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Advancing Wind Integration Study Methodologies: Implications of Higher Levels of Wind

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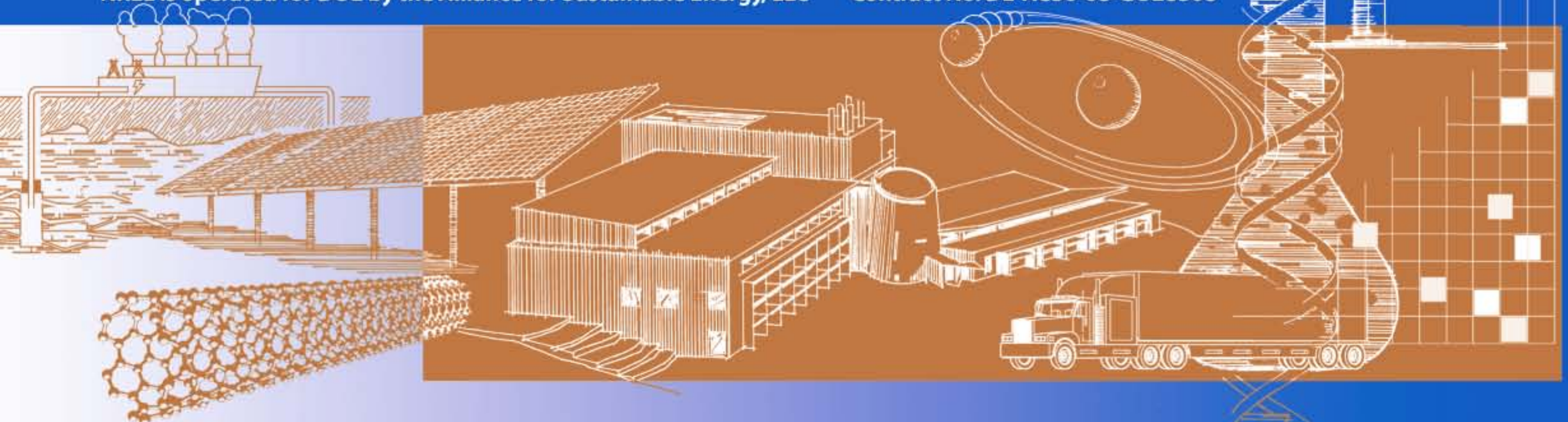

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Advancing Wind Integration Study Methodologies:

Implications of Higher Levels of Wind

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Abstract

Wind integration studies are now routinely undertaken by utilities and system operators to investigate the operational impacts of the variability and uncertainty of wind power on the grid. There are widely adopted techniques and assumptions that are used to model system operation, examine impacts on the regulation, load following, and unit commitment timeframes, and quantify costs. As wind penetration levels increase, some of the assumptions and methodologies are no longer valid and new methodologies have been devised. Based on involvement in conducting studies, reviewing studies, and/or developing datasets for studies in WECC, the Eastern Interconnect, Hawaii, and other regions, the authors report on the evolution of techniques to better model high penetrations (generally, 20% or more energy penetration) of wind energy.

Introduction

Many wind integration studies have been performed in the past several years. As more high quality data have become available, the studies have evolved significantly, bringing a higher degree of realism and sophistication to modeling techniques and statistical approaches that are typically utilized for wind integration analysis. NREL has recently completed two very large integration studies; the Western Wind and Solar Integration Study (WWSIS) and the Eastern Wind Integration and Transmission Study (EWITS), under the sponsorship of the United States Department of Energy. These studies have provided many significant insights on integration, methods, and data. However, there is much yet to be learned, and methods can still evolve. In this paper we discuss the key technical areas of wind integration studies:

- Weather and wind plant modeling and diagnostics.
- How wind forecasts play a role in the integration study and issues surrounding the development of synthetic wind forecasts for power systems operational modeling.
- Balance-of-generation assumptions and the impact this has on the operational characteristics of the power system, and ability to manage the increased uncertainty and variability that wind brings to power system operations.
- Approaches to develop wind scenarios for high-penetration studies.

We also discuss other factors that influence the ability of the system to absorb high wind penetration levels, such as baseload turn-down levels, and the complex topic of the interaction of wind with various types of reserves.

Many wind integration studies have pursued the goal of estimating the incremental operating cost that is caused by wind's variability and uncertainty. This is usually performed by comparing a simulation with wind power with some "no-wind" base case. While this appears to be a simple analysis, the many complex interactions among components of the power system and assumptions regarding the no-wind base case all have important influences on integration cost estimates. We discuss many of these concerns and implications, shedding some light on the difficulties involved in measuring and interpreting integration cost estimates. Of particular concern is whether the integration analysis (especially those with less formal modeling frameworks) correctly treats the separation of operating reserve requirements and energy, especially related to wind forecast errors.

Other studies focus on operational impacts and total production costs. These studies find that operating cost can be substantially reduced with wind. This conclusion is driven primarily by the essentially zero-marginal cost of wind, which in turn reduces (sometimes to zero or below) locational marginal prices. While this is an attractive result in the short run for consumers, it is not clear how these prices are sustainable, and whether they provide the right signals to investors and developers of new generation to provide for an economically optimal (or at least functional) generation portfolio with the required flexibility characteristics.

Because wind energy requires more flexibility from the remaining generation fleet, there are many potential sources of this flexibility. Examples range from different types of generation, to responsive load, plug-in hybrid vehicles, or storage. The required flexibility depends heavily on the wind and load characteristics, and on the institutional framework involved. Little work has been done to systematically evaluate the role of these and other ways of managing wind variability and uncertainty.

Similarly, there is evidence that production simulation tools may not always be well suited to the task at hand. Unit commitment, the process of starting generation so that it will be available when needed, is more complicated with significant variable generation such as wind. During the period when the committed unit may be online, there could be a significant operating range that the unit would need to cover, subject to its physical capabilities. The use of wind forecasting in the unit commitment process further complicates this problem. In fact, we are aware of anomalous results from one integration study that found that a smooth wind forecast results in lower wind integration cost than an accurate forecast. What is not clear is whether this is caused by weaknesses in the simulation model or by the assumptions used to measure wind integration cost, or a combination of both.

This paper begins with a discussion of wind data requirements and scenario development. The ability of the grid to manage high wind penetrations will be heavily influenced by the study's electrical footprint, transmission network, and mix of non-wind generation. The quantity and characteristics of the non-wind portion of the generation fleet will depend on wind's contribution to planning reserves and incremental requirements for flexible generation and scheduling practice. Because of the interdependence of these factors, they comprise the first chapter of this document.

We then focus on operational analysis. Recent wind integration studies in the United States have utilized electricity production simulation models and market models to analyze the impact that wind will have on unit commitment decisions and operating reserves.[1] Standard production models may not have the ability to correctly manage commitment and dispatch efficiently with high levels of wind, so separate statistical analysis of wind and load data is typically used to help develop operating reserve levels that are dynamically determined based on what the wind (and load) is doing at the time.

Finally, we discuss integration cost analysis and describe some of the evolution in methods of assessing integration cost. Early methods were developed to allow the side-by-side comparison of costs between wind and other generation technologies. We show some of the issues and shortcomings of these approaches, and suggest possible paths forward.

Data, Scenarios, and Planning

The quality of the wind data drives the results of any wind integration analysis. In this section, we discuss the evolution of datasets and suggest approaches for reasonability checks to ensure reasonableness of the data.

Wind Data

Early studies relied on crude representations of wind plant output. With the introduction of numerical weather prediction (NWP) models that can create high-quality time series data of wind speed that can be used to produce plausible wind plant generation output, it became possible to simulate and evaluate alternative wind plant development options with realistic representations of the alternative power delivery profiles associated with each scenario. Early studies did not always do extensive testing and diagnostics of the wind speed and power data that was produced (although some of this may have been done internally by the meteorologists who developed the data). Today, more sophisticated analyses of the simulated wind plant data may check the frequency spectrum, ramping characteristics and density functions, statistical checks on variability that may be introduced by modeling artifacts such as 24-hour observational assimilation or seams resulting from geographic or temporal discontinuities.

[1] We more fully define and develop the concepts related to “operating reserve” in a later section of this document.

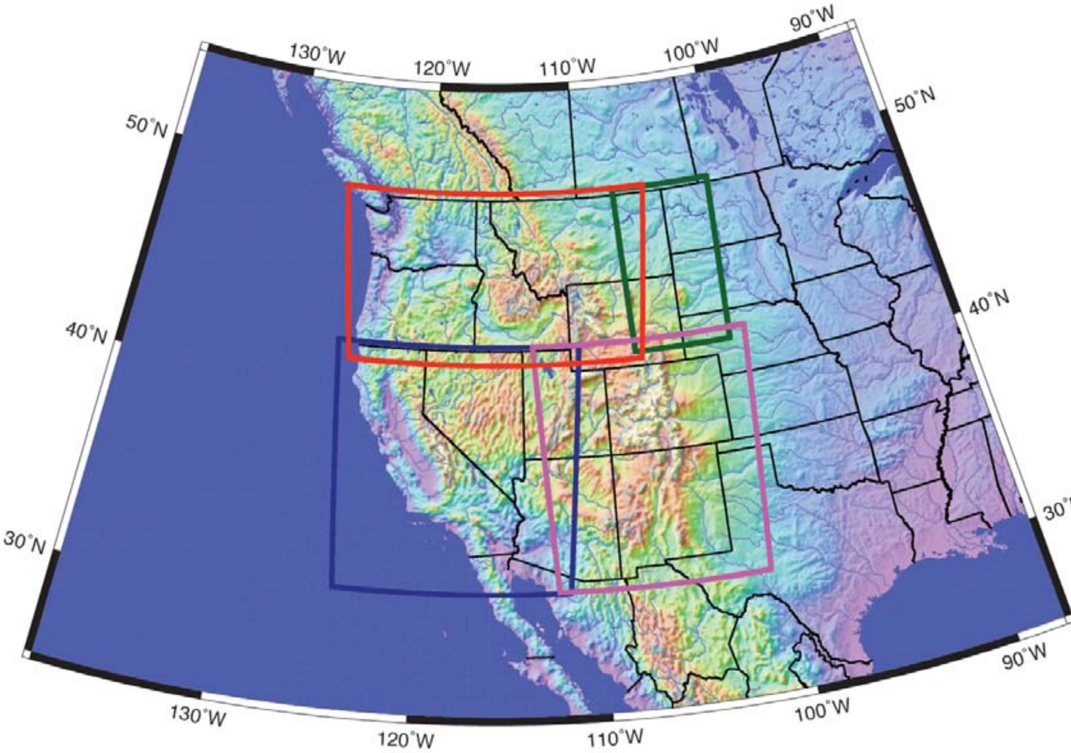

Figure 1 − Modeling domains used for the WWSIS included the Northwest Wind Integration Action Plan (NWIAP) dataset shown in red, along with three other domains.

Both the WWSIS and EWITS have large datasets that are available for other uses and are publicly available.[2] The datasets each cover 2004-2006 using a 10-minute time step and a 2 square km resolution (not all of this data is available on the web site). For integration studies, it is critical to use time-synchronized wind and load data to ensure that underlying weather drivers are properly accounted for in the statistical analyses and operational simulations. Unfortunately, the existing datasets are becoming somewhat stale with no immediate prospects to update them. This is leading to the development of questionable ad hoc methods to attempt the creation of high-quality, consistent wind datasets to be used for integration studies. Unfortunately, such methods will likely compromise integration analysis and interconnection planning until up-to-date datasets can be developed and kept up to date.

NWP models are complex and have many different parameter settings. This requires a knowledgeable user to exercise judgment on how best to run the model. The frequency of dataset assimilation, rolling in observed data to make sure the model doesn't wander too far from reality, can have an influence on the model behavior and ultimately on the wind speed output from the model. Figure 2 illustrates. When the model assimilates observations every 12 hours, the graph shows the difference (between red and green). The difference between the green and blue lines shows the impact of restarting or not restarting the NWP on Oct 16. This is clearly a large difference, and in fact led to the largest drop in wind power of the entire two years modeled. Of course this drop in wind power was simply an artifact of the modeling, and does not represent a real event.

[2] http://www.nrel.gov/wind/systemsintegration/

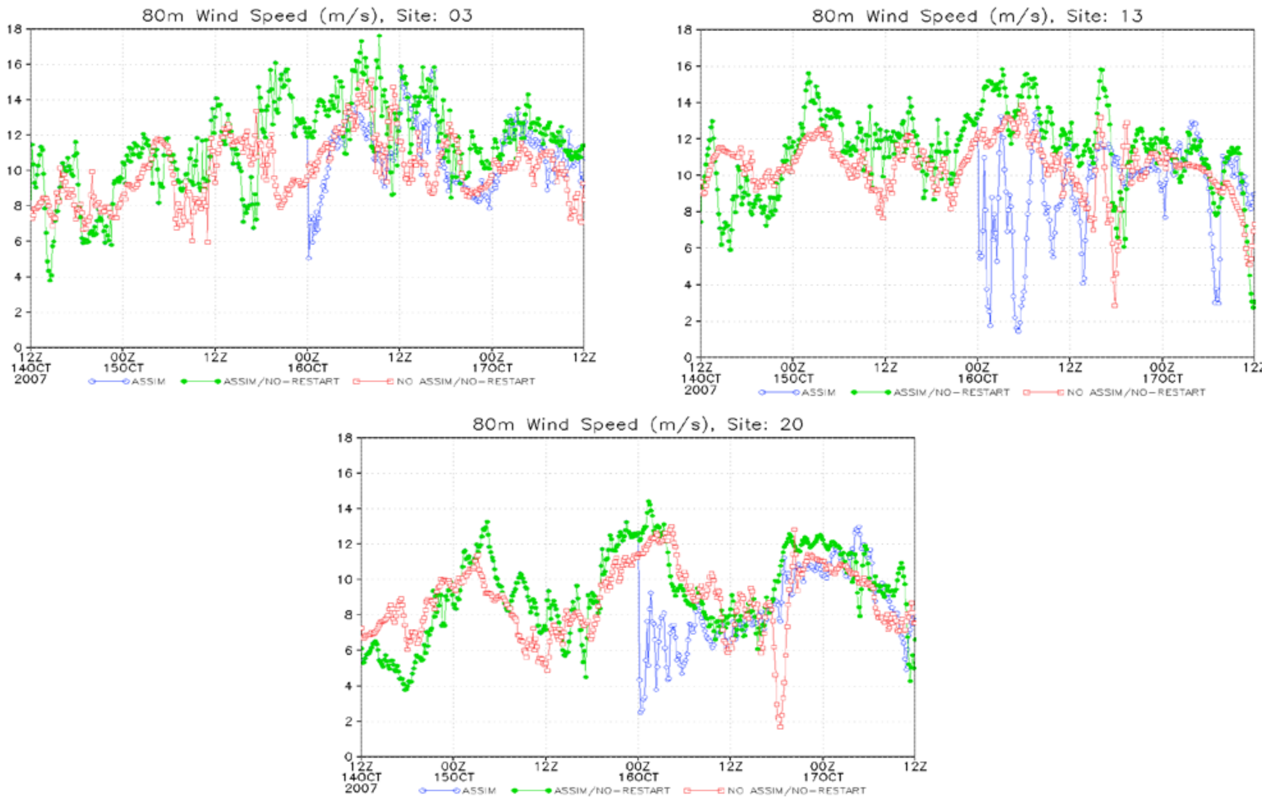

Figure 2 − Modeling in Hawaii shows the impact of alternatlve data assimilation approaches.

The WWSIS contained a component of analysis that evaluated the modeled wind speed at a number of selected sites (see http://wind.nrel.gov/public/WWIS/ValidationReports/NREL-Tower06008-Validation.pdf).

Example Validation of WWSIS Data

The WWSIS data validation had several components. The data from the NWP (also known as the mesoscale model) was compared to observed data from actual wind plants in Colorado and Texas to perform the validation.

Five wind power plants (King Mountain, Big Spring, Brazos, Texas Wind Power Project, and Delaware Mountain) in Texas were chosen for comparison because of availability of wind sites at those locations in the 3Tier mesoscale dataset. Eighteen wind sites in the mesoscale dataset that closely map these 5 wind power plants were identified and their 10-minute hysteresis-corrected power time series of 2004 through 2006 were summed up for comparison with the actual 2004-2006 combined output power of these 5 wind plants.

Table 1 lists the installed capacity of the 5 wind plants and their observed peak 10-minute power during the 3 year period. The last row of the table lists the coincidental factor of these 5 wind plants. The coincidental factor (ratio of the coincidental peak to the non-coincidental, which is the sum of individual plant peak output) is an indication of the degree of spatial and temporal diversity of wind resources among these 5 wind plants. By comparison, the combined mesoscale power output had a coincidental peak of 539 MW in all 3 years, or a coincidental factor of 99.8%, suggesting that the mesoscale model did not capture the full diversity of the wind resources.

