.3	0.6	0.7	1.0	0.5	0.5	0.7	0.0	-0.7	-1.7	-2.3	-2.7	-3.1	-2.7	-8.0	-9.2	-8.7	-6.1	-5.5	-4.7	-2.6
Aug	-2.0	-1.7	-1.0	-0.6	-0.3	0.9	0.0	-0.3	0.2	0.1	-0.7	-1.0	-1.5	-1.9	-2.7	-4.1	-3.6	-4.7	-5.6	-7.2	-5.0	-5.4	-5.1	-2.7
Sep	-1.5	-2.2	-0.8	0.4	0.6	1.4	0.8	0.4	0.6	-0.4	-1.0	-0.9	-1.4	-1.5	-2.4	-2.7	-3.3	-7.2	-5.2	-7.2	-6.9	-6.5	-6.3	-4.1
Oct	-2.4	-4.0	-2.0	-0.6	-0.1	0.3	0.2	-0.3	0.0	-1.5	-2.6	-2.4	-2.6	-2.0	-2.3	-3.0	-4.3	-9.0	-6.8	-8.6	-6.8	-4.6	-4.2	-2.3
Nov	-1.8	-2.7	-2.6	-1.9	-0.7	-1.0	-1.5	-1.2	0.6	-1.5	-2.1	-2.0	-2.2	-1.5	-1.8	-3.5	-4.7	-6.8	-10.4	-14.1	-9.5	-5.7	-4.1	-1.7
Dec	-2.9	-3.2	-2.8	-2.6	-2.2	-1.9	-2.6	-2.9	0.8	0.6	0.4	-1.3	-1.8	-1.4	-2.6	-3.5	-3.2	-3.1	-7.9	-11.8	-7.9	-4.2	-3.9	-3.4

¹ In this study, down-regulation is reported as a negative number. Thus, a negative adjustment in this table implies an increased amount of down-regulation requirement.

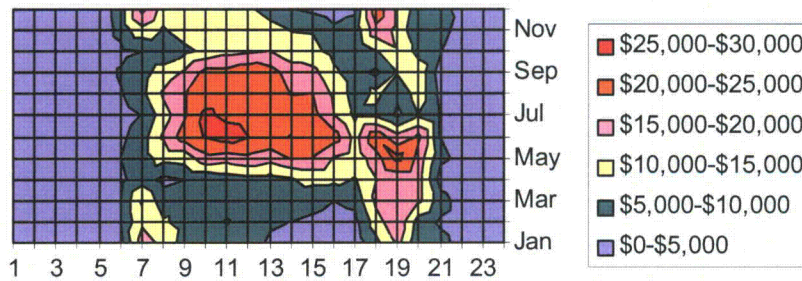
APPENDIX G REGULATION COST TEMPORAL CHARACTERISTICS

Up-Regulation (Perfect Forecast)

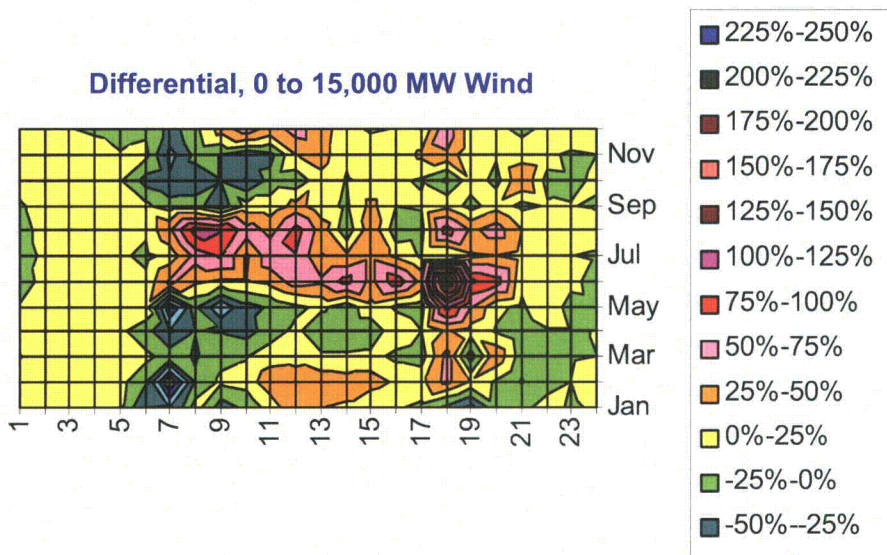
Load Alone



Load -15,000 MW Wind

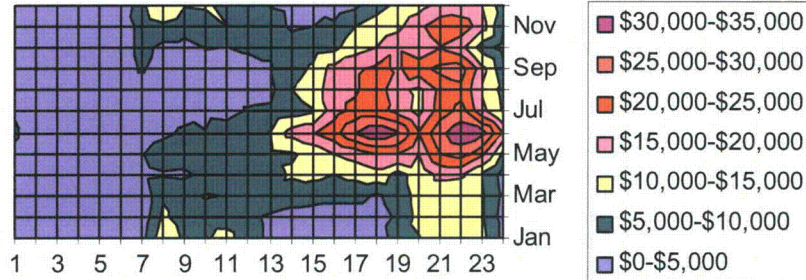


Differential, 0 to 15,000 MW Wind

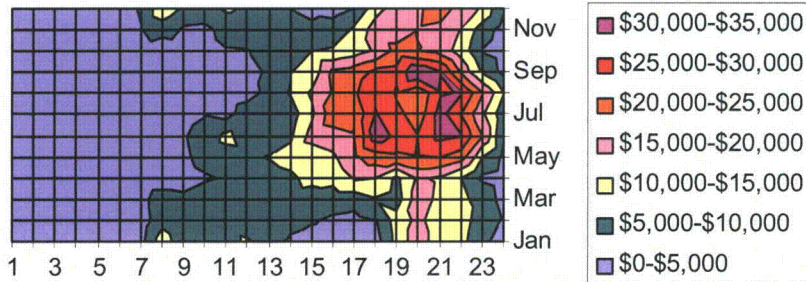


Down-Regulation (Perfect Forecast)

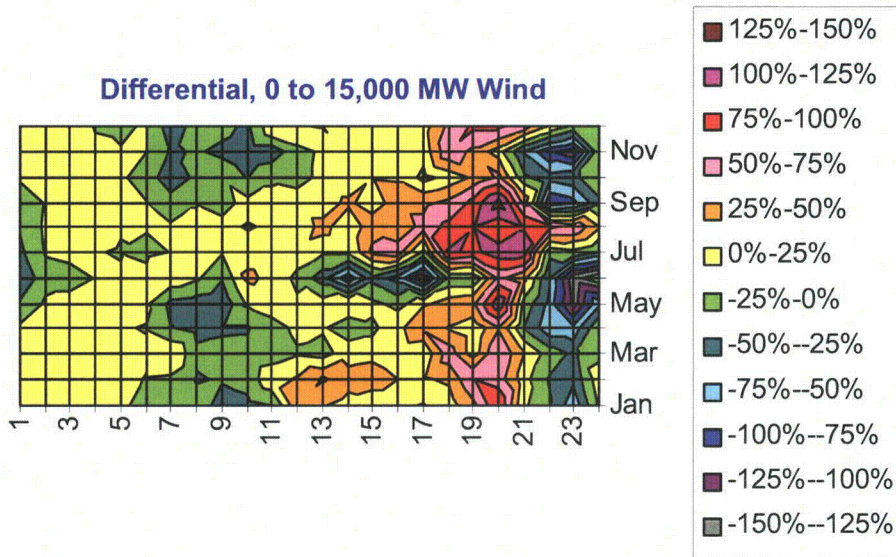
Load Alone



Load -15,000 MW Wind



Differential, 0 to 15,000 MW Wind



APPENDIX H AWS TRUEWIND REPORT:

***ANALYSIS OF WEST TEXAS WIND PLANT RAMP-UP
AND RAMP-DOWN EVENTS***



Analysis of West Texas Wind Plant Ramp-up and Ramp-down Events

Prepared for:

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January 28, 2008

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1. Introduction

The purpose of this report is to document weather-related causes in sudden excursions in wind power output from 14 interconnection points in the Electric Reliability Council of Texas (ERCOT) domain in 2005 and 2006 as well as a singular event in 2007, and to attempt to extrapolate the findings to a much larger deployment of wind energy in Texas. To identify and classify events, AWS Truewind:

- 1) Examined two years of one-minute plant output data provided by ERCOT and identified periods in which the aggregate wind generation increased or decreased by more than 200 MW in a 30-minute time frame (out of a total MW of 976 rated capacity). Obvious cases of non-weather curtailments and shutdowns were excluded.
- 2) Examined available meteorological records for the same periods and categorized the events by different meteorological causes.
- 3) Analyzed significant 2005-2006 weather events identified by ERCOT and determined which of those were associated with large changes in generation.
- 4) Analyzed the event of 24 February 2007 and established the cause for the decrease in energy production.

