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The Impact of Balancing Area Size and Ramping Requirements on Wind Integration[1]

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ABSTRACT
Balancing area reserve sharing[2] may significantly reduce wind integration costs. It also reduces utility costs without wind. Some recent studies indicate that large balancing areas can integrate wind more easily than small ones. The "hockey stick" pattern of dramatically increasing wind integration cost above some threshold wind penetration may not be as pronounced as expected. The existence and location of this threshold could have important implications regarding the cost of integrating significant wind penetrations. We examine wind integration impacts as a function of balancing area size to determine if the larger system size mitigates wind integration impacts at high penetrations. Using data from Minnesota, we show that ramping requirements can be reduced by balancing area consolidation. In a companion paper[3], we examine electricity market data in the United States that show how ramping capability is provided at low or no cost, and discuss its relevance to wind integration.

INTRODUCTION: POWER SYSTEMS OPERATION AND WIND
During the past several years, the use of wind energy has expanded around the world. In the United States, there were nearly 17 GW of wind capacity online at the end of 2007 (*http://www.awea.org/projects/*) and an additional 3 GW of wind under construction. The growth in actual and prospective wind energy facilities has in part stimulated a number of analyses of power system operations at the same time as additional experience with wind has helped grid operators become familiar with this relatively new energy source.

A significant focus of several wind integration analyses has been on the operational impact that wind has on the grid. These impacts arise from the variable nature of the wind resource and from the difficulty in accurately predicting wind energy hours or days in advance. Wind integration studies prior to 2006 have generally focused on the impact of wind on power system operations within existing balancing area boundaries. A recent study carried out for the Minnesota Public Utilities Commission by EnerNex (2006) examined the

[1]This work is based on a paper presented at WindPower 2007 by the authors.
[2]Balancing area obligation sharing involves the continuous sharing of ACE and imbalance obligations among two or more balancing areas in order to reduce regulation and load following requirements in meeting CPS 1 and 2. It is the continuous analogy to the current practice of sharing contingency response obligations within reserve sharing groups.
[3]The Impact of Balancing Areas Size, Obligation Sharing, and Energy Markets on Mitigating Ramping Requirements in Systems with Wind Energy, to appear, *Wind Engineering*.

impact of a 20% wind penetration (based on energy) statewide, and recognized the interconnection benefits to the MISO energy markets. Miller and Jordon (2006) illustrated the benefits of balancing area consolidation using data from GE Energy (2005) for the New York State Energy Research Development Authority.

Because wind energy is primarily an energy source used for saving fuel and not as a capacity resource used for meeting peak loads, the capacity value of wind will be a fraction of its rated nameplate capacity. In the extreme (and highly unlikely) event that wind has no capacity value, any system that is capable of operating in the absence of wind can continue to operate with wind. The installed non-wind generation would be capable of supplying needed capacity and energy during the times that it is needed. Although operational changes would be expected to arise with the addition of wind energy, the sufficiency of the pre-existing system would clearly still be adequate. For example, if a system with a 1,000 MW peak load and 1,200 MW of generation without wind is adequate, then adding 300 MW of wind will increase the generation that is available to serve the same load.

However, there has been recent concern about whether sufficient ramping capability exists to help manage the increasing variability that results from significant wind penetrations. Bonneville Power Administration (BPA) recently embarked on a study to determine the extent to which wind forecasts could help reduce wind integration costs. BPA also raised concern about the increased cost of dealing with wind ramp requirements at the Northwest Wind Integration Action Plan Technical Work Group Meeting, Aug 14, 2006. This concern has also been raised by other utilities and grid operators.

To help address the issue of ramping, we obtained data that could be used to calculate system ramping requirements both for individual balancing areas (formerly called control areas) and a combined, integrated balancing area. We used wind data from the Minnesota PUC's 20% Wind Integration Study (EnerNex, 2006), which was simulated by WindLogics to represent a geographically dispersed wind scenario for the study. Because of proprietary concerns, we were unable to secure load data from the utilities, nor were we able to obtain data for the non-wind generation. Instead, we used data from the Platts' Basecase database (a product of Platts, a subsidiary of McGraw-Hill) to extract hourly load data by balancing authority.

Because our work was limited to an analysis of hourly data, we are confident that we significantly understate the benefits of combined reserve sharing or balancing area operations. Miller and Jordan (2006) showed that, as measured by standard deviation of load and wind variability, the benefits of combined operations were greater for the 5-minute time slice as compared to the hourly period. The penetration of wind in the NY study was 10%, based on wind rated capacity to system peak load. In contrast, our MN data set is a much higher penetration. To accentuate wind's impact on the system, we used the Platts load data, as reported in 2004, without scaling to the higher load level that was used as the basis of the MN study. Our wind penetration is therefore approximately 30% based on energy, and approximately 50% based on capacity. Our system representation shows an annual combined peak load of 11,378 MW with rated wind capacity of 5,688 MW.

Our analysis examines the impact that wind has on balancing area ramp requirements, and compares the need for ramping under two scenarios: (1) balancing areas continue with separate operation, obtaining all needed ramping from within the area, and (2) the state of MN operates as a single balancing area. This second scenario was the basis for the MN 20% Wind Integration Study. Contrary to the MN study, we ignore any interaction with the MISO energy market or with generating units that are outside the MN footprint. This puts the entire ramping burden on generators that are within the balancing area.

RAMPING REQUIREMENTS FOR LOAD AND WIND

It is well known that larger balancing areas can more easily manage variability. A recent analysis by Miller & Jordon (2006) showed the benefit of aggregation in New York. The analysis was based on data used for a wind integration study, and illustrates the benefit of combining the transmission zones in the state. The benefits of consolidating loads, but without wind, are modest in the hourly time frame, but are more significant in the 5-minute time frame. Consolidation with 3,000 MW of wind added to the system was more beneficial in both time frames.

Our analysis differs from the NY analysis because we focus on ramping characteristics, both with and without wind. Our analysis examines the demand, or need for, ramping based on load and wind characteristics. We calculate the ramping needs for MN with and without balancing area consolidation, and look at load separately from wind. Although our concern is less with the impact that wind has on ramping requirements, we show data that illustrates how ramping requirements change with wind.

Minnesota is divided into four balancing areas for our analysis: Great River Energy, Minnesota Power Company, Northern States Power, and Otter Tail Power. Figure 1 shows the approximate balancing areas. Our data is based on the Minnesota 20% study which did not separate the other balancing areas in the state.

Ramping requirements have some degree of statistical independence, depending on the time frame. For relatively long time frames such as one hour, this independence is somewhat limited for load because of the prominent daily load cycle. During the morning load pickup, the general trend of load is increasing, which requires positive ramping from units that are on economic dispatch. Likewise, during the evening load drop off, the decrease in load requires negative ramping from the dispatch stack. For neighboring balancing areas, the morning load pickup and evening load drop off will likely be fairly correlated. This means that during those hours, balancing area consolidation benefits for load ramping alone may be minimal.

Figure 2 illustrates the benefit of balancing area consolidation with wind added to the system. The figure is based on data we used for this project, selected to illustrate how benefits of combined operations work. The upper panel of the graph shows one day of hourly ramp requirements (change in capacity at the top of the hour) for wind and load together, based on separate balancing area operations. The upper trace (solid blue) shows the total up-ramp requirements for the day. The green trace shows the hourly down-ramp requirements for the same period, assuming separate operations. The graph clearly illustrates that there are hours when some balancing areas require up-ramp capability at the same time that other areas require down-ramp capability. During these hours, more physical and economic efficiency can be achieved by offsetting the positive and negative ramping requirements, to the extent possible. This results in the combined balancing area ramp requirement, which is superimposed in yellow on the upper panel of the graph. The reduction in required ramping that can be achieved by combining operations is shown in the middle panel of the graph, and is called the ramp penalty.

To better quantify the benefits of combined operations, we develop a series of definitions and metrics. The *dominant ramp* is the maximum of the up-ramp and down-ramp for a given hour. The dominant ramp has the same sign as the required ramp for combined operations. In Figure 2 we can see that the dominant ramp is positive until 1:00 PM, remaining negative for the remainder of the day. The *secondary ramp* is the ramp that is in the opposite direction as the dominant ramp. We define the *ramp penalty* as the difference between the dominant ramps required by separate systems operation and combined operation.

