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Are Integration Costs and Tariffs Based on Cost-Causation?

Michael Milligan, Erik Ela, Bri-Mathias Hodge, Brendan Kirby, Debra Lew, Charlton Clark, Jennifer DeCesaro, and Kevin Lynn

***Abstract*-- Integration cost analysis has progressed significantly over the past ten years. There is also a much better understanding of the cost drivers among the system stakeholders. This paper 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. 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.**

***Index Terms*—Wind and Solar Integration; Integration tariffs.**

I. Introduction

Wind and solar generation, commonly called variable generation (VG) are prized for their environmental benefits, their low and stable operating costs, and their 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 based exclusively on conventional resources. It is very natural to ask what the additional cost of accommodating wind and solar generation is. Calculating an "integration cost" that only includes the added cost the power system incurs dealing with the variability and uncertainty of wind and solar, and excludes the fuel cost savings, is much more difficult. 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, and in fact raise questions of whether cost components that are commonly thought to be integration costs can be correctly untangled. Integration costs are sometimes evaluated so that the magnitude of the cost of variability and uncertainty can be traced to their cost-causation sources. We develop some principles for cost-causation tariffs, and introduce simple analytic techniques that can be used to test these tariffs,

II. Integration Cost

There is considerable interest and effort on the part of the power system industry to identify the impacts and costs associated with wind and solar integration into the bulk power system. We summarize a more detailed report [2], which builds on [1].

A. Principles of Cost-Causation

VG integration costs can be thought of as a tariff that is assessed to recover the increased cost that wind causes to power system operations; they are a special case of a cost-causation based tariff. 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 can be obvious to users of the system and its reliability future.
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;
   d. Tariffs should allocate joint production costs on the basis of the use of joint products (the cost allocation principle of "relative use").
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 is not necessary, is inconsistent with power system operations and, is very costly.
5. Tariffs should result in an efficient allocation of resources.

Tariffs can be tested empirically, both with real-world

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data or detailed modeling. During tariff design, hypothetical cases can be tested by the tariff to ensure underlying principles are upheld.

There are some broader principles that tariffs should also support. The first is horizontal consistency. Horizontal consistency means that if two individuals (loads or generators) each cause equal increases in costs, then the tariff should assess each of them the same amount. A corollary to this principle is that if two individuals impose similar costs, then they should be assessed similar payment amounts. We can extend the principle of horizontal consistency in cases where individuals contribute to cost mitigation. Equal cost mitigations or reductions should be matched by either identical reductions in cost assessment to the individuals, or equal payments to the individuals. If two individuals have similar cost mitigation impacts, then their payments should be similar.

Vertical consistency is the second additional principle. Vertical consistency implies that if individual A imposes a larger cost than individual B, then A should pay more than B. We can extend the concept of vertical consistency to cases where two individuals mitigate costs in a straightforward manner.

Horizontal and vertical consistency can be empirically tested, either through real-world experience or through detailed modeling of the grid and the individual behaviors in question. Application of the tariff to the individual behaviors can determine whether horizontal and vertical consistency is achieved by the tariff.

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 only some parts of the system while allowing free-riders in other parts of the system. Unfortunately, this is currently the case in some parts of the electric industry where utilities are requesting separate wind or other renewable energy integration tariffs without creating similar tariffs to recover integration costs for other conventional forms of generation. Rather than focusing on technology-specific tariffs, it would be appropriate to focus on performance-specific characteristics. This approach would allow any technology to adapt so that it could supply needed response, and converge to a cost-causation approach that would reduce or eliminate deadweight loss.

B. De-Composition and Re-Composition

The variability of wind and solar is often de-composed into regulation and load following components. We agree with and support this type of analysis because the decomposition allows the variability to be analyzed in the context of normal system operational procedures, as shown in Figure 1. We can illustrate this concept with a simple mathematical formulation:

(1) $V(g) = L(g) + R(g)$

where g represents the variable generator fleet, V(g) is the net load vector, L(g) is the load-following component of the net load accounting for g, and R(g) is the regulation component of the net load accounting for g. Each of the components L and R can be calculated from the original vector:

(2) $L(g) = p[V(g)]$
(3) $R(g) = q[V(g)]$

In a typical integration study, equations (2) and (3) are used to separate the load following and regulation signals for further analysis. However, equation (1) allows us to make the simple observation that the sum of the regulation and load following signals must sum to the original time series. We call this the 'principle of re-composition.' The power system itself only balances the total net load; V(g). L(g) and R(g) must be defined so that they sum to the actual system requirement V(g). This is important in integration analysis for the simple reason that we have seen this principle violated in numerous studies carried out by utilities. L(g) and R(g) are often defined independently with the result that the total variability exceeds the actual system balancing requirements. That is, V(g) calculated from equation 1 is not the same as the actual power-system total net-load when it is recalculated from the independently calculated components L(g) and R(g). This is similar to the problem of measuring the variability of individual loads and generators themselves and failing to account for the aggregation benefits that result from the lack of perfect correlation in individual fluctuations. We discuss this in more detail below.

This concept is not new for 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 the sum of the peak requirements of each piece of load equipment. If a utility charged each residential customer based on the capital cost of generation multiplied by the sum of the ratings of the water heater, oven, stove, dryer, all lights, TVs, computers, air conditioning, etc., the utility would collect many times the total cost of all generation needed to serve load. Instead, the cost of generation is allocated based on the customer's contribution to coincident peak load, not the sum of the customer's equipment ratings and not even the customer's peak load itself.

The cost to follow system load is similarly much less than the sum of the costs to follow the individual loads that, in aggregate, comprise the system load. This benefit occurs because the individual loads, especially the fluctuations, are generally not correlated with each other.

III. Testing a Tariff with Thought-Experiments

Thought experiments provide a means for testing a tariff to assure that it does what is intended and that it does not have undesired consequences. The behavior of the wind and solar plants, other generators, loads, and power system components are carefully specified to test each tariff attribute of concern. Here we present five thought experiments that can be used to test how a regulation tariff assesses a volatile resource like wind. Each thought experiment is mapped to at least one of our tariff principles.

A. Thought Experiment #1: Perfect Following of a Volatile or Block Schedule

In formal transactions, both loads and generators forecast their expected behavior and establish a schedule for generation or consumption. Regulation tariffs often impose penalties if a resource does not follow its schedule. Some tariffs are based exclusively on schedule deviations. The reasoning is that the system operator must have a reserve of regulating resources available to immediately compensate for unexpected changes in a generator or load's output or consumption. This is true. But does the regulation resource requirement go away if the resource follows its schedule perfectly? Figure 1 presents a typical system daily load with blocks of generation scheduled to meet that load. If the generation follows its schedule perfectly, is there a regulation burden imposed on the system? What charge does the tariff impose?

A regulation tariff that is based exclusively on schedule deviations would impose no charge on the block-scheduled generator. Indeed, many feel that scheduled imports and exports impose no regulation burden because the schedule is precisely known, often days in advance, and it is typically adhered to.

The right side of Figure 1 shows that block scheduling imposes severe ramping requirements on the system, adding \$2.26 to the cost of each MWh delivered through the block schedule in this example (based upon modeling an example control area). The fact that these requirements always happen at the top of the hour and they are known well in advance does not reduce the amount of fast response capability the system operator needs to have to balance the system and meet CPS 1 & 2 requirements. The tariff needs to assess the individual's impact on total system variability.

This example tariff would violate principle #2 (cost-causation, see Principles of Cost-causation, earlier section) because under the (unlikely) scenario of a perfect wind or solar energy forecast, the tariff would not assess any cost to the wind or solar generator even though there is a cost of moving the regulating units to mitigate variability in the wind output signal. It also violates principle #4, which says that individual movements (or in this case schedule deviations) of individuals do not need to be matched by a responsive unit – only the aggregate variability of the entire system must be compensated. Extrapolating this type of tariff to a case when all schedules and loads are known perfectly in advance, the implication is that there is no cost to the system to manage the total system variability. This is clearly wrong, and would result in distortions in the market.

