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ANALYSIS OF WIND PENETRATION AND NETWORK RELIABILITY THROUGH MONTE CARLO SIMULATION

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ABSTRACT

Generating electricity from wind resources has many environmental and economic advantages over traditional fossil-fueled generation. As a result, there is little doubt that energy from wind will be a significant contribution to the electricity portfolio of the future. Due to the sensitivity of the network and the volatility of the wind resource, analysis of power system operations using expected wind generation is not representative of actual system operations. In order to account for this fundamental uncertainty in wind generation, a Monte Carlo simulation model is developed based on an Optimal Power Flow model, and tested on the IEEE 39-bus test system. The results of these simulations indicate that while the average cost of serving load decreases with increasing wind penetration, the reliability of the system is highly sensitive to the ability of other generators on the system to ramp production either up or down on very short timescales.

1 INTRODUCTION

Although electricity generation from wind is increasing rapidly in many areas of the world, there is still much concern over the variability of this resource and its impact on the electric grid. An analysis of wind penetration on a national level, along with resource assessments and technology requirements are provided in (Lindenberg et al. 2008). In this paper, we consider the effect of wind penetration on the ability of the regional network to meet reasonable electricity load conditions. The stability of the electric grid is such that incremental changes in generation on short time scales can have significant negative impacts. Due to the sensitivity of the network and the volatility of the wind resource, analysis of these scenarios using expected, or forecasted, power generation from wind is not representative of actual power system operations. In order to assess the impact of this important source of uncertainty, a Monte Carlo simulation model is developed based on an Optimal Power Flow model , and is tested with the IEEE 39-bus test system.

Section II provides an overview of the simulation model, while results are presented in Section III. In Section IV, these results are discussed and preliminary conclusions developed.

2 THE MODEL

The simulation model developed here has two main foci: the first is the network model and the introduction of wind resources on this network. The second focus is the development of a Monte Carlo simulation based on the random errors in the forecasted wind generation. The incorporation of these two characteristics into the model is discussed in this section.

2.1 The Simulated Wind Farm

The power generation from a wind farm is modeled using time series wind speed data that is translated to power output using a turbine power curve. For the modeling presented here, wind speed data from Nantucket Sound, MA is used in conjunction with the GE 2.5MW turbine power curve (General Electric 2008) to represent the output from a 550 MW wind farm. This hypothetical wind farm represents approximately 10% of the regional generating capacity as modeled in the IEEE 39-bus test system. To capture the effect of geographic diversity of wind turbines over the land area of the wind farm, the method presented in (Nørgaard and Holttinen 2004) was implemented. This algorithm involves adjusting the wind speed data from a single point with a moving block average to represent the wind speed across the wind farm. The turbine power curve is also adjusted to represent the effective aggregated power curve from the multiple turbines in the wind farm. The result of this diversification is a smoothing of the variability of the aggregate output of the wind farm. A time series of output from a single turbine and a simulated wind farm are provided in Figure 1. Details regarding the application of this method to the Nantucket Sound wind data are provided in (Cardell and Anderson 2009).

