

# **The Economic Implications of Adding Wind Capacity to a Bulk Power Transmission Network**

by

**Tim Mount<sup>\*</sup>, Lindsay Anderson, Judy Cardell<sup>\*\*</sup>, Alberto Lamadrid, Surin Maneevitjit, Bob Thomas and Ray Zimmerman**

Cornell University and Smith College<sup>\*\*</sup>

## **Abstract**

The first part of the paper summarizes how “co-optimization” can be used to determine the correct nodal prices for an optimum AC dispatch that meets industry standards of operating reliability. The co-optimization criterion minimizes the expected cost of meeting load over an explicit set of credible contingencies. The corresponding nodal prices reflect the patterns of dispatch for the intact system as well as for the contingencies. Due to the computational limitations of solving large AC Optimal Power Flows (OPF) for real networks, system operators typically use proxy limits to approximate the non-linear constraints caused, for example, by limits on voltage. Even if the resulting dispatch using these proxy limits corresponds closely to the optimum AC dispatch, the corresponding nodal prices are highly misleading, particularly when the system is stressed. However, these are precisely the prices that must be determined correctly to measure the economic value of equipment on the network. For an optimum network, some equipment that is essential for meeting contingencies may have a shadow price of zero most of the time when the system is intact. Getting the prices right is the main contribution of co-optimization. The link between the short-run criterion of “operating reliability” and the long-run criterion of “system adequacy” is accomplished by allowing for load shedding as an expensive option to meet contingencies. The high cost of “energy-not-served” implies that some equipment can be very valuable in contingencies if it reduces the amount of energy-not-served. Calculating the nodal prices on a network correctly for different states of the system provides the basis for determining the economic value of improved reliability.

The objective of this paper is to extend the co-optimization framework to determine the net economic benefit of adding an intrinsically intermittent source of generation, such as wind capacity, to a network. Using the experience from Europe, the basic effect of having a high penetration of wind capacity is that additional spinning reserves are needed to meet standards of operating reliability. Using the co-optimization framework, this situation can be represented by defining new contingencies that correspond to unpredicted changes in the level of generation from the wind capacity. The additional reserve capacity required represents an important cost of increasing the penetration of wind capacity on a network that offsets the gains from reducing the quantities of other fuels used for generation. An empirical example illustrates how co-optimization can be used to determine the net benefits of additional wind capacity. A related issue is that the nodal prices in a restructured wholesale market for electricity are determined by the cost of the most expensive generating units in the market. Hence, the savings in fuel costs due to wind generation will only be passed on to customers through the wholesale prices if the generation from wind displaces relatively expensive generating units. This may not occur in urban load pockets like New York City unless additional transmission capacity is added. The contribution of this paper is to present a framework for evaluating the net-social benefits of adding wind to a network.

\* Corresponding author, [tdm2@cornell.edu](mailto:tdm2@cornell.edu).

# **The Economic Implications of Adding Wind Capacity to a Bulk Power Transmission Network**

## **1. Introduction**

It is clear that a major implication of the current scientific and public debate about climate change and sustainability is that our dependence on fossil fuels will and should be reduced substantially. Reductions of the global emissions of carbon dioxide into the atmosphere of at least 80% will be needed to stabilize the climate against global warming. For all intents and purposes, reaching this objective implies replacing the conventional uses of fossil fuels entirely from all but the most technically intractable applications (e.g. the military). Adapting lifestyles and production to a new low-carbon future implies a disruptive transformation of economies throughout the world that will be equivalent in importance to the first industrial revolution. Although the current administration in Washington has until recently been reluctant to address climate change effectively, all three Presidential candidates are committed to some form of new energy policy to reduce emissions of carbon. Hence, it seems likely that the nation will soon follow the lead of Europe and Japan and will initiate a transition to a low-carbon economy. The implication is that there will be many new programs that encourage the replacement of fossil fuels by renewable sources of energy such as wind and solar power. Enforcing Renewable Portfolio Standards (RPS) is an example of an existing type of program.

Most of the non-fossil sources of energy will involve the electric delivery system either directly (e.g. generation from wind) or indirectly (e.g. charging batteries for plug-in hybrid vehicles). Energy from liquid biofuels is one exception. Although the generation of electricity from fossil fuels is relatively inefficient, electricity actually delivers services very efficiently. Hence, solar power and wind power are intrinsically efficient because they avoid the losses that occur in a typical thermal power plant. In addition, using electric motors for transportation will avoid the losses due to the inherent inefficiency of internal combustion engines. Basically, one unit of electricity from a renewable source replaces three units of

energy from coal in a typical power plant and five units from petroleum in a typical gasoline engine. This is the good news. We will become much more dependent on electricity for delivering energy services to customers in a low-carbon economy.

The bad news is that most renewable sources of energy are intermittent, and as a result, policies that simply focus on increasing the penetration of renewables may undermine the reliability of the electric delivery system. Major blackouts attributable to unexpected drops in wind generation have already occurred in Texas and Germany. If this type of disruption of electricity supply becomes more widespread, it is likely to lead to a backlash against renewables by system operators. Hence, policies for a successful transition to a low-carbon economy should include the following three essential components: 1) generating more electricity from solar, wind and other non-fossil sources of energy, 2) storing energy to cover periods when these sources are not available, and 3) decentralizing the delivery of electricity while maintaining the reliability of supply. Since it is practical to use small-scale production for many of the non-fossil sources of electricity, there will be many opportunities for improving the design of new buildings and communities to accommodate new energy and storage technologies. In a low-carbon economy, the current centralized sources of energy will not simply be replaced by new non-fossil sources using the existing forms of distribution. It is quite possible that most of the growth in electricity generation, for example, will come from local, distributed sources, and this change will require a disruptive transformation of the existing electric delivery system.

The objective of this paper is to present an analytical framework for evaluating the implications for the bulk power transmission network of increasing the dependence on renewable sources of energy in terms of the effects on 1) Operating Reliability and System Adequacy, and 2) the net-social benefits of making changes to the electric delivery system. This framework uses co-optimization to minimize the expected cost of meeting load with the intact system and a set of credible contingencies (equipment failures). This criterion is consistent with current practices for maintaining a standard of Operating Reliability. By allowing for involuntary load shedding to occur at a specified Value of Lost Load, it is also possible to determine how components of the network contribute to maintaining reliability. In simple terms, if the system load is increased by increments, eventually load shedding will be required to obtain feasible solutions. Usually load shedding occurs first in the

contingencies. When this happens, the standard for Operating Reliability is effectively violated. It is then possible to determine where and how much additional capacity is needed on the network to avoid load shedding, and in this way, address the planning problem of maintaining System Adequacy. An important implication is that our co-optimization framework provides a consistent way to address both the real-time standard for Operating Reliability and the long-run standard for System Adequacy.

The discussion in Section 2 describes the current procedures used by regulators to maintain reliability, and explains why the use of proxy measures for reliability, such as reserve margins for generating capacity, obscures the true economic value of maintaining reliability. In Section 3, the co-optimization framework for determining an Optimal Power Flow (OPF) is presented. The new version of this software, the SuperOPF, uses a full AC representation of the network and includes a number of new capabilities, such as treating incremental and decremental real and reactive reserves explicitly, that will not be considered in this paper. Section 4 presents a case study using a 30-bus network. The network represents an urban center with relatively expensive local sources of generation and other regions with substantial amounts of relatively inexpensive sources of generation. Since the transmission capacity is limited, the urban center is in a load pocket. New wind capacity is added incrementally outside the load pocket, and this new capacity replaces some of the existing baseload capacity to represent a policy of switching from coal to renewables. The results of the case study are presented in Section 5 and are followed by the conclusions in Section 6.

## 2. Maintaining Reliability Standards

Federal legislators have formally recognized the importance of maintaining operating reliability in the Energy Policy Act of 2005 (EPACT05), and the major effect of this legislation is to give the Federal Energy Regulatory Commission (FERC) the overall authority to enforce reliability standards throughout the Eastern and Western Inter-Connections (see FERC [5]). The North-American Electric Reliability Corporation (NERC) has been appointed by FERC as the new Electric Reliability Organization (ERO), and NERC has been given the responsibility to specify explicit standards for reliability. Although it is still too early to know how well these arrangements will work, it is clear that the threat of paying penalties will be a tangible reason for state regulators to ensure that reliability standards are met.

In an electric supply system, the performance of the transmission network and the level of reliability are shared by all users of the network. Reliability has the characteristics of a “public” good (all customers benefit from the level of reliability without “consuming” it). In contrast, real electrical energy is a “private” good because the real energy used by one customer is no longer available to other customers. Markets can work well for private goods but tend to undersupply public goods, like reliability (and over-supply public “bads” like pollution). The reason is that customers are generally unwilling to pay their fair share of a public good because it is possible to rely on others to provide it (i.e. they are “free riders”). Some form of regulatory intervention is needed to make a market for a public good or a public bad socially efficient.

If a public good or a public bad has a simple quantitative measure that can be assigned to individual entities in a market, it is feasible to internalize the benefit or the cost in a modified market. For example, the emissions of sulfur and nitrogen oxides from a fossil fuel generator can be measured. Requiring every generator to purchase emission allowances for the quantities emitted makes pollution another production cost. Regulators determine a cap on the total number of allowances issued in a region, and this cap effectively limits the level of pollution. Independent (decentralized) decisions by individual generators in the market determine the pattern of emissions and the types of control mechanisms that are economically efficient. For example, the choice between purchasing low sulfur coal and

installing a scrubber is left to market forces in a “cap-and-trade” market for emissions of sulfur dioxide.

Unfortunately, when dealing with the reliability of an electric supply system, it is impractical to measure and assign reliability to individual entities on the network in the same way that emissions can be assigned to individual generators. This is particularly true for transmission lines that are needed to maintain supply when equipment failures occur. The NERC uses the following two concepts to evaluate the reliability of the bulk electric supply system (see NERC [8]):

*1. Adequacy — The ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.*

*2. Operating Reliability — The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated failure of system elements.*

Prior to EPACT05, the NERC standard of one day in ten years for the Loss of Load Expectation (LOLE) was widely accepted by regulators as the appropriate standard for the reliability of the bulk transmission system (i.e., this does not include outages of the local distribution systems caused, for example, by falling tree limbs and ice storms). Nevertheless, it is still very difficult to allocate the responsibilities for maintaining a standard of this type to individual owners of generating and transmission facilities because of the interdependencies that exist among the components of a network. This fundamental problem has not stopped regulators from trying to do it.

The basic approach used by state regulators in New England, New York and PJM is to assume that setting reserve margins for generating capacity (i.e., setting a standard for “generation adequacy”) is an effective proxy for meeting the NERC reliability standard. This new proxy for reliability can now be viewed as the sum of its parts, like emissions from generators, and the task of maintaining generation adequacy can be turned over to market forces once the regulators have set a reserve margin. In New York State, regulators have gone one step further and passed the responsibility for purchasing enough generating capacity to meet the adequacy standard on to Load Serving Entities (LSE). Regulators decide what the amount of installed capacity should be in a region and the responsibility for

acquiring this amount is prorated among the LSEs. An LSE that fails to comply would be fined (see NYISO [10] and [11]). In contrast, the ISOs in New England and PJM take the responsibility of purchasing the capacity needed in advance, and the cost is eventually prorated to LSEs using the actual load served in real time. This procedure identifies potential shortfalls of capacity in advance much more effectively than the NYISO procedure.

Even if the capacity markets are successful in maintaining generation adequacy, there are still important economic issues that are obscured when generation adequacy is used as a proxy for reliability. Changing a public good like reliability into a private good like installed capacity is a convenient sleight-of-hand for the advocates of deregulation because it then appears to be feasible to use market forces to maintain reliability standards. Nevertheless, this is not strictly correct because there is an implicit assumption that the transmission network is already adequate before decisions about generation adequacy are considered. It would be much more valuable for planning purposes to have a method of analysis that calculates the net-social benefits of generation and transmission assets in terms of both the delivery of real power to customers and the maintenance of reliability standards. This is particularly important for evaluating the role of renewables on a network because these sources are typically intermittent and require additional reserve capacity (or storage capacity) to maintain reliability. Before presenting the new analytical framework in the next section, some of the practical implications of adding an unreliable source of electricity are discussed.

