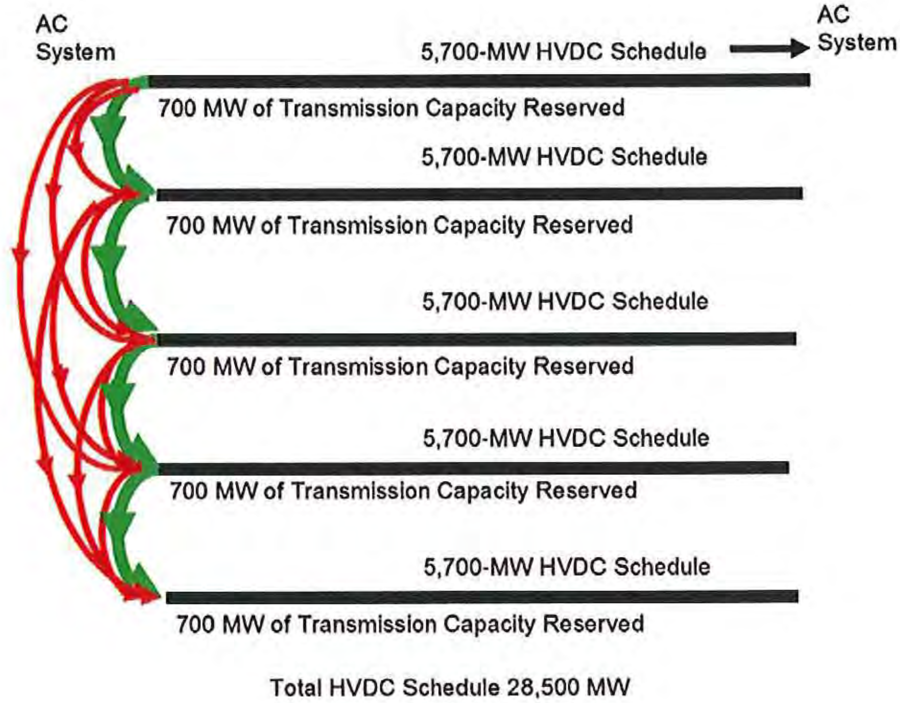


Figure 4-20. An example showing 800-kV HVDC lines (black) tied by 765-kV lines (green) and underlying 345-kV lines (red)

Postcontingency incremental flows are indicated in Figure 4-21. There is no change in generation. The postcontingent flows would be adjusted to a security-constrained dispatch within 30 minutes. The HVDC schedules would be less than the initial 5,700 MW because there are fewer lines to distribute the contingency. Detailed power flows and dynamic simulations would have to be performed to fine-tune the transmission design.

The use of the underlying AC system during an outage of an HVDC line would be in return for the use of the HVDC transmission reserve capacity during AC disturbances or generator outages. The overlay has ample capacity to back up a 1,500-MW design limit used in this example. With the HVDC response to AC disturbances, the severity of the AC disturbances in the area of the contingency and elsewhere would be considerably reduced compared to the case with no HVDC and 765-kV overlays. The probability of an HVDC bipole outage is much lower than the probability of an AC outage on a 345-kV network or the loss of the largest generator.

The EWITS conceptual transmission design uses three terminal HVDC lines that would tap the lines in the middle of the line. Three terminal lines would reduce the area affected by a contingency and reduce the impact of a contingency as more HVDC terminals than the end terminals could respond to the HVDC contingency. The AC system would not have to deliver power over such long distances because some of the power could be rescheduled back on the HVDC lines at the third terminal. The conceptual design of the overlay would be more robust than that of the example (an example of an overlay with three terminal HVDC lines would be too complex to show here).

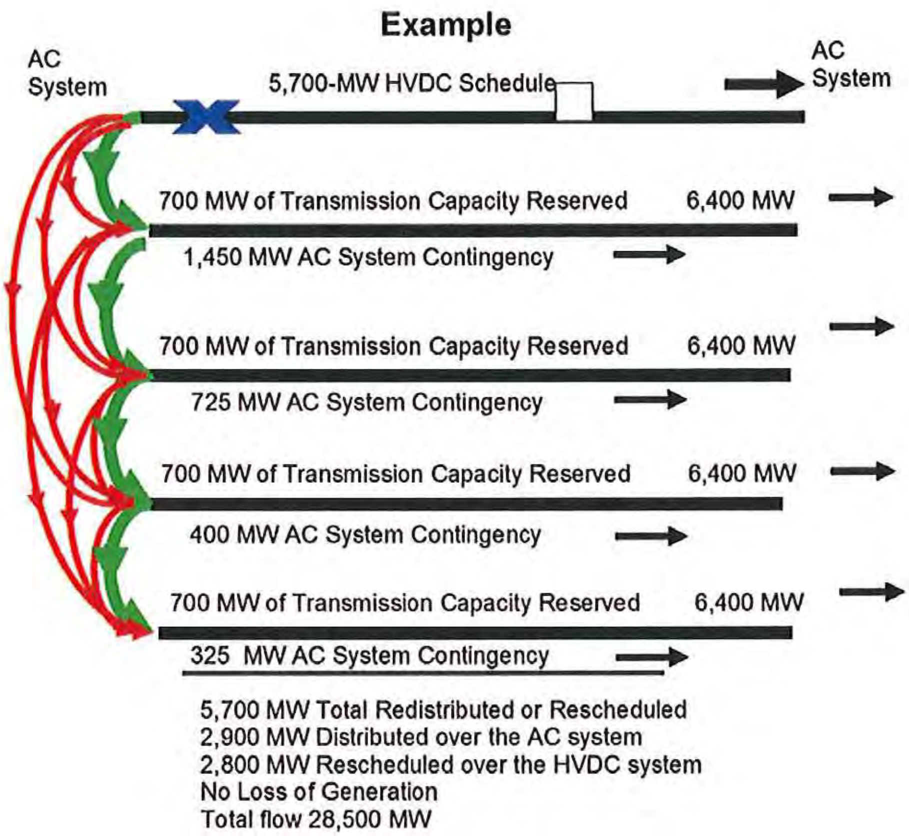


Figure 4-21. A postcontingency example showing five 800-kV HVDC lines (black) example tied by 765-kV lines (green) and underlying 345-kV lines (red)

Figure 4-22 details the assumed distribution of the flows on the underlying AC system for the example. The impact of a contingency is expected to reduce with distance from the area in which it occurs.

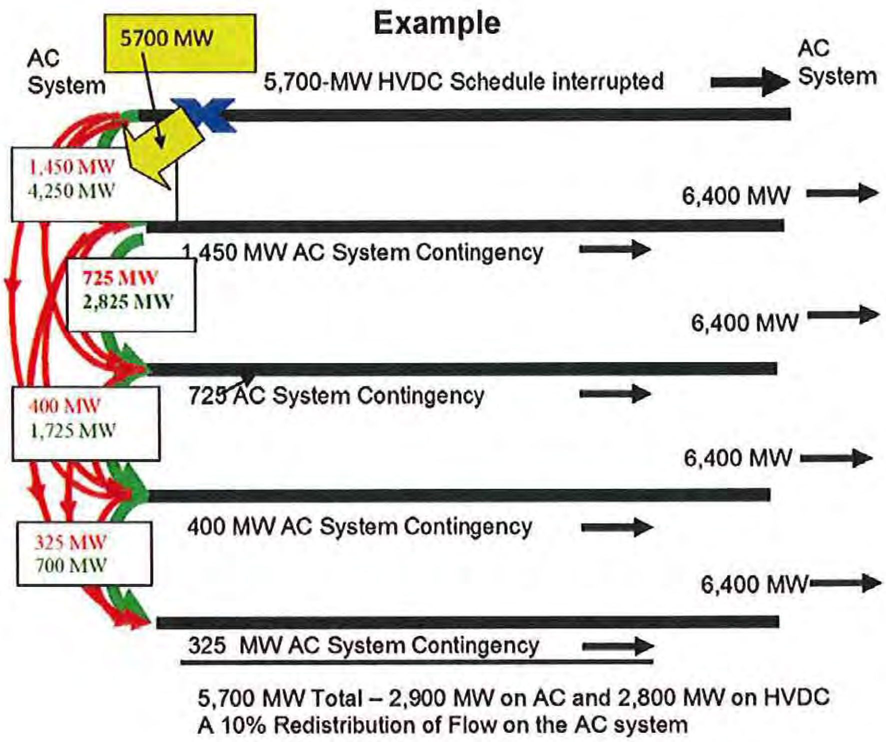


Figure 4-22. An example of the assumed distribution of the flows on the underlying AC system

The overlay is designed not to have an impact greater than 1,500 MW on any part of the underlying (red, 345-kV) AC system. The amount of power that can be scheduled on an HVDC line depends on the following:

1. The number of HVDC lines
2. The power transfer capacity of the 765-kV lines to move energy from an outage of the top HVDC line in these examples to the other HVDC lines and the other underlying 345-kV AC systems.
3. The rating of the underlying AC systems to be able to withstand a contingency in its area. A rating of 1,500 MW is assumed for these examples.

Again, a large number of detailed power flow and dynamic studies must be completed before the conceptual transmission plan in EWITS could be refined into a ready-for-construction transmission plan.

SECTION 5: POWER SYSTEM REGULATION AND BALANCING WITH SIGNIFICANT WIND GENERATION

Matching the supply of electrical energy to the demand for electricity, over time frames ranging from seconds to decades, is a fundamental building block for maintaining resource adequacy in the bulk power system. Wind generation introduces additional variability and uncertainty that make the general task incrementally more challenging.

POWER SYSTEM OPERATION AND CONTROL

Power system operation is near the real-time end of the spectrum of the operating time horizon. To maintain system reliability in day-to-day operations, several functions are necessary. These functions have traditionally been performed by individual utility "control areas," and now can be performed by one or several entities in a balancing authority that have been approved by the North American Electric Reliability Corporation (NERC). These reliability functions can be categorized by different names and are sometimes broken down into more components depending on the context. These functions—or ancillary services—follow:

1. Scheduling (unit commitment), system control, and dispatch
2. Reactive supply and voltage control from generation
3. Energy imbalance
4. Regulation and frequency response
5. Operating reserve—spinning
6. Operating reserve—supplemental (e.g., nonspinning)
7. Generator imbalance

As a result of the Energy Policy Act of 2005, reliability standards are now mandatory in the United States, and NERC is the federally mandated Electric Reliability Organization (ERO). In the NERC Functional Model, the actions in the list are called reliability-related services. These include the range of services, other than supplying energy for load, that are physically supplied by generators, transmitters, and loads to maintain reliability.

OPERATIONAL STRUCTURE

A balancing authority operates within metered boundaries that define a balancing authority area (BAA). Every element of the bulk power system—generator, transmission facility, and end-use customer—is in one and only one BAA.

The four synchronous interconnections in the United States and Canada each comprise one or more BAAs (the Electric Reliability Council of Texas [ERCOT] and Quebec are single BAAs). The original BAAs—except for the three "tight" power pools in the Northeast (the New England Independent System Operator [ISO-NE], the New York ISO [NYISO], and the PJM Interconnection [PJM])—were previously individual electric utility control areas.

The restructuring of the electric power industry over the past two decades and the emergence of wholesale energy markets have reduced the number of both BAAs and balancing authorities (Figure 5-1). Further consolidation is expected over the coming years. The Midwest ISO and the Southwest Power Pool (SPP) regional transmission organizations (RTOs) are examples. Balancing authorities that are part of the Midwest ISO (shown as MISO RTO in Figure 5-2) energy market, located in the Midwest Reliability Organization (MRO), Mid-American Interconnected Network (MAIN), Southeastern Electric Reliability Council (SERC), and ReliabilityFirst Corporation (RFC) regional reliability organizations, were consolidated under a single BAA when the Midwest ISO ancillary services market started up. The SPP RTO began market operations with an Energy Imbalance Service and is transitioning to other offerings that could eventually supplant conventional individual balancing authority functions within its market footprint.

In this Eastern Wind Integration and Transmission Study (EWITS), the subset of reliability-related services that involve the control of generation to meet demand, facilitate the delivery of wind energy, and maintain the security of the bulk power system is of primary interest. All are covered in this section, which also focuses on the control of generation in real time in response to changes in wind generation and load. The generation capacity assigned to serve these roles is generally known as reserves, and specific categories of reserves are designated to fulfill specific functions.

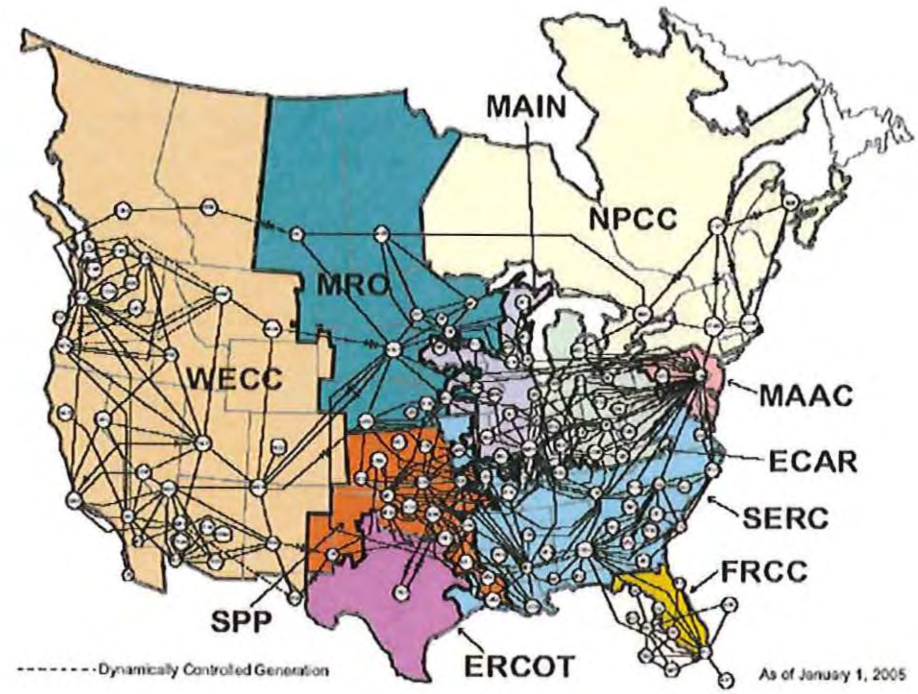
The terminology for reserves is not rigidly defined, and varies by region and country. For example, common definitions for operating reserve categories used in the Union for the Co-ordination of Transmission of Electricity (UCTE) in Europe are different than those used in the United States. Even within the United States, variations in operational practice have led to reserve definitions that are not uniform across the country.

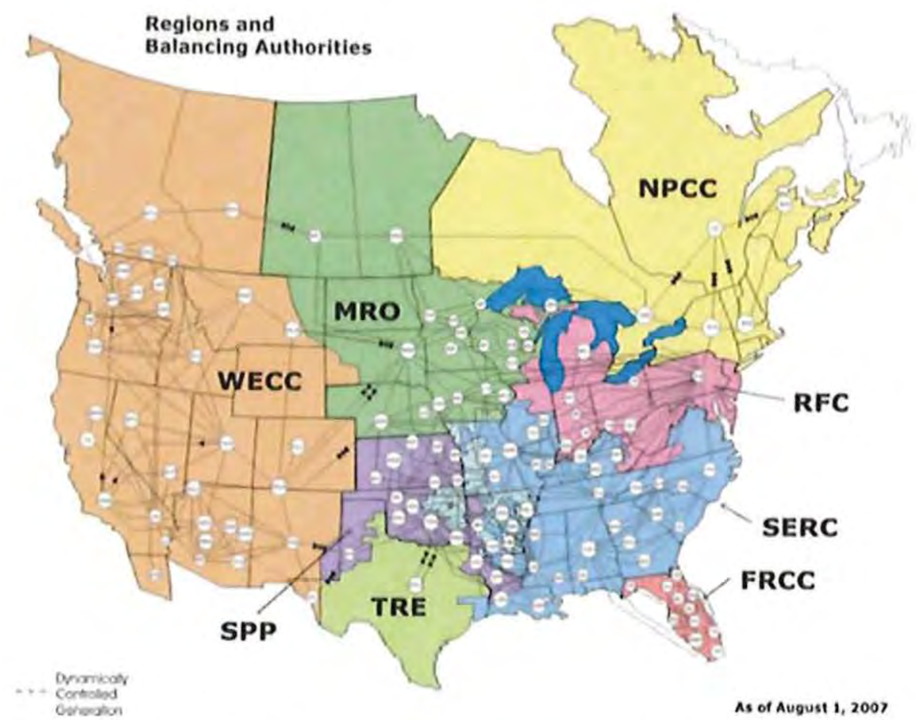
Table 5-1 lists relevant definitions from the NERC Glossary of Terms Used in Reliability Standards.[4] The definitions are somewhat overlapping—operating reserve comprises regulating reserve and contingency reserve—and not completely consistent or precise; "operating reserve—spinning" does not seem to include regulating reserve, and the general category of operating reserve does. Mapping each of these terms to the reliability-related services in the NERC Functional Model is also not straightforward.

For purposes of this study, the categories of operating reserve to be specifically evaluated are as follows:

- Regulating reserve: Generation responsive to automatic generation control (AGC) that is adjusted to support the frequency of the interconnection and compensate for errors in short-term forecasts of balancing area demand.
- Contingency reserve: The unloaded capacity carried to guard against major system disruptions such as the sudden loss of a large generating unit or major transmission facility.
- Contingency reserve—spinning: That portion of the contingency reserves that is synchronized to the system and fully available to serve load within the time specified by the NERC Disturbance Control Standard (DCS).
- Contingency reserve—supplemental: That portion of the contingency reserve consisting of generation that is either synchronized to the system or capable of being synchronized to the system within a specified window of time that is fully available to serve load within the time specified by the NERC DCS.

[4] *See http://www.nerc.com/files/Glossary_12Feb08.pdf. Accessed December 2009.*





Notes: WECC = Western Electricity Coordinating Council; FRCC = Florida Reliability Coordinating Council; NPCC = Northeast Power Coordinating Council; TRE = Texas Regional Entity. The Mid-Atlantic Area Council (MACC) and the East Central Area Reliability Coordinating Agreement (ECAR) are NERC reliability regions that no longer exist.

Figure 5-1. NERC reliability regions and balancing authorities as of January 2005 (top) and August 2007 (bottom)

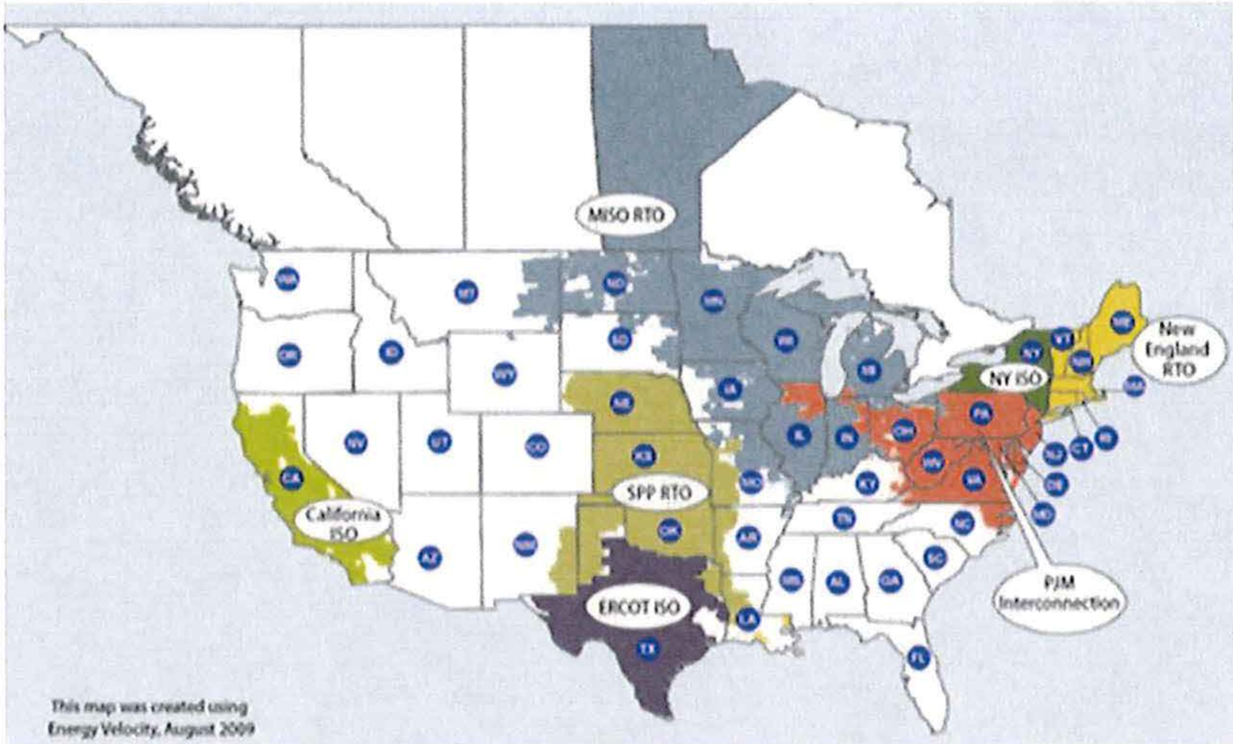


Figure 5-2. U.S. RTOs

TABLE 5-1. EXCERPTS FROM NERC GLOSSARY OF TERMS RELATED TO OPERATING RESERVES[a]	
TERM	**DEFINITION**
ANCILLARY SERVICE	Those services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission service provider's transmission system in accordance with good utility practice.[b]
CONTINGENCY RESERVE	The provision of capacity deployed by the balancing authority to meet the DCS and other NERC and regional reliability organization contingency requirements.
OPERATING RESERVE	That capability above firm system demand required to provide for regulation, load forecasting error, forced and scheduled equipment outages, and local area protection. Consists of spinning and nonspinning reserve.
OPERATING RESERVE—SPINNING	The portion of operating reserve that consists of • Generation synchronized to the system and fully available to serve load within the disturbance recovery period that follows the contingency event • Load that can be fully removed from the system within the disturbance recovery period after the contingency event.
OPERATING RESERVE—SUPPLEMENTAL	The portion of operating reserve that consists of • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the disturbance recovery period that follows the contingency event • Load that can be fully removed from the system within the disturbance recovery period after the contingency event.
REGULATING RESERVE	An amount of reserve that is responsive to AGC, which is sufficient to provide normal regulating margin.
SPINNING RESERVE	Synchronized unloaded generation that is ready to serve additional demand.

[a]Adapted from http://www.nerc.com/files/Glossary_12Feb08.pdf. Accessed December 2009.
[b]From Federal Energy Regulatory Commission (FERC) Order 888-A. See http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp. Accessed December 2009.

MANAGING VARIABILITY

Each BAA must assist the larger interconnection with maintaining frequency at the target level (usually 60 hertz [Hz]) and must maintain scheduled energy flows to the BAAs with which it is interconnected. Balancing real power supply with real power demand is the means by which frequency is maintained. Regulation and load following are mechanisms for achieving this control under normal operating conditions. Figure 5-3 illustrates the load characteristics that drive the demand for these services. Variations in the aggregate electric demand are continuous, and can be roughly separated into two components:

- Fast variations, nearly random in nature, that result from a great number (millions) of individual decisions or actions like flipping light switches

- Slower trends that are relatively predictable, such as the rising load in the morning and the falling load through the evening into nighttime.

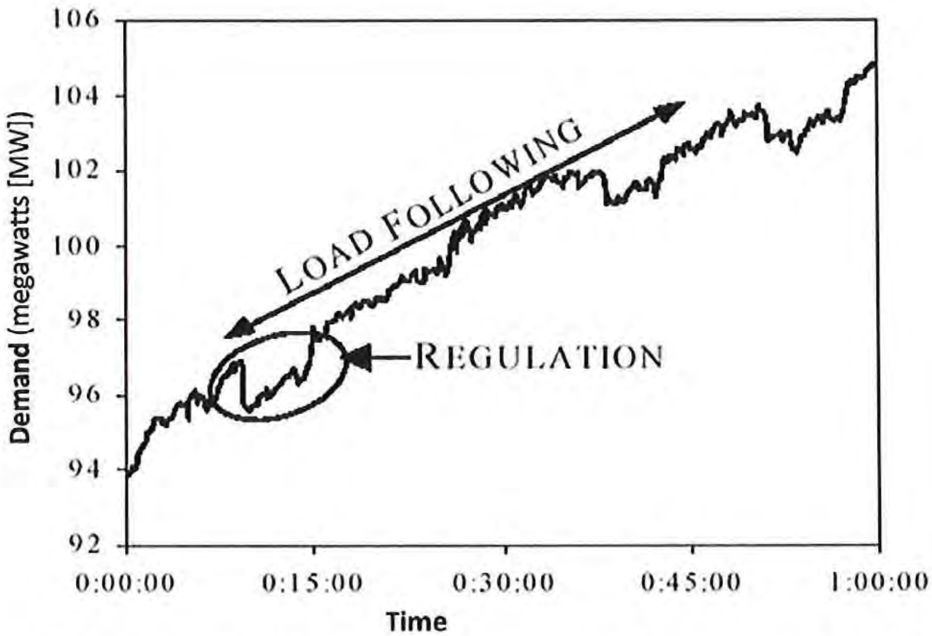


Figure 5-3. Depiction of regulation and load-following characteristics of demand

Generation units on regulation duty are adjusted to compensate for random or sudden changes in demand. These adjustments take place automatically through AGC and occur, depending on the characteristics of the balancing area, over tens of seconds to a minute. Regulation movements both up and down are required, and the amount of net energy over a period is small because the movements tend to cancel each other. To offer regulation, therefore, a generating unit must reserve capacity and operate below its maximum (to reserve room for upward movement) and above its minimum (for downward movement). In addition, only generating units that meet the balancing authority's requirements for providing regulation and frequency service can participate in the regulation market.

The term "load following" does not appear in NERC's glossary, but is generally taken to mean the adjustment of generation over periods of several minutes to hours to compensate for changes in demand. Generation movement is in response to economic-dispatch commands from the balancing area energy management system (EMS). In real-time or subhourly energy markets, clearing points are determined from short-term forecasts of demand, and generating units participating in that market are instructed to move to the forecast clearing point. Subhourly market intervals as short as 5 minutes are used today, with the clearing points established two or three intervals prior.

Subhourly markets are dispatched economically, meaning that the least costly units available (i.e., those participating in the subhourly market) that satisfy system security constraints are called on to follow the forecast change in demand. Regulation service requires a commitment on the part of generators to leave capacity both up and down and to allow their units to be moved automatically by the market operator. Consequently, analysis of current market operation reveals that regulation can be quite expensive (Kirby et al. 2009). Conversely, load following obtained in subhourly markets is not. Although prices within the hour can vary dramatically, on average prices in subhourly markets track day-ahead energy prices quite closely. This has important consequences for the method used to calculate incremental operating reserve requirements with large amounts of wind generation.

MEASURING CONTROL PERFORMANCE

A running evaluation of control performance is kept for each BAA. The primary measure of control performance is area control error (ACE). The equation for a BAA's ACE has interchange and frequency error terms:

$$ACE = (NI_A - NI_S) - 10\beta(F_A - F_S) - I_{ME}$$

where

NI_A = the sum of the actual interchange with other balancing areas

NI_S = the total scheduled interchange with other balancing areas

β = the balancing area frequency bias, reflecting the fact that load will change with frequency

F_A = the actual frequency of the interconnection

F_S = the scheduled frequency of the interconnection; usually 60 Hz, although there are times when the scheduled frequency is slightly above or below the nominal value to effect what is known as "time error correction"

I_{ME} = metering error, which is neglected for the purposes of this discussion.

ACE is computed automatically by the balancing area EMS every few seconds. The adequacy of generation adjustments by the balancing area operators and the EMS is gauged by two metrics that use ACE as an input. The first metric, Control Performance Standard 1 (CPS1), uses ACE values averaged over a 1-minute period. It is a measure of how the balancing area is helping to support and manage the frequency of the entire interconnection. If the interconnection frequency is low, it signifies that demand exceeds generation (the "machine" is slowing down). If a particular balancing area has a negative ACE, it is contributing to this frequency depression. Conversely, if the ACE were positive during that period, overgeneration in the balancing area would help restore the interconnect frequency.

The CPS1 score for balancing authorities is based on performance over a rolling 12-month period. This score must be greater than 100%, which is an artifact of the equations used to compute the compliance factor. Maintaining adequate capacity on AGC is a major factor in complying with CPS1.

The second metric is Control Performance Standard 2 (CPS2). It uses the average ACE over a 10-minute period. Over each period, the 10-minute average ACE for a balancing area must be within specific bounds, known as L10. These bounds, which are unique for each balancing area, are generally based on system size. Table 5-2 shows the 2009 CPS2 bounds for BAAs relevant to EWITS in the Eastern Interconnection.

TABLE 5-2. 2009 CPS2 BOUNDS FOR SELECTED EASTERN INTERCONNECTION BAAs

BAA	ESTIMATED PEAK DEMAND (MW)	FREQUENCY BIAS (MW/0.1Hz)	BIAS/LOAD (%)	BIAS/TOTAL BIAS (%)	L_{10} (MW)
NPCC	93,851	-975	1.04	14.98	
IESO	25,657		1.11	4.38	128.10
ISO-NE	28,480	-285	1.00	4.38	128.10
NBSO	5,547	-63	1.14	0.97	60.23
NYISO	34,167	-342	1.00	5.25	140.33
RFC	245,175	-2,480	1.01	38.10	
MISO	110,625	-1,106	1.00	16.99	252.36
PJM	134,428	-1,344	1.00	20.65	278.19

Note: IESO – Independent Electricity System Operator; NBSO = New Brunswick Security Operator.
Source: Adapted from http://www.nerc.com/docs/oc/rs/CPS2Bounds_2009.9b.pdf.

The CPS2 metric is tabulated monthly. To comply with CPS2 requirements, 90% or more of the 10-minute average ACE values must be within the designated L10 bounds for the balancing authority. Minimum performance allows 14.4 violations per day. Most balancing authorities maintain CPS2 scores in the mid-90% range. The equations for average ACE and CPS2 follow:

$$AVG_{10-minute}\ (ACE) \leq L_{10}$$

$$CPS2 = \left[1 - \frac{Violations_{\text{ month}}}{TotalPeriods_{\text{ month}} - UnavailablePeriods_{\text{ month}}}\right] \cdot 100$$

Balancing area compliance with NERC performance standards is defined as a combination of CPS1 and CPS2 scores:

- In compliance: CPS1 > 100% and CPS2 > 90%
- Out of compliance: CPS1 < 100% or CPS2 < 90%.

