Integration Costs: Are They Unique to Wind and Solar Energy?

Preprint

Michael Milligan and Bri-Mathias Hodge
National Renewable Energy Laboratory

Brendan Kirby
Consultant

Charlton Clark
United States Department of Energy

To be presented at the American Wind Energy Association Conference, WINDPOWER 2012
Atlanta, Georgia
June 3-6, 2012

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Conference Paper
NREL/CP-5500-54905
May 2012

Contract No. DE-AC36-08GO28308

Available electronically at http://www.osti.gov/bridge

Available for a processing fee to U.S. Department of Energy
and its contractors, in paper, from:

U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
phone: 865.576.8401
fax: 865.576.5728
email: mailto:reports@adonis.osti.gov

Available for sale to the public, in paper, from:

U.S. Department of Commerce
National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161
phone: 800.553.6847
fax: 703.605.6900
email: orders@ntis.fedworld.gov
online ordering: http://www.ntis.gov/help/ordermethods.aspx

Cover Photos: (left to right) PIX 16416, PIX 17423, PIX 16560, PIX 17613, PIX 17436, PIX 17721

Printed on paper containing at least 50% wastepaper, including 10% post consumer waste.

Integration Costs: Are They Unique to Wind and Solar Energy?

Michael Milligan (NREL), Bri-Mathias Hodge (NREL), Brendan Kirby (Consultant), and Charlton Clark, (U.S. Department of Energy)

Abstract

In the past several years there has been considerable interest and effort in assessing wind integration costs (solar integration costs have not been as rigorously pursued but this is expected to change with increasing solar energy penetration). This interest is understandable, because wind energy does increase the variability and uncertainty that must be managed on the power system. Measuring this integration cost can be challenging. In addition to wind and solar energy (and load), there are other sources of variability and uncertainty that must be managed in the power system. In this paper we describe some of these sources, which can include the performance of thermal plants. We also show that even the introduction of baseload generation can cause additional ramping and cycling, along with lower capacity factor, of at least some thermal units. The paper concludes by demonstrating that integration costs are not unique to wind and solar, and should perhaps instead be assessed by power plant and load performance instead of technology type.

Introduction

Wind and solar integration costs cannot be measured directly. Instead, at least two modeling cases are run, with and without wind/solar, and the costs are compared. This means that the "no wind" case definition is crucially important in any such analysis, and this is an area of significant disagreement among experts in this field. This paper summarizes a more extensive analysis in Milligan et. al (2011).

The concept of wind and solar integration cost is used to evaluate the *non-energy* cost of integration. This concept complicates the problem for three reasons.

(1) It is relatively easy to calculate the difference in total power system costs with and without wind and solar generation, but that difference tends to be dominated by the difference in the production cost of the wind and solar generation, which has no fuel cost, versus the cost of energy from conventional generation that burns fuel.

(2) A more explicit definition of integration costs is required;

(3) The "without wind/solar" case must be carefully designed. Because of the difficulties in untangling the many nonlinear impacts between generators and load, it may be impossible to calculate integration cost precisely.

Two schools of thought have emerged.

(1) Use a proxy resource, typically a flat energy block that is energy-equivalent to the wind/solar scenario and calculate integration cost as the difference between the nonwind/solar case and the wind/solar case, amortized over the megawatt-hours of wind/solar energy produced.

(2) It is not possible to develop a suitable proxy resource, and only total costs with and without wind/solar can be legitimately compared.

The difficulty is that production simulation cannot separate the cost of integration from the value of the wind/solar energy, as demonstrated by Milligan and Kirby (2009). Figure 1 illustrates the shortcomings of a common method of measuring integration costs. Two power production simulations are run. One simulation has the detailed time series of wind power, and the other simulation replaces the time series with a daily flat energy block, as depicted in the upper panel of the figure. Each daily energy value is equivalent to the daily wind energy. This approach provides a generating resource in the model that has no variability and no uncertainty. The figure, however, shows that the value of the flat energy block is significantly different than the wind energy, shown in the middle panel. In the lower panel, the figure shows that a 6-hour energy block comes closer to capturing the difference between the wind energy value and the flat block value, but differences remain