The established reliability standard proposed by NERC is to limit failures to less than 1 day in 10 years. Is this standard too stringent, and therefore, more expensive to enforce than it should be? The answer is almost certainly no. The reason is that the Value of Lost Load (VOLL) when an unscheduled outage occurs is very high, particularly for large urban centers. A survey report published by the Lawrence Berkeley National Laboratory (LBNL) in 2004 (LaCommare and Eto [6]) concludes that the total cost of interruptions in electricity supply is \$80 billion/year for the nation (op. cit. p. xi-xii), and 72% of this total is borne by the commercial sector (plus 26% by the industrial sector and only 2% by the residential sector). The frequency of interruptions is found to be an important determinant of the cost because the cost of an interruption increases less than proportionally with the length of an interruption. The costs of relatively short interruptions of only a few minutes are substantial.

The cost estimates in the LBNL report are developed from an earlier report prepared for the Office of Electric Transmission and Distribution in the U.S. Department of Energy (DOE, Lawton et al. [7]) that summarizes a number of different surveys of the outage costs for individual customers. For large commercial and industrial customers in different economic sectors, the average costs are reported for 1-hour outages in \$/Peak kW (op.cit. Table 3-3, p.13). These average costs range from negligible for Construction to \$168,000/MWh for Finance, Insurance and Real Estate, and the average cost for all sectors is \$20,000/MWh. Although there is a lot of variability in the reported costs of an unscheduled outage, the overall conclusion is that the VOLL is very high for urban centers. The current NERC reliability standard of 1 day in 10 years corresponds to a VOLL of \$33,393/MWh ( $60 + 80,000/2.4$ , based on an operating cost of \$60/MWh and an annual capital cost of \$80,000/MW for a peaking unit). Although this value is above the average value, it is still at the low end of the range of VOLL in the DOE report because the distribution of values is skewed to the right.

The key to deriving the economic value of maintaining a given reliability standard is to consider the benefits of avoiding unscheduled outages. In the empirical simulations discussed later in Section 4, a VOLL of \$10,000/MWh is used. Consequently, reducing the probability of an unscheduled outage by 0.1%, for example, still saves \$10/MWh. The analytical framework presented in the following section treats equipment failures (contingencies) explicitly. Some components of a network may only have a positive economic value when contingencies occur because they reduce the amount of Load-Not-Served (LNS). Other components, such as a new baseload unit, may reduce the cost of generation when the system is intact and have little effect on reliability. More generally, components will affect both operating costs for the intact system and reliability. For an intermittent source such as wind power, there is a fundamental tension between providing an inexpensive source of generation and making the existing network more vulnerable to outages. The solution to this predicament is to add new capabilities to the network that can compensate for the intermittent nature of wind power, such as load response and storage capacity. Evaluating the net-benefits of a portfolio of assets is the type of problem that can be evaluated using our new analytical framework.



### 3. The Analytical Framework

In a typical restructured market operated by an Independent System Operator (ISO), like the market in the New York Control Area, standards of Operating Reliability are met by requiring that minimum amounts of reserve capacity (spinning reserves) are available in different regions. These reserve requirements are the proxy measures of reliability discussed in the previous section. The generators submit price/quantity offers to sell energy and reserves into an auction, and the objective of the ISO is to determine the optimal patterns of generation and reserves by minimizing the total cost (the combined cost of energy and reserves) of meeting a forecasted pattern of load subject to network and system constraints and the specified amounts of reserves. The Last Accepted Offer is used to clear the market and set uniform market prices for energy and reserves. The market prices are adjusted for congestion and losses to determine the nodal prices for energy (i.e. Locational Based Marginal Prices (LBMP)). In addition, the auction determines the regional prices for reserves in a similar way.

Given the large number of nodes (over 400 in the New York Control Area) and the complexity of the network, it is computationally impractical to use a full AC representation of network flows to determine the OPF for a system of this size. As a result, a modified version of a DC OPF is used by the NYISO. For example, if the real flows on a transmission line are limited by a voltage constraint on a regular basis, the rated thermal capacity of the line is reduced in the dispatch to approximate this voltage constraint (an AC representation of network flows determines both real and reactive flows, but a DC representation determines only real flows). Hence, the lower thermal constraint on a transmission line is really another form of proxy limit that provides an additional distortion for determining the true shadow prices of transmission constraints. These distortions of the nodal prices are similar in effect to specifying minimum quantities of reserve capacity as proxies for reliability. The implications of using proxy variables in an OPF will be discussed in more detail in another paper. For this paper, the empirical analysis is based on an AC OPF using co-optimization to represent equipment failures (contingencies) explicitly in the objective function.

### Fixed Reserve Requirements

To illustrate the specific differences between using co-optimization in an OPF instead of using the traditional fixed reserve requirements, it is convenient to start with the structure of an AC OPF using fixed reserve requirements. The objective criterion is to minimize the combined cost of energy,  $G_i$ , and reserves,  $R_i$ , needed to meet the forecasted pattern of load as follows:

$$\min_{G_i, R_i} \sum_{i=1}^I [C_{G_i}(G_i) + C_{R_i}(R_i)] \quad (1)$$

subject to:

nodal power balancing constraints

$$F_j(\theta, V, G, Q) = 0 \quad \text{for } j=1, \dots, J \quad (2)$$

line power flow constraints

$$|S_l| \leq S_l^{\max} \quad \text{for } l=1, \dots, L \quad (3)$$

voltage limits

$$V_j^{\min} \leq V_j \leq V_j^{\max} \quad \text{for } j=1, \dots, J \quad (4)$$

real power limits

$$G_i^{\min} \leq G_i \leq G_i^{\max} \quad \text{for } i=1, \dots, I \quad (5)$$

reactive power limits

$$Q_i^{\min} \leq Q_i \leq Q_i^{\max} \quad \text{for } i=1, \dots, I \quad (6)$$

spinning reserve ramping limits

$$0 \leq R_i \leq R_i^{\max} \quad \text{for } i=1, \dots, I \quad (7)$$

unit capacity limits

$$G_i + R_i \leq G_i^{\max} \quad \text{for } i=1, \dots, I \quad (8)$$

**Fixed Reserve Requirement** for all N regions

$$\sum_{n=1}^N \sum_{i \in k} R_{ni} \geq \alpha \quad (9)$$

and **Fixed Reserve Requirements** for  $N^* < N$  regions

$$\sum_{i \in n} R_{ni} \geq \alpha_n \quad \text{for } n = 1, \dots, N^* \quad (10)$$

where $i$ :	generator index ( $i = 1, 2, \dots, I$ )
$j$ :	bus index ( $j = 1, 2, \dots, J$ )
$l$ :	transmission line index ( $l = 1, 2, \dots, L$ )
$n$ :	regions ( $n = 1, 2, \dots, N$ )
$G_i/Q_i$ :	real/reactive power output of generator $i$ .
$R_i$ :	spinning reserve carried by generator $i$ .
$\theta_j$ :	voltage angle of bus $j$ .
$V_j$ :	voltage magnitude of bus $j$ .
$S_l$ :	power flow of line $l$ .
$G_i^{\min}, G_i^{\max}$ :	minimum and maximum real energy for generator $i$ .
$Q_i^{\min}, Q_i^{\max}$ :	minimum and maximum reactive power for generator $i$ .
$R_i^{\max}$ :	maximum reserve for generator $i$ .
$V_j^{\min}, V_j^{\max}$ :	voltage magnitude limits for bus $j$ .
$S_l^{\max}$ :	power flow limit for line $l$ .
$C_{G_i}(G_i)$ :	energy cost for operating generator $i$ at output level $G_{ik}$ .
$C_{R_i}(R_i)$ :	reserve cost for generator $i$ carrying $R_{ik}$ spinning reserve.

Equations (1) to (8) represent a standard OPF for an AC network, and (9) and (10) represent the mandated levels of reserve capacity needed in different regions to cover the unscheduled failure of equipment. In practice, determining the specified levels of reserves needed to meet the established standard of Operating Reliability depends on prior analyses, but it is likely that the actual mandated levels of reserve capacity are relatively conservative (i.e. high) to reduce the likelihood of facing the unpleasant political consequences of a blackout.

If Generator  $i$  with capacity  $G_i^*$ , for example, is part of the optimal dispatch for the intact system, it could have an unexpected failure. In this case, Generator  $i$  would be eliminated and the OPF would be solved again using only the other generating units committed in the first optimal dispatch, after lowering the appropriate reserve requirements in (9) and (10) by  $G_i^*$ . Hence, the actual dispatch and the prices paid could be substantially different from the optimal solution for the intact system if a contingency occurs. Furthermore, there is no guarantee that an optimal solution will actually be feasible in a given contingency. The feasibility of the dispatch is dependent on there being enough reserve capacity available in the right locations to cover the contingency, and in practice, the mandated levels of reserves are reset relatively infrequently as the characteristics of the system change over time.

## **2.2 Responsive Reserves Requirements (Co-optimization)**

Chen et al. [3] have proposed an alternative way to determine the optimal dispatch and nodal prices in an energy-reserve market using “co-optimization” (CO-OPT). The new objective is to minimize the total expected cost (the combined production costs of energy and reserves) for a base case (intact system) and a specified set of credible contingencies (line-out, unit-lost, and high load) with their corresponding probabilities of occurring. Using CO-OPT, the optimal pattern of reserves is determined endogenously and it adjusts to changes in the physical and market conditions of the network. The initial motivation for developing the CO-OPT framework was to make the markets for reserves in load pockets less vulnerable to the exploitation of market power by generators. For this reason, the CO-OPT criterion is referred to as Responsive Reserve Requirements. If the offered prices for reserve capacity are high, the optimal solution will use fewer reserves by, for example, reducing the flow on a transmission tie line to reduce the size of the contingency if the tie line fails. This framework is equivalent to using a conventional  $n-1$  contingency criterion to maintain Operating Reliability. In practice, the number of contingencies that affect the optimal dispatch is much smaller than the total number of contingencies. In other words, by covering a relatively small subset of critical contingencies, all of the remaining contingencies in the set can be covered without shedding load.

In the new SuperOPF, the CO-OPT criterion is modified to include the cost of Load-Not-Served (LNS) and also distinguishes between positive and negative reserves for both real and reactive power. Using this modified criterion, the System Operator determines the optimal dispatch for energy and reserves for the base case (intact system,  $k = 0$ ) and for  $K$  different contingencies by minimizing the expected cost of meeting load in the  $(K + 1)$  states of the system as follows:

$$\min_{G_{ik}, R_{ik}, LNS_{jk}} \sum_{k=0}^K p_k \left\{ \sum_{i=1}^I [C_{G_i}(G_{ik}) + C_{R_i}(R_{ik})] + \sum_{j=1}^J VOLL_j \times LNS_{jk} \right\} \quad (11)$$

subject to (2) – (8) for each  $k = 0, 1, \dots, K$ ,

where  $p_k > 0$  is the probability of contingency  $k$  occurring

$VOLL_j$  is the Value Of Lost Load for load at bus  $j = 1, 2, \dots, J$

$LNS_{jk}$  is the Load Not Served at bus  $j$  in contingency  $k$

Implicitly, the constraints implied in (2) – (8) are replicated for  $k = 0, 1, \dots, K$  and adjusted to account for the failures of equipment that define each contingency. Note that the constraints (9) and (10) for Fixed Reserve Requirements are not included in (11). Given the structure of (11), the optimum criterion could be decoupled into  $K + 1$  separate OPFs for  $K + 1$  different systems. However, these solutions are coupled together through the following definition of reserve capacity:

#### Positive reserves

$$R_{ik+} = G_i^{* \max} - G_{i0}^* \quad \text{for } i = 1, 2, \dots, I \text{ and } k = 0, 1, \dots, K \quad (12)$$

#### Negative reserves

$$R_{ik-} = G_{i0}^* - G_i^{* \min} \quad \text{for } i = 1, 2, \dots, I \text{ and } k = 0, 1, \dots, K \quad (13)$$

where

$G_{ik}^*$  is the optimal dispatch of energy from generator  $i$  in contingency  $k$

$$G_i^{*\max} = \max_k (G_{ik}^*)$$

$$G_i^{*\min} = \min_k (G_{ik}^*)$$

Equations (11) – (13) represent a simplification of the SuperOPF because the real and reactive components of generation, reserves and load are not all identified explicitly, and for the remainder of the paper, the discussion only refers to real power (energy) even though reactive power is actually included in the case study. It would also be straightforward to include more flexible forms of load response in (11), such as interruptible contracts, but capabilities of this type were not used for this case study.