B. Thought Experiment #2: Reduced Ramping

It is tempting to design a regulation tariff that simply quantifies the peak-to-peak movements of the generator or

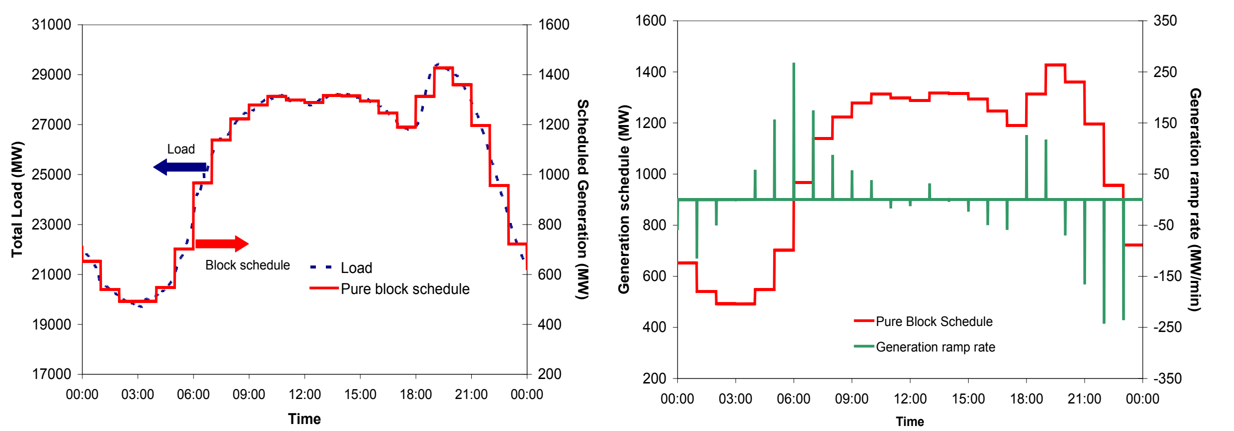

Fig 1 − How does the tariff treat perfect following of a volatile schedule?

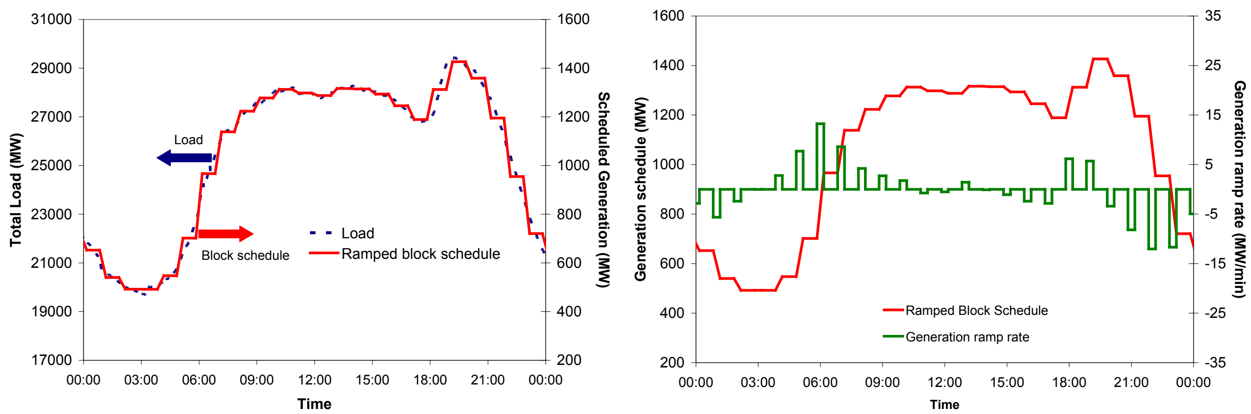

Fig 2 − Ramping the block schedule does not impact the energy delivery or forecast accuracy but reduces regulation requirements.

load. But this ignores the speed at which the resource moves from one power level to another. If the block schedule used in Thought Experiment #1 (where the schedules changed abruptly at the top of each hour) is provided with 20-minute ramps (where schedules linearly ramp from ten minutes before the hour to ten minutes after the hour), as shown in Figure 2, the regulation costs imposed on the power system drop to $0.20 per MWh (again based on modeling an example control area). Note that the ramp rate scale on the right axis of Figure 2 is one tenth of that in Figure 1.

This thought experiment violates principle #2, the principle of cost causation. Recognition of only the peak-to-peak ramp does not distinguish between the two behaviors illustrated here that have significantly different cost impacts. This also violates the principle of vertical consistency because there is a significant difference in imposed cost that would not be picked up in the tariff.

