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Integration of Variable Generation, Cost-Causation, and Integration Costs

This article examines how wind and solar integration studies have evolved, what analysis techniques work, what common mistakes are still made, and what and why calculating integration costs is such a difficult problem that should be undertaken carefully, if at all. Examples of integration costs for other generation technologies are examined to help illuminate underlying cost causation principles.

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I. Introduction

Wind and solar power generation are prized for their environmental benefits, low and stable operating costs, and help in reducing fuel imports. Advances in both technologies are reducing capital costs and providing significant control capabilities. Still, the primary energy source for both technologies is variable and uncertain, and a power system with significant wind or solar penetration must be operated differently than a power system with only conventional resources. It is very natural to ask what the additional cost of accommodating wind and solar generation is. However, calculating the integration cost of variable generation (VG) turns out to be surprisingly difficult.

Integration cost analysis has progressed significantly over

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the past 10 years. There is also a much better understanding of the cost drivers among the system stakeholders. This work examines how wind and solar integration studies have evolved, what analysis techniques work, what common mistakes are still made, and what and why calculating integration costs is such a difficult problem that should be undertaken carefully, if at all.

Analysis techniques are now very good at simulating power system operations with time-synchronized load, wind, and solar data. The best studies model security-constrained unit commitment and economic dispatch with hourly (or shorter) time steps covering one year or longer. They account for forecast errors of wind, solar, and load as well as actual output and consumption. Total system costs with and without renewables can be calculated accurately under a range of conditions. These cost differences are typically dominated by the fuel cost savings that renewables provide. Calculating an ''integration cost'' that only includes the added cost the power system incurs dealing with the variability and uncertainty of wind and solar is much more difficult. The many complex interactions among components of the power system and assumptions regarding the base case have important influences on integration cost estimates, and raise questions about whether integration cost components can be correctly untangled. We discuss many of these concerns and implications, shedding some light on the difficulties involved in measuring and interpreting integration cost estimates.

II. Variable Generation Impacts on Balancing Requirements

The variability and uncertainty of wind and solar power generation increase the response requirements from conventional generators, but they do not increase overall capacity requirements. Peak load with wind and solar is never higher than peak load without wind and solar. Wind and solar generation can only reduce the net load, which must be served by conventional generation; they can never increase the capacity required to serve load unless the existing generation fleet cannot respond quickly enough. In that case, the problem is not insufficient capacity, but rather that the existing capacity is not sufficiently flexible.

Analysis techniques are now very good at simulating power system operations with time-synchronized load, wind, and solar data.

Power system variability during normal operations is commonly separated into three time frames. Regulation deals with the random, minute-to-minute variability of loads and generation. Load following deals with slower trends that extend from minutes to hours. The scheduling process deals with day-ahead unit-commitment decisions, driven by forecasts of load, wind, and solar generation.

Power systems must also balance generation and load under contingency conditions, being able to respond to a sudden failure of any resource. A series of reserves are constantly maintained to provide immediate and sustained response to the largest credible contingency. Wind and solar typically have little impact due to the smaller size of individual plants. However, large wind and solar ramping events do share some characteristics with conventional generation contingencies; the largest events are relatively rare, with reserve standby costs dwarfing response costs. Large wind and solar ramping events differ from conventional contingency events in that they are much slower.

A. Regulation

The impact of wind power on the regulation time scale is relatively easy to calculate when synchronized high-resolution load and wind data are available.[1] There is less operating experience with solar power than with wind, but aggregation benefits should be

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similar. Because the minute-to-minute variability of individual loads, wind plants, and PV plants are highly uncorrelated, total power system regulation requirements are reduced with larger aggregations of load and generation.

B. Following

Following imposes a flexibility or ramping requirement on the power system, but not a capacity requirement. The morning load ramp can never ramp above the daily peak load. Similarly, if wind has been blowing at night and drops off during the morning load pickup, the morning ramp rate increases but the total system capacity requirement, set by the daily peak net load, does not increase.[2]

C. Scheduling

Conventional fuel-burning generators typically require preparation time before they can be operated.[3] Large coal-fired plants can require a day or longer. Combined-cycle plants typically require several hours. Combustion turbines require minutes to an hour or longer. Some hydro and reciprocating engine plants can start and fully load within minutes. Wind and solar never increase the amount of conventional generation that must be scheduled day-ahead, but ignoring the wind and solar forecast can result in excessive amounts of conventional generation being brought online. Inefficient operations result, with conventional plants operating below their optimal outputs. Uncertainty in the VG forecast can also result in a change in the optimal scheduling mix, with flexible generation preferred over inflexible.

III. Integration Cost

The *concept* of an integration cost for wind and solar generation seems simple and useful. What costs does the power system incur when wind or solar generation are included in the generation mix? Although this appears to be a simple question, calculating the integration cost has proven to be very complex. To date it has not been done in a completely satisfactory manner. The complexity does not stem from an inability to model the power system or to calculate system costs with and without VG, but rather from establishing what conditions to compare and the interactions between generation resources. Wind and solar integration costs cannot be measured directly. Instead, total power system costs with and without wind and solar generation need to be compared. Modeling the *with* wind and solar conditions is now relatively easy due to progress in modeling the power system with high penetrations of wind generation. The maturity of comparable solar modeling needs to evolve to match the current state of wind modeling.