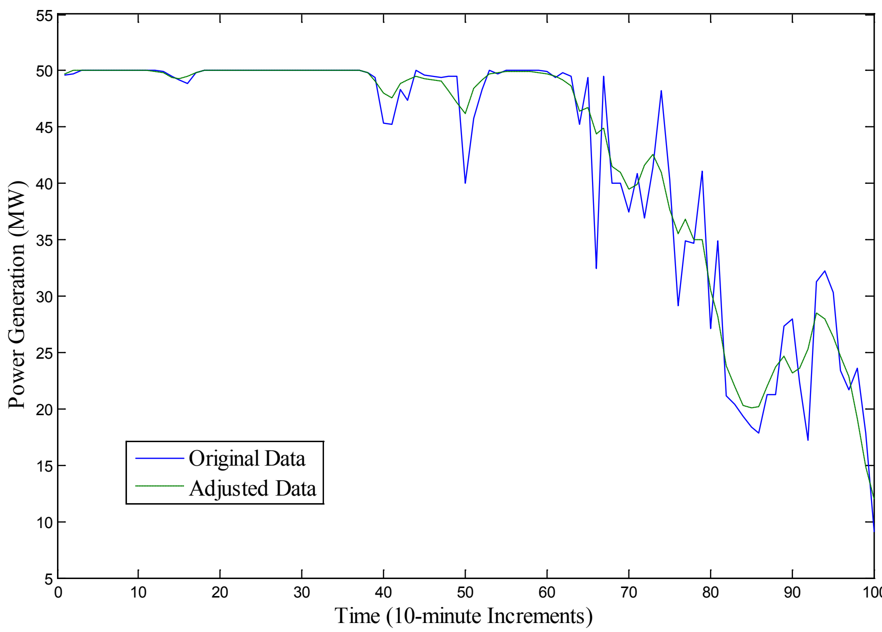

Figure 1: Simulated Wind Generation for Single and Multiple Turbines

The wind speed forecast is a critical component of the power flow analysis and dispatch planning. There are many detailed and advanced method for forecasting wind speeds, which are applicable over various time horizons (Blatchford et al. 2007, Munksgaard and Morthorst 2008). For the hour ahead time frame considered here, a persistence forecast is used. The 10-minute data is averaged to hourly data and hour-ahead forecasts are determined from regression model on existing data. Application of this forecast to existing data provided the empirical distribution of forecast errors given in Figure 2.

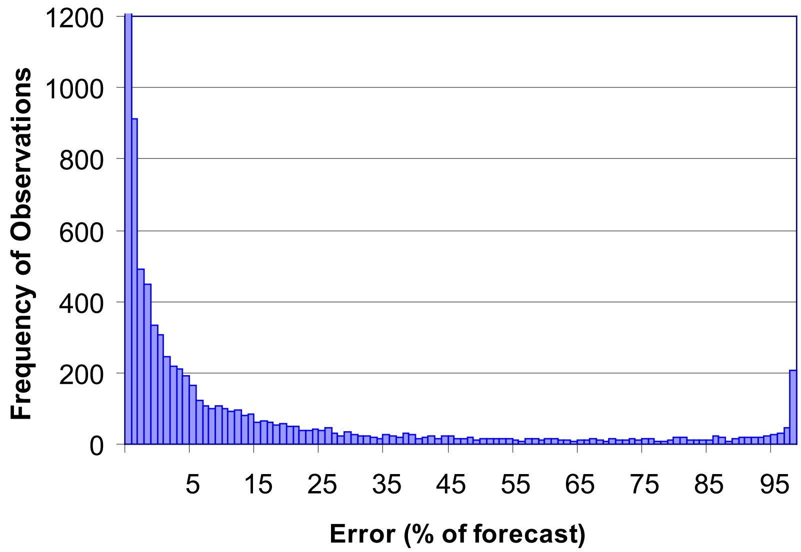

Figure 2: Empirical Distribution of Wind Generation Forecast Errors

2.2 Simulation of Wind Generation and Dispatch on a Network

The most significant characteristic of wind generation on a power system operations is the uncertainty on short time scales. It is the objective of the system operator to balance the electricity demand (load), with the available generation resources in real time. These plans are developed using forecasted loads and generation, usually an hour to a day ahead of actual dispatch. The dispatch decisions are made by the system operator, taking into account forecasted load as well as the ramping capabilities and production costs of each generator on the system. This information is used to solve the "Optimal Power Flow" (OPF) problem, which determines the minimum cost dispatch state for all generators while meeting transmission system constraints. The electric power system is modeled with the optimal power flow in Matpower (Zimmerman and Gan 1997), using the 39 bus test system. The 39-bus test system is a network reduction intended to represent the New England power system. This network is selected to correspond to the wind data described in Section 2.1, representing a hypothetical wind farm in at Nantucket Sound MA. It is important to note that a network reduction is at best a rough representation of the real system. A diagram of the 39-bus test system, showing the approximate location of the wind farm, is given in Figure 3.

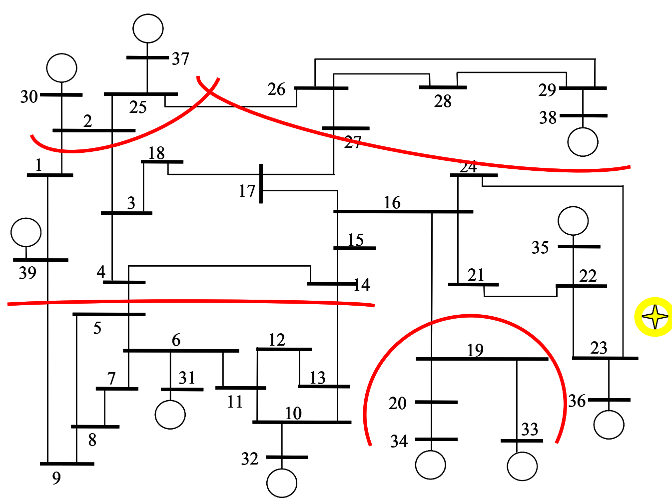

Figure 3: 39-Bus Test System

In power systems operation, a first dispatch is determined by the OPF calculations based on a wind forecast many hours ahead of dispatch (and is updated, with increasing constraints, 5 to 10 minutes ahead of real time). The uncertainty in the wind forecast is significant even a few hours ahead of time. Therefore, in real time the amount of wind generation available can be very different from the quantity that the system is expecting to meet load requirements. In this case, shortfalls can be met by ramping other generators. The ability of other generators to meet these contingencies is based strictly on their ability to quickly ramp generation output, as well as the ability of the transmission system to move the energy from generators to loads. As a result, even if the system can adapt to meet the electricity demand with reduced wind resources, an increase in system-wide electricity cost will result from this forecast error.