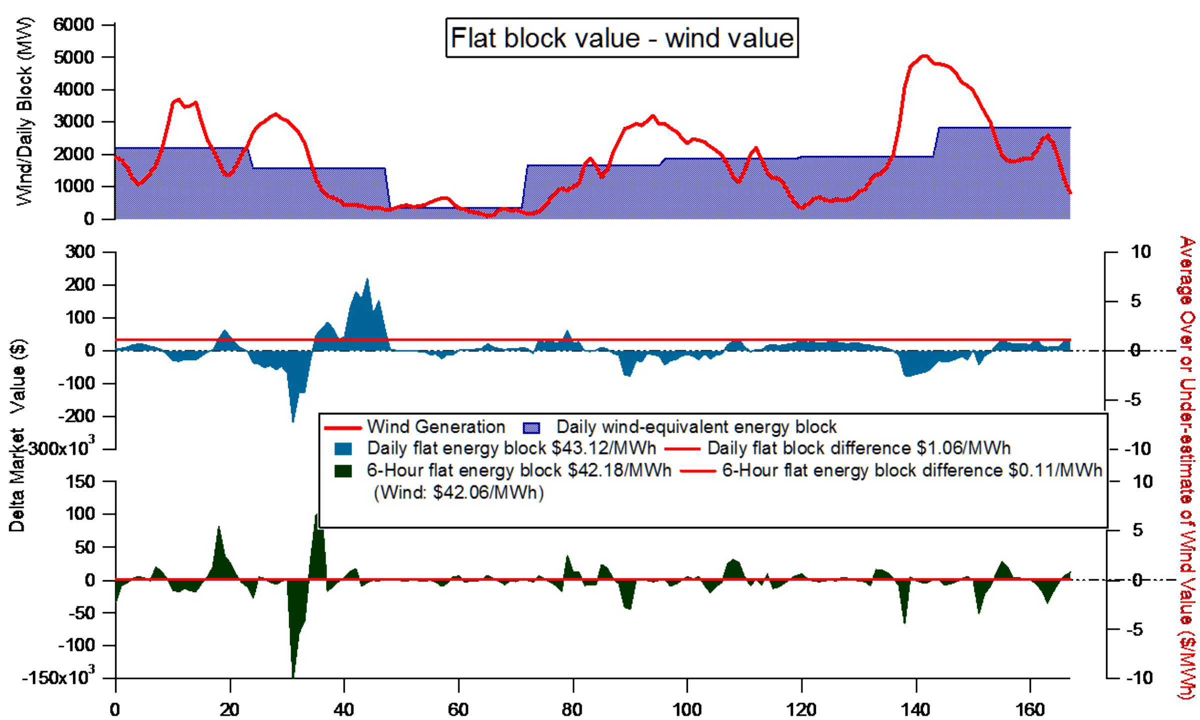

Figure 1. Using a daily flat energy block proxy to measure wind integration cost does not untangle market value from the cost impact on the conventional power plants.

Principles of Cost-Causation

Wind (and solar) integration cost analysis is predicated upon the notion of cost-causation. The principle says that the additional cost of operating the power system with wind/solar generation is caused by the wind/solar generation. Therefore, it is an integration cost. Although this is a very simple principle, it has some important implications.

(1) If the wind/solar generation is removed from the system, the integration cost would disappear.
(2) If wind/solar generation helps the system (for example by reducing costs elsewhere on the power system) then there should be a credit to the integration cost.

Furthermore, if integration costs are based on cost-causation, then it would follow that costs that are imposed by other technologies would then also incur an integration cost. We provide several examples in the following section.

Other Types of Generation Impose Integration Costs

Surprisingly, there can be integration costs imposed by conventional power plants and scheduling practices. We examine a few examples.

A coal plant that imposes a regulation burden

Some conventional power plants impose integration costs that are based on the inability of the plant to follow a regulation signal precisely. In that regard, this is similar to wind or solar power plants that respond to the variable wind or solar inputs, increasing the regulation needs of the power system.