One issue in modeling integration costs comes from trying to define the without case.

One issue in modeling integration costs comes from trying to define the *without* case. If the power system is modeled without the VG, the energy that wind and solar would have provided must come from another resource. If fuel costs are included, then wind and solar present a system benefit, not an integration cost. However, the integration cost is meant to cover the non-energy costs. This leads to three realizations. First, it is now (relatively) easy to calculate the difference in total power system costs with and without VG.[4] Second, a more explicit definition of ''integration costs'' is required. Third, the *without*-wind-and-solar case must be carefully designed. This discussion also leads to the possibility that integration costs may not be rigorously defined or calculated. The second difficulty arises because of the complex interactions between resources and loads that hinder the untangling and allocation of costs. Production cost modeling captures what *additional* costs the

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power system incurs because of the variability and uncertainty of VG, but it also captures the value of the wind and solar energy itself.

Two basic schools of thought have emerged concerning integration costs. One tries to develop a zero-energy-cost-proxy resource for the without case that supplies the VG energy without the variability and uncertainty. The other school maintains that it is not possible to develop a suitable proxy and only total costs with and without renewables should be compared.

A. Proxy resource

A proxy resource can be used to supply the VG energy without the variability and uncertainty. This will remove the energy value when the total costs are compared between the cases, leaving only the integration costs caused by the VG variability and uncertainty. Initial wind integration analysis efforts used a flat block of energy equal to the annual average wind and solar output. Unfortunately the *value* of the flat block energy is significantly different from the value of the wind and solar energy.[5] The proxy flat block likely has seasonal and daily energy differences compared to the variable resource, leading to cost differences. While the cost differences between the flat block proxy and the renewables are very real, they are representative of the costs of variability and uncertainty because they include the difference in the temporal value of the energy.

B. Comparing total system costs

An alternative analysis approach does not attempt to directly calculate integration costs. Instead, it focuses on calculating the total system costs and benefits of integrating renewables. The same time series, mesoscale data-based security-constrained unit commitment and economic dispatch modeling is performed, but without the proxy resource in the base case. The total change in production costs is calculated including the value of saved fuel, as well as the inefficiencies introduced by the variability and uncertainty of the VG.

IV. Other Types of Generation Impose Integration Costs

Integration impacts are not exclusive to wind and solar. Nearly all generators can impose costs when they are added to the power system. These impacts are seldom calculated as integration costs and never applied to conventional generators. Figure 1 shows an example of this effect by displaying the outputs of two similar coal-fired generators. The generator in the top figure is providing regulation while the

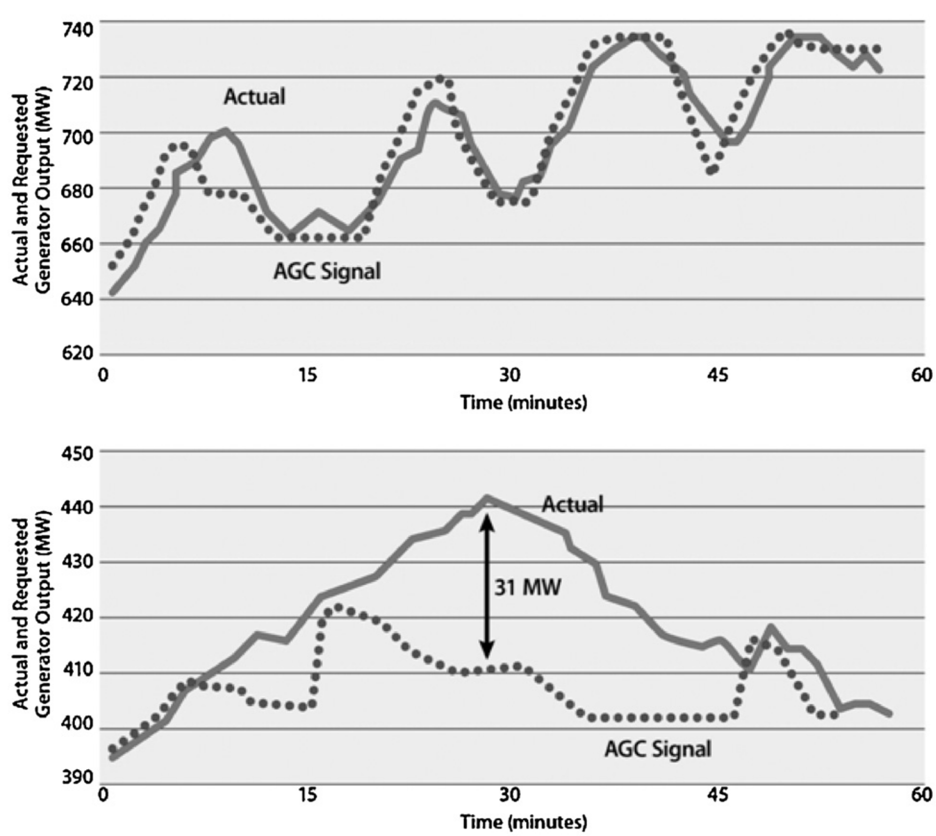

Figure 1: Two Similar Coal-Fired Generators; The Upper Generator Is Providing Regulation while the Lower Generator Is Imposing a Regulation Burden on the Power System