Compliance is based solely on control performance relative to the required scores for the two metrics; required reserve amounts are not directly specified for each operating area. Each operating area must establish policies and practices to comply with the NERC standards.

Field trials of a new reliability-based control standard (NERC draft standard BAL-007-1) are under way. If adopted, two new performance metrics—CPM (control performance measure) and BAAL (balancing authority ACE limit)—would replace CPS1 and CPS2. The new metrics are designed to improve interconnection frequency support, reduce short-term frequency deviations caused by ramping associated with transaction schedules, and ensure timely transmission congestion relief. The effects of the new standards on the challenge of managing significant wind generation in a balancing area have not yet been studied quantitatively.

MAINTAINING SYSTEM SECURITY

To achieve high levels of reliability, the bulk power system must be operated so that it can withstand the loss of major elements without cascading failure or tripping of additional elements. It must also be able to resume normal operation within a specified period of time. The operating reserve elements of the reliability-related services listed previously are intended to preserve bulk power system security.

Contingency reserve is the conventional name for the spare generating capacity that can be called on in system emergencies. The spinning portion of the contingency reserve is synchronized with the grid and ready to respond immediately; off-line capacity that can be called on, started, and synchronized within a defined period of time (10 minutes or 30 minutes) makes up the nonspinning or supplemental contingency reserve.

Unlike reserves for regulation, which are for supporting normal system operations within applicable reliability criteria, contingency reserves that are spinning are not dispatched continuously by AGC in response to ACE and are held in reserves for system emergencies. They are also unidirectional, in that the ability to move upward—serve more load—is counted as contingency reserve.

Currently, the basis for the required contingency reserves varies across the interconnection. The need is usually defined by the magnitude of the top one or two largest loss-of-source events, which could result from a single contingency. For example, in an operating region where the largest plant is a 900-MW nuclear unit, enough additional generation must be available to cover the sudden loss of this large unit, assuming it normally operates at its rated output. In many reliability regions, a substantial portion of this additional generation must be synchronized with the grid (i.e., spinning). The required fraction of contingency reserves that must be spinning is often about 50% of total contingency reserves.

Immediately on losing the large generator in the example, system frequency would begin to decline because the amount of load now exceeds the available supply. As frequency declines, however, governors on all generating units, whether they are regulating units, units participating in the energy market, or operating reserve units, would detect the abnormal low frequency. If the deviation is large enough or exceeds a defined deadband, the governors would increase the mechanical power inputs to the generators. The system operator would use the operating reserves to replace the loss of generation. The NERC DCS requires balancing authorities to rebalance their systems within 15 minutes of a major disturbance and to restore the deployed contingency reserves within 105 minutes.

EFFECTS OF WIND GENERATION ON POWER SYSTEM CONTROL

Actions to support frequency and maintain scheduled interchanges in a BAA are driven by the variety of errors in the generation and load balance. As a result, the effects of wind generation's variability and uncertainty on the net variability and uncertainty of the BAA's aggregate demand defines how a given amount of wind generation affects power system control. Measurable impacts would be manifested in increased requirements for regulation capacity and load-following capability. Wind plants typically do not affect contingency reserve requirements because the individual generators are relatively small.

Previous integration studies (see, for example, EnerNex Corporation and WindLogics 2004; GE Energy Consulting 2007; and AWS Truewind 2009;) have shown that the net variability concept is extremely important and the effects of aggregation and diversity are quite powerful. With load alone, in practice, the normalized variability of larger aggregations of load—that is, larger BAAs—is much less than for smaller areas. The same phenomenon is observed with wind generation because of spatial and geographic diversity effects. As the number of turbines grows and the area over which they are installed expands, the aggregate variability declines. When these aggregations increase to span multiple balancing authorities, realizing any potential benefit of these aggregations can require examining impacts on current operating protocols.

Figure 5-4 illustrates the effects of diversity on the variability of wind generation using actual scenario profile data. The curves represent the changes in wind generation over a 10-minute interval; the value plotted on the vertical axis is the standard deviation of all incremental changes over 3 years of data for hourly production levels (per unit) corresponding to the value on the horizontal axis. The curves illustrate that more variability can be expected when the wind generation is in the midrange of the aggregate nameplate production. Second, and also of great interest for EWITS, the per-unit variability declines greatly as more wind is aggregated.

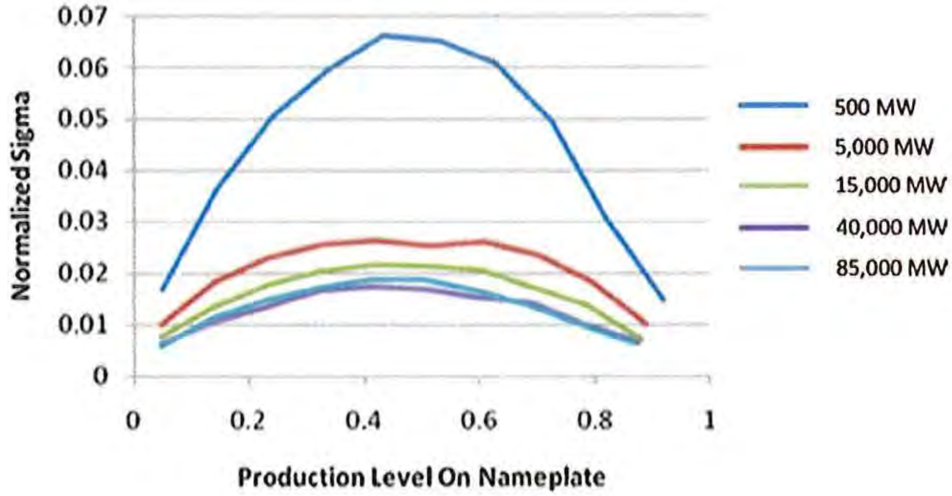


Figure 5-4. Normalized 10-minute variability for five different groups of wind generation. The 500MW scenario is part of the 5,000-MW scenario, which is part of the 15,000-MW scenario, and so on.

The magnitude of the effects of diversity on the variability of the balancing authority net load will depend on the amount of wind generation relative to load, the variability of load alone, and the amount of diversity that characterizes the aggregate wind generation. Figure 5-5 uses actual load and wind data for Scenarios 1 and 3 to illustrate the effect on the Midwest ISO and PJM operating areas in EWITS. The charts show the variability of load by itself from one 10-minute interval to the next, along with the variability of load net of wind generation for the defined scenario.

In the Midwest ISO, wind generation in Scenario 1 has a greater effect on net variability because of the much higher amount of installed capacity. The converse is true for PJM—in Scenario 1 the variability is just slightly higher, and in Scenario 3, with much more installed wind generation capacity, the effect is much more pronounced.

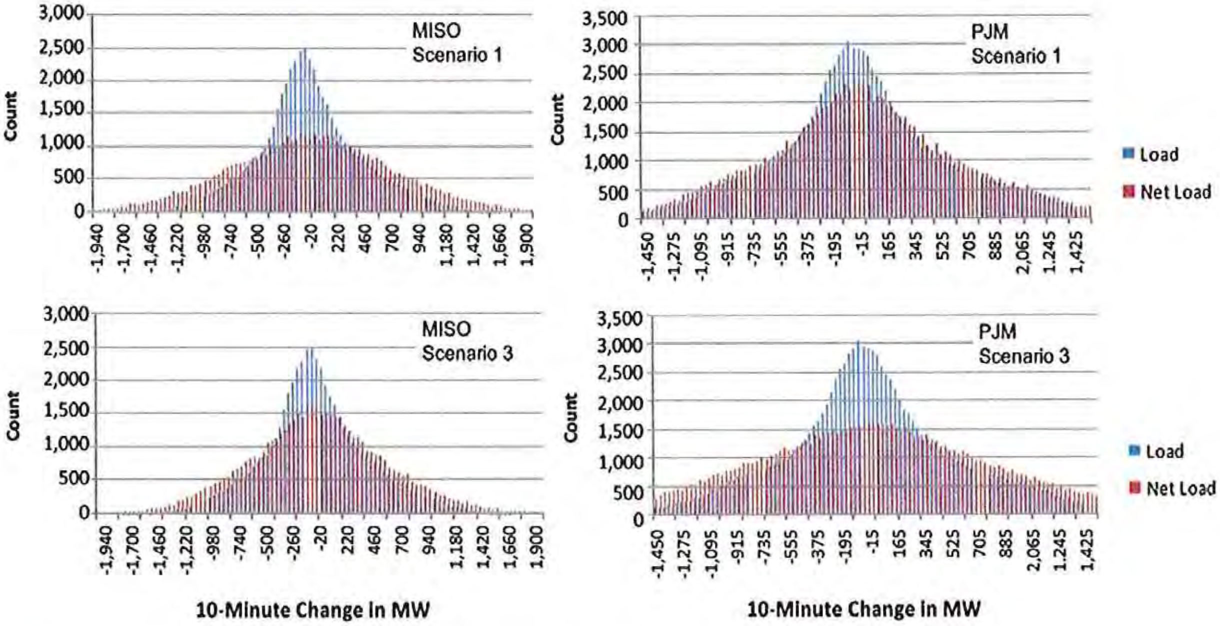


Figure 5-5. Ten-minute variability of load and net load for MISO (left) and PJM (right). Scenario 1 is shown at the top and Scenario 3 is depicted on the bottom.

Changes in wind generation over other time frames must also be factored into operational practices. Large drops in wind energy production could be as large as the contingency for which operating reserves are carried, but there would be a significant difference in the event duration. The nuclear unit described earlier could be lost in an instant, producing 900 MW 1 minute and going off line the next. Large reductions in aggregate wind generation do not occur suddenly—instead they can evolve over several hours. This is caused by the many individual turbines, the large geographic area over which they are installed, and the time it takes for major meteorological phenomena such as fronts to propagate.

Smaller, but more frequent, changes in wind generation over 1 to 4 hours are also operationally important. On these time scales, uncertainty about how much wind generation will be available becomes more important than variability. Because of the short lead time, replacement capacity for forecast wind generation that does not materialize in this time frame must be found. This replacement capacity can come from units already committed, regulating reserves (until economic replacement energy can be committed), units with quick-start capability if insufficient regulating reserves are available, or a neighboring balancing authority. Consequently, the expected error in wind generation forecasts over these horizons could play a role in the policy and practice for operating reserves. A centralized wind production forecast will assist balancing authorities in mitigating the impact of changes in wind generation; a level of operating reserves may, however, still be required to mitigate the remaining errors.

MODELING AND ANALYSIS FOR ASSESSING WIND INTEGRATION IMPACTS

In the analysis of wind generation impacts on power system regulation and balancing, the EWITS team had two primary objectives:

- Starting with wind generation and load profile data, use engineering judgment and technical knowledge of power system operation and control to develop a methodology for estimating how wind generation in the study scenarios would be managed in real-time operations.
- Develop a process for mapping these requirements to the chronological production simulations that will be used to assess overall wind integration impacts.

The second bullet is very important to the overall analytical methodology employed in EWITS. The within-the-hour impacts of varying load and wind generation are accounted for, at least approximately, in the production simulations by setting constraints on the unit-commitment and economic-dispatch algorithms. In each hour, specified amounts of reserves must be set aside and not used to serve load.

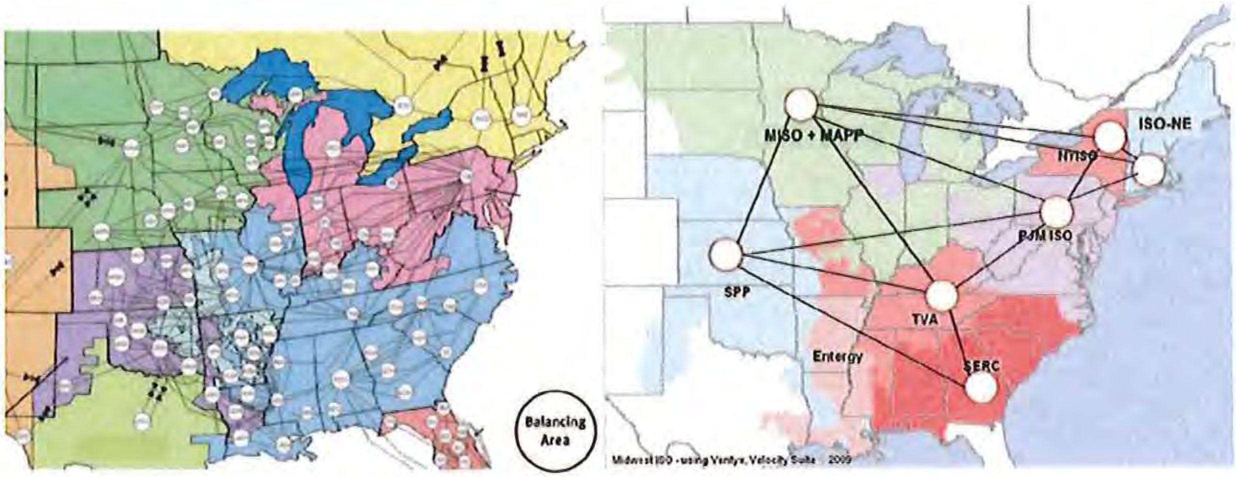
Impacts of changing load and wind generation are more explicitly considered in the production simulation at increments of 1 hour or more. Additional constraints are defined for each generating unit in terms of the amount of its output that can be changed over a single hour, maximum and minimum output, start-up and shutdown times, and minimum runtimes and downtimes. The unit-commitment and economic-dispatch steps must observe these constraints on each unit. Consequently, situations of specific interest for wind integration, such as minimum load and minimum generation periods, are evaluated in the production simulation program. Violations of constraints are reported, or appear as dump energy (see Glossary) or load that is not served.

ASSUMPTIONS

The U.S. electric power industry is trending toward larger effective operating pools, through either energy markets or interarea operating agreements. Previous wind integration studies (see Bibliography) concluded that larger operating areas are an effective means for managing wind integration because they take natural advantage of geographic diversity of load and wind and aggregate a larger set of discrete generating units to compensate for load variations; they also offer frequent economic dispatch of units with movement capability to follow slower variations in balancing area demand.

For the study horizon of 2024, the EWITS team assumed that the Eastern Interconnection will contain seven major operating areas corresponding to the current boundaries of the following entities, as shown in Figure 5-6: ISO-NE, NYISO, PJM, SPP, MISO, the Tennessee Valley Authority (TVA), and SERC.

The first five correspond to current wholesale energy markets in the interconnection.



As of August 1, 2007 Assumption for 2024

Figure 5-6. Eastern Interconnection balancing authorities (existing on left; assumption for study on right)

The study team further assumed that by 2024 all operating areas will have a uniform structure in terms of market products, unit dispatch, and real-time operations and will fulfill the functions of a balancing authority. This structure consists of the following:

- A day-ahead energy market followed by a security-constrained unit commitment (SCUC) later on the day before the operating day.
- A real-time energy market, cleared at frequent intervals during the operating hour. Each real-time market clearing point is based on short-term forecasts of load and wind generation. To align with the data available for EWITS, the clearing interval was defined as 10 minutes, with the market clearing point based on information available at the previous 10-minute interval.
- An ancillary services market, where a large pool of resources competes to offer the defined regulating and operating reserves.

The areas modeled in this study currently operate according to these assumptions in varying degrees. Although the progress in consolidating and advancing markets in the direction of the study assumptions is significant, the operation of the entire study footprint under these assumptions by 2024 is not a foregone conclusion. Additionally, the project team assumed that reserves could be shared across the entire operating area footprint; transmission congestion internal to a region does not create subregions with reserve requirements that must be met locally.

There is a general recognition that wind generation, in the current operating and markets constructs, would face very real barriers to realizing these levels of wind energy penetration. This analysis, then, looks at wind impacts in a possible "future world" operating and market construct that might be able to accommodate high levels of wind. This study team also recognizes that considerable work remains to be done before this operating scenario could be realized.

The study analysts used existing practice as a starting point for estimating the amount of regulating reserve required for load alone. They assumed a value of 1% of the hourly load. Although that fraction of the forecast daily peak load for each hour of the day would have been somewhat more reflective of current practice and policies, 1% of hourly load is a reasonable working assumption.

MAPPING RESERVE REQUIREMENTS FOR PRODUCTION SIMULATIONS

The methodology used in this study for assessing the impacts and cost of integrating wind energy into a utility balancing area is based on chronological simulations of scheduling and real-time operations. The study team used production costing and other optimization tools to conduct these simulations. In most cases, the time step for these simulations is in 1-hour increments. As a result, many details of real-time operation cannot be simulated explicitly. Generation capacity that operators use to manage the system in real time—i.e., the units on AGC used by the EMS for fast response to ACE and the capacity that is frequently economically redispatched to follow changes in balancing area demand—is assigned to one or more reserve categories defined in the various tools.

At this level of granularity, the reserve requirements for the system are constraints on optimization and dispatch. Supply resources are designated by their ability to contribute to system requirements in one or more reserve categories. During optimization or dispatch, the solution algorithm must honor system reserve needs, meaning that some capacity cannot be used to meet load or fulfill transactions.

The reserve requirements with wind generation for the study operating areas were computed on a technical basis from the functional considerations for system reliability and security. To allow their use in the production simulations, the various reserve components had to be translated into the reserve categories considered by the simulation tools. For the large-scale production simulations in this study, only two types of reserves could be considered: spinning and nonspinning. Note that synchronized and nonsynchronized would be clearer terms here, as "spinning" is generally associated with a specific ancillary service. But because the simulation tools actually use the terms spinning and nonspinning, they are retained here.

Table 5-3 shows the mapping for the reserve types discussed in this section. By definition, regulating reserve must be spinning, because it must continuously compensate for changes in balancing area demand to help control the frequency of the interconnection. In the mapping, the study team divided regulation into two components that were assumed to be additive. And, per the NERC glossary definition, regulation is also carried to cover errors in demand forecasts, so the team assigned forecast error as a regulation category as well. The rationale for this is explained in detail later in this section.

According to the reliability-related services definition, contingency reserve consists of both spinning and nonspinning portions. It was computed for the study scenarios as described in the next section.

TABLE 5-3. MAPPING OF RESERVE COMPONENTS IN CATEGORIES FOR PRODUCTION SIMULATIONS

RESERVE COMPONENT	SPINNING (%)	NONSPINNING (%)
REGULATION (VARIABILITY)	100	0
REGULATION (FORECAST ERROR)	100	0
CONTINGENCY	50 (or designated fraction)	50 (or designated fraction)

CONTINGENCY RESERVES

Because sufficient contingency reserves are maintained to respond to the largest generator within a balancing authority or as part of a reserve-sharing group, it is conceivable that the existing contingency reserves are sufficient to maintain the same level of reliability at varying levels of wind penetration. Contingency reserves would need to be increased if it were determined that the total output of a wind plant or multiple wind plants within a specific area is larger than the current contingency and has the potential to trip off line within a few minutes.

In this study, the team assumed that the spinning and nonspinning (supplemental) contingency reserves would not influenced by the amount of wind generation in the operating area, but would instead be a function of conventional equipment and the network, as is the current practice.

The operating regions defined for EWITS do not exactly conform to the existing reliability regions and reserve-sharing groups. Consequently, it was necessary to define requirements for contingency reserves on another basis. Where no information was available from current practice, the total contingency reserve requirement was defined as 1.5 times the single largest hazard (SLH) in the operating area. At least half of this requirement was required to be spinning.

The transmission overlays developed in Section 4 result in large high-voltage DC (HVDC) terminals in most of the operating areas in EWITS. The rating of an individual terminal is 1,600 MW, which would mean that the total contingency reserve requirement—assuming that the terminal is the SLH—would be 2,400 MW. The 800-kilovolt (kV) extra-high voltage DC (EHV DC) overlays, however, assume a self-redundant design; the maximum transfer on any single DC element of the overlay is limited so that if it were to fail, the transfer could be picked up by other portions of the DC overlay. Individual terminals are limited to 1,500 MW. Consequently, the contingency reserve requirement is established by the existing AC equipment for each area, and does not vary between the Reference Scenario and the high-penetration scenarios.

Table 5-4 lists the assumed contingency reserve requirements for each operating region and scenario. The requirement is split 50/50 between spinning and nonspinning (supplemental) except in the Midwest ISO, the PJM, and the TVA.

TABLE 5-4. CONTINGENCY RESERVE REQUIREMENTS BY OPERATION REGION FOR 2024

REGION	CONTINGENCY RESERVE REQUIREMENT—ALL SCENARIOS (MW)	SPINNING/SUPPLEMENTAL SPLIT (%)
ISO-NE	1,158	50/50
NYISO	1,200	50/50
PJM	3,350	100/0
SPP	1,539	50/50
MISO	2,271	100/0
TVA	1,750	23/77
SERC (partial)	1,140	50/50

Note: The spinning contingency reserve assumed for PJM is high by about 50%. Because of the size of the PJM market, effects of the error on the results were deemed to be minimal.

REGULATION AND LOAD FOLLOWING

The approach for calculating the incremental regulation and load-following capacity required to maintain control performance in each study BAA was based on observations from current market operations and experience from previous studies.

The minute-to-minute variability of wind generation, relative to that of the aggregate load, is very small. Because the National Renewable Energy Laboratory's (NREL) mesoscale data only goes down to a 10-minute resolution, actual wind data collected by NREL (Wan 2004) and others was used for the analysis in the quicker time frames.

Those measurement data show that the standard deviation of the minute-to-minute variability—faster than that which can be dealt with by the subhourly energy market or subhourly scheduling— is about 1 MW for a 100-MW wind plant, based on separating the fastest variations from longer term trends using a 20-minute rolling average window. (As the results show, the details of this process—i.e., resolution of the data, width of the averaging window—are not critical to the results and conclusions.)

Minute-to-minute variability is also uncorrelated between individual wind plants and between wind and load. Considering a BAA with 100 gigawatts (GW) of load and 60 GW of wind generation, the impact of wind generation on the fast variations of the net BAA demand can be estimated:

- Assume that the 60 GW of wind generation is made up of 100-MW plants (to use the variability characteristics given previously). If each of the 100-MW plants exhibits a minute-to-minute variability of 1 MW (as measured by the standard deviation of these variations), and they are uncorrelated with similar variations from other wind plants in the sample, the standard deviation of the variability for all 60 GW would be as follows:

$$\sigma_{(aggregate\ \ wind)} = \sqrt{\left(\frac{60{,}000}{100}(1\ \mathrm{MW})^2\right)} = 24.5\ \mathrm{MW}$$

- Assume that the 1% regulation amount carried for load alone (100 GW of load in this example) is three times[5] the standard deviation of the load variability on this same time scale:

$$\sigma_{\mathrm{load}} = \frac{100{,}000 \cdot 0.01}{3} = 333.3\ \mathrm{MW}$$

- The standard deviation of the load net of wind generation, which is a basis for the regulating reserve, can be computed assuming that the fast variations from load are not correlated with those from the aggregate

$$\sigma_{Total} = \sqrt{\left(\sigma_{\mathrm{load}}{}^2 + \sigma_{(aggregate\ wind)}{}^2\right)} = 334.2\ \mathrm{MW}$$

As the calculations show, the effect of the fast variations in aggregate wind production is negligible.

Considering the uniform structure assumed for the operating areas in EWITS, it becomes apparent that wind variability would most likely have larger impacts on time scales associated with the subhourly markets and economic dispatch of generating resources.

[5] *A multiple of 3 times the standard deviation encapsulates almost 99.9% of all samples in a normal distribution. There is precedent in the U.S. electric utility industry for using a multiplier of 3, although instances of higher multiples can be found. The multiplier assumed here is thought to be more appropriate for the very large balancing areas defined for the 2024 scenario. In smaller balancing areas, multipliers of up to 5 are used.*

Subhourly market clearing points are based on short-term forecasts of demand. In an existing 5-minute energy market, for example, the clearing point is based on projections of demand made 15 to 20 minutes before the interval. Participating units are instructed to move to cover the projected change in load; any difference between the forecast load and the actual load for the interval (assuming that all generating units follow dispatch instructions precisely) will effectively "spill over" into the regulation bin.

Very-short-term aggregate forecasts of large amounts of load can be quite accurate. For wind generation, the variations over these same time periods are less so. Errors in the short-term forecast of wind generation will therefore increase the requirement for regulation.

The wind generation profile data at a 10-minute resolution for each scenario were used to estimate this impact on regulation. Using a persistence forecast, where the average production for the last several intervals (six intervals in this case) is the forecast for the next 10-minute interval, the expected error in this simple, short-term wind generation forecast can be easily calculated and characterized. Persistence performs reasonably well as a forecast technique for limited horizons, on average. Other techniques might be better for predicting significant ramps, but over all the intervals in a year, those techniques might not outperform simple persistence. The team's objective here was to employ a simple, yet reasonable, approximation to a more sophisticated approach that would be used in practice.

Figure 5-7 illustrates the short-term forecast errors for load and wind generation with data from one of the scenarios and operating regions. Here the study team assumed that the subhourly market operates on 10-minute intervals (to match the resolution of data available for this study), and the load forecast is generated one interval prior. A simple regression-extrapolation technique performs very well for forecasting load; this is most likely caused by the smoothness of the variations. In reality, more sophisticated techniques are used, and can account for the expected load shape and other factors that would further improve performance near peak intervals.

The persistence forecast for wind generation performs reasonably well, but the variations at 10-minute intervals for even this large amount of wind generation exhibit more volatility than is observed in the aggregate load. Consequently, the errors in wind generation forecasts dominate the net error, as Figure 5-8 shows.

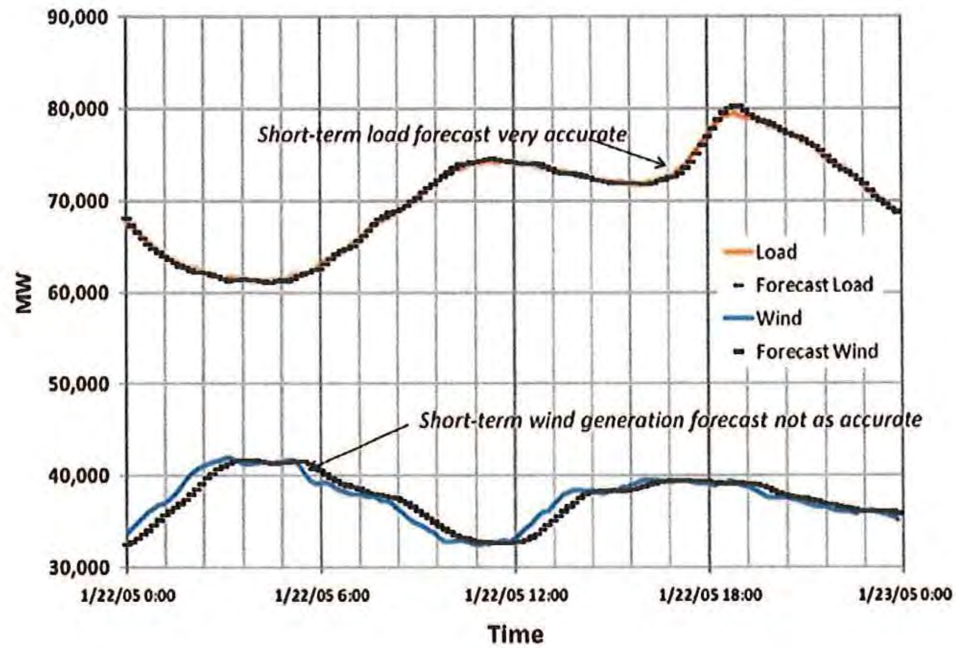


Figure 5-7. Illustration of short-term (next 10-minute interval) forecasts of load and wind generation

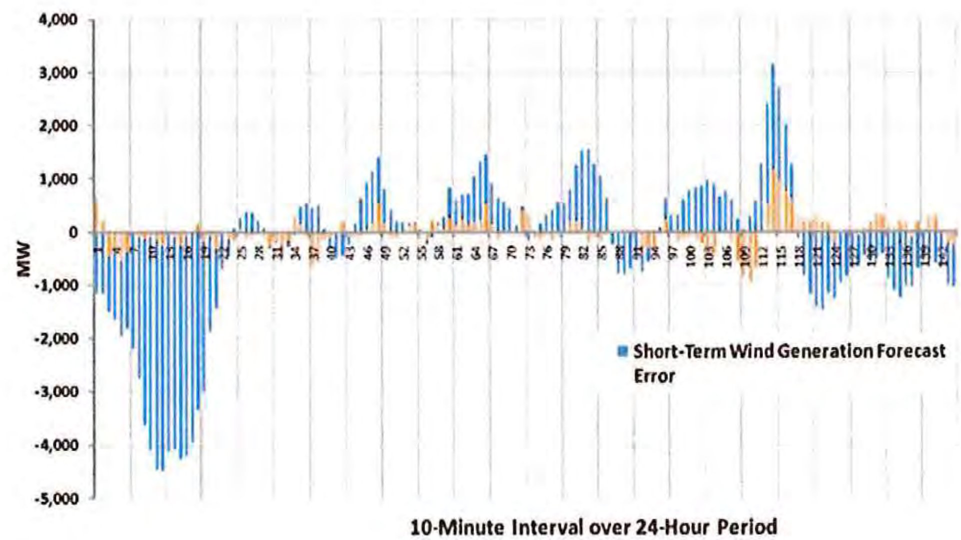


Figure 5-8. Errors in short-term forecasts of load and wind generation; load error is assumed to be zero in the mathematical procedure

The high-resolution data available for the study allowed the expected errors in short-term wind generation forecasts to be statistically characterized. The errors for each interval forecast were sorted into deciles based on the average hourly production at the time of the forecast. The errors in each of the deciles appear to be normally distributed, so the standard deviation was calculated and used as a measure of the expected forecast error.

Figure 5-9 shows the result for one scenario and operating region. The maximum expected error occurs in the midrange of the aggregate production, which is expected, because it would be where the largest number of turbines is operating on the steep part of their power curves. For low levels of production, the error is small because the output is small; at higher production levels, the error also declines, because in this region, many turbines are operating above rated wind speed, where fluctuating wind speed does not translate into varying energy production.

