The Impact of Improved Solar Forecasts on Bulk Power System Operations in ISO-NE

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The Impact of Improved Solar Forecasts on Bulk Power System Operations in ISO-NE

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Abstract—**The diurnal nature of solar power is made uncertain by variable cloud cover and the influence of atmospheric conditions on irradiance scattering processes. Its forecasting has become increasingly important to the unit commitment and dispatch process for efficient scheduling of generators in power system operations. This study examines the value of improved solar power forecasting for the Independent System Operator–New England system. A state-of-the-art production-cost modeling environment was used with both utility-scale and distributed solar photovoltaic power. Current state-of-the-art numerical weather prediction forecasting accuracies in the day-ahead and four-hour-ahead horizons were considered, in addition to uniform forecasting improvements of 25%, 50%, and 75%, as well as a base case of no solar power forecasting and a reference case of perfect forecasting. The results show how 25% solar power penetration reduces net electricity generation costs by 22.9%. If solar power forecasts were not considered, the power system would experience overcommitment of generation as well as a much higher solar curtailment, which would lead to a reduction in net generation costs of 12.3%. If solar power forecasts are uniformly improved by 25%, the net generation costs are further reduced by 1.56% ($46.5 M). However, if solar power forecasts are further improved, the results do not show significant differences in terms of net generation cost. The high solar power penetration case reduces electricity prices while increasing hourly variability. Solar power forecasting plays an influential role in the impact of solar power on electricity prices.**

Keywords-solar power forecasting; production-cost modeling; electricity prices

I. INTRODUCTION

Solar power forecasting is complex, because deviations in clear-sky power estimates are a localized phenomenon; whereas predicting solar power most likely occurs from a more global perspective. For example, sparse cumulus clouds over a photovoltaic (PV) plant sporadically attenuate power output, but the magnitude and timing of these changes are uncertain. For centralized solar power conversion, the resolution of models—whether based on numerical weather prediction (NWP) [1, 2] or satellite imagery [3]—is never perfect, and the aggregation of many plants can lead to additive or destructive variability depending on a plant's geographic proximity. There is a limit to the benefits that can be had from the law of large numbers and geographic smoothing effects. For distributed solar power conversion, problems occur because solar power output is mostly reshaping load from residential and commercial installations. Because load is stochastic, for all intents and purposes, there would be uncertainty in net power output even with perfect distribution solar power forecasting. Of concern to grid operations is: what is the economic value of enhanced forecasting of these centralized and distribution perturbations?

Power system operators' commitment to the integration of new forecasting approaches, models, and strategies must be predicated with knowledge of the associated economic benefits. The benefits to the unit commitment and economic dispatch process from superior renewable energy forecasting are largely unquantified in the power community. This is partly because such technologies are new and unproven, but it is more likely because current renewable energy penetration levels in the United States [4] are too low to appreciably quantify the value of improving renewable energy forecasting. In addition, the power system is very complex, and it is often difficult to assign costs or benefits to a single generator [5]. Nevertheless, solar power installations are rapidly growing, and penetration levels will soon require that increased attention is placed on the value of forecasting. A way forward is to examine power systems with likely future solar power scenarios and quantify how much value solar forecasting can provide. Modeling and simulation is one avenue to exploring electrical grid scenarios that can inform stakeholders of possible benefits and implications of evolving systems.

The Independent System Operator–New England (ISO-NE) system's electrical grid encompasses six U.S. states and serves an estimate 6.5 million customers with a peak load in 2006 of 28,130 MW [6]. The National Renewable Energy Laboratory (NREL) has modeled and simulated the ISO-NE system using a state-of-the-art production-cost modeling environment [7]. An envisioned future scenario of 25% solar power penetration was examined. Day-ahead (DA) and four-hour-ahead (4HA) forecasting time horizons were considered, with forecasting accuracies derived from a state-of-the-art NWP routine. A base case scenario of no solar power forecasting and a reference case of perfect solar power forecasting were also considered to provide lower and upper bound estimates on the value of solar power forecasting, respectively. Uniform forecasting improvements of 25%, 50%, and 75% were considered to assess the value of forecasting for the assumed future scenario.