Table 1 − Installed capacity for validation from 5 wind plants.

		10-minute Peak (MW)		
	Installed Capacity (MW)	2004	2005	2006
King Mountain	278	237	247	253
Big Spring	34	34	33	33
Brazos	160	159	160	161
Texas Wind Power Project	35	39	34	40
Delaware Mountain	29	25	25	25
Combined (coincidental)	536	461	456	474
Non-coincidental Peak		494	499	512
Coincidental Factor		93.3%	91.4%	92.6%

Table 2 lists the production and capacity factors of each of these locations. It can be seen from the table that the NWP consistently overestimates energy production for the 3-year period.

Table 2 − Comparison of NWP and actual wind energy generation.

	2004		2005		2006	
	GWh	CF	GWh	CF	GWh	CF
Actual	1,263	31.2%	1,317	33.0%	1,415	34.1%
Meso-scale	1,636	34.6%	1,512	32.1%	1,505	33.8%
% Change	29.5%		14.8%		6.4%	

Figure 3 shows the annual average diurnal patterns from the actual data and from the NWP data. It is clear from the graphs that the NWP does a reasonably good job of capturing the diurnal patterns of wind generation, but that does change somewhat from year to year.

Step Changes and Their Distribution

This is the area where the mesoscale model shows some deficiencies. Table 3 lists statistics of 10-minute and hourly step changes of actual and mesoscale data for 2004, 2005, and 2006. Average values are not listed because they are all very small as expected. It is clear that the mesoscale model overestimates the variability of wind power at those locations—large standard deviation values and larger extreme values.

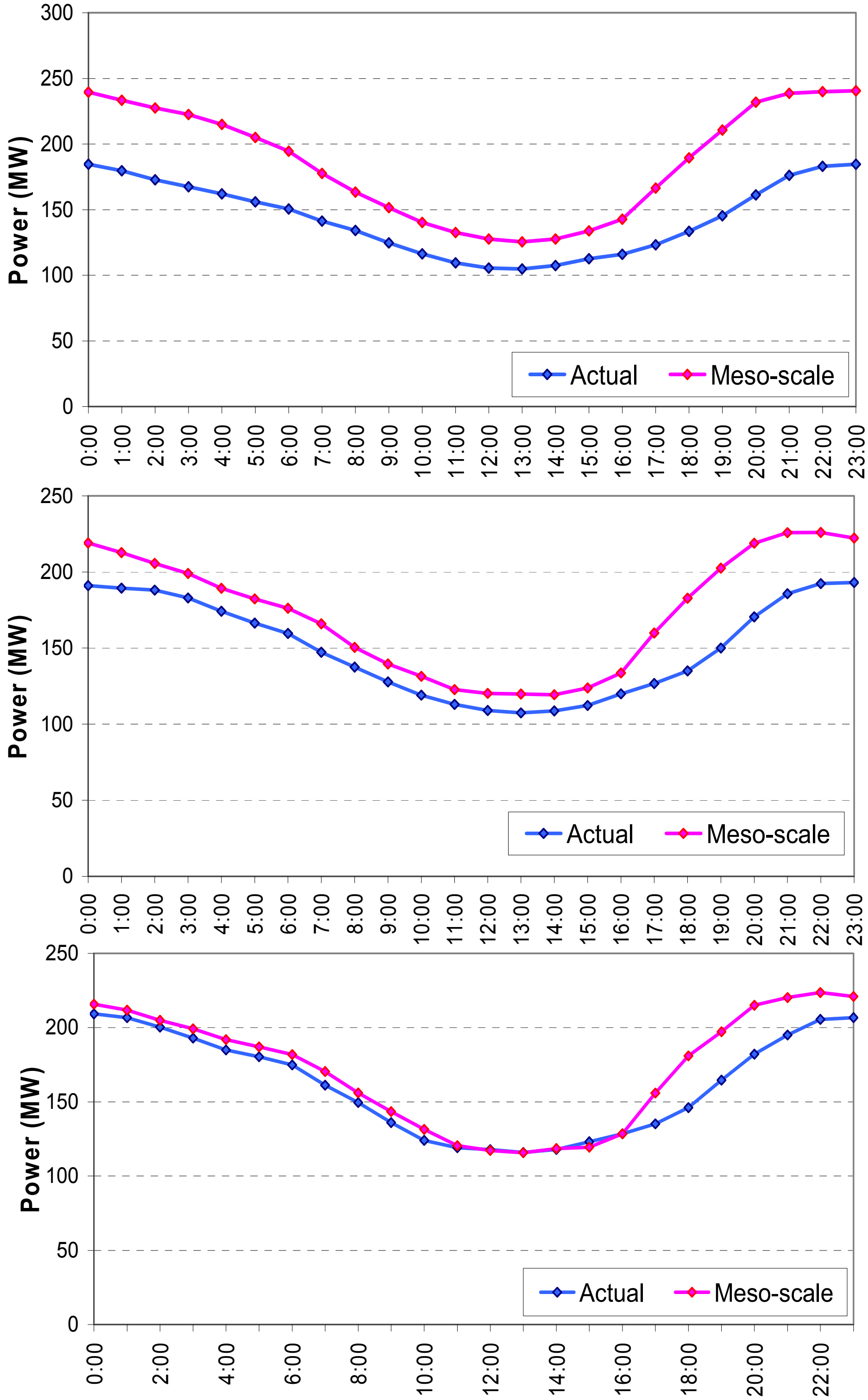

Figure 3 − Comparison of modeled vs. actual diurnal patters of wind energy, 2004-2006 (respectively from top to bottom).

Table 3 − 10-minute and hourly step changes.

	10-minute		1-hour	
	Actual	Meso-scale	Actual	Meso-scale
2004				
Std Dev	9.4	15.8	27.0	41.7
Max (+)	121	234	222	303
Max (−)	-145	-216	-166	-255
2005				
Std Dev	10.1	15.3	30.9	38.3
Max (+)	122	332	158	291
Max (−)	-116	-311	-202	-225
2006				
Std Dev	10.7	14.1	33.2	36.9
Max (+)	148	249	241	285
Max (−)	-128	-190	-198	-244

In general the wind power time-series data from the NWP model have larger step changes and more extreme values. The next table shows the distribution of step change values grouped in terms of wind plant installed capacity. The percentage values of each row heading (the first column) should be read as less than the value. For example, there are 52,576 10-minute power level changes with a magnitude of less than 10% of the plant capacity. The NWP model always produces more large step changes than the actual data shows.

Table 4 − Step change distributions.

	2004		2005		2006	
	Actual	Meso-scale	Actual	Meso-scale	Actual	Meso-scale
10-minute Data						
10%	52576	52050	52400	51990	52331	52073
20%	119	560	155	449	204	401
30%	8	51	4	55	23	37
40%	0	6	0	22	1	9
50%	0	1	0	5	0	3
60%	0	0	0	2	0	0
70%	0	0	0	1	0	0
Hourly Data						
10%	8257	7505	8004	7698	7732	7761
20%	498	1022	689	865	864	778
30%	24	189	65	137	142	159
40%	3	47	1	40	18	38
50%	1	13	0	12	2	13
60%	0	2	0	2	1	4
70%	0	0	0	0	0	0

Other Validation Approaches

The Oahu Wind Integration and Transmission Study (OWITS) utilized spectral analysis to diagnose and correct large 10-minute step changes in wind speed (AWS Truewind, 2009). The original power spectral density chart showed a divergence between the actual and modeled data, as evidenced by peaks in the spectra at high frequencies in the modeled data. The data problem was caused by binning of 2-second data blocks based on season. This limited the sample size and led to the data anomaly. The corrected spectral density graph shows a close correspondence between the actual and modeled data, as shown in Figure 4.

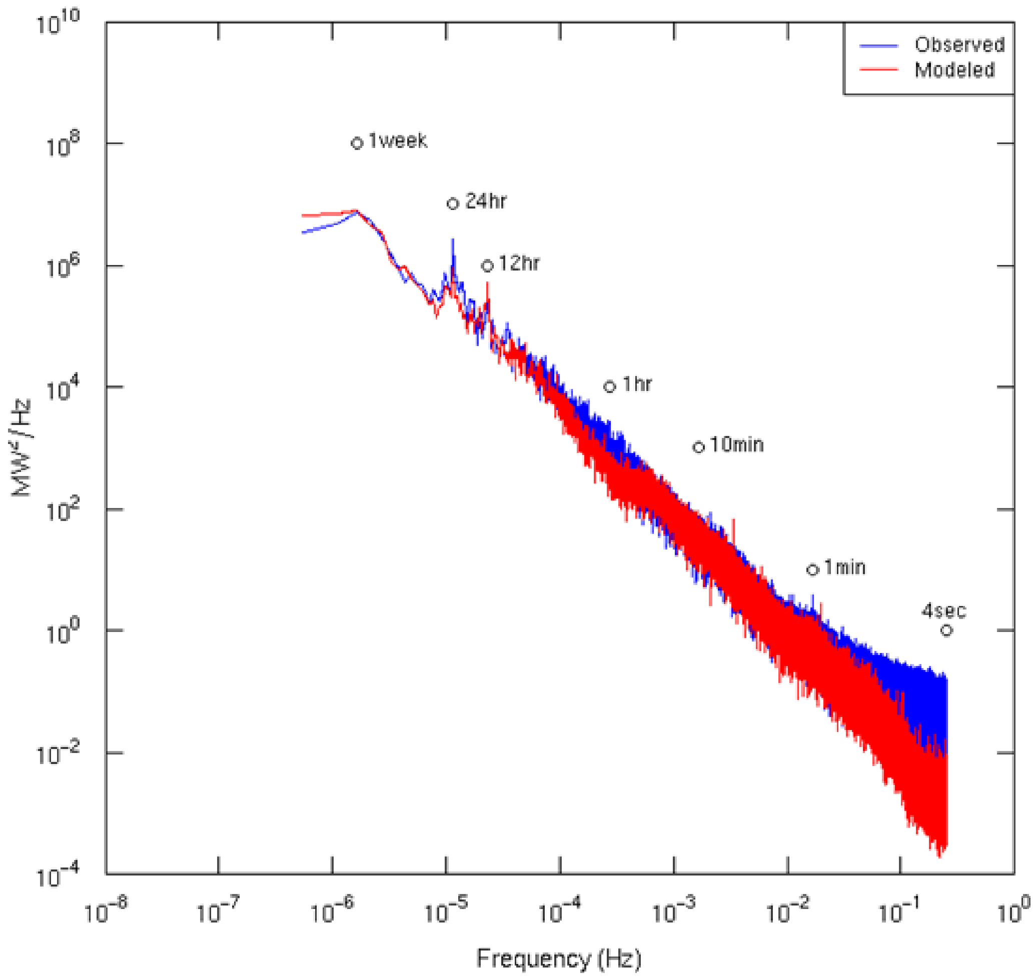

Figure 4 − Power spectral density of observed (blue) and modeled (red) high-frequency data from OWITS.

In our view, analyses such as these are critical so that the limitations to the underlying wind datasets are well understood. From the integration studies that have been done to date, it is apparent (and is probably obvious) that the renewable energy data drives the results of the models; therefore, efforts to ensure accuracy, or at least understand data limitations, appear quite valuable and desirable.

Synthetic Wind Forecasts

Modeling a prospective wind plant requires the use of a NWP that can simulate the atmosphere in time and space. Once this is done, usually at 5 to 10-minute intervals for a 3-year period, there is a large simulated dataset that represents wind energy generation at the appropriate time step. However, to successfully model power systems operation, in addition, it is necessary to have a wind forecast that can be used in the unit commitment process. Because the wind data itself is simulated, methods to develop a wind forecast from the simulated data are challenging. Several approaches have been used and we believe that much more research needs to be done in this area. In our view, it is unclear which of several methods are appropriate for developing simulated forecasts.

Examples of approaches that we have seen used include: (1) using different NWP inputs or models from those used in generating the wind plant "actuals", (2) applying statistical estimation techniques that are based on actual forecast error statistics. In one early study, there was insufficient budget to develop a high-quality wind forecast, so forecast errors from another part of the country were applied to the area of interest, causing problems with the simulation results. (3) Perturbing inputs to the NWP to simulate inaccurate wind forecasts.

In addition, it is no longer sufficient to produce day-ahead forecasts and 1 to 2-hour ahead forecasts. Because wind generation can be more accurately forecast for shorter time horizons, and because of recent advances in more advanced simulation tools, frequent wind forecast updates (both in reality and in a modeling framework) can help with system scheduling. Advanced production simulation models that use rolling planning and stochastic unit commitment, based on forecasts that can be updated every few hours, can reduce unit commitment errors in real time, reducing system costs. This further complicates the problem of producing a synthetic forecast because multiple forecasts with different time horizons are necessary for robust modeling with new simulation techniques.

In any case, part of a modern integration study also involves diagnostic checking of forecast errors using similar techniques as described for the "actual"[3] wind data. In addition, various comparisons between forecasts and actual data should be performed.

Potential forecast error bias can needlessly increase integration costs, and can have significant impacts on other aspects of wind integration. Forecast error distributions also need to be checked because actual forecasting errors are typically lowest when wind output is stable and highest when wind output is ramping. Other systematic errors can result in forecasts that are "too good" or unrealistically inaccurate.

Figure 5 shows an example of an unbiased simulated forecast that has an over-forecasting trend. At low-wind power output levels, the wind tends to be over-forecast. At higher wind power output levels, forecast errors tend to become negative. It seems clear that diagnostic checking of simulated wind forecasts should include analyses that examine the statistical distribution of forecast errors as a function of the actual wind energy output.

[3] For the remainder of this discussion, we use the term *actual* to denote the simulated actual wind energy output based on the NWP model after applying appropriate power conversion algorithms. In cases where the wind energy data is from an operating wind plant, there is no need to develop simulations, and our term *actual* would therefore apply to real wind energy data.

Simulated forecasts and the resulting forecast errors must be accurately estimated for individual utility integration studies, but this may be more critical for large interconnection-wide integration or transmission analysis. Because the wind energy level over a large geographic footprint has complex, dynamic correlations based on weather front movements, the errors will also tend to have complex temporal relationships. These characteristics are not currently well known. Additional analysis of forecast errors would help provide the ability to improve the modeling of forecasts for integration studies, possibly resulting in new statistical approaches that can take weather phenomena into account, both temporally and geographically.

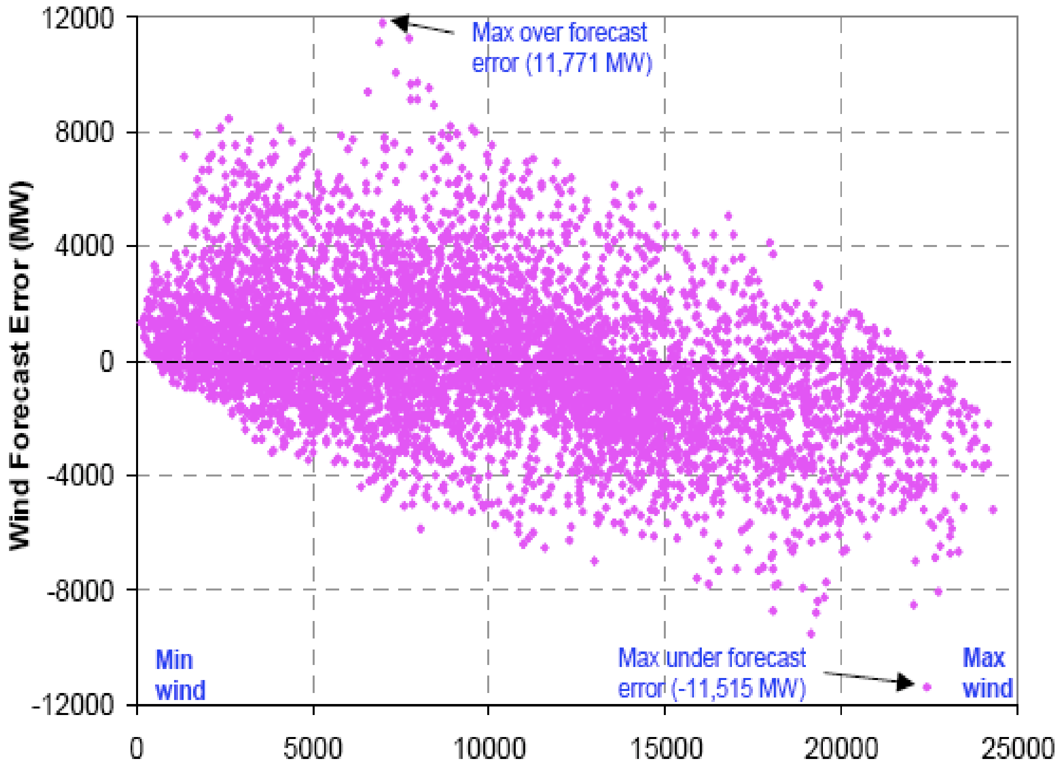

Figure 5 − This example set of wind forecasts is unbiased, but has an over-forecasting trend related to the level of wind.