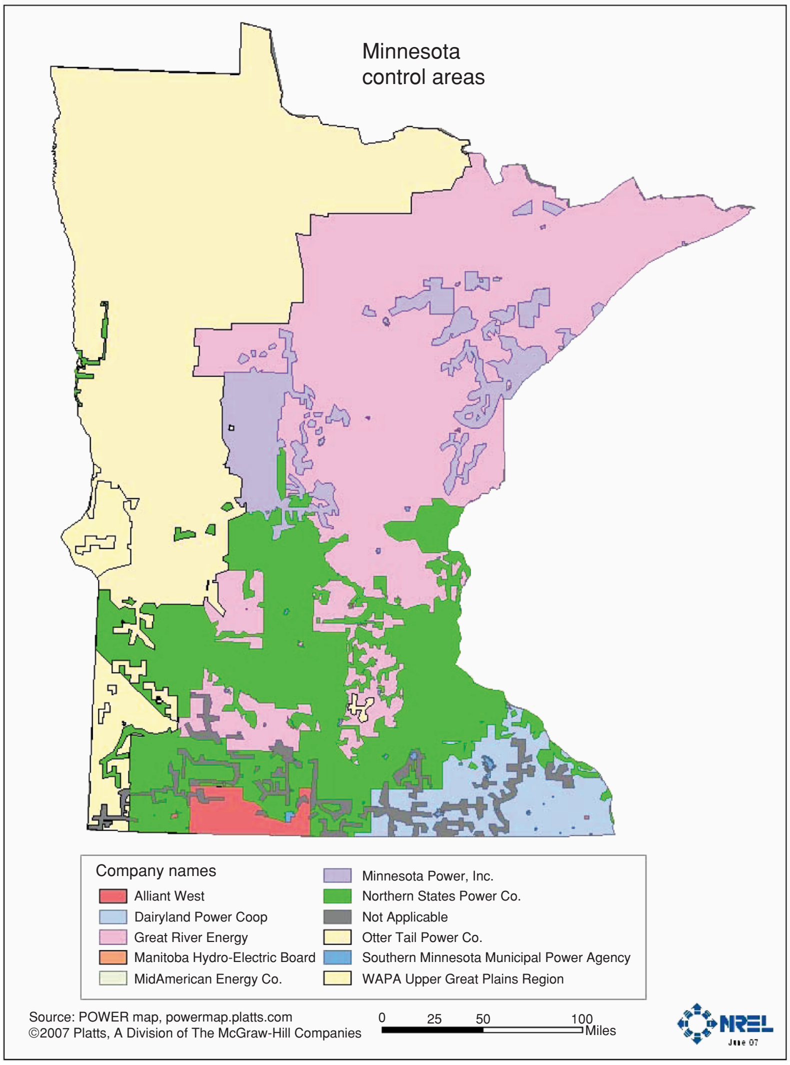

Figure 1: Balancing areas in Minnesota.

Excess ramping is a symmetrical positive and negative ramp. For example, in Figure 2 at 5:00 AM there is a positive ramp of about 1,000 MW at the same time there is a negative ramp of about 500 MW. If the balancing area were to combine, the dominant ramp of 1,000 MW could be reduced to 500 MW. This reduction in the dominant ramp is the ramp penalty for that hour. During this hour there is a reduction of the dominant ramp of 500 MW and an elimination of the secondary ramp of −500 MW. The excess ramp is therefore in both directions, and appears in the lower panel of Figure 2.

The general trend of the ramp penalty shows that during the early morning load pickup, the combined wind and load ramp requirement is increasing generally, but some areas are experiencing a need for down-ramp capability during that time. The combined system generally needs up-ramping during the morning, and down ramping during the evening. But as the graph makes clear, there are individual needs for down-ramp capability during the morning, and up-ramp capability during the evening. Combining operations across the balancing areas will reduce overall ramping needs.

The next section describes the benefits of combined operations in the absence of wind.

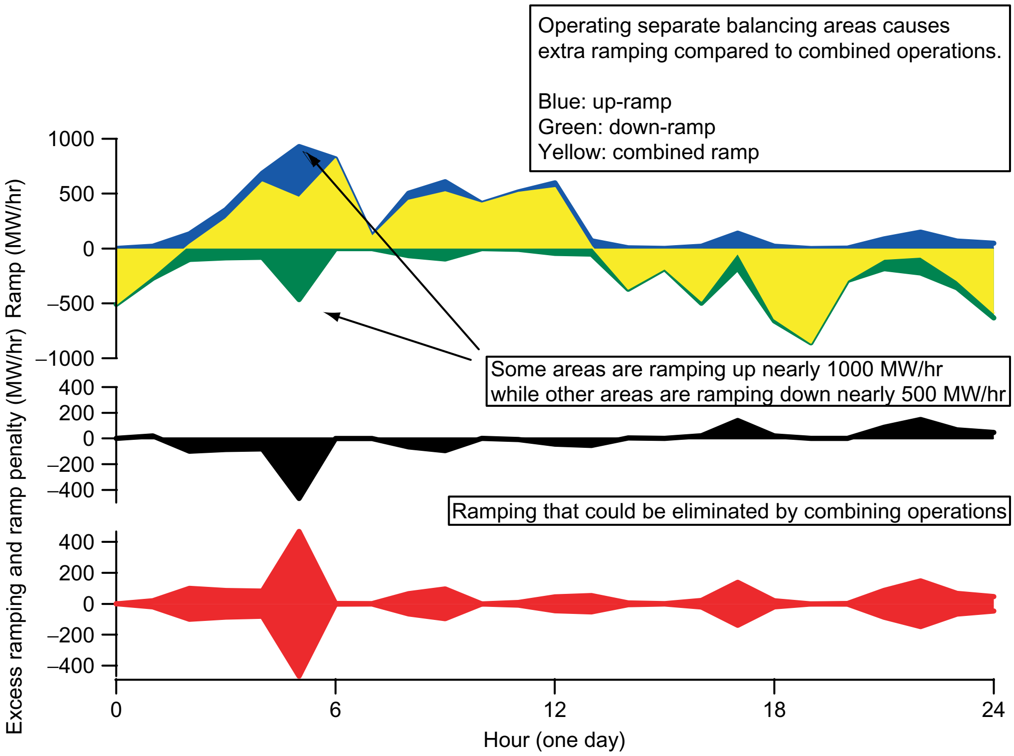

Figure 2: Potential benefits of combined balancing area operations.

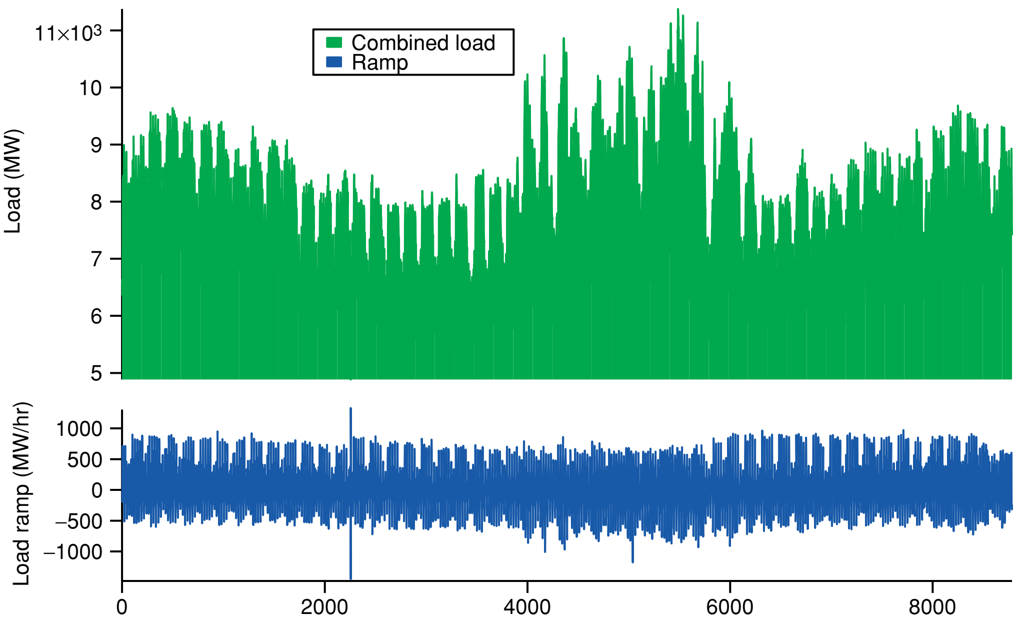

Figure 3: Combined Minnesota loads and ramping requirements.

Load Ramping Requirements: Benefits of Combined Operations

In the 1-hour time frame, the benefit of combining balancing area operations is less than that experienced in the sub-hourly time frame because of the relatively high degree of correlation between hourly load and ramp requirements. Figure 3 shows the combined load in the upper panel, and the required ramping in the lower panel.

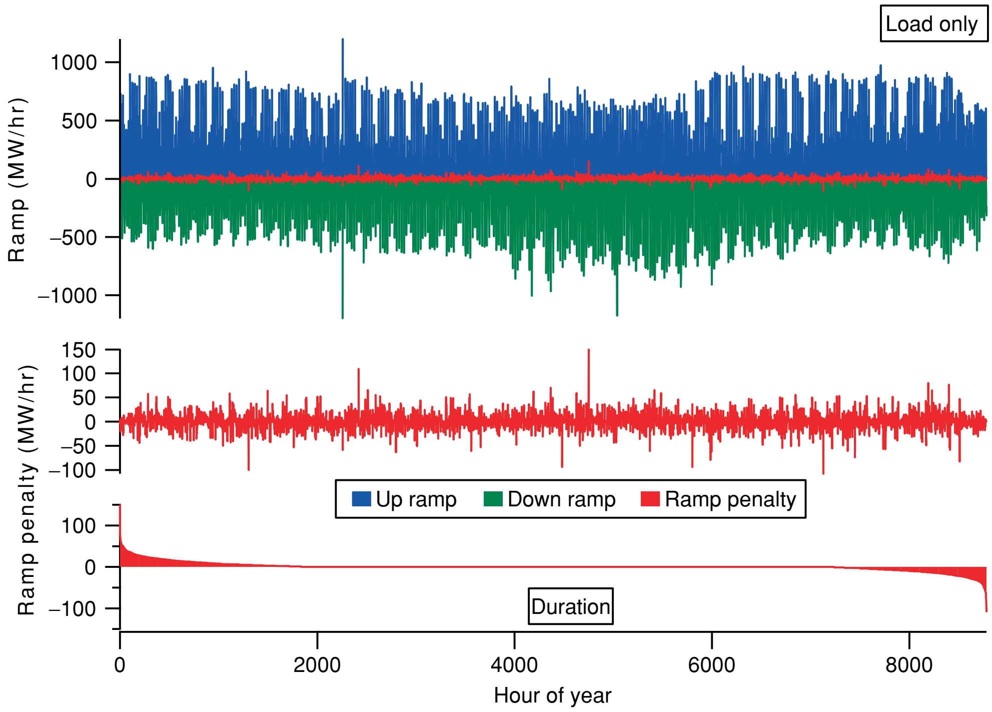

Figure 4: Ramping requirements and penalty, load only.