C. Thought Experiment #3: Ramp Rate or First Derivative Metrics

Another tempting regulation tariff simplification is to measure average ramp rate or the average first derivative of the minute-to-minute energy consumption. This can also be characterized as a "distance traveled" metric referring to the amount of "movement." This attempts to quantify the amount of ramping or changing of output that a generator has to provide. The flaw in this simplification is that behaviors with very different system impacts can result in the same measured performance, as shown in Figure 3.

Figure 3 compares the behavior of three hypothetical individuals (loads, wind, or solar generators, or balancing areas). The minute-to-minute change ("line slope"), integrated over the hour, is the same for all three; 60-MW-minutes. Clearly, however, the regulation burdens imposed by the three are radically different. In this very simple example, 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, should be, and is (in most locations) supplied by moving the baseload and intermediate generators. There is no regulation burden imposed by the dotted blue ramp.

Metrics based on average rate of change of an individual violate principle #2 (cost causation) and principle #4 (failure to recognize aggregation benefits).

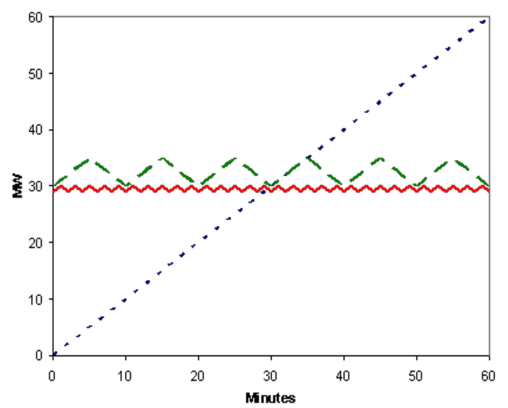

Fig 3 – These three individuals impose radically different regulation requirements but have the same minute-to-minute-change metric performance.

D. Thought Experiment #4: Equal but Opposite Behavior

One very powerful feature of thought experiments is that they can be carefully tailored to examine specific behavior characteristics. They do not have to be realistic to be useful in determining if a tariff will produce desired results. Unrealistic examples can be useful in understanding the pieces of complex behavior that are often buried in the intricacies of actual operations.

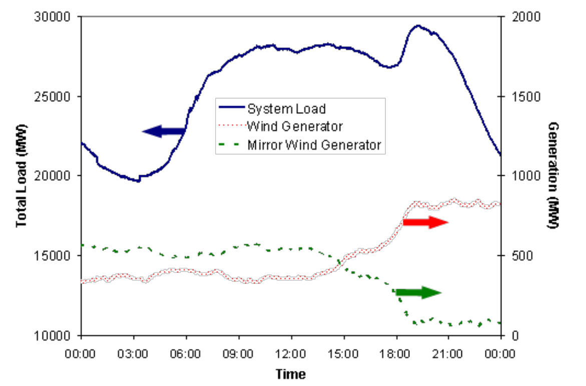

Fig 4 – How is equal but opposite behavior treated?

When designing a regulation tariff, it is tempting to assess the generator's or load's variability in isolation. This ignores the fact that the underlying reliability requirement to balance generation and load is imposed on the BA (hence its name) rather than on the individuals. Figure 4 shows two mirror-image wind plants and a total system load. If the wind plants were assessed for their variability in isolation of each other and the total system load they would both receive an identical regulation variability assessment. Together they present an absolutely constant output with no regulation burden.

This thought experiment is completely unrealistic but it illustrates an important point. A tariff that cannot recognize complete compensation of one plant for another will not recognize more subtle interactions or uncorrelated behavior that, consequently, does not add linearly.

A tariff that does not recognize the impact of equal but opposite behavior would collect payment from both of these hypothetical wind plants. However, because their impacts net to zero, there would be no cost to the system. This type of tariff would therefore violate principle #3 (the principle that if no cost is incurred, the tariff should not collect revenue) and principle #4 (the recognition that only the aggregate system variability must be compensated for).

E. Thought Experiment # 5: Beneficial Movement

The last thought experiment asks how the tariff treats movement that is beneficial. Regulation tariffs that only assess variability (total range, ramp rate, or adherence to a schedule) can penalize a resource that is actually helping reduce the total system aggregate variability. Figure 5 presents the measured variability of a number of generators and a total system. A tariff that simply charged for variability would penalize the automatic generator control (AGC) generator that is deliberately balancing the system. Presumably the tariff would not be applied to this generator but the principal remains the same. A generator that inherently has favorable response characteristics for whatever reason should not be penalized.