Stochastic Unit Commitment and Wind Forecasts

There has been much recent interest in more advanced approaches to unit commitment, including stochastic unit commitment. This type of algorithm depends on a series of scenario trees, representing alternative futures that may range from one to several hours, or even days, in advance. Each branch of the tree represents a single scenario with a probability attached to its likelihood of occurrence. Although different objective functions are possible, expected operational cost is typically minimized with respect to the various system constraints and costs. For wind integration modeling, branches on the scenario tree can be based at least in part on the alternative realized wind, based on the wind forecast error distribution. When combined with a rolling unit commitment algorithm, a more robust unit commitment stack can be developed that can hedge against unlikely but severe wind forecast errors. In studies that utilized this type of model, it is clear that a suite of forecast values and associated probabilities are necessary, and need to be developed consistently and on rolling time periods. The role of the simulated wind forecasts in developing the unit commitment stack is clearly critical, and in our view this is the key limiting factor in achieving a robust understanding of the benefit of this type of advanced modeling.

Stochastic methods require information about probability density functions that can accurately describe wind power data characteristics at any time of the day, month, or year. These characterizations are necessarily complex because they must take into account geographic locations, both absolute and relative, and reflect realistic underlying weather characteristics. Development of the proper scenario trees that are used for stochastic unit commitment remain an arcane subject, with little widespread involvement and understanding by the wind integration community and the meteorological community. More on stochastic unit commitment appears later in this paper.

Anomalies in Unit Commitment with Forecast Filters

In one recent wind integration study that NREL was involved with, some unusual results were found when applying wind forecasts from another region to the study footprint. Experiments with wind forecasting errors were carried out to assess the sensitivity of unit commitment and operational cost to the forecasts.

One such analysis utilized a 6-hour rolling average of wind forecast errors. The rolling average filter smooths the forecast errors and reduces the accuracy of the forecasts generally. However, production simulation that used the rolling average forecast errors resulted in less production costs than when the actual, more accurate, forecasts were used.

Unfortunately, the study did not have the resources available for detailed follow-up analysis, so the reasons for the production cost anomaly is unknown. However, the following hypotheses have been suggested:

- Unit commitment algorithm does not perform well when there is a high range of net load values in the commitment time frame;
- The rolling average may act as a simplified form of stochastic unit commitment, putting the system in a “center” position that is within closer reach of the range of net loads that must be met;
- Actual forecasts result in putting the unit commitment stack too far in one direction (high or low), making it difficult to cover variations from forecasts if there are severe.

In any case, it is clear that wind forecast errors play an important role in wind integration studies. We think that this area of research is critical if the impacts of large-scale wind development on power system operations will be well understood.

Wind and Load Forecast Errors Both Contribute to Imbalance

Although wind forecast errors play a significant role in wind integration analysis because of the impact on uncertainty, these errors must be netted against load forecast errors that occur simultaneously. Failure to do this will result in either over-estimating or under-estimating what the system operator must do in real time to bring the system into balance. For example, if wind unexpectedly increases its output 100 MW above forecast at the same time that load also increases by 100 MW, then the system operator would not need to modify the economic dispatch of other units.[4] However, if in this case the load dropped 100 MW unexpectedly, the system operator would need to reduce output of the generation fleet by 200 MW. Although generally this would be done by reducing output of the non-wind fleet, it may be the case that some or all of the wind power would be curtailed, depending on the operating posture of the system at the time.

In our view, much more work is needed on this issue. It is clear that there is no widespread agreement on which approach is most appropriate to estimate future wind forecasting errors. In our view, we don't know the right way to model wind forecast errors for integration studies.

Scenario Development

Depending on the scope of the study, specific regions may be modeled in detail with entire grids (the Eastern or Western Interconnects) modeled at a coarser level to capture interchanges between specific study regions and their neighbors. As wind power penetrations increase, it becomes increasingly important to model the entire grid because significant power flows across the interchanges during times of high wind . Additionally, it becomes more important to model wind penetrations in neighboring regions, and significant wind penetrations in both a study region and neighboring regions may constrain how much the study region can 'lean' on its neighbors in accommodating large amounts of variable generation. In the WWSIS, it was found that increasing the penetration of wind in the rest of WECC had a significant operational impact on the study region.

Both WWSIS and EWITS developed a set of "book-end" cases to analyze the impact of alternative wind build-out scenarios on transmission and costs. For the WWSIS, alternative wind development patterns were based on:

- In-area development – all wind and solar generation necessary to satisfy state renewable energy standards were built in-state;
- Mega-projects – wind (and solar) sites were based on annual capacity factor. The best sites were developed irrespective of location (other than screening for locations that cannot be reasonably used for wind power development);
- Local-priority – a blend of the previous two cases.

The In-area scenario results in no additional required transmission between balancing zones because the energy is generated close to load. However, more installed wind is

[4] Of course this discussion is somewhat simplistic, but captures the point that we are pressing; the load net wind is what must be balanced.

needed because of the relatively low capacity factors. This puts upward pressure on wind technology costs, but does not require significant transmission build-out or costs. The Mega-project case does require additional transmission build-out, which is expected because so much wind power is developed in low-load areas like Wyoming. WWSIS did not do a detailed transmission plan, but did provide an overall estimate of likely transmission additions required to enable the wind/solar delivery to load. These two build-out scenarios appear in Figure 6.

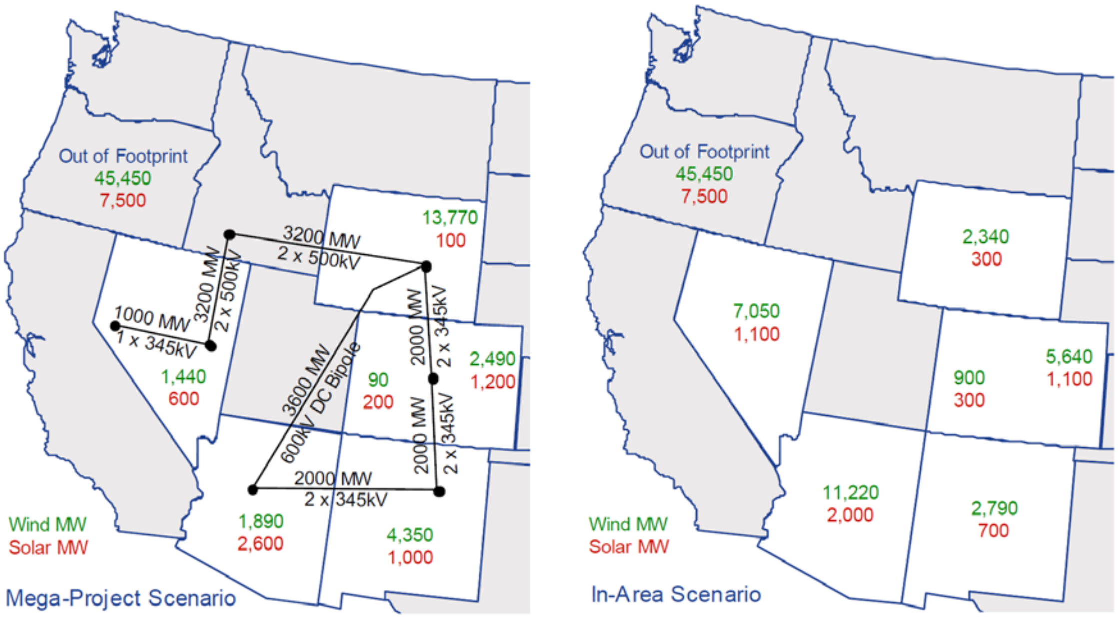

Figure 6 − WWSIS scenarios include in-area and mega-projects that result in different transmission expansions.

The EWITS project did a more refined analysis of transmission, but contained similar book-end scenarios to help bracket relatively extreme differences in wind development patterns. Three cases that represent a 20% wind energy penetration were examined, along with a single 30% penetration case. For this discussion we focus on the 20% cases.

Figure 7 illustrates two scenarios from EWITS. The upper panel shows a large concentration of wind power in the northwest portion of the footprint, which is generally where the best wind resources are. The lower panel shows some off-shore development along the Atlantic coast and less development in the northwest.

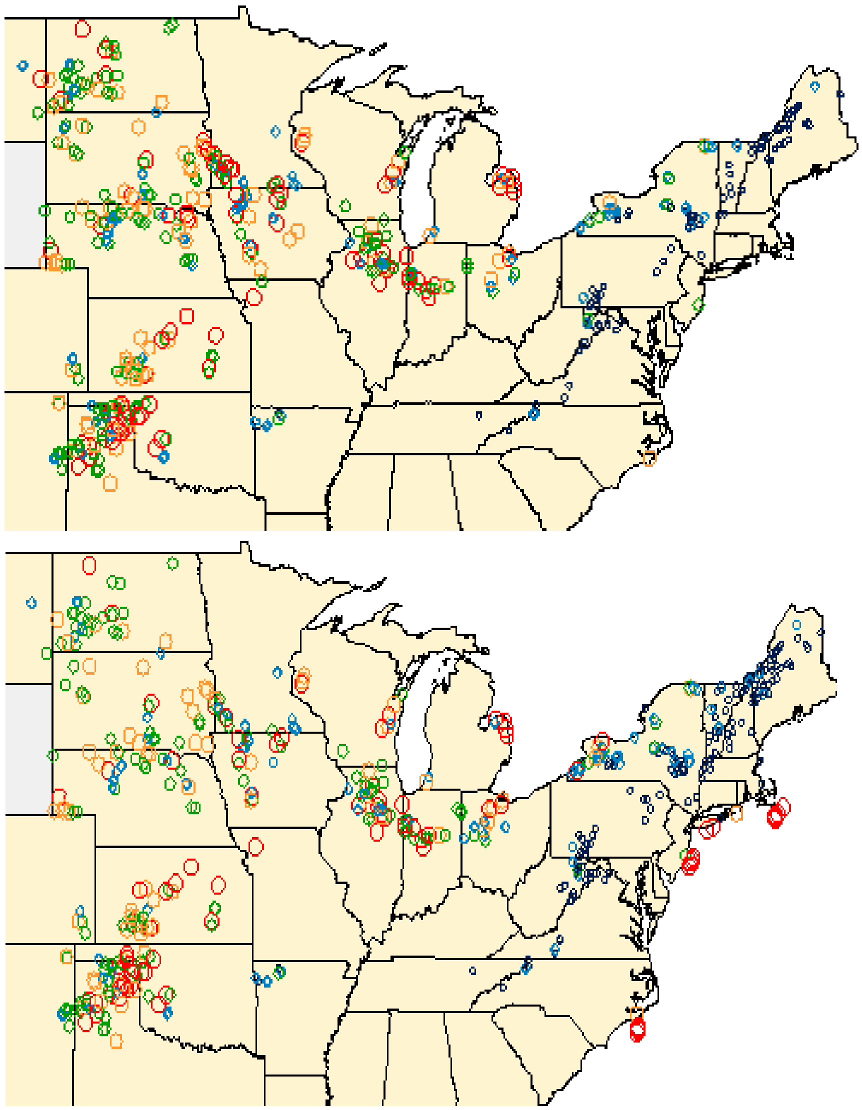

Figure 7 − EWITS wind locations based on heavy development in western MISO (above) and blended offshore/onshore case (below).

Transmission Scenario Development

Transmission has a significant impact on the ease with which wind power can be integrated into the power system. EWITS did considerable analysis on transmission since that was a part of the study. In developing the transmission scenario, there is a natural iteration between the resource scenario and transmission. This is best explained with reference to Figure 8.

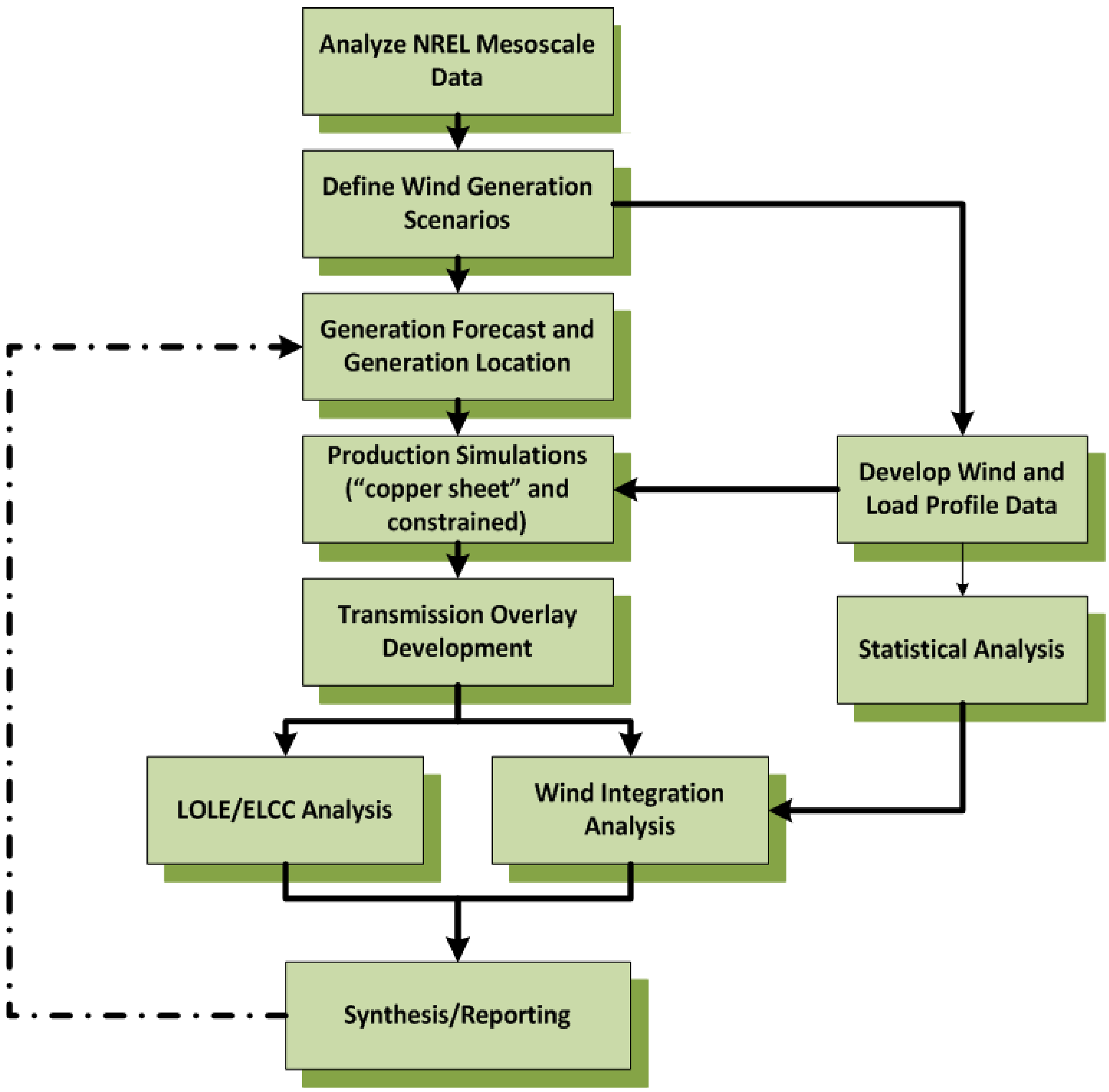

Figure 8 – The EWITS process to develop consistent transmission and resource assumptions.

This figure illustrates the iterative process of developing a robust transmission plan, which is in part a function of the future load demand, and in part a function of the location and characteristics of the generation fleet.

Once the wind and load scenario has been developed, it is merged with the other generators and their characteristics. Then a 'copper sheet' analysis is undertaken, in which there are no binding transmission constraints in the study footprint. This allows the energy to flow unconstrained towards load areas based on prices and costs. To help enable this efficient flow of power, a transmission overlay plan is developed and tested by running a loss-of-load expectation (LOLE) study to determine whether the system has sufficient installed capability to meet a reliability target.[5] At this stage, a wind integration analysis

[5] The reliability target is set by the entity performing the study. Often a 0.1 day/year LOLE target is used. These metrics and their use is discussed in a later section of this report.

can be performed if desired, and the contribution of wind to resource adequacy, or capacity value, can be calculated using some form of the effective load carrying capability (ELCC) metric. Depending on the outcome of the reliability analysis, additional generation can now be added to the system or redundant generation can be removed. The production simulation can then be re-run and a new set of transmission constraints will likely emerge. The study then iterates between adding/evaluating transmission additions/subtractions, and generation additions/subtractions. Recent studies that have used this approach include the Joint Coordinated System Plan (www.jcspstudy.org) and EWITS, although in EWITS, only one iteration of the flowchart was performed because of limited resources.

