

An Introduction to Variable-Energy-Resource Integration Analysis

Energy Exemplar

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1. Introduction

Increased Renewable Portfolio Standards (RPS) are being enacted at the state, provincial, and federal level, causing significantly larger amounts of renewable resources to be added to the regional electric system, both now as well as in the future. A substantial amount of these new resources are currently envisioned to be either wind or solar Photovoltaic (PV). These types of resources are frequently labeled “Variable-Energy-Resources” (VER) since their output can be highly variable depending on weather fluctuations such as wind speed and cloud cover.

A second characteristic of Variable-Energy-Resources, in addition to having highly variable output, is the associated weather conditions are difficult to precisely forecast very far into the future. For example, a wind forecast 24 hours in advance may be as much as 10 percent in error or greater. Hence, there is a significant “forecast error” that also needs to be considered in addition to the intermittent output.

Given the increased penetration of these resources and their variability and forecast uncertainty, many balancing areas are re-evaluating the sufficiency of their Ancillary Service (AS) requirements, as well as the “integration cost” of incremental levels

of VER. This white paper will provide a high-level summary of how a balancing area or governmental authority can gain a significantly increased understanding of operating sufficiency and integration costs with the PLEXOS software model¹ and highly-experienced consulting personnel.²

2. Determination of Increased Ancillary Services

In order to operate reliably, a balancing area must provide certain system capabilities in addition to providing sufficient energy to meet the load demand. These capabilities are often referred to as Ancillary Services (AS) and are frequently in the form of operating reserves, regulation, and load-following requirements. These AS ensure the balancing-area generation and load are matched on a second-to-

¹ PLEXOS is a proven simulation software solution that uses cutting-edge mathematical programming and stochastic optimization techniques to provide a robust analytical framework for power market models. PLEXOS is developed and supported by Energy Exemplar (www.energyexemplar.com).

² Energy Exemplar has industry-leading wind integration consultants at its Sacramento, California office. The principal technical leads each have 20+ years of unit commitment / dispatch algorithm experience and PhDs in power system engineering and operations research.

second basis and that the system can be reliably operated, even if a generation unit or transmission line suddenly becomes unavailable.

As Variable-Energy-Resources are added to the balancing area, increased amounts and potentially new types of ancillary services are required to maintain the operability and reliability of the system. There are at least two commonly-accepted methodologies for determining this incremental AS requirement.

$$\text{Net Load} = \text{System Load} - \text{Wind} - \text{Solar PV}$$

The first method is to compute the increase in “net load” volatility. In this context, the “net load” is defined as the remaining system load, after the contribution of wind and solar PV resources has been recognized in the formula above.

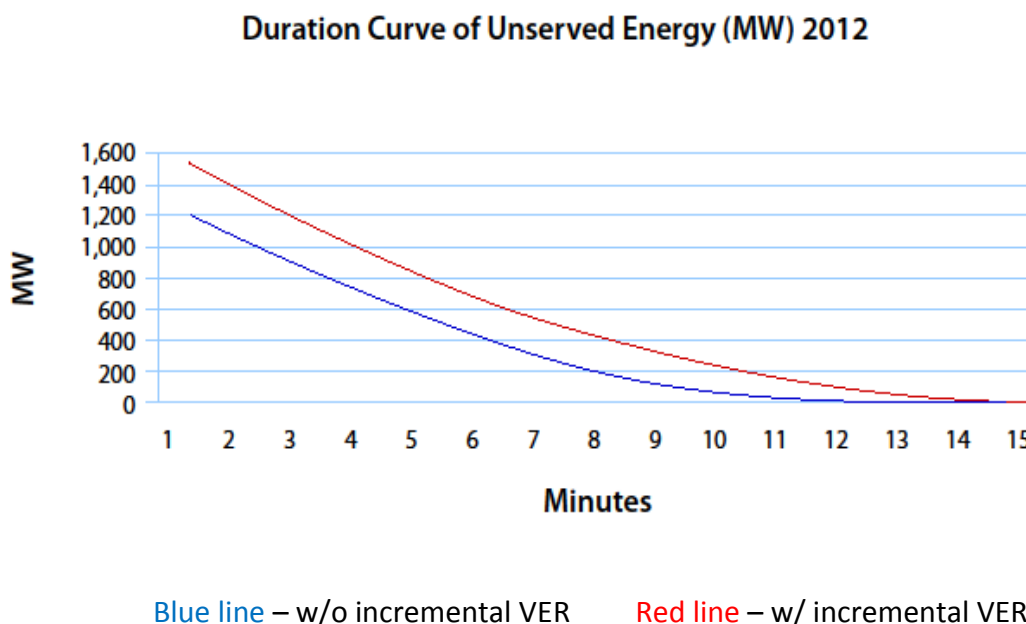
The standard deviation of the change in load (load delta) over a specified period of time can be computed for both the original “system load” as well as the “net load.” Frequently, a 10-minute,

change-in-load standard deviation is used as a basis for comparison. For example, existing regulation standards might be based on 95 percent of the 10-minute, delta-load standard deviation. In this case, the increased regulation reserve could be defined as 95 percent of the increase in the 10-minute standard deviation. If the 10-minute standard deviation increases by 50 MW, the regulation requirement would be increased by 45 MW. The advantage of this methodology is its common acceptance and its specific, formulaic approach that is easily computed.