In (12) and (13), the reserve capacity for each generator in contingency  $k$  is defined as the difference between the maximum (minimum) of the  $K + 1$  optimal levels of dispatch (which may be less than the true physical maximum) and the optimal level of dispatch for the intact system  $k = 0$ . In other words, the optimum quantities of energy and reserves for  $k = 0$  are contracted ahead of real time and then the generators are also paid for the additional energy generated in real time. The maximum (minimum) dispatched capacity of every generator,  $G_i^{*\max}$  ( $G_i^{*\min}$ ), is needed for energy in at least one contingency. The level of reserve capacity for any generator is determined endogenously, and it responds to conditions on the network, such as the pattern of forecasted load. This feature is important for the case study due to the wide range of wind conditions that affect the actual generation from a wind farm and the difficulty in forecasting wind conditions accurately.

The regulated standard of Operating Reliability is maintained if load is met in all of the contingencies. Finding optimal values of  $LNS_{jk} > 0$  is equivalent to violating this reliability standard, and it signals a failure of System Adequacy in a planning application that would be corrected by increasing the system capacity in some way. Since the  $VOLL$  is specified to be very large compared to typical market prices, it is important to note that a major part of the total benefit of many components of the grid comes from avoiding unscheduled load shedding when contingencies occur. When the system is Adequate, no failures of Operating Reliability will be observed, and therefore, it is no longer possible to use the observed market prices to determine the full net-benefit of an investment that was

made to avoid unscheduled outages. These are the “Events that didn’t Happen” that should be considered when calculating the economic value of reliability in a planning model (see Mount et al. [8]).

One of the many useful capabilities of the SuperOPF is that the optimization can be considered in two stages. The first stage is the full co-optimization represented by (11) – (13) and it can be viewed as the optimum way to minimize the expected costs and maintain Operating Reliability when the system is Adequate (i.e. all  $NSL_{jk} = 0$  for all credible contingencies). This stage determines the amounts and prices of energy and reserves contracted in advance of real time (e.g. one day ahead). The second stage corresponds to a real-time OPF when the actual state of the system is known and a contingency may have occurred. The objective cost is now to minimize the incremental cost of adjusting from the contracted amounts of resources from the first step to meet the actual system conditions.

The second stage of the SuperOPF treats the actual state as the new base ( $k = 0$ ) and includes all of the remaining contingencies in the same way as before in (11) – (13). This implies that the optimum dispatch in the second stage still attempts to maintain Operating Reliability. However, if a major failure has already occurred, it may not be possible to meet the load in all situations if a second failure occurs. This would not be a violation of the typical standard of Operating Reliability assuming that the specification of the first stage covered all credible contingencies. For example, if the regulators define System Adequacy as the ability to cover all single failures, there is no guarantee that the system can cover the relatively rare event that two or more failures occur. Following any major contingency, bringing the system back into compliance with Operating Reliability would require adding existing resources that were rejected from the auction in the first stage of the optimization.

The current practices adopted in restructured markets are more in line with the optimization for Fixed Reserve Requirements in (1) – (10), and the expected cost of meeting the contingencies is not explicitly part of the objective function. In the New York Control Area, for example, a modified DC OPF minimizes the expected cost of meeting load for the intact system with specified levels of reserves included. If a contingency occurs, there is an ordered list of options, such as using reserve capacity and exercising contracts for interruptible load, with shedding load as the least desirable option. Since the contingencies are not considered explicitly in the optimization, it is virtually impossible to determine the

true economic benefit of reliability from the market solutions, and meeting a given reliability standard is treated as a physical constraint rather than as an explicit economic component of the objective function as it is in the SuperOPF.

After a contingency occurs, the objective in the SuperOPF is still to minimize the expected cost over all contingencies even if this requires shedding some load in some contingencies. The amount and location of load shedding is determined optimally. For example, if the VOLL in an urban region is much higher than the VOLL in other regions, the solution will implicitly put more weight on avoiding the shedding of load in the urban area. In fact, the SuperOPF is consistent with the relatively successful market design in Australia.

In the Australian system, the market clears in real time every five minutes to meet load and to set the prices paid for the energy generated over the following five-minute period. These are the only prices used by the system operator to pay for energy. There are also forward markets, but these markets are financial and are not run or regulated by the system operator. The five-minute auction for energy includes a market for regulation and fast-responding reserves. These ancillary services receive payments for the reserve capacity contracted at the beginning of each five-minute period and for any energy that is actually generated. This is just like the first stage of the SuperOPF, but in the Australian market, the second stage never occurs. The five-minute auctions are like a continuous series of first stage optimizations. Capacity rejected in one period can still be entered into the next period's auction. Consequently, when a contingency occurs, the next market solution will bring new capacity into the market that was not needed (i.e. rejected from the auction) before the contingency occurred.

The incentive for ensuring that additional capacity will be ready to enter the market is provided to generators and loads by reporting forecasts of the prices a few hours ahead. These forecasted prices are determined by the existing offers and bids that have been submitted in advance but they are not binding for making payments. All payments for energy and ancillary services are made using the real-time prices. When the forecasted prices are high, and the price cap of \$10,000/MWh is relatively high in the Australian market, more generators are likely to enter the market and loads may adopt procedures for reducing demand in anticipation of the high prices. Another important feature of the Australian market is that the responses to a contingency before the next five-minute market clears are



preset and automatic by, for example, using smart appliances as a fast way to shed load for a short period of time in response to a drop in frequency.

The following section describes the characteristics of the network used for the case study and the specifications of the simulations. The basic objective of the analysis is to evaluate the effects of replacing some installed coal generators by new wind generators. The initial amounts of installed capacity are sufficient to meet the standard for System Adequacy. However, since the generation from wind power is inherently intermittent, the rated capacity of the wind generators must be substantially larger than the coal capacity replaced to maintain the reliability standard. In addition, more reserve capacity is needed to maintain Operating Reliability when wind capacity is installed, and this is an important illustration of why it is desirable to use the SuperOPF and determine the optimum amounts of reserve capacity endogenously. In another paper that is in preparation, the SuperOPF will be used to demonstrate how valuable it is to compensate for the variability of wind generation using load response and storage capabilities such as charging batteries for plug-in hybrid vehicles. In this case study, the focus is on showing how to determine the economic benefit of having adequate transmission capacity to get the full value from a wind farm in a remote location.

## **4. The Specifications for the Case Study**

The case study is based on a 30-bus network that has been used extensively in our research to test the performance of different market designs using the *PowerWeb* platform. The one-line-diagram of this network is shown in Figure 1 below. The 30 nodes and the 39 lines are numbered in Figure 1 and this numbering scheme provides the key to identifying the locations of specific contingencies, constraints and shadow prices in the following discussion. In addition, the six generators are also identified. The network is divided into three regions, Areas 1 – 3, and Area 1 represents an urban load center with a large load, a high VOLL and expensive sources of local generation from Generators 1 and 2. The other two regions are rural with relatively small loads, low VOLLs and relatively inexpensive sources of generation from Generators 3 – 6. Consequently, an economically efficient dispatch uses the inexpensive generation in Areas 2 and 3 to cover the local loads and as much of the loads in Area 1 as possible. The capacities of the transmission tie lines linking Areas 2 and 3 with Area 1 (Lines 12, 14, 15 and 36) are the limiting factors. Since lines and

generators may fail in contingencies, the generators in Area 1 are primarily needed to provide reserve capacity. The general structure of the network poses the same type of problem faced by the system operators and planners in the New York Control Area. Most of the load is in New York City (i.e. Area 1) and the inexpensive sources of baseload capacity (hydro, coal and nuclear) are located upstate (i.e. Areas 2 and 3).

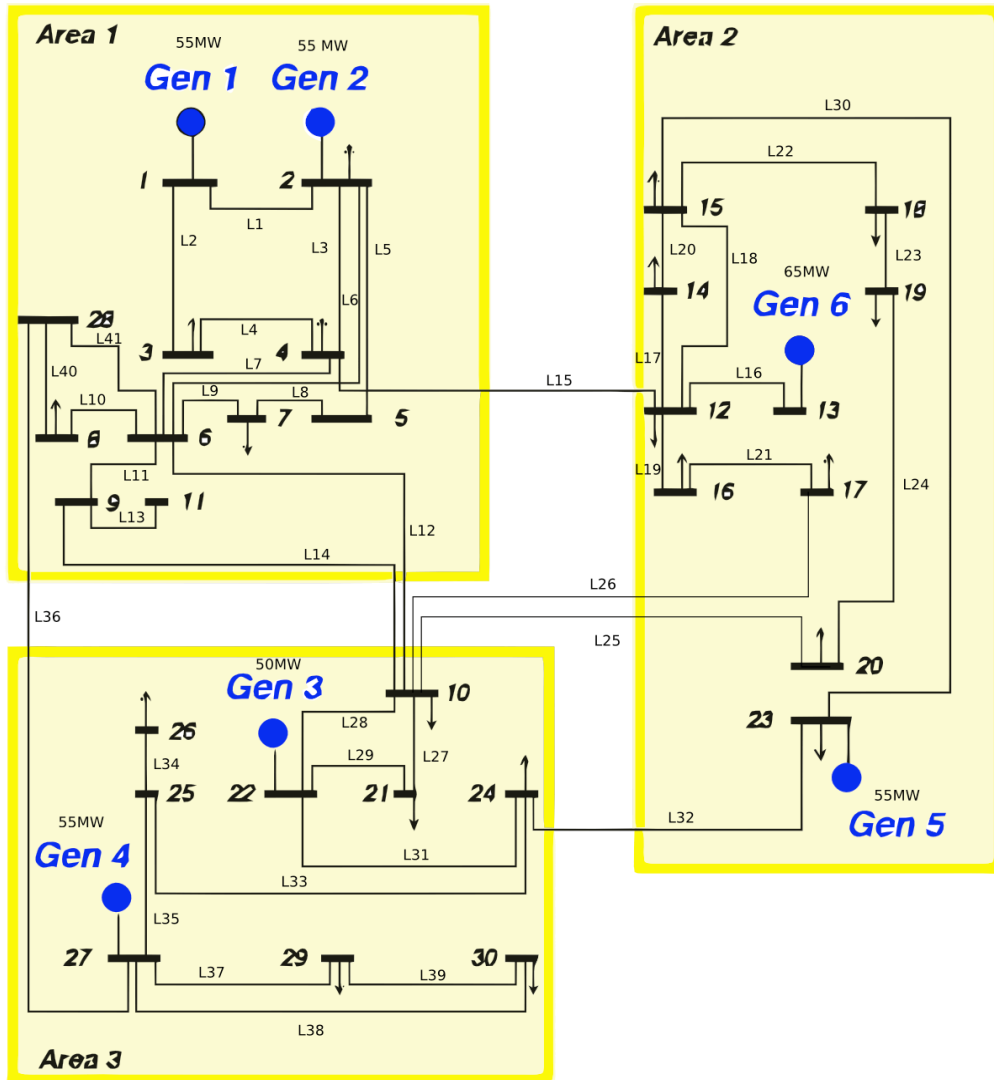


Figure 1: The One-Line-Diagram of the 30-Bus Network.

In an earlier case study, the simulation increased the load in Area 1 in small increments until the capacity of the network was no longer able to meet all loads in all contingencies (see Mount et al. [8]). In other words, the standards for Operating Reliability and System Adequacy were eventually violated after the load had been increased sufficiently. For this case study, the pattern of load is fixed at a level that is slightly less than the level at which the violations first occurred. Our original expectation was that by using this procedure the initial system would meet the reliability standards without having an excessive amount of reserve generating capacity. However, the actual amount of installed capacity in Area 1 turned out to be larger than expected. The implication is that the violations of Operating Reliability that occurred at slightly higher levels of load were caused by localized limitations of the network's topology rather than by an overall limitation of generating capacity.