To calculate the benefits of combined operations, the ramping requirements for each balancing area were first calculated separately. Up ramp requirements are not netted with down ramp requirements because each area must supply only its own loads in this scenario. Figure 4 shows the up-ramp and down-ramp requirements in the upper panel of the graph, assuming that each balancing area operates independently. Superimposed on this is the ramp penalty that is imposed by foregoing joint operations, using the same calculation as illustrated in Figure 2. The ramp penalty is also shown in the middle panel of Figure 4 for clarity.

Another way to view the ramp penalty is as a duration curve. The bottom panel of Figure 4 shows the ramp penalty duration curve and is based on the data represented in the middle panel.

We can also compare the ramp penalty with the excess ramp chronologically and as duration curves. Figure 5 shows that the excess ramping is nearly always non-zero, although it is small for many hours of the year.

It is clear that there are some ramping benefits that occur in the hourly time frame, but this benefit is not large. Based on the analysis of Miller & Jordan, we expect that the benefit would be larger in a faster time scale that shows less correlation across balancing areas. We know that the benefit is substantial in the minute-to-minute regulation time frame, with regulation requirement rising only with the square-root-of-the-sum-of-the-squares of the individual areas requirements.

Wind Ramping Behavior: Benefits of Combined Operations

To obtain some insight into the combined behavior of wind plants across the region, this section illustrates how the ramping behavior of wind is a function of the footprint of the wind resource and the size of the balancing area. It is important to realize that the individual or combined movements of *wind* do not need to be matched by the remaining

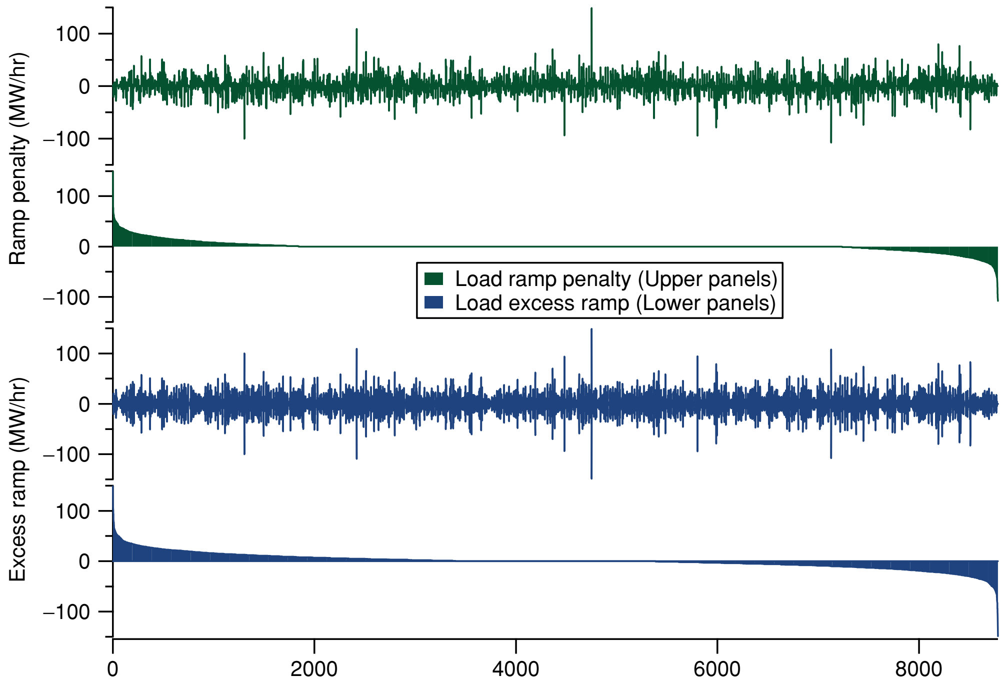

Figure 5: Ramp penalty and excess ramp, load only.

generation on the system. Instead, the system operator must take action to balance the aggregate load with aggregate generation. The required operator responses to variations in wind would be carried out in the context of the overall system, which is analyzed in the following section.

Regional wind resources' ramping behavior is damped compared to individual sites (Wan, 2004). Figure 6 is based on a comparison of wind that is separated by balancing area, and shows the sum of the individual up-ramps and down-ramps of the wind alone. The blue and green in the upper panel represent the separate up-ramp and down-ramp characteristics of wind, and the red trace illustrates the ramp penalty that occurs if the wind ramps are viewed within each balancing area. The middle panel zooms in on the chronological ramp penalty, and the bottom panel shows the duration curve for the ramp penalty.

It is clear that wind aggregation has a more dramatic impact on ramping than load aggregation. Figure 6 shows that the maximum up-ramp penalty is 482 MW, and the maximum down-ramp penalty is -382 MW. The average ramp penalty is approximately zero, which is expected, and implies that the impact of this ramp is a capacity impact, not an energy impact. This issue is discussed in more detail in a later section of this paper.

The ramp duration penalty curve, shown in the bottom panel of Figure 6, shows the most significant impact occurs at the tails of the distribution. Based on this data set, the maximum combined wind-only ramp is 1340 MW/hr, and the maximum ramp penalty is 482 MW/hr.

It is also useful to examine the excess ramp results. Figure 7 is similar to Figure 5, except that it shows the wind-only excess ramp and ramp penalty. The scale of the excess ramp for wind is about four times greater than for load alone. Comparing the two duration curves, we see that excess wind ramps are more prevalent than the reduction in primary ramp, as shown by the ramp penalty duration curve. However, it is important to note that the wind-only behavior, although interesting, does not provide an estimate of what the system needs are.

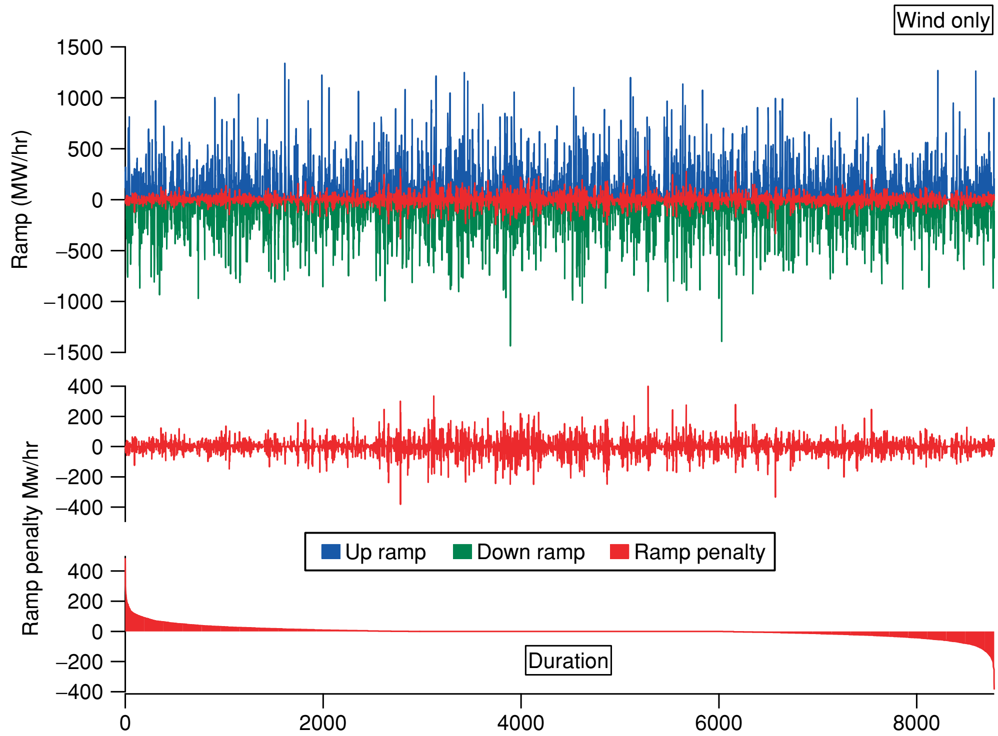

Figure 6: Wind plant hourly ramp behavior and ramp penalty for separate balancing areas.