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generator in the lower figure is imposing a regulation burden on the power system.[6]

Baseload plants can also increase the costs of operating other generators. Figure 2 provides a comparison of the addition of wind generation to the addition of a new baseload generator on cycling in the rest of the generation fleet. The top figure shows coal generation providing flat output for the week. Combined-cycle plants and combustion turbines cycle daily and follow the load ramps. The middle figure shows that the addition of wind does force coal to cycle while increasing cycling in combined-cycle plants. The bottom figure shows that adding a lower-cost baseload generator forces coal to cycle, and displaces the gas generation.

Contingency reserve requirements are typically based on the size of the largest generator. Each balancing area (BA) must keep enough spinning and non-spinning reserve ready to respond if a generator fails. The cost of maintaining these reserves is not allocated to the generators that cause the need, however. Instead, the cost is spread across all users of the transmission system. This has the effect of allocating costs based on capacity or output rather than on contribution to contingency reserve requirements. Costs are not allocated based on cost-causation.[7] Instead, these costs are socialized. Current practice has the effect of subsidizing large generators at the expense of small generators.

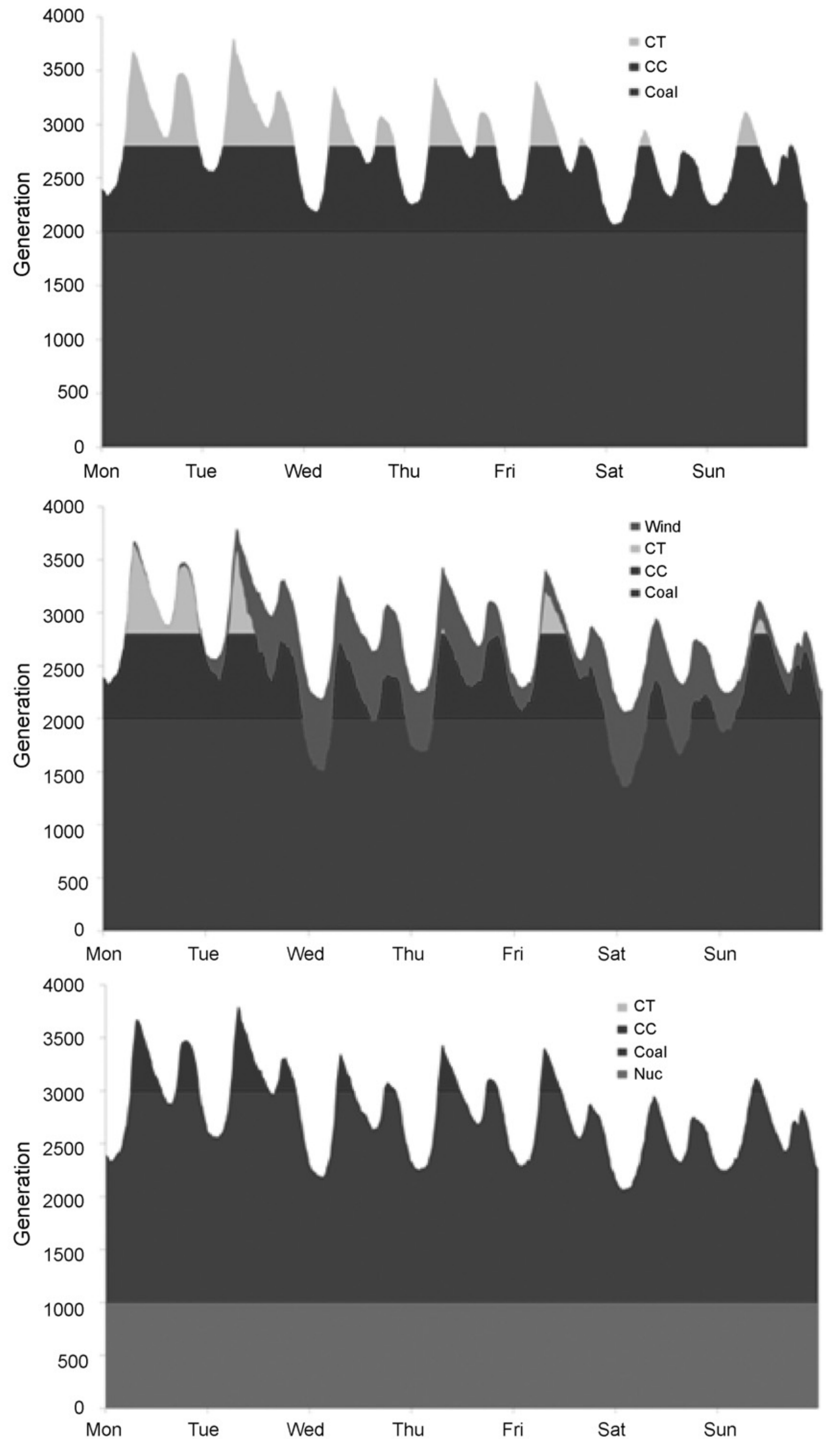

Figure 2: The Addition of Any Generation Can Impact the Cycling Requirements of the Existing Conventional Generators