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II. LITERATURE REVIEW

Wind power forecasting is more common than solar power forecasting in the United States because of wind power's greater level of penetration, but literature about the true value of forecasting improvements is still sparse. Because of the overlapping concerns about wind and solar power—namely, variable and uncertain power conversion—both were considered in a literature review to understand the issues surrounding renewable power forecasting.

Pinson et al. [8] considered probabilistic forecasts for a wind farm within the Dutch electricity market with the assumption that wind generation had negligible influence on imbalance prices, and they showed that regulation costs are reduced when wind power is overestimated rather than underestimated. McGarrigle and Leahy [9] considered the Irish electricity market and found an average savings of 4.1 million pounds for every percentage point decrease in the normalized mean absolute error (NMAE) as measured between forecast and actual wind for the 4% to 8% mean absolute error (MAE) range for the year 2020. The caveat is that the NMAE metric can be misleading, because forecasts that have different error distributions can have the same NMAE but differ significantly in cost, especially during time steps characterized by extreme forecast errors. Meibom et al. [10] appraised the value of a perfect forecast for the Irish electrical grid to be €1 million to €65 million, finding that that value generally increased with the level of wind penetration. Tuohy, Meibom, et al. [11] used a model adapted from earlier work [10] that compared deterministic, stochastic, and perfect forecasting; interestingly, in some cases demand was not met. Ummels et al. [12] found minimal cost savings for thermal generation units in the Danish interconnection. This may be because the majority of thermal units were combined heat and power, which have additional operating constraints.

Pedro and Coimbra [13] compared various mathematical approaches to solar power forecasting and assessed their performance using MAE, mean bias error (MBE), and coefficient of correlation. Findings showed that artificial neural networks outperformed other techniques, and enhancements from genetic algorithm optimizations of their parameters were vital. Mathiesen and Kleissl [14] validated common NWP forecasting methods using SURFRAD data. The European Centre for Medium-Range Weather Forecasts (ECMWF) model was found to be most accurate for cloudy conditions; whereas the Global Forecast System had the best clear-sky accuracy. Bacher et al. [15] considered online forecasting of PV power production by predicting hourly values during a 36-hour forecasting horizon using 15-min data. Autoregressive (AR) and AR with exogenous (ARX) methods (fed with NWP inputs) showed that short-term (<2h) performance was dominated by recent data; whereas longer term (>2h) performance was driven by the NWP system; and ARX outperformed AR by 35% as measured by the root mean square error (RMSE). Lorenz et al. [16] examined regional PV power forecasting up to a 3-day horizon using the ECMWF. Forecasting accuracy was found to be a function of the size of the region, in which a single location showed an RMSE of 36% and the entire area of Germany showed an RMSE of 13%. Kostylev and Pavlovski [17] proposed a common methodology to evaluate forecasting performance. The proposed standards include intra-hour, hour ahead, day ahead, and week ahead. Statistics considered include MAE, MBE, and RMSE.

III. METHODOLOGY

The PLEXOS production-cost modeling software [7] is used to simulate the operation of the ISO-NE power system to assess the value and impact of improved solar forecasts on bulk power system operations. The ISO-NE model simulates the DA, 4HA, and real-time (RT) markets. ISO-NE does not have a 4HA market in place; however, we model it in PLEXOS to represent the rolling security-constrained unit commitment process at the last timescale when it is possible to commit gas combined-cycle (CC) power plants as well as gas and oil steam turbines. The three markets are modeled with 1-hour time steps.

The ISO-NE model assumes a mixed-integer programming (MIP) optimality gap of 0.1%. The model is run nodally for voltage levels equal to or above 69 kV using 2006 load [18] and solar time series [19]. The electricity generation mix includes the conventional generators present in ISO-NE in 2010 in addition to 25% solar power penetration in terms of electricity demand. The PV solar power generators are grouped into utility-scale solar power and distributed solar power. Table I shows the installed capacity for each electricity generation source.