From the results of the above analysis, AWS Truewind estimated the maximum likely change in a 30-minute period for the 15,000 MW scenario defined in the Ancillary Services study. The period over which the maximum was to be estimated is two years.

2. Data and methodology

To identify ramp events, a 30-minute running mean filter was applied to two years of one-minute plant output data provided by ERCOT. The data represented the recorded output for 14 different interconnection points, some representing different parts of the same wind farm. The total rated capacity (judging from the maximum recorded output) was 976 MW. For the 24 February 2007 event, the estimated maximum output from 29 interconnection points analyzed was approximately 2000 MW. All of the projects are located in west central Texas (Figure 1).

From the distribution of step changes from one 30-minute period to the next, a 200 MW threshold was established, representing roughly 20% of the rated capacity of plants in the data sample. This resulted in the selection of 59 ramp-up and ramp-down events in 2005 – 2006 (see Tables 1a-d). Relevant meteorological data were acquired and analyzed, including 1) surface meteorological charts archived by the National Climatic Data Center (NCDC); 2) National Oceanographic and Atmospheric Administration (NOAA) wind profiler data from Jayton, Texas;¹ 3) NOAA National Weather Service (NWS) sounding data from Midland, Texas; 4) high-resolution (one-minute averaged wind speed and direction, temperature, humidity, pressure, etc.) Automated Surface Observation System (ASOS) station surface meteorological data from

¹Wind profilers measure vertical profiles of horizontal wind speed and direction from near the surface to above the tropopause with a vertical resolution of 250 m and temporal averages of wind speed, direction and temperature every 6 to 60 minutes.

several sites nearest to the wind farms;² 5) visible and infrared satellite imagery archived by NOAA; and 6) NWS Doppler Next Generation Radar (NEXRAD) Weather Surveillance Radar 88 Doppler (WSR-88D) level II data archived at NCDC to identify convective features such as thunderstorm clusters and outflow boundaries. The ERCOT plant data were also used to examine the spatial and temporal variability of the meteorological forcing(s) associated with each ramp event.

3. Discussion and analysis

3.1. Meteorological causes

Thirty-five positive (increasing) ramps and twenty-four negative (decreasing) ramps met the threshold of a 200 MW change over a 30 minute period for the entire two-year study period. The meteorological causes of these events are described below. (Meteorological terms are defined in Appendix A.)

A. RAMP-UP EVENTS

- 1) Frontal system/trough/dry line. These are density fronts or air mass discontinuities that move through parts or all of the ERCOT domain with an accompanying fall/rise pressure couplet, which can result in a rapid wind speed increase followed by a (more gradual) decrease. These systems mostly move from west to east or northwest to southeast, but can occasionally move from north to south. Fronts propagating at a speed in excess of 15 m s^{-1} (34 mph) are more likely to cause ramp-up events. These systems usually scale up to 1000 km in length and 100 - 200 km in breadth.
- 2) Thunderstorms and convection-induced outflow or gust fronts. These occur on the mesoscale (tens to hundreds of square kilometers) and can move in any direction and at speeds in excess of 25 m s^{-1} . Outflow boundaries usually propagate radially outward from thunderstorm clusters (or other mesoscale convective systems). Although gust fronts often lose strength rather quickly, they can instigate additional convection and subsequent gust fronts.
- 3) Low-level Jet (LLJ). This phenomenon occurs regularly throughout the year in the southern Great Plains. Southerly LLJs tend to be strongest but northerly LLJs do occur—mostly during the warm season. There are two types: (1) the nocturnal LLJ, a phenomenon unique to the plains of Texas, Oklahoma, and Kansas, caused by radiative cooling after sunset, and (2) a pre-frontal LLJ caused by an increasing pressure gradient ahead of a cold front. LLJ wind speed maximums occur between 100 m and 500 m above the ground, with a temporal maximum around 5 AM local time for the nocturnal LLJ. A special concern introduced by LLJs is the large vertical shears (upwards of 10 m s^{-1} [100 m^{-1}]) that can occur across the turbine rotor plane. Direct evidence of LLJs affecting wind farms is not clear from this analysis but their presence was noted in many of the frontal cases from the sounding and profiler data.

B. RAMP-DOWN EVENTS

²Parameters available from the ASOS stations include temperature, dew point, pressure, wind speed and wind direction (both at 10m mast height), present weather, visibility and obstructions, present weather and accumulated precipitation.

- 1) These events generally occur with the rapid slackening of a pressure gradient or the passage of local pressure couplet. This feature is can be associated with (1), (2), or (3) above.
- 2) Ramp-down events can also be caused by high wind speeds that exceed the cut-out speed of wind turbines (typically 22-25 m/s). This occurred during the 24 February 2007 event, and on several other occasions associated with transient convective systems such as 23 June 2006.

For the 59 events considered during 2005 and 2006, the largest changes occurred on 9 July 2005 (a nearly 400 MW increase, or over 300% from a low of about 200 MW) and 12 May 2005 (a 331 MW decrease, or more than 58% from the peak of 571 MW). Although the 24 February 2007 event observed a peak 30 minute decrease of 455 MW, this was based upon roughly twice the rated capacity, and thus was not proportionately as severe as the 12 May 2005 event (see analysis in section 4 below).

3.2 Statistical Breakdown of the Ramp Event Types

Approximately 60% of the 59 events identified during 2005 – 2006 were ramp-up events, and 40% were ramp-down events (Table 3). The slight favoring of ramp-up events is consistent with the finding that rapidly moving transient features such as frontal systems and convective outflow boundaries tend to produce rapid wind increases, which then subside more gradually.

Convective events were the primary cause of all ramp events, followed by frontal passages and weakening pressure gradients (Table 3). Although a distinct low-level jet (LLJ) was common to several events, it did not appear to be a primary cause of the ramps discussed in this report.

The most frequent cause of ramp-down events is a weakening pressure gradient (Table 3). The ramp downs listed as “convective” are associated with pressure couplets—a rapid fall followed by a rapid rise in pressure. Within the couplet is the strong pressure gradient. Once it passes, winds quickly weaken in response to the slackening gradient.

Most convective cases (14 of 19) initiated ramp ups (Table 3). Analysis of the plant output data showed that subsequent ramp downs associated with convective systems are below the established threshold (200+ MW change within 30 minutes).

During the cold season (October – March), frontal passages account for most ramp events. Weakening pressure gradients also account for a significant number of these events. Consistent with climatology, convective events are less frequent during the cold season.

3.3 Temporal Distribution of Ramp Events

There is a distinct diurnal maximum (Figure 2) in the frequency of ramp-up events during the evening hours, particularly around 19:00 (5 PM) local time, when convection, especially strong to severe thunderstorms, is climatologically favored.³

³ See <http://www.srh.noaa.gov/ssd/techmemo/sr-191.htm>, available online from NWS Midland-Odessa.

There is a broad maximum in the frequency of ramp-up events from late winter through summer (Figure 3), while ramp-down events show no clear pattern. This is consistent with the dominance of convection as a cause of ramp-up events, as the warm season in Texas begins during the early spring. Ramp-up events increase in frequency during spring and summer and decrease rapidly once the convective season ends in September.

3.4 Ramp Events—Case Studies

Here we present representative cases with a more detailed analysis of the relationship between meteorological conditions and plant output.

- 1) *11 August 2006: Convective (outflow boundary causing positive ramp event).* A complex of thunderstorms was oriented south-north and just west of Midland (KMAF). These thunderstorms showed little movement between 18:00 and 19:00 local daylight time (LDT) but generated multiple outflow boundaries (stretching from just north of Fort Stockton (KFST) to south of Lubbock (KLBB))--a distance of nearly 300 km) that propagated eastward across several of the interconnection points by 20:00 LDT (Figure 4). As the outflow boundaries passed, wind speeds increased considerably (peak sustained winds exceeded 15 m/s at Fort Stockton and Odessa around 18:00 LDT), and resulted in a rapid increase in output at most interconnection points by 21:00 LDT. The thin white line marked by the red arrows (Figures 4a and b) shows visible evidence of outflow from the thunderstorm complex; such outflow boundaries occur with most strong to severe thunderstorms. Climatologically, between 40 and 50 such storms occur within any given 25 km square area in west Texas. They are, however, difficult to forecast more than a few hours in advance, and the temporal predictability of movement and intensity of associated gust fronts is usually less than an hour.
- 2) *Frontal passage with pressure couplet:*
 - a. *28 December 2006: weak gradient ahead of cold front.* An area of weak pressure gradient moves eastward across west-central Texas between 14:00 and 15:00 local standard time (LST) (Figures 5 and 6). Since wind speed is proportional to the pressure gradient, there is a significant reduction in wind power output and wind speed as this feature passes (Figures 5a-c). The drop in wind speed is most notable Fort Stockton (KFST), Lubbock (KLBB) and Odessa (KODO). There is a secondary drop in power output around 16:00 LST as winds continue to diminish (to below the cut-in value of 4 m s^{-1} at the stations mentioned above).
 - b. *28 December 2006: frontal passage.* Following the weak pressure field, a stronger gradient moves into the area after the frontal passage (approximately 15:00 – 16:00 LST), and wind speeds and output increase rapidly by 18:00 LST (Figure 7a-c). Plant output, which had decreased to about 100 MW (or 10% of the rated capacity), then rapidly rose as wind speeds rose above the cut-in value.
- 3) *14 November 2006: Dry line.* Dry lines are similar in effect to frontal passages, except they tend to occur mostly during the warm season, forming during the late morning in eastern New Mexico and moving eastward into central Texas by evening before returning westward overnight. They can trigger outbreaks of severe weather and locally strong winds. During the morning of 14 November, a tightening pressure gradient ahead of a dry line located in west Texas produced an increase in wind speed and power output around 11:30 LST (Figure 8).

