Managing the Reliability Risk and the Consumer and Producer Cost of Intermittent Renewables Integration

by

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1. Introduction

Many jurisdictions around the world have significant intermittent renewable energy goals. California's investor-owned utilities are required to obtain 33 percent of their electricity from qualified renewable resources by 2020. Governor Jerry Brown recently signed legislation raising this requirement to 50 percent by 2030. Achieving these renewable energy goals is likely to require significant storage and operating reserves to manage the intermittent supply of electricity from the wind and solar resources slated to meet the majority of these renewable energy goals.

Wolak (2015) shows that where these wind and solar resources are located significantly impacts the mean and standard deviation of the hourly production of all wind and solar generation units. Specifically, for the same amount aggregate installed wind and solar generation capacity, it is possible to increase substantially the mean hourly output of all these resources or significantly reduce the standard deviation of their total hourly output by optimizing where and how much capacity is built at each renewable resource location in the California Independent System Operator (ISO) control area.

Consequently, by optimizing where and how much solar or wind capacity is constructed at each resource location in California, the cost of achieving a given renewables portfolio standard goal can be significantly reduced. This project first investigates how increasing the share of wind and solar energy impacts the hourly, weekly, and monthly variability of the energy produced from these units. It then computes the distribution of the thermal dispatch costs associated with managing the real-time supply and demand balance in the ISO control area. This distribution is then use to compute the optimal mix of renewable capacity investments across all wind and solar locations in California to minimize the expected thermal dispatch costs or a weighted sum of expected thermal dispatch costs and the standard deviation of these dispatch costs. These distributions will also be used to derive methods for setting day-ahead schedules of wind and solar units to minimize the various measures of the cost of maintaining real-time supply and demand balance in the California ISO control area. The result of this analysis will be used to construct locational-specific interconnection charges for locating new wind and solar generation units that price the expected thermal energy and ancillary services costs of intermittent solar and wind generation unit location decisions.

2. Managing Reliability Risk

The first phase of this project builds on the analysis in Wolak (2015) of the trade-offs between the mean hourly output and the standard deviation of hourly output and mean hourly revenue and the standard deviation of hourly revenue of wind and solar resources in the California ISO control area. The analysis reported in Wolak (2015) is based on the wind and solar generation capacity in place as of April 1, 2011. For the April 1, 2011 to March 31, 2012 sample period in Wolak (2015), the actual portfolio of wind and solar generation capacity is shown to deviate significantly from the hourly output mean-standard deviation efficient frontier and but not nearly as much from hourly revenue mean-standard deviation efficient frontier. This result is consistent with the unilateral profit-maximizing location decisions of wind and solar generation capacity investors caused by the prevailing power purchase agreements used to compensate these unit owners for the energy their units produce. These are incentives are discussed in Wolak (2015).

More than 4,000 megawatts (MWs) of new solar and wind generation capacity has been added in the California ISO control area since April 1, 2011. An important question is whether the current mix of wind and solar generation capacity is closer to either or both the hourly output and hourly revenue mean-standard deviation efficient frontier as a result of these new wind and solar investments. Using hourly generation unit-level output data from April 1, 2012 to September 1, 2015, efficient frontiers will be computed using hourly output data from all existing wind and solar generation locations following the same procedure outlined in Wolak (2015).

Wolak (2015) focused on measuring output risk on hourly basis, but there is also the potential for output risk on a daily, weekly, or even a monthly basis. With the longer period of generation unit-output data, this project will explore the wind and solar output variability risk with a significantly larger amount of solar and wind capacity by constructing estimates of the joint distribution across locations of daily, weekly, and monthly wind and solar output. An accurate estimate of the joint distribution of wind and solar output over longer horizons than the operating hour is a key input into storage capacity investment decisions and in managing low hydroelectric energy availability, which periodically occurs in the Western US. More grid-connected storage capacity and more water stored behind hydroelectric turbines can allow the California ISO to manage a longer period of time with limited wind and solar energy production. Consequently, accurate estimates of these distributions are important input into the annual and quarterly planning of generation outages in response to hydroelectric conditions

The estimated joint distribution of the hourly output per MW of capacity at all California wind and solar locations can be scaled up to simulate the distribution of hourly wind and solar output with more wind and solar generation capacity in the California ISO control area. This distribution can be used estimate the wind and solar curtailment risk associated with more wind and solar capacity at existing locations and probability of over-generation as different mixes of wind and solar capacity are expanded. This information can help address the reliability challenges associated with scaling wind and solar capacity to meet the 33 percent mandate by 2020 and the recently approved 50 percent Renewables Portfolio Standard (RPS) mandate by 2030 and demonstrate the economic benefits of storage capacity investments in meeting these goals.