Characteristics of other generation and sources of flexibility

Wind integration depends on sufficient operating range and flexibility from the balance of generation on the system. At low penetration rates, this is not an important issue because little additional flexibility, beyond that required to serve load, is typically needed. But as wind penetration rates increase to the level currently being analyzed (10-30% of annual electricity demand), the characteristics of the remaining generation fleet become more important.

The primary types of flexibility needed to integrate large penetrations of wind power include lower turn-down levels on conventional generation, along with increased ramping capability. These are illustrated in Figure 9 and Figure 10, which are based on data from Milligan and Kirby (2008). The first of these graphs shows load and net load in the upper panel. Load ramping requirements are approximately 4,000 MW over a few-hour period, varying somewhat from day to day. The ramps of the net load sometimes cover a wider range in a similar time frame. This sample week is based on a 25% wind energy penetration annually, and there can be significant changes from week to week. The next of these two graphs shows the impact of high levels of wind energy during low load periods. The annual minimum load is approximately 8,000 MW, but when wind is added to the system, the minimum net load is less than half that amount. During those periods, it may be difficult for the remaining generation fleet to reduce output low enough so that the wind energy can be integrated. In some cases, units may be de-committed, but if they will be needed the next day to serve higher loads when the wind energy output is less, de-commitment may not be possible. There are several potential solutions to this issue; (1) markets may exist that allow for the excess energy to be exported, and (2) over time, the relatively inflexible generation can either be modified so that it can achieve lower turn-down levels, or can be retired and replaced with units that can be turned to a lower level of output.

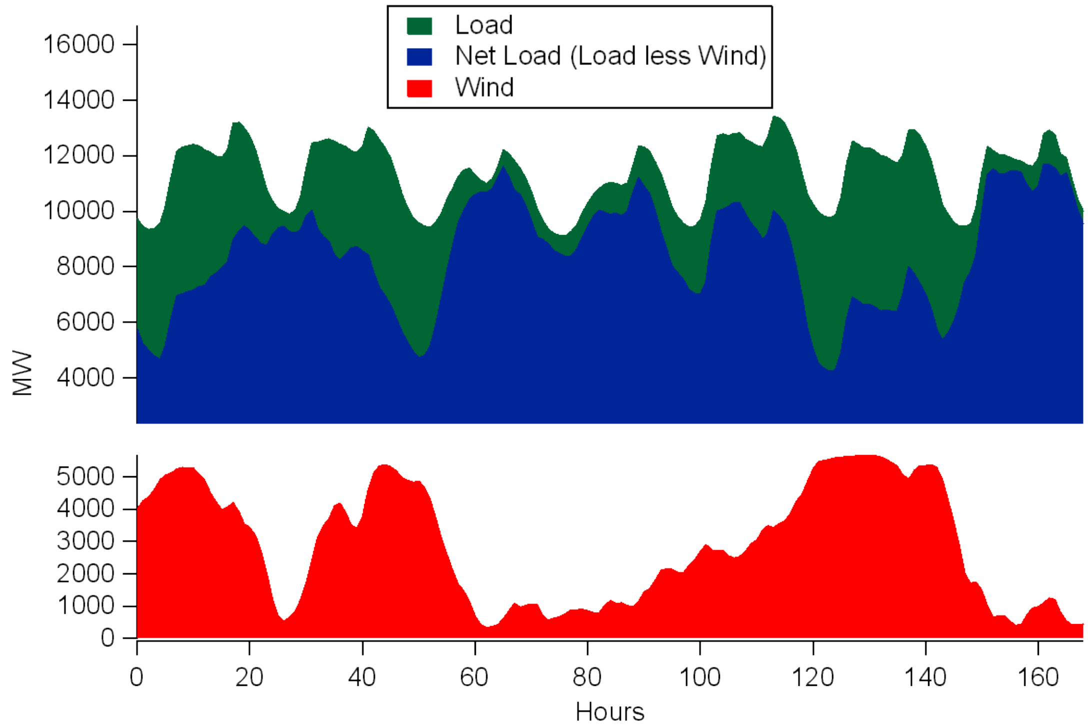

Figure 9 − High levels of wind power penetration increase the required ramping range of the remaining generation fleet.

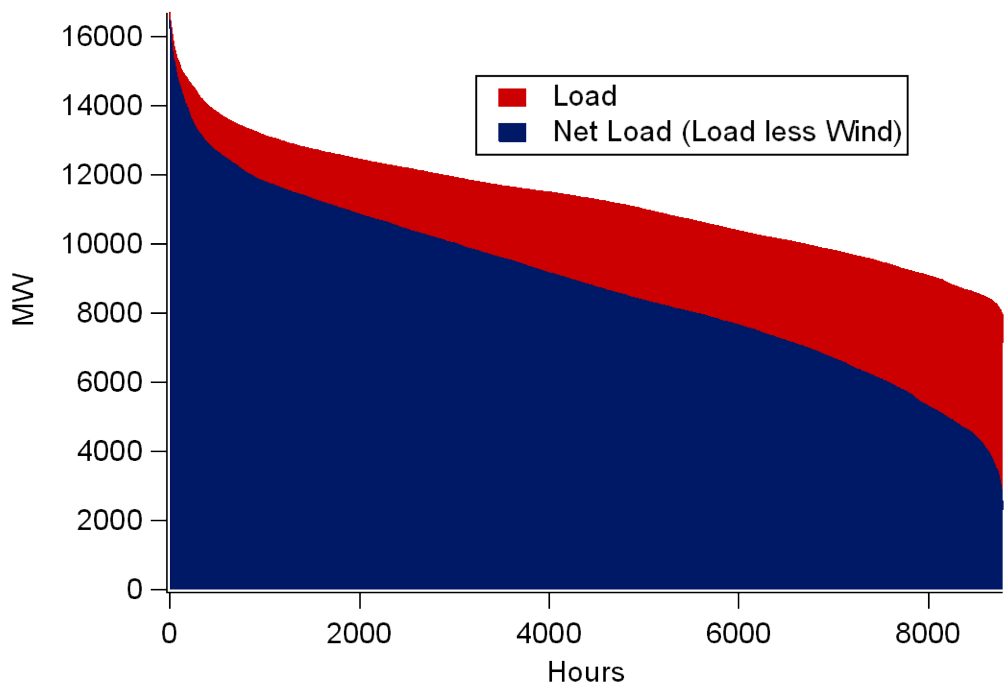

Figure 10 − The minimum net load is less than the minimum load, so lower turn-down capability is needed.

Many wind integration studies begin with a portfolio of generation that can adequately serve load without wind. The wind scenario is then added to the generation mix, and the analysis proceeds. In some ways this can be a fair representation of reality, for example, as was the case with Xcel Colorado which added approximately 750 MW of wind in a single year. However, many other studies focus on future years and the transition between the present and the future can include the development of complementary generation with the flexibility attributes that would help manage large amounts of wind. Older, less flexible generating units may be excluded from the scenario to test the impact of a more flexible generation fleet. There may be valid reasons for using either approach, but this should be made clear in the study.

EWITS modified the remaining generation fleet by running a generation expansion model (GEM) that considered the load and wind requirements together. GEMs have been utilized for many years, and often use a load duration curve (LDC) approach to reduce potentially extensive computer run-time so that large numbers of expansion cases can be examined in a timely fashion. As can be seen in Figure 10, a LDC does indeed consider the minimum net load level, so that the generation fleet chosen by the model will be able to operate during low load and high wind periods.

However, it is clear that the LDC does not include chronological information that can be used to determine the depth and frequency of ramping requirements on the system, such as those shown in Figure 9. It is possible that the algorithms in GEMs may need to be modified so that ramping can be considered in the generation expansion process, and research into this important issue is needed.

WWSIS took a different approach of building out the generation portfolio and achieving resource adequacy before adding wind and solar generation to the mix. This results in a generation portfolio that may make it challenging to integrate high levels of wind and solar energy. Baseload units are called upon to cycle more than they have in the past, raising the potential for higher operation and maintenance costs over the lifetime of the unit. The resulting system is also overbuilt somewhat, because both the wind and solar generation have some capacity value that is not accounted for by the system expansion model. However, this study is useful because it does show that, with changes to the way the power system is operated, even this relatively inflexible generation mix can physically respond to the needs of the significantly higher level of variability and uncertainty, although this will be a challenge at the 35% penetration rate in the study.

In addition to physically available flexibility to help mitigate wind impacts, institutional factors can also be significant. We discuss work that has examined some of these institutional constraints, and discuss limitations in the current state of knowledge about the institutional flexibility that is available from physically flexible hydro systems. Controllable hydro may offer promise in integrating wind power, but the lack of publically-available information and data about hydro operations has provided another institutional roadblock to determining how hydro can play a potentially significant role in helping to manage wind generation.

Determining the flexibility that can be tapped in the existing generation fleet can also be complicated. For example, WWSIS uses data from WECC that contains maximum and minimum capacities and ramp rates for each thermal generator. However, at least one utility expressed concern that the coal units may have operated outside of their limits during some particularly high-wind time periods, causing the coal units to be dispatched to minimums. It is clear that assumptions regarding minimum turn-down levels, the type of minimum turn down (emergency or economic), and the duration that the unit can operate in these ranges are all important and will have potentially significant impacts on the ability of the power system to successfully absorb significant wind energy. WWSIS addressed this issue by examining a range of minimum run levels on the coal fleet.

Kirby and Milligan (2005) calculated the ramping capability of thermal generation in several regions of the United States. The overall approach was to utilize hourly emissions data collected by the U.S. Environmental Protection Agency in the Continuous Emissions Monitoring System (CEMS). The Platts database was used to extract hourly generation levels from all thermal plants. From that data, ramping and turn-down levels can be calculated based on actual plant performance. Units' startup and shutdown cycles must be evaluated carefully so as not to distort the actual capability of the unit. This approach can be used to estimate a lower bound of the flexibility in a given power system. Because only data from emitting plants are collected by CEMS, hydro and nuclear data are not available for this type of analysis, and must be obtained elsewhere.

It has also become clear that small balancing areas (BAs) will be limited in their ability to integrate wind, as demonstrated by Kirby and Milligan (2008), Kirby and Milligan (2008), and the WWSIS final project report. Many different approaches can be used to move towards either a full physical consolidation of BAs, or other cooperative approaches to manage variability over a larger electrical footprint. Furthermore, wind scenarios that feature wind that is exported from the host BA to the load center will place large integration challenges on the host if scheduling rules are not flexible and fast (see Milligan and Kirby, 2010b). For example, a large wind plant (or multiple plants) developed in a wind-rich area like Montana and exported to the Pacific Northwest would likely need to be dynamically scheduled out of the host BA and into the load BA. But there may be other economic options; a third BA could provide some or all of the required ancillary services to enable wind integration. The assumptions regarding these issues will drive the integration analysis and conclusions. There may be other approaches, such as the ACE[6] Diversity Interchange or Dynamic Scheduling System and other ways to enable the sharing of ancillary services over a larger footprint. Because pooling the variability of larger regions is effective in reducing the per-unit variability that the power system must respond to, dynamic scheduling of ACE or other aggregate metrics of imbalance would have a larger benefit than dynamic scheduling of individual loads or resources. Other approaches are discussed in Milligan, Kirby, and Beuning (2010).

Assumptions regarding these aspects of flexibility sources, whether hardware or institutional, along with the size of the geographic and electrical footprint that is analyzed, will have a highly significant impact on how wind and solar can be integrated on the power system.

There are several types of reserves maintained by power system operators for distinct purposes. Examples include contingency reserves and regulating reserves. Both of these are

[6] Area control error.

reasonably well-defined and commonly understood. However, because of its uncertainty and variability, wind induces the system operator to ensure that sufficient flexibility or ramping capability is available when needed. This additional flexibility must be accounted for by the unit commitment and dispatch algorithms, and does not have a commonly used definition[7] or calculation method. Some recent wind integration studies have developed a dynamic reserve concept that accounts for this needed flexibility, using a variety of ad hoc approaches, some of which may be quite promising. Surprisingly, some wind integration studies have used a static reserve level for the entire year. This technique will typically over-schedule reserves and will needlessly increase costs without providing additional reliability.

Contribution to planning reserves

A fundamental planning task is to perform an evaluation to determine whether there is sufficient installed capacity at some future date to serve loads. In market areas, this function is typically used by the system operator to quantify the resource adequacy going forward, whereas in regulated monopoly environments, this activity can be tied to resource acquisition. There are two primary components to this type of analysis. The first is to determine whether there is sufficient resource adequacy for some base system, possibly today's system at a future date. This is done by a probabilistic study whose goal is to provide an estimate of LOLE (or another related metric) of the future system or alternative future systems. A resource adequacy target is developed, and any plan that hits the target is judged to be adequate. A common target is 0.1 day/year LOLE.[8] An iterative process such as the one in Figure 8 is commonly used to develop a plan that meets the reliability target.

The second aspect of this type of study is to determine the particular contribution to resource adequacy that is made by a given generator or group of generators. This yields the capacity value, measured in ELCC. Figure 11 shows a graphical example using the common target of 1 day per 10 years LOLE.

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[7] Possible terms include *variability reserve* and *flexibility reserve.*

[8] Although technically not correct, the term LOLP, loss of load probability, is often used in place of LOLE.

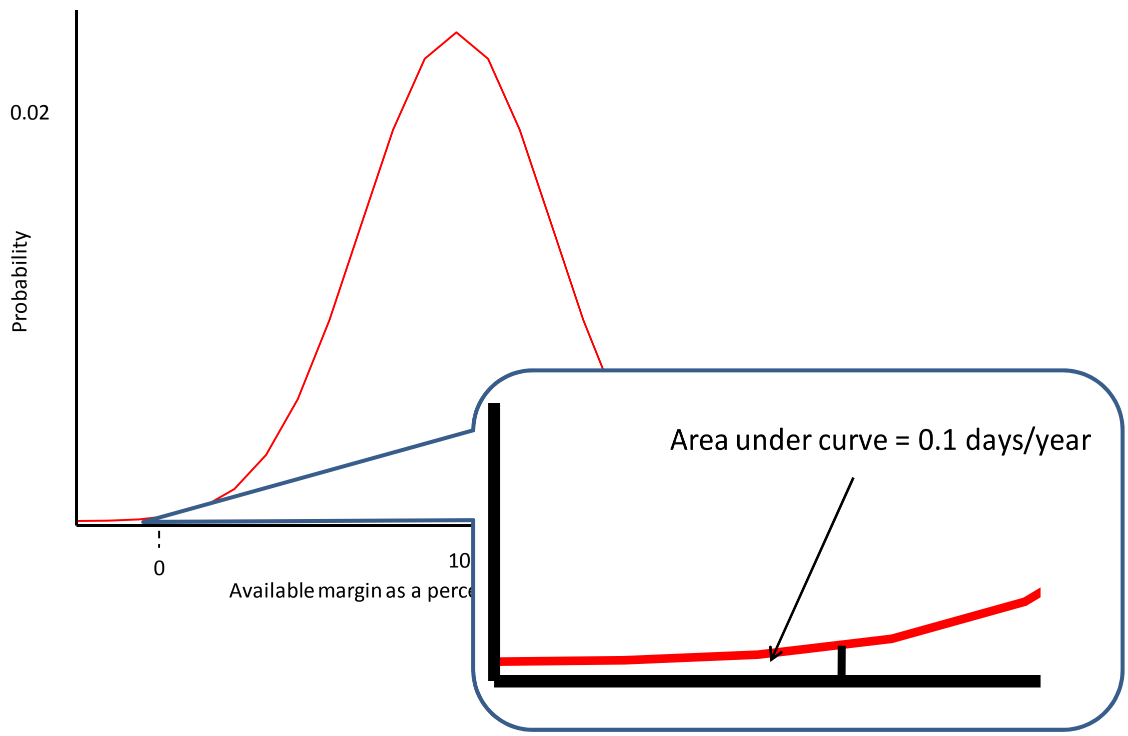


Figure 11 − ELCC measures a generator's contribution to resource adequacy, holding reliability constant.

This issue is the subject of an IEEE Task Force paper (Keane et al, 2010) and the North American Electricity Reliability Corporation (NERC) Variable Generation Task Force.

Integration studies often include an element of resource adequacy and calculation of wind capacity value. The traditional approach to reliability analysis is the calculation of a daily LOLP for the peak hour of each day. However, because wind can fundamentally change the time of the peak net load, there has been much interest in alternative approaches to use when there is a significant contribution of wind or solar generation. Examples of alternative approaches include:

- Retaining the LOLP calculation on the daily peak, but allow the algorithm to look for the highest net-load hour, which may differ from the peak hour. The highest net-load for the day would be used in the calculation;
- Move to an hourly LOLE calculation. This would involve developing a new target of loss of load hours (LOLH). Although this target need not be equivalent to 0.1 day/year LOLE, the differences should be well understood;
- Move towards an expected energy not served (EENS) metric (sometimes called expected unserved energy, EUE). With more energy resources such as wind in the power system of the future, this may be the most appropriate metric to utilize.