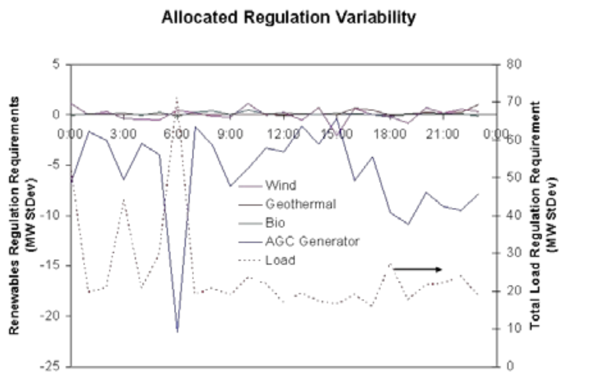

Fig 5 – Tariffs should recognize and reward favorable behavior.

A tariff that assesses a cost based on an individual's variability in isolation of what the system needs would discourage helpful behavior. Because this type of tariff would impose a cost on the generator when in fact the resource is providing a system benefit and reducing system costs by helping to mitigate system variability, this kind of cost in a tariff clearly violates principle #2 (cost causation), principle #3 (imposing a cost instead of paying the generator), and principle #4 (does not recognize system balance).

IV. Common errors in integration analysis

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. Because it is not our intent to single out entities that have committed these errors, we do not identify them, but attempt to extract the issues so that they can be identified and subsequently contribute to more accurate analyses. We also point out that the studies we have been involved with have occurred over the past decade, and there has been considerable evolution in methods and data. However, in spite of significant progress, there are many entities that are apparently not engaged in this evolution and repeat some of the errors that have been previously identified, and for the most part, corrected with the evolution of studies.

A. Double counting

Double counting in one form or another is probably the most common error made in integration studies. This usually results from failing to account for aggregation benefits, either among wind facilities and/or between wind and load.

Double counting can also result from including the same variability or uncertainty in multiple services. There are several ways in which this error can be manifest in the integration studies. The most common is violating the principle of re-composition. For example, a rolling average or other suitable filter is applied to the net load to separate regulation. Load following is then estimated by applying heuristics or rules of thumb based on utility scheduling practice. When these rules of thumb include the entire wind or solar output, which naturally contains both following and regulation components, double counting occurs. 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 (which is not plausible). The sum of the balancing requirements allocated to individual wind and solar plants, and loads should not exceed the total system balancing requirements.

Forecasting errors are often another source of double counting. Production simulation runs may be performed assuming perfect foresight: the load, wind, and solar are forecast perfectly and system costs are calculated. Another simulation is run, this time using wind and solar forecasts for the unit commitment process, and using "actual" wind and solar data for the economic dispatch. The total costs of the two simulation runs are compared and the difference is the integration cost. However, the impact of load forecast error has not been removed nor accounted for. Therefore, part of what remains in the erroneously calculated wind/solar integration cost is in fact the integration cost of load forecast errors. Similarly, the variability of the variable generation (VG) resource and the relevant forecasts are not perfectly correlated, and are thus not additive.

Load and wind forecast errors typically do not add linearly and consequently benefit from aggregation. The sum of the forecast error reserves allocated to wind and load should not exceed the total system forecast error reserves. If individual wind plant forecasts are considered, the problem is amplified. Diversity among the individual wind plant forecasts should be considered, with total reserves reduced accordingly.

Another form of double-counting is the overestimation of reserves that are needed to balance wind and solar energy. Some amount of reserve is naturally provided as a function of economic operation of the system; as mentioned earlier, integration studies that attempt to calculate integration costs typically compare the increased variability of the net load of the case with wind/solar versus the case without wind/solar. For example, increased load-following reserve requirements could be estimated by examining the distribution of 10-minute net load deltas. On average in the WWSIS, the load-following reserve requirement increased by a factor of two. However, it was only by running the actual production simulation analysis and looking at the amount of load following reserves online during each hour that it was found that the system naturally provided these extra load following reserves, because many of the thermal units were backed down, as opposed to being decommitted. As a result, WWSIS recommended that no additional load following reserves needed to be deployed because they would naturally be available as wind/solar came online. Therefore, no additional cost for committing extra load-following reserves was incurred.