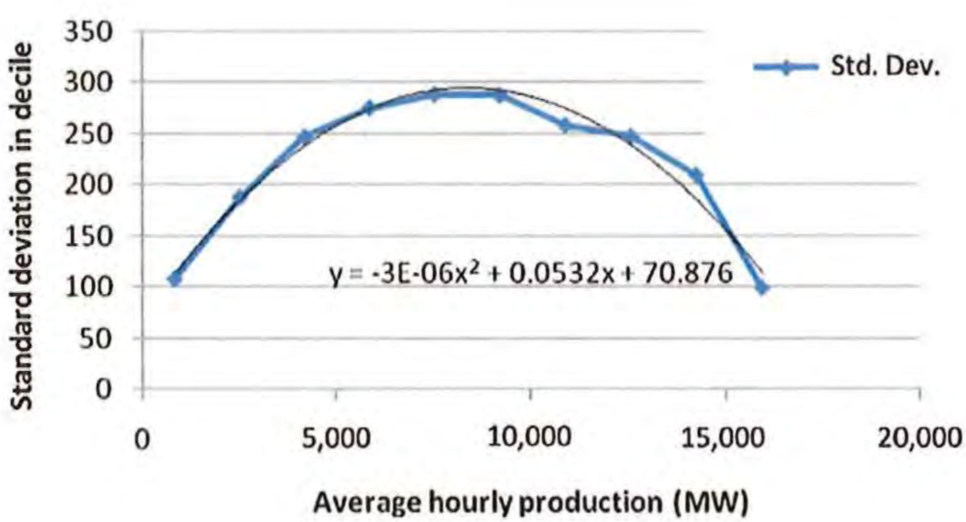


Figure 5-9. Illustration of short-term (10-minute ahead) wind generation forecast errors as a function of average hourly production

The empirical expected error characteristic can be approximated with a quadratic expression as shown in Figure 5-9. The input to this expression is the average hourly production, and the output is the standard deviation of the expected error in the short-term wind generation forecast for the current level of wind production.

Fast variations in load are almost certainly uncorrelated with the short-term forecast errors for wind generation. Therefore, the regulation requirements for load alone and short-term wind generation forecast errors do not add arithmetically. To account for this, the individual requirements are combined as a root of the sum of the squares.

In summary, for regulating reserves with no wind generation, the amount of regulation capacity carried is equal to 1% of the hourly load. The total spinning reserve carried forward to the production simulations is the regulation amount plus the spinning part of the contingency reserve defined earlier:

$$Spinning\ Reserve\ (Load\ Only) = 1\% \cdot (Hourly\ Load) + Spinning\ Contingency\ Reserve$$

With wind generation, the regulation reserve is augmented to account for the short-term wind generation forecast errors using statistical characterizations like the one shown in Figure 5-10. The resulting regulation reserve requirement, using this characterization, follows:

$$Regulation\ Requirement(with\ Wind) = 3 \cdot \sqrt{\left(\frac{1\% \cdot HourlyLoad}{3}\right)^2 + (\sigma_{ST}(HourlyWind)^2}$$

where

σ_{ST}(Hourly Wind) = the function described in Figure 5-9 for the specific operating area and wind generation scenario.

The amount of regulation capacity is taken to be three times the standard deviation of the combined variability of load and wind, which accounts for the division of load regulation by three and the multiple of three on the radical in the previous equation. Again, a multiplier of 3 was selected because of the large size of the operating areas in EWITS.

As described previously, movements of generators to follow trends in load were assumed to come from the subhourly energy market. Economic dispatch in the production simulation honors individual unit ramp rates on an hourly basis, and, to reiterate, the average price for energy in the subhourly market was assumed not to diverge from the day-ahead price. As a result, the movements of generation to follow trends in the aggregate load are reasonably captured in the production simulations. This is, of course, based on an additional assumption that a significant increase in demand for such capabilities would not increase the price.

Uncertainty in the amount of wind generation to be delivered in the next hour also has an effect on the reserve picture. A procedure similar to that the team employed to characterize the very-short-term forecast errors can characterize the expected hour-ahead error for wind generation in each operating area and scenario (Figure 5-10). The expected next-hour forecast errors exhibit characteristics similar to those of the very-short-term forecasts; the highest errors occur when the aggregate wind production is in the midrange of capability, and the errors decline for both lower and higher production levels.

Reductions in next-hour wind generation output—which, given the persistence forecast assumption, is equivalent to the forecast being more than what actually is delivered—could possibly be covered by quick-start (nonspinning) generation.

For EWITS, the study team assumed that some additional spinning reserve would be held to cover next-hour forecast errors, which are expected to be frequent (once or more per day). The amount of additional spinning reserve was set at one standard deviation of the expected error. Additional supplemental or nonspinning reserve was also allocated to cover the larger but less frequent forecast errors. An amount equivalent to twice the standard deviation of the expected next-hour wind generation forecast error was used here.

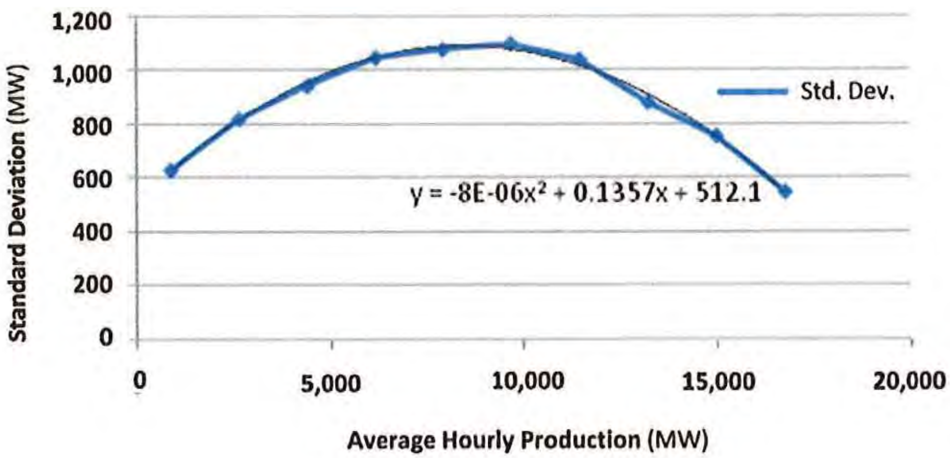


Figure 5-10. Standard deviation of 1-hour persistence forecast error for PJM in Reference Case

Table 5-5 summarizes the elements of the spinning and nonspinning reserves used in the production simulations. Because hourly wind and load are inputs to certain components, the result is an hourly profile instead of a single number. Using the statistical characterizations of short-term and next-hour wind generation forecast error embeds aspects of the specific wind generation scenarios within the reserve determination.

TABLE 5-5. SUMMARY OF RESERVE METHODOLOGY FOR STUDY SCENARIOS

RESERVE COMPONENT	SPINNING (MW)	NONSPINNING (MW)
REGULATION (VARIABILITY AND SHORT-TERM WIND FORECAST ERROR)	$3\times\sqrt{\left(\frac{1\%\cdot HourlyLoad}{3}\right)^2+\sigma_{ST}(HourlyWind)^2}$	0
REGULATION (NEXT-HOUR WIND FORECAST ERROR)		0
ADDITIONAL RESERVE	$1\times\sigma_{NextHourError}\ (PreviousHourWind)$	2 × (Regulation for next hour wind forecast error)
CONTINGENCY	50% of 1.5 × SLH (or designated fraction)	50% of 1.5 × SLH (or designated fraction)
TOTAL (USED IN PRODUCTION SIMULATIONS)	**SUM OF ABOVE**	**SUM OF ABOVE**

Load forecast errors, both in the very short term and for the next hour or hours, have similar effects on the regulating and load following reserves. Some of these errors were considered in the assumption of 1% regulation for load. With sufficient data and information on load behavior and forecast accuracy, the study analysts used the process to assess whether requirements with wind generation could be applied to determine the regulation and load-following requirements for load.

Table 5-6 gives an example of the calculations used to determine the hourly regulating and spinning reserve requirement for each operating area. Hourly load (column 1) and wind generation (column 2) are the key inputs, along with the equations from Figures 5-9 and 5-10. These equations were developed for each operating area for each scenario from the high-resolution and hourly production data.

The regulation amount for load alone was assumed to be 1% of the hourly load (column 3). The standard deviation of the short-term wind generation forecast error was calculated using the appropriate equation and the hourly average wind production (column 4). The regulation for load net of wind generation was then computed by statistically combining the load regulation (assuming that it represents three times the standard deviation of load) with the standard deviation of the short-term wind generation forecast error (column 5).

The spinning portion of the contingency reserve (column 6) is constant for each hour. In column 7, the expected error of the forecast wind generation for the hour was computed using the appropriate equation and the previous hour's wind generation. The total spinning reserve requirement for the hour (column 8), then, is the sum of total regulation (column 5), the spinning portion of the contingency reserve (column 6), and the additional regulating reserve that was set aside during the previous hour to cover expected reductions in wind generation (column 7).

TABLE 5-6. EXAMPLE APPLICATION OF RESERVE METHODOLOGY TO HOURLY DATA								
COLUMN NUMBER	1	2	3	4	5	6	7	8
HOUR	ACTUAL LOAD (MW)	ACTUAL WIND (MW)	REGULATION FOR LOAD (MW)	σ_{ST} (MW)	TOTAL REGULATION (MW)	CONTINGENCY RESERVE--SPINNING (MW)	$\sigma_{Next\ Hour\ Error}$ (MW)	TOTAL SPINNING RESERVE (MW)
1	56,341	11,860	563	280	1,011	2,271	1,037	4,319
2	54,788	15,174	548	187	785	2,271	996	3,056
3	53,993	14,261	540	219	851	2,271	729	3,122
4	53,786	11,926	538	279	994	2,271	820	3,265
5	54,922	10,843	549	295	1,042	2,271	993	3,313
6	58,120	10,283	581	301	1,073	2,271	1,043	3,344
7	63,929	9,193	639	306	1,120	2,271	1,062	3,391
8	69,969	7,942	700	304	1,150	2,271	1,083	3,421
9	72,432	8,077	724	305	1,167	2,271	1,085	3,438
10	72,992	8,726	730	307	1,174	2,271	1,086	3,445
11	73,475	9,736	735	304	1,172	2,271	1,087	3,433
12	73,502	9,838	735	304	1,171	2,271	1,075	3,442
13	73,316	9,201	733	306	1,176	2,271	1,073	3,447
14	72,894	8,801	729	307	1,174	2,271	1,083	3,445
15	72,704	10,146	727	302	1,161	2,271	1,087	3,432
16	72,201	12,733	722	262	1,067	2,271	1,065	3,338
17	73,160	13,937	732	230	1,005	2,271	943	3,276

Notes: The equation for column 3 is from Figure 5-9 and uses current hour wind generation from column 2:

$$\sigma_{ST}(HourlyWind) = -3 \cdot 10^{-6} \cdot (HourlyWind)^2 + 0.0532 \cdot (HourlyWind) + 70.876$$

The column 5 value is computed from column 3 and column 4 using:

$$3 \cdot \sqrt{\left(\frac{1\% \cdot HourlyLoad}{3}\right)^2 + \sigma_{ST}(HourlyWind)^2}$$

The equation for column 7 is from Figure 5-10 and uses wind generation from the previous hour:

$$\sigma_{NextHourError}\ (Wind_{H-1}) = -8 \cdot 10^{-6} \cdot (Wind_{H-1})^2 + 0.1357 \cdot (Wind_{H-1}) + 512.1$$

The total spinning reserve contains a component that is allocated specifically to be used if wind generation is less than was forecast in the previous hour. To avoid double counting of these reserves, the profile is adjusted to deploy this capacity in the production simulation. This is accomplished by reducing the hourly spinning reserve constraint by the amount of the reduction in wind generation from the previous hour, up to the amount that was held. This is illustrated in Table 5-7. In hour 3, 729 MW of extra spinning reserve was being carried to cover hourly wind generation forecast error (column 3). Wind generation declined by 913 MW from the previous hour (column 5). All of the 729 MW was deployed to cover this drop, so the total spinning reserve constraint for that hour in the production simulation is reduced by that amount, from 3,122 MW to 2,392 MW.

As can be seen in hour 2, if wind generation increases from the previous hour, there is no adjustment.

If covering a larger number of the reductions in wind generation output with regulation versus nonspinning (quick-start) generation was desired, the amount of regulating reserve would increase. In this example, an amount equivalent to one standard deviation of the next-hour persistence forecast error was held; increasing the amount to two standard deviations, which would be adequate to cover about 90% of the reductions in next-hour wind generation output, would double this component of the overall spinning reserve. It would also result in more spinning reserve that is not actually dispatched to cover forecast errors, thus increasing the cost.

The "cost" of releasing the spinning reserves is tabulated by the production simulation program; generation capacity that would have otherwise been unloaded is dispatched to cover the loss in wind, and associated production costs are accumulated.

TABLE 5-7. ADJUSTMENT OF SPINNING RESERVE FOR REDUCTION IN WIND GENERATION							
COLUMN NUMBER	1	2	3	4	5	6	7
HOUR	ACTUAL LOAD (MW)	ACTUAL WIND (MW)	σ_{Wind_1Hour} (MW)	TOTAL SPINNING RESERVE (MW)	CHANGE IN WIND GENERATION (MW)	ADJUSTMENT (MW)	ADJUSTED SPINNING RESERVE (MW)
1	56,341	11,860	1,037	4,319	50	0	4,319
2	54,788	15,174	996	3,056	3,314	0	3,056
3	53,993	14,261	729	3,122	(913)	729	2,393
4	53,786	11,926	820	3,265	(2,335)	820	2,445
5	54,922	10,843	993	3,313	(1,084)	993	2,320
6	58,120	10,283	1,043	3,344	(559)	559	2,785
7	63,929	9,193	1,062	3,391	(1,090)	1,062	2,329
8	69,969	7,942	1,083	3,421	(1,252)	1,083	2,337
9	72,432	8,077	1,085	3,438	135	0	3,438
10	72,992	8,726	1,086	3,445	649	0	3,445
11	73,475	9,736	1,087	3,443	1,010	0	3,443
12	73,502	9,838	1,075	3,442	101	0	3,442
13	73,316	9,201	1,073	3,447	(636)	636	2,810
14	72,894	8,801	1,083	3,445	(400)	400	3,045
15	72,704	10,146	1,087	3,432	1,346	0	3,432
16	72,201	12,733	1,065	3,338	2,586	0	3,338
17	73,160	13,937	943	3,276	1,204	0	3,276

The resulting 8,760-hour profiles for each year and scenario are input to the production simulation program as operating area requirements, which constrain the algorithms for optimization and economic dispatch.

REGULATING RESERVE RESULTS FOR STUDY SCENARIOS

Tables 5-8 through 5-12 document the statistics of the regulation portion of the spinning reserves for each operating region and wind generation scenario. These amounts include the additional amount of spinning operating reserve for covering next-hour wind generation deficits from the hour-ahead forecast. The tables list the maximum and average values of an 8,760-hour profile.

Figure 5-11 shows a more detailed view of the PJM requirements, showing distributions of the regulating requirement for load only and load net wind for Scenario 3.

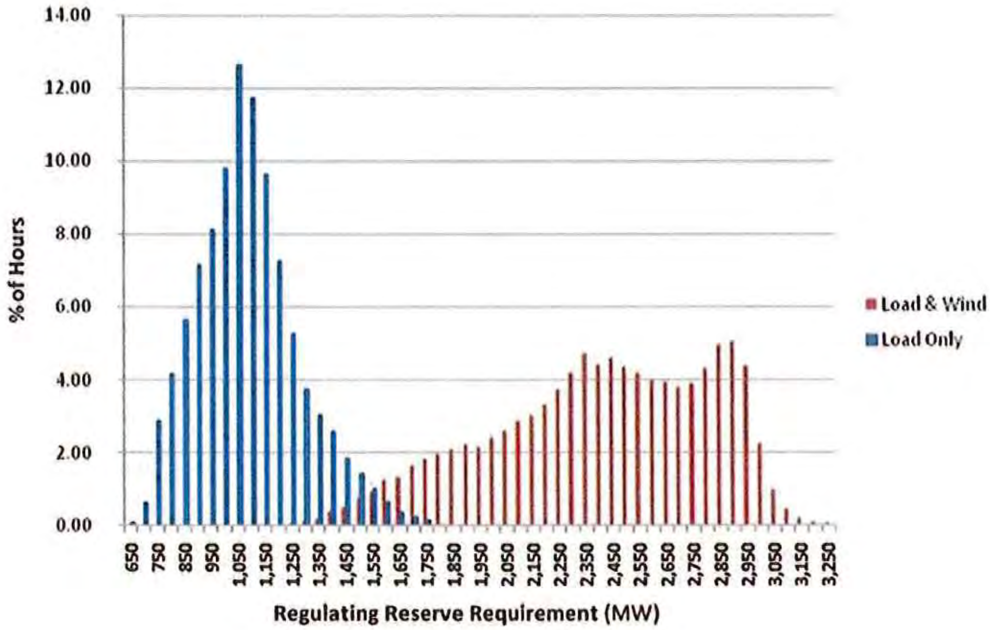


Figure 5-11. Distributions of hourly regulating reserve requirements for PJM Scenario 3, for load only (ideal wind generation) and load net of wind generation

TABLE 5-8. SPINNING RESERVE REQUIREMENTS FOR THE REFERENCE CASE					
REGION	LOAD ONLY		LOAD AND WIND		CONTINGENCY—SPINNING (MW)
	MAXIMUM (MW)	AVERAGE (MW)	MAXIMUM (MW)	AVERAGE (MW)	
MISO	1,480	924	2,235	1,635	2,271
ISO-NE	399	202	1,040	762	579
NYISO	390	219	738	531	600
PJM	1,741	1,060	2,545	1,817	3,350
SERC	1,343	744	1,549	886	570
SPP	870	514	1,135	800	770
TVA	721	365	769	419	403

TABLE 5-9. SPINNING RESERVE REQUIREMENTS FOR SCENARIO 1					
REGION	LOAD ONLY		LOAD AND WIND		CONTINGENCY—SPINNING (MW)
	MAXIMUM (MW)	AVERAGE (MW)	MAXIMUM (MW)	AVERAGE (MW)	
MISO	1,480	924	6,806	5,460	2,271
ISO-NE	399	202	600	395	579
NYISO	390	219	921	623	600
PJM	1,741	1,060	2,966	2,006	3,350
SERC	1,343	744	1,348	753	570
SPP	870	514	8,154	6,245	770
TVA	721	365	769	419	403

TABLE 5-10. SPINNING RESERVE REQUIREMENTS FOR SCENARIO 2					
REGION	LOAD ONLY		LOAD AND WIND		CONTINGENCY—SPINNING (MW)
	MAXIMUM (MW)	AVERAGE (MW)	MAXIMUM (MW)	AVERAGE (MW)	
MISO	1,480	924	5,131	4,094	2,271
ISO-NE	399	202	1,392	1,041	579
NYISO	390	219	1,565	1,124	600
PJM	1,741	1,060	3,247	2,377	3,350
SERC	1,343	744	1,665	954	570
SPP	870	514	8,179	6,110	770
TVA	721	365	769	419	403

TABLE 5-11. SPINNING RESERVE REQUIREMENTS FOR SCENARIO 3					
REGION	LOAD ONLY		LOAD AND WIND		CONTINGENCY RESERVE—SPINNING (MW)
	MAXIMUM (MW)	AVERAGE (MW)	MAXIMUM (MW)	AVERAGE (MW)	
MISO	1,480	924	3,759	2,934	2,271
ISO-NE	399	202	2,401	1,780	579
NYISO	390	219	2,161	1,616	600
PJM	1,741	1,060	5,690	4,467	3,350
SERC	1,343	744	1,665	954	570
SPP	870	514	4,837	3,658	770
TVA	721	365	769	419	403

TABLE 5-12. SPINNING RESERVE REQUIREMENTS FOR SCENARIO 4					
REGION	LOAD ONLY		LOAD AND WIND		CONTINGENCY RESERVE—SPINNING (MW)
	MAXIMUM (MW)	AVERAGE (MW)	MAXIMUM (MW)	AVERAGE (MW)	
MISO	1,480	924	6,832	5,478	2,271
ISO-NE	399	202	2,401	1,780	579
NYISO	390	219	2,161	1,616	600
PJM	1,741	1,060	7,006	5,413	3,350
SERC	1,343	744	1,665	954	570
SPP	870	514	8,412	6,423	770
TVA	721	365	769	419	403

SUMMARY

As mentioned previously, the algorithms in the production simulation program treat the spinning reserves profiles for each operating region as constraints. Generation must be committed and dispatched to meet load at minimum costs while honoring all constraints, including the hourly spinning reserve requirement.

The reserve constraints have an impact only when they are binding on either the unit commitment or economic dispatch. In Tables 5-8 through 5-12, the regulating reserve requirements appear to be very large (e.g., SPP). Note that these requirements are highest when wind generation is moderate to high. If the generation mix does not change except for the introduction of wind, heavy penetration of wind generation frees up nonwind generation to supply the required regulating reserves that support frequency and balance generation with demand. The decreased revenues of the fleet of intermediate generation and market structures, however, could affect the availability of these services in the market, as discussed further in this summary.

Costs are associated with carrying significant spinning reserve for wind generation. If additional conventional generation must be committed simply to meet the spinning reserve requirement, the reserve constraint is binding and additional operating costs will be incurred. Even without a change in commitment, units might not be loaded to their maximums, and as a result, will not operate as efficiently.

The reserve costs that can be extracted from production simulations reflect the less efficient dispatch and opportunity costs. Some additional operational costs associated with regulation duty, however, are not captured. In current markets, regulation is a relatively expensive service compared to the provision of spinning operating reserve.

The assumptions defined earlier are critical to the results presented here, and merit some additional discussion. First, although the philosophy behind the view of short-term forecast errors in wind generation as a contributor to needs for incremental regulation is sound, the persistence forecast technique is rudimentary and would not be implemented in practice. Improvements in short-term forecasts would reduce the impact on regulation requirements. The persistence assumption employed here has most likely led to conservative estimates of regulation requirements.

Second, high penetrations of wind generation and the increased requirements for regulation and flexibility mean that providing those services would have more value. Moving up the supply curve for those services might reach into units that are much less efficient, further increasing the cost. In addition, questions arise about the depth of the resource "stack" for flexibility, which could potentially be another limitation. Alternatively, loads and storage are beginning to supply regulation in at least three ISOs. Responsive load and storage could significantly increase the supply of regulation by 2024.

Third, if large amounts of wind energy displace conventional units and significantly reduce capacity factors, additional questions are raised about compensation in lieu of energy sales for those units and keeping them economically feasible to ensure the flexibility that the system requires.

Finally, the importance of the assumptions about the structure for operations in this 2024 scenario must be reiterated. Functional subhourly markets are the most economic means to compensate for short-term changes in load and wind generation that can be forecast. Very large balancing areas with adequate transmission take maximum advantage of diversity in both load and wind generation. By contrast, the Western Interconnection, with the exception of California, comprises smaller, less tightly interconnected balancing areas. Even modest penetrations of wind generation, much smaller than those considered here, can have very significant operational and cost impacts because of the additional requirements they bring for regulation and balancing.

The penetrations of wind generation considered in EWITS are well beyond what experience can speak to definitively; further analysis is certainly warranted. The knowledge gained from operating experience around the country and the world as wind generation penetrations continue to grow will build an increasingly better foundation for technical insights into this important challenge.

SECTION 6: ASSESSING IMPACTS ON POWER SYSTEM OPERATION

For this Eastern Wind Integration and Transmission Study (EWITS), analysts assessed wind generation impacts on the operation of the Eastern Interconnection through chronological production simulations. They used a nodal model, in which all transmission is represented explicitly along with all generating units and loads at bulk delivery points. In the simulation, units are committed and dispatched to serve load at each bus while honoring transmission constraints and recognizing the security needs of the system.

Annual hourly profiles of wind generation and load, described in Section 2, are primary inputs to the process. The power system model is built on the data and assumptions described in Section 3. Transmission overlays and new conventional generation defined by the process in Section 4 are added to the model for each of four high-penetration wind generation scenarios.

The intent of these simulations is to mimic as closely as possible the assumed operational structure for the Eastern Interconnection in the 2024 study year. The simulations also quantify the specific impacts of the increased variability and uncertainty introduced by wind generation in each scenario.

WIND INTEGRATION IMPACTS AND COST

There is no formal or rigorous definition of wind integration costs. Many previous studies (see Bibliography) have used the following working definition: wind integration costs include those incremental costs incurred in the operational time frames that can be attributed to the variability and uncertainty introduced by wind generation. Calculating costs using this definition involves running chronological production simulations for an extended period of time—usually one or more years—with correlated wind generation and load data. Operating policies and practices are mapped as closely as possible to the production simulations. This is accomplished by mimicking the established (or desired) practices for unit commitment, transaction scheduling, and the maintenance of adequate reserves for system control and security.

The increased uncertainty of wind generation is considered in the unit-commitment step, where forecasts of both load and wind generation are the basis for optimizing generating unit deployment. The economic-dispatch step of the production simulation represents how the power system operates in real time. In

EWITS, the increased variability and short-term uncertainty of wind generation require that additional operating reserves be carried.

The basic process for assessing the impacts of wind generation on power system operations involves running a production simulation that uses forecasts of load and wind generation in the unit-commitment step and honors operating reserve constraints in the economic-dispatch step that are adequate for managing the increased variability. The production costs incurred over the simulation, then, reflect the effects of both factors.

Extracting or isolating that increased cost requires an additional step. With significant wind generation, the conventional generation stack will change as marginal units are displaced by what is usually considered to be a "must take" resource. Because of this displacement, the costs related to uncertainty in the optimization process and the requirements for carrying additional reserves will differ from those in a case with no wind. In recognition of this factor, previous studies (see Bibliography) used the concept of a "proxy resource" to represent the energy provided by wind generation, but in a way that affects scheduling and real-time operations as little as possible (i.e., it neither helps nor hurts the scheduling and dispatch of other conventional resources and is therefore close to operational cost-neutrality. One conceptual energy resource that meets this definition is a daily flat block of energy equivalent to the energy produced in the actual wind profile for that same day. Despite much discussion and debate—but little consensus—about alternatives, many of the previous integration studies used this type of proxy resource. The amounts of wind in several of the scenarios and operating areas in EWITS, however, far exceed those considered previously. A cursory examination of the wind generation data for the 20% penetration scenarios revealed that using a flat daily block of energy as a proxy resource was not workable; very large ramps between days would have artificially affected the commitment and dispatch process. Instead, study analysts used the actual hourly delivery of the wind energy per the scenario profile data.

Integration costs are estimated by comparing the case where wind generation introduces additional uncertainty into the commitment process and requires additional reserves in the economic-dispatch steps to the case with the proxy resource, where only load carries uncertainty and exhibits variability.

Although previous studies focused on the costs of integrating wind generation, it must be noted that those costs are only one piece of the larger set of wind generation costs and benefits.

ANALYTICAL APPROACH

The general analytical approach for assessing operational impacts attributable to wind generation is quite straightforward, and was the basic method used in many previous integration studies. The size and extent of the model for this study, though—the entire Eastern Interconnection with a nodal representation—posed some new challenges.

The Reference Scenario (defined in Section 2), which includes about 6% wind energy penetration in the Eastern Interconnection, was the basis for exploring some issues related to using an extremely large production model to assess wind integration impacts. The EWITS team explored two major issues in early iterations of the Reference Scenario:

1. The effect of various approaches for calculating reserve requirements with wind generation variability and short-term uncertainty

2. The approach for extracting the incremental production costs caused by wind generation variability and uncertainty (integration costs)

The costs of carrying additional spinning reserves were also explored through several iterations of the Reference Scenario. The results revealed a strong correlation between cost and the amount of spinning reserve. Consequently, the study analysts carefully evaluated the calculation of the spinning reserve requirements, and the approach described in Section 5 was the result.

Calculating the cost of wind generation variability and uncertainty involves running at least two annual production simulations for each scenario:

1. An ideal wind case, where the energy initially delivered on a daily basis was shaped into a flat block. Because the wind is ideal, there is no day-ahead forecast error and no requirement for incremental reserves. Load is uncertain in the day-ahead commitment and requires a baseline of operating reserves.

2. An actual wind case, where wind is delivered in the hourly shapes from the National Renewable Energy Laboratory's (NREL) mesoscale database, is uncertain in the day-ahead commitment (per the day-ahead forecasts in the data) and requires additional spinning reserves for regulation and load following. The difference between production costs for this case and the ideal wind case is the total integration cost.

To estimate the effects of either the day-ahead forecast error or incremental regulating reserves individually, two additional cases can be run:

1. A case where wind is known perfectly 1 day ahead, but more spinning reserve is carried because of the variability and short-term uncertainty of wind generation. Comparing this case to the actual wind case produces an estimate of the cost of the wind generation forecast error.

2. A case where wind imposes no additional burden in real time (i.e., additional spinning reserves), but the day-ahead forecast for unit

commitment is imperfect. The uncertainty costs can then be computed as the difference between production costs for this case and for the actual wind case.

Applying this approach to the Reference Scenario produced some results that were initially in contrast to conclusions from previous integration studies. After some intensive analysis, the EWITS team determined that the costs of integrating wind generation had meaning only across the entire model; integration cost calculations on an individual operating footprint basis were subject to some difficulties associated with valuation of the hourly energy exchanges with other operating areas.

In earlier studies, the subject area was usually "isolated"—transactions with outside areas were of a defined hourly shape. The result was that the additional variability of wind generation had to be managed with internal resources only. In this study, transactions between operating areas are determined by the program algorithms and made on an economic basis (i.e., if surplus energy in one operating area is less expensive than native generation in that area, and transmission capacity is available, the energy will be sold). Consequently, incremental variability from wind generation can be exchanged with other areas if the appropriate economic signals are present. For this reason, the effects of wind generation variability and uncertainty in this study are for the entire Eastern Interconnection and are not allocated to individual operating areas.