The amounts and locations of the different types of installed generating capacity are shown in Table 1 together with the production costs. The levels of loads, generation and reserves by Area are shown in Table 2. The total amounts of generating capacity in each Area are similar in Table 1, but the corresponding costs of production vary a lot and are much higher in Area 1. The level of generation in Area 1 in Table 2 is only 24% of the load and is smaller than the level of reserves. Exactly the opposite situation exists in Areas 2 and 3. The levels of generation are much higher than the loads in each Area, and the corresponding levels of reserves are relatively small. The amounts of idle capacity (i.e. not used for either generation or reserves) are relatively small in Areas 2 and 3, implying that most of the installed capacity is needed to maintain Operating Reliability. However, there is a substantial amount of idle capacity in Area 1, and this capacity will eventually be needed to compensate for the uncertainty of wind generation when the capacity of the wind farm is large.

**Table 1: Installed Generating Capacity by Type and Location and the Production Costs**

Area	Nuclear Hydro	Coal	Oil	Combined Cycle Gas	Gas Turbine	Total by Area
1	0	0	65MW	0	45MW	110MW
2	50MW	70MW	0	0	0	120MW
3	65MW	0	0	40MW	0	105MW
<b>Total by Type</b>	<b>115MW</b>	<b>70MW</b>	<b>65MW</b>	<b>40MW</b>	<b>45MW</b>	<b>335MW</b>
<b>Production Cost</b>	<b>\$5/MWh</b>	<b>\$25/MWh</b>	<b>\$95/MWh</b>	<b>\$55/MWh</b>	<b>\$80/MWh</b>	<b>-</b>

**Table 2: Initial Patterns of Load, Generation and Reserves (Case 1 with No Wind Capacity Installed)**

Area	Load (MW)	Gen. (MW)	% of Load	Res. (MW)	% of Load	Idle (MW)	% of Load	Inst. (MW)	% of Load
1	88.70	20.65	23%	26.59	30%	62.76	71%	110	124%
2	56.20	103.14	184%	16.86	30%	0.00	0%	120	214%
3	48.50	81.97	169%	13.11	27%	9.92	20%	105	216%
<b>Total</b>	<b>193.40</b>	<b>205.77</b>	<b>106%</b>	<b>56.56</b>	<b>29%</b>	<b>72.67</b>	<b>38%</b>	<b>335</b>	<b>173%</b>

Gen. - Generation (contracted amount)  
Res. - Reserves (upward reserves only)  
Inst. - Installed capacity

By maintaining Operating Reliability using the initial set of conditions on the network, there is an implicit assumption that the system is robust enough to meet all loads in all credible contingencies. The specific contingencies included in the SuperOPF are listed in Table 3. These contingencies include the failures of individual generators and transmission lines, and also the uncertainty about the actual level of load associated with the errors of forecasts when the optimum dispatch is determined one day ahead of real time, for example. When wind capacity is added to the network, this type of uncertainty about actual outcomes is exacerbated, and for this case study, the combined forecasting errors for load and wind generation are represented by four possible outcomes (Wind 1 - 4 in Table 3). Each outcome specifies a level of generation from a wind farm and the corresponding pattern of loads, and each outcome has a specified probability of occurring. This information is summarized in Table 4.

For generators and lines, there are only two possible outcomes. The first outcome is to perform as required in the optimum dispatch, and the second is to fail completely. However, the probability of failure is very small (0.2% for each failure in this case study), and as a result, the probability that each piece of equipment will perform as required is 99.8%. Since there are 15 failures identified in Table 3, the expected number of failures is 3 in 100 periods because the individual failures and periods are specified to be statistically independent. In other words, the system is expected to be intact 97% of the time. In contrast to the high probabilities that equipment will not fail, the probability that a forecasted level of wind generation will actually be realized is relatively small. Hence, it is unlikely that anyone of the four different outcomes for wind generation (Wind 1 – 4) will have a dominant probability. In addition, the range of possible outcomes is large, and as a result, one would expect that the quantity of reserves needed to maintain Operating Reliability should increase as more wind capacity is installed. This phenomenon has already been observed in Europe and the levels of operating reserves have increased by almost 10% in some countries.

There are three different forecasts of the level of wind generation (high, medium and low), and each forecast has four possible outcomes, summarized in Table 4. With no wind capacity installed, the contingency  $k = 0$  corresponds to the intact system using the forecasted level of load (i.e. the network shown in Figure 1). The analysis that underlies the information presented in Table 4 has three components that are described in a recent paper by Anderson and Cardell [1]. The first component is a set of time-series data for hourly wind speeds at a specific location (in New England for this case study). The second component is an ARMA model for predicting wind speed (one hour ahead for this case study), and finally, there is a power curve for a wind turbine that converts a given wind speed to the amount of energy generated (wind turbines are also specified as a potential source of positive reactive power in the SuperOPF).

The data set of observed wind speeds provides the information needed to 1) derive a probability distribution of the wind speed, 2) estimate a forecasting model, and 3) compute the forecasts of wind speed for each hour. The forecasted wind speeds are then assigned to three bins by dividing them into three different ranges (Column 1 in Table 4). For each bin of forecasted wind speeds, the probability of being in a bin is calculated (Column 2). For each bin of forecasted wind speeds, the corresponding observed wind speeds for each bin of

forecasts are collected. The next step is to divide each collection of observed wind speeds into four new bins, and then to determine the average wind speed and the corresponding probability (Column 4) for each bin of observed wind speeds. The final step is to convert the average observed wind speeds in the four bins to the corresponding levels of generation using the power curve for a wind turbine. These levels of generation are reported as percentages of the maximum output (rated capacity) of a wind farm (Column 3).

**Table 3: The Contingencies Used in the Case Study**

- 0 = wind 1 (root case)
- 1 = wind 2
- 2 = wind 3
- 3 = wind 4
- 4 = line 1 : 1-2 (between gens 1 and 2, within area 1)
- 5 = line 2 : 1-3 (from gen 1, within area 1)
- 6 = line 3 : 2-4 (from gen 2, within area 1)
- 7 = line 5 : 2-5 (from gen 2, within area 1)
- 8 = line 6 : 2-6 (from gen 2, within area 1)
- 9 = line 36 : 27-28 (main tie, areas 1-3)
- 10 = line 15 : 4-12 (main tie, areas 1-2)
- 11 = line 12 : 6-10 (other tie, areas 1-3)
- 12 = line 14 : 9-10 (other tie, areas 1-3)
- 13 = gen 1
- 14 = gen 2
- 15 = gen 3
- 16 = gen 4
- 17 = gen 5
- 18 = gen 6

The probabilities for Contingencies 0 - 3 are summarized in Table 4  
 The probabilities for each one of Contingencies 4 -18 is 0.2%

An important point that underlies the levels of generation in Column 3 of Table 4 is that the ranges of observed wind speeds for each wind forecast (Low, Medium or High) are much larger than the range of the forecasts that define each bin. Consequently, the ranges of generation for a given wind forecast are also very large. For a Low wind forecast, the distribution of outcomes is skewed to the right. The modal outcome is zero generation but there is still a small probability that the actual generation from wind will be 73% of the maximum. The outcomes for a Medium wind forecast are more uniform in distribution but have a wide range from 6% to 93% of the maximum. The outcomes for a High wind forecast

are the most challenging for system operators because there is a substantial probability of 14% that a turbine will cut out at very high wind speeds (>25meters/second) to avoid damaging the generator. Hence, the distribution of wind speeds is bimodal with modes at 0% and 100% of the maximum level of generation.

**Table 4: Specifications of the Wind Contingencies in the Case study**

<b>Forecasted Wind Speed</b>	<b>Probability of Forecast Occurring</b>	<b>Wind Generation (% of Installed MW)</b>	<b>Probability of Actual Generation</b>
<b>LOW (0-5meters/second)</b>	<b>11%</b>	0%	66%
		7%	26%
		33%	5%
		73%	3%
<b>MEDIUM (5-13meters/second)</b>	<b>46%</b>	6%	24%
		38%	20%
		62%	18%
		93%	38%
<b>HIGH (&gt;13meters/second)</b>	<b>43%</b>	0%	14%
		66%	4%
		94%	3%
		100%	79%

For this case study, the wind farm is located at the same node as Generator 6, and before any wind capacity is installed, this generator represents the combination of a coal plant with a capacity of 35MW, and a nuclear/hydro plant with a capacity of 30MW. The rationale for doing this case study is that policy makers are assumed to be interested in evaluating the effects of replacing the coal capacity by wind capacity for environmental reasons. In fact, an ongoing project using the SuperOPF has already been initiated to investigate the effects of introducing a cap on the total emissions of carbon dioxide from power plants in New England and New York State associated with the new Regional Greenhouse Gas Initiative (RGGI). In our simulation, the coal capacity of Generator 6 is replaced in increments by new wind capacity. Since the generation from wind capacity is more variable than the generation from a coal plant, 1MW of coal capacity is replaced by 3MW of wind capacity for a maximum of 105MW when the 35MW of coal capacity at Generator 6 is replaced completely. The justification for doing this is that it approximates the current procedures used by regulators to determine whether the capacity of a network

meets the reliability standard for Generation Adequacy. For example, in New England, the rated capacities of different types of generation in the Forward Capacity Market are converted to the expected amounts that will be available to meet peak loads. A coal plant may have an availability rating of over 90% but a wind farm is likely to have a rating of less than 20%. Hence, the implicit use of 33% for the availability of wind capacity in the simulation is relatively high, and this value was chosen to avoid having the wind farm overwhelm the capacity of the network. In spite of adopting this strategy, the network is still unable to use all of the potential generation for a High wind forecast well before the coal plant is replaced completely unless the transmission capacities of the tie lines into Area 1 are increased.

## **5. Results of the Simulation**

The basic structure of a simulation is to replace the 35MW of coal capacity at Node 13 (Generator 6) in increments (steps) by three times as much wind capacity to give a total of 105MW of wind capacity by the end of the simulation. This example represents the type of policy options that regulators face in setting a target for the penetration of wind capacity as the goal of, for example, a Renewable Portfolio Standard. Hence, a complete simulation ranges from the initial conditions shown in Figure 1, with no wind capacity and a total 335MW of installed capacity, to a network with 405MW of installed capacity that includes 105MW of wind capacity. The pattern of load is kept constant throughout the simulation at the levels shown in Table 2. For each step in the simulation, the SuperOPF determines the optimal dispatch to meet load and Operating Reliability using the 19 contingencies listed in Table 3. A separate optimization is computed for each one of the three different wind forecasts (Low, Medium and High in Table 4), and the expected average cost of meeting load, for example, can be computed as a weighted average of the three solutions using the probabilities of each forecast as the weights (Column 2 in Table 4).