TABLE I. INSTALLED CAPACITY FOR DIFFERENT ELECTRICITY GENERATION SOURCES

Electricity Generation Source	Installed Capacity (MW)
Nuclear	4,878
Coal	3,740
Gas	17,101
Oil	5,691
Hydro	1,675
Pumped hydro	1,692
Biomass	844
Solar—utility scale	11,344
Solar—distributed	16,304

NREL's solar power data for integration studies [19] is the source for the solar sites included in this study. The database includes 68 utility-scale solar power plants and 76 distributed solar power plants in ISO-NE. The total installed capacity of all the sites in the database present in ISO-NE amounts to 4,874 MW. To simulate a future scenario with 25% solar power penetration, we multiply the distributed solar power plants by eight and the utility-scale solar power plants by four. Both the utility-scale and the distributed solar power plants are already well distributed throughout the ISO-NE power system; thus, the solar output smoothing for high solar penetrations is the same in the case with additional solar sites as it is in our case, in which we multiply the units included in the database. An examination of the spatial smoothing experiences for various subsets of the data revealed that there was very little additional smoothing when a large number of plants (>20) were considered. Table II shows the normalized hour-to-hour solar variability for scenarios with solar power penetrations constructed from the solar database introduced above.

TABLE II. NORMALIZED SOLAR VARIABILITY FOR DIFFERENT SOLAR POWER PENETRATION LEVELS

Penetration Level (%)	Solar Capacity (MW)	Normalized Hour-to-Hour Solar Variability (%)
0.54	584	6.85
1.08	1,180	6.78
2.08	2,246	6.77
2.5	2,424	6.81
4.5	4,874	6.73
12.5	13,824	6.73
25	**27,648**	**6.73**

The time series for the actual RT solar power as well as the 4HA forecasts are provided in the solar database [19]. DA solar power forecasts are derived from a state-of-the-art NWP model, namely the Weather Research and Forecasting Model (WRF) [20]. DA and 4HA solar power and load forecasts are included in the ISO-NE model to more accurately represent the corresponding DA and 4HA markets.

The ISO-NE model simulates the electricity exchanges among ISO-NE and its neighboring regions of New Brunswick, Hydro Québec, and the New York Independent System Operator. The model holds both contingency and regulation operating reserves. Contingency reserves are a 10-minute product defined by the largest system contingency. Only the spinning part of contingency reserves is considered; non-spinning reserves are assumed to be always available from units outside of the generation stack. Upward and downward regulation reserves are a 5-minute dynamic product equal to 1% of load without considering the variability provided by solar power.

The following seven scenarios have been modeled for an entire year to study the value and impact of improved solar power forecasting in ISO-NE:

- No solar power
- No solar power forecasting
- Solar power forecasting
- Solar power forecasting—25% uniform improvement
- Solar power forecasting—50% uniform improvement
- Solar power forecasting—75% uniform improvement
- Perfect solar power forecasting (100% uniform improvement)

IV. RESULTS

A comparison of net generation costs for the seven simulations listed in the previous section is shown in Figure 1. Net generation costs are defined as the annual electricity generation costs in ISO-NE (the sum of fuel costs, variable operations and maintenance costs, and start-up and shutdown costs), plus the annual electricity import costs, minus the annual electricity export revenues.