More research is needed to better understand the implications of these alternative approaches. The North American Electric Reliability Corporation (NERC) has convened a task force as part of its Integrating Variable Generation Task Force to examine the capacity value methods for variable generation such as wind.

To calculate the ELCC for a conventional generator, the long-term forced outage rate (FOR) for that size and type of unit is the most appropriate. Data can usually be found in the NERC Generation Availability Data Set (GADS). However, for wind energy there is no such dataset. Thus ELCC calculations for wind have typically been done year by year for up to 3 years of data, and concern has arisen regarding the variability of wind's capacity value from year to year. Longer datasets are clearly required so that the wind capacity value can be put on the same footing as those of conventional generators. We also point out that a conventional generator that trips during the high-risk peak season may have a significantly higher inter-annual variation in ELCC (about 90% of its rated capacity) than a wind plant, which may vary by 3-10% of its rated capacity.

As noted elsewhere in this paper, the development of a long-term database for wind data, both from NWP models and from actual wind plants, is a critical element for providing solid analytical understandings of the behavior and resource adequacy contribution of wind power plants.

Operational Analysis

Early integration studies focused on single utilities and modest wind penetration rates. As interest in wind energy has grown and wind energy has been adopted into the generation mix around the United States, larger study footprints accompanied higher penetration analyses. For example, Xcel Energy in Minnesota was the subject of two early integration studies which were eventually followed by a state-wide study that analyzed wind energy penetration of 25% of annual electricity demand. The larger the system sizes and wind energy penetrations become, the more difficult it is to accurately model large wind plants and the remainder of the power system.

Many different questions are pursued in wind power integration studies. Once the study participants understand and agree on the study objectives, different techniques are used to answer each question. Most studies evaluate the effect that wind energy has on system operation, total annual production costs, and on energy spot prices. Some studies evaluate the changes in the generation mix that would result in more efficient operation, and the energy shares of different fuel types or technologies will produce. Generation schedule results show how existing generation types may be operating differently; ramp rates or commitment hours may change, for example. Sometimes the level of wind curtailment on the system is also investigated. Since many studies also evaluate transmission expansion scenarios, many studies will also analyze the flows on the lines. Other areas that some, but not all studies, will look at include operating reserve requirements, voltage stability, transient stability, loss of load probability, power exchange between regions, and many other topics.

Before the modeling of the power system begins, there are a number of assumptions that must be made. Assumptions on the generation mix, transmission expansion, and locations and amounts of the wind in the scenario have already been discussed. Operation of the power system, however, also depends on the market structure assumptions. The first is that the study system is usually optimized in its entirety. For large regional studies, this is somewhat different than today's actual operations. Many small BAs will operate their own system individually, and power transfers between regions may not be fully optimized based on economics. Sometimes special techniques are used to replicate this behavior. However, with very large penetrations of wind power, it has been concluded that the seamless coordination of BAs and rational economic operation between them is essential to fostering an efficient integration of wind power. This is why many studies will perform the simulations based on operation of the power system by a single entity.

Other assumptions are made before the simulations are performed. Many studies assume that the areas operate with day-ahead and real-time energy markets. They also assume that the energy and ancillary services (e.g., operating reserves) markets are co-optimized with each other so that the most efficient solution is made. Many studies also assume that sub-hourly energy markets exist in the study area and this assumption helps drive the operating reserve analysis. Lastly, most studies will assume that the market participants will offer into the energy market with bids based on their marginal cost to operate. The subject of changing of market behavior with high penetrations of wind power has not been studied in detail in any U.S. wind integration study. Lastly, much of the analysis that goes into the study needs to make the assumption of keeping the power system at the same general level of reliability.

Production simulation

To get a realistic view of how the system operates in these studies, detailed simulations are run with the system conditions modeled. Production cost simulation tools are commonly used when simulating the power system behavior of the generating units and the power flows on the transmission system. These tools are very popular in use by utilities, independent system operators (ISOs), and others when evaluating profit outlooks based on locational marginal pricing (LMP), financial transmission rights price forecasting, and transmission planning, to name a few applications. The use of these programs as the main tool in wind power integration studies is new and challenges arise because they were not built with this type of application in mind. That being said, their use of security constrained unit commitment (SCUC) and security constrained economic dispatch (SCED) show great realizations of how the system may behave with high wind power penetrations. A very large portion of the analysis on steady state operations can be seen by the use of these powerful tools.

SCUC performs an optimization to determine the least cost solution of units that should be on-line to meet the load and reserve demands without violation of certain constraints. These constraints include limitations on the generation fleet like the following: minimum run times, ramp rate limits, minimum generation limits and startup times. These are actual constraints that some generators have that must be replicated in the simulation. SCUC also models transmission constraints usually using a dc power flow. It makes sure that its decision creates power flows that are within reliable operation of the transmission system. In some cases, it also ensures that following "n-1" contingencies, power flows are still within limits. It is important to note that commitments must be made well in advance since many thermal generating units need substantial time to start up and be ready to serve load. Once those units have started up, they are committed to stay online in real-time even if system conditions change.

In SCED, dispatch is adjusted to meet load while minimizing production costs and meeting all generator and transmission constraints. This is the second stage of the production cost tool. In most cases, quick start units (e.g., combustion turbines) are allowed to be turned on and off, but all other thermal units must remain in their unit commitment status from the SCUC. The costs and LMPs that come from the SCED are those used in the results, and represent the actual generation and load.

As discussed elsewhere in this report, the wind power forecast errors become very important when analyzing the operational impacts of wind. These simulations have to use the wind power forecasts in a way that represents how BAs use or are planning on using them. Generally, this means that the wind power forecast is used in SCUC and the actual wind power production is used in SCED. The same can be done for load, and both of these usually will represent the day-ahead forecasts. The result is that unit commitment is made with consideration of the forecast, while the actual dispatch is made towards the actual production. The larger the error in forecast, the more inefficient the unit commitment decision. More inefficient unit commitment will lead to higher production costs. In some studies, sensitivities are run to show the value of using wind power forecasts. The general process of the production cost simulation tool is shown in Figure 12.

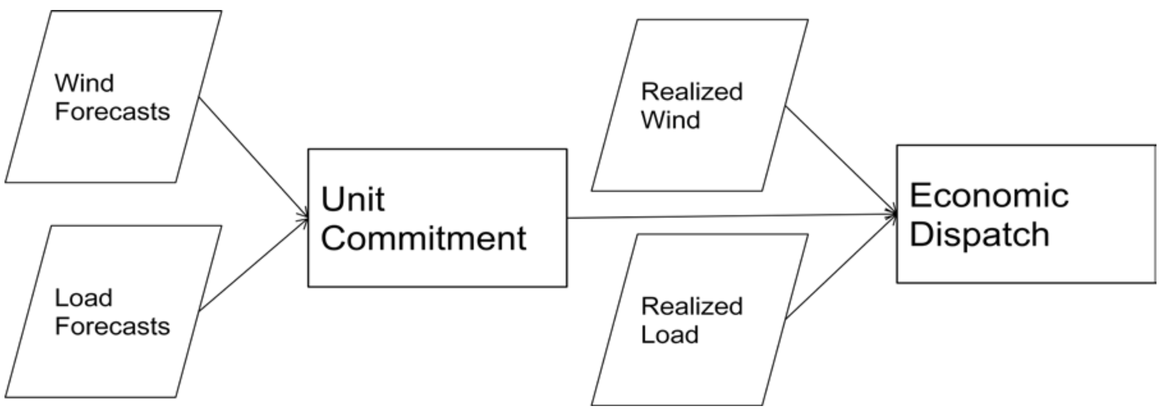


Figure 12 − General production cost simulation model process.

The general application of these models works fairly well for a predicted system operation. New techniques have been performed in recent studies to discover new results as sensitivity studies using these models. However, as many market rules begin to change and standards and practices are being developed to better accommodate new resources, it becomes difficult to keep the models up to date. Many of these enhancements are not currently being practiced in actual system operations; therefore, it is likely that tools that simulate system operations would not be up to date. However, since the studies are often looking at time frames of more than ten years in the future, it is becoming critical that future enhancements that may help facilitate wind integration be part of the modeling exercise. The enhancements can also be used in comparison with the base case models so that additional benefits of these enhancements towards the integration of high penetrations of wind power can be better realized.

Figure 13 shows an example of the types of outputs that are created from typical integration studies. The figure (see Lew et al, 2009) shows one day in April with no wind (left panel) with a typical dispatch – nuclear, coal, combined cycle, and hydro generation that meets local load within WestConnect and some exports. When the 20% annual wind energy plus 3% solar penetration is added, the dispatch changes significantly. Combined cycle generation is reduced significantly, and hydro is moved around somewhat. There is even an impact on the coal stack. This particular day is the most challenging of the 3-year study period, so is not representative. Detailed simulation of multiple years is a valuable way to find rare situations that may be very challenging for system operations.

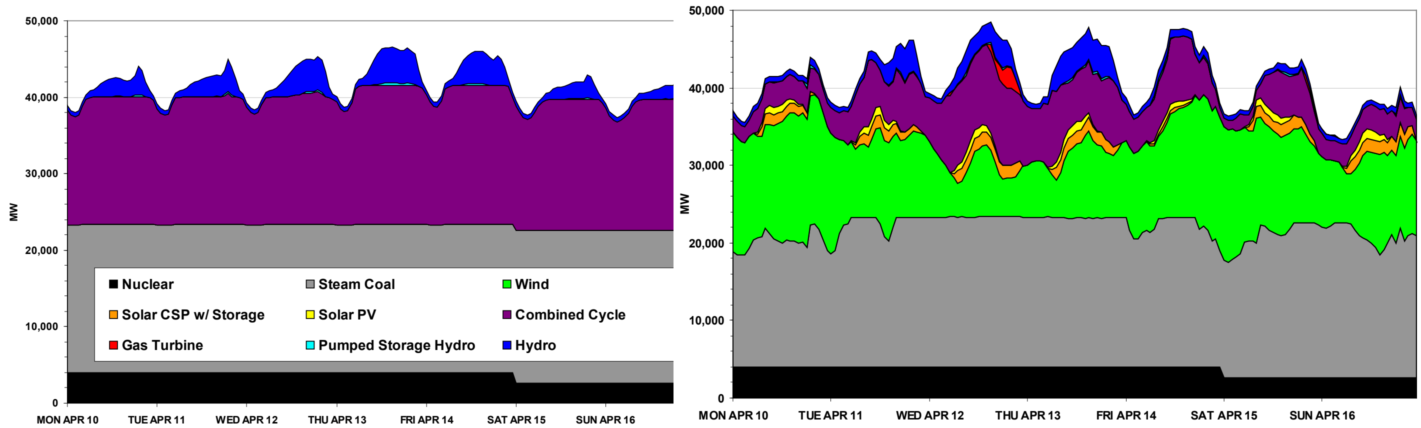
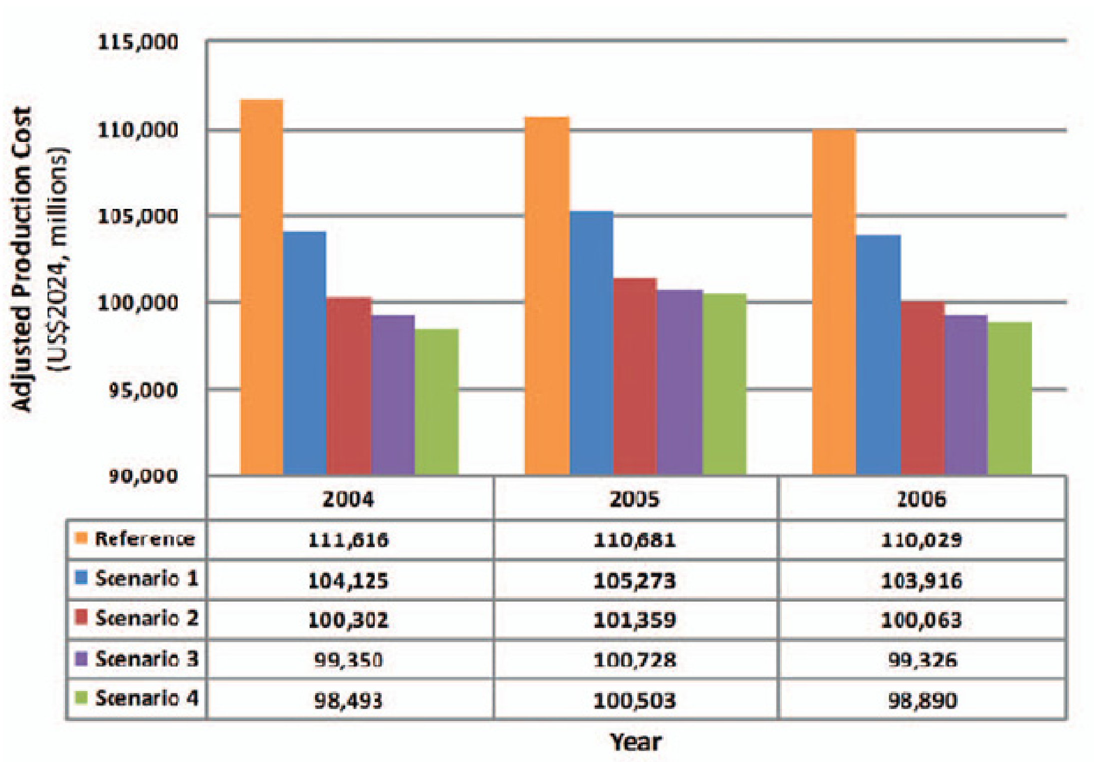


Figure 13 − Example dispatch when wind energy is added to the system. Left: no wind, right, 20% annual wind penetration during low-load and high wind period.

A common goal of wind integration studies is to examine how production costs change as wind is added to the system. Production costs do not include capital costs, and consist primarily of fuel cost, and are a function of the unit commitment and dispatch schedules. Because wind is a price-taker, the economically optimum situation is to use all the wind that is available unless there is a reliability concern. This will displace other fuels, reducing production costs. Figure 14 is taken from the EWITS study, and shows how production costs change with wind penetration and location.[9]

[9] Scenarios 1-3 have a 20% annual wind energy penetration, (a) concentrated in the western part of MISO, (b) more geographically dispersed with some off-shore wind, and (c) heavy off-shore. Scenario 4 is a 30% penetration.



	2004	2005	2006
Reference	111,616	110,681	110,029
Scenario 1	104,125	105,273	103,916
Scenario 2	100,302	101,359	100,063
Scenario 3	99,350	100,728	99,326
Scenario 4	98,493	100,503	98,890

Figure 14 – EWITS production cost by year and scenario (EnerNex, 2010).

Stochastic unit commitment

The traditional SCUC used in both day-ahead markets and in production cost simulation tools that are used in wind power integration studies solves toward deterministic conditions. In other words, uncertainty in day-ahead predictions against real-time outcomes is not modeled explicitly. Instead, operating reserves are used to cover any uncertainty in a loss of generation or load forecast error. The probability of outages occurring is generally pretty consistent during all times, and system operators usually will carry enough reserves to cover the largest single contingency. Load forecast errors are often not as significant and any large errors can be accommodated by different types of operating reserves or system flexibility in real-time. With high wind power penetrations, the uncertainty is not as straight forward. There has been lot of research (see Ruiz et al, 2009, Tuohy et al, 2009, Lei et al, 2007, and Risoe, 2006) that looked at a stochastic unit commitment program that solves the unit commitment towards a robust set of resources being able to meet multiple possible scenarios. This creates an efficient solution that in the long term is both more economic and more reliable if probabilistic forecasts are representative of their outcomes.

The objective of a deterministic SCUC can be written as:

$$minimize\ \mathcal{L} = \sum_{h=1}^{NH} \sum_{i=1}^{NG} P_{ih} * c_i + u_{ih} * NLC_i + z_{ih} * SUC_i$$

The objective of the stochastic SCUC differs:

$$minimize\ \mathcal{L} = \sum_{s=1}^{NS} \pi_s * \sum_{h=1}^{NH}\sum_{i=1}^{NG} P_{ihs} * c_i + u_{ihs} * NLC_i + z_{ihs} * SUC_i$$

where: h = hour index; NH = number of hours; i = generator index; NG = number of generators; P = power schedule; c = variable energy cost; u = unit status; NLC = no load cost; z = unit startup; SUC = startup cost; s = scenario index; NS = number of scenarios; and p = probability.

As can be seen, stochastic unit commitment will minimize the expected cost based on weighting its solution on their probability. Therefore, it is more important to reduce costs for more likely scenarios and scenarios with very low probabilities are not as significant for making cost efficient. Stochastic unit commitment represents a two stage process (or sometimes more) where the first stage ensures a unit commitment and the second is a multiple branch scenario tree of possible real-time outcomes as seen in Figure 15. Unit commitment, however, must be made no matter what the scenario turns out to be since it must be made in advance.