B. Fixed schedules and fixed resources

Fixing transaction schedules, often hydro schedules, based upon the without-wind case optimization and holding those schedules for the with-wind case typically results in seriously sub-optimal resource scheduling and significantly higher balancing costs. Typically, system operators would not schedule hydro or conventional generation while ignoring the presence of significant amounts of wind generation. Accounting for wind (and load) forecasting errors is appropriate, but fixing hydro schedules based on assuming no VG is not.

A related error is the assumption that only a subset of generation is available for balancing response. This error is typically made when studying a region where response has historically been obtained from only one resource or only one type of resource. A BA with a significant amount of energy-limited hydro generation, for example, modeled integration of large amounts of VG 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 had not been the historic practice. It had not been historic practice because there was no need, not because there was any actual limitation. Another case results from the assumptions made about hydro response. Even though hydro generation is subject to various constraints, it should not be treated as a constant resource in integration analyses. Models are often capable of accurately representing ramp constraints, over various time steps, and yet these constraints are sometimes substituted by constant constraints on the hydro performance. These will nearly always result in different commitment and dispatch scenarios.

It is appropriate to hold the conventional installed generation mix relatively constant when studying renewable integration for the next year or two. It is not appropriate to fix the resource mix for studies examining conditions over decades, or very large changes in penetration rates of wind or solar generation. There will be generation retirement and new installations with or without wind and solar additions. The selection of the optimal generation fleet will likely be strongly influenced by the expected presence of large amounts of wind and solar. Similarly, demand response will likely be developed if the flexibility it offers is valuable and properly valued.

Scheduling practices are changing within the power industry, with or without wind and solar. Half of the load in the country is now located in regions that have five-minute energy scheduling. The fraction is continuing to grow. Some studies still calculate excessively high balancing cost based on an assumption that only hourly scheduling will be allowed in the future. This restricts access to the response capability that physically exists in the conventional generation mix.

A final scheduling error involves bilateral contracts. While the host utility that is conducting the integration analysis may have no control over some of the bilateral contracts within its BA, it is more reasonable to assume that they will change to reflect economic opportunities rather than assuming they will remain fixed for decades.

C. Balancing individual wind/solar plants or the fleet of VG separately from the system

Power system balance requires the aggregate load to be equal to the aggregate generation (ignoring imports and exports for this discussion). Therefore, not every generation movement in a wind or solar plant must be matched one-for-one with a movement in other generation. If wind generation increases at the same time as load increases, this reduces or eliminates the need for other generation to follow the load increase. Similarly, if solar generation is decreasing when load decreases, there is no need to increase other generation to fully compensate for the decline in solar generation. The concept of balancing the net load with conventional generation is well-understood in the integration literature and 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, within the past year we have seen two integration analyses that have attempted to balance wind and solar in isolation from the remaining load. This means that when wind/solar and load are both increasing, a conventional generator must decrease output to hold the wind and solar constant, but at the same time, generation must increase to meet the increasing load. This does not reflect how power systems are operated and greatly overstates the balancing costs of wind and solar.

D. Scaling

Wind and solar integration studies typically study future conditions when there is expected to be a larger amount of wind and solar generation present in the power system. Almost by definition, there is no 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. [1] and [2] shows the output from a set of 300 wind turbines. Clearly, linearly scaling the output of a single turbine (left curve) would dramatically overstate the variability of the plant (right curve). Unlike conventional power plants where a larger individual generator can be installed, larger amounts of wind and solar require installation of more individual wind turbines and solar collectors. There is inherent geographic diversity, even within a single facility. This reduces the correlated variability.

It is similarly inappropriate to simulate a new wind plant simply by time delaying or advancing the output of an existing plant based on prevailing wind speed and direction. Wind does not remain coherent over inter-plant distances, so the resulting simulation will have too much correlation and too much variability. Mesoscale modeling is currently the best way to generate the required time-synchronized wind and load data needed for valid integration studies. This also points out the importance of expanding the database of high-resolution resource (wind, solar) data that is updated annually.