Wind speeds had been rather low earlier in the morning, but rapidly increased ahead of the dry line, resulting in a 264 MW increase in output between 11:30 and 12:00 LST.

- 4) *23 May 2006: Weakening pressure gradient.* Winds were rather strong during the early morning of this event, exceeding sustained speeds of 10 m/s at Fort Stockton (Figure 8b) and generating a total of 800 MW. However, a rapidly decreasing pressure gradient (Figure 8c) resulted in a steep drop off in power production (224 MW; see Figure 8a) between 4:45 and 5:15 LDT. As the pressure gradient increased later in the morning, wind speeds and output gradually increased.

4. The 24 February 2007 Ramp-Down Event

During this event, high wind speeds exceeded the turbine cut-out threshold across most wind projects, resulting in a rapid drop in energy production. A strong upper-level storm system passed over northern New Mexico and the panhandle of Texas into Oklahoma. This substantially tightened the pressure gradients over west Texas, resulting in strong to severe winds along a straight line across much of the area. The maximum wind gust reported was 42 m/s (94 mph). Analysis of the aggregate plant output for 24 February shows that, in response to the tightening pressure gradient and increasing winds, aggregate output increased from just over 1100 MW to nearly 2000 MW (the aggregate rated capacity) by approximately 9 AM (Figures 9 and 10). By 10 AM, as sustained winds at ASOS stations exceeded 25 m s^{-1} (55 mph) at Guadeloupe Pass and Abilene (Figure 9b) and certainly higher at hub height, the output at most wind farms declined as the turbine-cutoff threshold wind speeds were reached (Figures 9a and 10). As the most intense pressure gradients and winds moved eastward, wind speeds relaxed and turbines resumed power production, resulting in a more gradual increase in total output to pre-event levels.

The drop in plant output amounted to over 1500 MW over a 90 minute period, with the most rapid declines occurring at the Horse Hollow interconnections (Figure 10). The largest decrease in 30 minutes, however, was about 450 MW (between 1104 and 1134 LST). On a proportional basis, this 450 MW decrease represented about 22.5% of the plant rated capacity. Scaled to the 976 MW rated capacity studied in 2005-2006, it would have been a 220 MW ramp-down event. Although it would have exceeded the threshold of detection, it would not have been classed as one of the more severe ramp downs observed in this period. However, this event was unusual both in the magnitude of the 90-minute drop it caused and in the large geographic area it affected. Its implications for much larger deployments of wind generation in the state are discussed in the following section.

5. Probability and Predictability of Ramp Events

Based upon the period 2005 - 2006, ramp events as defined in this report are likely to occur about once every 6 - 7 days (Table 2); multiple events in one day may occasionally occur (see 28 December 2006), especially when pressure couplets are involved (i.e. ahead and behind a frontal system).

Frontal passages/troughs/dry lines of any severity generally occur about once every 3 – 5 days during the cold season, and 5 – 7 days during the warm season. From Table 2, such events initiating ramp-up excursions meeting the threshold of detection in this study would occur about

20 days per year, or once every 2 – 3 weeks. Ramp-down events are much rarer, occurring about once every two months.

Convective events occur with widely varying frequency. The Storm Prediction Center (SPC), part of the National Weather Service (NWS), monitors and forecasts severe weather over the continental United States. An examination of the annual total number of severe thunderstorm wind events (defined as winds estimated to be in excess of 29 m/s) as compiled by the SPC for the last 10 years shows a wide variation, from 32 in 2000 to 134 in 2003, within the ERCOT domain, illustrating the large variability in year-to-year severe thunderstorm winds.

Forecast Skill and Lead Time. All weather phenomena causing ramp events can be forecast. However, the effective lead time and skill of the forecasts varies considerably, as indicated in Table 2. Generally speaking, frontal passages and related phenomena can be forecast several days in advance, although the accuracy of the forecast and in particular of the timing of the frontal passage improves markedly as the event approaches. Several hours ahead of time, the arrival of the frontal passage may be forecast within perhaps a 30-minute to one-hour window.

Severe thunderstorms and other convective events are much more difficult to forecast. Among its suite of forecasting products, the SPC issues convective outlooks which serve as guidance to the local NWS forecast offices. These forecasts identify separate severe weather risk areas (slight, moderate, and high) and are used to describe the expected coverage and intensity for the severe weather threat one to three days ahead along with severe weather probabilities for the potential threat. When conditions become favorable for severe thunderstorms (those that produce winds in excess of 58 mph (26 m/s) and/or hail 3/4 inch or larger) to develop, the SPC usually issues a severe thunderstorm watch. These watches are generally issued a few hours ahead of expected severe weather.

The NWS assesses its thunderstorm forecasting success using several measures, including the probability of detection, false alarm ratio, and average lead time. These are defined below.

Probability of Detection (POD): This is the percentage of all severe weather events which were successfully predicted (a perfect score would be 100%). For example, if 60 warnings were issued and there were 100 total severe weather events reported (60 warned, 40 unwarned), the POD would be 60%.

$$\text{POD} = \text{warned events} / (\text{warned events} + \text{unwarned events})$$

False Alarm Ratio (FAR): This ratio measures how often false alarms (forecasted event, but none occurs) are issued. Ideally this number should be close to 0%. Some false alarms occur as a result of storms that may appear severe, or are borderline severe, while others occur because the severe weather occurred where no one was around to observe the event.

$$\text{FAR} = \text{unverified warnings} / (\text{verified warnings} + \text{unverified warnings})$$

Average Lead Time: This is simply the length of time from when the warning is issued until the first report of severe weather in the warned area. This time can be anything from 0 minutes up to the total valid time of the warning.

Table 3, provided by the NWS, list the forecast statistics for the spring (March, April, and May) and summer (June, July, and August) seasons of 2005 and 2006 for the ERCOT domain. The results indicate a significant amount of variability in severe thunderstorm cases from season to season and year to year. Forecasts tend to be better during active periods since they often have more organized weather systems. Inactive periods, on the other hand, tend to have disorganized weather systems that are more difficult to track, model, and predict. From the statistics in this table, the average lead time for severe thunderstorms in west Texas during this two-year period was about 20 minutes. The probability of correctly forecasting a severe thunderstorm averaged between 70% and 85%. However, the percentage of false alarms was also relatively high, ranging from about 60% to 70%.

Analysis of 15,000 GW Scenario. Based on the foregoing analysis of the 2005-2006 and 24 February 2007 events, we assessed the probability and severity of possible extreme ramp events for the proposed distribution of wind projects in the 15,000 GW scenario (see Table 4). It should be stressed that this analysis is highly uncertain as it is based on limited wind project data for a two-year period. It should be confirmed through a more detailed assessment spanning both a longer period and a larger geographic area.

For convective events, we find CREZ 5, 6, and 9 would be the most susceptible to large excursions in power generation. Since the maximum propagation rate of the systems identified above is perhaps 25 m/s, and the orientation of these features tends to be north-south, under a worst-case scenario, where CREZ 5 and 9 are simultaneously affected (with rated capacities of 3251 - 4529 MW under the 15000 MW scenario), excursions of ± 1300 MW can be expected at least 2 - 4 times per year. In addition, as CREZ 10 would have by far the largest wind capacity (4607 MW), a weather system affecting this entire zone could conceivably result in a 30-minute excursion of more than 1100 MW. Based on the largest events observed in 2005-2006 ($> 25\%$ excursion), the frequency of such events is estimated to be about 2 - 4 times per year.

For frontal events, dry lines, and pressure couplets, a larger area would be affected but as propagation speeds are generally lower ($15 - 20 \text{ m s}^{-1}$), it is highly unlikely that more CREZs would be affected during any 30 minute period than during convective outbreaks.