A second method is based on directly measuring system operational performance. Violations (or deficiencies) of defined operational parameters are measured both before, and after, the addition of a specified amount of VER. Operating parameters that are often computed and evaluated in this type of analysis include:

- Unserved energy
- Overgeneration
- Spinning reserve
- Non-spinning reserve
- Regulation-up
- Regulation-down

Figure 1
Illustrative Unserved-Energy Violation-Duration Curve



The addition of incremental Variable Energy Resources such as wind or solar PV can cause operational reliability parameters to degrade. The amount and cost of the increased system Ancillary Services to restore the system to its original capability can be defined and quantified as an integration cost.

Once a summary of operational violations can be summarized for the two cases (without and with additional VER) for each of the operating parameters listed above, additional AS

are added until the operational performance of the two cases are comparable. This is not a formula-driven process, but more of a trial-and-error approach, until operational equivalence is achieved.

The advantage of this approach is that it measures the most important system characteristic, overall operational performance, instead of focusing on a proxy parameter such as net-load changes. For example, a system may have a 10 percent increase in its 10-minute-load deviation, but a 30 percent degradation in one or more operational parameters.

The primary disadvantage of this approach is that it requires much more computation time than the first approach. Generally, up to 100 (or more) samples are required, incorporating VER intermittency and forecast uncertainty before a reasonably-clear picture of the magnitude and frequency of the operational violations can be determined.

3. Incorporation of Forecast Uncertainty

There is also a significant amount of forecast uncertainty with Variable Energy Resources. This forecast uncertainty increases as the forecast period increases from the next 5 minutes to the next 24 (or more) hours in advance. Clearly, predicting the wind speed and the cloud cover 14 to 38 hours ahead of the actual conditions is an exercise subject to much imprecision, despite the significant progress made in forecasting accuracy over the last few years.³

Often when the output of a generating resource is subject to a significant amount of uncertainty, that variable is modeled stochastically. In other words, the uncertain variable is modeled not as a single value, but a distribution of values.⁴ For example, the person

responsible for the resource schedule the next day, (i.e. day-ahead scheduler) might use a distribution of hourly profiles (i.e. generation values) for a wind farm, instead of a single hourly profile. These hourly profiles may represent actual historical conditions.

The difficulty with modeling these potential outcomes is that all simulation tools have what is frequently termed in the industry as “perfect foresight.” Since the distribution represents a series of potential actual outcomes, each time an outcome is selected, the model is fully aware of this situation when the resource schedule is prepared. For example, if a generating unit has a forced outage rate of 5 percent, and a Monte Carlo draw is employed, the draw will inform the model whether the unit is available or unavailable prior to scheduling all the other units. Thus, the model has the benefit of perfect foresight.

Unfortunately, day-ahead schedulers do not have perfect foresight. They must develop schedules based on the forecast as opposed to actual conditions. In order to accurately represent this uncertainty facing the day-ahead scheduler, the day-ahead schedule is developed based on forecast values, but the real-time schedule is done with actual conditions.

Therefore a 100-sample simulation for a single day will contain 100 different day-ahead load, wind, and solar PV forecasts. For each forecast, a resource schedule (i.e. unit commitment and dispatch) is developed based on that forecast information. Each forecast will lock in a specific set of resources. These

³ Schedulers will often finish their day-ahead schedule at about 10 am of the preceding day. This schedule becomes effective at midnight or 14 hours after submitting the day-ahead schedule, and remains in effect for the following 24 hours.

⁴ In the software model PLEXOS, any variable can be treated stochastically, provided the distribution of that variable and the correlation with other stochastic variables is quantifiable and input into the model.

resources will either be available or unavailable for the actual conditions, based on the decisions made by the day-ahead scheduler using forecast values. It is critical when trying to understand the impact of forecast error, to model both the day-ahead resource schedule with forecast values, as well as the real-time performance.

If the purpose of the analysis is to determine expected or average production costs, only a few day-ahead to real-time samples may be required. On the other hand, if the purpose is to understand operational shortfalls or violations, these are considered infrequent events and many samples may need to be undertaken in order to understand these “tail-end events.”

The day-ahead schedule is developed based on forecast values, but the real-time schedule is done with actual conditions when modeling the markets.