A. Hydro integration costs

Hydro generation is typically very responsive, flexible, and has low cycling costs. However, there is both seasonal and annual variability and uncertainty in the water availability. Recently, environmental restrictions associated with preserving endangered fish have reduced the flexibility of many hydro projects, and may impose an integration burden. Excess water during times of light load may exceed the reservoir storage capability. Historically, the power system would use as much water as possible for generation and the rest would be spilled. This was an unavoidable economic lost opportunity. Better understanding of fish biology has led to additional operational restrictions due to dissolved gases that represent an unacceptable threat to fish. The water must be run through the turbine generators instead of spilled, and the system must accept the excess power. This may require uneconomic cycling of thermal power plants or curtailing wind. What was previously just a lost economic opportunity is now a direct real cost of constrained hydro.

B. Gas integration costs

The physical flexibility of natural gas-fired generation depends on the technology. Engine-driven plants are extremely flexible, with some able to start in two minutes with zero cycling costs. These plants ramp quickly and can provide the full set of generation-based ancillary services.[8] Large gas-fired steam plants represent the other extreme, requiring hours to days to start and are slow to ramp. Combined-cycle plants and combustion turbines fall in between. Gas contracting can limit the flexibility of gas generators significantly below their physical capability. Gas is typically nominated day-ahead, reducing flexibility. This problem is compounded on weekends as schedules are set on Friday for Saturday, Sunday, and Monday's operations. Gas scheduling restrictions represent a significant integration cost to gas generators 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 result in gas shortages that impact all gas generators in a region. System operators are forced to shed firm load to cope with the loss of generation. This occurred in Texas and the Southwest in February 2011. This significant cost is born directly by the affected loads and represents an integration cost not allocated to natural gas generation.

V. Principles of Cost-Causation

Wind and solar integration costs can be thought of as a tariff that is assessed to recover the increased operating costs caused by these variable generators. Cost-causation based tariffs provide transparent signals to markets and regulators that, if well defined, provide appropriate incentives for efficient investment and behavior. Kirby et al. (2006) describe cost-causation based tariffs in the following principles:

1. Because maintaining power system reliability is critical, tariffs should base prices on costs so that the costs of maintaining reliability are obvious.

2. Tariffs should be based on cost-causation and the cost of providing the service.

a. Those individuals who cause costs to the system should pay for those costs;

b. Those individuals who mitigate costs to the system should either incur a lower cost or be paid for helpful actions;

c. Complex systems like electric grids produce both joint products and joint costs of production that must be allocated among users of the system[9];

d. Tariffs should allocate joint production costs on the basis of the use of joint products.

3. Tariffs should not collect revenue if no cost is incurred.

4. Tariffs should be based on the physical behavior and characteristics of the power system.

a. Recognize the need to balance aggregate system load and aggregate system generation;

b. Recognize that balancing individual loads or resources unnecessary and inconsistent with power system operations.

5. Tariffs should result in an efficient allocation of resources.

Tariffs should also support the broader principles of horizontal and vertical consistency. Horizontal consistency means that if two individuals cause equal increases in costs, then the tariff should assess each the same amount. Vertical consistency implies that if an individual imposes a larger cost, they should pay more. Both principles can be extended to cost mitigation.

Horizontal and vertical consistency can be tested, either through real-world experience or detailed modeling of the individual behaviors in question. Application of the tariff to the individual behaviors can determine whether horizontal and vertical consistency is achieved. However, it is important for regulatory bodies to exercise great care in creating such tariffs lest they elect to only create tariffs that recover integration costs from some parts of the system while allowing free riders in other parts. Unfortunately, this is currently the case when utilities are requesting separate renewables integration tariffs without creating others to recover integration costs from conventional generators. Rather than focusing on technology-specific tariffs, it would be more appropriate to focus on performance-specific characteristics. This approach would allow any technology to adapt to supply needed response and reduce deadweight loss.[10]

A. De-composition and re-composition

The variability of wind and solar is often de-composed into regulation and load following components. We support this type of analysis because it allows variability to be analyzed in the context of normal system operations. However, *the sum of the regulation and load following signals must sum to the original time series* following the ''principle of re-composition.'' The power system only balances the total net load and so regulation and load following components must be defined so that they sum to the actual system requirement. We have seen this principle violated in numerous studies carried out by utilities. This concept is not new to the utility industry. The power system only has to meet the system's coincident peak load, not the sum of the peak requirement of each customer or each appliance. If a utility charged each residential customer based on the capital cost of generation multiplied by the sum of the ratings of each individual appliance, the utility would collect many times the total cost of generation needed. Instead, the cost of generation is allocated based on the customer's contribution to coincident peak load, not the customer's peak load. The cost to follow system load is much less than to follow the individual loads. This benefit occurs because the individual loads are generally not correlated with each other.[11]

VI. Testing a Tariff with Thought Experiments

Thought experiments provide a means for testing a tariff to assure it does what is intended without undesired consequences. Here we present three thought experiments that can be used to test how a regulation tariff assesses a volatile resource like wind, and map each one to our tariff principles.