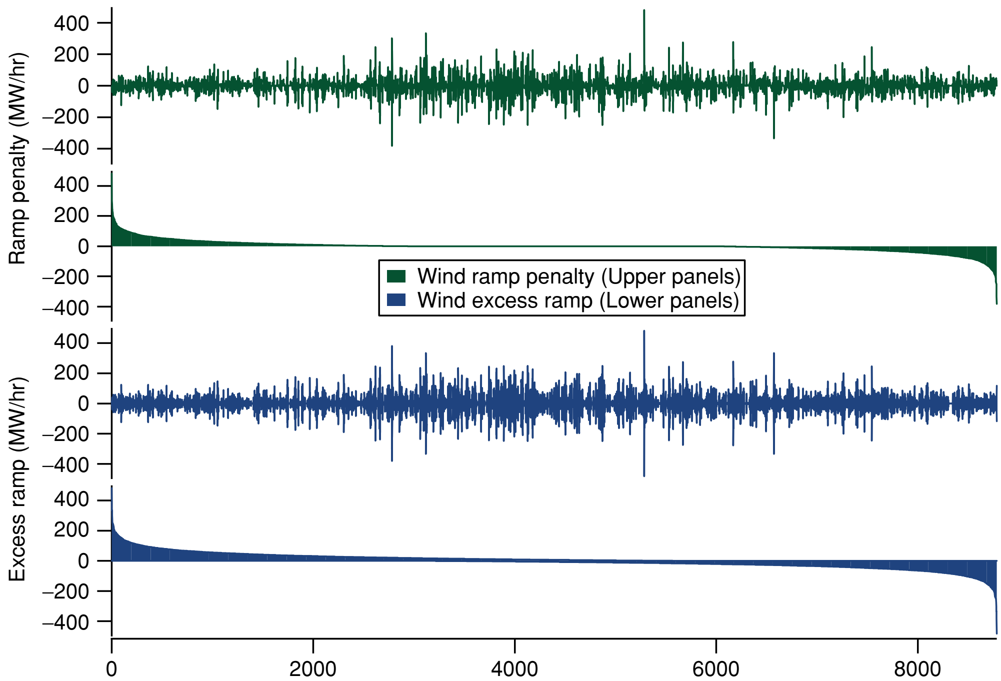

Figure 7: Ramp penalty and excess ramp, wind only.

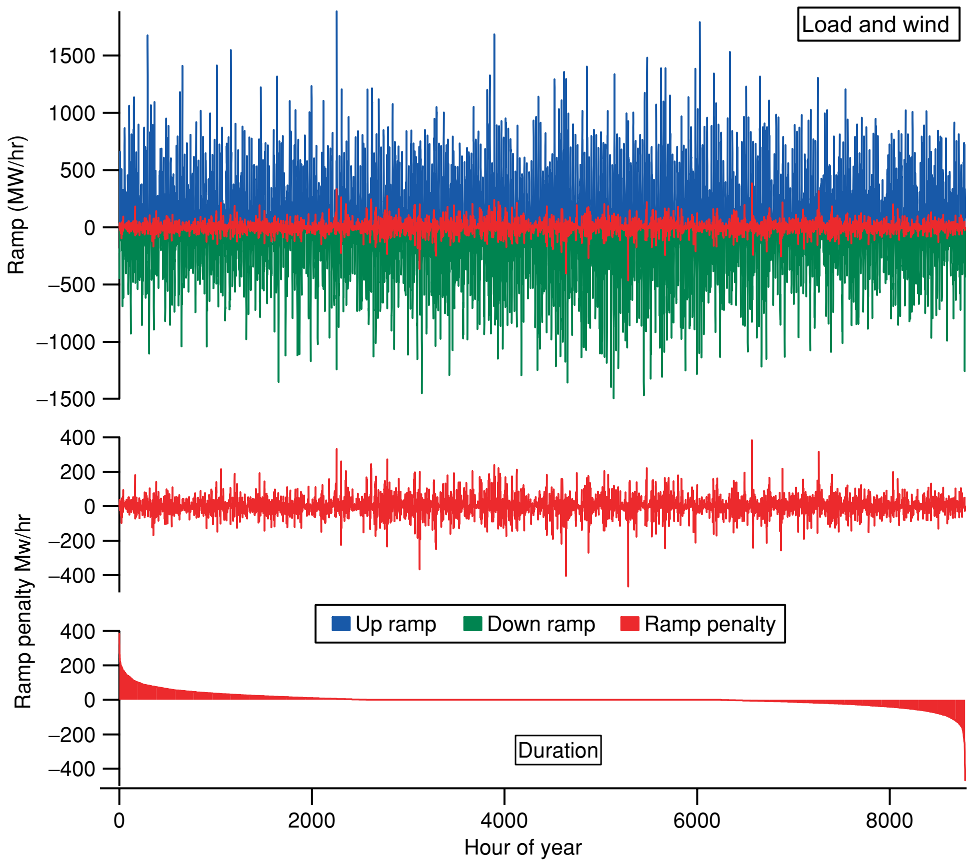

Figure 8: Ramp penalty and duration curve, load and wind.

Load and Wind Ramping Requirements: Benefits of Combined Operations

To run the grid effectively and reliably, the system operator must balance aggregate loads and aggregate resources within statistical tolerances. In an hourly time frame, this implies that the load, less wind generation, must be matched by conventional resources (ignoring interchanges for simplicity). Figure 8 is similar to the previous figures, and shows the net load and wind up-ramp requirements, down-ramp requirements (both assuming separate balancing-area operations), and the resulting ramp penalty. It is clear from comparing Figure 8 with Figure 4 and Figure 6 that combined wind and load have similar magnitude ramping requirements as the ramping requirements of wind alone. It is also clear that combined operations will have a significant impact on the tails of the ramp duration curve.

Figure 9 compares the ramp penalty with the excess ramp requirement for the load with wind case. The scale of the ramp penalty and excess ramp is similar to the wind-only case. It is clear that balancing area consolidation offers the promise of significantly reducing hourly ramp requirements in systems with high wind penetration.

Seasonal Ramp Penalties

Because of the seasonal differences in load and wind, we repeated the analysis for each of the four seasons. Based on load characteristics, we separated the seasons as indicated in Table 1.

The seasonal graphs, Figure 10 through Figure 13, illustrate each seasons' chronological ramp penalty (load and wind) and duration in the upper panels, followed by the chronological excess ramp and excess ramp duration curves in the bottom panels.

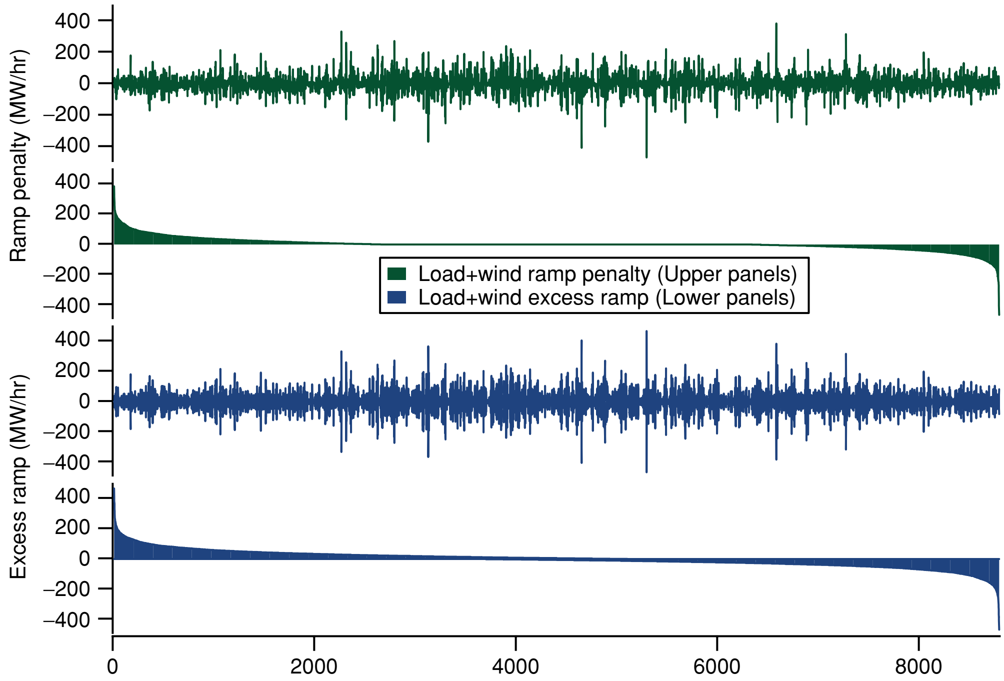

Figure 9: Ramp penalty and excess ramp, load and wind.