RESULTS

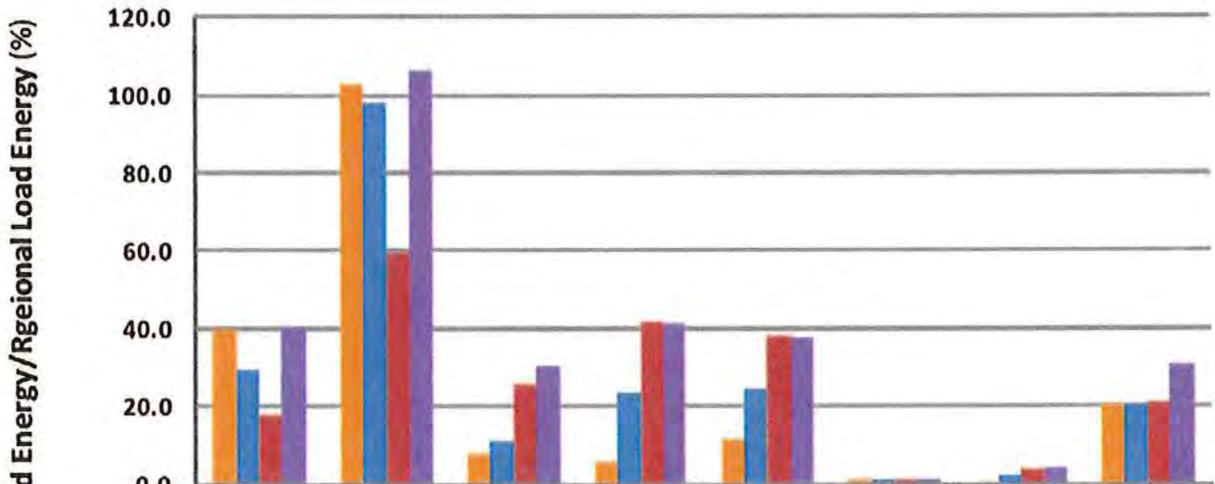
HIGH-PENETRATION WIND SCENARIOS 1–4

The primary inputs for evaluating the operational impacts of wind generation variability and uncertainty are simulated wind generation data sets synchronized with historical load over an extended time series. The study team used NREL mesoscale wind data for 2004 through 2006 for this analysis. This section gives the production-cost simulation results using 2004 hourly wind and load profiles. Further analysis results with 3-year wind and load profiles are presented later in this section.

SCENARIO CHARACTERISTICS

After considering various locations of wind resources and different wind penetration levels, four wind scenarios were developed: three 20% wind energy scenarios and one 30% wind energy scenario. Figure 6-1 summarizes the wind penetration levels by region and scenario. Among the three 20% wind scenarios, Scenario 1 has the highest penetration levels in the western regions because it uses the most high-quality wind resources in the Great Plains. Because wind is moved eastward and more offshore wind is used in Scenarios 2 and 3, the penetration levels increase in the PJM Interconnection, the New York ISO (NYISO), and the New England ISO (ISO-NE) as the levels drop in the western regions. To meet the 30% wind mandate, Scenario 4 uses a significant amount of good-quality wind across the footprint and offshore wind along the East Coast with the highest wind penetration levels in almost all the regions. Based on wind quality and availability, the Tennessee Valley Authority (TVA) and Southeastern Electric Reliability Council (SERC) have very little installed wind capacity and are the primary wind import regions. Conversely, the Southwest Power Pool (SPP) has very high wind penetration levels for all four scenarios.

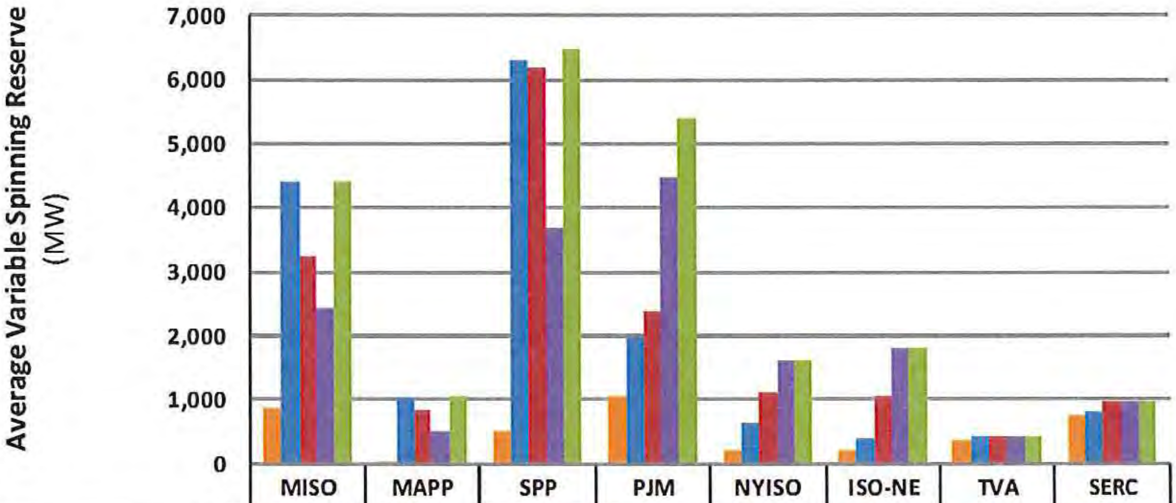
Because of the unique characteristics of the wind resource, additional reserve requirements are required to regulate the wind and maintain system reliability. The incremental reserve for each region is an hourly profile and varies hourly with the amount of wind generation at that particular hour. Figure 6-2 shows the annual, average, variable spinning reserves by region and scenario. As the figure shows, the level of required operating reserves increases with wind penetration levels, as expected.



	MISO	SPP	PJM	ISO-NE	NYISO	TVA	SERC	Total Footprint
Scenario 1 (%)	39.9	102.9	7.8	5.9	11.5	1.2	0.4	20.3
Scenario 2 (%)	29.1	98.2	11.1	23.4	24.6	1.2	2.0	20.4
Scenario 3 (%)	18.0	59.3	25.6	41.8	38.0	1.2	3.7	20.8
Scenario 4 (%)	40.0	106.2	30.5	41.3	37.5	1.2	4.1	30.7

Region

Figure 6-1. Wind energy penetration levels by region using 2004 hourly profiles



	MISO	MAPP	SPP	PJM	NYISO	ISO-NE	TVA	SERC
Load Only	885	43	514	1055	217	202	365	741
Actual Wind, Scenario 1	4,424	1,020	6,308	1,994	618	399	420	816
Actual Wind, Scenario 2	3,245	835	6,176	2,359	1,118	1,046	418	955
Actual Wind, Scenario 3	2,419	503	3,695	4,463	1,614	1,789	418	955
Actual Wind, Scenario 4	4,423	1,038	6,487	5,410	1,614	1,789	418	955

Region

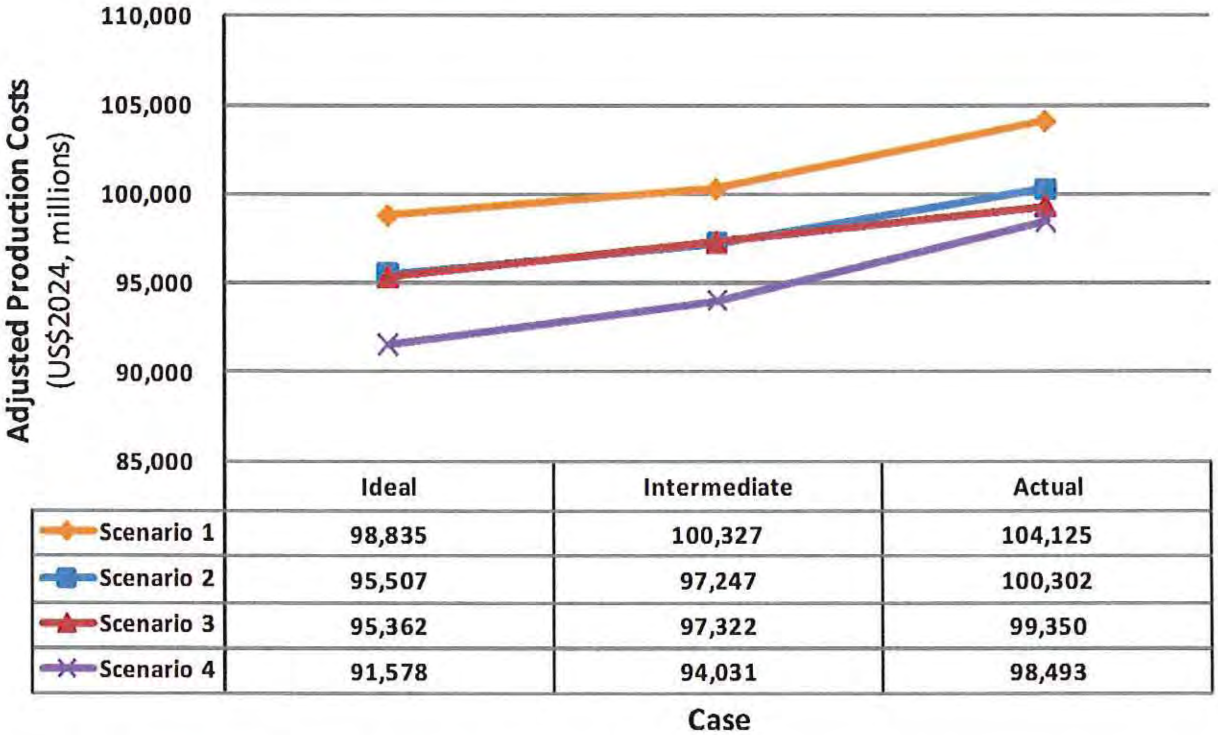
Figure 6-2. Annual average variable spinning reserve using 2004 hourly profiles

OPERATIONAL IMPACT

To calculate the costs of operational impact associated with wind variability and uncertainty, the analysts initially defined two cases, the ideal wind case and the actual wind case. Given the assumption that the day-ahead wind forecast is perfect, no wind forecast error and incremental variable reserves for wind were modeled in the ideal wind case. Considering wind uncertainty and variability, the actual wind case modeled both the day-ahead wind forecast error and additional variable reserves driven by wind. Load uncertainty was accounted for in both cases by including hourly load forecast error and that portion of the additional reserves that resulted from the load uncertainty.

The cost difference between the actual and ideal wind cases is the total integration cost. To separate the individual operational effects of the day-ahead wind forecast error and the variable reserve requirement, an intermediate case was defined. That case included only the day-ahead wind forecast error and ignored the incremental reserve requirements driven by wind. Comparing this case to the ideal wind case gives the day-ahead wind forecast error cost; comparing this case to the actual wind case gives the cost of carrying the incremental reserves associated with wind. Adjusted production cost (APC) was used to calculate the integration cost with regional interchanges and associated costs captured as described in Section 4.2.

Figure 6-3 shows APCs of the ideal, intermediate, and actual cases for each scenario. With the increased 30% wind energy penetration offsetting base-load steam generation, Scenario 4 has the lowest APCs of the four wind scenarios.



	Ideal	Intermediate	Actual
Scenario 1	98,835	100,327	104,125
Scenario 2	95,507	97,247	100,302
Scenario 3	95,362	97,322	99,350
Scenario 4	91,578	94,031	98,493

Figure 6-3. Annual APCs using 2004 hourly profiles

Table 6-1 summarizes the integration costs for each scenario in US$2024 per megawatt-hour (MWh) of wind energy. Carrying additional reserves has a much larger effect on total integration costs than the day-ahead wind forecast error, which could be caused by the resulting total forecast error reduction of aggregating many individual wind plants over a very large geographical area.

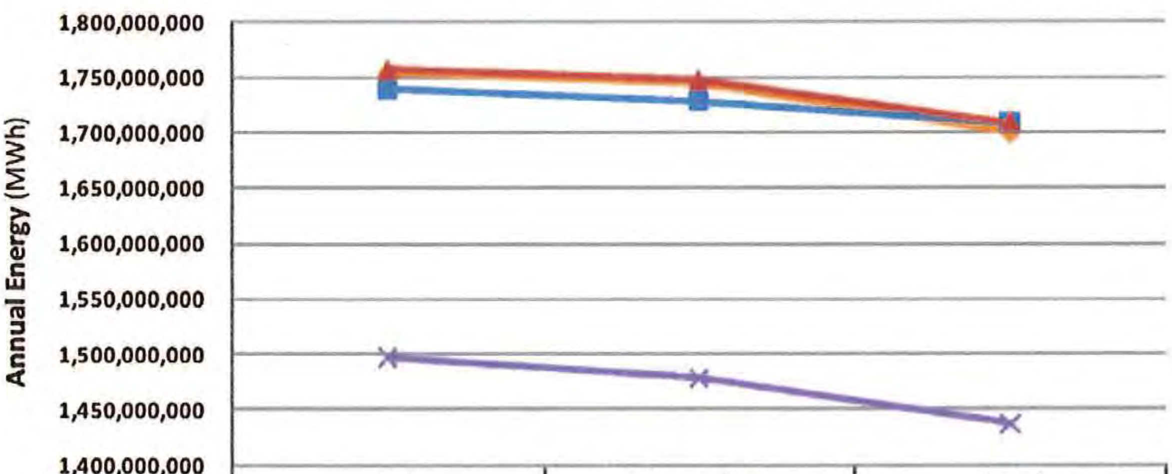
TABLE 6-1. INTEGRATION COSTS ($/MWh of wind energy in US$2024)

SCENARIO	DAY-AHEAD FORECAST ERROR ($/MWh)	VARIABLE RESERVE ($/MWh)	TOTAL INTEGRATION COST ($/MWh)
1	2.26	5.74	8.00
2	2.61	4.59	7.21
3	2.84	2.93	5.77
4	2.51	4.56	7.07

Table 6-2 lists the integration costs for each scenario from different perspectives, in dollars per megawatt-hour ($/MWh) normalized over total wind energy ($/MWh), as a percentage of total APCs, and in dollars normalized over the total load amount ($/MWh). With 20% to 30% wind energy penetration levels for the Eastern Interconnection footprint, the total system operational costs caused by wind variability and uncertainty range from \$5.77/MWh to \$8.00/MWh of wind energy (in US\$2024).

TABLE 6-2. INTEGRATION COSTS US\$2024				
SCENARIO	1	2	3	4
INTEGRATION COST (\$)	5,290,351,725	4,795,114,783	3,988,497,258	6,915,311,563
APCs (\$)	104,125,330,202	100,302,223,283	99,350,363,256	98,493,233,640
INTEGRATION COST (\$/MWh of WIND)	8.00	7.21	5.77	7.07
INTEGRATION COST (% of APC)	5.08	4.78	4.01	7.02
INTEGRATION COST (\$/MWh of LOAD)	1.52	1.37	1.14	1.98

Figures 6-4 and 6-5 show the detailed annual generation production for the ideal, intermediate, and actual cases by fuel type and scenario. With day-ahead wind forecast error modeled in the intermediate case, the base-load coal units are displaced to some degree. And as a result of carrying additional reserves to accommodate wind variability and uncertainty in the actual wind case, the coal units are even further displaced in favor of more flexible gas-fired combined cycle (CC) and combustion turbine (CT) units.



	Ideal	Intermediate	Actual
Scenario 1	1,753,857,366	1,744,621,254	1,699,861,537
Scenario 3	1,738,926,602	1,728,377,567	1,707,958,311
Scenario 2	1,756,972,623	1,747,107,661	1,708,844,597
Scenario 4	1,496,808,215	1,478,430,891	1,436,986,157

Case

Figure 6-4. Annual steam turbine coal generation summary with 2004 hourly profiles

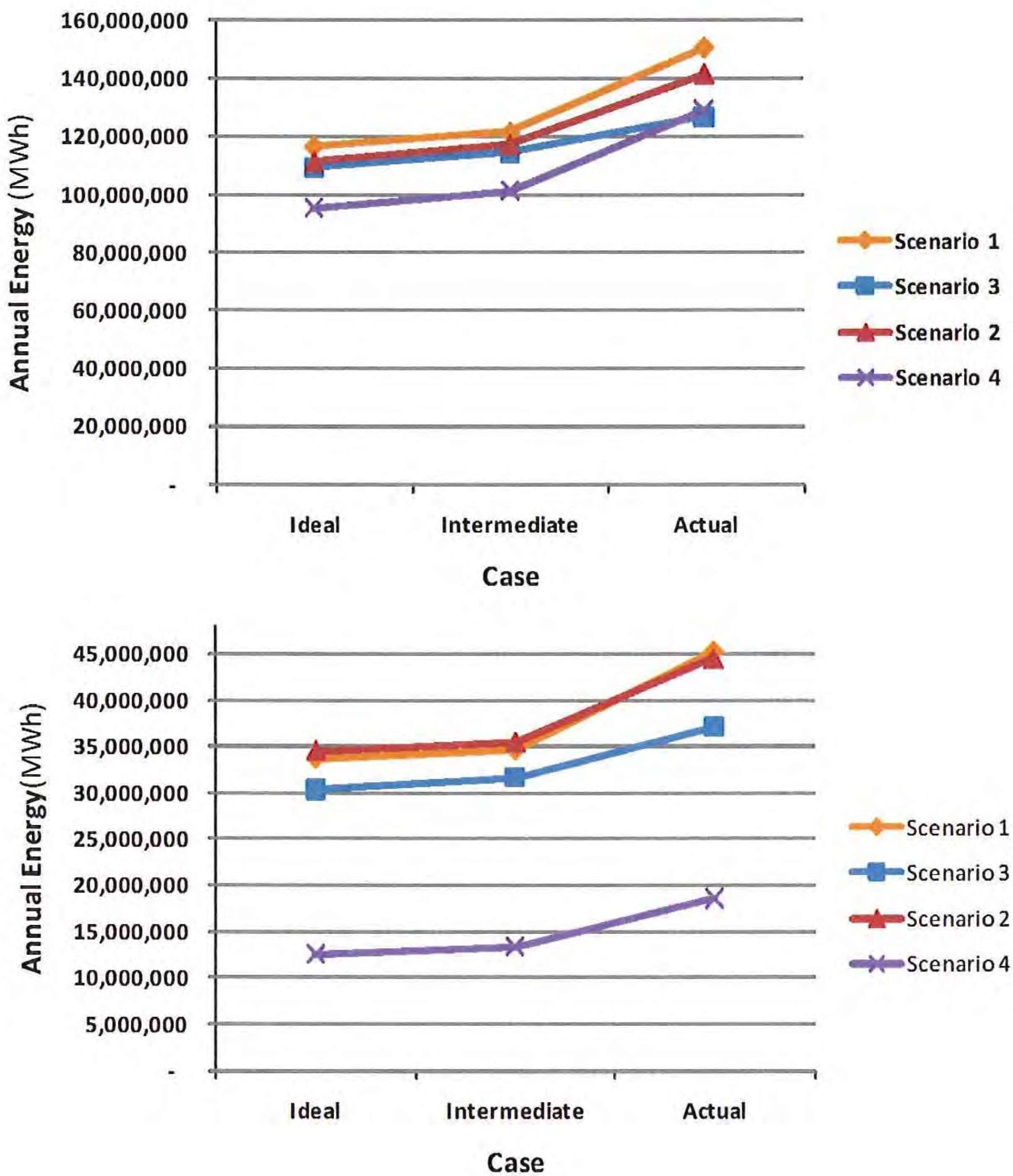


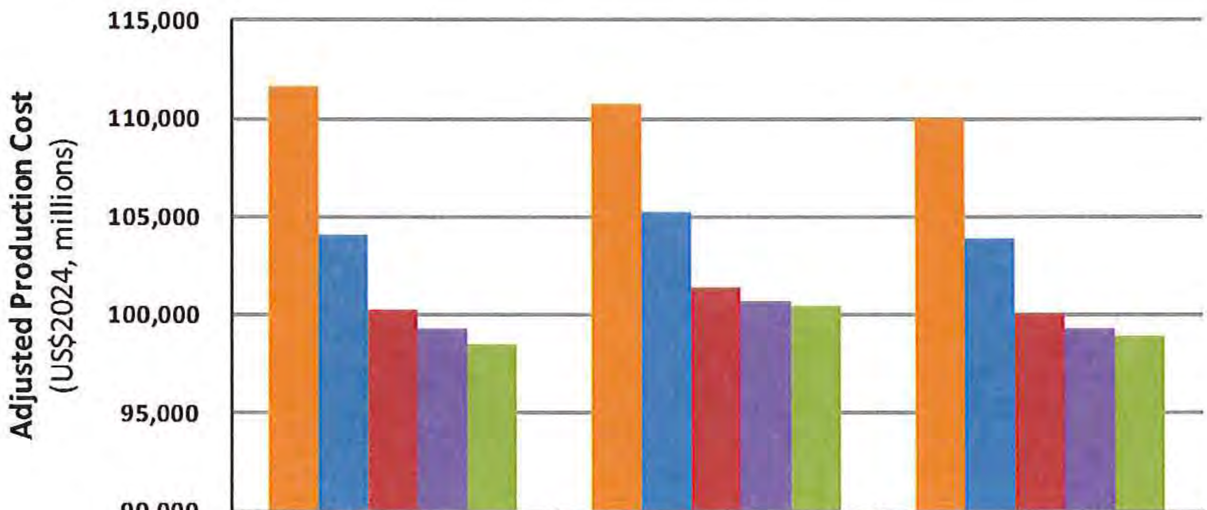
Figure 6-5. Annual combined cycle and combustion turbine gas generation with 2004 hourly profiles

SCENARIO ANALYSIS

The production-cost simulations using 2004 hourly wind and load profiles produced a substantial amount of information on what could be expected in terms of operational impacts and the associated costs of wind variability and uncertainty. Study analysts completed the production-cost simulations with

2005 and 2006 wind and load patterns as a follow-up. The 3-year results for all scenarios, summarized here, offer more detailed analysis on integration cost, wind curtailment, generation production by fuel type, locational marginal prices (LMPs), and regional interchanges. All costs in this section are in US$2024.

Wind penetration levels, geographical locations of wind, and additional variable reserve amounts for wind are a few of the key elements driving the total APC and integration cost for each scenario. As Figure 6-6 illustrates, Scenario 4 has the lowest APC because the least amount of conventional generation resources are committed to accommodate the aggressive 30% wind penetration. Among the three 20% wind scenarios, Scenario 1 has the highest APC, with wind resources concentrated in the western regions and the largest variable reserve amount carried because of wind on the whole study footprint. The Reference Scenario, with the least amount of wind energy and thus the most amount of conventional generation, has the highest APCs.



	2004	2005	2006
Reference	111,616	110,681	110,029
Scenario 1	104,125	105,273	103,916
Scenario 2	100,302	101,359	100,063
Scenario 3	99,350	100,728	99,326
Scenario 4	98,493	100,503	98,890

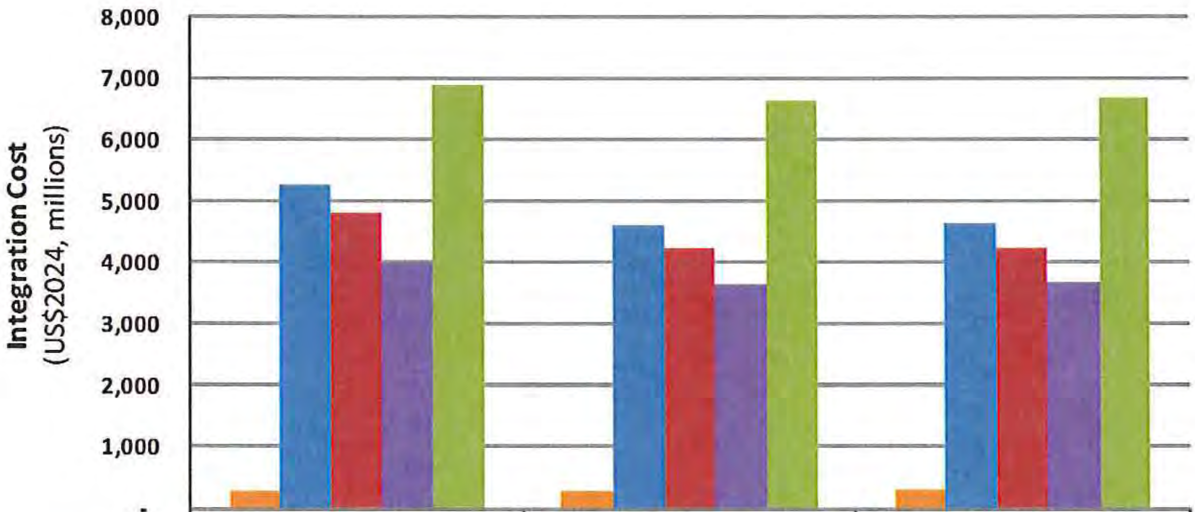
Year

Figure 6-6. Annual APC comparison for actual cases

INTEGRATION COSTS

Figures 6-7 and 6-8 summarize 3-year wind integration costs by scenario in millions of dollars and dollars per megawatt-hour of wind, respectively. The costs for integrating wind across the Eastern Interconnection vary by scenario.

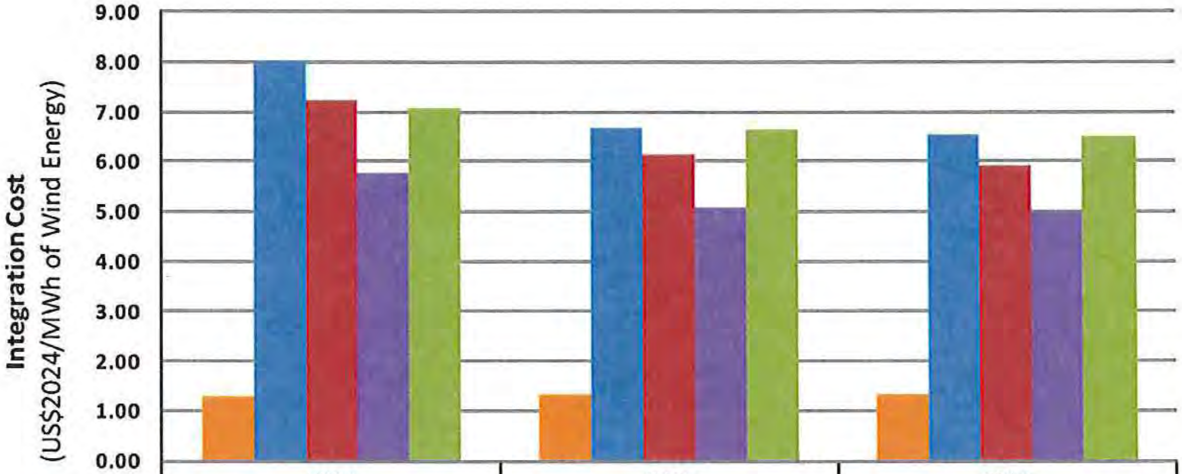
As expected, the total integration cost of Scenario 4 is the highest among all the scenarios because it has the highest wind penetration level. The integration costs are reduced as wind moves toward load centers from Scenario 1 to 3. By normalizing over wind generation for each scenario, the integration cost for Scenario 1 is the highest, up to $8/MWh of wind energy. For Scenario 3, a low of approximately $5/MWh integration cost is obtained. These costs show very good consistency between the study results with 3-year wind and load patterns. As with production costs, the Reference Scenario integration costs are much lower because of the lower wind penetrations and associated reserves and forecast errors.



	2004	2005	2006
Reference	271	294	310
Scenario 1	5,290	4,623	4,657
Scenario 2	4,795	4,250	4,238
Scenario 3	3,988	3,641	3,676
Scenario 4	6,915	6,651	6,675

Year

Figure 6-7. Wind integration costs (US$2024, millions)



	2004	2005	2006
Reference	1.29	1.33	1.34
Scenario 1	8.00	6.68	6.53
Scenario 2	7.21	6.13	5.91
Scenario 3	5.77	5.10	4.97
Scenario 4	7.07	6.63	6.50

Year

Figure 6-8. Wind integration costs ($/MWh of annual wind energy in 2024)

WIND ENERGY AND CURTAILMENT

Each year offers a unique wind data hourly profile driven by a particular weather pattern corresponding to the historical hourly load shape of that year. Using realistic wind patterns is critical to ensure that an assessment of the operational impacts of wind variability and uncertainty on the system is credible. To account for wind uncertainty in production-cost simulations, forecast wind profiles are treated as firm transactions in the day-ahead unit commitment, and in the real-time dispatch wind, forecast errors are included to adjust the amount of wind energy to be essentially the actual wind data. Figure 6-9 shows the annual energy inputs for forecast wind and actual wind using 2004, 2005, and 2006 wind and load hourly profiles for Scenario 1. Year 2005 shows a more balanced wind pattern compared to the other 2 years and is applied in some of the further sensitivity analyses in Section 6.5.