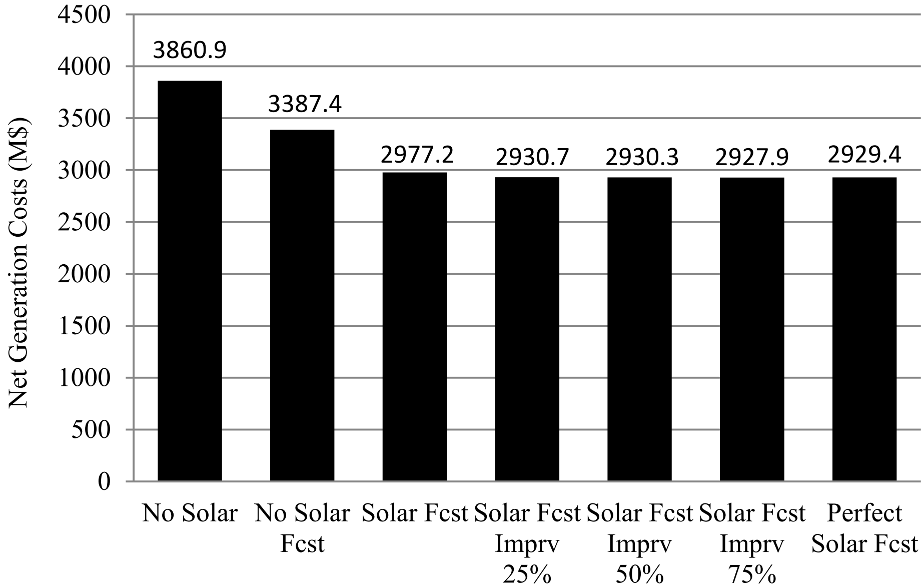

Figure 1. Net generation costs

Figure 1 shows how 25% solar power penetration reduces net generation costs by 12.3% ($473.5 M), even when solar power forecasts are not considered in the DA and 4HA generation unit commitment decisions. The relatively small reduction in net generation costs is driven by the very large solar curtailment. As shown in Figure 2, the ISO-NE power system experiences 34.5% solar power curtailment without solar power forecasts. In other words, solar power penetration is reduced from 25% to 16.4% because of the very large curtailment.

On the other hand, if DA and 4HA solar power forecasts are used when committing conventional generators in the DA and 4HA simulated markets, 25% solar power penetration reduces net generation costs by 22.9% ($883.7 M). In this case, solar power curtailment equals 11%, and the actual solar power penetration is reduced from 25% to 22.3%. DA and 4HA solar power forecasts reduce solar curtailment to less than one-third, because conventional power plants are committed more efficiently. If solar power forecasts are not used, the ISO-NE power system must deal with an overcommitment of electricity generation when the sun is shining and the PV power plants are producing electricity.

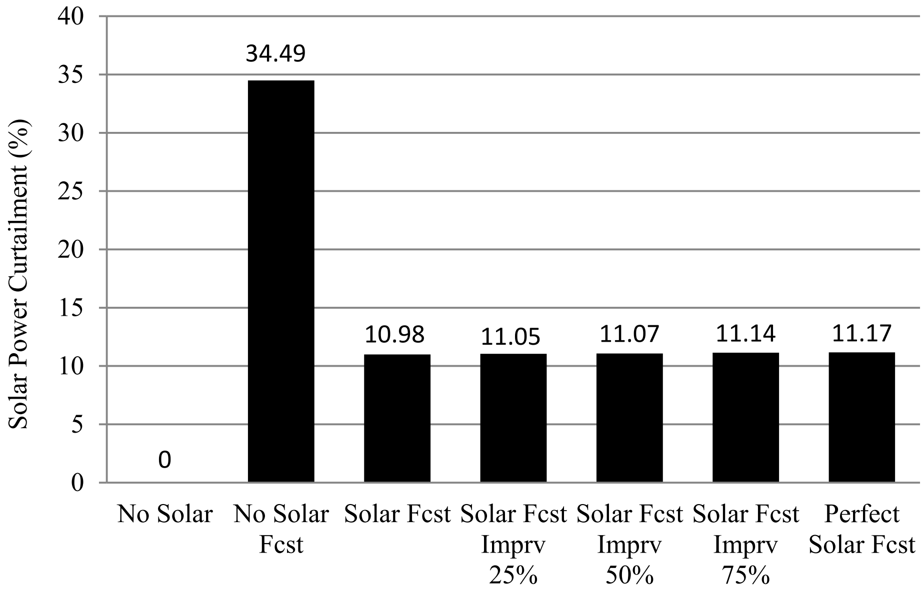

Figure 2. Solar power curtailment

If DA and 4HA solar power forecasts are uniformly improved by 25%, net generation costs are reduced by 1.56% ($46.5 M) when compared to the case with the current solar power forecasts. This reduction in net generation costs is driven by a more efficient commitment of conventional power plants and not by lower solar power curtailment, which does not vary by a significant amount. If solar power forecasts are further improved, the results do not show any significant differences in terms of net generation costs and solar power curtailment, as shown in Figure 1 and Figure 2, respectively. (The differences are smaller than or very close to the MIP gap used in the ISO-NE PLEXOS model.) In other words, 50%, 75%, and 100% (perfect) uniform improvements of solar power forecasts do not provide any significant reductions in net generation costs and solar power curtailment when modeling the ISO-NE power system with 25% solar power penetration. Solar power curtailment is not reduced further by solar power forecasting improvements.