Figure 2 compares the ability of two different coal units in the Midwest to follow an automatic generation control (AGC) signal. The upper panel shows a unit that follows the AGC signal quite well. The lower panel shows a unit that can't follow the signal. In fact, the second unit imposes an additional 31-megawatt (MW) regulation burden on the power system. In this example, the coal plant imposes an integration cost on the system.

New inexpensive baseload generation can impose cycling impacts and lower capacity factors on other plants

Even baseload generation that provides a relatively constant level of output can impose additional cycling on other generators, and cause them to generate at lower annual capacity factors. This situation can happen when a new baseload generator enters the mix, and if it is more economic than at least one other baseload generator. Figure 3 depicts this scenario. The figure shows a dispatch plan over one week for a simple system, calculated by an economic dispatch model. The upper panel establishes a base case with only three generators: coal, combined cycle gas, and a combustion turbine. The middle panel shows the addition of wind energy, which reduces the capacity factors and increases the cycling duty of all three conventional generators. The lowest panel adds a new inexpensive baseload generator to the base case (with no wind energy). The economic dispatch solution now reduces the capacity factors of both the coal and combined-cycle plants, and increases their cycling. The combustion turbine is pushed out of the market. Although the impacts of the wind generation and the new baseload generation differ in magnitude, they both have similar impacts on the incumbent gas and coal generation.