Table 1 Seasonal definitions

Season	Start date
Spring	March 15
Summer	June 15
Fall	September 15
Winter	November 15

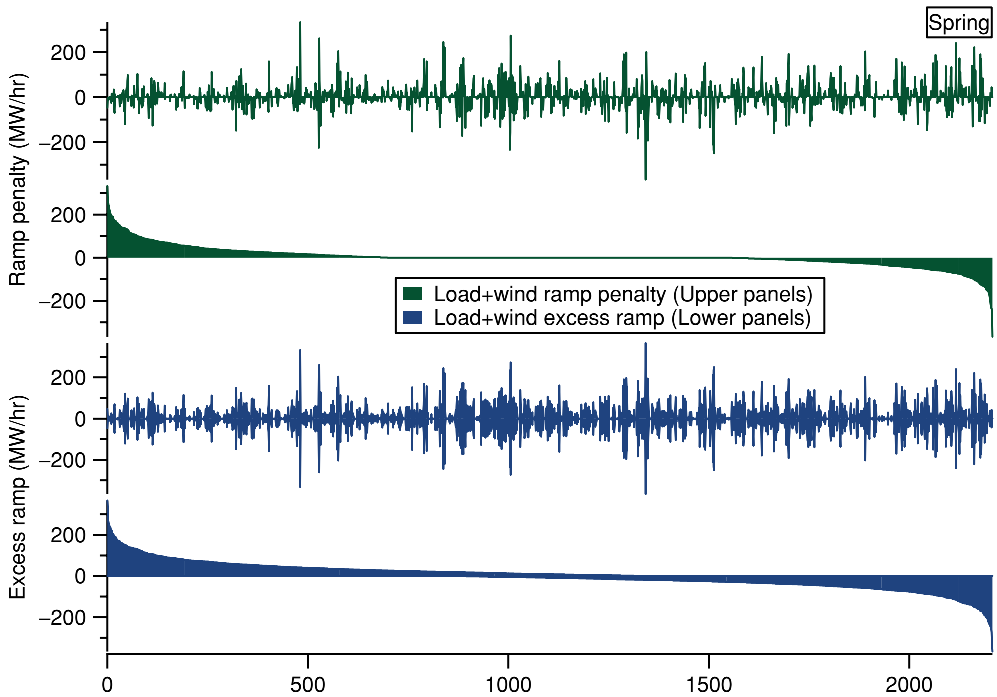

Figure 10: Spring ramp penalty and excess ramp, load and wind.

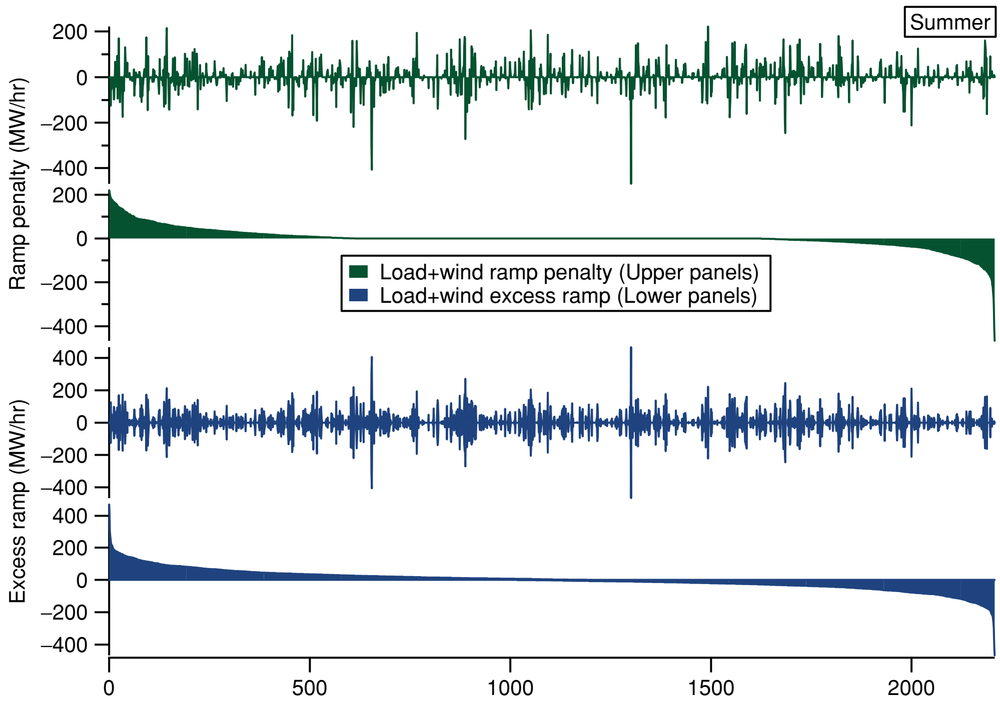

Figure 11: Summer ramp penalty and excess ramp, load and wind.

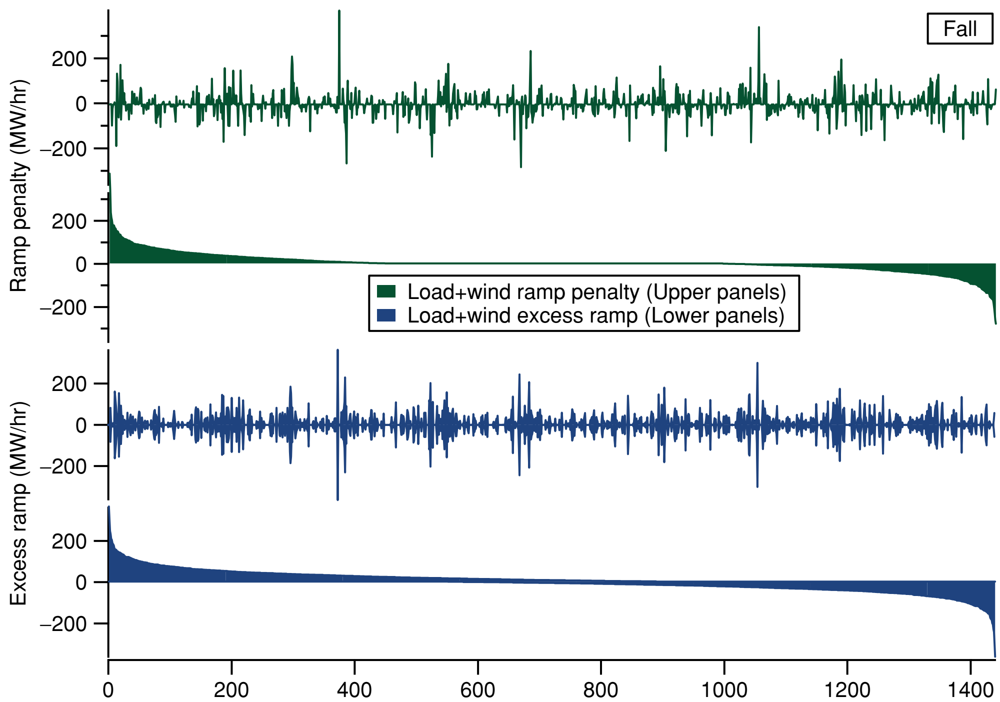

Figure 12: Fall ramp penalty and excess ramp, load and wind.

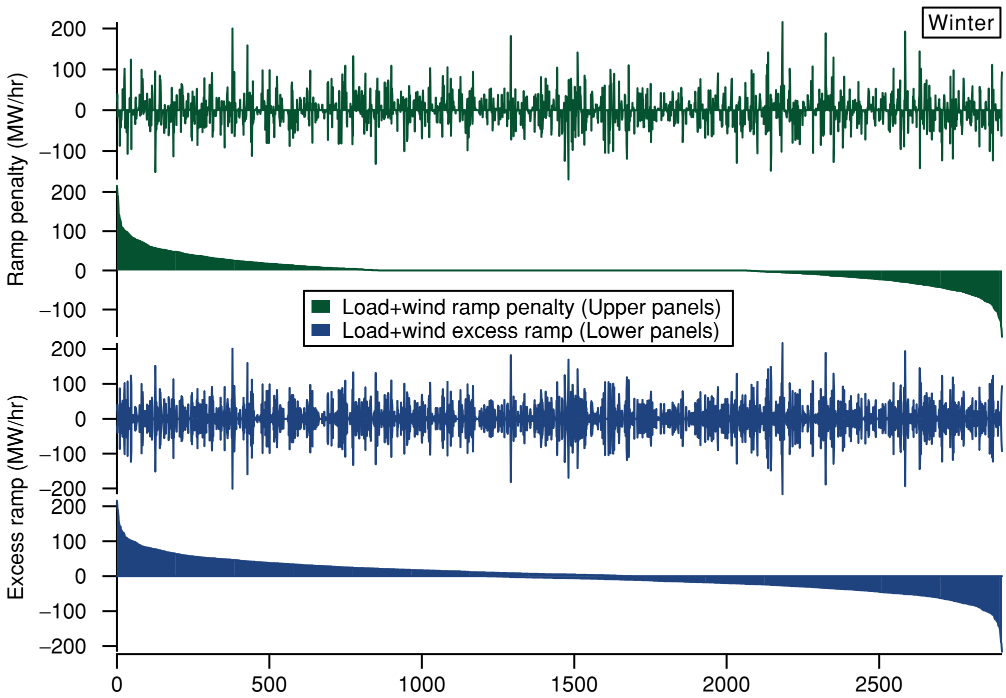

Figure 13: Winter ramp penalty and excess ramp, load and wind.

The tails of the excess ramp duration curves by season indicate a difference in the benefits of consolidation. Maximum excess positive ramps are 467 MW for summer, 367 MW for spring, 384 MW for fall, and 216 MW for winter.