3. Managing the Producer and Consumer Cost of Intermittency

This phase of the project will study the question of how to best locate and schedule wind and solar resources to minimize expected thermal generation dispatch costs and sum of these expected thermal generation dispatch costs and expected ancillary services costs. Total thermal dispatch costs each hour of the day can be computed using information on the heat rate curves of thermal generation units in the California ISO control area and the daily prices of natural gas in Northern and Southern California. The mix of wind and solar generation capacity can be chosen to minimize the expected cost thermal generation needed to meet demand or the weighted sum of this expected cost and the standard deviation of this expected cost (as a proxy for the expected cost of ancillary services).

Conditional on a given mix of wind and solar generation capacity, the day-ahead wind and solar generation schedules can be chosen to minimize the expected wholesale electricity costs to consumers. Specifically, using information on the day-ahead and real-time thermal offer

curves submitted to the California ISO, it is possible to compute day-ahead schedules for all intermittent generation units to minimize the expected wholesale energy procurement costs. Because thermal generation unit offer curves are significantly steeper in the real-time market relative to the day-ahead market and the fact that real-time wind and solar output tends to be highly positively correlated across locations with the same renewable generation technology, optimizing the day-ahead schedules of these generation units can significantly reduce the total wholesale costs to consumers of the thermal energy purchased to maintain system balance. Most US ISOs offer day-ahead scheduling services for wind and solar generation resources in their control area. The results of this modeling effort can be used to design scheduling protocols that reduce the need for transactions in the real-time energy market and limit the ISO's demand for ancillary services.

Both the generation capacity location problem and wind and solar generation scheduling problem will be studied using hourly output data and the daily thermal marginal cost curve for the period April 1, 2012 to September 1, 2015. By optimizing where a given total MWs of wind and/or solar capacity is located, the expected thermal energy cost or the expected thermal energy and ancillary services costs can be minimized. By optimizing the day-ahead schedules of the existing mix of intermittent resources the total of the day-ahead and real-time cost of maintaining the real-time supply and demand balance can be minimized.

3.1. Optimal Location Decision

To understand the solution to the expected cost minimizing renewable generation mix problem, define the residual thermal demand in hour h as QD(res,h) = QD(tot,h) – QS(renew,h), where QD(tot,h) is the total system demand in hour h and QS(renew,h) is the aggregate renewable output during hour h. Let w_j equal the capacity share at location j, f_{jh} equal the capacity factor of renewable generation at location j during hour h, and K_T equal total amount of renewable capacity in the control area. In terms of this notation, the hourly total output of renewable resources, $QS(renew, h) = \sum_{j=1}^{J} w_j^{act} f_{jh} K_T$, where w_j^{act} is the actual capacity share at location j. Let C(Q(res,h)) equal the realized thermal cost of producing Q(res,h) during hour h. This is simply the area under the aggregate thermal marginal cost curve during hour h up to output level Q(res,h).

Solving the following optimization problem yields the minimum expected thermal dispatch cost mix of wind and solar capacity:

$$\min_{\{w_j\}} \mathrm{E}(\mathrm{C}(\mathrm{Q}(\mathrm{tot,h}) - \sum_{j=1}^{J} w_j f_{jh} K_T)) \text{ subject to } \sum_{j=1}^{J} w_j = 1.$$

The solution to this problem yields the shares of wind and solar capacity investments at each location that minimizes expected thermal dispatch cost. This problem can be operationalized with actual hourly generation unit-level production data, using the sample mean across all hours in a year in place of $\mathrm{E}(\mathrm{C}(\mathrm{Q}(\mathrm{tot,h}) - \sum_{j=1}^{J} w_j f_{jh} K_T))$. The solution to this problem can provide valuable input into the transmission planning process and intermittent generation investment decision-making process as discussed below.