Finally, an event of the magnitude and areal coverage of 24 February 2007 could produce over a 20% reduction in power over most of the CREZs (with estimated combined capacity of 12,300 MW) in 30 minutes, resulting in a *maximum* power reduction for affected CREZ areas in excess of 2800 MW (see Table 4). We estimate the probability of such an event as one occurrence every 3 - 5 years.

6. Uncertainties

Every meteorological event, although exhibiting many structural similarities, is nevertheless temporally and spatially unique. Frontal systems propagate at different (and not necessarily consistent) speeds, and pressure couplets and convective systems (and associated outflow

boundaries) also dynamically evolve over time. Therefore, the above analysis cannot capture every possible scenario that could occur in the ERCOT region.

Furthermore, not all plants will experience a ramp up or ramp down simultaneously as they are geographically displaced from each other and rarely oriented in parallel with these features. Thus, increasing the spacing between wind farms and altering their distribution may mitigate the aggregate ramping due to small-scale meteorological phenomena such as these pressure couplets, or from convective outflows, common in the warmer months.

Appendix A

Glossary of Weather Terms (from the American Meteorological Society's Glossary of Meteorology, 2nd Edition)

Convection. Motions that are predominantly vertical and driven by buoyancy forces arising from static instability,

Dryline. A low-level mesoscale boundary or transition zone hundreds of kilometers in length and up to tens of kilometers in width separating dry air from moist air. In the United States the dryline, which marks the boundary between moist air from the Gulf of Mexico and dry continental air from the west, is found in the Plains region. It is most often present during the spring, where it is often the site of thunderstorm development. Typically the dryline in the United States advances eastward during the day and retreats westward at night.

Front. The interface or transition zone between two air masses of different density. Generally, the temperature distribution is the most important regulator of atmospheric density. However, in the southern Plains, especially over west Texas, humidity differences are commonly separate distinct air masses (see "dry line")

Low-level Jet (LLJ). A region of relatively strong winds in the lower part of the atmosphere. Specifically, it often refers to a wind maximum in the boundary layer (from 100 - 500 m above the ground), common over the Plains states at night during the warm season (spring and summer).

Mesoscale. Atmospheric phenomena having horizontal scales ranging from a few to several hundred kilometers.

Pressure gradient. The rate of decrease (gradient) of pressure in space at a fixed time.

(Thunderstorm) Outflow Boundary. A surface boundary formed by the horizontal spreading of thunderstorm-cooled air. Outflow boundaries may intersect with each other or with other features (fronts, low-level jets) and act to focus new convection. Outflow boundaries may be short-lived, or last for longer than a day.

Trough. An elongated area of relatively low atmospheric pressure. A weaker feature than a "front."

Table 1a. Negative Ramp Events For ERCOT Domain 2005			
Date	Begin Time (Local)	Ramp (MW)	Event Classification
12-May	5:20 AM	-331	weakening pressure gradient
15-Jul	3:40 AM	-265	convective pressure couplet
19-Feb	11:45 PM	-239	weakening pressure gradient
27-Feb	7:31 PM	-235	weakening pressure gradient
28-Aug	9:39 PM	-230	convective pressure couplet
21-Mar	8:28 PM	-225	weakening pressure gradient
23-May	6:58 AM	-218	weakening pressure gradient
12-Aug	7:06 PM	-218	Stabilization
24-Apr	3:45 PM	-218	frontal passage
9-Oct	6:38 PM	-214	convective pressure couplet
10-Jun	8:14 AM	-206	weakening pressure gradient
14-May	3:49 AM	-204	frontal passage
18-Feb	12:11 PM	-202	weakening pressure gradient

Table 1b. Positive Ramp Events For ERCOT Domain 2005			
Date	Begin Time (Local)	Ramp (MW)	Event Classification
9-Jul	8:14 AM	397	thunderstorm outflow
28-Aug	8:48 PM	321	convective
10-Feb	7:27 AM	291	Frontal passage
10-Jul	5:42 PM	251	thunderstorm outflow
10-Aug	6:18 PM	248	convective
3-Aug	7:19 PM	248	convective
11-Sep	8:28 PM	246	convective
15-Jul	4:47 AM	246	thunderstorm outflow
23-Jul	4:07 PM	229	convective
10-Mar	8:29 PM	226	frontal passage
29-Apr	9:27 PM	226	frontal passage
26-Mar	7:18 PM	215	frontal passage
10-Apr	10:54 AM	212	frontal passage
13-May	7:02 PM	210	dry line (frontal)
15-May	8:54 AM	209	convective
29-Mar	3:22 PM	206	frontal passage
12-Jan	11:10 AM	204	frontal passage
25-Apr	9:39 AM	201	frontal passage
23-Feb	11:04 PM	200	frontal passage

Table 1c. Negative Ramp Events For ERCOT Domain 2006			
Date	Begin Time (Local)	Ramp (MW)	Event Classification
15-May	2:40 AM	-291	weakening pressure gradient
28-Dec	2:29 PM	-281	weak gradient ahead of front
22-Mar	9:14 PM	-266	weakening pressure gradient
24-Feb	10:58 PM	-252	convective
30-May	8:02 AM	-225	weakening pressure gradient
20-Jan	1:17 AM	-225	trough passage
23-May	4:46 AM	-224	weakening pressure gradient
23-Jun	5:40 AM	-221	outflow pressure couplet
13-Aug	8:15 PM	-219	weak gradient ahead of front
28-Sep	11:26 AM	-216	frontal passage, slack gradient
20-Dec	12:26 AM	-214	Frontal passage, slack gradient

Table 1d. Positive Ramp Events For ERCOT Domain 2006			
Date	Begin Time (Local)	Ramp (MW)	Event Classification
23-Jun	4:49 AM	294	thunderstorm outflow
14-Nov	11:29 AM	264	dry line
28-May	7:11 PM	264	dry line
28-Apr	3:49 PM	258	frontal passage
20-Jul	7:33 PM	257	trough passage
26-Sep	7:58 PM	255	trough passage
19-Dec	10:16 PM	253	trough passage
11-Aug	8:28 PM	242	Surface trough/convection
1-Jul	10:48 PM	241	trough passage
1-Aug	2:10 AM	234	thunderstorm outflow
28-Dec	6:30 PM	224	frontal passage
25-Aug	6:32 PM	215	thunderstorm outflow
27-Oct	2:07 PM	211	frontal passage
17-Oct	12:56 AM	208	surface trough
4-Aug	2:13 AM	203	convection
16-Jun	10:34 PM	202	dry line

Table 2. Summary of weather phenomena associated with ramp events, their frequency, and typical forecast lead time

	Ramp up/Ramp down	Typical Events per year	Preferred time of day/season	Forecast Lead Time
Frontal Passage	12/3	Around 50	Winter, followed by Spring or Fall, no preference for time of day, although pre-frontal convection usually occurs during evening.	Can usually be forecast days in advance with better accuracy of timing as event approaches. More precise frontal timing can be accurately forecast with a few hours lead time on a given day. Within 2-5 hours of anticipated frontal passage they can be forecast to perhaps within 30 minutes.
Dry Line	4/0	40-50	Spring, Summer. The dry-line generally advances east by day, retreats by night	Dry line formation can typically be anticipated a day or so in advance. When formed, dry line passage can be forecast on the local scale a few to several hours in advance.
Troughs	5/1	Around 50	Anytime, no strong seasonal preference, no hourly dependency	Similar to frontal passages, above.
Weakening Pressure Gradient	0/14	80-100	Anytime, no strong seasonal preference, no hourly dependency	Large scale gradients similar to "fronts"; smaller scale gradients related to small scale pressure couplets similar to "convection".
Convective Outflow	14/5	40-60 days in the project area at a given point. Can have multiple outflows from one event.	Spring or Summer, afternoon and evening	Occurrence can be "nowcast" using current data, with a few hours lead. Individual outflows perhaps 20-30 minutes in advance of arrival at a particular site. Probabilities in a region may be forecast a few (2-3) days in advance with good confidence
Stabilization	0/1	unknown	Around sunset	Can be anticipated perhaps a day or two in advance for probabilities.
High Wind	1/1	1	Anytime, preference for cold season	A few hours to several days

Table 3. NWS Severe Thunderstorm forecasting statistics (2005-2006)

	# of Events	# of Warnings	POD	FAR	Lead Time (minutes)
Spring 2005	57	140	0.72	0.70	18
Spring 2006	414	821	0.86	0.59	21
Spring 2005-2006	471	961	0.84	0.61	21
Summer 2005	343	588	0.80	0.58	20
Summer 2006	106	217	0.75	0.67	15
Summer 2005-2006	449	805	0.79	0.60	19

Table 4. Extreme Events Summary: 15,000 GW Scenario

Weather Event	CREZs Affected	Aggregate Rated Capacity (MW)	Maximum 30-Minute Ramp (MW)	Frequency (# times approaching max ramp per year)
Convective	5, 9	3251	+1300	2 - 4
Frontal/dry line/trough	5, 6, 9	4529	+1324	2 - 4
Weak gradient	5, 6, 9	4529	-1313	2 - 4
High Wind	2, 4, 5, 6, 7, 9, 10, 12, 14	12,329	-2836	< 1



Figure 1. Locations of Wind Farms, ASOS stations (yellow text), profiler (cyan text) and NEXRAD (red text). Identifiers for surface meteorological data include KODO (Odessa), KABI (Abilene), KLBB (Lubbock), KGDP (Guadeloupe Pass) and KFST (Fort Stockton). KMAF is the Midland NEXRAD.