Discussion of the Benefits of Combined Operations

To measure the benefits of combined balancing area operations, it is often useful to use the standard deviation ("sigma") as a metric to describe how variation can be mitigated by integrating over broader regions. One example of this is Miller and Jordon (2006). However, sigma is not appropriate for ramping behavior. To illustrate with a simple example, suppose that a balancing area ramps continuously at 100 MW/hr for a 6-hour period. The standard deviation of this ramp is zero. Alternatively, if 3 ramps were 100 MW/hr, and the other 3 ramps were 0, then the standard deviation would be approximately 55 MW. Clearly, a higher sigma may be associated with *less* ramping, and therefore sigma is not suitable. Alternatively, we can quantify the total up-ramp and down-ramp in terms of MW-hr (MW-hr is a measure of capacity, and is not the same as MWh which is an energy measure), which measures the ramping capacity during the period of interest.

Figure 14 collects results from the previous sections and illustrates the impact of combined balancing area operations on load alone, wind alone, and load with wind. As seen in the more detailed graphs above, combined operation has a more significant impact when there is wind on the system. The maximum hourly ramp for combined system operation with wind is 1,887 MW/hr, which can be compared to the maximum excess ramp of 467 MW/hr. It is clear that combined operations hold the promise of a significant reduction in system ramping requirements.

To get an idea of the benefit over the entire year, Figure 15 shows the total excess ramp and penalty in MW-hr for load alone, wind alone, and load with wind. The graph illustrates a significant reduction in ramping requirements can be achieved by combining operations.

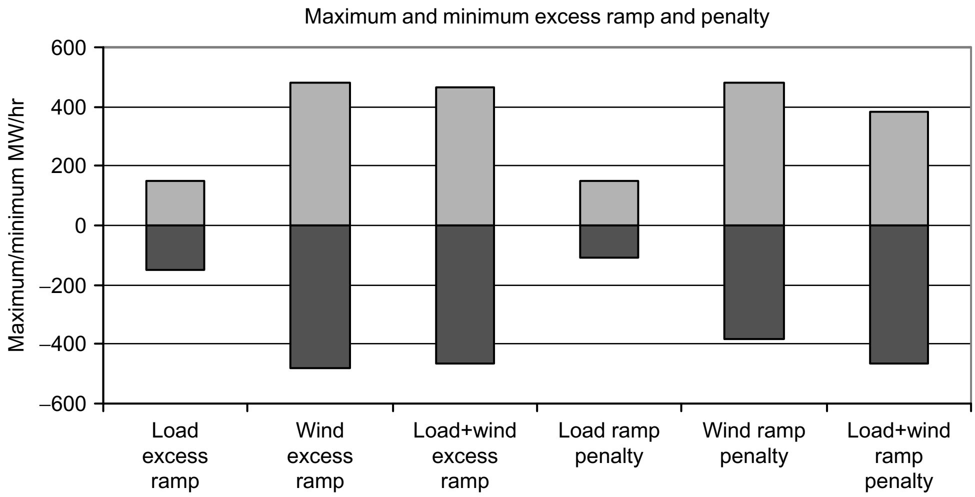

Figure 14: Up-ramp and down-ramp penalty and excess ramp required from separate operations, maximum and minimum.

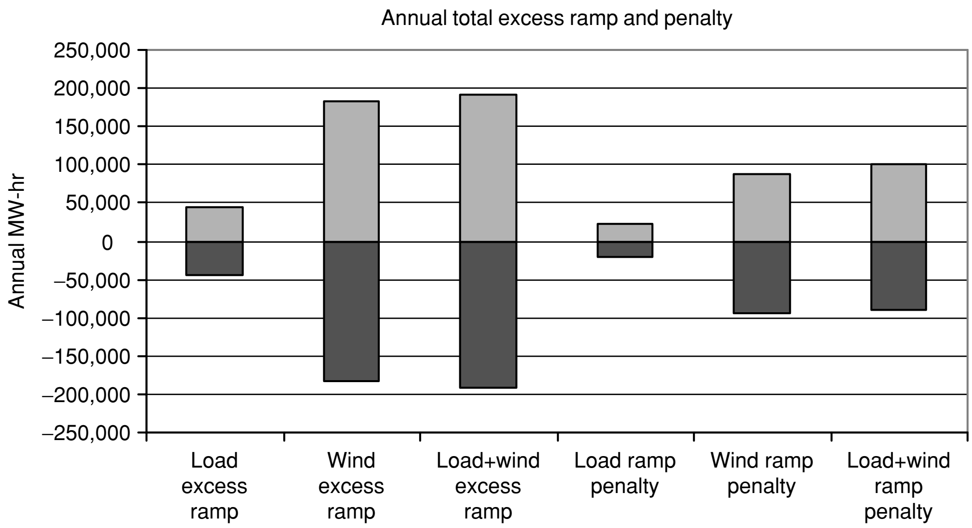

Figure 15: Total excess up and down ramp and penalty from separate operations.

Figure 16 illustrates the ramping penalty by season for the load and wind combined case only. Figure 17 shows the percentage of hours of each season that experience an excess ramp with separate balancing area operations.

The ramping benefits from combined operation result from changes in load and wind that are not highly correlated. In the hourly time frame, there can be significant correlation among loads that are within the same time zone and that are subject to similar weather effects. It is well known that the correlation between loads will decline over progressively smaller time scales. In the regulation time scale (typically seconds to minutes), loads are generally uncorrelated, which is why regulation impacts tend to add geometrically.

To obtain a better sense of the excess ramping requirements in the context of overall ramping requirements, Figure 18 shows that the excess ramping is frequently at least 5% of the

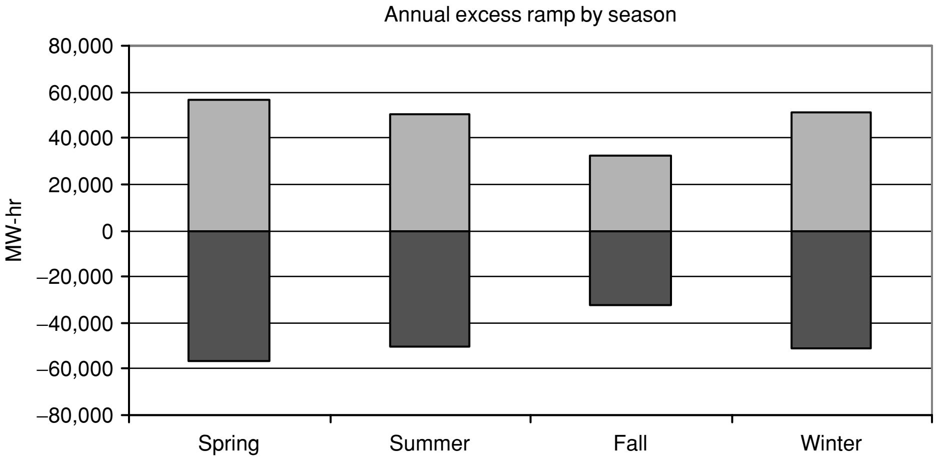

Figure 16: Seasonal excess ramp and penalty for load and wind.

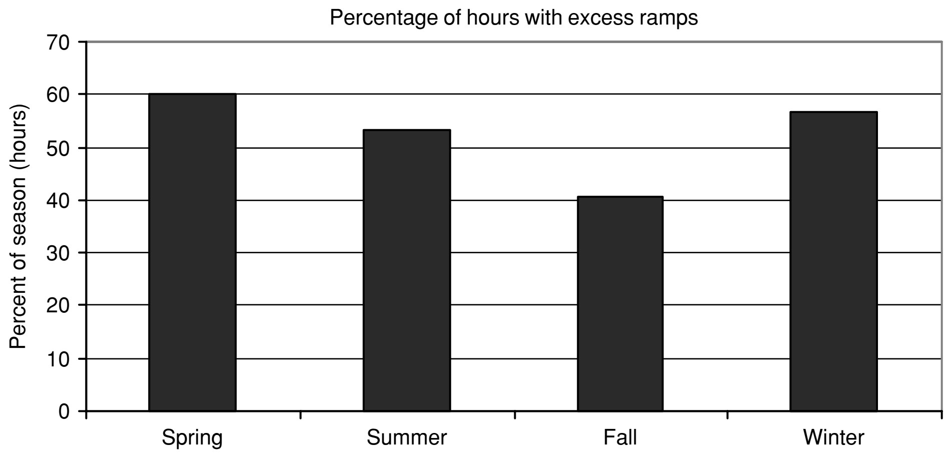

Figure 17: Percentage of hours of each season that experience excess ramping with separate balancing area operations, load and wind.

annual maximum ramp requirements for the combined system. Another way to view the excess ramp is as a percentage of the average up-ramp and down-ramp requirements. Figure 19 shows that in most hours, the excess ramp is less than average, but in a few cases it exceeds 300%, both in the positive and negative directions.

Wind generation in the hourly time scale may be correlated if the wind sites are nearby and if there is similar geography and underlying weather impacts. As the distance between wind sites increases, there tends to be less coincident correlation, and there may be more lagged correlation, depending on the wind regimes and weather drivers.

Combining correlated loads or wind will not have as much benefit as combining uncorrelated load or wind. Table 2 shows the Pearson cross-correlations between the 14 wind plant locations used in this study. Some wind site pairings have low correlation (approximately 0.21–0.40) and others are more highly correlated (for example, wind2 and wind4).