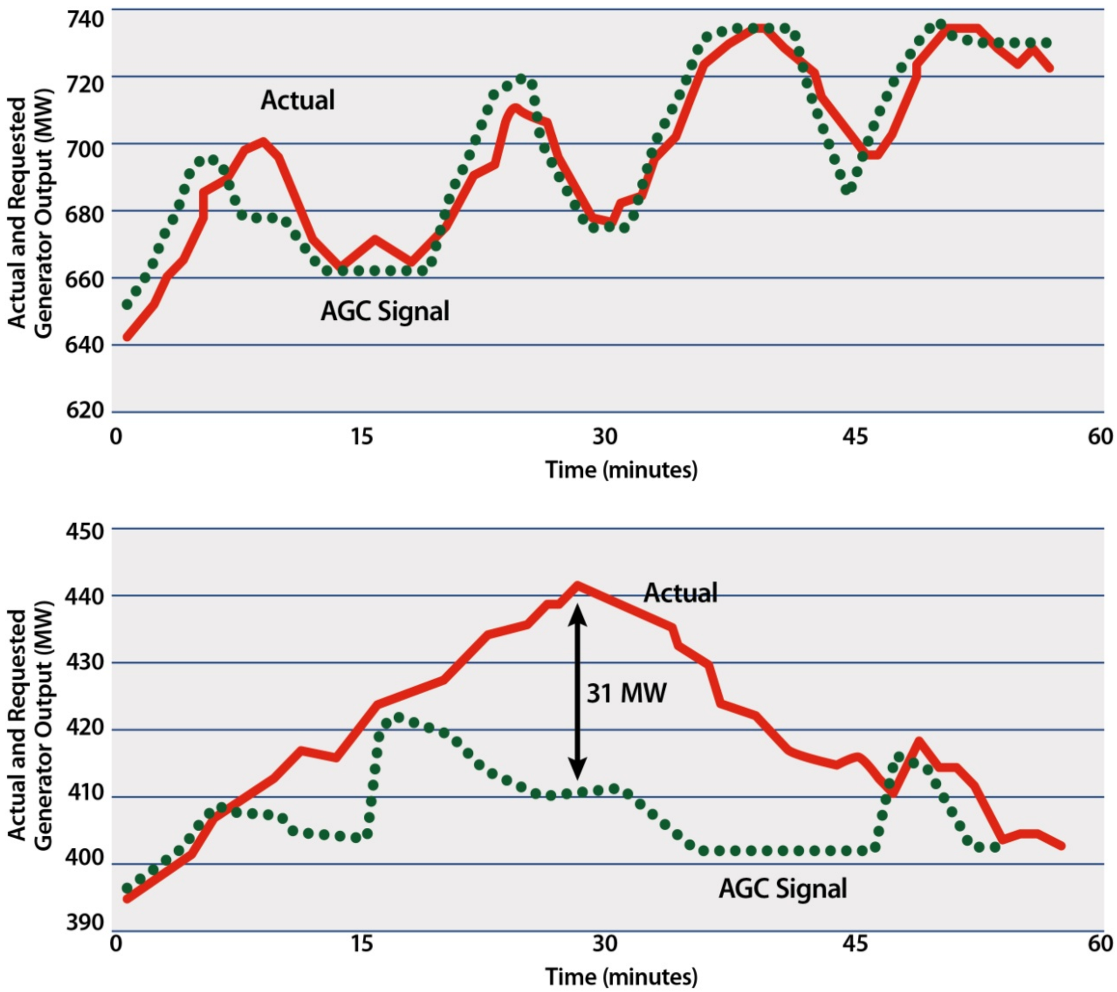

Figure 2. Two coal units in the Midwest illustrate a difference in ability to follow an AGC signal.