Thought Experiment No. 1: Perfect Following of a Volatile or Block Schedule

Both loads and generators use forecasts to establish a schedule for generation or consumption. Regulation tariffs often impose penalties if a resource does not follow its schedule. The reasoning is that the system operator must have regulating resources available to compensate for unexpected changes in a generator or load's output or consumption. But does the regulation resource requirement go away if the resource follows its schedule perfectly? **Figure 3**

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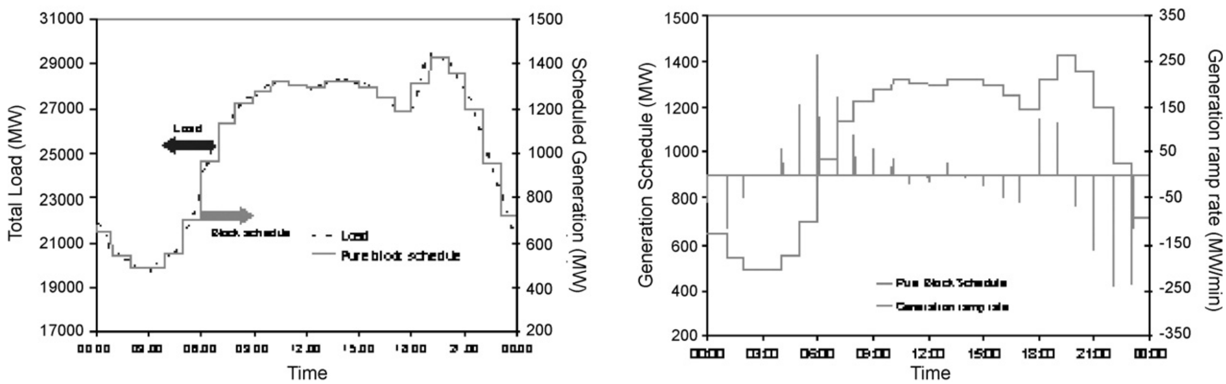

Figure 3: How Does the Tariff Treat Perfect Following of a Volatile Schedule?

presents a typical system daily load with blocks of generation scheduled to meet load. If the generation follows its schedule perfectly, is there a regulation burden imposed on the system? The right side of Figure 3 shows that block scheduling imposes severe ramping requirements on the system, adding \$2.26 to the cost of each MWh delivered. The fact that these requirements always happen at the top of the hour does not reduce the amount of fast response capability the system operator needs to meet CPS1 & 2 requirements.

This tariff violates principle No. 2 because under the scenario of a perfect wind or solar energy forecast, the tariff would not assess any cost to the generator even though there is a cost of moving the regulating units to mitigate variability. It also violates principle No. 4. Extrapolating this tariff to a case when all schedules and loads are known perfectly, the implication is that no cost to manage system variability. This is clearly wrong, and would result in distortions in the market.

Thought Experiment No. 2: Ramp Rate or First Derivative Metrics

Another tempting regulation tariff simplification is to measure average ramp rate of the minute-to-minute energy consumption. This can also be characterized as a ''distance traveled'' metric. The flaw here is that behaviors with very different system impacts can result in the same measured performance. Figure 4 compares the behavior of three hypothetical types of loads. The minute-to-minute change integrated over the hour is the same for all three: 60 MW-minutes. However, the regulation burdens imposed are radically different. The solid red entity requires 1 MW of regulation compensation. The dashed green entity requires 5 MW. The dotted blue entity requires a total of 60 MW, but not of regulation. A sustained ramp is a following requirement that can be supplied by moving baseload and intermediate generators. Metrics based on average rate of change of an individual violate principle No. 2 and principle No. 4.

Thought Experiment No. 3: Equal but Opposite Behavior

Thought experiments need not be realistic to be useful in determining if a tariff will produce desired results. Unrealistic

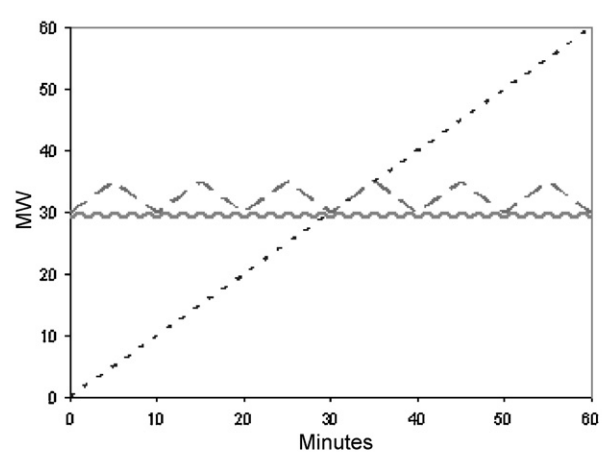

Figure 4: These Three Alternative Hypothetical Loads Impose Radically Different Regulation Requirements but Have the Same Minute-to-Minute-Change Metric Performance