3.2. Optimal Scheduling Decision

One objective for the wind and solar generation day-ahead scheduling process is to minimize the expected total wholesale market procurement costs for day-ahead and real-time non-renewable energy and ancillary services. The realized value of the total non-renewable wholesale energy and ancillary services costs of balancing supply and demand in real-time can be computed from hourly generation unit-level offer curves into the day-ahead and real-time markets for energy and ancillary services.

Recognizing that wind and solar generation capacity will produce as much energy as is available from wind and solar resource locations subject to the transmission network configuration, this portion of the project will assess the extent to which different generation-unit-level wind and solar scheduling strategies that account for the spatial and temporal correlation in real-time output of these units can minimize the following two objective functions: (1) the weighted sum of expected thermal generation dispatch costs and the standard deviation of thermal generation costs, and (2) the expected value of non-renewable wholesale energy and ancillary services procurement costs to electricity retailers. Unit-specific wind and solar schedules day-ahead schedules that minimize each of these objective function will be found using sample moments computed from actual hourly production and offer curve data.

The results of this project should be of use to ISOs in a number of ways. First, information on the system-wide hourly output and hourly revenue mean/standard deviation trade-off can assist ISOs in understanding how much of the variability in wind and solar output is intrinsic to the these technologies and how much is caused by specific location decisions made by expected profit-maximizing resource wind and solar generation developers. Second, information on the distribution of wind and solar output on an hourly, daily, weekly and monthly basis is useful to ISOs in scheduling annual generation outages and in making decisions about whether to allow generation units to retire. For example, the distribution of wind and solar generation for a geographic region that contains a major load center can be used to determine whether a combustion turbine in that load center can be retired without adversely impacting system reliability. The results of the wind and solar scheduling problem can be used by ISOs to design a lower cost wind and solar scheduling process. This approach to setting generation unit-level wind and solar day-ahead schedules could be a win-win in the sense that is reduces imbalances charges to wind and solar resource owners and minimizes the cost that loads have to pay to the remaining resource owners for ancillary services and imbalance energy.

3.3. Transmission Interconnection Pricing

The final phase of the project will build on results from the optimal mix of wind and solar generation resources to explore the viability of setting location-specific interconnection charges for intermittent renewable resources that price the increased costs of ancillary services and imbalance energy caused by the additional renewable generation capacity at that location in the control area. Because ancillary services costs are paid by loads in all US ISOs, renewable resource owners have little incentive to account for the impact of their location decisions on the increased cost of ancillary services and system imbalance costs to load in their location decisions. As shown in Wolak (2015), the same number of megawatts of intermittent renewable generation capacity built at different locations in the California ISO control area will have a different impact on both the expected amount of aggregate renewable energy produced and the

variability in the amount renewable energy supplied. By setting locationally-differentiated interconnection charges for new intermittent renewable generation investments, ISOs can provide incentives for entry at locations that enhance, rather than detract from the overall reliability of the grid. For example, a properly constructed location-specific interconnection charges could help the California ISO manage a higher share of intermittent renewable generation at lower cost.

The major anticipated benefit of this portion of the project is to provide methods for planning and pricing transmission network interconnections to minimize the overall cost of serving load and meeting renewable energy goals.

References

Wolak, F.A. (2015b) "Mean versus Standard Deviation Trade-offs in Wind and Solar Energy Investments: The Case of California," available subject to California ISO approval for release.

Data to Be Used for Project

The following data for the period April 1, 2012 to September 1, 2015 will used for this project.

Day-ahead market data

1) Bids and offers into day-ahead market
2) Accepted schedules in day-ahead market
3) Bids and offers into day-ahead ancillary services markets
4) Accepted offers into day-ahead ancillary services markets
5) Day-ahead hourly LMPs at all locations (including interties and LAPs)
6) Day-ahead hourly ancillary services prices for all products

Real-time market data

1) Bids and offers into real-time market
2) Bids and offers into real-time ancillary services markets
3) Accepted offers into real-time ancillary services markets
4) Real-time 5-minute LMPs at all locations (including interties and LAPs)
5) Real-time ancillary services prices for all products

Settlement Data

1) Real-time production and withdrawals from California ISO grid by location