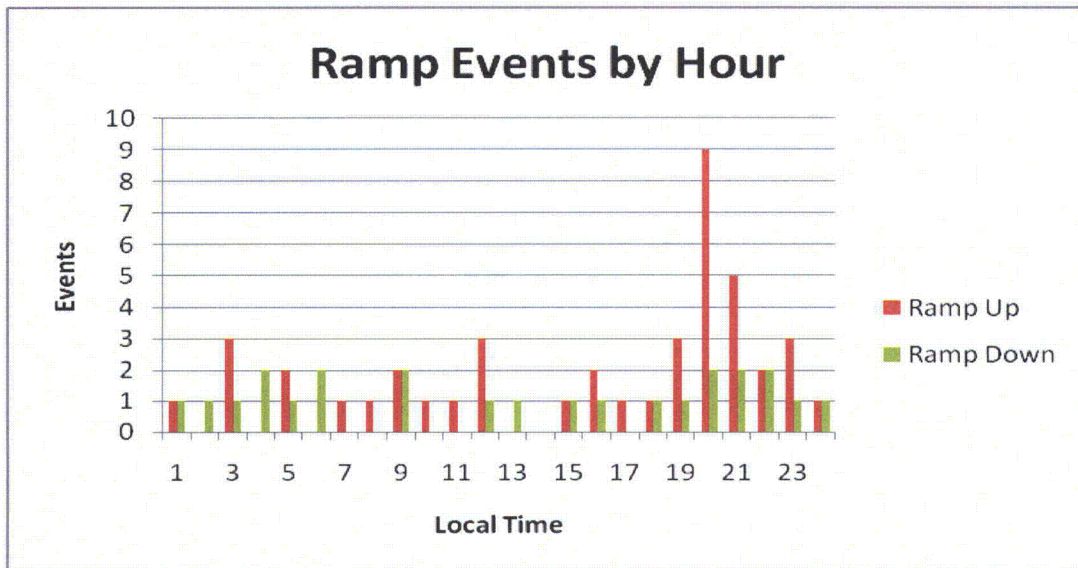


Figure 2. Distribution of ramp events by hour of day.

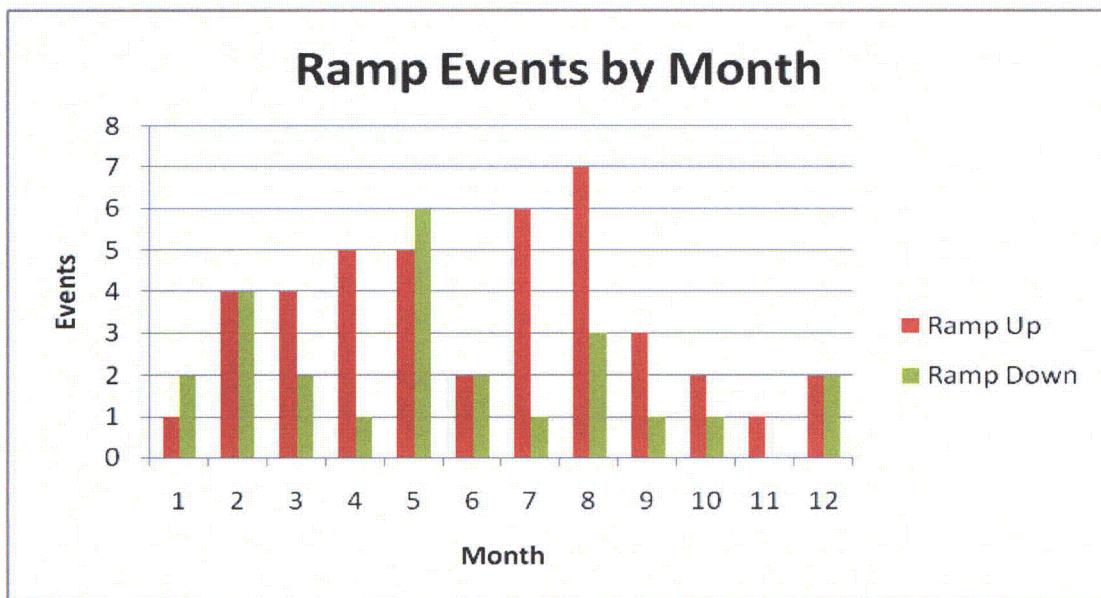


Figure 3. Distribution of ramp events by calendar month.

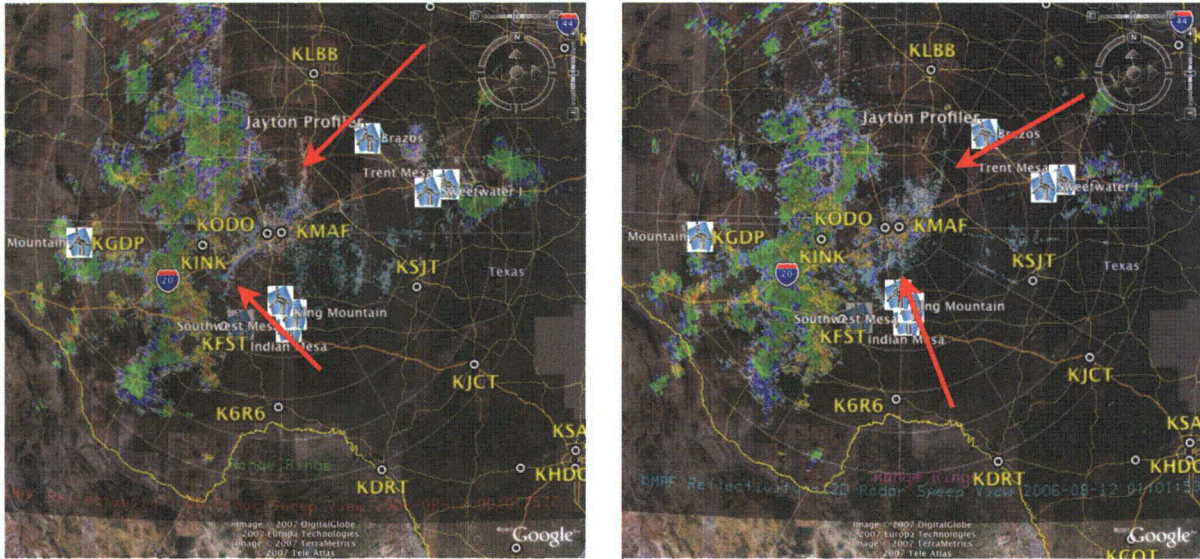


Figure 4. Left: NEXRAD (radar) image from Midland TX (KMAF) for 1801 LT on 11 August 2006. Red arrows show outflow from thunderstorm complex to the west. Right: outflow boundary an hour later (1901 PM LT) now approaching cluster of wind farms south and northeast of KMAF. Shortly after, ramp event of +600 MW was observed within a 30 minute period. Lower arrows indicate boundary traversed about 100 km in 1 hour.