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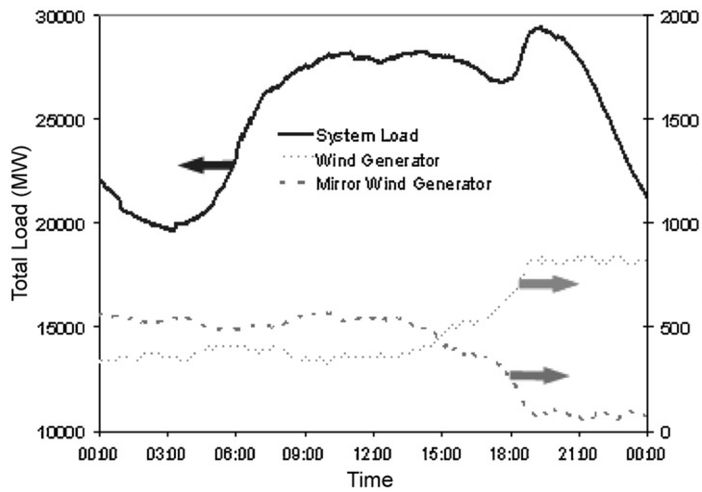

Figure 5: How Is Equal but Opposite Behavior Treated?

examples can be useful in understanding the pieces of complex behavior that are often buried in the intricacies of actual operations. Figure 5 shows two mirror-image wind plants and a total system load. If the wind plants were assessed for their variability in isolation of system load, they would both receive an identical regulation variability assessment. Together, they present an absolutely constant output with no regulation burden. A tariff that cannot recognize complete compensation of one plant for another will not recognize more subtle interactions. Such a tariff would collect payment from both of these wind plants, but there would be no cost to the system. This type of tariff would therefore violate principle No. 3 and principle No. 4.

VII. Common Errors in Integration Analyses

In our experience participating in technical review activities for most major wind integration studies in the United States, we have seen honest mistakes made in the technical analysis. It is not our intent to single out entities that have committed these errors, but to extract the issues and contribute to more accurate analyses.

A. Double counting

Double counting is probably the most common error made in integration studies. This usually results from failing to account for aggregation benefits or including the same variability or uncertainty in multiple services. The most common example is violating the principle of re-composition. The sum of the reserves required for regulation and following should not exceed the total system balancing requirements. Similarly, wind, solar, and load balancing requirements are often calculated separately, which is only valid if these parameters are perfectly correlated. Failing to remove the load forecasting errors from integration costs is another example of double counting. Load and wind forecast errors typically do not add linearly and so the forecast error reserves allocated to wind and load should not exceed the total system forecast error reserves. Another form of double counting is the overestimation of reserves that are needed to balance VG. Some amount of reserve is naturally provided as a function of economic system operation. In the Western Wind and Solar Integration Study (WWSIS), the load following reserve requirement increased by a factor of two. However, by running the actual production simulation analysis, it was found that the system *naturally provided* these extra load following reserves because many thermal units were backed down instead of de-committed. Therefore, no additional cost for committing extra load-following reserves was incurred.

B. Fixed schedules and fixed resources

Fixing transaction schedules based upon the without-wind case optimization and holding them for the with-wind case typically results in sub-optimal resource scheduling and significantly higher balancing costs. A related error is the assumption that only a subset of generation is available for balancing response. A BA with a significant amount of energy-

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limited hydro generation modeled integration of large amounts of wind and calculated high integration costs. The modeling showed that the maneuvering capability of the hydro unit was exhausted. The analysts did not allow the production cost software to utilize the response capability of the conventional generators simply because that was not the historic practice. A similar case results from treating hydro generation as a constant resource. Models are often capable of accurately representing ramp constraints, over various time steps, and yet constant constraints on the hydro performance are sometimes assumed.

Scheduling practices are changing within the power industry, regardless of VG. Some studies still calculate excessively high balancing costs assuming hourly scheduling, although sub-hourly scheduling is already operational in many regions. This restricts access to the response capability that physically exists in the generation mix. A final scheduling error involves bilateral contracts, though it is reasonable to assume that they will change to reflect economic opportunities instead of remaining fixed for decades.

C. Balancing individual wind plants

Power system balance requires the aggregate load to be equal to the aggregate generation. Therefore, not every movement in a wind plant must be matched one-for-one by another generator. If wind generation increases at the same time as load, this reduces or eliminates the need for other generation to follow the load increase. The concept of balancing the net load is well understood in power system operations. In fact, the NERC Area Control Error (ACE), Control Performance Standards (CPS1&2) standards, Disturbance Control Standard (DCS), and balancing requirements are based upon it. However, we have seen two recent integration analyses attempting to balance VG in isolation from load. This means that when wind and load are both increasing, a conventional generator must decrease output to hold the wind constant, but must also increase to meet the increasing load. This does not reflect how power systems are operated and greatly overstates the balancing costs of VG.