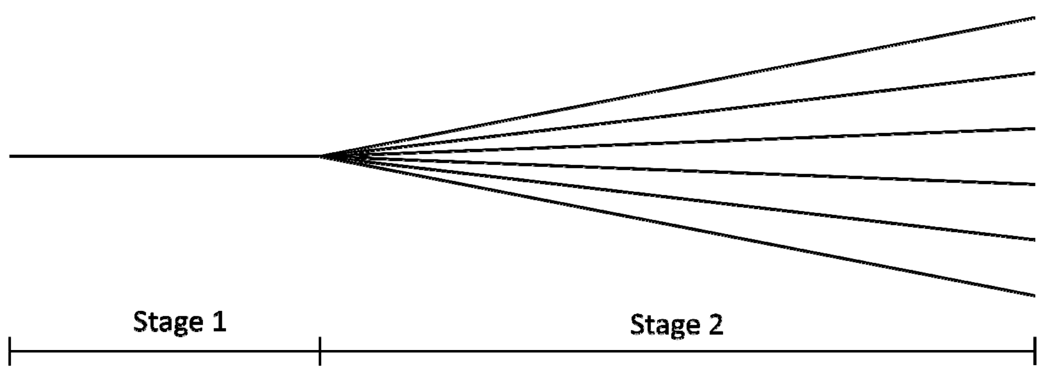


Figure 15 – Two-stage scenario tree.

The constraint is specified as:

$$u_{ihs} = u_{ih} \quad \forall\, s\ \in\ NS;\ \ \forall\, i\ \in NGLS$$

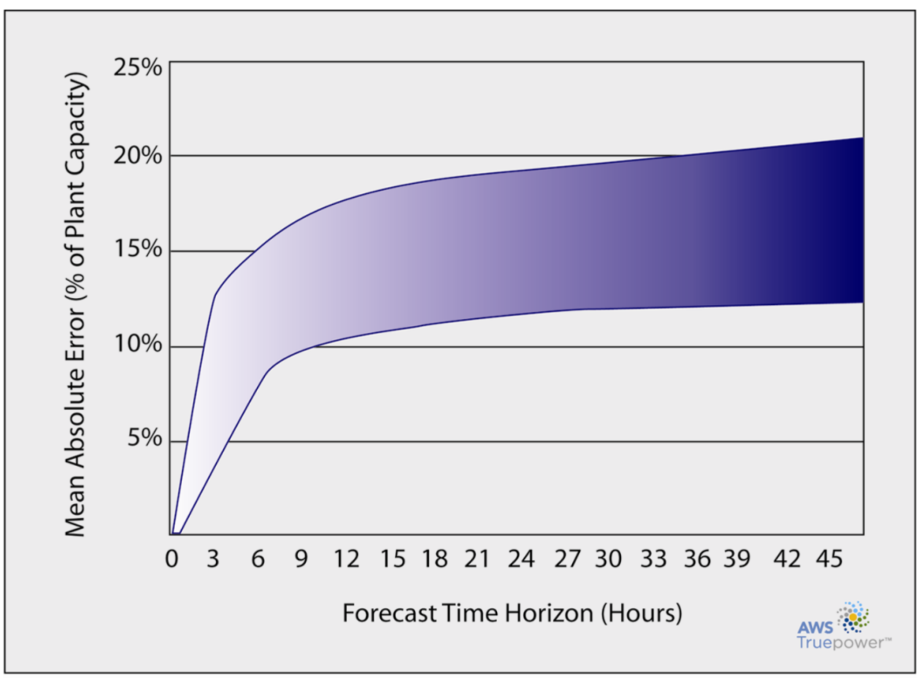
where NGLS is the set of generators with long start times. This ensures that one single-unit commitment solution is made robust toward multiple solutions. When different outcomes occur in real-time, the system is already built to meet conditions reliably, and because costs are reduced for all scenarios, it will be met efficiently as well.

The main issue with stochastic SCUC is its computation times. For increases in the number of scenarios, computation times increase as well. Scenario reduction techniques have been researched as well to help reduce computation times. However, reduction in scenarios may cause a reduction in accuracy and efficiency. It is likely that research will continue in this area, and that sophisticated programs will eventually be able to solve the stochastic unit commitment problem in reasonable computation times.

Rolling unit commitment

Generally, in the U.S. market regions, there is a day-ahead market and a real-time market. The day-ahead market runs the SCUC program and the real-time market runs the SCED program. Unit commitment is considered fixed after the day-ahead market solution is complete. This is identical to how production cost simulation models are run for wind power integration studies. However, many resources have start times of only a few hours and therefore would be able to change the commitment decision any time throughout the day.

Figure 16 shows wind forecast errors as a function of the forecast time horizon. As one would guess, forecast errors are generally higher as one looks further ahead in time. When decisions are made closer to real-time, those decisions may be more efficient than if they were made further ahead in time. Some research has looked at using rolling unit commitment strategies, where the unit commitment solution can be adjusted on frequent intervals throughout the day. The unit commitment process would have the opportunity to change the previous commitment decision for any one generator if its start time has not exceeded the time horizon needed if it is initially on and is to be turned off, or if its start time is not less than the time horizon needed if it was initially committed and is to be turned on. This strategy could further facilitate the integration of wind power by increasing the efficiency of unit commitment and reducing integration costs.



Approximate range of Mean Absolute Error (MAE) for increasing forecast time horizons for AWS Truepower's Hour-Ahead (0-8 hours) and Day-Ahead (9-48 hours) forecasting services

Figure 16 − Forecast errors (mean absolute error) as a function of time horizon (courtesy of AWS Truepower).

Sub-hourly time resolution

The original application of these production cost simulation tools was made for hourly scheduling resolution. Hourly averages of wind generation and load were used and their hourly variability had to be met by the system resources. This means that ramp rates on conventional units were limited by hourly rates. Any errors or variability inside an hour are ignored in the simulation runs. Instead, the common technique is to use statistical analysis to determine an amount of operating reserve that can be used to meet the within-hour variability and uncertainty.

It is unclear as to whether the statistical analysis is capturing the integration impacts of wind power that would occur within the hour. It is likely that sophisticated simulations would validate the analysis. Many of the studies have discussed the use of sub-hourly scheduling that can help facilitate the integration of wind. Rarely can the studies show detailed quantitative results on these benefits. More research is needed to model power system behavior and response to better replicate the U.S. energy markets, most of which operate at intervals as fast as five minutes.

Transmission analysis

As discussed, models that are run in wind power integration studies may have different representations of the transmission system. Some studies ignore the transmission system, others model the system as a transportation model that allows as much power to go in any direction under the transfer limits given, and some finally will use a dc power flow representation. It is very rare for production cost models to model the transmission system using an ac power flow, which gives an actual representation of power flow on the system. Generally, dc power flow is a good approximation and errors are usually less than 5%. DC power flow ignores reactive flow on transmission lines and assumes all voltage magnitudes on the system to be 1 per unit. DC power flow also ignores resistances on lines when solving the power flow. Generally, reactive flow, which can increase total current on the line, is fairly small compared to real power. Voltage magnitudes are also generally pretty close to 1 per unit. Resistances are usually quite small compared to reactance of the line. Therefore, dc power flow is a very good approximation and because it ensures a linear problem, keeps computation times reasonable compared to using ac power flow, a non-linear problem. Differences in how dc power flow is modeled and how ac power flow is modeled and how transmission flow is calculated can be seen in the following general equations.

DC power flow equation:

$$\boldsymbol{P}_i = [B'_{i,j}] * \boldsymbol{\theta}_j$$

DC line flow calculation:

$$P_{ij} = \frac{\theta_i - \theta_j}{x_{ij}}$$

AC power flow equation:

$$\boldsymbol{P}_i + j * \boldsymbol{Q_i} = \overline{\boldsymbol{V}_i} * \{[\overline{Y_{ij}}] * \overline{\boldsymbol{V}_j}\}$$

AC line flow calculation:

$$P_{ij} + j * Q_{ij} =$$

$$|V_i|^2 * (g_{ij} + j * b_{ij}) - |V_i| * |V_j| * [cos(\theta_i - \theta_j) + j * sin(\theta_i - \theta_j)] * (g_{ij} - j * b_{ij})$$

where P = real power; Q = reactive power; B' is the dc power flow admittance matrix; $\overline{Y_{ij}}$ is the complex Ybus admittance matrix; θ = the voltage angle; |V| and $\overline{\boldsymbol{V}_i}$ are the voltage magnitude and complex voltage, respectively; x = reactance of the line; g = the conductance of the line (inverse of resistance); and b = susceptance (inverse of reactance).

The difference in linearity and non-linearity and complexity can be seen from these equations. The assumption that dc power flow is a good approximation of system conditions is very much based on current system flows. Changing of flows due to variation in wind can possibly change this assumption. In dc power flow, losses on transmission lines are also approximated since losses are also non-linearly dependent on the line current. Since wind power can be sited in locations distant from the load and line losses increase with distance, it is very important that system losses with high penetrations of wind be correctly modeled. It is expected that more research on how to better model power flow simultaneously with SCUC and SCED will be ongoing, and better assumptions on how the system will be modeled for wind power integration studies will be discovered.

Most studies generally analyze the power system's steady state behavior. Other impacts can occur on a more dynamic time frame. More studies are attempting to analyze the system at all time frames including system frequency response. Wind turbines do not have physical capabilities of providing inertia[10] to the system as do synchronous machines. Therefore, it is important to analyze system frequency response with high penetrations of wind to analyze predicted behavior and determine appropriate mitigation procedures if issues arise.

Operating Reserves

Current practice for power system operation involves carrying reserve capacity to ensure a reliable and secure system. In the United States, operating reserves are typically separated into contingency reserve and regulation reserve. Contingency reserve is generally used for system failures and usually a BA will make sure it has enough to withstand the largest single contingency. Regulation reserve is used to keep system frequency stable and BA-ACE close to zero. The amount of regulation reserve usually carried is based on meeting NERC Control Performance Standards in North America. These reserves are based on current variability and uncertainty on the system and most experts agree that the types and amounts of these reserves will change with higher penetrations of wind power. For instance, reliability events due to wind power changes do occur, but the speed at which they do is on a different time scale than that of generation contingency and therefore the same rules generally don't apply.

[10] At least one turbine vendor has developed a method of simulating physical inertia via software controls on the turbine.

Most wind power integration studies put a lot of effort into analysis on quantifying reserve requirement increases due to wind. Methods are evolving with each study and with wind power penetrations of up to 30% of total energy, current methods used today cannot be used anymore. One basic assumption is that the amount of operating reserves with higher wind penetrations must be made based on meeting the same level of reliability as today.

In the United States, the first two large scale wind power integration studies were performed in New York State and Minnesota. Both of these had extensive analysis on determining operating reserve increases. In New York, the study evaluated 3,300 MW of wind power on the 33,000-MW peak load NYISO system (see GE Energy, 2005). The study concluded that no incremental contingency reserves would be needed since the largest single severe contingency would not change. The study then concluded that an additional 36 MW of regulating reserve was required on top of the current 175 to 250 MW procured today. This is a result of analyzing the standard deviation of 6-second changes in load net of wind compared with that of load alone. The standard deviation with wind increased from 71 MW to 83 MW, presenting a 12 MW increase that was multiplied by three to achieve 99.7% confidence. In Minnesota, a study (EnerNex, 2006) evaluated 15, 20, and 25% wind energy as a percentage of total annual demand (3441 MW, 4582 MW, and 5688 MW on a system with a peak demand of roughly 20,000 MW). Similar to New York, it was concluded that there would be no impact on contingency reserve requirements with the added wind penetrations. The regulating reserve requirement similarly evaluated the added variability of wind, but calculated it to be a 2-MW standard deviation for every 100-MW wind plant installed. This calculation was based on operational data from existing wind plants. The ratio was used to calculate the regulating reserve requirement as seen in the following equation:

$$Reg\ Req = k\sqrt{\sigma_{load}^2 + N(\sigma_{W100}^2)}$$

where k is a factor relating regulation capacity requirements to the standard deviation of the regulation variations (assumed to be 5 in this study reflecting current practices); σ_{load} is the standard deviation of regulation variations from load; σ_{W100} is the standard deviation of regulation variations from a 100-MW wind plant; and N is the wind generation capacity in the scenario divided by 100. The results showed increases of 12, 16, and 20 MW for the 15, 20, and 25% cases, respectively. The Minnesota study quantified two other defined categories that the New York study did not. In the Minnesota study, these are defined as load following and operating reserve margin. These categories are not usually defined in current system procedures and unique methods were used to determine how variability and uncertainty of wind impacted their results.

Most recently, three large regional wind power integration studies have been performed for the WestConnect footprint of the Western Interconnection, the Eastern Interconnection, and the Southwest Power Pool (SPP). Each of these produced highly sophisticated engineering techniques to determine additional operating reserve needs on its system. We discuss each of these methods below.

In WWSIS, the team used the term variability reserve to note the capacity that must be available to meet the increased variability apparent from wind power. The team analyzed

10-minute wind net load data and compared its variability to that of load-alone data. The team investigated how different wind penetrations and load levels influenced the total net load variability on the system. Three standard deviations of this variability were then used and simple formulas based on wind and load levels were created to achieve the reserves needed. For example, Table 5 shows these rules for the 30% wind, local priority scenario. For each area, variability reserves were calculated based on a percentage of hourly forecasted load, plus a percentage of hourly wind forecast up to some level of wind. Once above that level of wind, it was seen that variability reserves did not need to increase as wind power was increased. The project also looked at more non-linear functions that better represented statistical distribution of variability.

Table 5 – WWSIS reserve rules for 30% local priority scenario.

	Load Only	30% LP Scenario		
	(% of load)	Load Term (% of load)	Wind Term (% of wind production)	up to (% of wind nameplate)
Footprint	1.3	1.1	5	47
Arizona	2.2	2.2	5.6	36
Nevada	2.1	1	10.7	54
Colorado East	2.4	2	5.7	68
New Mexico	2	3.1	3.5	70
Wyoming	1.3	2.7	8.7	33
Colorado West	1.8	3.1	7.3	100

In EWITS, reserve requirements were determined slightly differently than WWSIS. The team basically showed increases in two types of operating reserves, with contingency reserves remaining based on the largest single contingency for each region. For regulation reserves, the minute-to-minute variability of wind that had been the main driver of the requirement in past studies was deemed to be insignificant because of geographic diversity impacts of the large geographic scope of the study area. However, it was noted that because economic dispatch signals that are created and sent to generating units every five or ten minutes cannot be changed inside those same five or ten minutes. Therefore, any forecast errors made with each dispatch signal must be met with regulation reserves. The team then calculated the amount necessary by assuming that 10-minute persistence forecasts were used. The actual requirements also took note that these errors were larger at different percentages, mainly towards the 50% portion and therefore a function was used that depended on the hourly wind production by hour. Three standard deviations of this value were used and the totals were geographically added with the regulation required due to load, because of their lack of correlation. Lastly, an additional reserve requirement was used for the hour-ahead forecast errors. This was also an hourly function of wind, but only one standard deviation was required to be spinning reserve due to its slower response requirement. The full EWITS methodology can be seen in Figure 17.

Reserve Component	Spinning (MW)	Nonspinning (MW)
Regulation (variability and short-term wind forecast error)	$3 \cdot \sqrt{\left(\frac{1\% \cdot HourlyLoad}{3}\right)^2 + \sigma_{ST}(HourlyWind)^2}$	0
Regulation (next-hour wind forecast error)	$1 \cdot \sigma_{NextHourError}\ (PreviousHourWind)$	0
Additional Reserve		2 × (Regulation for next hour wind forecast error)
Contingency	50% of 1.5 × SLH (or designated fraction)	50% of 1.5 × SLH (or designated fraction)
Total (used in production simulations)	Sum of above	Sum of above

Figure 17 – EWITS reserve methodology overview.

In the SPP Wind Integration Task Force (WITF) Integration Study, the reserve determination methodologies were unique once again. The study evaluated reserve requirement needs for regulation reserves, load following reserves, and contingency reserves. For regulation reserves, the team explicitly used the NERC-CPS2 standard to determine the increases. [11]Therefore, to equate to the 90% compliance requirement of CPS2, the 5th and 95th percentiles were used as the requirement boundaries. Also, because ACE is out of compliance only if the ten-minute average is above the BA-L_{10}, this is taken into the overall equation of determining the requirement. The overall equations are shown below:

$$R_{up} = \sqrt{(0.01 l_{peak} + L_{10})^2 + a\Delta W_{95}{}^2} - L_{10}$$

$$R_{down} = \sqrt{(0.01 l_{peak} + L_{10})^2 + a\Delta W_{5}{}^2} - L_{10}$$

Where l_{peak} = peak load; a is a calculated coefficient, and ΔW are the respective percentile of ten-minute deltas. Figure 18 shows the regulation requirements for peak days. Like in the other two studies, the project team proposes that regulation requirements be dynamic and are time varying based on system conditions. The study also recommends the possibility of a load following reserve requirement and provides analysis on some of the ramping requirement increases in this time frame. Lastly, the contingency reserve requirement was not changed for the study, but it was recommended that it be reevaluated if extensive high-voltage transmission expansion occurs needed to transfer high penetrations of wind power from remote locations.