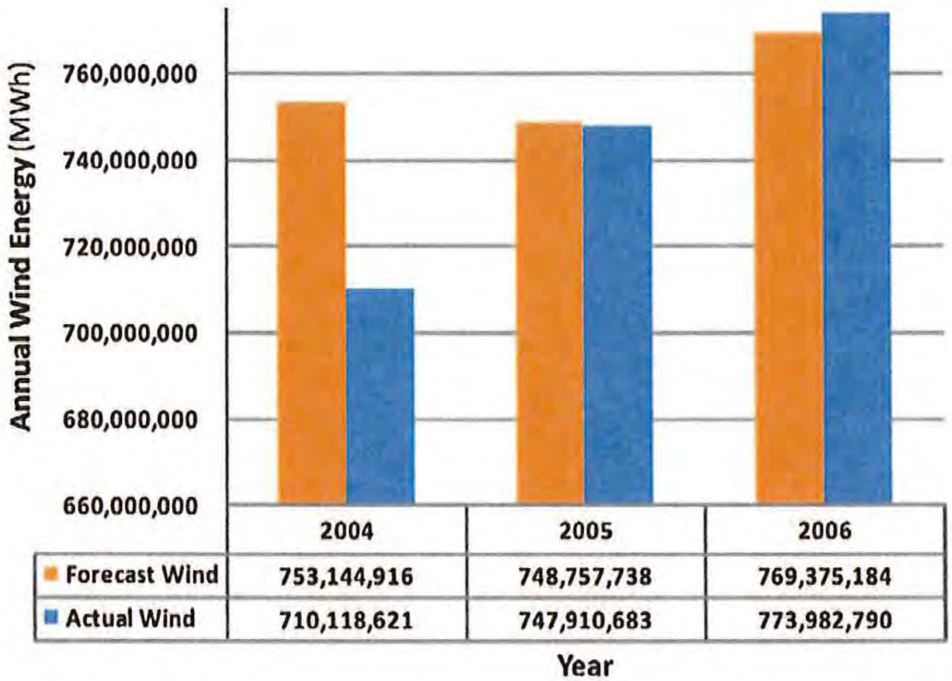
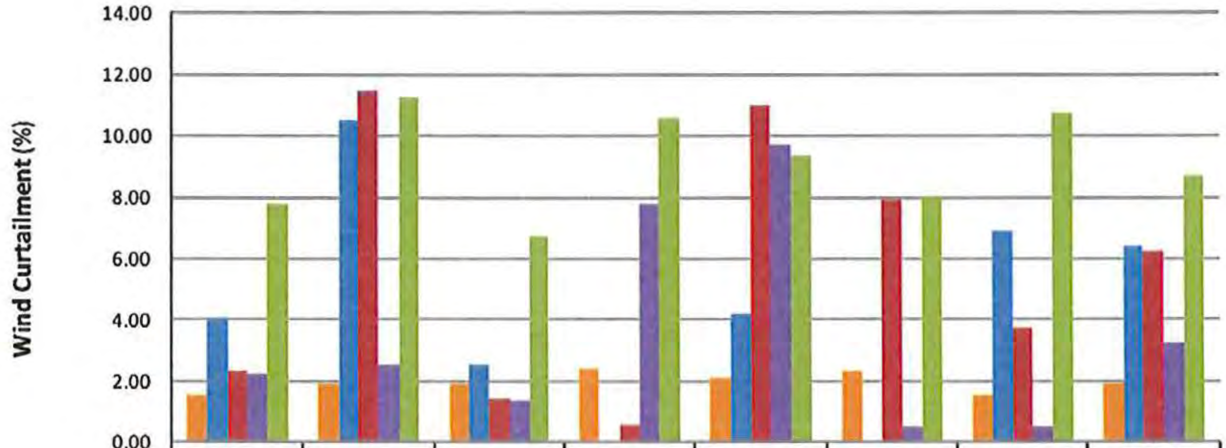


Figure 6-9. Annual wind energy input summary for Scenario 1

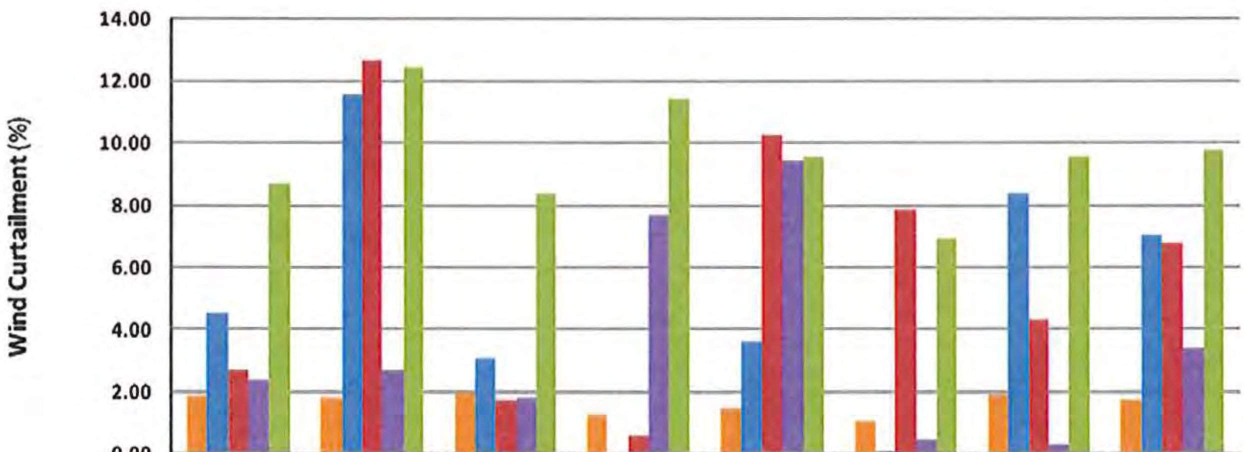
Figures 6-10 through 6-12 summarize the wind curtailment levels by region and scenario with 2004, 2005, and 2006 wind and load patterns, respectively. Roughly 2% to 10% wind curtailment occurs across the study footprint. SPP has the highest wind curtailment levels in all scenarios except Scenario 3. The lowest wind curtailment level occurs in Scenario 3, with wind spreading more evenly over the footprint. With their intertwined nature, transmission constraints and minimum generation events are clearly the main drivers for wind curtailment. To further investigate wind curtailment, the study team conducted detailed sensitivity analyses, and the results are discussed in Section 6.5.1.



	MISO	SPP	PJM	ISO-NE	NYISO	SERC	TVA	Total Footprint
Reference (%)	1.53	1.90	1.93	2.41	2.12	2.34	1.54	1.92
Scenario 1 (%)	4.05	10.52	2.56	0.03	4.22	0.04	6.89	6.38
Scenario 2 (%)	2.32	11.49	1.43	0.59	11.00	7.92	3.75	6.25
Scenario 3 (%)	2.26	2.58	1.38	7.76	9.72	0.53	0.52	3.26
Scenario 4 (%)	7.81	11.28	6.70	10.57	9.36	8.03	10.71	8.72

Region

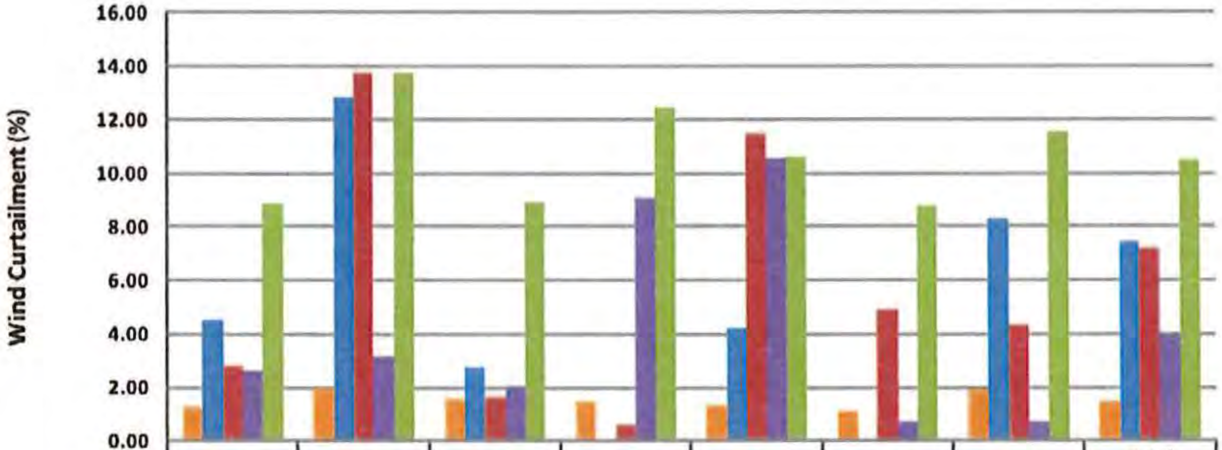
Figure 6-10. Annual wind curtailment summary using 2004 hourly load and wind profiles



	MISO	SPP	PJM	ISO-NE	NYISO	SERC	TVA	Total Footprint
Reference (%)	1.87	1.80	1.98	1.25	1.48	1.06	1.93	1.73
Scenario 1 (%)	4.51	11.57	3.07	0.02	3.63	0.07	8.37	7.02
Scenario 2 (%)	2.69	12.64	1.73	0.56	10.25	7.84	4.34	6.79
Scenario 3 (%)	2.41	2.70	1.81	7.67	9.43	0.47	0.32	3.39
Scenario 4 (%)	8.69	12.46	8.37	11.45	9.56	6.91	9.53	9.77

Region

Figure 6-11. Annual wind curtailment summary using 2005 hourly load and wind profiles



	MISO	SPP	PJM	ISO-NE	NYISO	SERC	TVA	Total Footprint
Reference (%)	1.27	1.94	1.56	1.43	1.30	1.08	1.86	1.46
Scenario 1 (%)	4.52	12.79	2.76	0.02	4.20	0.08	8.28	7.46
Scenario 2 (%)	2.77	13.75	1.62	0.60	11.44	4.87	4.29	7.21
Scenario 3 (%)	2.62	3.16	2.05	9.06	10.57	0.72	0.71	3.94
Scenario 4 (%)	8.87	13.73	8.90	12.44	10.61	8.76	11.53	10.51

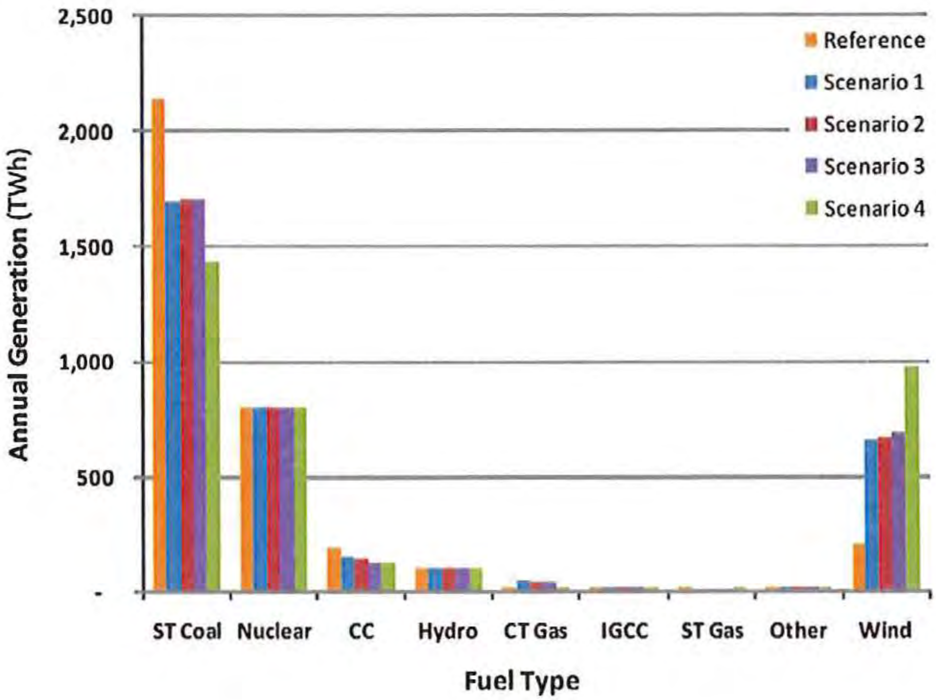
Region

Figure 6-12. Annual wind curtailment summary using 2006 hourly load and wind profiles

GENERATION BY FUEL TYPE

The operating costs associated with wind variability and uncertainty depend on the nature of the generation mix developed for each scenario. For example, fuel prices, carbon emission regulations, variable operations and maintenance (O&M) costs, and renewable energy mandates all feed into operating costs. Examining the generation dispatch pattern can offer valuable insights into understanding the effect of wind on system operations.

Generation by fuel type for each scenario with 3-year wind and load profiles is illustrated in Figures 6-13 through 6-15, and with the same information, Figures 6-16 through 6-18 show a different way to look at the dispatchable generation resources. Among the three 20% wind scenarios, more gas-fired combined cycle (CC) units are dispatched in Scenario 1 to manage the largest variable reserves because the majority of wind units are located in the western regions. In Scenario 4, the increased off-peak energy contribution of the 30% wind mandate results in an approximately 16% reduction of steam turbine (ST) coal generation compared to the three 20% wind scenarios, whereas a fairly comparable level of combined cycle production remains in Scenarios 3 and 4. In Scenario 4 (30% wind penetration), wind becomes the second largest energy producer, behind only coal-fired steam turbines in terms of energy output.



Note: IGCC = integrated gas combined cycle

Figure 6-13. Annual generation energy by fuel type using 2004 hourly load and wind profiles

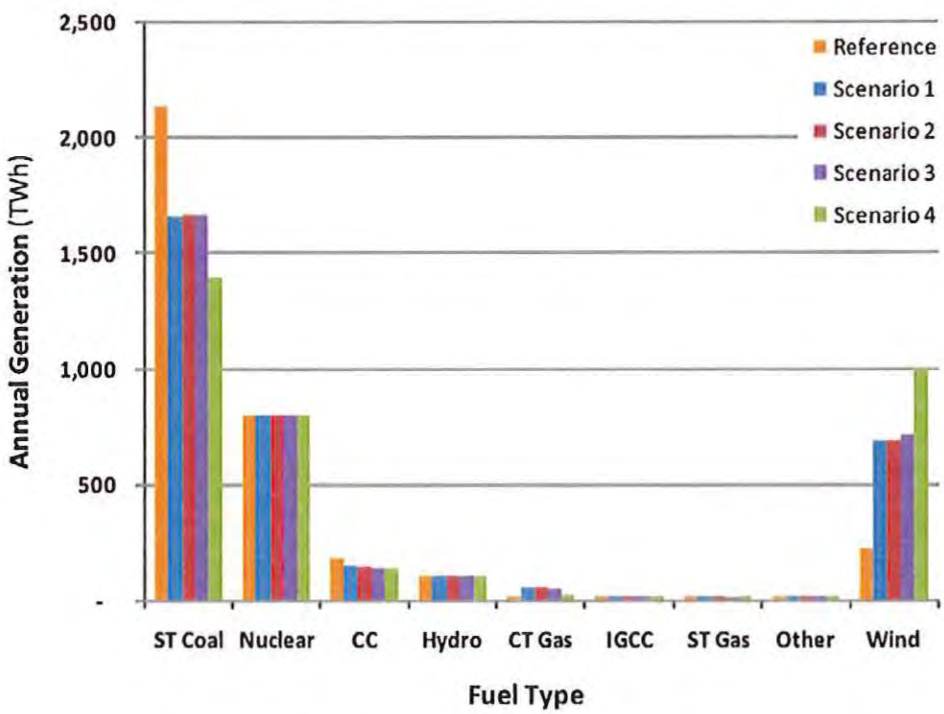


Figure 6-14. Annual generation energy by fuel type using 2005 hourly load and wind profiles

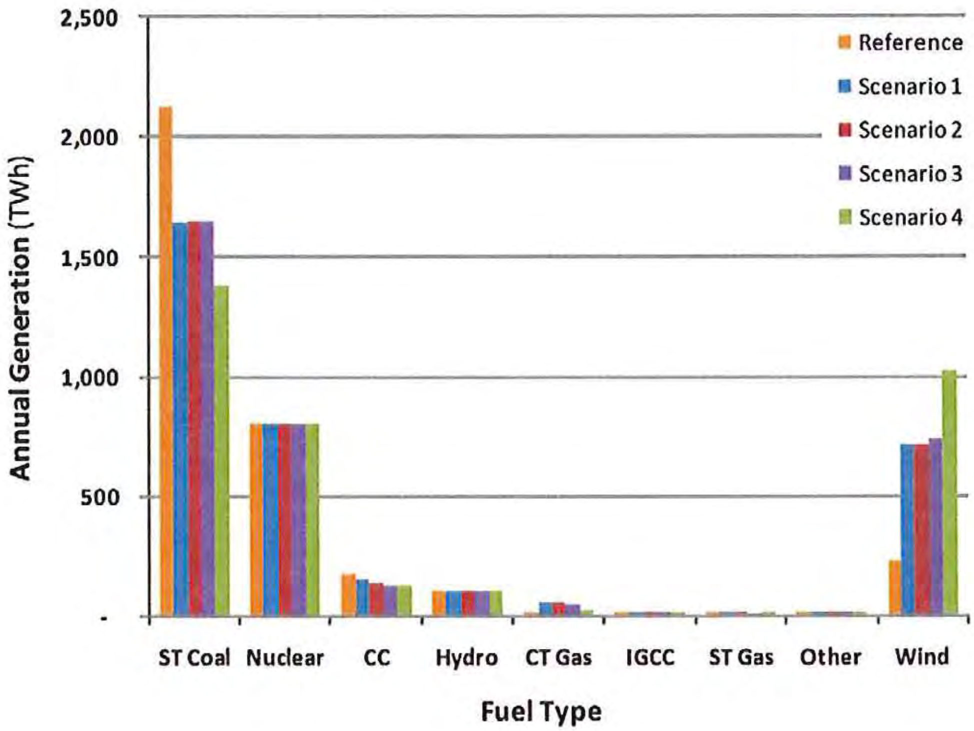


Figure 6-15. Annual generation energy by fuel type using 2006 hourly load and wind profiles

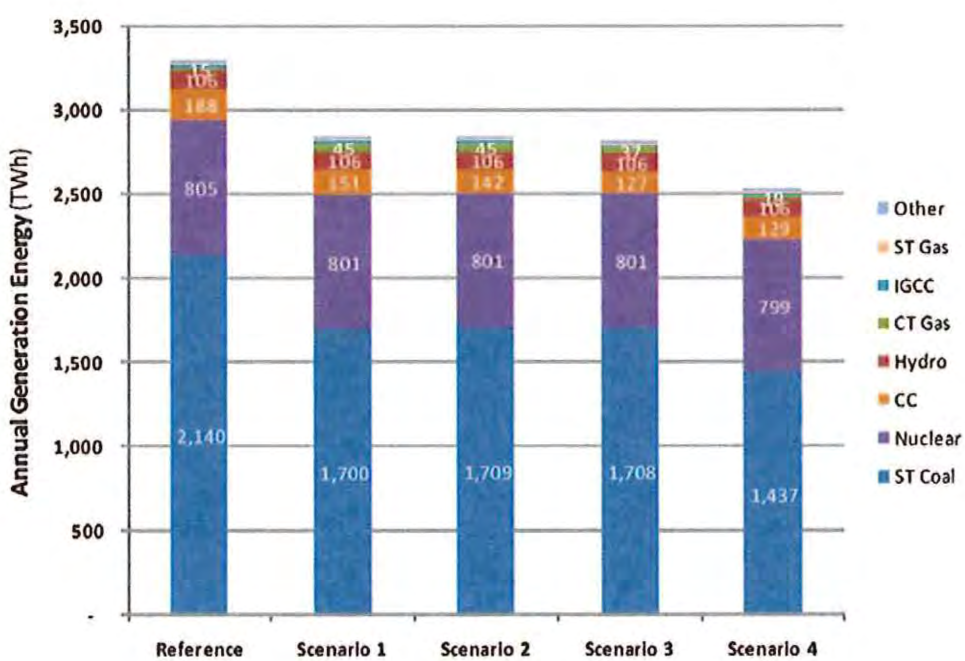


Figure 6-16. Annual generation energy by fuel type using 2004 hourly profiles

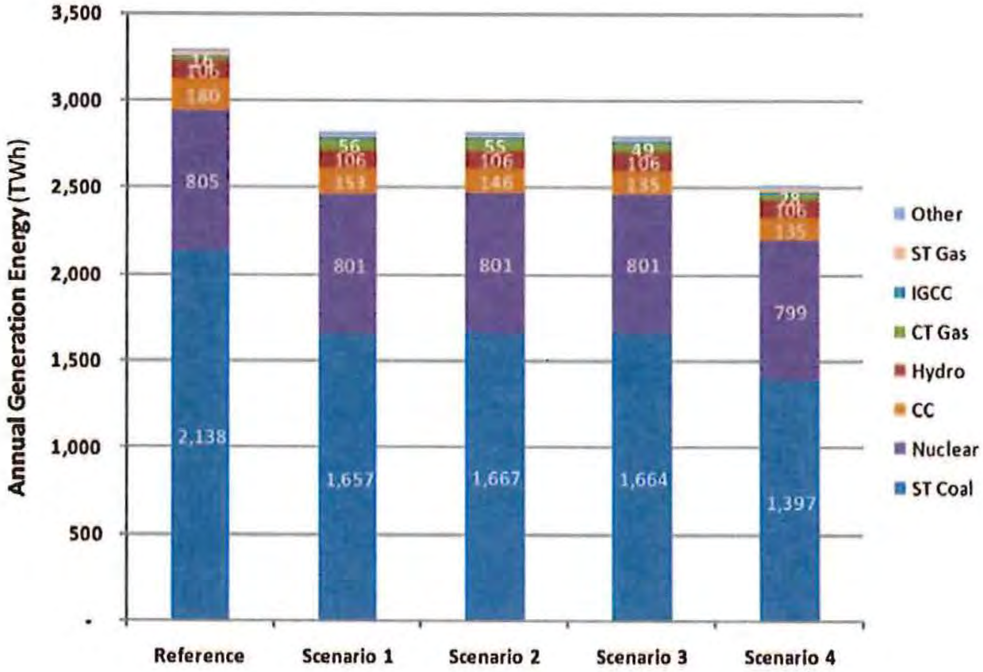


Figure 6-17. Annual generation energy by fuel type using 2005 hourly profiles

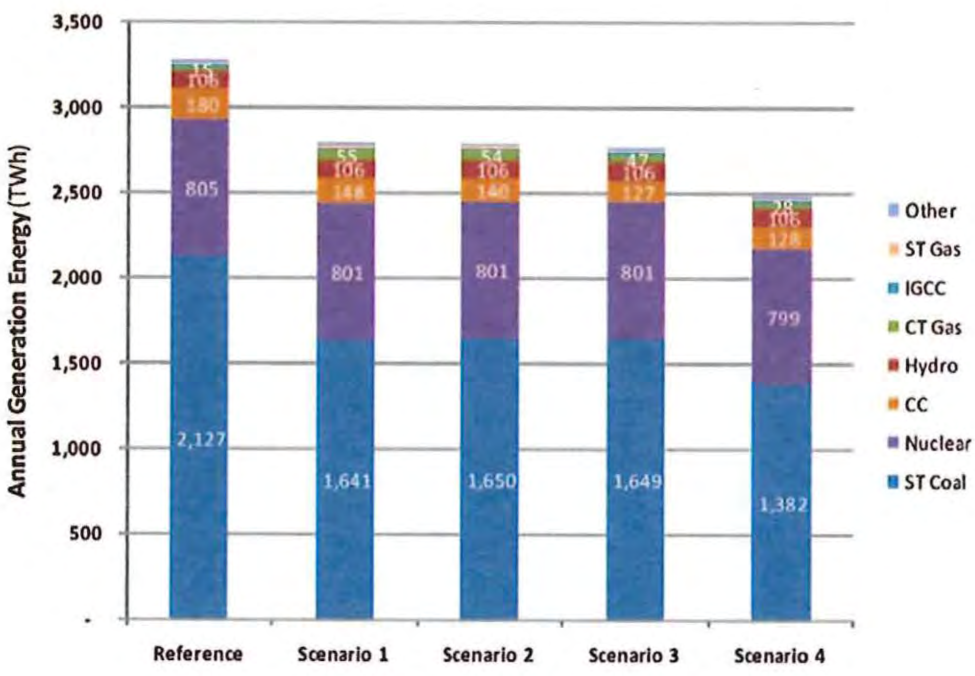


Figure 6-18. Annual generation energy by fuel type using 2006 hourly profiles

Figures 6-19 through 6-21 summarize the annual generation changes between the ideal and actual wind cases by fuel type and scenario for the 3-year wind and load patterns. As described in Section 6.2, the day-ahead wind forecast error and additional reserve carried because of wind are used to differentiate the actual wind case from the ideal wind case and are the significant drivers for generation changes between these two cases. All the scenarios follow the same trend, with coal-fired steam turbines displaced primarily by gas-fired combined cycle and combustion turbines. To deal with the highest wind penetration and associated incremental reserve requirement, the most significant generation shifting is observed in Scenario 4. The generation shift in Scenario 3 is the most modest of the high-penetration wind scenarios because it has the least additional reserve requirement (as a result of moving wind close to load centers). Consistent with low wind penetration and integration costs, the Reference Scenario shows the least generation shift from the ideal to actual wind cases.

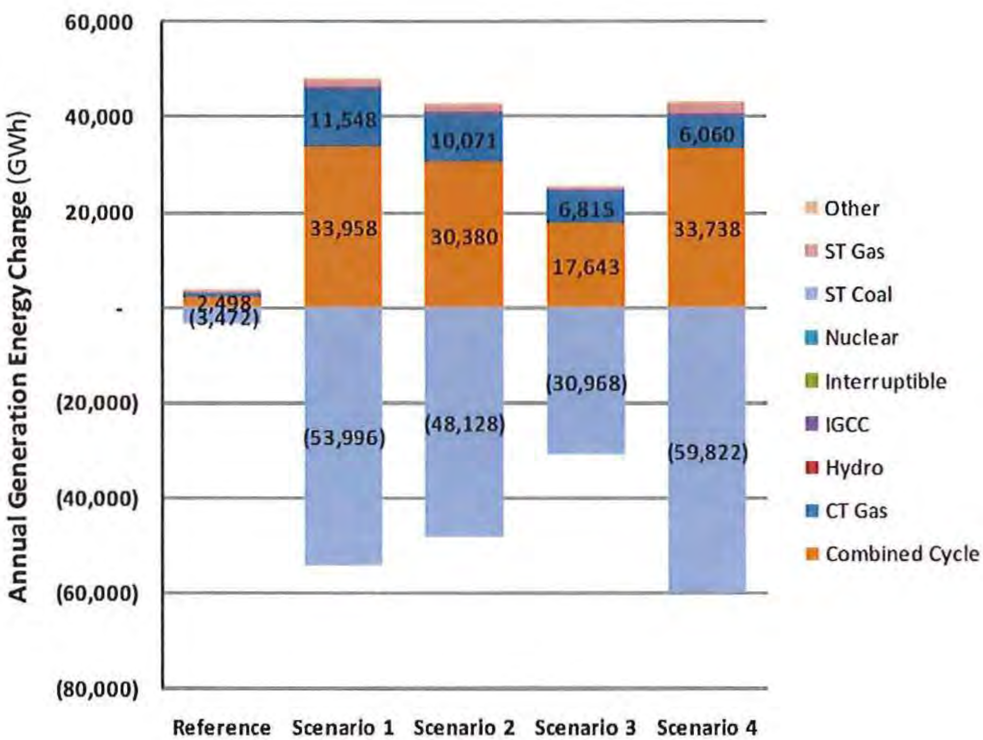


Figure 6-19. Change in annual generation from ideal to actual cases using 2004 hourly profiles

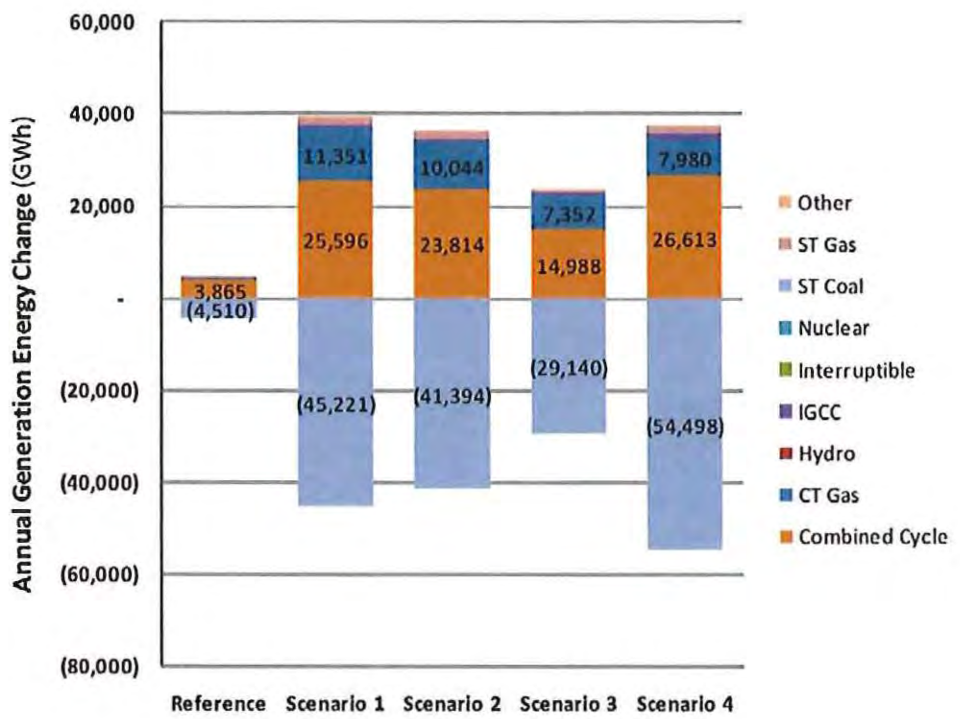


Figure 6-20. Change in annual generation from ideal to actual cases using 2005 hourly profiles

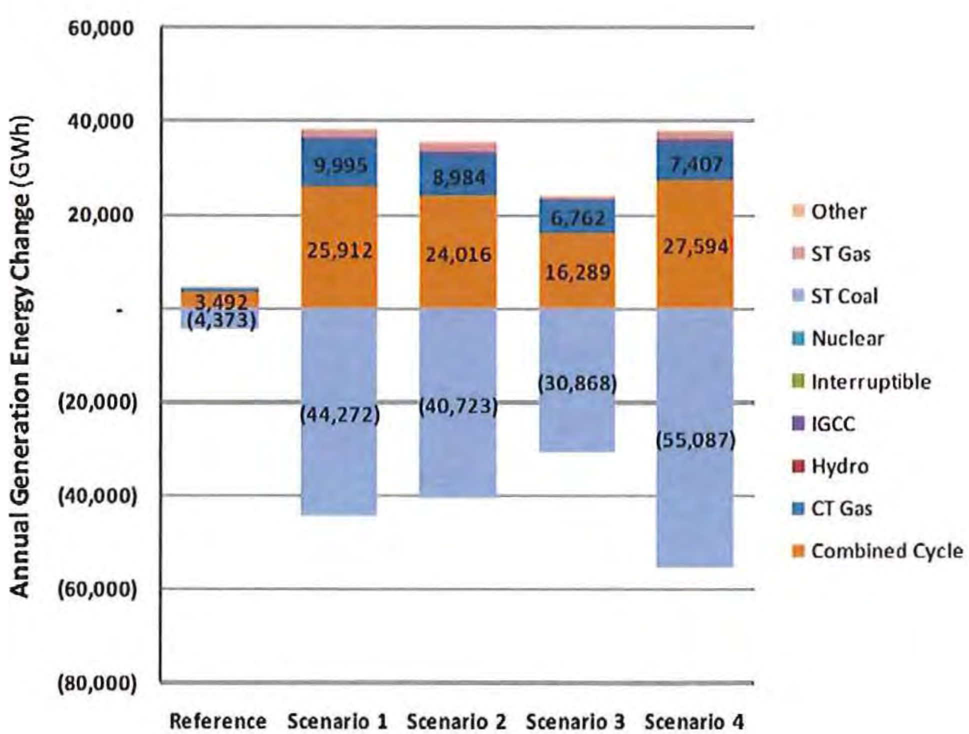
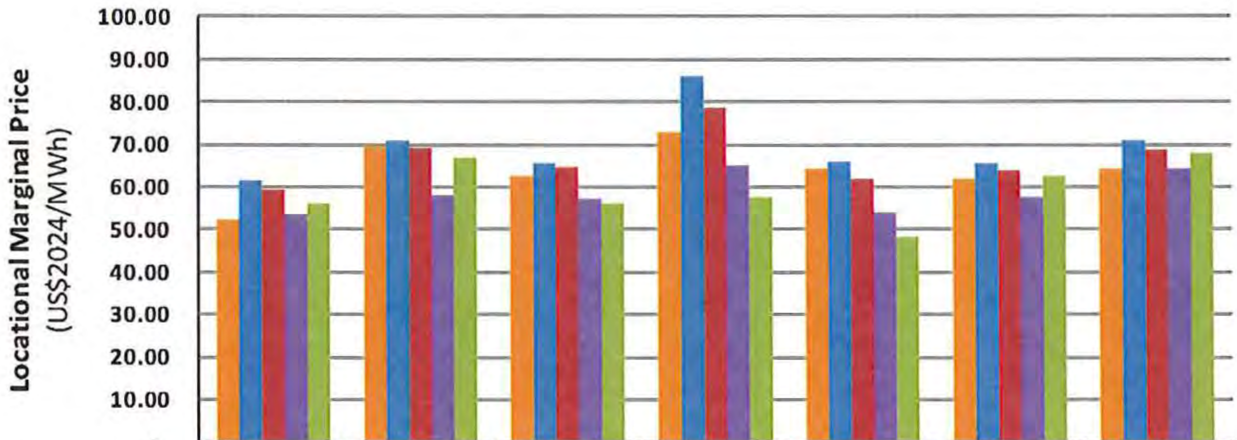


Figure 6-21. Change in annual generation from ideal to actual cases using 2006 hourly profiles

LOCATIONAL MARGINAL PRICES

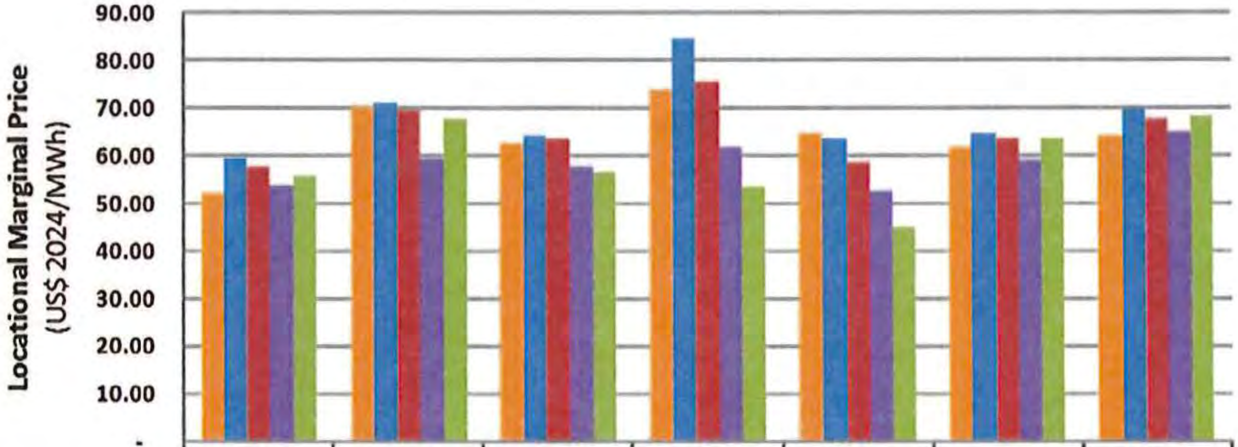
Figures 6-22 through 6-24 illustrate the effect of wind on annual generation-weighted LMPs by region and scenario for the 3-year wind and load patterns. The LMP is the marginal cost of serving the next megawatt of demand and depends on the system transmission constraints and the performance characteristics of generation resources. Because there is less congestion with wind moving toward load centers, it is intuitive to expect that the regional generation-weighted LMPs decrease from Scenario 1 to 3.