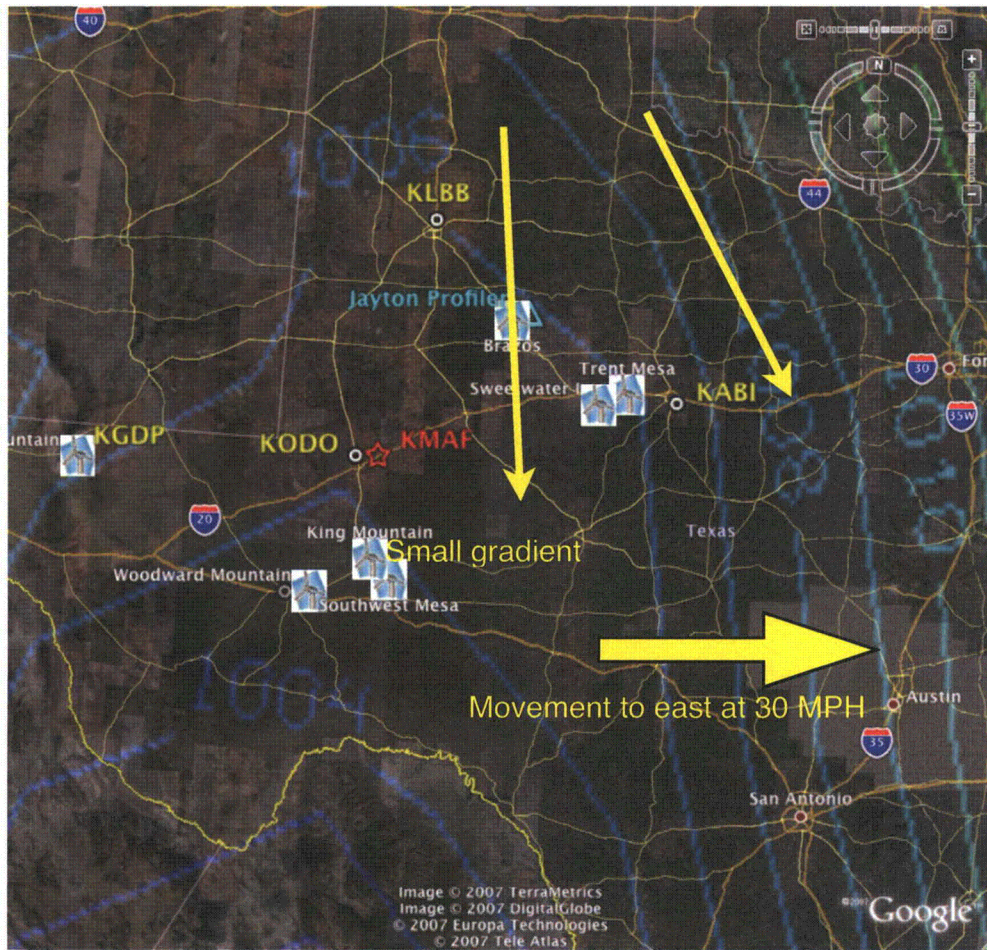


Figure 6. Sea level pressure (hPa, blue lines) for 1900 LT 28 December 2006. Note large pressure gradient has just moved through wind farms near Abilene (KABI) to be followed by rapidly slackening gradient.

28 December 2006

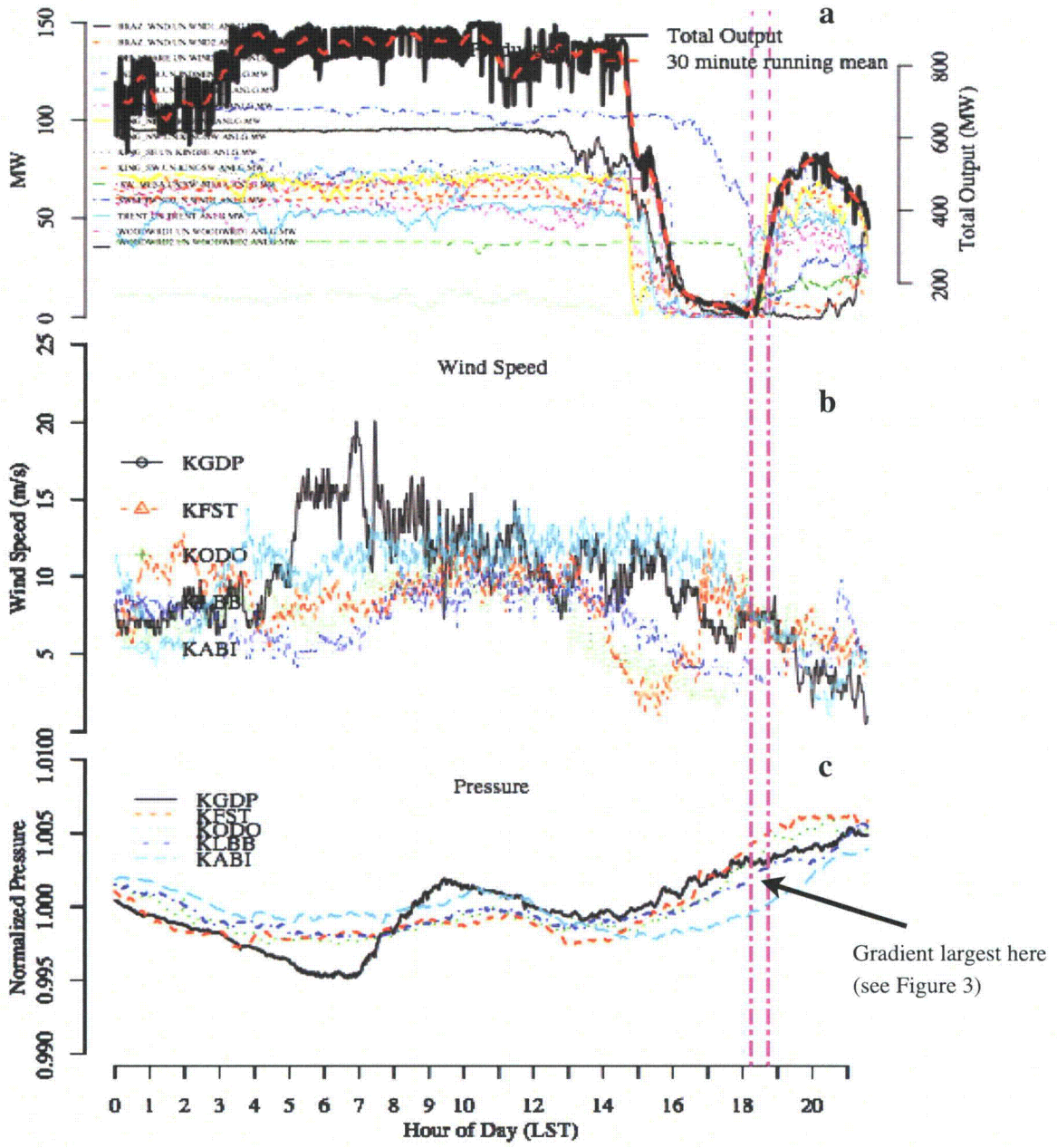


Figure 7. Same as Figure 5, except for ramp up event.

Ramp Event Summary and ASOS 1-minute Data For: Day = 14 November 2006

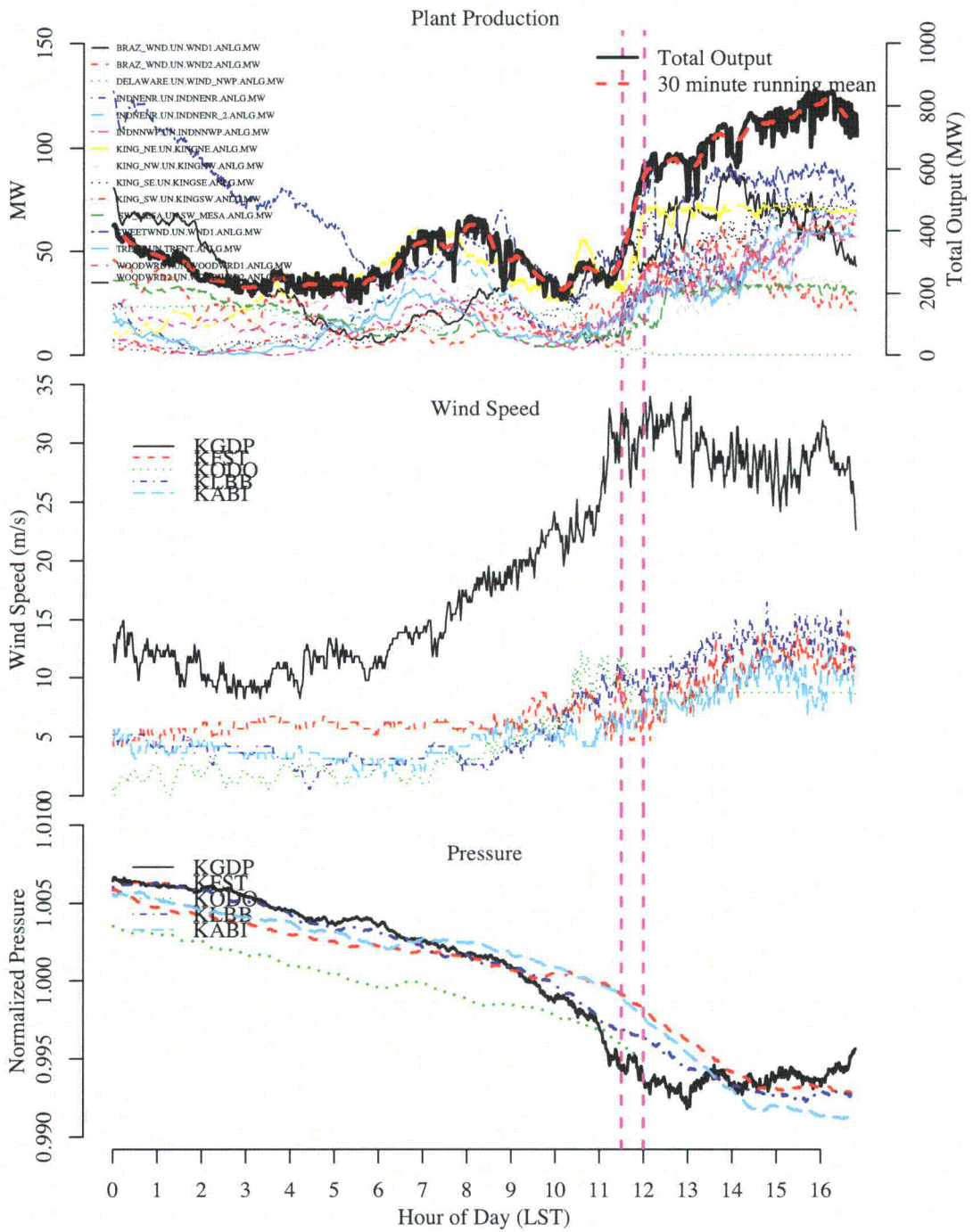


Figure 8. Same as Figure 5, except 14 November 2006.