Table 3 shows the correlation between the separate balancing areas for loads only. Loads are generally highly correlated in this region, with the exception of MNP's correlation with

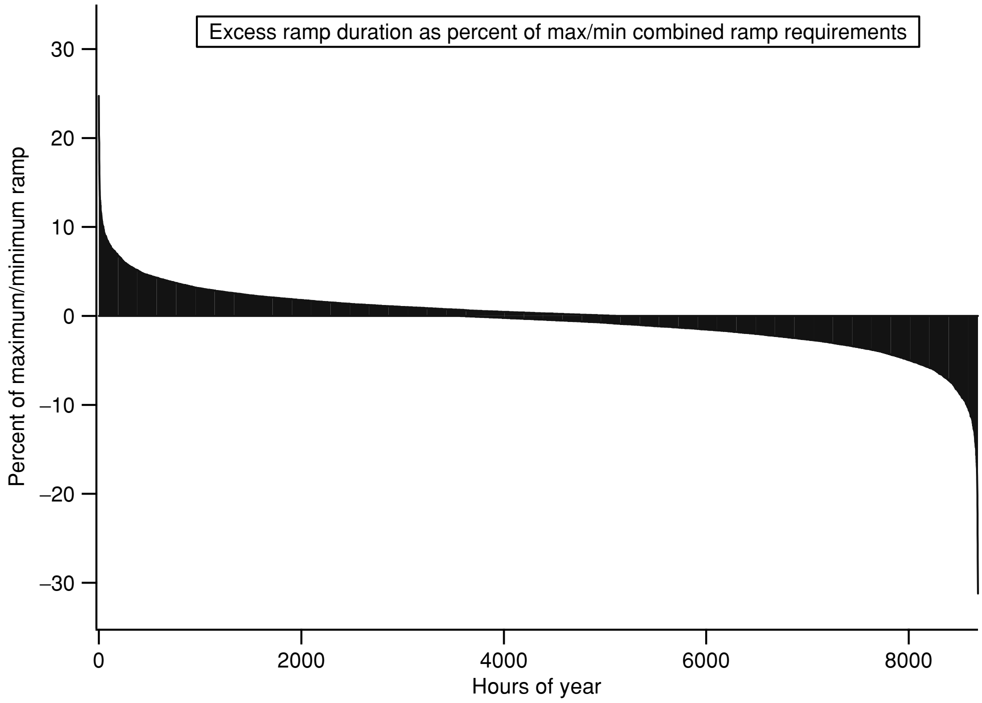

Figure 18: Duration of excess ramp requirements as a percentage of maximum and minimum ramps from combined operation.

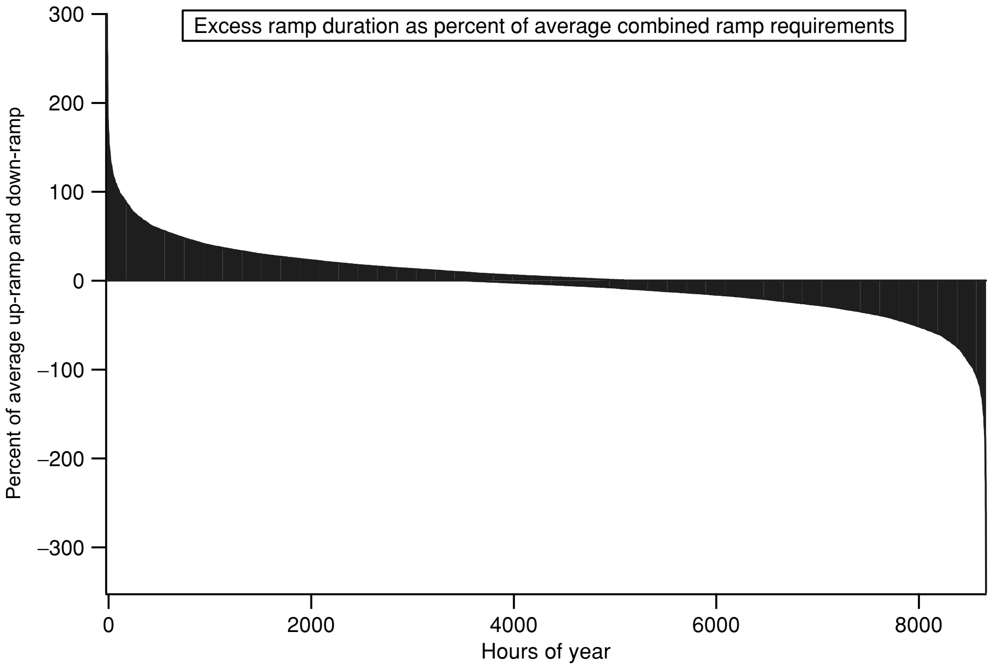

Figure 19: Duration of excess ramp requirements as a percentage of the average up-ramp and down-ramp requirements from combined operations.

NSP. The impact of wind on this correlation matrix is seen in Table 4, which shows the correlation between net loads (load minus wind) in the balancing areas. In some cases, wind actually increases the correlation between balancing areas, and in other cases, this correlation decreases with the addition of wind.

Table 2 Correlation between wind locations

	Wind1	Wind2	Wind3	Wind4	Wind5	Wind6	Wind7	Wind8	Wind9	Wind10	Wind11	Wind12	Wind13	Wind14
wind1	1													
wind2	0.61	1												
wind3	0.31	0.68	1											
wind4	0.59	0.88	0.62	1										
wind5	0.34	0.68	0.84	0.68	1									
wind6	0.64	0.75	0.54	0.87	0.63	1								
wind7	0.52	0.74	0.63	0.80	0.74	0.85	1							
wind8	0.64	0.64	0.47	0.75	0.55	0.92	0.79	1						
wind9	0.52	0.62	0.50	0.71	0.60	0.83	0.88	0.88	1					
wind10	0.57	0.38	0.25	0.45	0.29	0.60	0.45	0.73	0.59	1				
wind11	0.62	0.46	0.31	0.54	0.36	0.70	0.56	0.83	0.69	0.94	1			
wind12	0.56	0.54	0.39	0.63	0.47	0.78	0.73	0.90	0.89	0.77	0.85	1		
wind13	0.50	0.55	0.43	0.65	0.52	0.78	0.78	0.87	0.95	0.66	0.75	0.94	1	
wind14	0.21	0.48	0.63	0.53	0.73	0.51	0.62	0.45	0.55	0.22	0.28	0.42	0.50	1

Table 3 Correlation between loads

	NSP	MNP	GRE	OTP
NSP	1			
MNP	0.48	1		
GRE	0.83	0.67	1	
OTP	0.65	0.69	0.85	1

Table 4 Correlation between load with wind

	NSP	MNP	GRE	OTP
NSP	1			
MNP	0.73	1		
GRE	0.91	0.73	1	
OTP	0.62	0.59	0.57	1

Although we were unable to obtain sub-hourly data for this analysis, we make some observations on the likely impact of aggregation on the intra-hourly balancing requirements and benefits of combined operations. In our analyses of other data sources, and based on the results of wind integration studies, it is apparent that correlation tends to decrease at faster time frames. That is, sub-hourly variability and minute-to-minute variability show less correlation between individual loads, individual wind plants, and individual balancing areas than do multi-hour ramps. This implies that combined operations would likely result in more benefits in the sub-hourly and minute-to-minute time frames than in the hourly case.

The ramping penalty for separate balancing area operations is a capacity service. This is because the energy requirements from the separate balancing areas add linearly. There is therefore no difference in energy requirements when the separate operations case is compared to the combined case. The ramping penalty represents capacity that must be provided separately by balancing areas, but is not required under the combined case. That this is a capacity service can be verified by integrating the excess ramp and the ramp penalty – the result is zero in both cases.

February 24, 2007 – An Interesting Wind Day for ERCOT

February 24, 2007 provides an excellent example of the benefits and limitations of aggregation for wind. Wind production was fairly high throughout ERCOT that morning. Aggregate wind production was over 2000 MW at 9 a.m.; about 70% of the total 2900 MW state

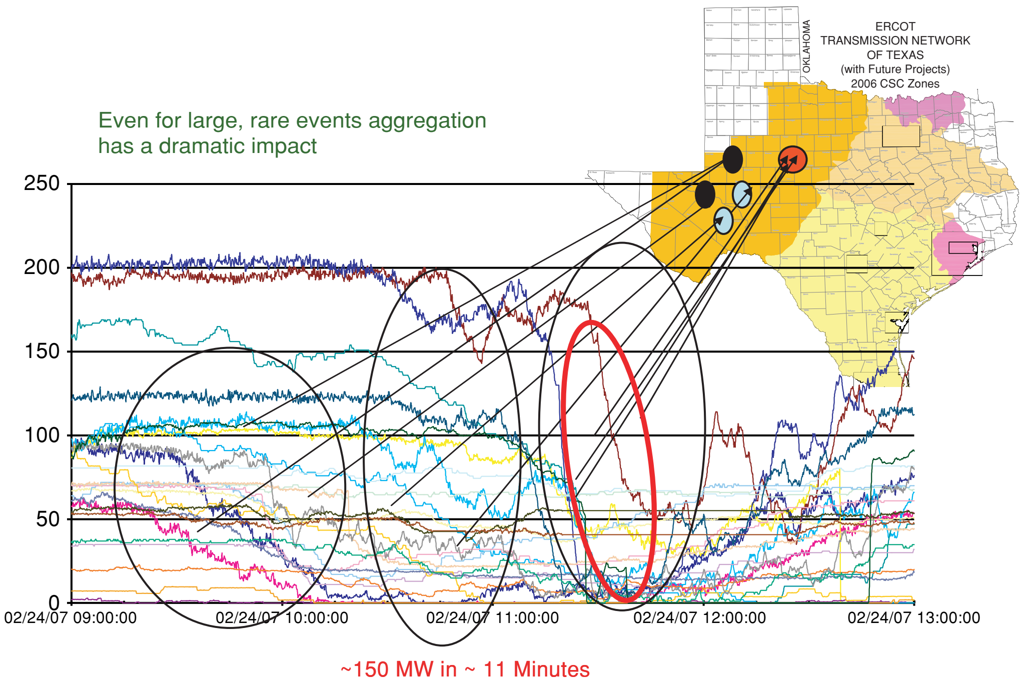

Figure 20: A strong weather pattern increased winds on the morning of February 24, 2007 throughout western Texas, forcing many wind turbines to shut down. Figure supplied by Stuart Nelson.

wind capacity. A strong weather pattern increased winds further throughout the western part of the state forcing many wind turbines to shut down as the morning progressed. Individual wind plants can be seen shutting down in Figure 20.