Uniform solar power forecast improvements larger than 25% do not provide additional value in net generation costs, because the electricity generation mix of the ISO-NE power system is characterized by a very large share of gas-fired generators, as shown in Figure 3. Net generation costs can only be further reduced with more efficient commitment of conventional power plants. The ISO-NE power system does not have much “base load” generation, which means that the DA and 4HA solar power forecasts do not have a large impact on DA commitments, because all the nuclear, coal, and biomass power plants are almost always committed. The large available gas-fired electricity generation capacity present in ISO-NE reduces the value of improving solar power forecasts above a certain threshold, because there are always units online that can ramp up and down their generation without the frequent need to start up and/or shut down power plants because of solar power forecast errors. However, better solar power forecasts at the HA or subhourly timescale could still provide additional economic savings from more efficient economic dispatch.

Figure 4 shows how solar power penetration and solar power forecasts as well as their uniform improvements impact mean electricity prices in ISO-NE.

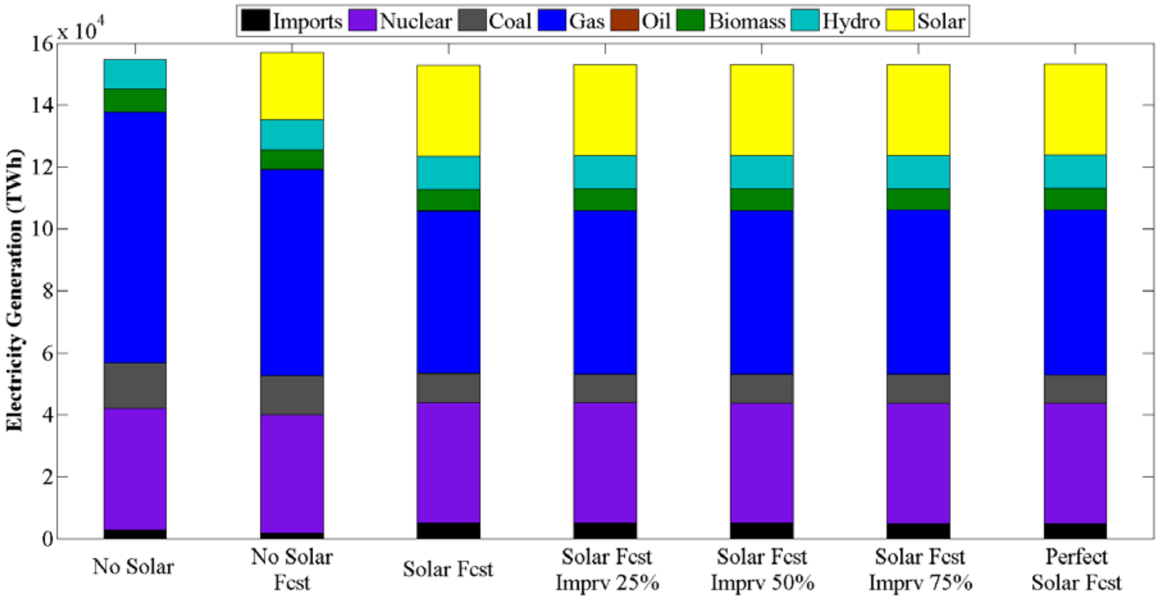

Figure 3. Electricity generation stack

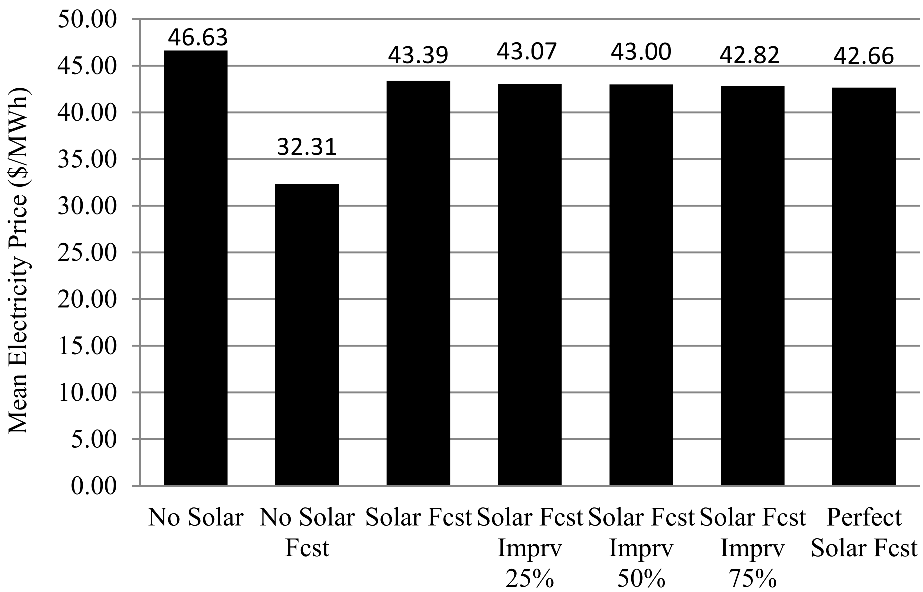

Figure 4. Mean electricity prices

A 25% solar power penetration reduces the mean electricity price in ISO-NE by 31% (from 46.63 $/MWh to 32.31 $/MWh) when solar power forecasts are not considered in the DA and 4HA unit commitment decisions. The large reduction in electricity prices results from the large solar power penetration unplanned in the DA and 4HA simulations, which leads to the overcommitment of electricity generators during the