Ramp Event Summary and ASOS 1-minute Data For: Day = 23 May 2006

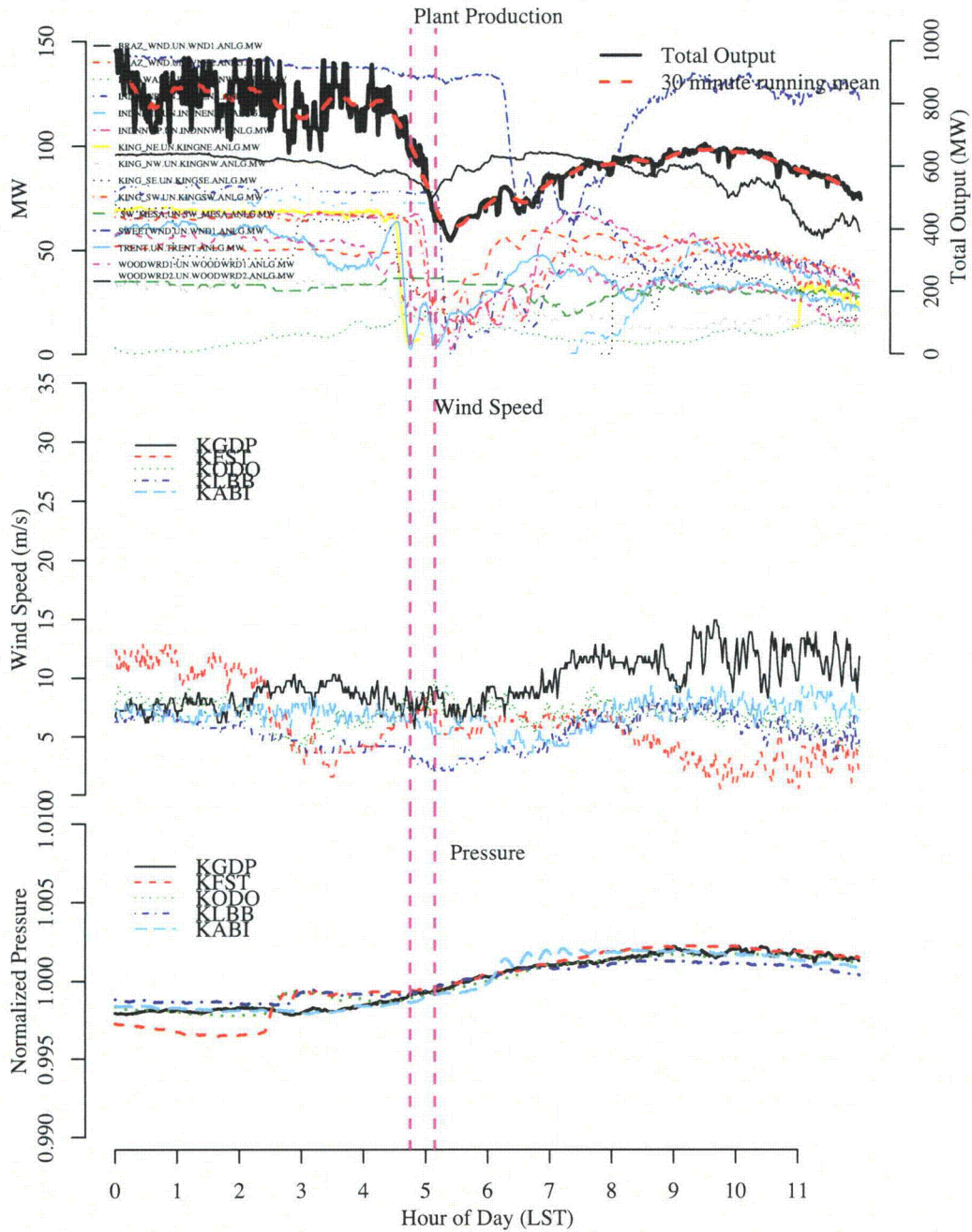


Figure 9. Same as Figure 8 except for 23 May 2006.

Ramp Event Summary and ASOS 1-minute Data For: Day = 24 February 2007

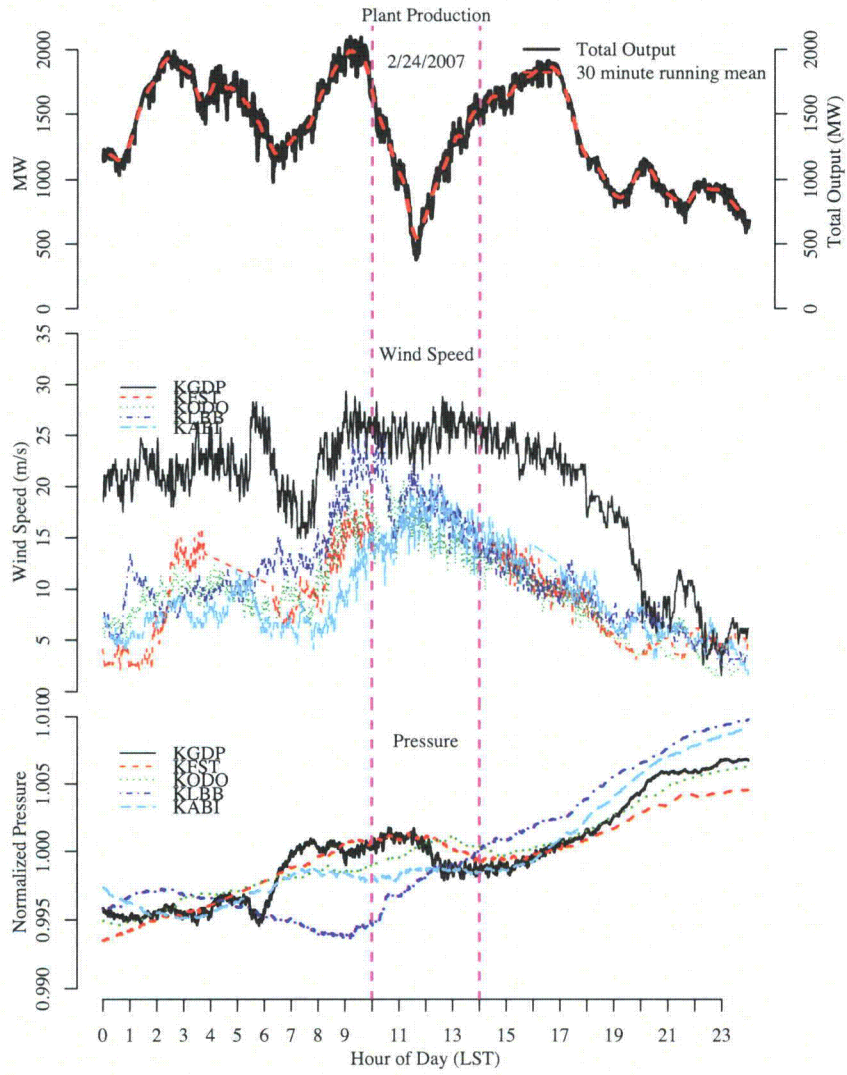


Figure 10. Same as Figure 9 except for 24 February 2007.