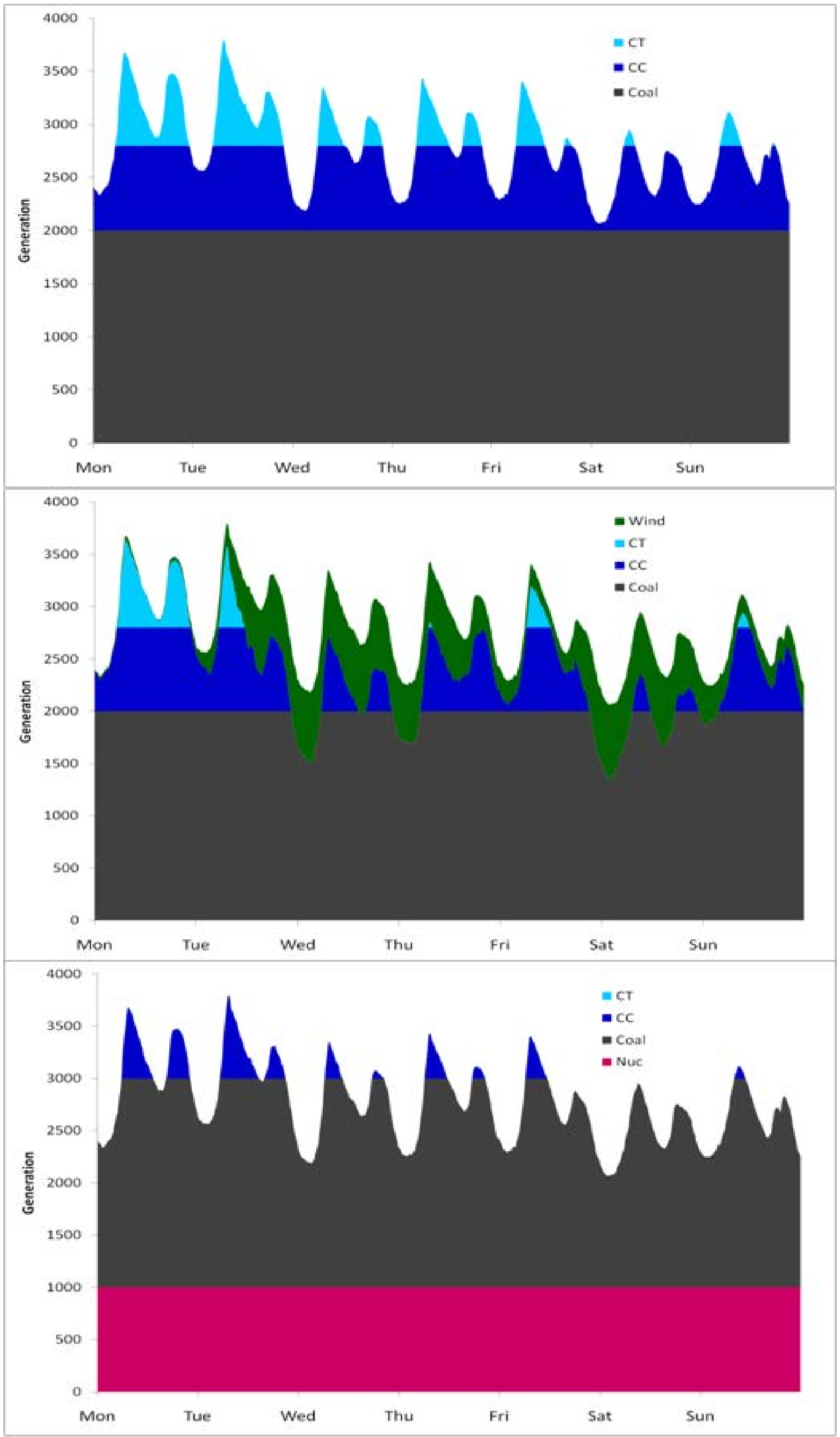

Figure 3. A new baseload generator can cause other units to be displaced, increasing their cycling and decreasing their annual capacity factor.

Changes in contingency reserves for a pool

Contingency reserve is typically based on the loss of the largest generating unit. Reserve sharing groups (RSGs) are common, allowing for the sharing of contingency reserves over a broader electrical area, which can reduce costs for all. In RSGs, there are typically multiple entities, which may include generation owners, traditional utilities, or others. The cost of providing the contingency reserves is not typically allocated to those who cause the need for the reserve. As an example, consider an RSG composed of five utilities, with the largest generator consisting of a 350-MW coal unit. If the five utilities share the burden equally (for simplicity in the example), they each carry a 70-MW contingency reserve. Suppose now that one of the utilities builds a new 500-MW generator. Each member is now obligated to carry 100 MW of reserve, a 30-MW increase. This new 500-MW generator incurs a real contingency reserve cost, but it is not charged back to the 500-MW unit — or even exclusively to the utility that acquired it.

The cost of providing contingency reserve is therefore not calculated on the basis of the units that drive the need. Costs could be allocated based on cost causation, as shown in another example in Figure 4, but they are not (Hirst and Kirby 2003). Instead, these costs are socialized to loads, and have been for many years. Current practice has the effect of subsidizing the large generators at the expense of the small generators (or their customers).