day in ISO-NE. On the other hand, if DA and 4HA solar power forecasts are used when committing conventional generators in the DA and 4HA simulated markets, 25% solar power penetration reduces the mean electricity price in ISO-NE by 7% (from 46.63 $/MWh to 43.39 $/MWh). Even if solar power forecasts reduce electricity prices to a much smaller extent, they still reduce net generation costs significantly compared to when solar power forecasts are not considered. If DA and 4HA solar power forecasts are uniformly improved by 25%, 50%, 75%, and 100% (perfect forecasts), the mean electricity price in ISO-NE is further reduced only to a small extent. If solar power forecasts are improved by 100%, the mean electricity price is reduced by only 1.7%, (from 43.39 $/MWh to 42.66 $/MWh).

Integrating solar power has a large impact on the hourly variability of electricity prices. Figure 5 shows how 25% solar power penetration increases the mean hourly electricity price variability in ISO-NE by 40% (from 4.43 $/MWh to 6.22 $/MWh) when solar power forecasts are not considered. If the latter were to be used in the DA and 4HA commitment decisions, the mean hourly electricity price variability would increase to a much larger extent, by 116% (from 4.43 $/MWh to 9.57 $/MWh). When solar power forecasts are not used, the power system experiences overcommitment of generation and is much less flexible when integrating variable and uncertain solar power. Most of the price variability is a result of the variability of solar power, not its uncertainty, as shown by the very small reduction in the mean hourly electricity price variability when DA and 4HA solar power forecasts are uniformly improved. Better solar power forecasts at the HA or subhourly timescale could provide larger changes in electricity prices and their hourly and subhourly variability.