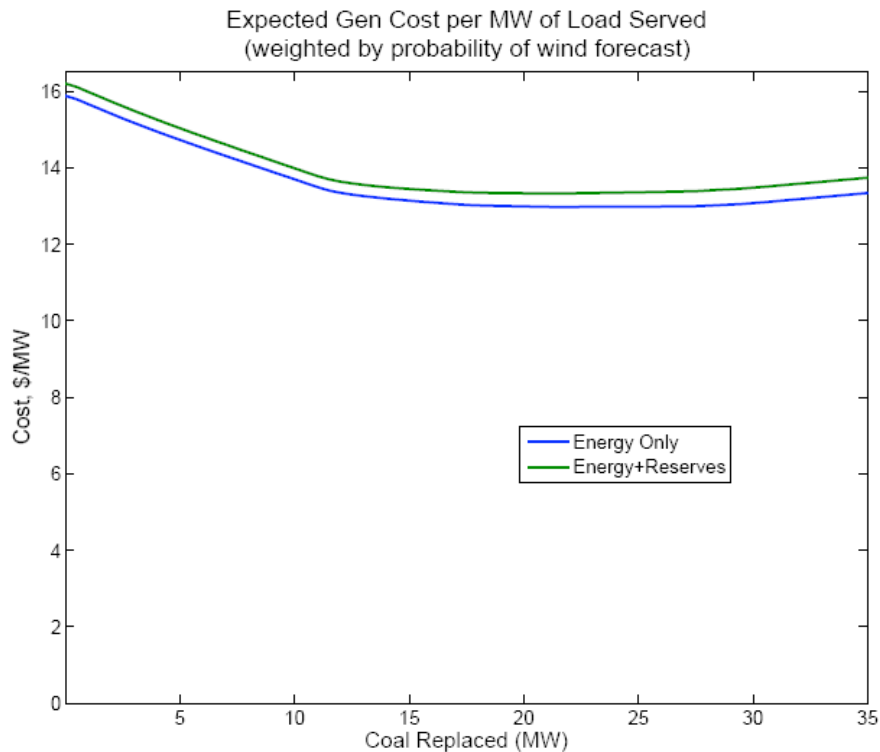
There are two different sources of uncertainty that need to be identified before presenting the results of the simulation. The first source comes from the inherent uncertainty about the state of the system in a co-optimization because the objective function in (11) considers a set of different contingencies. It is not certain in a day-ahead market, for example, exactly what the state of the network will be in real time. The optimal dispatch



determined by the SuperOPF represents a contracted pattern of generation and reserves, and the corresponding nodal prices (shadow prices) are the expected prices over the set of contingencies listed in Table 3. Maintaining Operating Reliability corresponds to having no unscheduled outages in any of the contingencies, and this was found to be the case in all of the simulations. The main restriction on the choice of an optimal dispatch is that it must be possible to meet any one of the contingencies starting from the intact system ( $k = 0$ ) without violating ramping constraints.

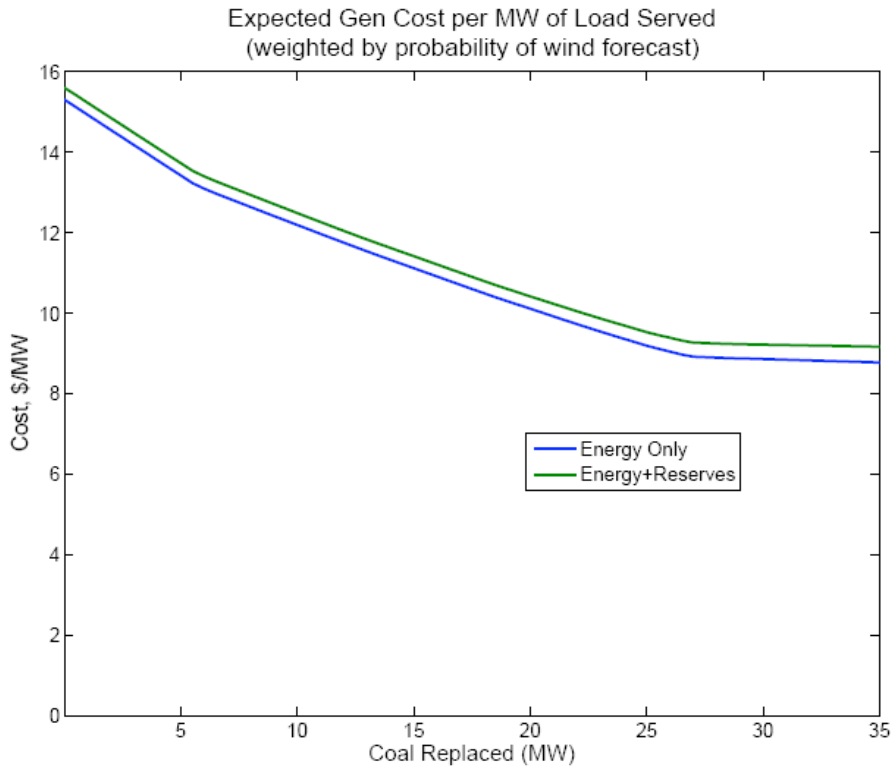
The second source of uncertainty is the expected wind speed, due to the three different forecast levels in Table 4. A separate optimal dispatch is determined for the Low, Medium and High wind forecasts. When wind capacity is installed, the optimal results of the SuperOPF consider the first source of uncertainty only, and the dispatch is optimal conditionally on a given forecast of wind speed. As a result, it is also useful to determine the unconditional optimal results by taking the expectation over the three different forecasts of wind speed. In this paper, the results are presented first as the “unconditional” optimal dispatch that are, in effect, an expectation over both contingencies and wind speed, and then, the “conditional” results are presented for each one of the three forecasts of wind speed. The real-time results for a known state of the network (the second stage optimization) are also very interesting and surprising, but these more detailed results will be discussed in another paper.

The unconditional expected cost per MWh of both generation and reserves for meeting the fixed pattern of load are presented in Figure 2 below. The horizontal scale from left to right measures the amount of coal capacity replaced and it corresponds to increasing the size of the wind farm by three times as much capacity. Since the operating cost of generation from wind is specified to be zero, wind power, if available, is the least expensive source of generation. This effect is offset to a small extent by an increased cost of reserves with more wind generation. The average production cost decreases initially as wind capacity increases but it reaches a low plateau when the amount of coal capacity replaced is  $>12\text{MW}$ . In fact, the average cost increases slightly for the highest levels of wind penetration. The reason for this is that the transmission capacity of the main tie line from Area 2 to Area 1 (Line 15) is limited and it is not possible to use all of the generation from wind if the installed capacity of the wind farm is too large.



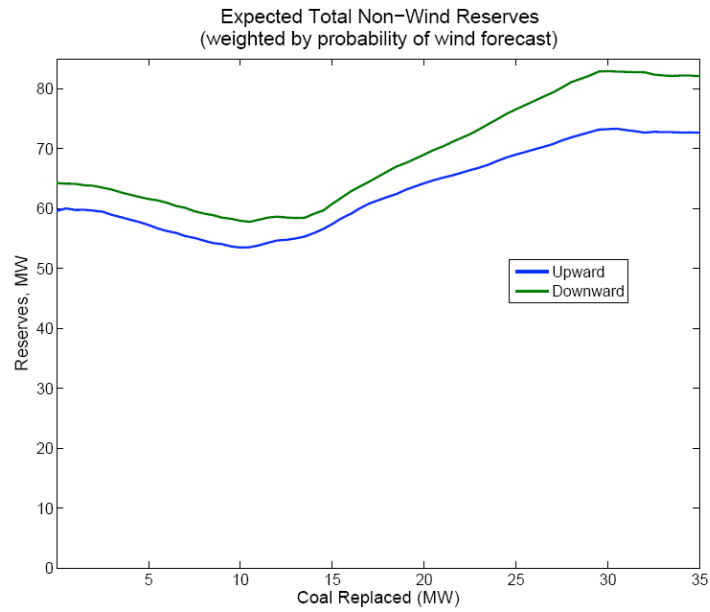
**Figure 2: The Unconditional Expected Cost of Production for Different Levels of Coal Replaced by Wind in Case 1 (\$/MWh Delivered to Loads)**

Given the limited capacity of the network to transfer power from Area 2 to Area 1, another specification of the network was considered with the capacity of the tie line from Area 2 to Area 1 doubled (Line 15 in Figure 1). The original network capacity is called Case 1 and the augmented network with higher transfer capabilities is called Case 2. The results corresponding to Figure 2 for Case 2 are presented in Figure 3. In Case 2, all available wind generation is used and the average production cost in Figure 3 falls as coal capacity is replaced. The different slopes in Figure 3 correspond to replacing different fuels, first natural gas, then coal and finally nuclear/hydro even though the production costs of the latter are only \$5/MWh. Overall, the average production cost (ignoring capital costs) decreases by about 40% (from >\$15/MWh to <\$9/MWh).

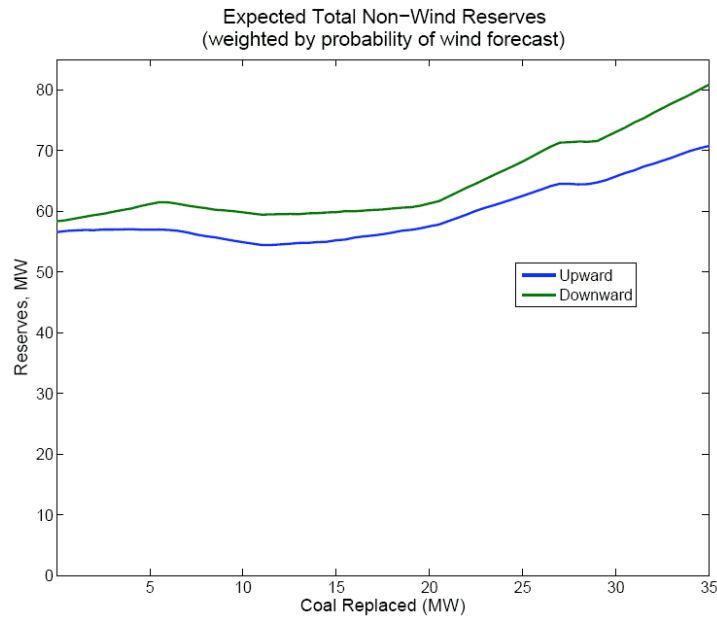


**Figure 3: The Unconditional Expected Cost of Production for Different Levels of Coal Replaced by Wind in Case 2 (Average \$/MWh Delivered to Loads)**

An important feature of using co-optimization in the SuperOPF is that the optimal pattern of reserve generating capacity is determined endogenously, and the level of reserves reflects the increasing uncertainty of generation from wind as the capacity of the wind farm increases and replaces the coal capacity at Generator 6. In particular, the possibility that generation from wind will cut out at high wind speeds has to be considered in determining the optimal dispatch. The growing variability of wind generation as the wind farm increases in size is reflected by the increases of reserves shown in Figures 4 and 5 for Case 1 and Case 2, respectively. It is interesting to note that the total amount of reserve capacity is similar in the two cases even though the level of useable wind generation is much higher in Case 2 than it is in Case 1 when more than 12MW of coal capacity are replaced.



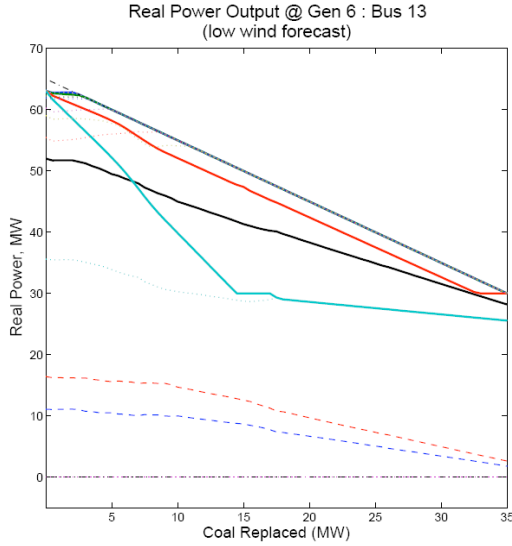
**Figure 4: The Unconditional Level of Reserve Generating Capacity for Different Levels of Coal Replaced by Wind in Case 1 (MW of Upward and Downward Reserves)**



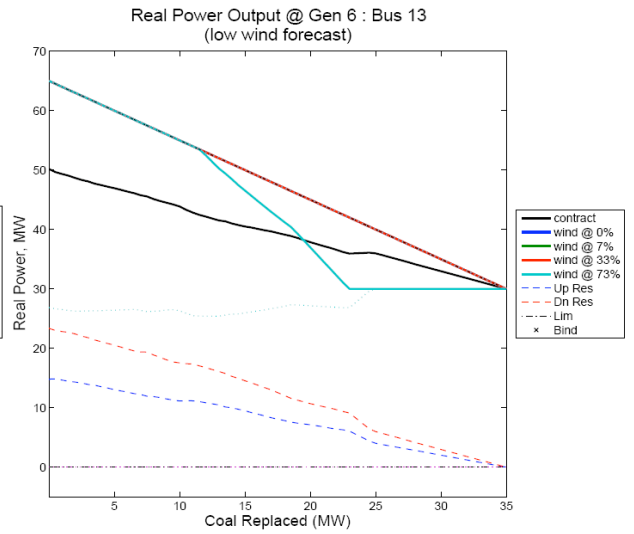
**Figure 5: The Unconditional Level of Reserve Generating Capacity for Different Levels of Coal Replaced by Wind in Case 2 (MW of Upward and Downward Reserves)**