One 200-MW wind plant dropped 150 MW, 75% of its name plate capacity, in 11 minutes; a fairly dramatic ramping event. Given this single plant behavior, power system planners and operators are legitimately concerned with the possible ramping impact of large amounts of wind on their system. Fortunately aggregation helps.

Clearly this single plant behavior, dropping 75% in 11 minutes, is a much slower than what is exhibited by a single turbine which will drop from full output to zero nearly instantaneously. Looking at the aggregate behavior of all ERCOT wind plants (Figure 21) it can be seen that aggregation continued to slow even the extreme wind event as it is scaled up to cover much of Texas.

The total wind fleet dropped ten times as much generation, ~1500 MW, but it took ten times as long, ~120 minutes. This is a dramatic drop in production, to be sure, but it is not extremely fast. It was certainly not a contingency event, and therefore, was not eligible to rely upon contingency reserves. This is a large ramping event

If this event is typical, increasing the size of the wind fleet will increase the size of potential large ramping events, but it will not increase the ramp rate as dramatically. The power system must be capable of responding to the loss of wind, but the resources need not be spinning. Fast-start resources would be adequate to cover infrequent large wind events.

It is also likely that large ramping events like that experienced by ERCOT on 2/24/2007 could be forecast at least some time in advance. Figure 22 shows (to those that can interpret such pictures) a dust cloud caused by high winds moving towards the wind turbine plants. If forecasting tools could give system operators warning that such an event was likely, they might be able to redispatch both the wind and conventional generation fleets to better

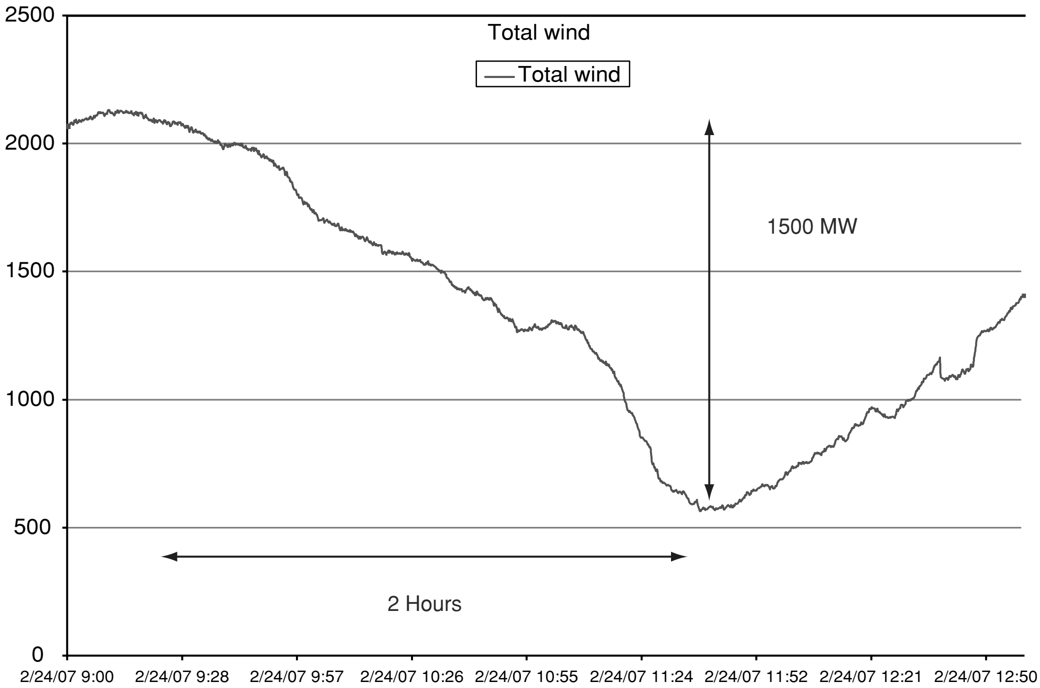

Figure 21: Aggregate wind plant behavior exhibits a slower response.

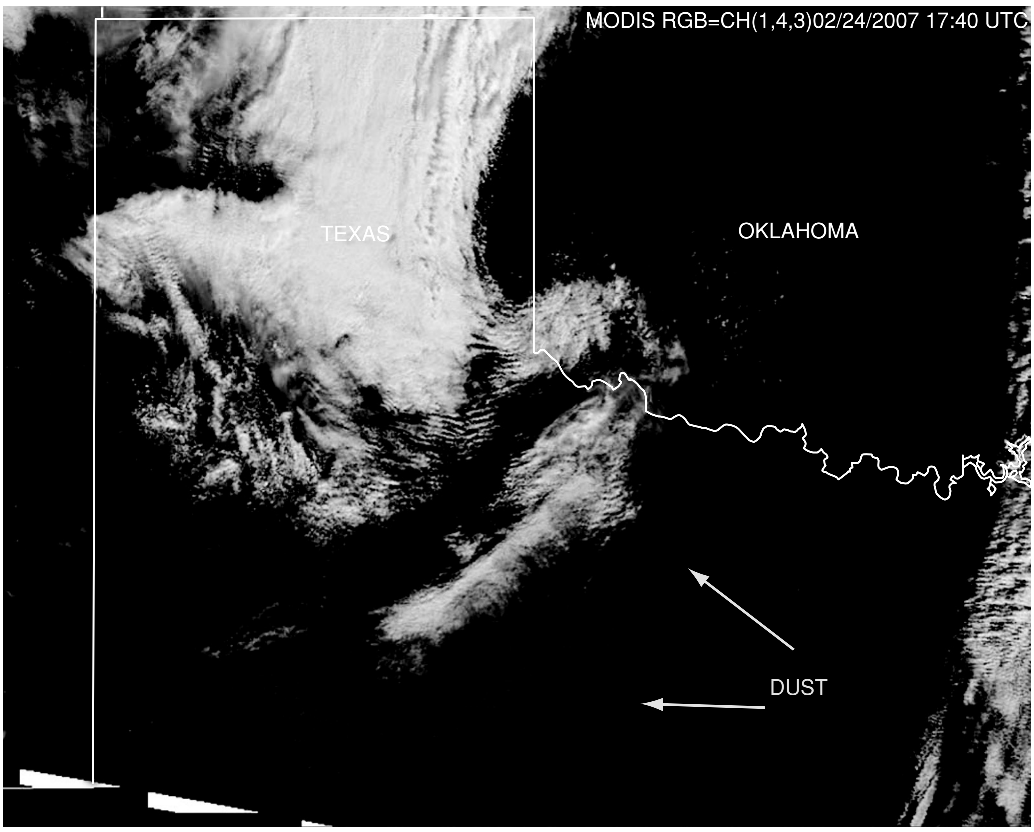

Figure 22: Wind Logics interprets this satellite photograph as showing high winds lofting dust.

respond to the wind ramp when it materialized. This would be similar to the way system operators redispatch the power system as lightning approaches or in preparation for geomagnetic storms.

CONCLUSIONS

Increasing the size of balancing areas, or collectively sharing the balancing obligation among a group of balancing areas (much as is done now for contingency events with reserve sharing groups), holds the promise of significantly reducing wind integration costs. It also reduces utility costs without wind. Some recent studies of integrating wind into large power systems seem to indicate that wind integration costs may rise more smoothly than previously assumed, based on analysis of smaller power systems. The "hockey stick" pattern of dramatically increasing wind integration cost above some threshold wind penetration may not be as pronounced as expected. This paper provides some explanation as to why costs may rise more uniformly than previously assumed.

Based on the hourly data used for this analysis, we showed that balancing area consolidation will reduce the ramping requirements for load, wind, and load with wind. Our results show that the ramping penalty associated with operating independent balancing areas increases significantly when there is significant wind on the system, particularly with the extremely high penetration represented by our data set. Because of the declining correlation between wind and load for faster time frames, the aggregation benefit is expected to increase for faster load following time frames. This can be verified by reviewing results from wind integration studies that evaluate the regulation time frame, and is supported by Miller & Jordan's analysis of the NYISO system.

In summary, increasing the effective size of balancing areas, either through consolidation or through sharing of balancing obligations, reduces the cost of wind integration.

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