The uncertainty of wind generation is extremely important both for system stability and production cost. The simulation of a wind farm in a network using expected values for wind forecasts and forecast errors will not provide any useful information about the functionality of the power system under real conditions. To capture this uncertainty, a Monte Carlo approach is used to capture wind variability, and the sensitivity of the network to this variability.

2.3 A Monte Carlo Framework

Capturing the impact of this wind generation uncertainty on the network requires serial simulations. Initially, the network OPF calculations must be conducted using the forecasted wind generation. The results of this base case calculation act as the "dispatch point" for all generators on the system. A forecast error is then repeatedly sampled from the distribution of forecast errors, shown in Figure 2, and the wind generator output is adjusted by this amount. For each sampled forecast error, the OPF calculation is executed again given the adjusted wind output with the remaining generators on the system restricted in their ramping ability from this dispatch point. It is interesting to consider the impact this ramping ability on the ability of the power system to meet the required loads in real time. The more restrictive, or less flexible these generators are, the higher the probability of system failure.

The distribution of errors used is a percentage of forecast, so the same distribution is used in each scenario, and the error is scaled as a function of the level of the initial forecast. In the initial development of this framework, three scenarios are considered. These scenarios vary by the percentage of total generation on the system that is contributed by the wind farm, including 5%, 10%, and 20%. For each scenario, a base case is simulated wherein the wind generator output is as forecasted and the overall system cost is calculated. Subsequently, the traditional (non-wind) generators on the system are constrained to within each of 1%, 5%, and 10% of their dispatch point in the base case. A flow diagram of the simulation framework is given in Figure 4. The simulation results are provided in Section 3.

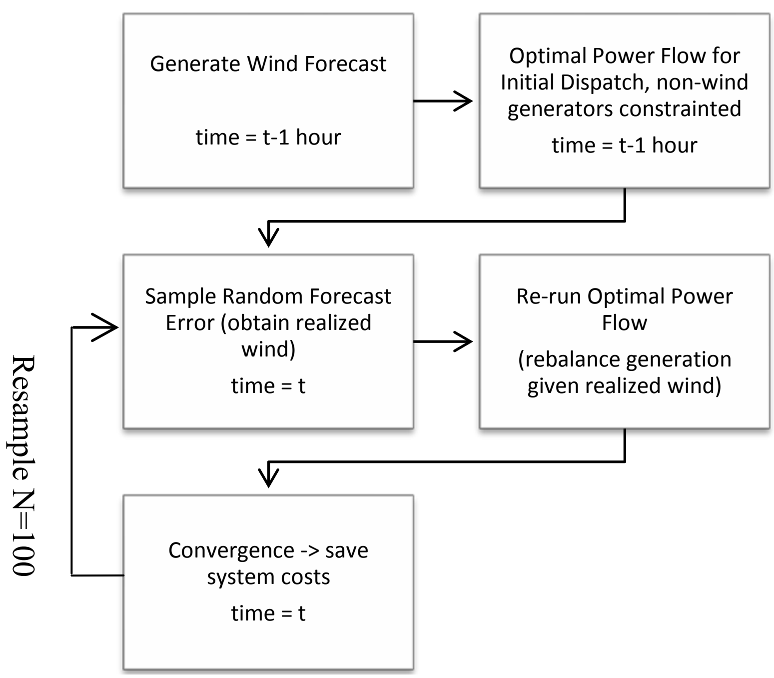

Figure 4: Simulation Flow Diagram

3 RESULTS & DISCUSSION

The scenarios considered, and the resulting system costs are summarized in Figures 5 and 6. In each case the average, maximum and minimum system costs are calculated for the simulations.