D. Scaling

Wind and solar integration studies typically study future conditions when larger amounts of VG are expected. By definition there is insufficient actual wind and solar data available to study. A common error is to scale the output of an existing generator to represent the expected output of a larger fleet. This greatly overstates the variability of wind and likely overstates the variability of solar.[12] There is inherent geographic diversity, even within a single facility, that reduces the correlated variability. It is similarly inappropriate to simulate a wind plant simply by time delaying the output of an existing plant, as the resulting simulation will have too much correlation. Mesoscale modeling is currently the best way to generate the required time-synchronized wind and load data needed for valid integration studies.

E. Forecast data

The wind and solar forecast datasets must also be time-synchronized to historical weather patterns. If the forecasts are assumed to be generated for a large region, then the forecasts should show similar spatial correlation to the wind and solar datasets. If forecasts are assumed to be generated individually for each power plant by different providers, they may show less spatial correlation over larger regions. Temporal correlation must also be preserved. Wind power forecast error distributions are not normal distributions.[13] Missing the tails of the forecast error distributions can underestimate the uncertainty impacts of wind and solar.

F. Replacement power cost assumptions

An early wind integration study calculated high integration costs based on an assumed differential in up and down balancing costs. Balancing power required to compensate for a wind power shortfall was assumed to come from quick-start combustion turbines, but any excess of wind power would be credited with the fuel saving from backing down coal. The result was that wind was charged $70/MWh for shortfalls and credited $20/MWh for excess, creating a default $50/MWh imbalance charge characterized as an operating cost. While the described situation is conceivable, it will not be the norm during most hours. Imbalance costs should be calculated through economic dispatch and will typically be nearly equal for up and down reserves during most hours.

G. Failure to release reserves

Non-spinning and supplemental operating reserves are often appropriate for wind and solar ramping events since the standby costs are more important than the deployment costs. While conventional contingency reserve requirements are modeled as reserves that are held throughout the analysis, wind and solar reserves must be released for response in economic dispatch. This is because the contingencies themselves are not actually modeled, while the wind and solar ramps are modeled in the integration analysis. If the reserves are not released, then the model double counts the reserve requirements because it has to deal with the actual event while simultaneously holding additional reserves.

VIII. Other Assumptions That Drive Results

Many assumptions drive an integration analysis. We briefly discuss these with the intent to illustrate that, even if one accepts that integration costs can be calculated accurately in the first place, that comparing them is fraught with difficulties because of the widely varying assumptions that can significantly contribute to the results.

1. **Mix of generation.** The so-called ''minimum generation problem'' occurs when there is high wind output during a low-load period, and the remaining generation fleet cannot back down far enough. This results in low or negative prices and overgeneration that can be solved by curtailing wind or increasing exports. However, a different generation mix may alleviate the problem. Integration studies that hypothesize high VG penetrations over long timescales, yet keep the same generation mix may find problems that can be alleviated with an alternative plausible future generation mix.
2. **Institutional constraints and operating practice do not change even with high penetrations of VG.** Changes in operational practice or institutional constraints are difficult to forecast, but holding on to uneconomic practices with high penetrations of VG is not likely. The structure of markets and contracts will likely change if there is significant contribution from VG to the overall generation mix. Because there are no markets in the United States that value flexibility, it is likely that new market products will be available to induce high value services that are not currently compensated.
3. **Scheduling intervals may change.** Because wind and solar forecasts become less accurate for longer time frames, late gate-closing allows the system operator to take account of more accurate forecasts. There is

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currently significant effort in the development of better weather forecast models that can run hourly instead of every six hours. At the same time, computer and communication technologies will make it possible to incorporate forecasts closer to real-time. Thus the ''lock-down'' period for generator dispatching could be shortened, resulting in more accurate positioning of the existing generation fleet and a reduction in regulation.

4. **Operating footprint.** The ramping capability of the generation fleet adds linearly with more generation; the ramping needs of the system less than linearly. Compliance costs and operational inefficiencies may drive small BAs to coordinate or merge with neighboring systems. Milligan, Kirby, and Beuning[14] have shown that there are considerable efficiencies that accrue in both operating and planning for coordinated planning and operations.

In spite of the considerable progress that has been made in integration modeling and analysis, the discipline is still maturing. Integration studies have grown in scope, complexity, and sophistication. As we have shown, integration analyses are sometimes still subject to error, and even if performed correctly, there are variations in methods that make comparisons difficult or impossible. Although we are aware of attempts to develop simplified integration tools, we do not believe that this field of study has achieved sufficient maturity to allow the generalizations necessary for the development of such a tool.