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[11] An alternative approach is under consideration and is receiving field trials in WECC. See NERC, 2009.

Season	Peak Load	Case	Wind Short-Term Variability			Regulation Requirement	
			ΔW_{95}	ΔW_5	Std Dev	Up	Down
Winter	33,237	Base	51	49	31	338	338
		10%	114	107	67	357	360
		20%	216	206	129	417	425
		40%	381	362	228	562	581
Spring	37,169	Base	62	59	37	379	379
		10%	130	122	78	401	405
		20%	237	225	141	465	474
		40%	407	390	242	617	635
Summer	45,822	Base	68	64	41	465	466
		10%	140	131	84	487	491
		20%	251	235	148	546	557
		40%	422	397	249	684	710
Fall	36,621	Base	52	50	31	371	372
		10%	116	110	68	390	393
		20%	218	208	129	448	455
		40%	383	363	228	586	606

Figure 18 − Total regulation requirements for seasonal peak loads (MW).

These three studies have opened new doors on how system operators think of operating reserves. All propose time varying requirements, which differ from how systems act today. Different reserve types have been proposed that are not currently part of standards or common operating practice. Many other new methods have been proposed as well in other integration studies, for example Makarov et al, (2008). Even though there are commonalities between the approaches, it is very interesting to see methods that differ. More work should examine the strengths and weaknesses of different methodologies. Simulations that model sub-hourly and sub-minute market operations that attempt to replicate operator actions when deploying operating reserves with high wind penetrations should help validate the various methods. Having enough reserves is never really the issue since additional generation can always be committed. The real question is how to use the information available to determine the efficient amount of operating reserve for a given situation to keep a certain pre-defined reliability level. It may be appropriate to ignore current standards and start from scratch to discern the most optimal standards to maintain a reliable system. Some of the examples of further research questions we recommend are listed below. The full list, however, is much longer. An example of how different operating reserves may look and relate to each other is shown in Figure 19.

Examples of further operating reserve analysis:

- What is the right level of spinning vs. non-spinning reserve for the different categories? (Tradeoff between high standby cost of spinning reserve vs. high utilization cost of non-spinning reserve)
- Can certain reserves be shared or should specific causes trigger each reserve type?
- What is the correct response time of non-spinning reserve?

- When is it appropriate for load following reserves to have specific requirements rather than allow them to be met through energy markets?
- How to determine a specific requirement for frequency responsive reserve? Is there a need for it?
- What are the true causes of regulation reserve? (short term uncertainty vs. variability)
- What are the appropriate standards for regulation reserve requirements? (the current CPS or the new proposed Balancing Authority Area Limits (BAAL) or others)
- Should ramping reserve requirements require a response time that is a function of ramping predictions or static responses?

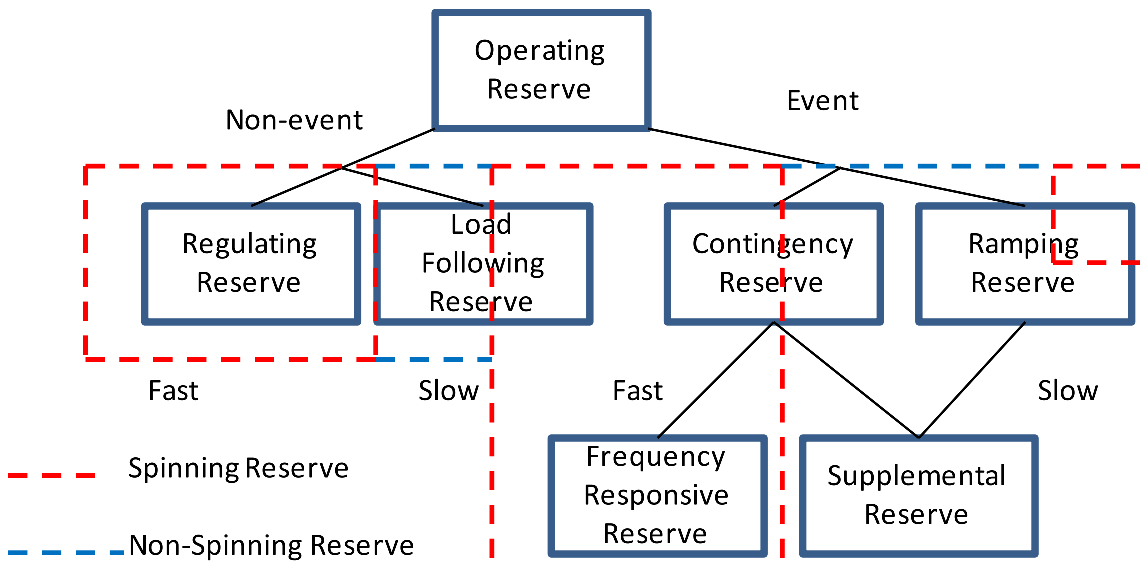

Figure 19 – Example of operating reserves on a system with high wind power penetrations.

Integration Cost

Many wind integration studies have examined the issue of wind integration cost. These studies typically have had an objective of attempting to determine how the increased variability and uncertainty of wind translates into increased operating costs. Sometimes the objective has been to compare these costs to a benign generating unit that has neither variability nor uncertainty. In a pure sense, such a unit does not exist. As a result, various types of theoretical benchmark units have been proposed, most of which have been some form of flat energy blocks that are equivalent to wind energy over some agreed upon time period (such as a daily-equivalent block of energy).

In this section, we discuss the issue of integration cost, and whether wind is the only technology that might impose additional variability or uncertainty on the power system. We also discuss shortfalls that have been identified in recent analysis.

Other generating units may impose an integration cost by altering the efficiency of other plants.

Wind integration costs generally consist of the cost associated with increased cycling and additional reserves that must be provided by other generators. For example, a thermal unit that increases its cycling to help accommodate the wind will typically perform less efficiently, using more fuel per unit of output. The additional cycling duty may also result in increased operations and maintenance cost, and potentially a shorter useful life.[12] This has been identified in Milligan and Kirby (2009).

Because of the many complex relationships between units in the commitment and dispatch stacks, and the requirement that loads and resources must be balanced, a new entry into the generation fleet may cause changes in the way that one or more incumbent units are operated, imposing additional cycling, wear and tear, and reduced efficiency. Consider the following simplistic example.

A power system has two types of generators; one is base loaded and the others are cycling units. A sample daily dispatch curve appears in Figure 20. The baseload generation never changes its output, incurring no cycling costs or efficiency losses.

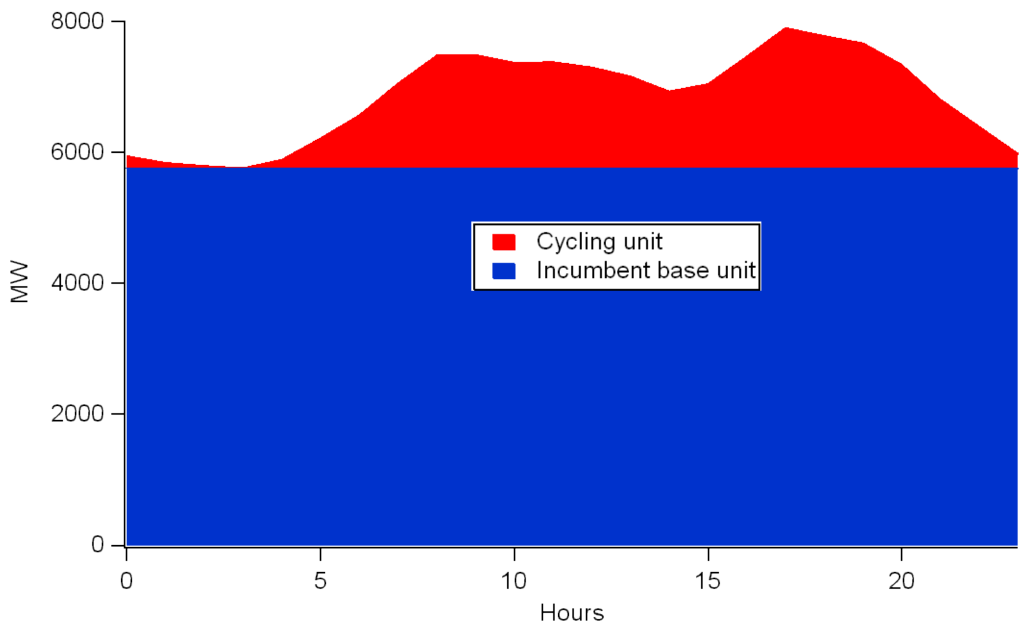

Figure 20 − A simple system with generation lumped into two categories: incumbent baseload and cycling units.

Starting with this simple scenario, we now add a new fleet of base-load generation that is less expensive than the incumbent baseload units. This changes the merit order in the economic dispatch stack. The new, less expensive generation is dispatched first. This moves

[12] The wear-and-tear cost of additional deep cycling is widely acknowledged, but little if any public data are available to inform analysis.

both of the incumbent units up the stack, reducing the capacity factor (and revenue) and reducing efficiency. Excess cycling may impose additional wear and tear on the incumbent baseload units.

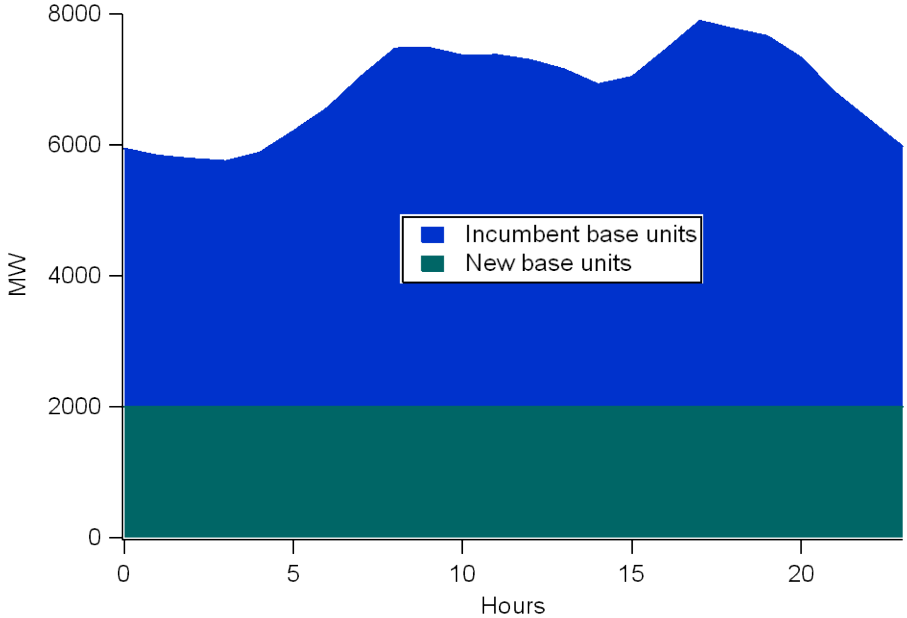

Figure 21 − After introducing new, lower marginal-cost units, the incumbent generation now begins to cycle, and the incumbent cycling units are out of market.

Into this simple example, we introduce some parametric costs to illustrate the concept. If the incumbent base units were selling energy at $50/MWh before the new competition arrived, and assuming that it would continue to sell at $50/MWh after reducing its output, it would lose revenue. Depending on the efficiency losses, its generation (fuel) cost would be higher per-unit of output, imposing another cost.

We capture this in Table 6, which shows the two cases: before and after introduction of new baseload competition. In keeping with the simple nature of the example, the incumbent base generation receives the same price in both cases. We also calculate potential efficiency cost at two levels: $2.00/MWh and $5.00/MWh. The actual efficiency cost may be higher or lower, depending on the frequency and depth of cycling, heat rates, and other unit properties.

Table 6 − Hypothetical example of integration cost of baseload generation.

	Case 1	Case 2
Energy Revenue	$6,907,200	$5,822,800
MinGen (MW)	5756	3756
Variability (COV)	0.0	14.6
Cycling/Efficiency cost		
at $2/MWh	$0	$43,376
at $5/MWh	$0	$108,440
Net Revenue		
at $2/MWh	$6,907,200	$5,779,424
at $5/MWh	$6,907,200	$5,714,360
Capacity Factor (%)	100.0	82.3

Flat proxy

Most, if not all, integration studies that calculate wind integration cost use a flat-block proxy resource for the no-wind case. The method develops the proxy resource by calculating the wind energy-equivalent for each day of the study, and then inserting this daily flat energy block at zero cost into the dispatch stack. Since the block has no variability or uncertainty during its 24-hour lifetime, it has been used as the no-wind case by which wind integration cost can be calculated. Integration cost is then the difference in total operating cost between the wind case and the flat-block proxy case, divided by the wind energy in MWh to obtain a cost per MWh.

Applying the flat-block proxy in EWITS revealed significant problems with that approach. To be fair, this method was developed to answer a particular question about wind integration: How much does incorporating wind's additional variability and uncertain cost affect the system operator? As more studies have been performed that look at higher wind penetrations, the usefulness of this metric and approach appears to have become limited. In EWITS, there were extremely large transitions between days whenever wind output changed as a result of a large frontal passage or other significant change in daily wind energy.

Milligan and Kirby analyzed the performance of alternative proxy resources, including various flat block durations, and found that at high wind penetrations they all imposed a significant artificial ramp during the intra-block transition. Wind integration studies up through 2009 that used flat proxy resources used 24-hour blocks, which have extremely high intra-block proxy ramps. Figure 22 is adapted from that work, and shows that both the daily block and 6-hour block have much higher extreme ramping behavior than wind.

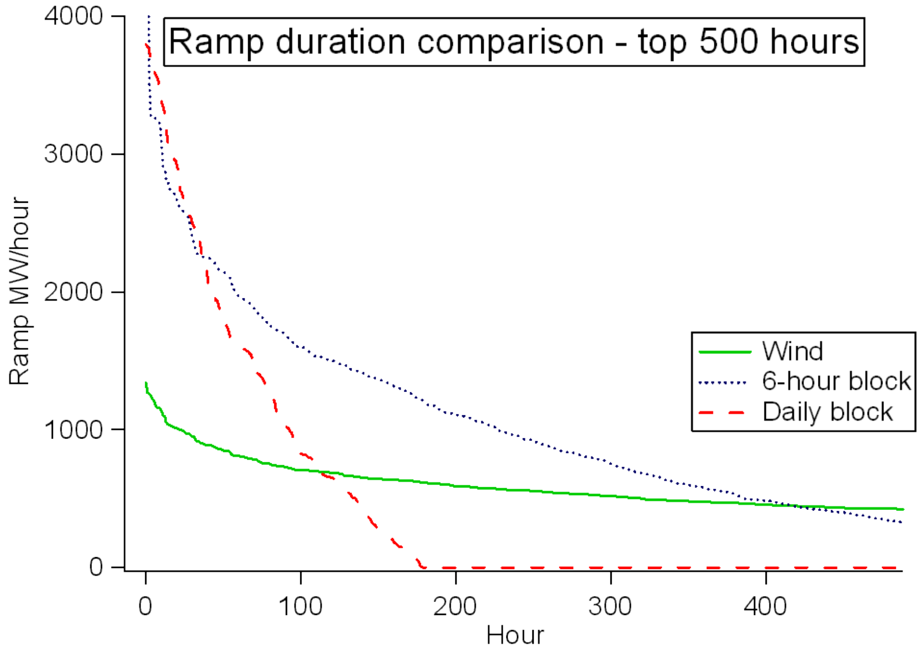

Figure 22 – 24-hour and 6-hour flat blocks introduce large positive artificial ramps to the proxy resource.