# LOW WIND FORECAST

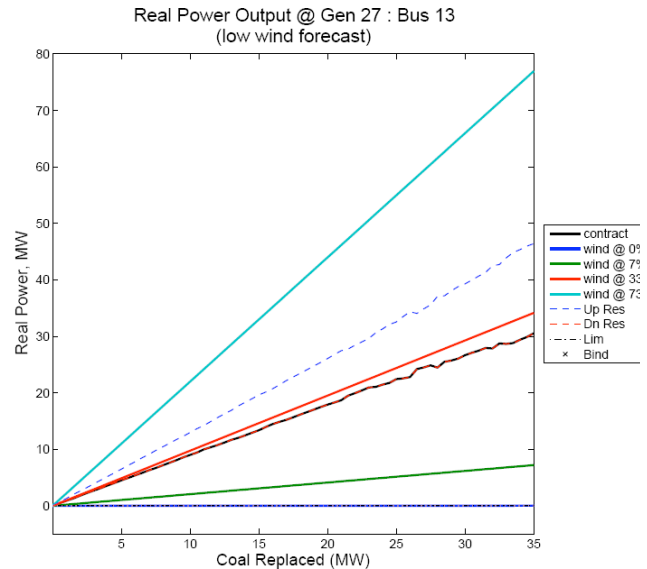
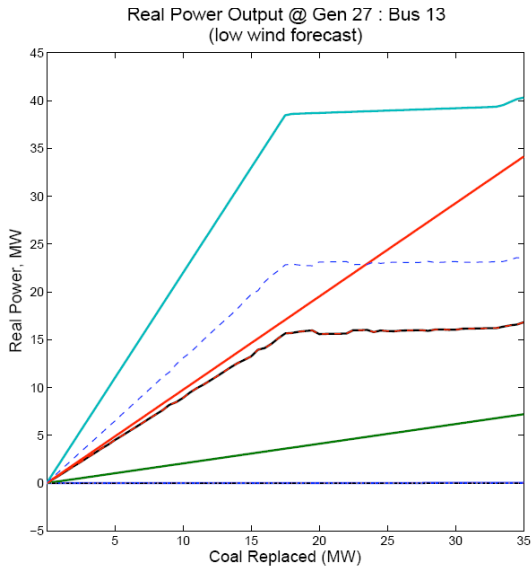
## Non-Wind Generation by Generator 6 CASE 1



## CASE 2



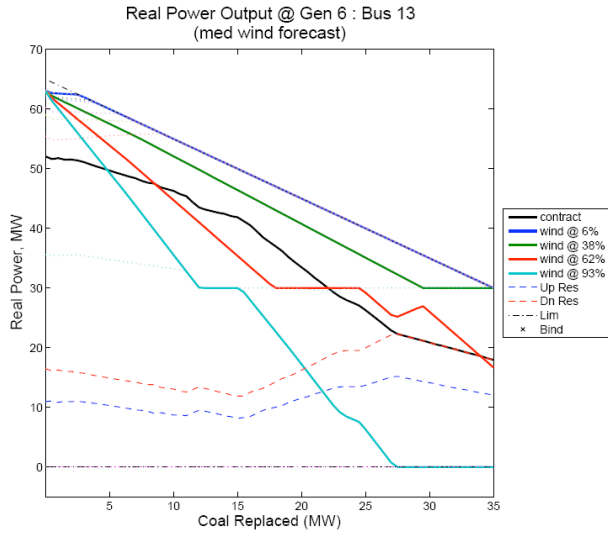
## Wind Generation by Generator 6



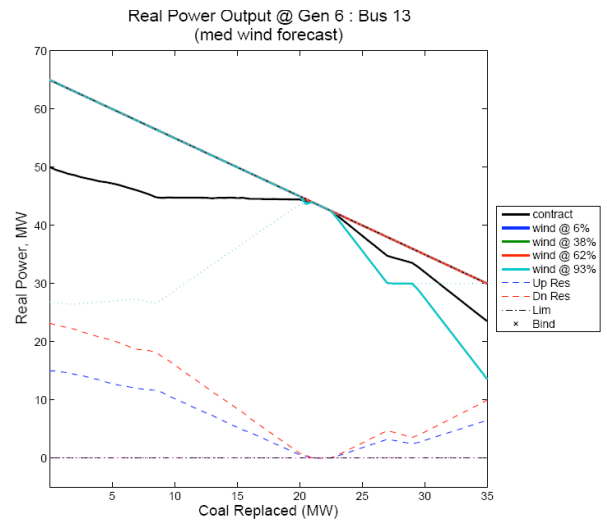
**Figure 6: LOW Wind Forecast: Actual and Contracted Generation for Wind Generation and for Coal/Nuclear/Hydro Generation from Generator 6**

# MEDIUM WIND FORECAST

## Non-Wind Generation by Generator 6 CASE 1



## CASE 2



## Wind Generation by Generator 6

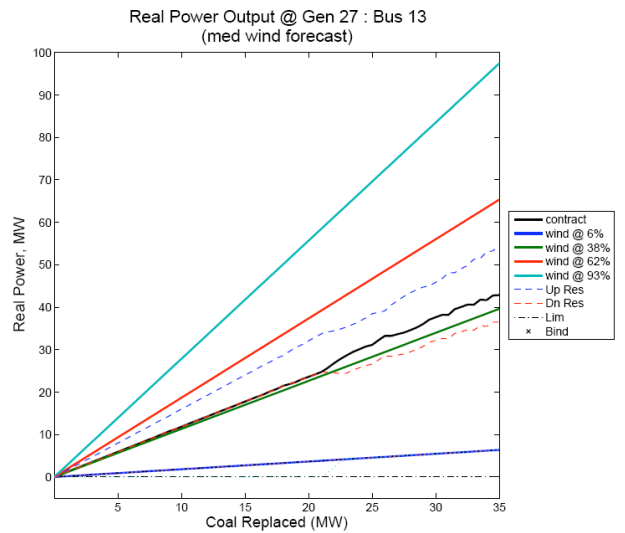
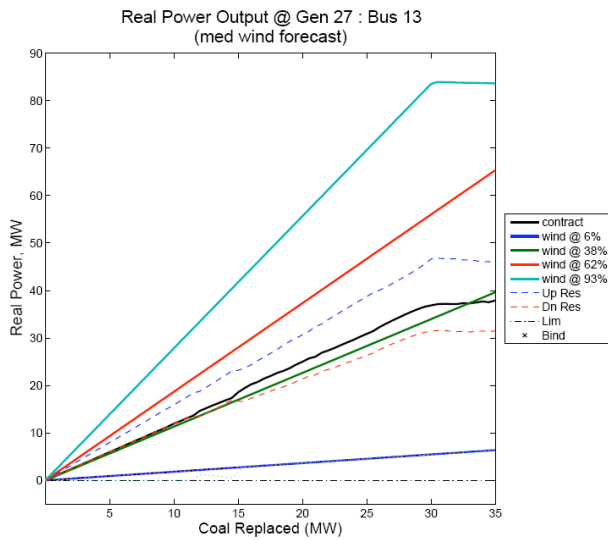
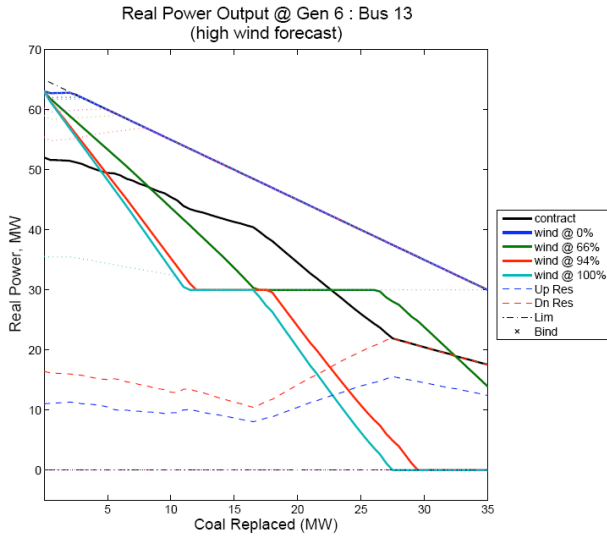


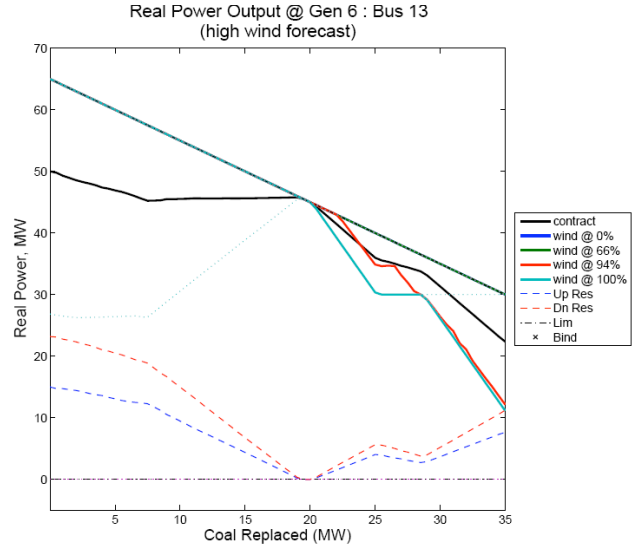
Figure 7: MEDIUM Wind Forecast: Actual and Contracted Generation for Wind Generation and for Coal/Nuclear/Hydro Generation from Generator 6

# HIGH WIND FORECAST

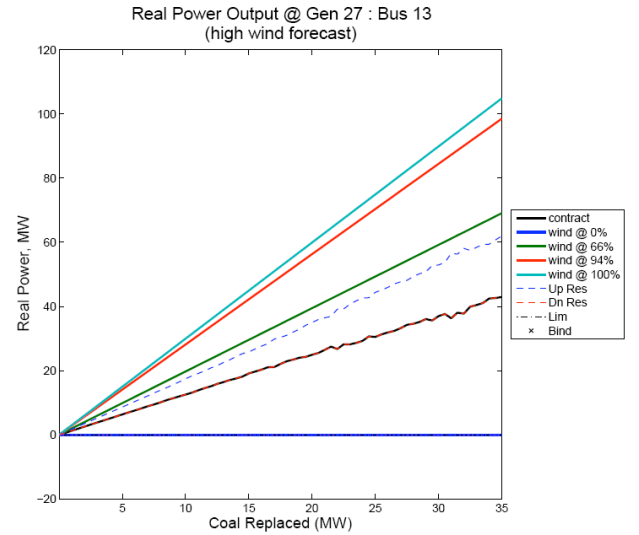
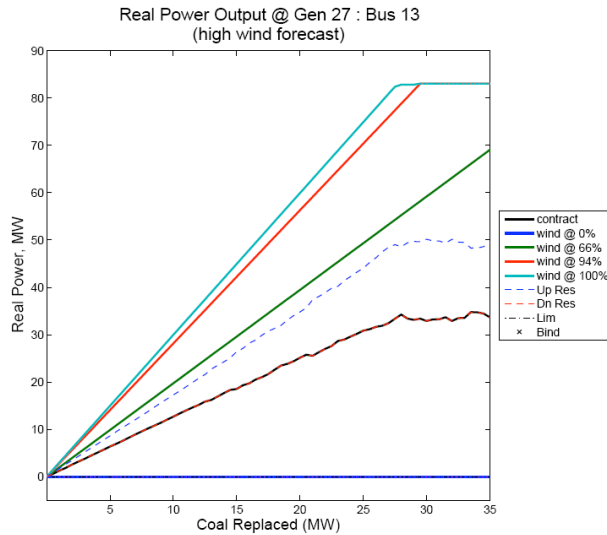
## Non-Wind Generation by Generator 6 CASE 1



## CASE 2



## Wind Generation by Generator 6



**Figure 8: HIGH Wind Forecast: Actual and Contracted Generation for Wind Generation and for Coal/Nuclear/Hydro Generation from Generator 6**

Since the amount of generation from wind may be either substantially higher than expected or substantially lower than expected, both upward and downward reserves must be available to maintain standards of Operating Reliability. Hence, an interesting feature of the conditional optimal dispatch for a given forecast of wind speed is to determine how much wind generation should be contracted in advance. Figures 6 – 8 show the optimal dispatch of the non-wind and wind capacity installed at Generator 6 for the four possible wind outcomes given one of the three different wind forecasts (note that the vertical scales for Cases 1 and 2 are not the same for wind generation). In addition, the optimal quantity of contracted generation is also identified. For the Low wind forecast (Figure 6), the modal level of generation is zero (see Table 4), and if the actual realization of wind generation turns out to be high, the amount of wind that can be used in Case 1 is limited by the transmission capacity when more than 16MW of coal capacity is replaced by wind capacity. In other words, some of the potential generation from wind is wasted at high levels of wind penetration. This phenomenon is repeated for the Medium and High wind forecasts in Case 1 (Figures 7 and 8). In contrast, all of the wind generation is used for all three wind forecasts when the capacity of the tie line between Areas 3 and 1 is doubled in Case 2.