	MISO	SPP	PJM	ISO-NE	NYISO	TVA	SERC
Reference	52.00	69.63	62.63	72.82	64.08	61.95	64.18
Scenario 1	61.35	71.14	65.44	86.13	66.01	65.40	70.97
Scenario 2	59.30	69.00	64.58	78.66	61.80	63.92	68.48
Scenario 3	53.48	58.03	56.99	65.26	54.09	57.75	64.13
Scenario 4	56.37	67.02	56.40	57.52	48.06	62.31	67.92

Region

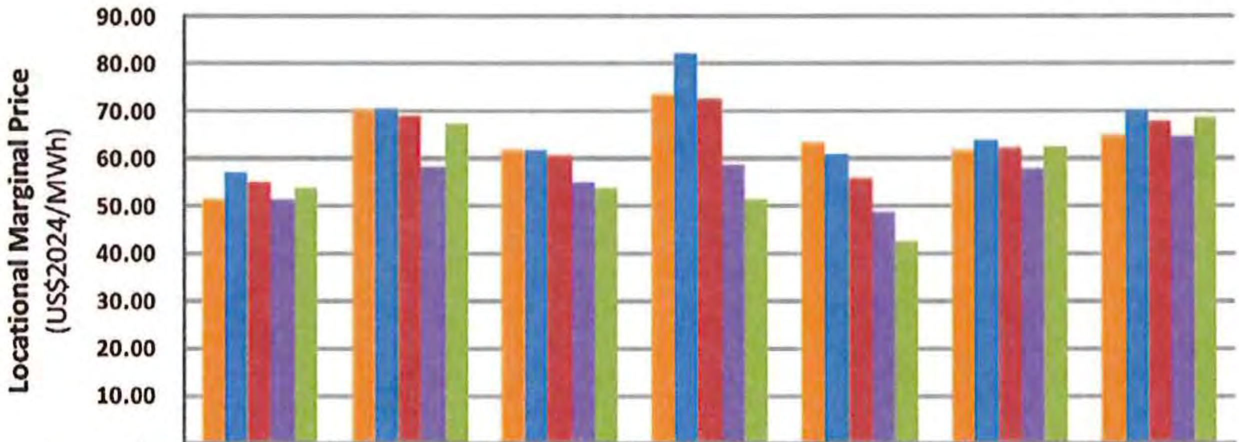
Figure 6-22. Annual generation-weighted LMPs using 2004 hourly profiles



	MISO	SPP	PJM	ISO-NE	NYISO	TVA	SERC
Reference	52.17	70.09	62.73	73.79	64.48	61.95	64.35
Scenario 1	59.30	71.22	64.28	84.52	63.35	64.68	69.83
Scenario 2	57.82	69.43	63.53	75.55	58.70	63.49	67.82
Scenario 3	53.63	59.27	57.84	61.92	52.42	59.00	64.95
Scenario 4	55.88	67.93	56.45	53.42	44.87	63.50	68.40

Region

Figure 6-23. Annual generation-weighted LMPs using 2005 hourly profiles



	MISO	SPP	PJM	ISO-NE	NYISO	TVA	SERC
Reference	51.50	70.39	61.67	73.66	63.59	61.81	64.90
Scenario 1	57.20	70.78	61.80	82.28	60.90	63.87	70.21
Scenario 2	55.13	68.89	60.66	72.53	55.76	62.18	67.93
Scenario 3	51.29	58.14	55.16	58.51	48.60	57.92	64.69
Scenario 4	53.73	67.55	53.92	51.27	42.36	62.57	68.69

Region

Figure 6-24. Annual generation-weighted LMPs using 2006 hourly profiles

Scenario 4 elevates the effect on energy market prices because it has the most aggressive wind penetration level. Regionally, the results are as follows:

- Even though both Scenarios 3 and 4 use a substantial amount of offshore wind along the East Coast with approximately the same installed wind capacity in ISO-NE and NYISO, the LMPs in East Coast regions are lower in Scenario 4 because more wind resources are accessible in the western regions for importing with the extra-high voltage (EHV) transmission overlay.
- For western regions SPP, Midwest ISO, and Mid-Continent Area Power Pool (MAPP), however, the LMPs in Scenario 4 are actually higher than those in Scenario 3. This is in recognition of the significant difference of the installed wind capacity and the resulting variable reserve requirement driven by wind between these two scenarios.
- As a consequence of the increased energy import in TVA and SERC because of little installed wind capacity, more flexible gas-fired units must be committed or available to accommodate the larger amount of imported variability and uncertainty in Scenario 4. As a result, Scenario 4 has higher LMPs than Scenario 3.

REGIONAL TRANSACTIONS

The conceptual transmission overlay enables wind and base-load steam energy in the western regions to reach a wider footprint and results in a different unit commitment and dispatch across the entire study footprint. The associated regional transaction costs have a great impact on the APC calculation for each region. Figures 6-25 through 6-27 show the annual transaction energy by region with the 3-year wind and load profiles.

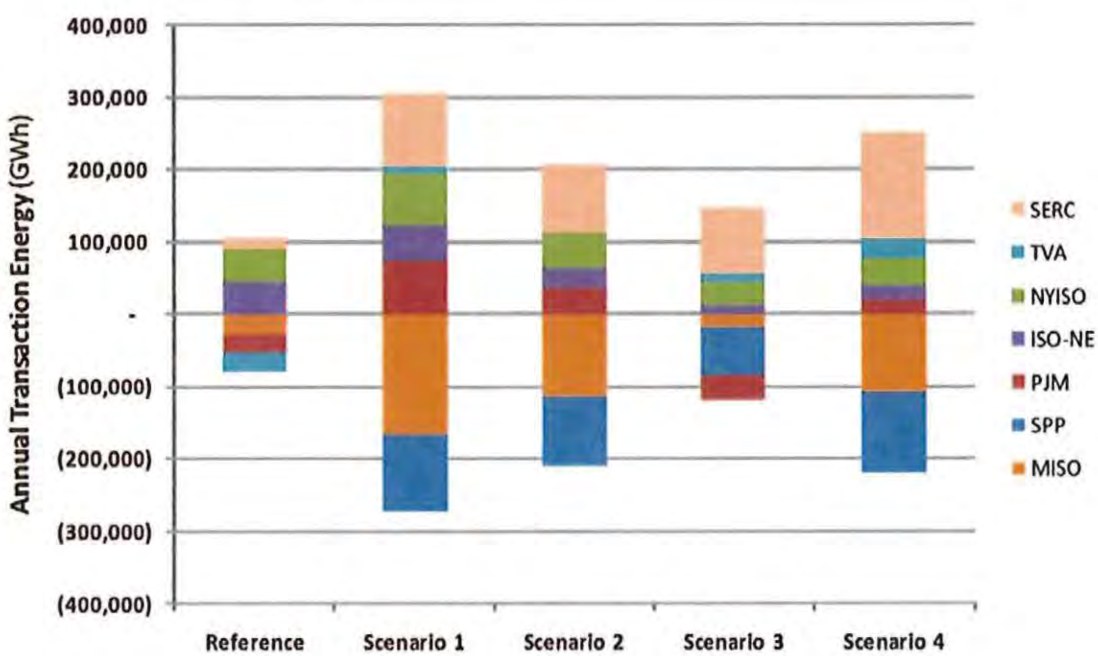


Figure 6-25. Annual regional transaction energy using 2004 hourly profiles

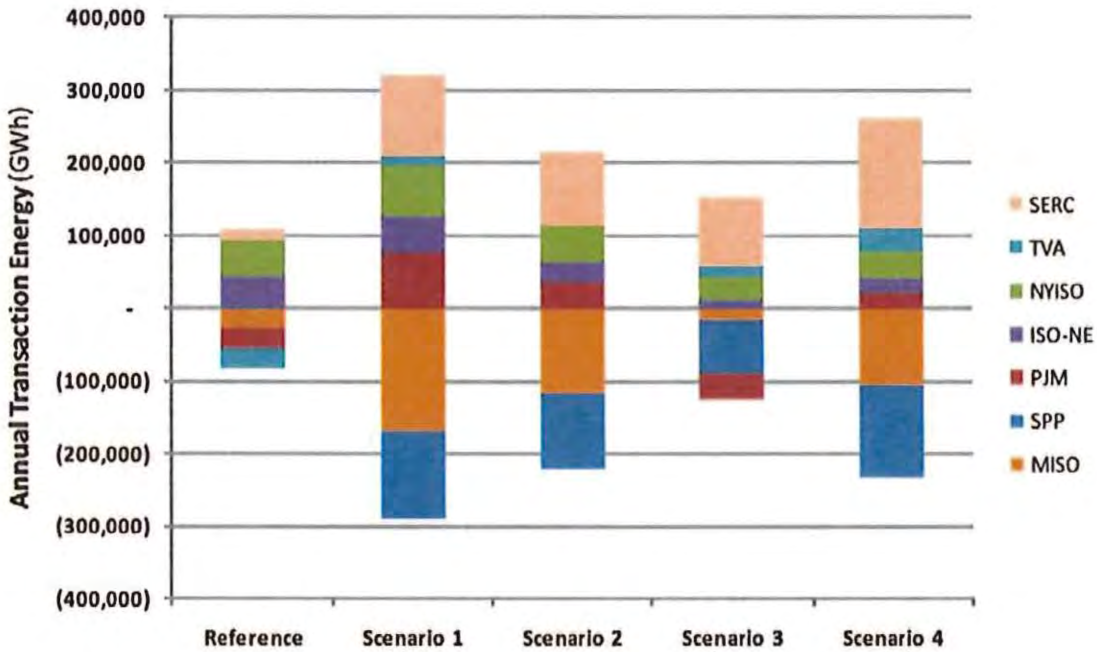


Figure 6-26. Annual regional transaction energy using 2005 hourly profiles

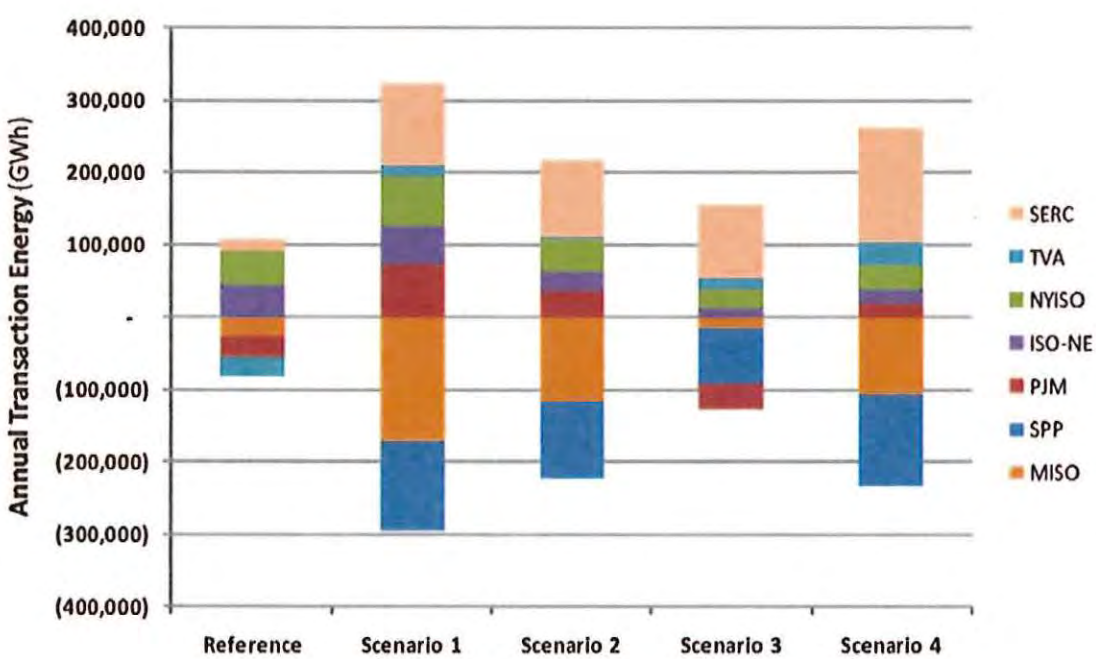


Figure 6-27. Annual regional transaction energy using 2006 hourly profiles

The effects of wind generation on regional transactions can be summarized as follows:

- SPP, MISO, and MAPP are the primary export regions and SERC is the predominant import region because of low wind availability in all the scenarios. The total transaction amount decreases from Scenario 1 to 3 as wind resources move toward the East Coast. Scenario 3 has the least regional transaction energy among the high-penetration wind scenarios.
- As a result of using aggressive amounts of offshore wind capacity in eastern regions, Scenario 4 has smaller amounts of transactions on the total study footprint compared to Scenario 1.
- The import amounts are roughly the same in SERC for the three 20% wind penetration scenarios, and there is an approximate 40% increase in Scenario 4 because the eastern regions need to import less.
- PJM, NYISO, and ISO-NE are exporters in Scenario 3 as more wind moves toward load centers. This results in a large increase of installed wind capacity in the eastern regions for export.
- With a different transmission overlay, different thermal expansion plan, and lower wind penetration with different siting, the Reference Scenario shows much lower total energy interchange and some different net positions for regions.

SENSITIVITY ANALYSIS

WIND CURTAILMENT

Continuing the study effort described in Section 4.4.2, more detailed sensitivity analyses were performed to further investigate wind curtailment in the high-penetration wind scenarios. Wind curtailment ranges from approximately 3% to 10% with the conceptual transmission overlays developed for EWITS.

Using the Scenario 1 actual wind case with 2004 hourly wind and load profiles, the study team conducted three sensitivity analyses:

- Sensitivity Case 1, Non Must-Run: The must-run constraint is removed from coal units (i.e., the program is allowed to actually shut them down).
- Sensitivity Case 2, Copper Sheet: There are no transmission constraints in the system.
- Sensitivity Case 3, Wind Energy Credit: The wind curtailment price is set at negative $40/MWh, twice as much as the current production tax credit (PTC).

Figure 6-28 shows the duration curve of the hourly flows across the sample interface. As described in Section 4, the transmission line across the interface is sized to deliver 80% of desired energy flow as an initial estimate of the preliminary economic transmission requirement. For very short periods of time, some wind energy curtailment would be expected for the four high-penetration wind scenarios.

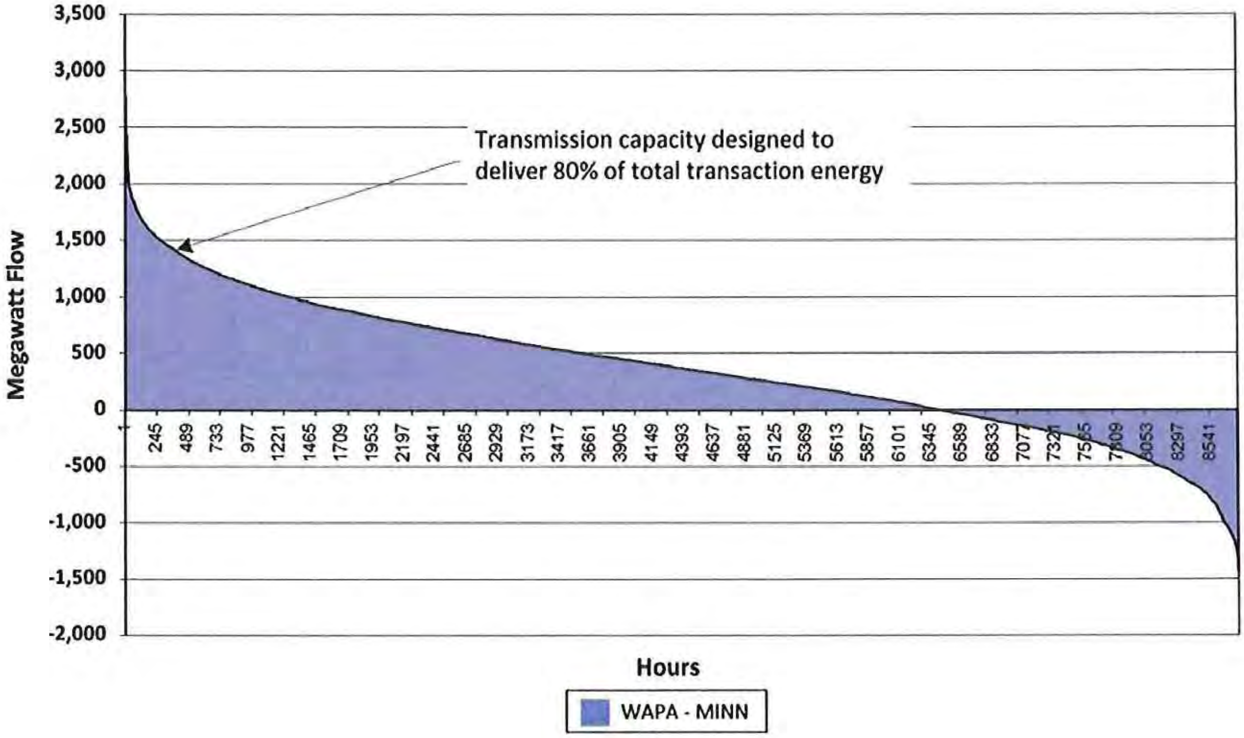


Figure 6-28. Interface flow duration curve sample

Tables 6-3 through 6-5 summarize the annual wind curtailment results by region for the three defined sensitivity cases, respectively. Removing the must-run status from coal units has the least effect on wind curtailment, with only 0.27% curtailment reduction compared to the original actual wind case. With a wind curtailment price at negative $40/MWh, approximately 3.51% wind curtailment is achieved for the whole study footprint as opposed to the original 6.38%. The majority of wind curtailment is caused by transmission constraints because wind curtailment is significantly reduced with no transmission constraints in the system. Only 0.12% wind curtailment is left, which is most likely caused by the minimum generation events.

TABLE 6-3. WIND CURTAILMENT COMPARISON FOR SENSITIVITY CASE 1, NON MUST-RUN					
REGION	SENSITIVITY NON MUST-RUN		ORIGINAL ACTUAL CASE		WIND INPUT DATA
	TOTAL	CURTAILMENT (%)	TOTAL	CURTAILMENT (%)	TOTAL
E_CAN	648,088	0.03	648,088	0.03	648,283
ISO-NE	10,514,801	0.03	10,514,801	0.03	10,517,477
MAPP	173,422,697	4.33	172,292,204	4.95	181,271,613
MHEB	2,598,952	1.01	2,600,815	0.93	2,625,348
MISO	129,742,596	2.90	129,844,931	2.83	133,622,952
NYISO	21,326,536	3.72	21,216,681	4.22	22,151,455
PJM	70,241,841	2.52	70,206,710	2.56	72,054,440
SERCNI	3,171,641	0.03	3,171,218	0.04	3,172,523
SPP	251,687,576	10.28	251,004,870	10.52	280,512,355
TVASUB	3,369,879	4.86	3,297,972	6.89	3,542,176
TOTAL	**666,724,607**	**6.11**	**664,798,290**	**6.38**	**710,118,621**

Notes: SERCNI, E-CAN, and TVASUB are monikers used in EWITS for subregions in the PROMOD IV model. MHEB = Manitoba Hydro Electric Board.

TABLE 6-4. WIND CURTAILMENT COMPARISON FOR SENSITIVITY CASE 2, COPPER SHEET					
REGION	SENSITIVITY COPPER SHEET		ORIGINAL ACTUAL CASE		WIND INPUT DATA
	TOTAL	CURTAILMENT (%)	TOTAL	CURTAILMENT (%)	TOTAL
E_CAN	648,024	0.04	648,088	0.03	648,283
ISO-NE	10,514,801	0.03	10,514,801	0.03	10,517,477
MAPPCOR	180,775,920	0.27	172,292,204	4.95	181,271,613
MHEB	2,625,200	0.01	2,600,815	0.93	2,625,348
MISO	133,617,070	0.00	129,844,931	2.83	133,622,952
NYISO	22,147,645	0.02	21,216,681	4.22	22,151,455
PJM	72,047,686	0.01	70,206,710	2.56	72,054,440
SERCNI	3,172,046	0.02	3,171,218	0.04	3,172,523
SPP	280,148,134	0.13	251,004,870	10.52	280,512,355
TVASUB	3,541,986	0.01	3,297,972	6.89	3,542,176
TOTAL	**709,238,512**	**0.12**	**664,798,290**	**6.38**	**710,118,621**

Note: MAPPCOR is the service provider to MAPP.

TABLE 6-5. WIND CURTAILMENT COMPARISON FOR SENSITIVITY CASE 3, WIND ENERGY CREDIT					
REGION	SENSITIVITY NON MUST-RUN		ORIGINAL ACTUAL CASE		WIND INPUT DATA
	TOTAL	CURTAILMENT (%)	TOTAL	CURTAILMENT (%)	TOTAL
E_CAN	648,088	0.03	648,088	0.03	648,283
ISO-NE	10,514,801	0.03	10,514,801	0.03	10,517,477
MAPPCOR	179,024,767	1.24	172,292,204	4.95	181,271,613
MHEB	2,625,069	0.01	2,600,815	0.93	2,625,348
MISO	130,820,220	2.10	129,844,931	2.83	133,622,952
NYISO	22,014,540	0.62	21,216,681	4.22	22,151,455
PJM	71,400,322	0.91	70,206,710	2.56	72,054,440
SERCNI	3,171,925	0.02	3,171,218	0.04	3,172,523
SPP	261,480,631	6.78	251,004,870	10.52	280,512,355
TVASUB	3,463,917	2.21	3,297,972	6.89	3,542,176
TOTAL	**685,164,280**	**3.51**	**664,798,290**	**6.38**	**710,118,621**

TABLE 6-6. ANNUAL GENERATION ENERGY SUMMARY BY FUEL TYPE (MWh)								
CASE	CC	CT, GAS	CT, OIL	IGCC	ST, COAL	ST, GAS	ST, OIL	DUMP ENERGY
ORIGINAL	150,745,894	45,260,490	125,404	16,311,970	1,699,861,537	11,635,944	201,453	2,663,506
CASE 1	135,636,423	42,194,976	132,876	16,360,553	1,711,360,316	15,275,894	517,574	2,236,014
CASE 2	143,133,853	38,051,768	75,377	16,372,149	1,673,395,676	1,808,557	126,010	39,851
CASE 3	150,896,689	45,658,954	125,974	16,189,417	1,698,071,417	11,820,054	197,049	13,660,546

As illustrated in Table 6-6, by setting coal units as non must-run in Sensitivity Case 1, the coal units become more flexible and displace the higher cost combined cycle units. Coal prices vary across the Eastern Interconnection, with an average of $1.7/million British thermal units (MBtu) in the SPP, an average of $2.91/MBtu in the SERC, and up to $3.50/MBtu on the East Coast. Because of this, without enforcing the must-run constraints, coal and combined cycle resources in the high-cost regions are decommitted by importing the available low-cost, off-peak energy from the western regions. Because there are no penalties or additional costs associated with carbon emissions, energy from fossil resources in the Midwest can be exported when wind is not available. Adding restrictions or additional costs on carbon emissions would decrease the amount of exports from coal-fired units.

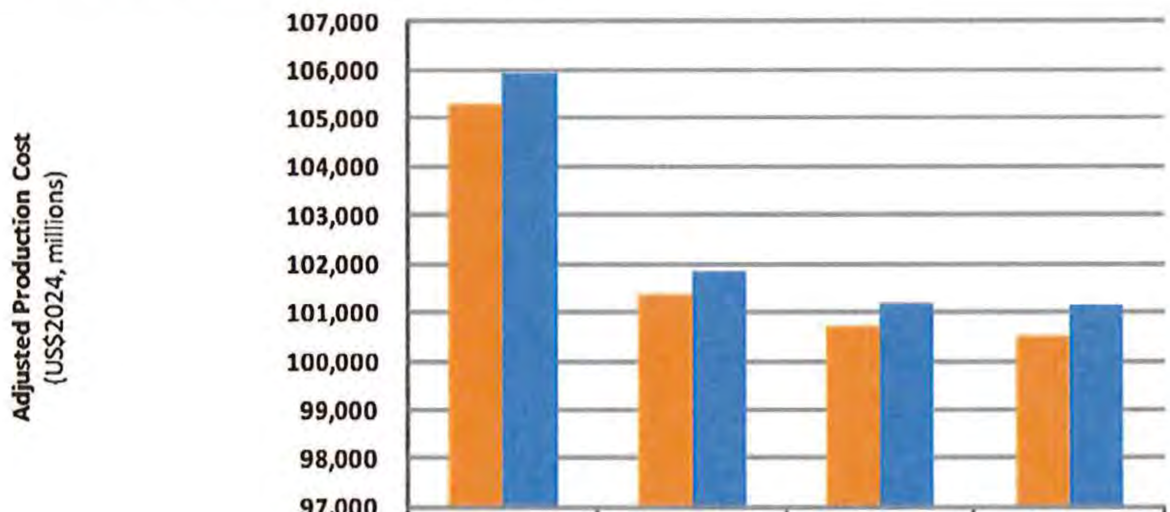
With the negative $40/MWh wind curtailment price, increased wind energy is forced into the production-cost model and results in substantial amounts of dump energy from conventional generation resources. Dump energy represents the unavoidable surplus minimum segment generation that cannot be used to serve the load because of either unit operating constraints or transmission constraints, and it occurs once the bus LMPs are negative. It is conceptual and is used only for the purpose of this report. Because the wind can be curtailed only when the bus LMPs go below negative $40/MWh, before the price can reach that point, dumping energy from conventional generation is used to produce counter congestion and increase bus LMPs to greater than zero.

BID-UP COMMITMENT LOGIC

A multistep security constrained unit-commitment and dispatch process is used in the production-cost model (refer to details in Section 3). It includes a preliminary unit-commitment step (ignoring unit operating constraints and start-up costs), the bid-up commitment step with all unit constraints and commitment bid adders applied, and the final dispatch step to complete the linear optimization solution. Because the bid-up commitment logic increases runtime significantly, the study team bypassed the second step in all the production-cost simulations performed for EWITS.

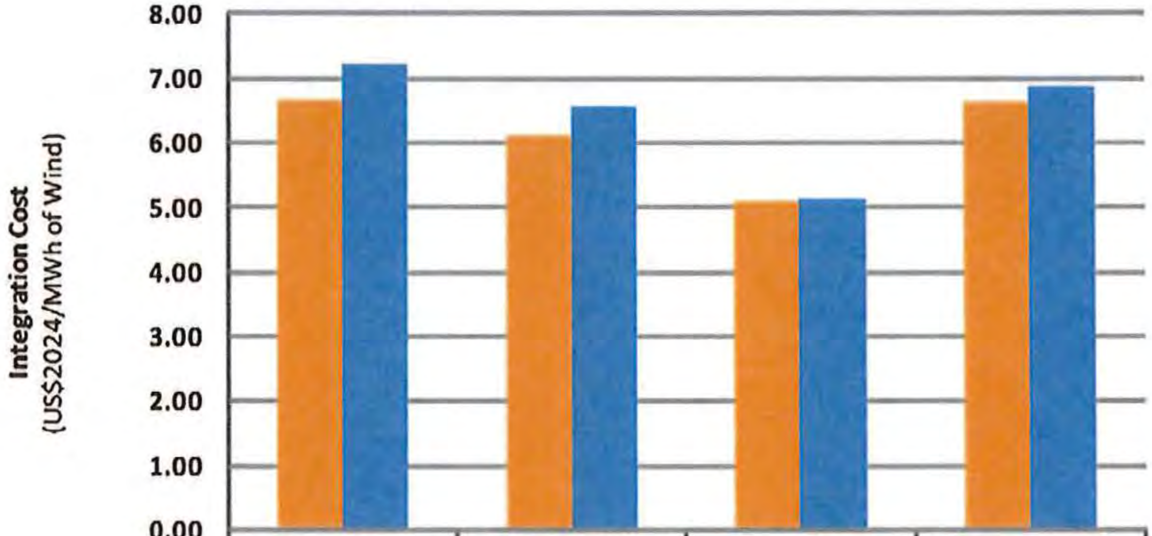
Additional production-cost simulations were run to determine the integration costs for all four EWITS wind scenarios with the bid-up commitment step included. The Technical Review Committee decided to use 2005 hourly wind and load profiles.