Stochastic Unit Commitment -- There is a second, recent and more advanced method that can be used to develop the day-ahead resource schedule. In the method described in the previous section, the day-ahead unit commitment is based on a single forecast without considering the uncertainty of that forecast. On the other hand “stochastic” unit commitment directly incorporates the uncertainty of the underlying events into tomorrow’s resource schedule.

For example, assume a Balancing Area has a relatively large generating unit on

its system that represents 30 percent of the generating capacity. The operator could make one of two assumptions – either the unit would be available or not for the following day. If this large unit were online at the time the day-ahead schedule was developed, the day-ahead scheduler would likely assume that it would continue to be available for the following day.

However, if the operator assumed that the large unit would be available the following day, and it was not available, there would be insufficient generation to meet the load (since most systems only have about a 15 percent planning reserve margin). In those situations, the outcome could be disastrous.

A detailed description of the stochastic unit commitment algorithm is beyond the scope of this introductory paper.⁵ However, the essence of the stochastic resource schedule allows for the operator to do the following:

- Consider many potential outcomes and their relative costs when developing the day-ahead unit commitment
- Develop a more conservative and robust commitment solution for the following day

The stochastically-developed resource schedule costs for the original VER case could then be compared against the same methodology for an incremental VER case. The difference in production

⁵ The stochastic unit commitment algorithm has been successfully incorporated in PLEXOS. For details regarding this and other PLEXOS capabilities, contact Eric Toolson at eric.toolson@energyexemplar.com.

costs between these two cases can provide an interesting insight into the additional system costs of increased wind and / or PV solar.

4. Calculation of “Integration Cost”

The Variable Energy Resource “integration cost” represents the incremental system cost that is incurred by adding intermittent resources with variability and forecast uncertainty, as opposed to traditional resources whose generation output is more predictable. Although there are multiple methodologies utilized for computing the integration cost, perhaps the most common one is to model the incremental VER energy as a predictable flat resource in first case. The second case then models the VER as an intermittent resource with variability and forecast uncertainty. The difference in total system production costs between the two cases, divided by the amount of additional Variable Energy Resource is the “integration cost” expressed in \$/MWh in the formula below.

Using this formula, the incremental cost of increasing levels of Variable Energy Resource can be determined. The incremental costs of increasing VER is generally expected to increase as the least expensive system solutions are utilized first and the more expensive solutions are utilized later as less costly alternatives are no longer available.

$$\text{VER Integration Cost} = \frac{(\text{Var. Resource Cost} - \text{Flat Resource Cost})}{\text{Increment of VER}}$$

5. Advantages of the PLEXOS Software

PLEXOS for Power Systems™ is an advanced fundamental market simulation tool developed and continually enhanced over the last 10 years. PLEXOS has three features that are currently unique to resource planning simulation tools and are of tremendous value when performing VER integration analyses.

The first feature is that PLEXOS performs a **“simultaneous optimization”**. Instead of the traditional Lagrangian Relaxation theorem which is employed by most planning models and utilizes heuristics and an iterative solution for resource scheduling, PLEXOS uses a Mixed Integer Program (MIP) which allows for all decision variables to be solved at the same time. No heuristics or iterative methodologies are needed.

This process allows for an “operational-quality” level of solution. PLEXOS is the only planning tool which is used routinely by utility operation departments for day-ahead unit commitment and dispatch due to the sophistication of its simultaneous optimization. The PLEXOS algorithm mimics the market-clearing mechanism of Independent System Operators (ISO) in their Day-Ahead (DA) and Real-Time (RT) markets. The PLEXOS approach also allows the user to easily define and implement additional ancillary services such as regulation-up, regulation-down, load-following, and other user-defined system requirements.

The second feature is that PLEXOS can perform **“5-minute time step”** simulations whereas other planning

models are usually limited to an hourly time-step. This allows PLEXOS to accurately model the Real-Time (RT) market and the intra-hour constraints which are ignored with an hourly model. This level of modeling is crucial when performing VER integration studies since many of the system constraints are intra-hourly as opposed to inter-hourly.

The third feature is the **“stochastic unit commitment”** as described in the preceding section. This capability allows PLEXOS to develop a more robust next-day resource schedule which directly incorporates the potential risk from unexpected events.

6. Conclusion

The intent of this white paper is to present several current methodologies for establishing the integration reliability and cost for increasing amounts of Variable Energy Resources such as wind and solar PV. The tool that is used for this purpose, PLEXOS for Power Systems, coupled with a very capable staff, allows for new insights and observations to be analyzed and evaluated.

For further questions regarding this paper, please contact:

Eric Toolson
Regional Director, North America
Energy Exemplar LLC
3009 Douglas Blvd., Suite 175
Roseville, CA 95661
eric.toolson@energyexemplar.com
(916) 722-1484, ext. 4