The upper plots in Figures 6 – 8 show the level of generation from the non-wind capacity at Generator 6. Initially, there are 35MW of coal capacity, with a production cost of \$25/MWh, and 30MW of nuclear/hydro capacity, with a production cost of \$5/MWh (see Table 1). Since the production cost of wind capacity is \$0/MWh, an efficient dispatch will use as much wind generation as possible until the costs of constraints become prohibitive. As the wind capacity is increased in a simulation, the coal capacity at Generator 6 is physically reduced from 35MW to 0MW and levels of generation below this physical constraint reflect economic considerations.

When the actual realization of wind generation is low, all of the installed coal capacity is used until the physical constraint is reached. Levels of non-wind generation at Generator 6 below this physical constraint indicate that non-wind generation is being displaced by wind generation for economic reasons. When the actual realization of wind generation is sufficiently high in both Cases 1 and 2, the non-wind generation at Generator 6 eventually falls to zero, and if the non-wind generation falls below 30MW, wind generation is displacing the relatively inexpensive nuclear/hydro generation. Since the pattern of loads



remains constant in the simulations, the total level of generation also remains relatively constant (losses may vary slightly from step to step). Consequently, if wind generation is increasing and non-wind generation at Generator 6 remains constant for a number of steps, non-wind generation at another location is being displaced for economic reasons.

The expected prices paid to the six generators are shown in Figure 9 for Cases 1 and 2 and the three different wind forecasts. The expectation is taken over the entire set of contingencies, including the four realizations of wind generation shown in Table 4 for each wind forecast (note that the vertical scales for Case 1 and Case 2 are not the same). When the prices are substantially different at different locations, it implies that transmission constraints are binding and the market is fragmented due to congestion. The prices for the Low wind forecast in Case 1 show that the initial level of congestion is reduced for a number of steps as wind capacity replaces coal capacity but congestion reappears in a different area when the amount of wind capacity is sufficiently high. In Case 1, the transmission constraint from Area 3 to Area 1 is always binding for the Medium and High wind forecasts, and as a result, there are substantial differences in the prices paid to generators throughout the simulation. With the increased transmission capacity in Case 2, congestion is less of a problem and the prices at different locations are generally closer together than they are in Case 1. The anomaly in Case 2 is the price paid to Generator 4 with the Low wind forecast. Even though this generator has relatively low production costs, generation is limited by a binding transmission constraint from Area 3 to Area 1 (Line 36).

For the Low wind forecast, prices tend to increase in both Case 1 and Case 2 as more coal capacity is replaced by wind. This is caused by the fact that there is less coal capacity installed, and as a result, more expensive sources of non-wind generation have to be used to meet the load when the wind does not blow. When there is a lot of wind generation in Case 2, the prices decrease with increased wind generation because it displaces other expensive sources of generation. The steps in the price plots reflect the steps in the simulation when different fuel types are being replaced by wind and different constraints are binding. Changes to the set of binding constraints can lead to unexpected reversals in the behavior of prices (e.g. for the Medium wind forecast in Case 2).

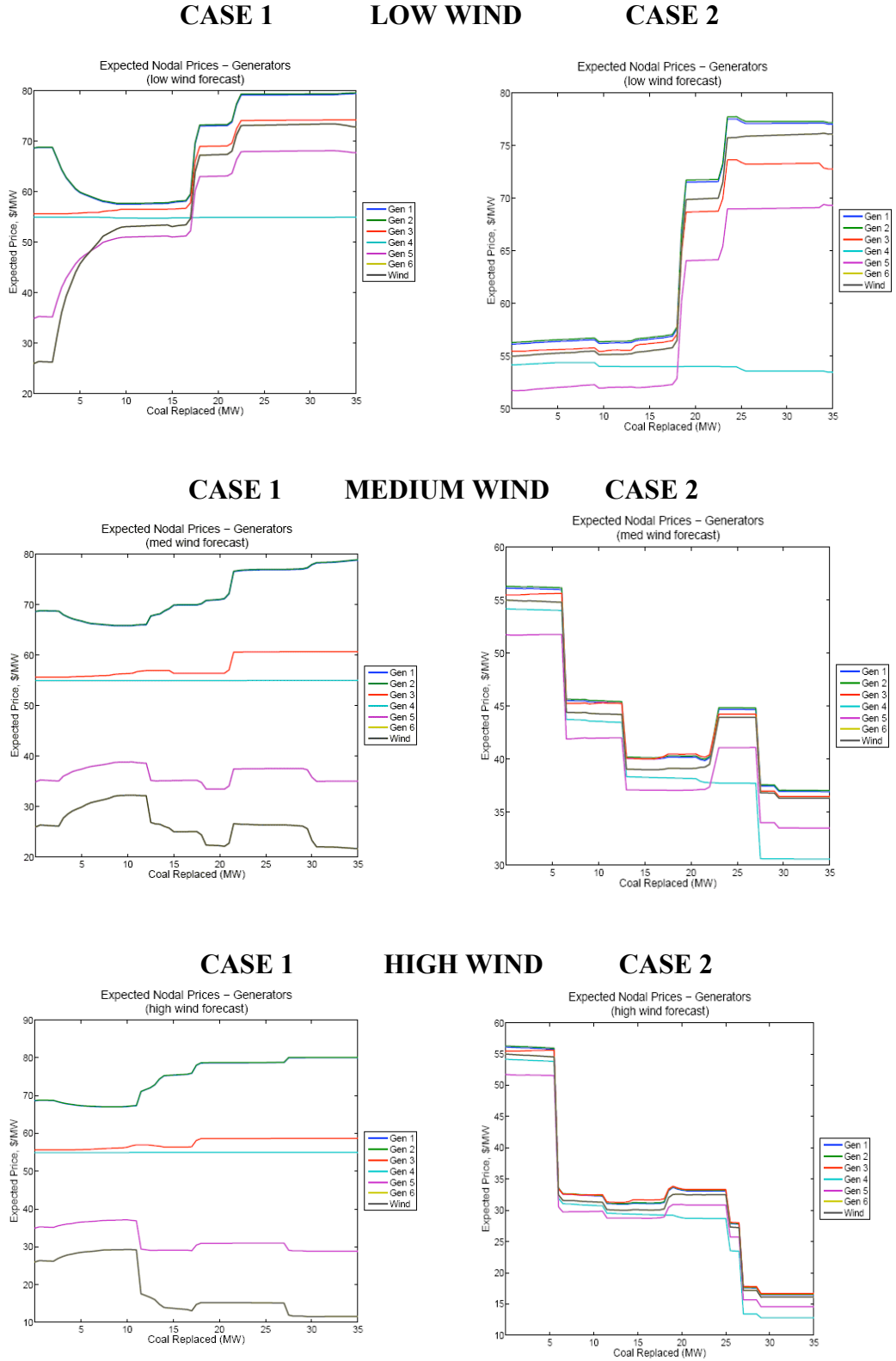


Figure 9: Expected Market Prices of Real Power at Generator Nodes (\$/MWh)

## 6. Conclusions

The main purpose of this paper is to illustrate how the new SuperOPF developed by PSERC researchers at Cornell can be used to determine the net social benefit of adding wind capacity to replace coal capacity on a network with a fixed pattern of loads. The important features of the SuperOPF are 1) failures of equipment (contingencies) are considered explicitly in the optimization, 2) load shedding at a high Value-of-Lost-Load (VOLL) is allowed in all contingencies, and 3) the optimization incorporates the nonlinear constraints of a full AC network. These three features make it possible to 1) determine the correct shadow prices for different components of the network under different operating conditions, 2) calculate the correct net social benefit of maintaining Operating Reliability, and 3) evaluate the net economic benefit of relying more on an intermittent source of generation, such as wind capacity, that lowers production costs (by displacing more expensive generation from fossil fuels) but increases the cost of ancillary services needed to maintain reliability.

In contrast, most conventional algorithms for determining the dispatch of generators simplify the nonlinear computations by using proxy limits on network capacity, such as lowering the thermal limits of transmission lines. These proxy limits inevitably distort the shadow prices computed in the optimization. Furthermore, proxy measures, such as minimum reserve margins for generating capacity in different locations, are included in the optimization as additional constraints to represent the Operating Reliability. This procedure makes Operating Reliability a physical constraint rather than an economic requirement. In reality, the economic benefits of some components of a network are determined exclusively by avoiding the high cost of unscheduled outages when equipment fails in relatively rare contingencies. In the SuperOPF, the shadow prices and the level of Operating Reliability reflect the actual operating conditions, and high shadow prices tend to occur under adverse conditions when the network is congested due, for example, to high levels of load or equipment failures. These adverse situations are the most important for determining the true economic benefit of different components of a network, but these situations are exactly the ones when the shadow prices are the most distorted using conventional algorithms.

Using conventional dispatching algorithms, it is potentially misleading to use the observed nodal prices of real power and ancillary services in a market as a guide for identifying what should be fixed on a network when standards of Operating Reliability are

violated. The fundamental limitations of conventional planning tools are largely responsible for the attempt by many regulators to make a clear distinction between “economic” investments and “reliability” investments when planning capacity expansions. Although this is a convenient simplification, this practice completely ignores the true economic benefit of maintaining a high level of reliability. In reality, most upgrades of a network, particularly of transmission lines, affect both production costs and reliability. Determining how much of the capital cost of an upgrade should be allocated to reliability is quite arbitrary using conventional planning tools. When the additional complications of operating a network with a substantial amount of intermittent generation from wind farms are considered, conventional planning tools fail completely because the established proxy measures for reliability (i.e. the locational reserve margins) are no longer appropriate.

Reliability should be treated as an economic decision that depends on the actual operating characteristics of the network. Using the SuperOPF, shedding load at specific locations in one or more contingencies is an explicit indication that the level of reliability has deteriorated and where on the network the problems have occurred. The basic planning decision is to determine whether an investment in upgrading capacity is justified by showing that the cost of this investment is less than the product of the high value of not shedding load times the small probability that a contingency occurs. It is not economically efficient or practical to cover all possible contingencies.

The results of the simulation presented in Section 5 illustrate the importance of treating Operating Reliability as an integral part of the economic optimization process in the SuperOPF. The optimal level of reserve generating capacity increases as the amount of installed wind capacity increases to compensate for the uncertainty about the actual wind speeds. Under the initial network conditions with no wind capacity installed, the optimization considers the intact system with a high probability of occurring and a set of contingencies with low probabilities of occurring. When wind capacity is installed, different wind speeds are treated as additional contingencies for a given forecast of wind speed (High, Medium and Low). Typically, these wind contingencies cover a wide range of operating conditions, and furthermore, the probabilities for different wind outcomes are relatively high compared to the probabilities of equipment failures. For example, the probability of a conventional generator failing is only 0.2% in the simulation, but the corresponding

probability of a failure is 14% for wind capacity if the forecast of wind speed is High (because the turbines automatically cut out when the actual wind speed is above a specified maximum to protect the turbines from physical damage). The implication is that the optimum level of reserves is different for different forecasts of wind speed, and it is misleading to use a fixed reserve margin as a proxy measure for reliability.