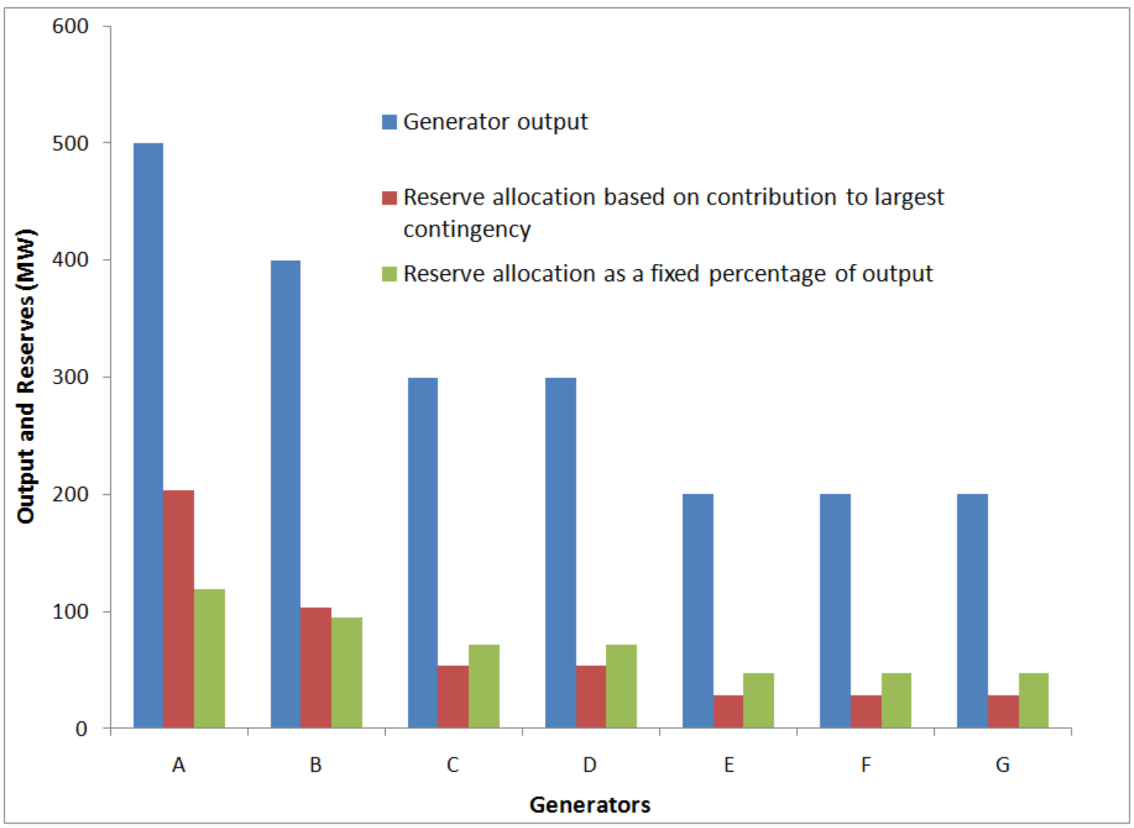

Figure 4. Contingency reserve costs could be assessed based on the units that drive the need, but are not.

Hydropower

Environmental restrictions associated with preserving endangered fish have reduced the flexibility available to the power system from many hydropower projects, and may impose an integration burden. For example, excess water during times of light power system load may exceed the reservoir storage capability. Historically, the power system would use as much of the water as possible for generation and the rest would be spilled. This was an unfortunate and unavoidable economic lost opportunity, but nothing more. Better understanding of fish biology has led to additional operational restrictions. Spilling water can increase dissolved gasses, however, and now can represent an unacceptable threat to fish. The water cannot be spilled but must be run through the turbine generators. The power system must therefore accept the excess power. Absorbing the extra power may require uneconomic cycling of thermal power plants or curtailing wind power production, causing the plants to lose production tax credits and renewable certificates. What was previously just a lost economic opportunity (spilled water that did not generate electricity revenue) is now a direct cost (uneconomic cycling of thermal plants and curtailed wind production). This represents a real integration cost of constrained hydropower.

Hourly block energy schedules

Hourly schedules can impose potentially significant integration costs. For example, GE Energy Consulting (2007) found that in the California Independent System Operator (CAISO) footprint the "largest ACE [area control error] excursions correspond to hourly schedule changes. Thus, the schedule changes may be causing avoidable ACE violations." The violations occur because the hourly interchange in the West constrains generators from responding to changes in load or other conditions, except during the 20-minute window surrounding the top of the hour. Because all the ramping must occur within this limited time period, it is not uncommon for generators to under-shoot or over-shoot, causing an increase in ACE violations during scheduling changes. A similar conclusion was reached by the Western Wind and Solar Integration Study (WWSIS)(GE Energy 2010), which showed that hourly block scheduling in the West has a larger impact on regulation needs than wind and solar generation.

Gas scheduling

Gas scheduling and contracting can limit the flexibility of gas-fired generators significantly below the physical capability. Gas is typically nominated day-ahead, committing the generator to operate or not operate in essentially the same time frame as coal plant commitment. While there is ample physical capability to respond to changing load conditions and changes in the rest of the generation fleet up until the operating hour, the gas scheduling restricts this flexibility. This problem is compounded on weekends and holidays. Gas schedules are typically set on Friday for Saturday's, Sunday's, and Monday's operations. If a holiday falls on one of these days, the schedule stretches to four days and includes Tuesday. Gas scheduling restrictions represent a significant integration cost that is not based on limitations in the physical capabilities of the generator.

Gas also presents another integration cost related to the potential for a common mode failure. Extreme weather conditions can cause gas shortages that impact all gas-fired generators in a region. This impact represents a much larger contingency than the power system is designed to survive. System operators are forced to shed firm load to cope with the loss of generation. This situation occurred in Texas and the Southwest in February 2011. The significant cost is born directly by the loads that are blacked out and represents an integration cost of natural gas, which is not allocated directly to natural gas generation.