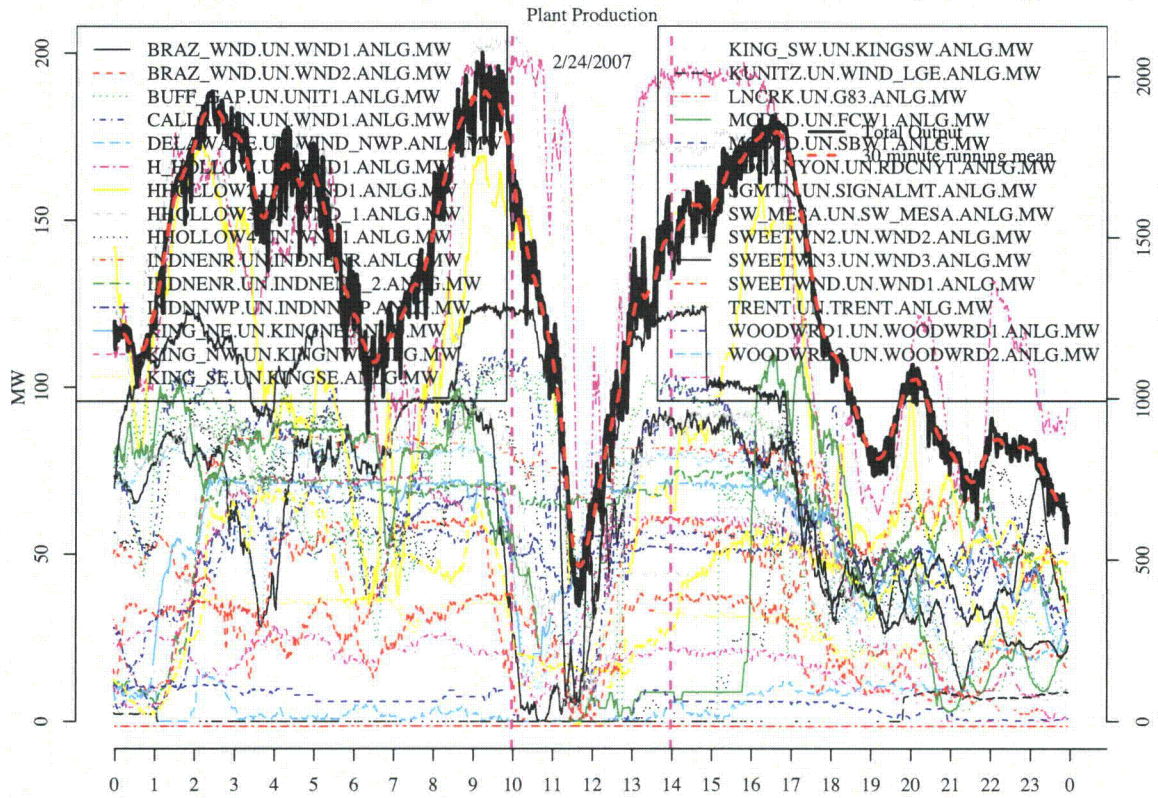
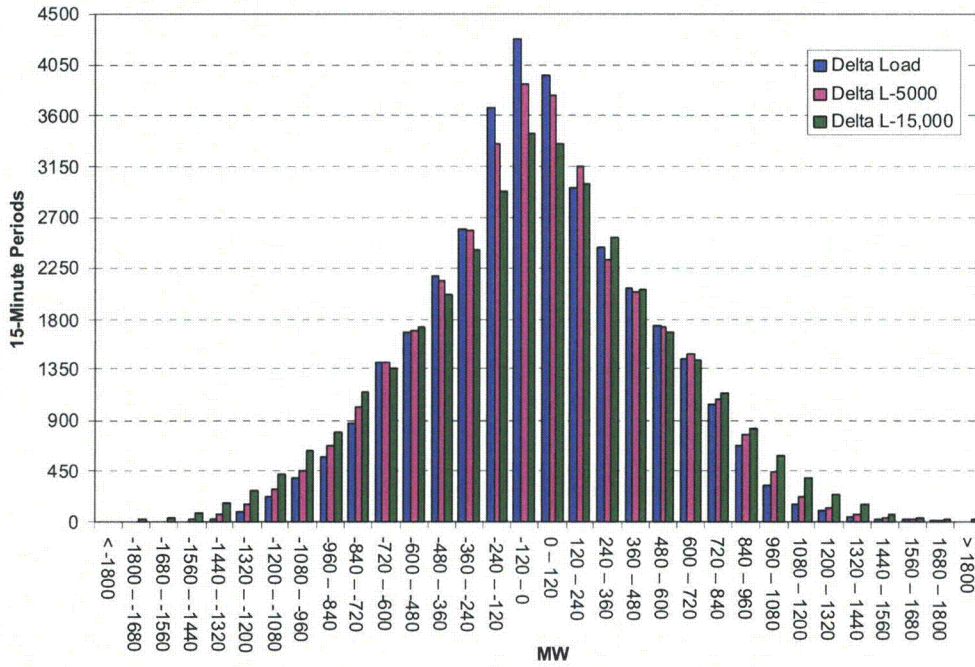


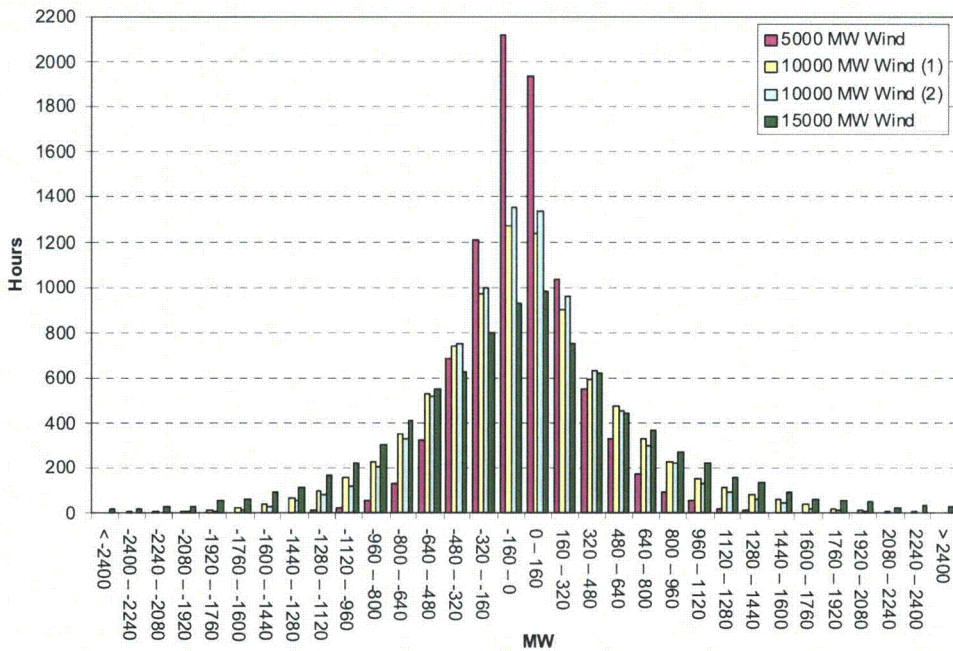
Figure 11. Same as Figure 10(a) except for 24 February 2007 .

APPENDIX I SUPPLEMENTAL EXTREMA ANALYSIS PLOTS

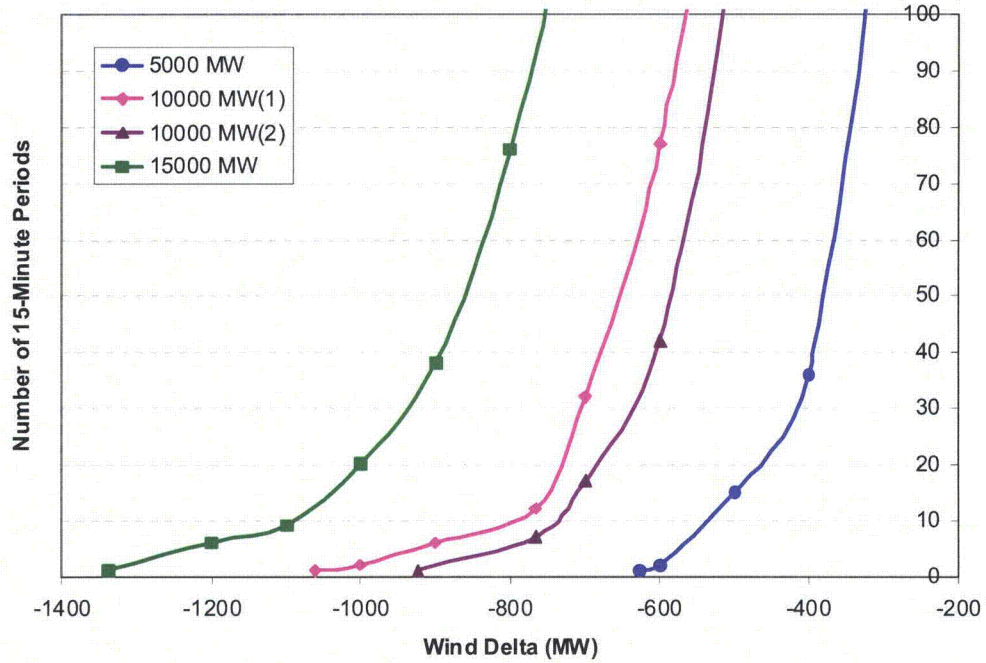
Fifteen Minute Delta Frequency Distribution



One-Hour Delta Frequency Distribution



Cumulative Frequency of Extreme 15-Minute Wind Output Drops



Cumulative Frequency of Extreme One-Hour Wind Output Drops