E. Synchronized Load and Mesoscale Wind / Solar Data vs. Statistical Data Synthesis

Wind and solar integration studies typically model wind and solar plants that do not exist yet. Wind and solar output data must be generated for the study. It is tempting to create data with appropriate statistical characteristics based on a shaped series of random numbers. The temptation should be resisted. Not enough is known about all of the interactions between wind and load. Both are driven by atmospheric conditions, but the relationships are not simple or straightforward. The large geographic areas with varying conditions further complicate the relationships. Inter-temporal relationships for wind, solar, and load are complex and not well understood. Results from integration studies performed with statistically generated wind data do not compare well with actual data taken after the wind generation was installed.

The best current technology for generating wind data for integration studies is to use mesoscale atmospheric modeling to calculate wind speed at hub height at locations of expected wind plants. Wind speeds are typically generated at ten-minute time steps or less with a geographic grid spacing of 2 kM or smaller for a historic time period of a year or longer. The mesoscale wind data must be time-synchronized with actual load data. The load data can be scaled to future conditions. Linear scaling of load data does introduce some error, but that error is typically reasonably small because the scaling and variability are also reasonably small and well-understood.

F. Forecast data

Similar to the wind and solar dataset, the wind and solar forecast datasets must be time-synchronized to historical weather patterns. If the forecasts are assumed to be generated by a single provider for a large region, then the forecasts should show similar spatial correlation to the wind and solar datasets, over varying distances. That is, the wind forecast for a plant is more likely to be accurate if the wind forecast for a nearby plant is also accurate. 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. There is a much higher probability of significantly missing the forecast in the current hour if the provider missed the forecast in the previous hour. Forecast error distributions are not normal distributions. Missing the tails of the forecast error distributions can underestimate the uncertainty impacts of wind and solar.

G. Excessive or unknown Control Performance Standards (CPS) performance

It is important to maintain consistent reliability between the base case and the high wind and solar penetration cases. This assures that integration costs are not either subsidized by reduced reliability or charged for increased reliability. Maintaining an excessively high CPS score can be inappropriate as well. If, for example, a BA has abundant reserves and is able to maintain a CPS2 score of 98% at little cost with no wind, it is not necessary or appropriate to require a high penetration case to also have a 98% CPS2. Instead, CPS2 requirements should be relaxed to 92%-93% for both the base case and the high penetration case. This is reasonable because it reflects how operations at that BA would likely evolve as reserves became scarce and therefore more accurately reflects true integration costs.

H. Replacement power 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 because, it was assumed, no excess coal capacity would be committed day-ahead. Conversely, any excess wind power would be credited with the fuel saving from backing down coal since, it was assumed, only coal-fired generation would be running absent wind. The result was that wind was charged $70/MWh for shortfalls and credited $20/MWh for excess, creating a default $50/MWh imbalance charge that was characterized as an operating cost, not as a penalty. While the described situation could happen during some hours, 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.

I. Constant reserves

In our view, this it is surprising to see this in current or recent studies because the state of the art has evolved considerably past this. Numerous integration studies continue to assume fixed reserve amounts for wind and solar integration. Clearly, additional up reserves are not required if wind or solar are operating at full capacity. Similarly, additional down reserves are not required if wind or solar are at zero output. Reserves should be adjusted at hourly intervals to reflect the expected operating conditions, with an allowance made for forecast error. Holding fixed reserves overstates integration costs and does not reflect good operating practice. Integration studies performed during the past several years have recognized the dynamic nature of this reserve, and methods have evolved and are expected to continue to improve as more advanced methods are developed and tested.

J. Failure to release reserves

Wind and solar ramp events are similar to contingency events for conventional generators, except slower. While a large thermal generator can trip off instantaneously, it typically takes hours for a similar sized wind ramp. The events are similar, however, in that they are relatively rare. Non-spinning and supplemental operating reserves are often appropriate since the standby costs are more important than the deployment costs. There is an important modeling difference with wind and solar integration, however. Conventional contingency reserve requirements are modeled as reserves that are held throughout the analysis. This is because the contingencies themselves are not actually modeled. Instead, the analysis appropriately assumes that reserves must be available at all times, ready to respond to a random failure. Appropriate reserves must be included in the unit commitment time fame for wind and solar analysis, based on the forecast wind and solar conditions. Wind and solar reserves must be released and made available for response in the economic dispatch time. This is because the wind and solar ramps are modeled in the integration analysis. This is an important distinction between analysis of variable renewables and conventional generators. 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.