**Table 5: Final Patterns of Load, Generation and Reserves in the Simulation (Case 2 with 35MW of Coal Capacity in Area 2 replaced by 105 MW of Wind Capacity)**

Area	Load (MW)	Gen. (MW)	Change from Initial (MW)	Res. (MW)	Change from Initial (MW)	Idle (MW)	Change from Initial (MW)	Inst. (MW)	Change from Initial (MW)
<b>1</b>	<b>88.70</b>	<b>31.79</b>	<b>11.14</b>	<b>35.51</b>	<b>8.92</b>	<b>42.70</b>	<b>-20.05</b>	<b>110</b>	<b>0</b>
2 (Non-wind)	-	65.28	-	19.72	-	0.00	-	85	-
2 (Wind)	-	41.54	-	0.00	-	63.46	-	105	-
<b>2 (Total)</b>	<b>56.20</b>	<b>106.82</b>	<b>3.68</b>	<b>19.72</b>	<b>2.86</b>	<b>63.46</b>	<b>63.46</b>	<b>190</b>	<b>70</b>
<b>3</b>	<b>48.50</b>	<b>80.23</b>	<b>-1.74</b>	<b>15.54</b>	<b>0.19</b>	<b>9.23</b>	<b>-0.69</b>	<b>105</b>	<b>0</b>
<b>Total</b>	<b>193.40</b>	<b>218.84</b>	<b>13.07</b>	<b>70.77</b>	<b>14.21</b>	<b>115.39</b>	<b>42.72</b>	<b>405</b>	<b>70</b>

- Gen. - Generation (contracted amount)
- Res. - Reserves (upward reserves only)
- Idle - (not contracted for generation or reserves)
- Inst. - Installed capacity

The results summarized in Table 5 show the expected levels of Generation, Upward Reserves and Idle capacity for the three Areas on the network for the Final step in the simulation when all 35MW of coal capacity at Generator 6 is replaced by 105MW of wind capacity and there are no constraints on the transmission capacity from Area 2 to Area 1 (Case 2). The values are the unconditional expectations over the three different wind forecasts. Table 5 also shows the changes from the corresponding results in the Initial step when there no wind capacity was installed (shown in Table 2). These changes imply that more Generation and Upward Reserves are needed in Area 1 to meet the same pattern of load when wind capacity replaces coal capacity, and roughly one third (20MW) of the Idle capacity in Area 1 in Table 2 is now needed for reliability purposes. If this additional capacity in Area 1 had not been available, it is likely that load shedding would have occurred in some contingencies. The amounts of Generation and Upward Reserves contracted in

Areas 2 and 3 are quite similar in the Initial and the Final steps, and all of the available non-wind capacity in Area 2 is needed in the Final step.

Overall the results in Table 5 demonstrate how the SuperOPF can be used to determine the amount of additional reserve capacity needed to maintain reliability when wind capacity is added to a network. For this particular application, load shedding did not occur in any of the contingencies throughout the simulation for both Case 1 and Case 2 because there was a substantial amount of surplus generating capacity available in the initial specification of the network in Figure 1. Given these favorable conditions for adding wind capacity, the average cost of meeting the fixed pattern of load decreases as the amount of wind capacity increases because the money saved from using less fuel is more than enough to cover the additional cost of higher reserves when the wind capacity is added. The plots of the average production costs shown in Figures 2 and 3 illustrate this conclusion for Cases 1 and 2, respectively. The gains from lower production costs are limited in Case 1 by the capacity of the tie line from Area 2 to Area 1. When more than 35MW of wind capacity is installed, some of the potential generation from wind is wasted because there is not enough transmission capacity to deliver all of the wind generation to loads. Hence, an important question that will be addressed in another paper is whether the lower production costs in Case 2 are sufficiently large to cover the investment cost of upgrading the transmission capacity.

The focus of the discussion about Table 5 is on the total amount of installed generating capacity needed (generation plus upward reserves) to meet load and maintain reliability. There is another issue that has important implications for generators and that is the wide range of generation levels that individual generating units are required to operate over when wind capacity is installed. Table 6 shows the contracted amounts of Generation (Gen.), Upward Reserves (Res.<sup>+</sup>) and Downward Reserves (Res.<sup>-</sup>) for the Initial step of the simulation (no wind capacity) and the Final step (105MW of wind capacity) for the six generators in Case 2 (unlimited transmission capacity from Area 2 to Area 1). The implication is that there is a contingency under which the generator will be required to increase generation to (Gen. + Res.<sup>+</sup>) and another contingency under which the same generator will be required to reduce generation to (Gen. - Res.<sup>-</sup>). Hence the generator must be prepared to operate anywhere over the range (Res.<sup>+</sup> + Res.<sup>-</sup>). With no wind capacity in the

Initial step, the contracted generation from a generator that fails will be covered by increased generation from other generators (i.e. using upward reserves). If a transmission line fails, it may be necessary to reduce the level of generation from certain locations (i.e. using downward reserves). These extreme situations are relatively rare for generators because the probabilities of equipment failures are small.

**Table 6: Initial and Final Patterns of Generation, Upward Reserves and Downward Reserves by Generator (Case 2)**

Area	Gen. #	Gen. (MW) Initial	Res. <sup>+</sup> (MW) Initial	Res. <sup>-</sup> (MW) Initial	Range (MW) Initial	Gen. (MW) Final	Res. <sup>+</sup> (MW) Final	Res. <sup>-</sup> (MW) Final	Range (MW) Final	Final Range - Initial Range
<b>1</b>	<b>1</b>	8.68	11.73	8.68	<b>20.40</b>	10.24	12.46	10.24	<b>22.70</b>	<b>2.29</b>
	<b>2</b>	11.97	14.86	11.97	<b>26.84</b>	21.54	23.05	21.54	<b>44.60</b>	<b>17.76</b>
<b>2</b>	<b>5</b>	53.11	1.89	2.81	<b>4.71</b>	41.54	13.46	18.69	<b>32.15</b>	<b>27.44</b>
	<b>6 NW</b>	50.04	14.96	23.22	<b>38.18</b>	23.74	6.26	9.40	<b>15.66</b>	<b>-22.52</b>
	<b>6 W</b>	0.00	0.00	0.00	<b>0.00</b>	41.54	<b>56.84</b>	<b>38.61</b>	<b>95.45</b>	<b>95.45</b>
<b>3</b>	<b>3</b>	45.03	4.97	4.00	<b>8.97</b>	41.67	8.33	11.67	<b>20.00</b>	<b>11.03</b>
	<b>4</b>	36.94	8.14	7.68	<b>15.82</b>	38.56	7.21	9.31	<b>16.52</b>	<b>0.70</b>
<b>Total</b>		<b>205.77</b>	<b>56.56</b>	<b>58.36</b>	<b>114.93</b>	<b>218.84</b>	<b>127.61</b>	<b>119.47</b>	<b>247.08</b>	<b>132.15</b>

- Gen. - Generation (contracted amount)
- Res.<sup>+</sup> - Upward Reserves (contracted amount)
- Res.<sup>-</sup> - Downward Reserves (contracted amount)
- Range - Res.<sup>+</sup> + Res.<sup>-</sup>
- 6 NW - Non-Wind component of Generator 6
- 6 W - Wind component of Generator 6

With 105MW of wind capacity installed in the Final step of the simulation, the ranges of generation are larger for all generators except the Non-Wind component of Generator 6, but the size of this unit has been reduced from 65MW in the Initial step to only 30MW in the Final step. The reported values of “reserves” for the Wind component of Generator 6 in the Final step are not like regular reserves but represent the expected range of generation for different wind speeds. Given the specified capacity of the network in Case 2, wind generation is always able to displace generation from non-wind sources. The expected levels of wind generation over the different forecasts of wind speed range from 3MW to 98MW,

and unlike the rare occurrence of equipment failures in contingencies, substantially different levels of wind generation are likely to occur. In addition, there is a lot of variability in wind speed through time so adding more wind capacity to a network will require the presence of flexible generators with high ramping capabilities. Potentially better ways to deal with the variability of wind speeds are the use of storage devices for energy and the ability to defer some load through time to balance the availability of wind generation.

An interesting example of storage and deferrable load is to charge batteries in plug-in electric vehicles when/if the wind blows at night so that the vehicles are fully charged before the morning commute to work. It does not matter exactly when the batteries are charged over night as long as it gets done sometime. The batteries in these vehicles can also be used to shave the system load during the peak hours in the day as long as there is enough charge left in the battery to get back home in the evening. Evaluating the net benefits of installing different portfolios of devices that combine renewable sources of electricity with the ability to control/modify loads is a very promising topic for future research. The structure of the SuperOPF makes this type of evaluation feasible, and the results of such an analysis will help to identify combinations of devices that lower production costs and also improve system reliability. In contrast, a common practice used by regulators as a planning goal is to enforce a “Renewable Portfolio Standard” on the purchases made by Load Serving Entities (i.e. mandate that a minimum share of purchases must come from renewable sources). If this practice is followed blindly without considering the implications for network operations, it is likely to undermine system reliability, reinforce public opposition to renewable energy, slow down the transition to a low-carbon economy and jeopardize our ability to stabilize climate change effectively.

## **7. Acknowledgements**

This research was supported by the US Department of Energy through the Consortium for Electric Reliability Technology Solutions (CERTS) and by the Power Systems Engineering Research Center (PSERC). The authors are responsible for all conclusions presented in the paper, and the views expressed have not been endorsed by the sponsoring agencies.



## 8. References

- [1] Anderson, Lindsay and Judy Cardell, *Reducing the Variability of Wind Power Generation for Participation in Day Ahead Electricity Markets*, Proceedings of the 41<sup>st</sup> Annual Hawaii International Conference on System Sciences, January 2008.
- [2] Chen, J., T. D. Mount, J. S. Thorp and R. J. Thomas, *Location-based scheduling and pricing for energy and reserves: a responsive reserve market proposal*, Decision Support Systems, 40, pp. 563-577, October 2005.
- [3] Chen, J., J. S. Thorp and R. J. Thomas, *Time-space methods for determining locational reserves: a framework for location-based pricing and scheduling for reserve markets*, CERTS Report on Reliability Adequacy Tools, 2002.
- [4] Chen, J., J. S. Thorp, R. J. Thomas and T. D. Mount, *Locational Pricing and Scheduling for an Integrated Energy-Reserve Market*, Proceedings of the 36th Annual Hawaii international Conference on System Sciences - Track 2 - Volume 2, IEEE Computer Society, pp. 54.1, 2003.
- [5] Federal Energy Regulatory Commission (FERC), *Energy Policy Act of 2005 (EPACT05)*, Washington DC, 2005.
- [6] K. H. LaCommare and J. H. Eto, *Understanding the cost of power interruptions to U.S. electricity consumers*, Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley, CA (US), 2004.
- [7] Lawton, Leora, Michael Sullivan, Kent Van Liere, and Aaron Katz (Population Research Systems, LLC) and Joseph Eto (LBNL), *A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys*”, Office of Electric Transmission and Distribution, U.S. Department of Energy, Washington DC, November 2003.
- [8] Mount, Tim, Alberto Lamadrid, Surin Maneevitjit, Bob Thomas and Ray Zimmerman, *The Economics of Reliability and the Importance of Events that Didn't Happen*, Invited Presentation at the Fourth Annual Carnegie-Mellon University Conference on the Electricity Industry, March 2008.
- [9] North-American Electric Reliability Corporation (NERC), *2007 Long-Term Reliability Assessment 2007-2016*, Princeton NJ, October 2007.

- [10] New York Independent System Operator (NYISO), *2004 Load and Capacity Data*, Rensselaer NY, 2004.
- [11] New York Independent System Operator (NYISO), *Comprehensive Reliability Planning Process Draft Reliability Needs Assessment*, Rensselaer NY, September 2005.
- [12] New York Independent System Operator (NYISO), *Installed Capacity Manual Revision 5.1.1*, Rensselaer NY, September 2004.