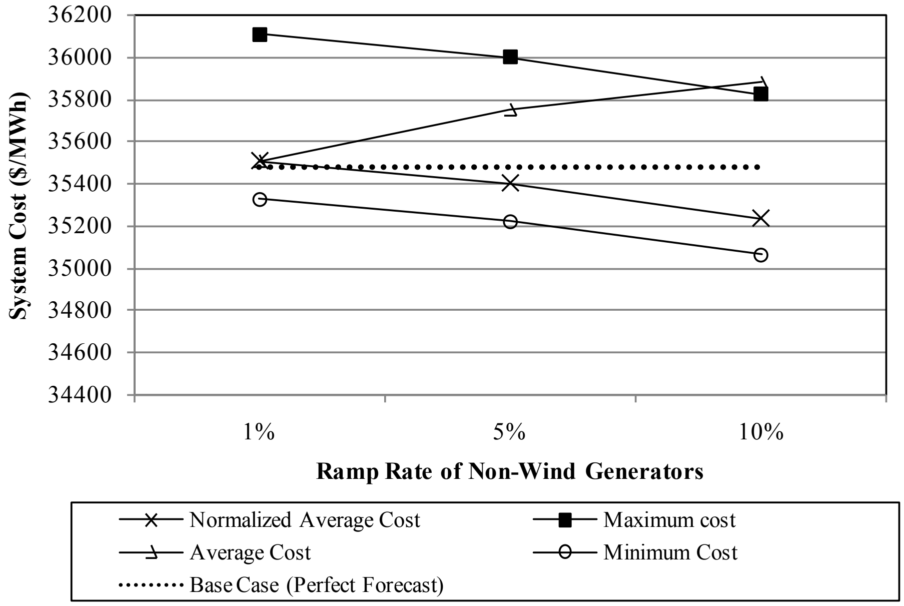

Figure 5: System Cost Analysis for 5% Wind Penetration

Due to the fact that the higher ramp rates facilitate solution convergence for power flow simulations in scenarios with larger shortfalls in wind generation, the average system cost appears higher as ramp rates increase. . This is as an artifact of the larger number of feasible scenarios. To provide a basis for comparison with this effect removed, a normalized average system cost is also calculated, and shown on the same figure denoted by 'X'. The normalized average includes only those samples that converged at all ramp rates. Finally, the base case cost is provided, which is the minimum cost of serving load on this system, when the wind forecast is perfectly accurate.

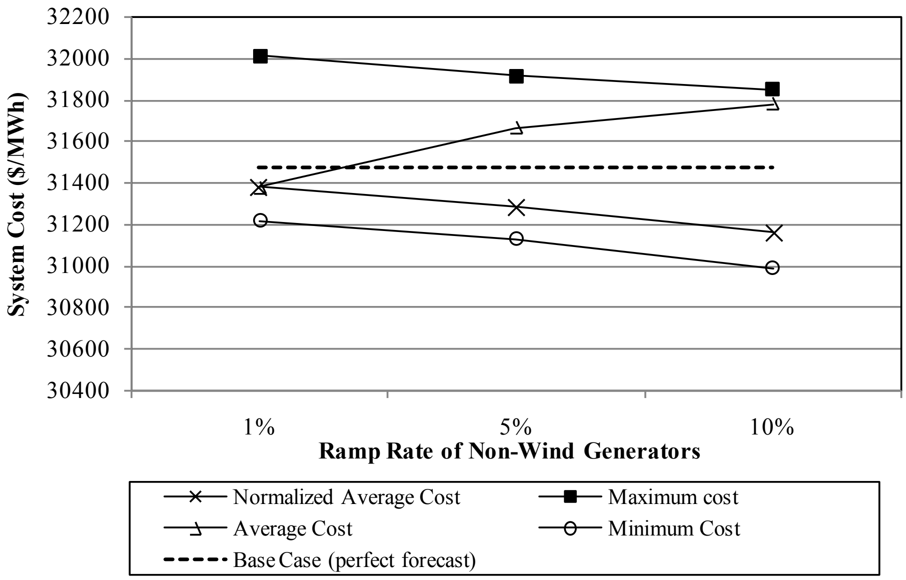

Figure 6: System Costs Analysis for 10% Wind Penetration

In both the 5% and 10% penetration cases, the non-normalized system cost is actually increasing as the ramp rates are increased. This is a result of the fact that the number of infeasible cases are decreasing as the generators become more flexible. The system is able to handle larger wind generation shortfalls with the dispatchable generators, though at high cost. The fact that these cases are more expensive increases the average system costs overall. When this effect is taken into consideration, normalized average system costs are decreasing as non-wind generators have larger ramp rates. In Table 1, the normalized system costs are calculated as a percentage of system costs calculated for the zero-wind case.