Operational staffing

In the Western Interconnection of the United States, excluding the market areas of California, energy trading for weekend periods is done in advance. The schedule for Monday is typically set on Friday, whereas weekday schedules are set one day in advance. When a holiday falls on Monday, the load and wind forecasts for Monday are set by Friday, resulting in larger forecast errors and therefore generally higher operational cost. For example, the recent wind integration study by Portland General Electric (Portland General Electric 2011) used wind forecasts (mean absolute error, or MAE) of 17.8%, 20.3%, and 22.1% for day-ahead, 2-day-ahead, and 3-day-ahead wind forecasts, respectively. The higher costs that result from using a 3-day-ahead forecast are caused by the unavailability of schedulers, not by changed wind conditions.

Cost vs. Benefit

As typically calculated, wind integration cost is a function of the fuel cost of the generation that is on the margin of the dispatch stack. Depending on relative fuel prices and the instantaneous penetration in a study, this could be either gas or coal. In one study (Xcel Energy 2008) the Public Service Company of Colorado calculated wind integration costs and performed a sensitivity analysis on natural gas prices. At higher gas prices, the integration cost increased. However, at the higher gas prices, the wind energy provided higher value because it was displacing more expensive gas.

Integration Depends Heavily on Generation Plant Mix

Because integration cost depends on the characteristics of the nonwind/solar generation, any attempt to calculate integration cost would change as the installed plant mix changes. For example, the WWSIS used an extrapolation of today's generator mix and then included wind and solar. In reality, a 35% combined wind and solar penetration would likely occur alongside a change in the conventional plant mix. That mix will have a significant influence on the way the system operates. To efficiently integrate large amounts of wind and solar, the balance of the generation fleet will need more flexible characteristics, as was demonstrated in the Western Wind and Solar Integration Study (GE Energy 2010). An example of this need for flexibility is shown in Figure 5. The upper panel of the figure shows the load (black) and load-less-wind, or net load (blue). The red lines show the operating range for this sample 1-week period. The lower panel shows the need for ramping capability, both with wind power and without it. With high levels of wind, the minimum turn-down level needed from conventional generation is much lower and the need for ramping capability increases. Although these characteristics are already present in the power system without wind energy, there will be a significant increase in the need for this flexibility at high penetration rates.

Such a need implies that the result of integration studies will be tied very closely to the assumptions regarding the future mix of generation. And because integration cost (assuming it can be calculated) depends on the performance of the remaining plants in the system, impacts and costs are a function of this plant mix.

Loads

Loads differ dramatically in the burdens they place on the power system. A single load accounted for 53% of the regulation requirements for one utility studied (Kirby and Hirst 2000). Although regulation costs are typically allocated to loads in aggregate, they are never allocated among loads based on cost causation. Regulation costs are broadly allocated to all loads regardless of individual load requirements.