Figures 6-29 through 6-31 illustrate the effect of bid-up commitment logic on APC, integration costs, and regional LMPs. Enforcing unit minimum run- and downtimes, ramp rates, and unit bids, the bid-up commitment step allows more gas-fired fast-response units to be committed to meet all the unit operating constraints, and results in higher APCs and LMPs relative to the original cases with this logic bypassed. The overall effect on the integration costs is minimal for the high-penetration wind scenarios, with an increased cost range from a low of $0.03/MWh of wind energy in Scenario 3 to $0.52/MWh of wind energy in Scenario 1.



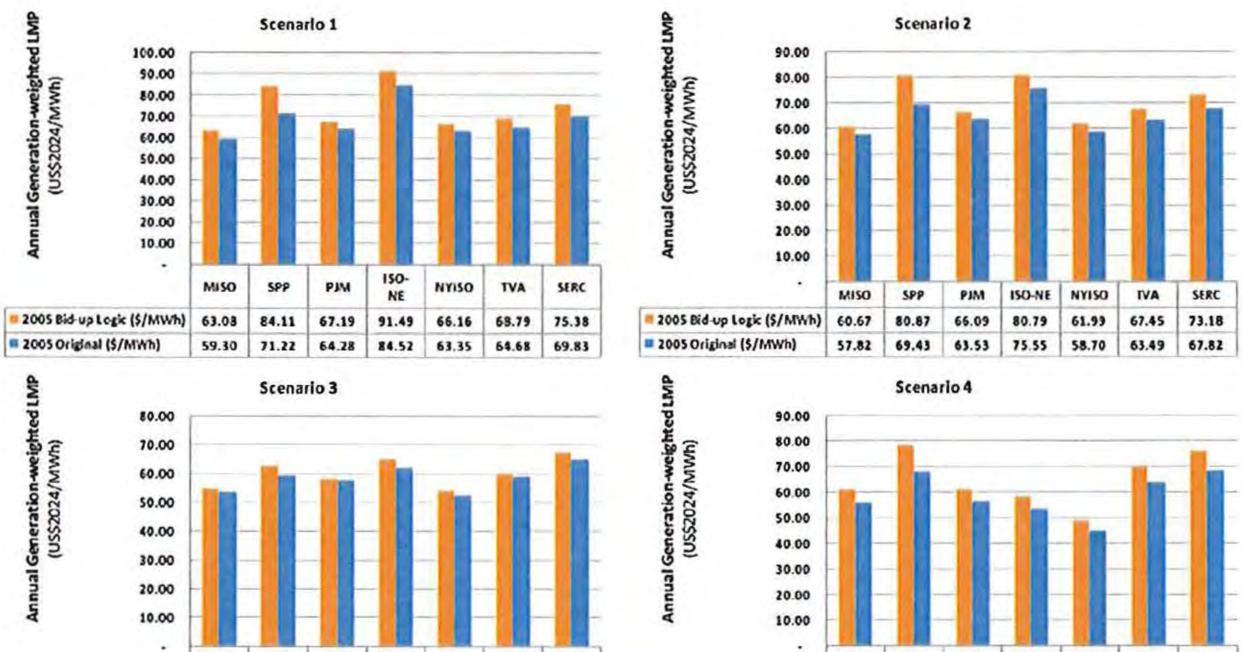
	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Original (US$2024, millions)	105,273	101,359	100,728	100,503
Bid-up Logic (US$2024, millions)	105,908	101,822	101,186	101,171

Figure 6-29. APCs with 2005 hourly wind and load patterns



	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Original ($/MWh)	6.68	6.13	5.1	6.63
Bid-up Logic ($/MWh)	7.2	6.55	5.13	6.86

Figure 6-30. Integration cost summary with 2005 hourly wind and load patterns



Scenario 1

	MISO	SPP	PJM	ISO-NE	NYISO	TVA	SERC
2005 Bid-up Logic ($/MWh)	63.08	84.11	67.19	91.49	66.16	68.79	75.38
2005 Original ($/MWh)	59.30	71.22	64.28	84.52	63.35	64.68	69.83

Scenario 2

	MISO	SPP	PJM	ISO-NE	NYISO	TVA	SERC
2005 Bid-up Logic ($/MWh)	60.67	80.87	66.09	80.79	61.99	67.45	73.18
2005 Original ($/MWh)	57.82	69.43	63.53	75.55	58.70	63.49	67.82

Scenario 3

	MISO	SPP	PJM	ISO-NE	NYISO	TVA	SERC
2005 Bid-up Logic ($/MWh)	54.79	62.60	58.12	64.88	54.13	59.72	67.19
2005 Original ($/MWh)	53.63	59.27	57.84	61.92	52.42	59.00	64.95

Scenario 4

	MISO	SPP	PJM	ISO-NE	NYISO	TVA	SERC
2005 Bid-up Logic ($/MWh)	61.35	78.00	61.09	58.28	48.57	69.67	75.86
2005 Original ($/MWh)	55.88	67.93	56.45	53.42	44.87	63.50	68.40

Figure 6-31. Annual generation-weighted LMPs with 2005 hourly wind and load patterns

HURDLE RATES

Hurdle rates are used in the production-cost model to allow regional transactions during the security-constrained unit commitment (SCUC) and dispatch process. Two separate hurdle rates were defined for unit commitment and dispatch. The dispatch hurdle rates are the economic adders between applicable price zones to reflect either regulatory tariffs or market efficiency impacts. Within a regional transmission organization (RTO), there are no hurdle rates; the hurdle rates are between RTOs. The commitment hurdle rate is a mechanism to commit pool generation for pool load and then, based on price differentials, to commit additional units to serve load outside the pool.

The project team performed sensitivity analyses on Scenarios 1 and 3 to evaluate the effect of the system-wide integrated energy market on the operational impact of wind variability and uncertainty. The regional reserve requirements remain the same as in the original cases and the hurdle rates between regions are set at zero.

Table 6-7, Table 6-8, and Figure 6-32 demonstrate how the hurdle rates affect the integration costs for Scenarios 1 and 3. The results show that allowing more economic energy interchanges under the integrated energy markets across the study footprint results in less wind curtailment, lower APCs, and regional LMPs. And there is a very modest reduction in the integration costs because of the zero hurdle rates.

TABLE 6-7. SCENARIO 1, HURDLE RATE SENSITIVITY RESULTS

SCENARIO 1	ORIGINAL	ZERO HURDLE RATE SENSITIVITY	DIFFERENCE
ANNUAL WIND ENERGY (MWh)	664,798,102	665,611,102	812,812
WIND CURTAILMENT (%)	6.38	6.27	-0.11
APCs ($)	104,125,330,202	102,203,930,939	-1,921,399,263
INTEGRATION COST ($)	5,290,351,725	4,879,216,581	-7.77
INTEGRATION COST ($/MWh of wind)	8.00	7.37	-0.63
INTEGRATION COST (% OF APC)	5.08	4.77	-0.31

TABLE 6-8. SCENARIO 3, HURDLE RATE SENSITIVITY RESULTS

SCENARIO 3	ORIGINAL	ZERO HURDLE RATE SENSITIVITY	DIFFERENCE
ANNUAL WIND ENERGY (MWh)	696,093,674	698,339,429	2,245,755
WIND CURTAILMENT (%)	3.26	2.95	-0.31
APCs ($)	99,350,363,256	98,712,905,090	-637,458,167
INTEGRATION COST ($)	3,988,497,258	3,993,564,039	0.13
INTEGRATION COST ($/MWh of wind)	5.77	5.76	-0.01
INTEGRATION COST (% OF APC)	4.01	4.05	0.03

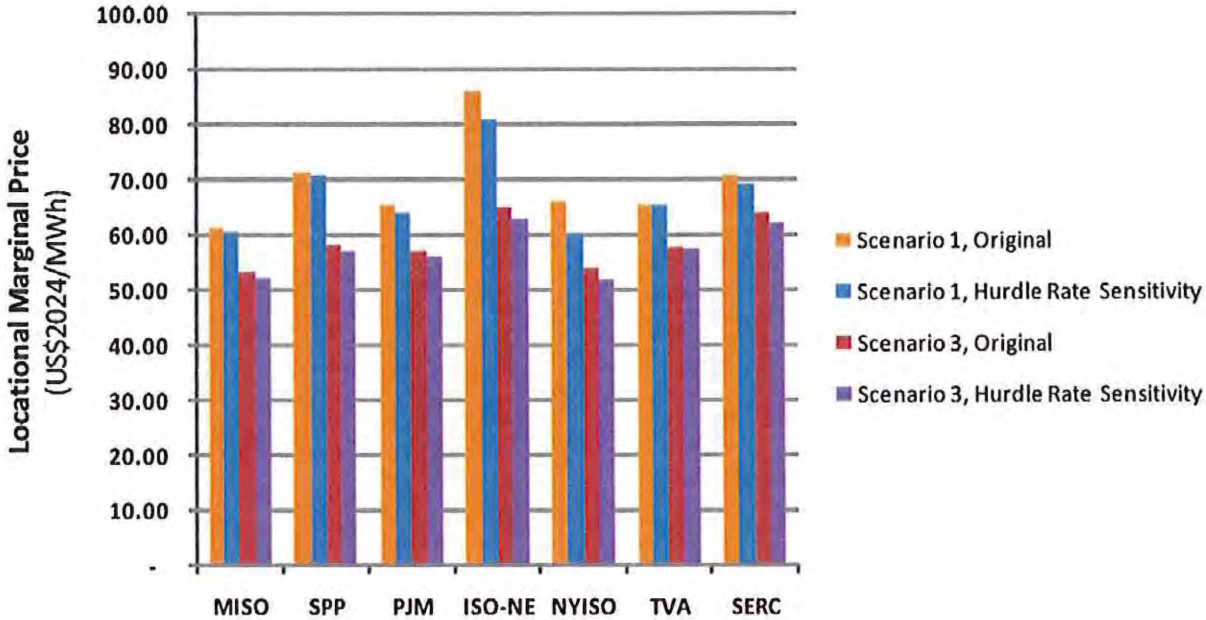


Figure 6-32. Annual generation-weighted LMP comparison

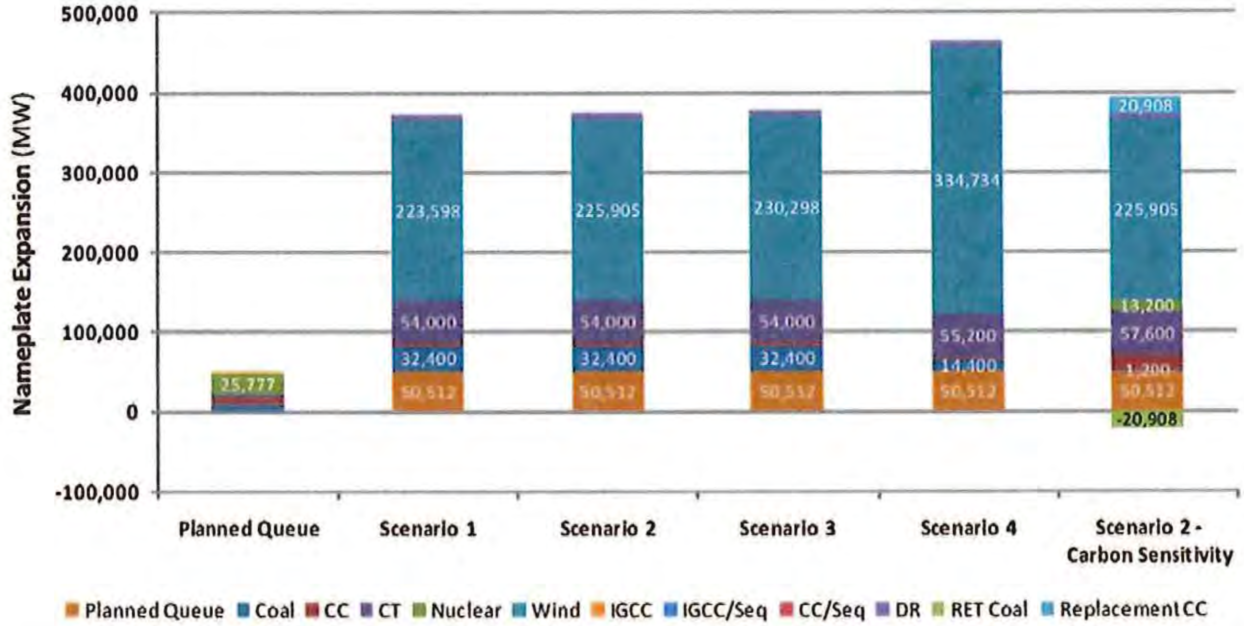
CARBON SENSITIVITY

EGEAS REGIONAL RESOURCE FORECASTING EXPANSION

The EWITS team ran a sensitivity analysis based on carbon production cost on Scenario 2. It holds all assumptions in the Electric Generation Expansion Analysis System (EGEAS) economic model the same except for the price to produce a ton of carbon. This sensitivity analysis places a cost on carbon of \$100 per ton of CO_2 starting in 2008 and escalated by inflation thereafter.

Figure 6-33 shows the nameplate capacity expansion comparison when the carbon sensitivity is applied to Scenario 2. The primary difference in the new output is that the economic benefit of base-load expansion moves from coal-fired capacity to nuclear power because of the penalty applied to the production of carbon from the coal-fired plant. Because nuclear capacity has minimum must-run requirements greater than the coal capacity, however, off-peak minimum generation events became a problem and limitations had to be set on the amount of base-load nuclear capacity that could be placed within the model.

Finally, a limited option of existing fleet retirements was offered as an alternative in the model. The retired existing coal capacity would be replaced with new combined cycle capacity. The model recognized the benefit of removing the higher carbon-producing coal facilities from the fleet and replacing them with the more moderate carbon-producing combined cycle facilities.



Notes: IGCC/Seq = IGCC with sequestration; DR = demand response; RET Coal = coal plant retirements; Replacement CC = replacement combined cycle

Figure 6-33. Capacity expansion by scenario including carbon sensitivity, 2008–2024

Energy growth will inherently increase carbon production on the system if the new energy demand is met primarily with carbon-producing resources. Within the modeling performed, however, increasing wind energy penetration to 20% of Eastern Interconnection energy requirements by 2024 (Scenarios 1 through 3) would reduce actual annual carbon production compared to 2008 modeled production by about 5% (see Figure 6-34). Increasing the wind energy penetration to 30% of the Eastern Interconnection energy requirements for 2024 (Scenario 4) reduces annual modeled carbon production nearly 19% from the 2008 production. Finally, adding the $100/ton cost to carbon for Scenario 2 produces significant carbon reduction benefits of about 33%. This, however, has significant effects on the cost of energy to the system; see Figure 6-35.

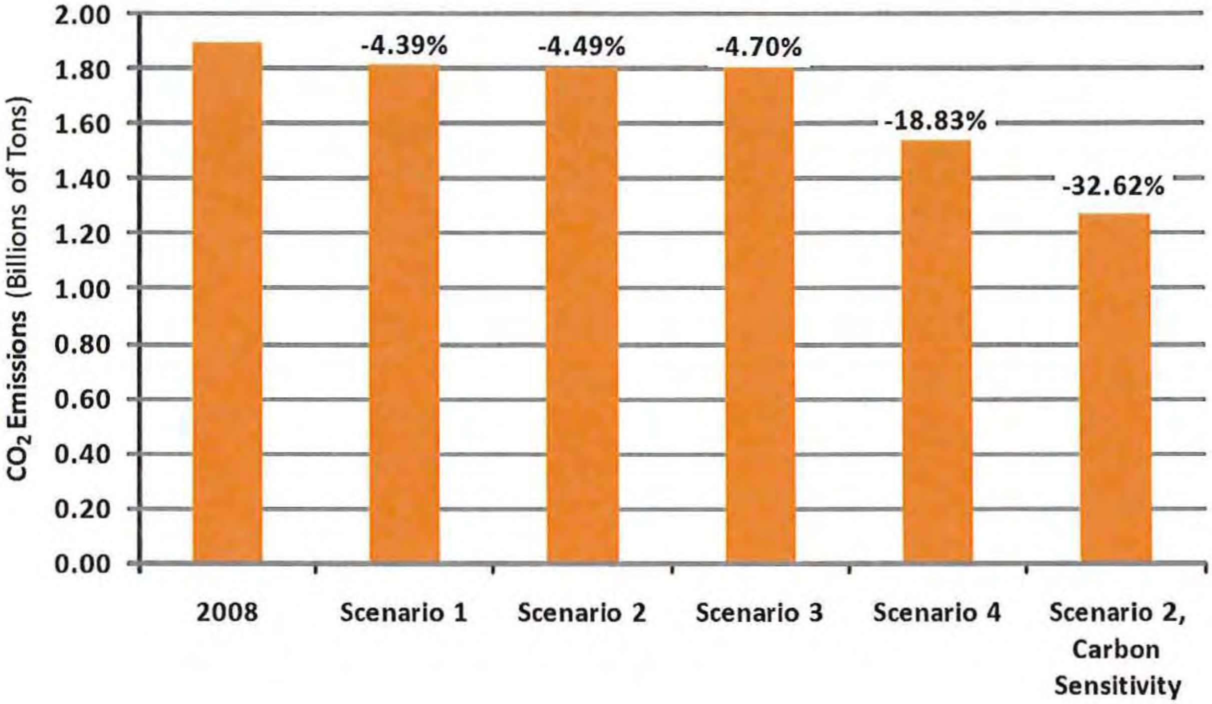


Figure 6-34. Carbon impact of modeled scenarios

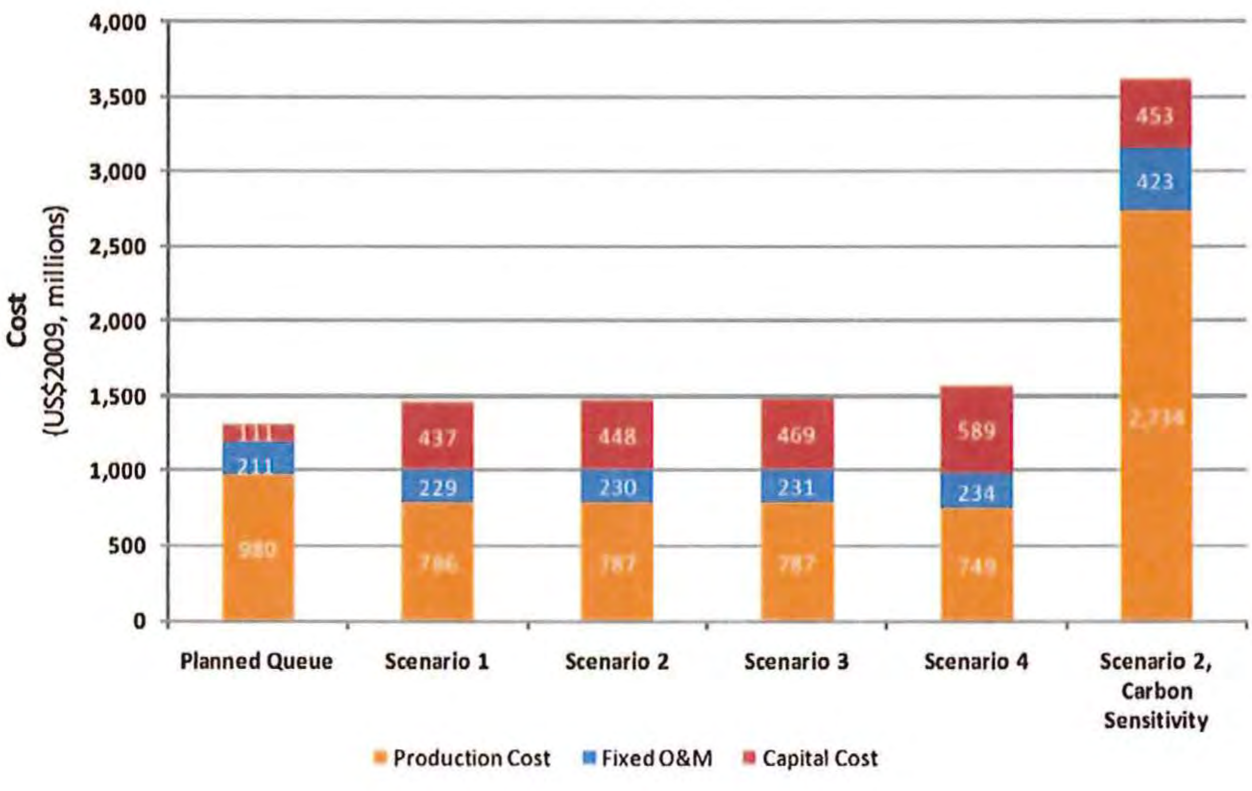


Figure 6-35. Cost impact of modeled scenarios

CAPACITY SITING FOR SENSITIVITY

Again, the EGEAS model gives only a type and a timing result of what capacity would be needed to meet resource adequacy requirements. Using the same wind locations as Scenario 2, the study team sited thermal units locally using brownfield and queue facilities. Figure 6-36 shows the locations of new generation for the carbon sensitivity scenario, along with the locations of the wind generation facilities for Scenario 2.

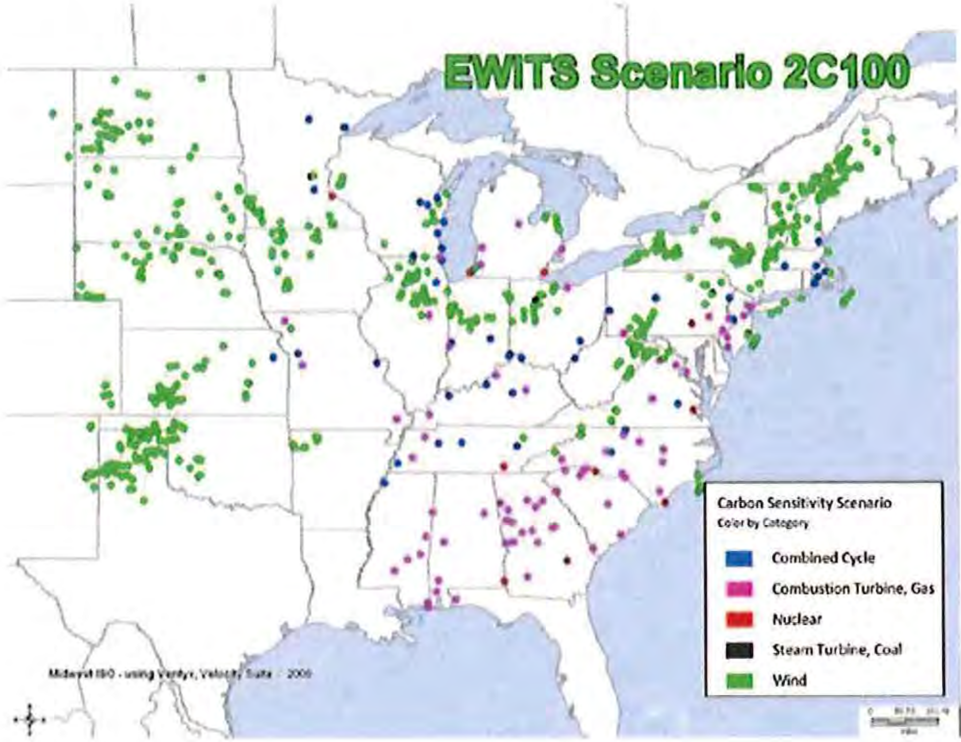


Figure 6-36. Forecast generation locations for sensitivity to Scenario 2

OPERATIONAL IMPACT ANALYSIS

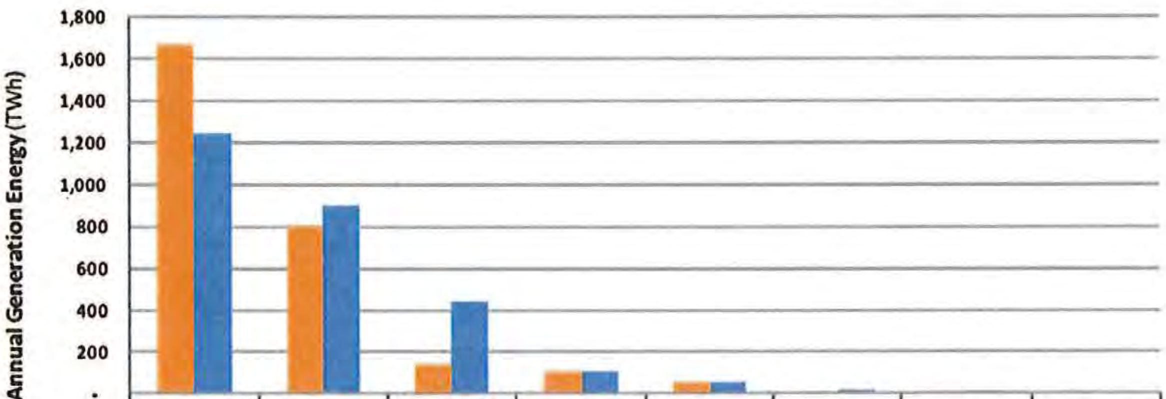
The potential effects of carbon cost on the system operational cost caused by wind variability and uncertainty were evaluated with the capacity expansion results. This sensitivity analysis used the same day-ahead wind forecasts and additional reserve requirements as in Scenario 2 with 2005 hourly wind and load patterns.

Figure 6-37 shows the annual production of conventional generation resources by fuel type. With a carbon cost penalty in capacity expansion, the base-load expansion shifts from coal-fired resources to nuclear and less carbon-intensive gas-fired combined cycle resources. This results in higher nuclear production and lower coal generation than in Scenario 2. Coal, however, is still required to meet the majority of demand compared to other types of resources.

Figure 6-38 shows the annual generation changes between the ideal and actual wind cases by fuel type and scenario with 2005 wind and load patterns.[5] As in

Scenarios 1 to 4, the carbon sensitivity scenario follows the same trend of coal-fired units displaced by primarily gas-fired combined cycle and combustion turbines. There is a significant increase in the installed combined cycle capacity in the carbon sensitivity. Because of this, the coal and combined cycle generation changes from the ideal to actual wind cases are much higher in carbon sensitivity, as seen in Figure 6-38.

Figure 6-39 shows a major increase in the average generation-weighted LMPs caused by a $100/ton carbon cost. As summarized in Table 6-9, the carbon cost penalty has a significant effect on the APC, about a 25% increase, but has little wind curtailment improvement and only a minimal integration cost reduction.