At both the 5% and 10% penetration levels, the average system cost is decreased by the addition of wind generation, when the system is able to meet load. In the case of 20% wind capacity on the test system, the number of feasible solutions was essentially zero for all ramp rates. This is a scenario in which the wind farm is by far the largest generator on the system, which is an unlikely situation in a real system, and is shown to be highly unstable. With the forecast error expressed as a percentage of forecasted load, and deviation from forecasted dispatch point is extremely stressful to the system. Even though the average system cost only 24260 $/MWh, the system converges less than 5% of the time in all ramp rates. This illustrates that although system cost is an important consideration in assessing the impact of wind generation on existing power systems, it is more critical that the existing system to has the ability *meet* the required electricity demand with the available resources.

Table 1: Normalized System Cost Reduction (% of no-wind costs)

Ramp Rate of Non-wind Generators	*Wind Penetration* 5%	10%
1%	3.2	14.4
5%	3.5	14.7
10%	3.9	15.0

In order to assess this outcome, we consider the frequency with which the optimal power flow is able to find a solution to the power flow problem. Samples which did not converge on a solution can be considered an inability to meet load, or a "blackout" situation on some or all of the test system. In Figure 6, the probability of system convergence is plotted against the level of wind penetration on the system, for various ramp rate restrictions on the non-wind generators.

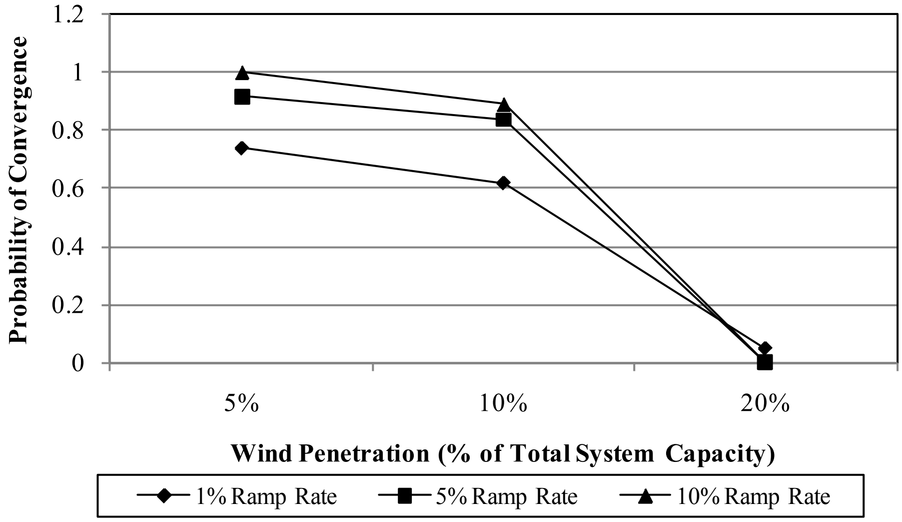

Figure 7: Probability of Power Flow Solution for Wind “Must Take” Conditions

As shown in Figure 6, the unreliability in the system is increasing with the level of wind penetration in the system. At 20% wind penetration, the uncertainty in the system is too high, and the model has significant difficulty finding load flow solutions. At higher levels of wind penetration, it is unrealistic to assume that all wind generation capacity would exist at a single site on the network. The model results also show that this would be an operationally infeasible configuration.

4 CONCLUSIONS AND FUTURE WORK

The simulations discussed here were designed to examine the effect of increasing levels of wind penetration on system costs and ability to meet electricity demand. The model is based on a 39-bus test network, which solved the optimal power flow problem on the network. The uncertainty in wind generation is introduced through a Monte Carlo framework with random sampling of wind forecast errors. The ability of the model to converge on a power flow solution is a proxy for the ability of such a system to avoid load shedding, or system blackouts. Results indicate that increasing the wind penetration on the system will reduce average system costs, while simultaneously reducing system reliability. This reliability reduction can be counteracted with non-wind generators that have the ability to ramp generation up or down over short time scales. This does not imply that addition of wind generation to existing systems will result in system blackouts. It does indicate increasing that wind penetration could impact system reliability. This reduction in reliability can be mitigated by more ancillary services such as reserves, storage and/or responsive load. The importance of wind generation forecasting should not be underestimated, and the impact of improvements in accuracy could be incorporated into this modeling framework.

The next phase in development of this framework is the inclusion of differentiated ramping costs in the non-wind generators, and other alternative resources on the network. In order to consider high levels of wind penetration, it is important to provide geographic diversification of these resources over the system as well. An important next step in this modeling framework is the introduction of diversified resources at more generation buses across the system. The result of this will be a reduction in the overall variability of the wind generation on the network, allowing the system to accommodate higher levels of this intermittent resource.

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