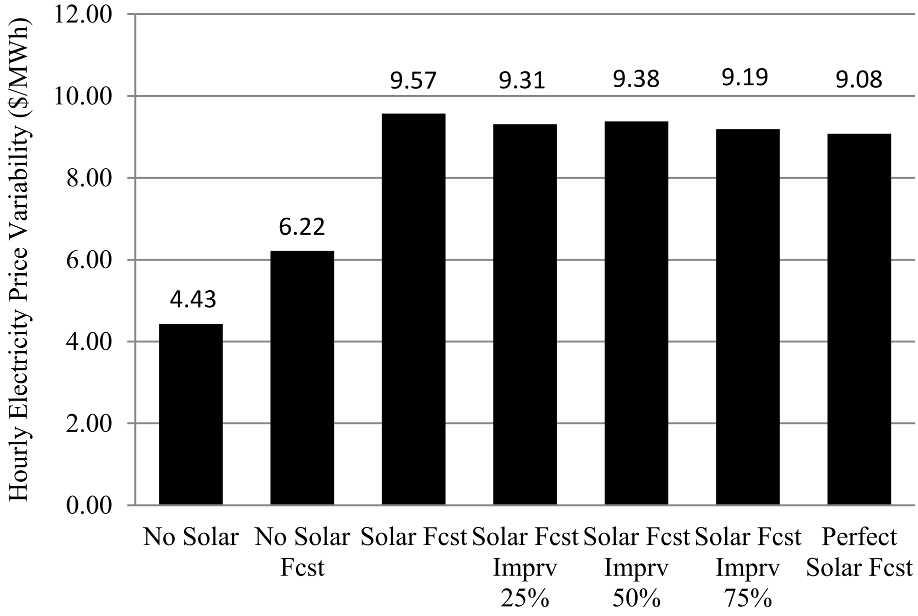

Figure 5. Mean hourly electricity price variability

V. Conclusions and Future Work

This study examined the value of improved DA and 4HA solar power forecasting in ISO-NE. The PLEXOS production-cost modeling software is used to simulate the operation of the ISO-NE power system with 25% solar power penetration with both utility-scale and distributed solar power. Current DA and 4HA state-of-the-art NWP forecasting accuracies were considered, in addition to uniform forecasting improvements of 25%, 50%, and 75%, as well as a base case of no solar power forecasting and a reference case of perfect forecasting.

The results presented in this paper show how integrating 25% solar power penetration in ISO-NE with DA and 4HA solar power forecasting reduces net generation costs by 22.9%. If solar power forecasts were not considered, the power system would experience overcommitment of generation as well as a much higher solar curtailment, which would lead to a much lower reduction in net generation costs, 12.3%. If DA and 4HA solar power forecasts are uniformly improved by 25%, net generation costs are further reduced by 1.56% ($46.5 M) when compared to the case with the current solar power forecasts. However, if solar power forecasts are further improved, the results do not show any significant differences in net generation costs, because the electricity generation mix in the ISO-NE power system is characterized by a very large share of gas-fired generators and a relatively small share of "base load" power plants. However, better solar power forecasts at the HA or subhourly timescale could still provide additional economic savings.

A 25% solar power penetration reduces the mean electricity price in ISO-NE by 31% when solar power forecasts are not considered. On the other hand, if DA and 4HA solar power forecasts are used, the mean electricity price in ISO-NE is reduced by 7%. In addition, 25% solar power penetration increases mean hourly electricity price variability in ISO-NE by 116% when solar power forecasts are considered. If the latter are not used, the mean hourly electricity price variability would increase to a much smaller extent, by 40%, because the power system experiences overcommitment of generation and is much less flexible when integrating variable and uncertain solar power, which leads to high levels of curtailment. Solar power forecasting improvements show small reductions in electricity prices and their variability.

The study presented in this paper simulates the transmission-level operation of the ISO-NE power system allowing solar power curtailment and considering load forecasting. A large portion of solar power is distributed, and it is mostly invisible to the system operator. Therefore, the authors suggest that future work should analyze the impact and value of solar power forecasting improvements when solar curtailment is not allowed. In addition, it would be interesting to rerun the analysis presented in this paper without load forecasting and compare the results to study the interactions among load and solar uncertainties.

The value of solar power forecasting improvement has been studied in this work assuming a 4HA market in which CC and steam power plants are committed. Such an intra-day market does not currently exist in ISO-NE, but it is used to represent the recommitment of power plants to avoid reliability issues rather than for economic benefits; however, it does also have economic implications in our study. In the future, we would like to rerun the analysis with only DA solar power forecasts to see their economic benefits without the additional 4HA market.

Finally, we believe that future research should also look at the impact of solar power forecasts at the HA or subhourly timescale on net generation costs as well as on electricity prices and their variability.

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