A similar impact is seen with large negative ramps, as shown in Figure 23

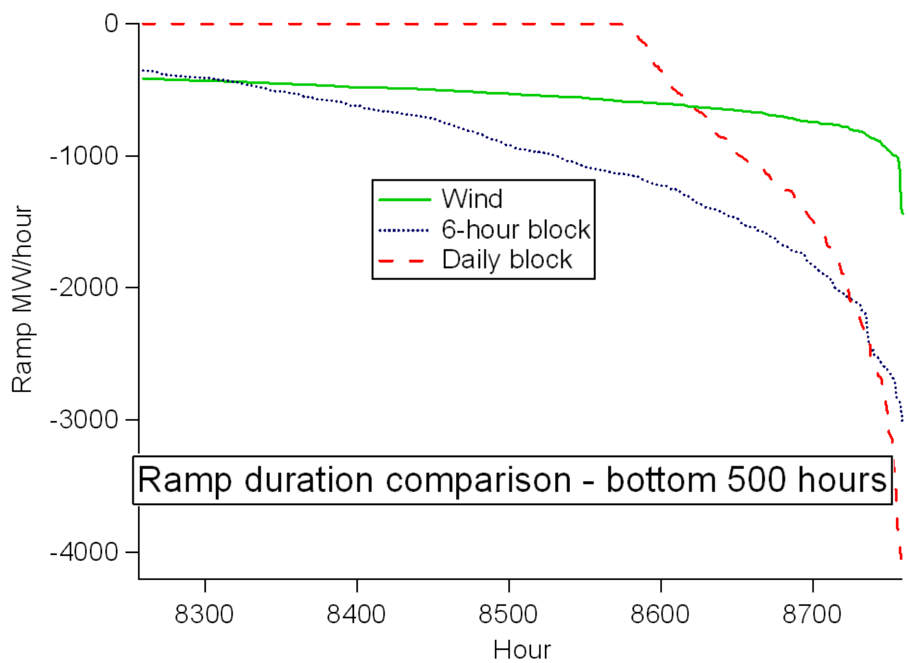

Figure 23 – Large negative ramps also appear in flat proxy resources.

There are also concerns regarding the intermixing of value with cost. These are also detailed by Milligan and Kirby (2009). Because of the timing of wind energy delivery, it will likely have a different (lower) value than the proxy resource. In that eventuality, part of the differential in production cost between the wind as-delivered and the proxy resource will be caused by this value differential, and is not the same as the cost of additional reserves or efficiency.

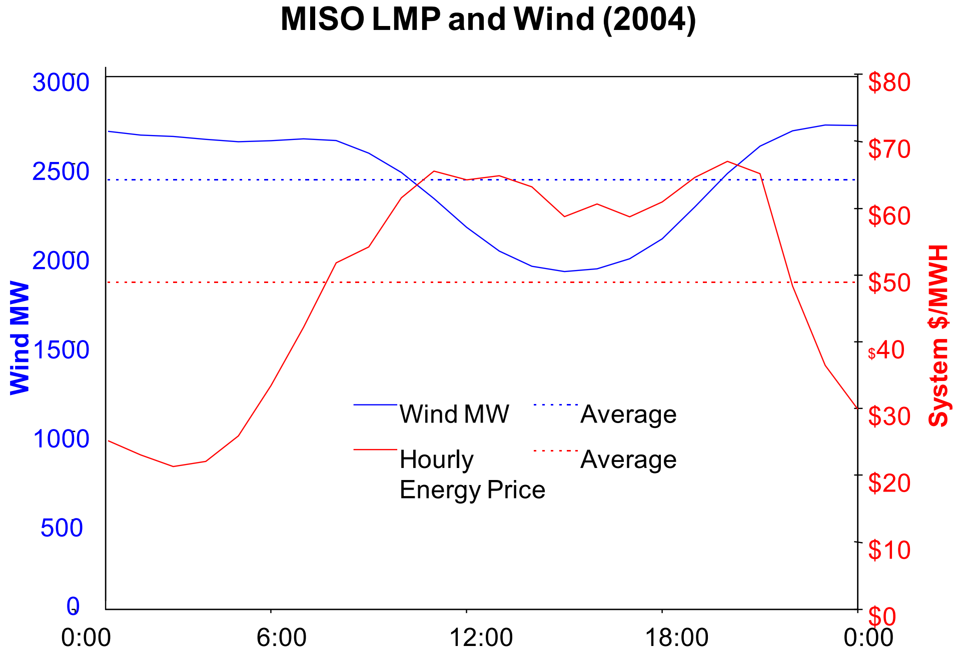

Figure 24 − Prices from the Midwest Independent System Operator and wind data show the average diurnal value swing of wind energy (Milligan and Kirby, 2009).

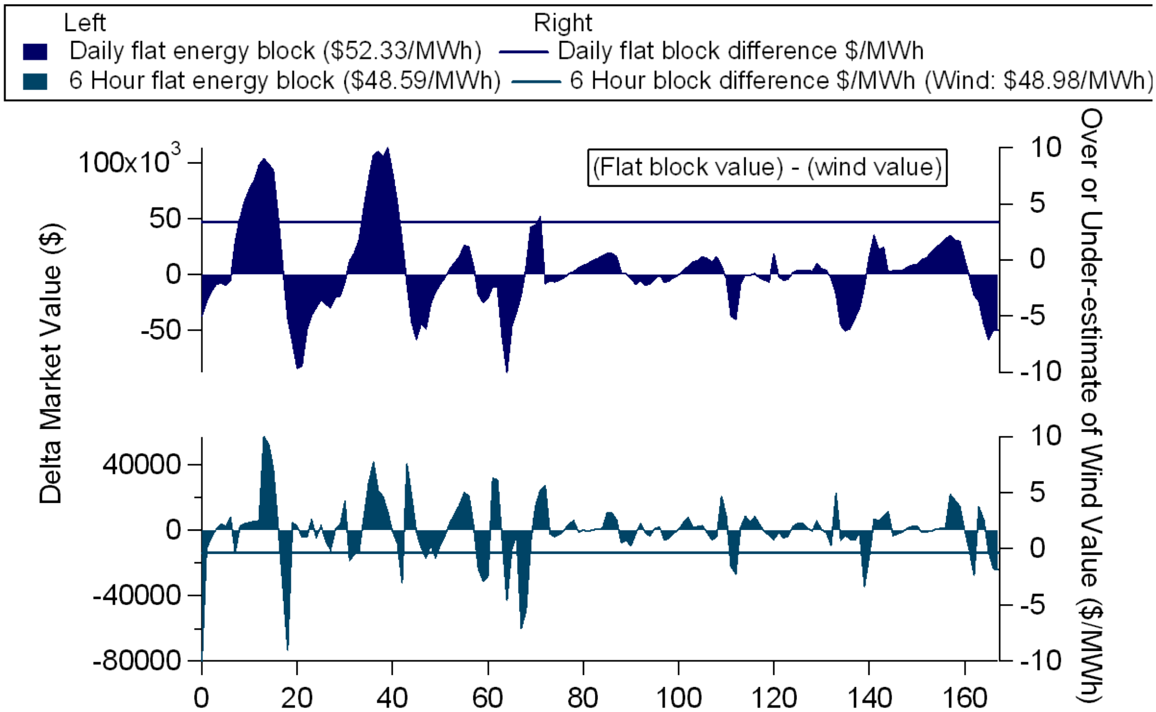

Figure 25 − Comparison of 24-hour flat block proxy with 6-hour block proxy (adapted from Milligan and Kirby, 2009).

A further concern arose with EWITS. Because of the high penetration of wind analyzed, some regions found it economic to secure additional ancillary services from adjacent areas. This occurs often in areas that have electricity markets. Area *A* has a need for ancillary services that it could provide itself, but area *B* can provide the services at lower cost. *A* pays *B* for the service. *B* incurs additional operating cost because it may have moved generation units to less efficient points on the heat rate curve, or incurred more ramping, both of which come at a cost. However, these costs were compensated by *A*. But when integration costs are tallied across a multi-region footprint, there may be no recognition that *B* benefited by making a sale, and the benefit from the revenue stream was not counted in the integration cost.

For this and other reasons, it may be time to move in a new direction. Because of the difficulty in assessing wind integration cost (compared to what?) and because it can be difficult to untangle costs from benefits, it may be time to assess total operational cost with and without wind. Of course this comparison will be complicated in cases that have different generation mixes. The flat-block comparisons, although problematic, have provided significant insights into wind integration impacts and costs. A full accounting of all operating costs, assuring that the system is reliable and secure and that the modeling is realistic, encompasses all such costs of integrating wind.

Not all conventional generators can follow control signals.

Some generators have difficulty following an automatic generation control (AGC) signal, which is sent to AGC units to provide frequency regulation. In cases like this, the generator can actually increase the need for regulation instead of providing helpful regulation. This imposes an integration cost on the system that is rarely, if ever, assessed. Figure 26 illustrates two coal units in the Midwest. The unit in the left panel of the graph does a good job in following the AGC signal, whereas the unit on the right imposes a 31 MW regulation burden for this hour because of its inability to follow the AGC signal.

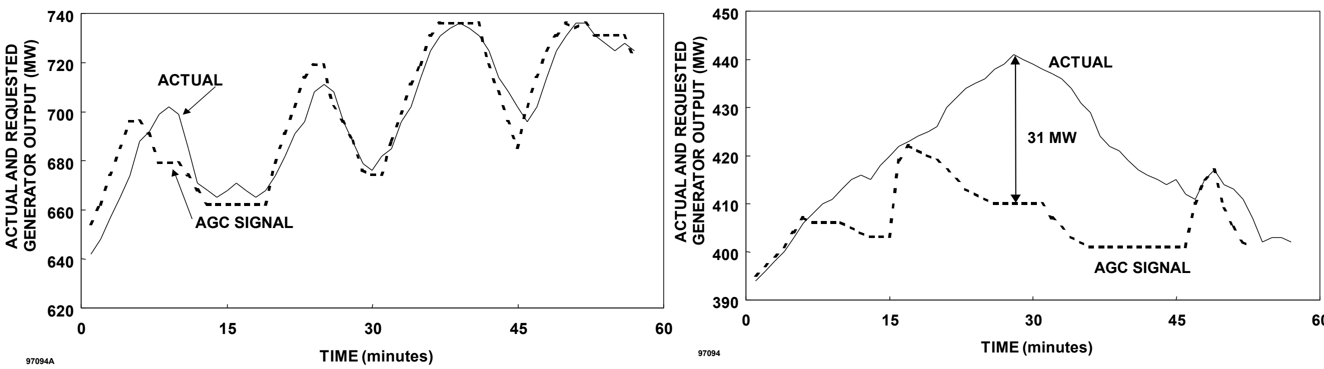

Figure 26 − The coal unit on the left provides regulation to the system, whereas the unit on the right cannot follow AGC and imposes an additional 31 MW of regulation during this hour.

Market Considerations

Milligan and Kirby (2010) analyze the role of energy markets in helping to integrate variable generation. A complete discussion of that work is outside the scope of the current paper, however it is worthwhile to extract key points from that work and show the relevance to wind integration analysis.

Fast energy markets, operating at 5-minute intervals, allow variability in load, wind, and other variable generation to be managed with a potentially large fleet of generation. The economic dispatch calls upon units that are economic to move to new operating points, increasing or decreasing output as needed. At each of these time steps, units on AGC that are providing regulation can move back to their preferred operating points near the middle of their respective operating ranges. Conversely, when the dispatch is changed only once an hour, the economic dispatch stack is constrained and all of those units will keep their position until the top of the next hour (allowing time at the top of the hour for units to ramp into their new position).

Current practice in integration analysis typically involves a statistical analysis of wind and load data, respecting the chronology by using synchronized data, focusing on time steps that include sub-hourly (5 or 10 minutes) to days, weeks, or even months. Usually the sub-hourly analysis is done to complement the hourly production simulation. Therefore, the operation of a fast market is often beyond the resolution of the production model, since those models rarely have the ability to run at a faster time step. At this point it is likely that the combination of tools comes quite close to representing economic dispatch, load following, and regulation requirements, although it is also possible that models will evolve to run at relevant sub-hourly time steps.[13]

As shown in Milligan and Kirby, fast energy markets can often supply needed ramping capability, which is a capacity service, at little or no cost. However, there are times that the units on economic dispatch may not have sufficient response capabilities to ramp quickly enough, and an out-of-merit dispatch of a fast-start unit may be required to supply the ramp. A simplified diagram appears in Figure 27. The figure illustrates a case that has insufficient ramping capability online, causing a peaking unit to follow the ramp until the baseload capacity can catch up. The peaking unit sets the price for the hour. In such cases, it might be beneficial to design a load following market as a supplement to the energy market. It would not be necessary to invoke the load following market at all times, because sufficient ramping capability may be available much of the time. In cases where ramping supply is limited, the load following market could be used to procure more, without distorting the energy price.

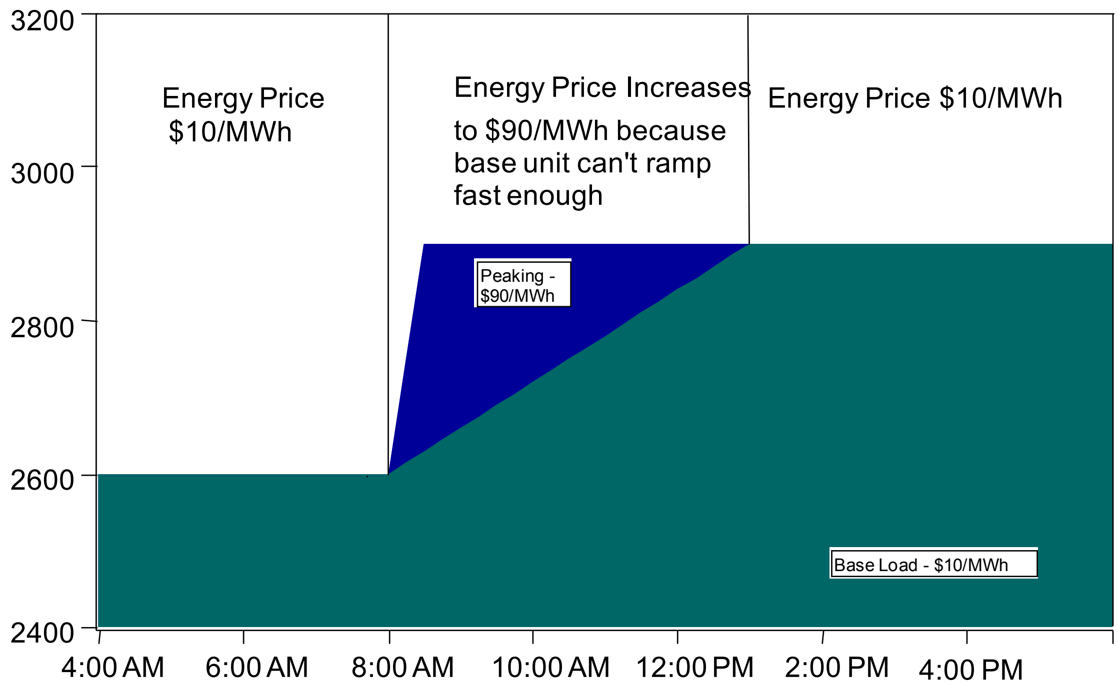

Figure 27 − Insufficient ramping capability from the dispatch stack may result in peaking response which could set the energy price for the period.

Other concerns regarding the sustainability of existing energy markets at high wind penetration rates may be more important. The low LMPs that are often seen in wind integration studies are not due solely to wind; they are exacerbated by the inability of baseload

[13] At the time of this writing, WECC is investigating whether its hourly production simulation model can be "tricked" into running at a faster time step if it is provided with appropriate input data.

units to move to a lower generation level or shut down. During high-wind and low-load times, this situation causes an excess of generation and consequently low or negative prices. With a different non-wind generation mix or transmission infrastructure, this situation might be alleviated. Will the markets successfully encourage a workable generation mix that is sustainable economically/financially? Is there a need for more targeted markets for ramping products?

Summary and Conclusions

Wind integration analysis has progressed significantly in the last several years. Advances in wind data development, reserves modeling, operational analysis, incorporating sub-hourly information into hourly models, and performing unit commitment based on forecasts have all enhanced our collective knowledge about integration. New advanced methods that include rolling stochastic unit commitment, and introducing ramp constraints and other factors into unit commitment algorithms will further improve the quality and accuracy of the analysis. Further work in variability reserves, incorporating sub-hourly constraints into hourly models, developing models with sub-hourly economic dispatch, improved methods for simulating actual wind power and forecasted wind power, and continued validation of datasets are needed. A detailed analysis of generation expansion model characteristics and need may lead to the development of new algorithms and models. All of these improvements will greatly enhance resource development, both wind and non-wind, and better transmission planning. Furthermore, with the anticipated increases in solar energy utilization and possibly other forms of variable generation, these improvements in methods should not be undertaken solely with wind in mind.

Further work is needed to either refine methods for integration cost analysis, or propose entirely new approaches with transparent accounting for the complex interactions among generating units. Additional work is also needed to understand the complex interactions between transmission build-out, resource mix, BA size, and markets.

Markets cover a large fraction of the U.S. power grid, and much valuable experience has emerged from operating the various markets over the past several years. However, questions remain about whether the markets in their current form will support needed services and provide market signals that will induce an economically efficient level of flexibility in the long-term with significant levels of variable generation like wind. There may be a need for a supplemental ramp product so that energy prices are not severely distorted during fast ramps. Hypothetically, very low LMP's over a significant fraction of the year will induce generation developers to favor flexible units, with a disincentive to overly-develop baseload generation. Whether this is realistic remains to be seen.

Finally, it is critical to improve, update, and keep current the existing public wind databases developed from NWP models to help inform the critical decision-making that must occur over the next decade if the nation wants to pursue a future with significant quantities of wind energy.

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