V. Additional Assumptions Play a Key Role in Results

Because of the numerous and complex interactions between the various generators and other system components, the impacts of wind and solar will be, at least partly, a function of the balance of system. Therefore, other assumptions about the non-wind and non-solar generation, along with assumptions regarding transmission availability and other institutional factors such as scheduling practice will have a potentially significant influence on integration impacts and costs (See Cost-Causation and Integration Cost Analysis for Variable Generation, www.nrel.gov/docs/fy11osti/51860.pdf, TP-5500-51860 for discussion of limitations of integration cost). The following assumptions are those that we believe are most critical to integration analysis.

A. Mix of generation

Issues such as minimum generation constraints are in large part a function of the non-VG fleet interacting with the VG during periods of low load. In the future it is possible, or even likely, that more flexible generation will replace inflexible base-load generation, reducing or eliminating this problem.

B. Institutional constraints may change in the future

Changes in operating practice, balancing area configurations, or other institutional constraints that increase the difficulty and cost of integrating VG may change in the future, especially one or more decades out, which is when many integration studies are focusing. Likewise, power purchase contracts that are in place today may be modified in the future if that can improve the operating or economic efficiency of a system with large penetrations of VG.

C. 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 the latest information and more accurate forecasts. At the time of this writing, there is significant effort going into the development of better underlying weather forecast models, such as the High Resolution Rapid Refresh (HRRR) model that can run hourly instead of every six hours, taking advantage of recent weather data to provide more accurate inputs to wind and solar forecast models. At the same time, increasing adoption of computer and communication technology will make it possible to incorporate these forecasts closer to real-time. Thus the “lock-down” period for generator notification and movement to subsequent dispatch levels could be shortened, resulting in more accurate positioning of the hydro and thermal generation fleet and a corresponding reduction in expensive regulation, which must pick up the dispatch errors.

D. More frequent dispatch/scheduling in the Western Interconnection

Until and unless the EIM (or other similar process) is implemented in the West, schedules and much of the economic dispatch is hourly. An hourly scheduling process strands the physically-available flexibility that is inherent in the generation fleet, calling on the economic dispatch stack once an hour to move to a new operating point. All changes within the hour must then be managed by regulating units, which comprise a relatively small proportion of the online generation. Moving to sub-hourly markets running 5-minute dispatch and schedule changes for imports and exports will substantially increase the ability of the system to manage higher penetrations of VG.

E. Operating footprint

Larger operating footprints (balancing areas) can do more with less. The ramping capability of the generation fleet adds linearly with expansion; the ramping needs of the power system add less than linearly. Compliance costs and operational inefficiencies may drive small BAs to coordinate or merge with neighboring systems. EWITS showed that adding a transmission overlay decreases loss of load probability (LOLP), thus decreasing or delaying the need for new generation. [3] shows that there are considerable efficiencies that accrue in both operating and planning (long-term costs) for coordinated or combined planning and operations.

F. Methods to simulate wind and solar forecast errors are still quite primitive, yet have a significant impact on integration

Representing a future build-out of large-scale wind/solar requires time-synchronized wind/solar data at short time steps of no longer than 10 minutes for at least 3 years. These datasets are derived from numerical weather prediction models that are run for the desired time period, and wind/solar data are extracted at high geographic and temporal resolution. To adequately simulate power system operations, it is necessary to also have forecasts over several time horizons that can inform the unit commitment and dispatch processes; however, there is substantial disagreement within the wind forecasting community (solar forecasting is not yet well-developed) regarding methods to do this. Yet wind forecast distributions and timing can have a significant impact on integration.

VI. CONCLUSIONS

In spite of the considerable progress that has been made in integration modeling and analysis, the discipline is still maturing and there are significant questions still remaining. 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. Integration studies have grown in scope, complexity, and sophistication. 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 simplifications and generalizations that would be necessary in the development of such a tool.

In this paper we have discussed cost-causation tests that can be applied to integration analyses, and have shown some of the shortcomings that we have observed in wind integration studies around the United States.

VII. REFERENCES

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