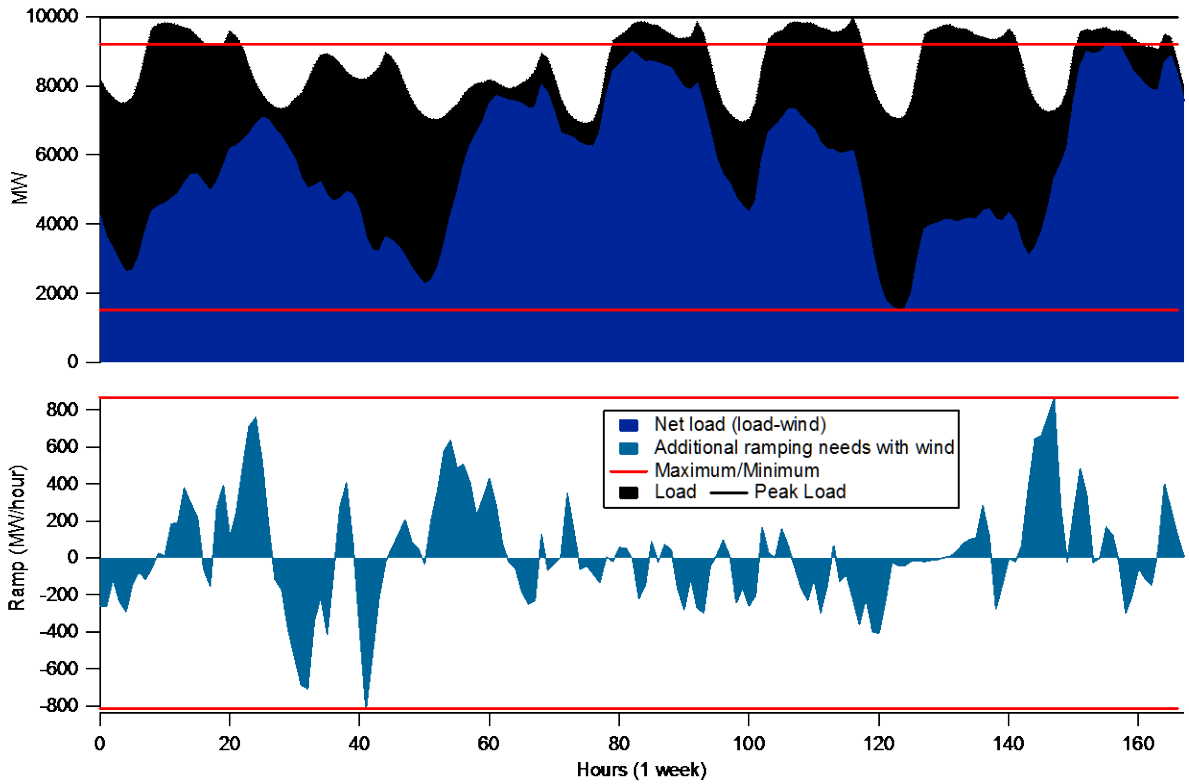

Figure 5. High penetrations of wind and solar will require a flexible generation fleet.

Summary

Wind integration analysis has progressed significantly. However, in spite of numerous attempts at calculating wind integration costs, there are key questions about the validity of methods used thus far. It is difficult or impossible to untangle all of the complex interactions among the components of the bulk power system. Additionally, other types of generation or institutional characteristics can also impose integration costs that are neither recognized nor captured. Integration costs, if they are to be assessed, should therefore be based on plant performance, not plant type. Similarly, either all system impacts should be allocated to individuals based on cost causation or none should be. It is not reasonable to allocate integration costs to wind and solar at the same time that contingency reserve is not allocated to the large units that drive the requirement. Future work could investigate these issues further by performing analyses on alternative generator type and performance characteristics, utilizing production simulation tools.

References

GE Energy (2010), Western Wind and Solar Integration Study. National Renewable Energy Laboratory. Available at http://www.uwig.org/CRPWindIntegrationStudy.pdf

GE Energy Consulting (2007). Intermittency Analysis Project: Appendix B. Impact of Intermittent Generation on Operation of California Power Grid. California Energy Commission report CEC-500-2007-081-APB. Sacramento, CA.

Hirst, E; Kirby, B. 2003, *Allocating Costs of Ancillary Services: Contingency Reserves and Regulation*, ORNL/TM 2003/152, Oak Ridge National Laboratory, Oak Ridge TN, June.

Kirby, B.; Hirst, E 2000, *Customer Specific Metrics for the Regulation and Load-Following Ancillary Services*, ORNL/CON-474, Oak Ridge National Laboratory, Oak Ridge, TN, January.

Milligan, M.; Ela, E.; Hodge, B. M.; Kirby, B.; Lew, D.; Clark, C.; DeCesaro, J.; Lynn, K. (2011). Cost-Causation and Integration Cost Analysis for Variable Generation. 37 pp.; NREL Report No. TP-5500-51860. Available at http://www.nrel.gov/docs/fy11osti/51860.pdf.

Milligan, M.; Kirby, B. (2009). Calculating Wind Integration Costs: Separating Wind Energy Value from Integration Cost Impacts. 28 pp.; NREL Report No. TP-550-46275. Available at http://www.nrel.gov/docs/fy09osti/46275.pdf.

Portland General Electric (2011), PGE Wind Integration Study Phase II. PGE, available at http://www.uwig.org/PGE_Study/PGE_Phase%202_Wind_Integration_Report_9-30-11.pdf.

Xcel Energy (2008), Wind Integration Study for Public Service of Colorado Addendum: Detailed Analysis of 20% Wind Penetration. Available at http://www.uwig.org/CRPWindIntegrationStudy.pdf