IX. Conclusions

While VG integration studies have progressed significantly in the past few years, there is still no universally agreed upon method to calculate the integration costs associated with the variability and uncertainty of these resources. Progress in wind and solar integration analysis has been spurred on by the increasing amounts of wind and solar power being deployed in systems around the world. State-of-the-art wind and solar integration analysis now uses the same security-constrained unit commitment and economic dispatch software that is used to operate the power system. Mesoscale modeling is used to generate wind and solar time-series data that is time-synchronized with actual load data. Modeling is done for multiple years with 10-minute or faster resolution. Wind and solar forecasts are included for unit commitment. A base case without VG is compared with one or more high penetration VG cases to determine the impact of wind and solar on fuel and operating costs, reserve requirements, and the operation of conventional generators. Total system costs with and without VG can be calculated with reasonably high confidence.

There is less ability to explicitly calculate *integration costs* for wind and solar. Fuel savings naturally dominate any comparison of wind and solar with conventional generation. Finding an appropriate zero-fuel-cost proxy resource for the base case has proven to be more difficult than expected. Calculated ''integration costs'' can be as much an assessment of the characteristics of the proxy resource as they are of the VG.

The current status of VG integration modeling is:

- There is no universal agreement on methods for calculating renewables' integration costs, and even if agreement on methods is reached, they are not consistently applied;
- There are many potential base cases that may be relevant for comparison;
- High penetrations of VG impact the optimal mix of conventional generation, further complicating the base case selection;

- There is general agreement that wind has an impact on operations, but there is substantial disagreement about whether/how integration costs can be measured.

While there are technical difficulties calculating VG integration costs, there are also public policy and regulatory questions concerning what to do with renewables integration costs, if they can be accurately calculated. Other generation technologies impose integration costs which are not allocated to those technologies. Large generators impose contingency reserve requirements, block schedules increase regulation requirements, gas scheduling restrictions impose system costs, nuclear plants increase cycling of other baseload generation, and hydro generators create minimum load reliability problems. None of these costs are allocated to the generators that impose them on the power system. Any policy that assigns integration costs to wind and solar needs to be thought through very carefully to assure that it is not discriminatory.

Generation integration costs are typically broadly shared because the benefits are also broadly shared. Contingency reserves are shared within a large reserve sharing pool because aggregation reduces the physical reserve requirement and therefore reduces everyone's costs. Variable renewables bring fuel diversity, price stability, energy security, and environmental benefits that accrue widely to all users of the power system, so it is reasonable that integration costs should likewise be broadly shared. With such broad and intertwined benefits, the focus should be on capturing those benefits, which can be accurately quantified, rather than on allocating costs to individuals, which cannot be accurately quantified.■

Endnotes:

1. M. Milligan and B. Kirby, *Calculating Wind Integration Costs: Separating Wind Energy Value from Integration Cost Impacts*, NREL Report No. TP-550-46275, July 2009.

2. B. Kirby and M. Milligan, *Capacity Requirements to Support Inter-Balancing Area Wind Delivery*, NREL Report No. TP-550-46274, July 2009.

3. Hydro generators, reciprocating engine driven generators, and some fast-start combustion turbines do not require significant preparation time before they can start operating.

4. We do not mean to trivialize the difficulty of performing this analysis. As will be discussed below, significant data is required and significant care must be taken to perform the analysis correctly. There are many common errors that some analysts continue to make.

5. See Milligan and Kirby, *supra* note 1.

6. E. Hirst and B. Kirby, *Ancillary-Service Details: Regulation, Load Following, and Generator Response*, ORNL/CON-433, Oak Ridge National Laboratory, Oak Ridge, TN, Sept. 1996.

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

8. B. Kirby, *Ancillary Services: Technical and Commercial Insights*, Wärtsilä North America Inc., June 2007, at www.consultkirby.com.

9. The classic example is a sheep. A farmer raises a sheep. She sells mutton, hide, and wool. These are joint products. She incurs various costs for raising the sheep, the joint costs of production. The electric system produces joint products: reliability, energy, capacity, convenient system access, ancillary services. The costs for producing these joint products must be allocated to the joint products. The most common allocation principle is relative use, the more you use, the more you pay.

10. See B. Kirby, M. Milligan and Y. Wan, *Cost-Causation-Based Tariffs for Wind Ancillary Service Impacts: Preprint*, NREL Report No. CP-500-40073, 2006, at http://www.nrel.gov/docs/fy06osti/40073.pdf.

11. E. Hirst and B. Kirby, *Electric-Power Ancillary Services*, ORNL/CON-426, Oak Ridge National Laboratory, Oak Ridge, TN, Feb. 1996.

12. See Y.H. Wan, *Wind Power Plant Behaviors: Analyses of Long-Term Wind Power Data*, NREL Report No. TP-500-36551, 2004, or Y.H. Wan, *Primer on Wind Power for Utility Applications*, NREL Report No. TP-500-36230, 2005.

13. See B.-M. Hodge and M. Milligan, *Wind Power Forecasting Errors over Multiple Timescales*, NREL Report No. CP-5500-50614, 2011.

14. M. Milligan, B. Kirby, and S. Beuning, *Combining Balancing Areas' Variability: Impacts on Wind Integration in the Western Interconnection*, at http://www.nrel.gov/docs/fy10osti/48249.pdf.

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