	ST Coal	Nuclear	Combined Cycle	Hydro	CT Gas	IGCC	ST Gas	Other
Scenario 2	1,667	801	146	106	55	16	13	16
Scenario 2, Carbon 100 US$2024/Ton	1,249	906	444	106	53	18	14	5

Figure 6-37. Annual generation production by fuel type with 2005 hourly wind and load patterns

[5] *Note that in the ideal case, wind generation is known perfectly and does not add within-the-hour variability. In the actual case, day-ahead forecasts of wind generation will contain some error, and more regulating reserves must be carried to deal with increased variability. The combination of additional forecast error and additional variability will favor units that are more flexible.*

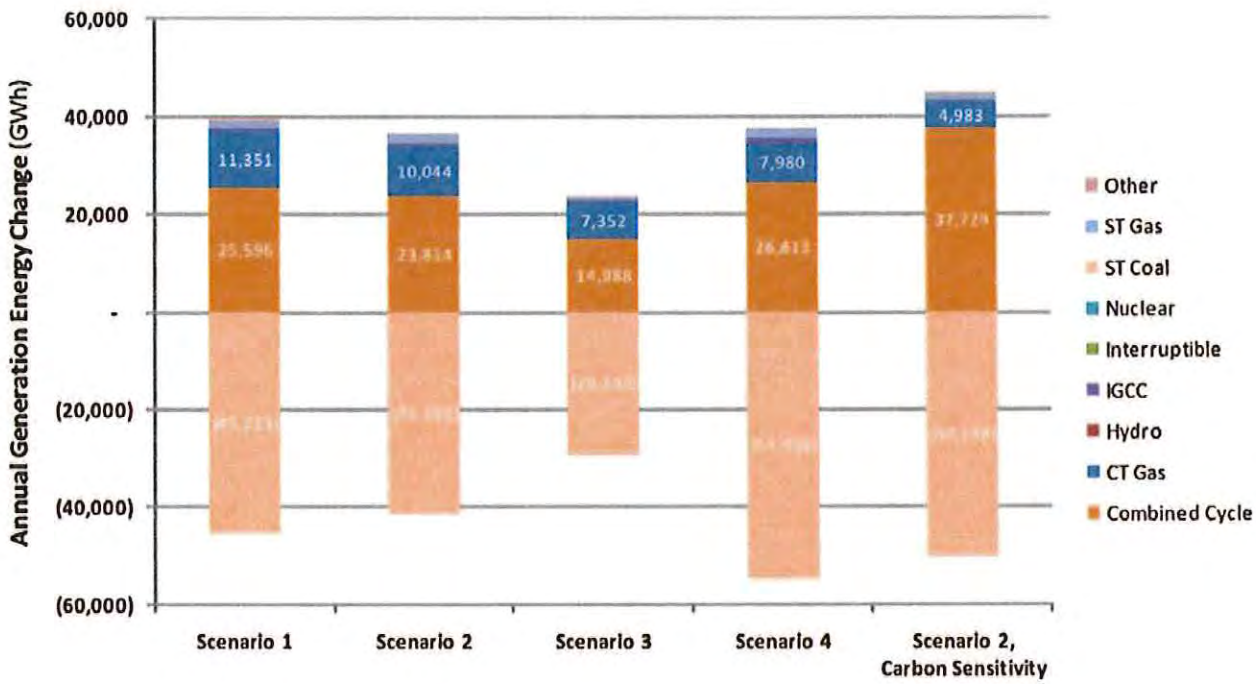
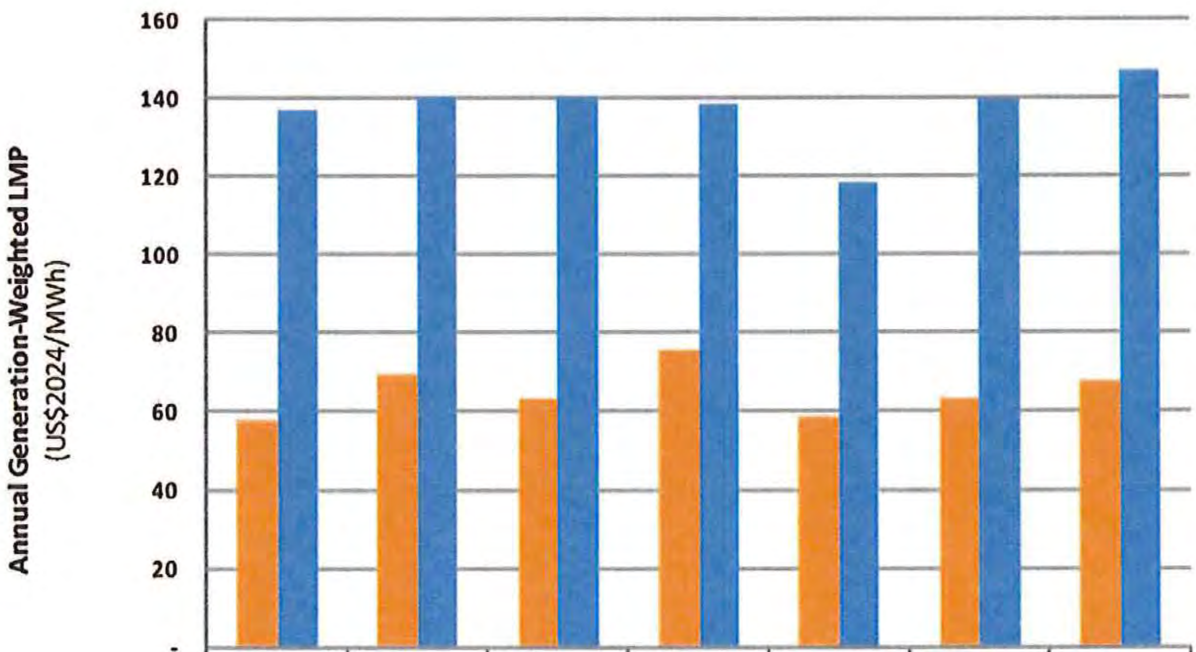


Figure 6-38. Annual generation energy changes from ideal case to actual case



	MISO	SPP	PJM	ISO-NE	NYISO	TVA	SERC
Scenario 2	57.82	69.43	63.53	75.55	58.70	63.49	67.82
Scenario 2, Carbon 100 US$2024/Ton	136.87	140.47	140.54	138.51	118.75	140.12	147.07

Figure 6-39. Annual generation-weighted LMP comparison

TABLE 6-9. SCENARIO 2, CARBON SENSITIVITY OPERATIONAL IMPACT RESULTS			
SCENARIO 2	ORIGINAL	CARBON SENSITIITY	DIFFERENCE
ANNUAL WIND ENERGY (MWh)	696,317,330	706,155,399	9,838,069
WIND CURTAILMENT (%)	6.79	5.47	-1.32
APCs ($)	101,359,089,490	127,228,010,909	25,868,921,419
INTEGRATION COST ($)	4,249,967,969	4,652,597,813	402,629,844
INTEGRATION COST ($/MWh of wind)	6.13	6.70	0.57

SECTION 7: WIND GENERATION CONTRIBUTIONS TO RESOURCE ADEQUACY AND PLANNING MARGIN

BACKGROUND

The Eastern Interconnection reliability analysis in the Eastern Wind Integration and Transmission Study (EWITS) has two goals. The first is to estimate the possible future capacity value of wind generation based on projected penetration levels and potential wind location scenarios. The second is to isolate and quantify the reliability benefits of the prospective transmission system overlay. Note that the reliability-focused analysis described in this section is an independent piece of work done separately from the economic and operation effects analysis covered in the other report sections.

ANALYTICAL APPROACH

To estimate a 2024 capacity value for wind, analysts used the 2004, 2005, and 2006 simulated wind output and historical load profiles for the same 3 years to calculate the effective load-carrying capability (ELCC) of wind at the future penetration level. This analysis was also conducted using the same four wind penetration scenarios examined in Section 2.

The four scenarios are as follows:

- Scenario 1, 20% penetration—High Capacity Factor, Onshore
- Scenario 2, 20% penetration—Hybrid with Offshore
- Scenario 3, 20% penetration—Local with Aggressive Offshore
- Scenario 4, 30% penetration—Aggressive On- and Offshore.

The team also performed three different transmission level sensitivity analyses in this study. The level of transmission being modeled varied from no ties between areas to the different transmission levels of each existing and conceptual overlay scenario. The three transmission sensitivities are as follows:

- Isolated system—stand-alone zone (no zone-to-zone interfaces modeled)
- Existing transmission system—constrained case and interface limits
- Conceptual transmission overlay—increased zone-to-zone interface limits and new ties.

ELCC CALCULATION METHODOLOGY

ELCC is defined as the amount of incremental load a resource like wind can dependably and reliably contribute to serve load, considering the probabilistic nature of generation shortfalls and random forced outages that result in load not being served. The probabilistic measure of load not being served is known as loss of load probability (LOLP), and when this probability is summed over a time frame (e.g., 1 year), it is referred to as loss of load expectation (LOLE). The accepted industry standard for what has been considered a reliable system has been the "less than 1 day in 10 years" criterion for LOLE. This measure is often expressed as 0.1 d/yr (0.1 d/yr = 1 day per 10 years), because that is often the time period (1 year) over which the LOLE index is calculated.

To measure the ELCC of a particular resource, the reliability effects of all the other sources must be isolated from the resource in question. This is accomplished by calculating the LOLE of two different cases: one with and one without the resource (Figure 7-1). Inherently, the case with the resource should be more reliable and consequently have fewer days per year of expected loss of load (smaller LOLE).

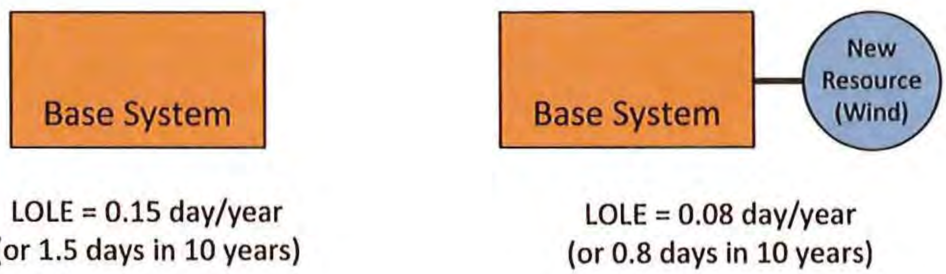


Figure 7-1. ELCC example system with and without resource

ELCC EXAMPLE SYSTEM WITH AND WITHOUT RESOURCE

The new resource in the ELCC example made the system 0.07 d/yr more reliable, but there is another way to express the reliability contribution of the new resource besides the change in LOLE. The other option requires establishing a common baseline reliability level and then adjusting the load in each case with and without the new resource to a common LOLE level (Figure 7-2). The common baseline is the industry-accepted reliability standard of the 1 day in 10 years (0.1 d/yr) LOLE criterion.

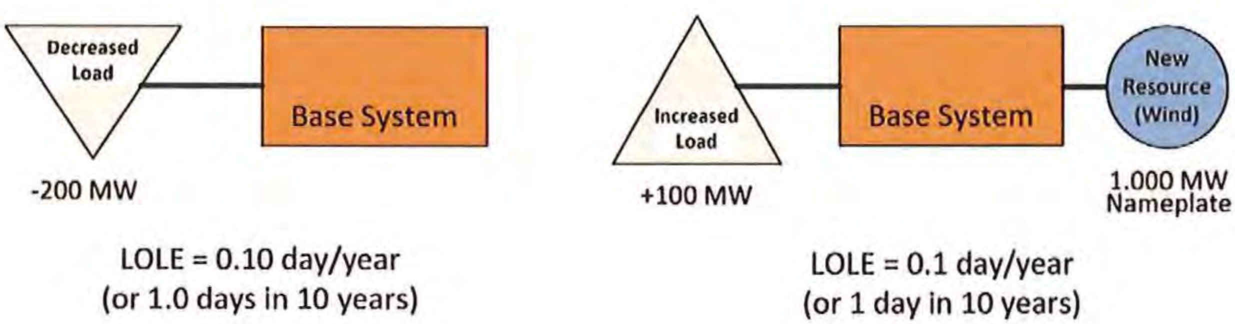


Figure 7-2. ELCC example system at the same LOLE

ELCC EXAMPLE SYSTEM AT THE SAME LOLE

With each case at the same reliability level, the only difference between them is the amount by which the load was adjusted in each case. This difference is the amount of ELCC expressed in load or megawatts (MW). Sometimes this number is divided by the nameplate rating of the new resource and then expressed as a percentage. The new resource in the ELCC example has an ELCC of 300 MW, or 30% of the resource nameplate.

The same analytical approach used in this simple single-zone example was employed to calculate ELCC in the much more complex Eastern Interconnection system, with one very slight simplification. EWITS analysts used the LOLE model in GE Energy's Multi-Area Reliability Simulation (GE-MARS) program, and in that model, a load-modifying resource is adjusted in each interconnected zone to make the LOLE equal to 0.1 d/yr. In EWITS, this was performed instead of adjusting the 8,760 hourly load values of each of the multiple zones for each of the different hourly profiles and scenarios being studied. This modeling technique is implemented in the software program by means of the LOLE calculation and does not result in any difference from the indirect load adjustment method.

LOLE MODEL INPUT ASSUMPTIONS

The source for all LOLE model input data was the same database and source used to develop PROMOD IV. The data were conditioned into the correct format for use in the LOLE model. Because the GE-MARS LOLE model uses a transportation style of modeling, which consists of a system of interconnected zones (sometimes referred to as areas), those zones must be defined. This requires data to be aggregated and organized up to the level of the defined zones and interface limits between these zones must be calculated. Analysts used predefined regional and subregional planning areas as the modeling zones for this study; they are listed in Table 7-1 with their total nameplate amount of wind for each study scenario.

TABLE 7-1. RELIABILITY ZONES FOR LOLE ANALYSIS WITH INSTALLED WIND GENERATION CAPACITY (NAMEPLATE WIND IN MEGAWATTS)				
ZONE	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4
MISO West	59,260	39,953	23,656	59,260
MISO Central	12,193	11,380	11,380	12,193
MISO East	9,091	6,456	4,284	9,091
MAPP USA	13,809	11,655	6,935	14,047
SPP North	48,243	40,394	24,961	50,326
SPP Central	44,055	46,272	25,997	44,705
PJM	22,669	33,192	78,736	93,736
TVA	1,247	1,247	1,247	1,247
SERC	1,009	5,009	5,009	5,009
NYISO	7,742	16,507	23,167	23,167
ISO-NE	4,291	13,837	24,927	24,927
Entergy	0	0	0	0
IESO	0	0	0	0
MAPP Canada	0	0	0	0
FULL STUDY SYSTEM	**223,609**	**225,902**	**230,299**	**337,708**

Notes: Midwest ISO is shortened to MISO here because of space considerations. Other definitions follow: MAPP = Mid-Continent Area Power Pool; SPP = Southwest Power Pool; PJM = PJM Interconnection; TVA = Tennessee Valley Authority; SERC = Southeastern Electric Reliability Council (Entergy is operated as part of SERC); NYISO = New York ISO; ISO-NE = New England ISO; IESO = Independent Electricity System Operator.

The last step in developing the LOLE model and the input parameters was to calculate the interface limits between the study zones. Because of its ability to realistically model unit operating characteristics and produce detailed hourly output, the study team used PROMOD IV to calculate these interface limits. PROMOD IV runs were conducted for each zone on an import basis, meaning that dispatchable generators within the zone are given a penalty factor to induce flow from outside the zone to inside the zone. Interfaces were defined and import flows were monitored and recorded. The hourly interface flow values (8,760 values) were filtered down to only those values that occur at the time of the each zone's daily peak load (365 values). The logic behind using only those interface flow values is derived from the use of the daily LOLE index, which is also calculated over the same daily peak load hours. These values were then averaged into monthly interface numbers, which is what the LOLE model program uses. This calculation was performed for every zone and every scenario twice, once with only the existing transmission system and once with the new additional transmission system of the scenario overlays included. Figures 7-3 through 7-10 show the results of these calculations. The diagrams also illustrate the interconnectivity of the zones for each scenario and transmission sensitivity. Note that for simplicity, only the values for August are shown in the diagrams (August is the study system's peak load month).

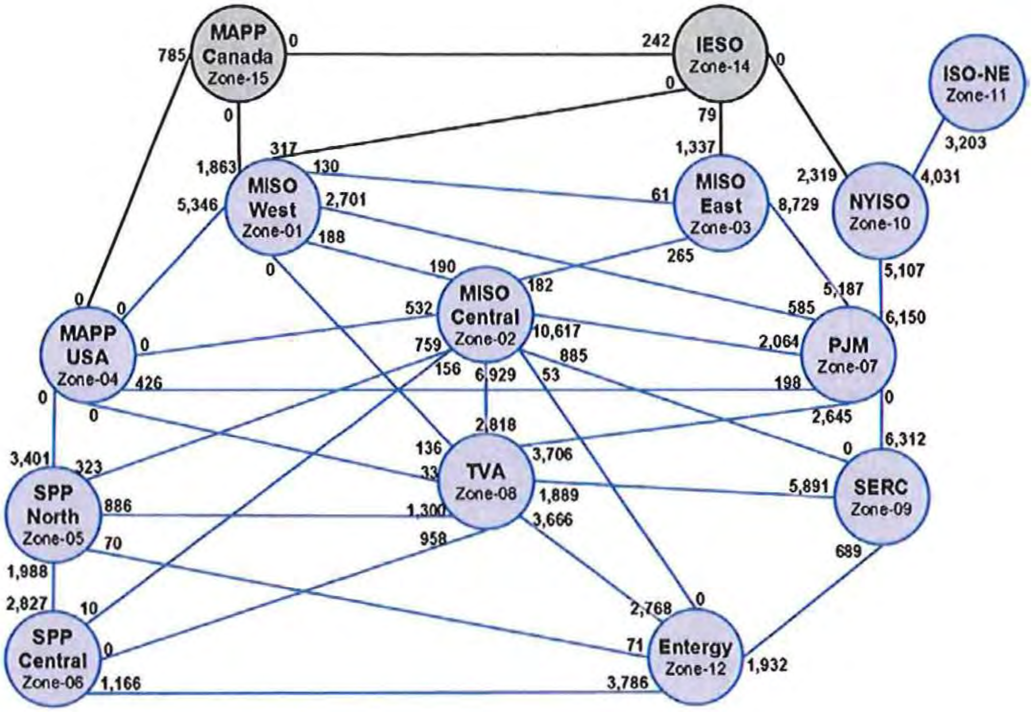


Figure 7-3. Scenario 1, existing transmission system August interface limits (MW)

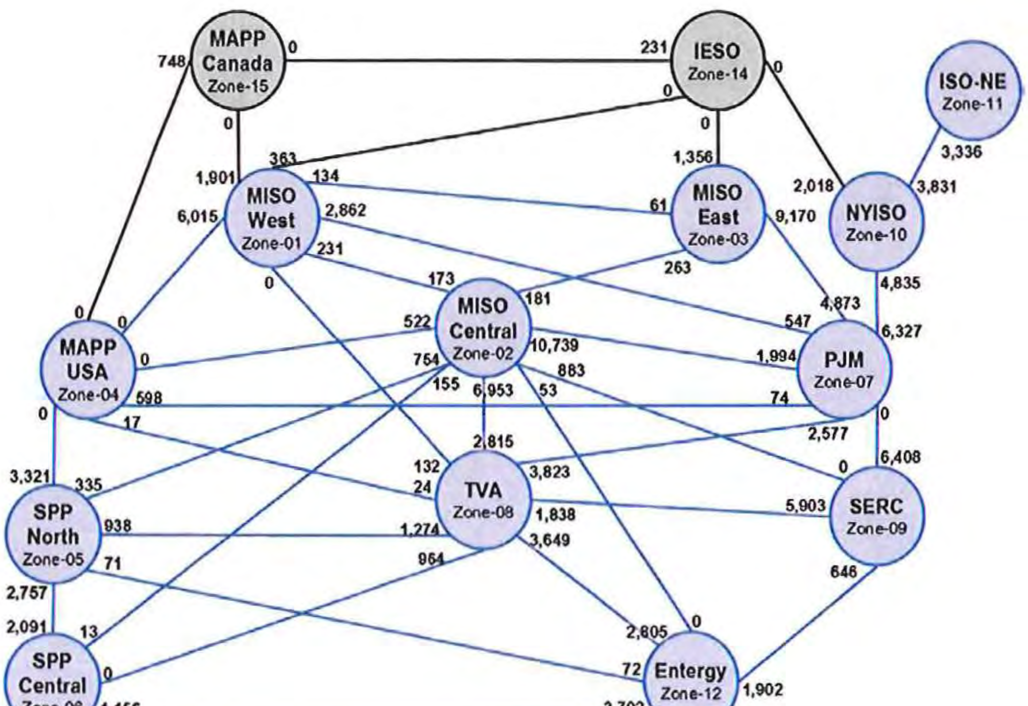


Figure 7-4. Scenario 2, existing transmission system August interface limits (MW)

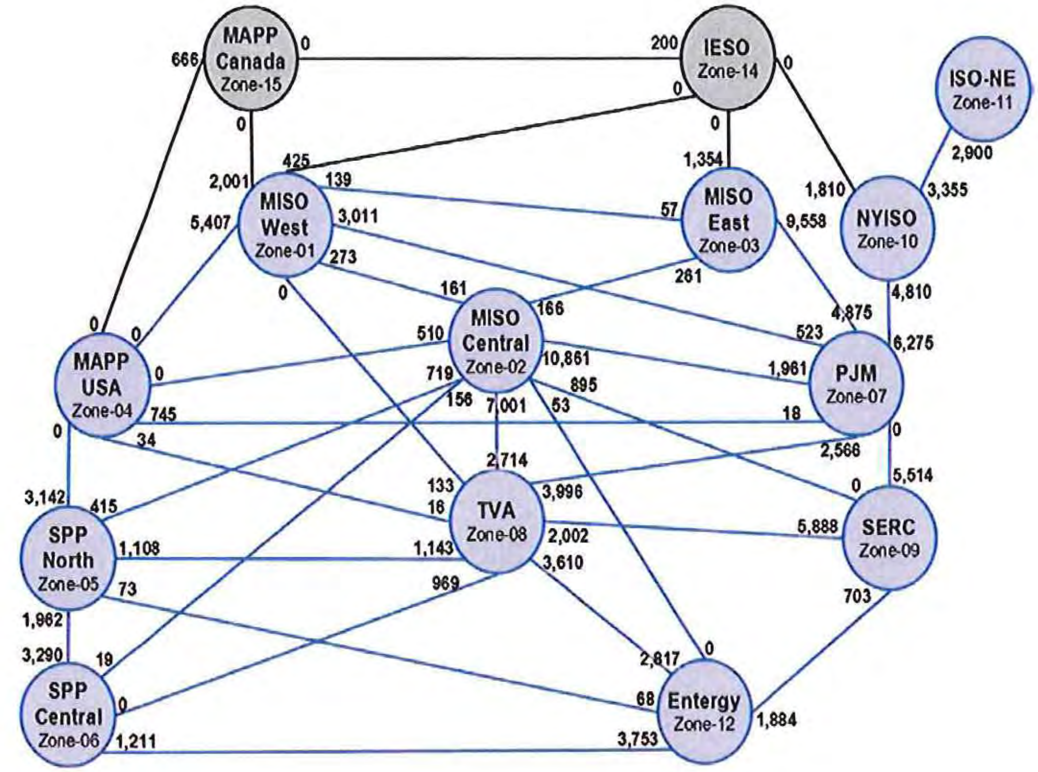


Figure 7-5. Scenario 3, existing transmission system August interface limits (MW)

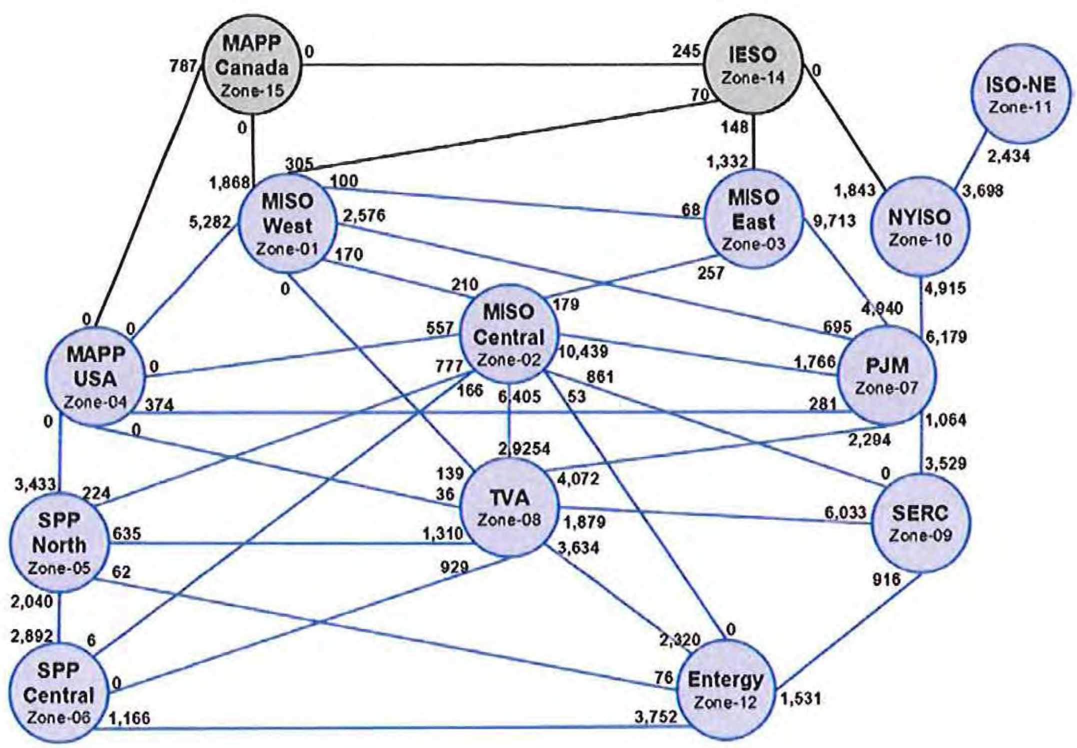


Figure 7-6. Scenario 4, existing transmission system August interface limits (MW)

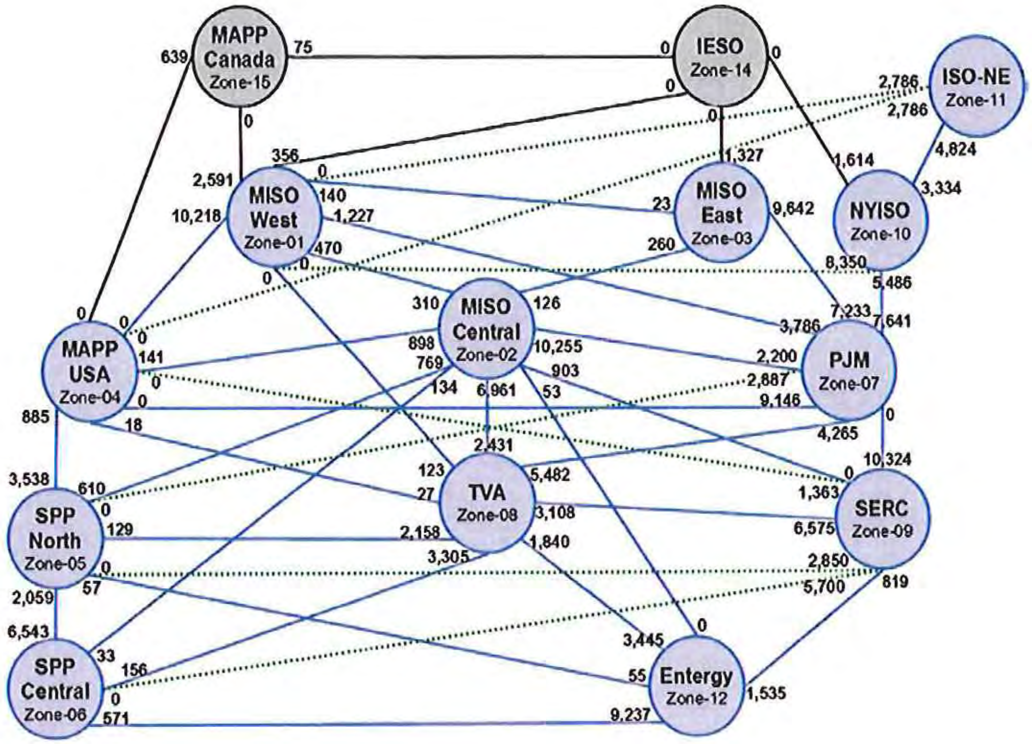


Figure 7-7. Scenario 1, conceptual transmission overlay August interface limits (MW)

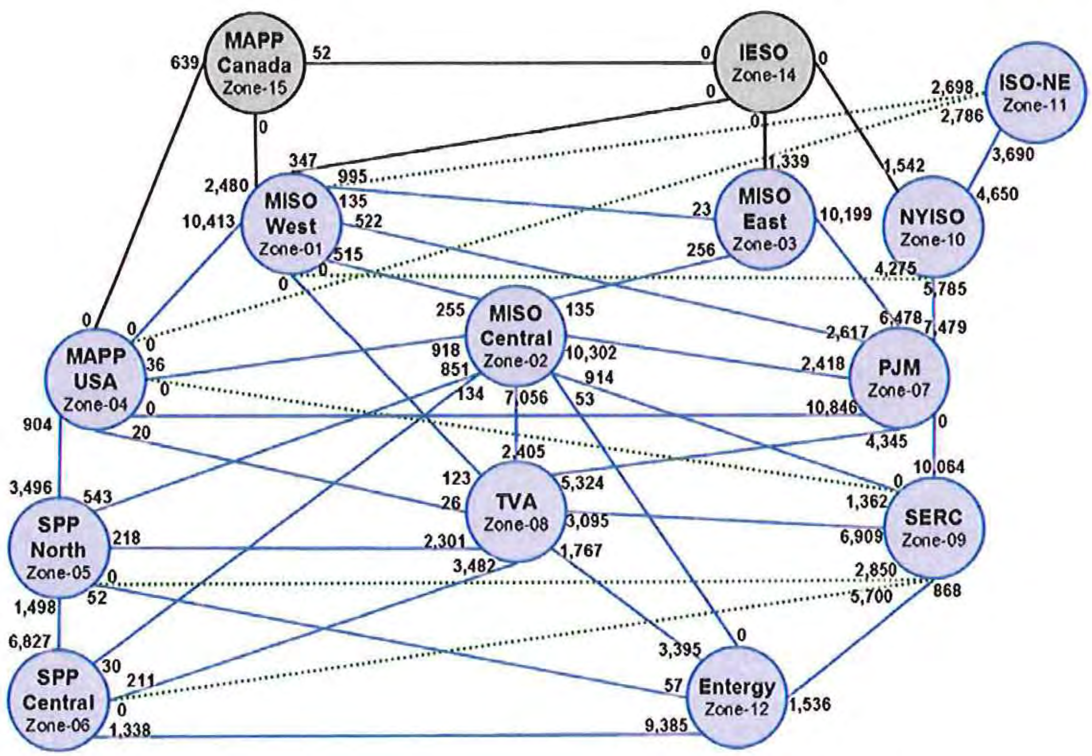


Figure 7-8. Scenario 2, conceptual transmission overlay August interface limits (MW)

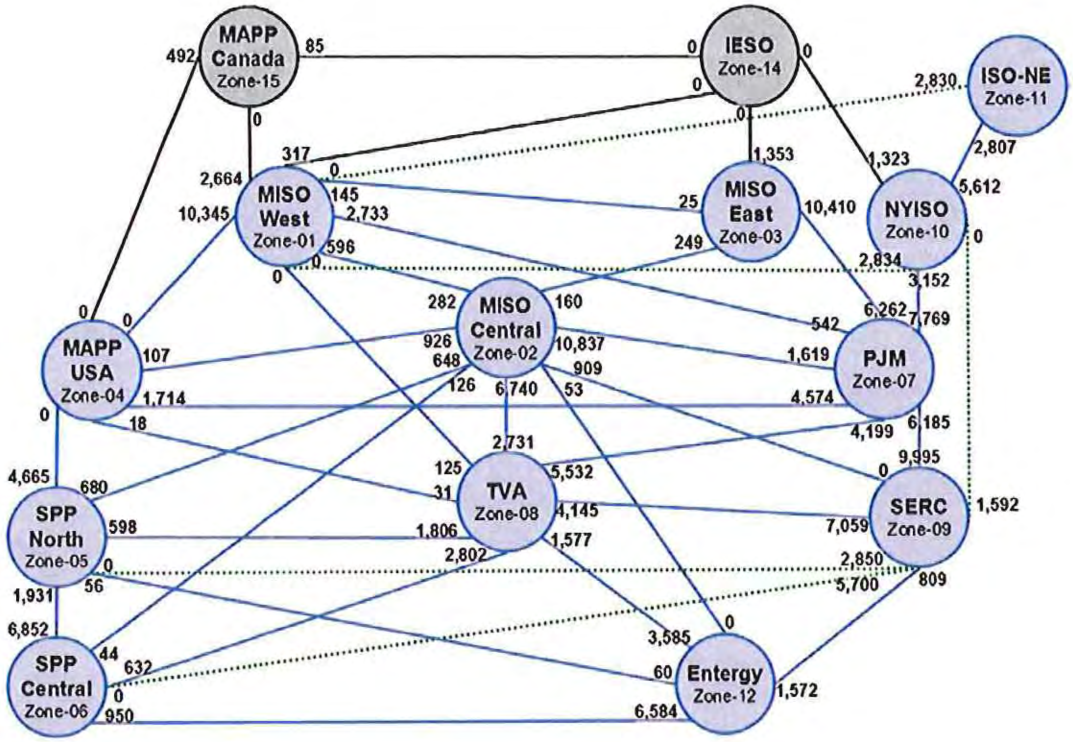


Figure 7-9. Scenario 3, conceptual transmission overlay August interface limits (MW)

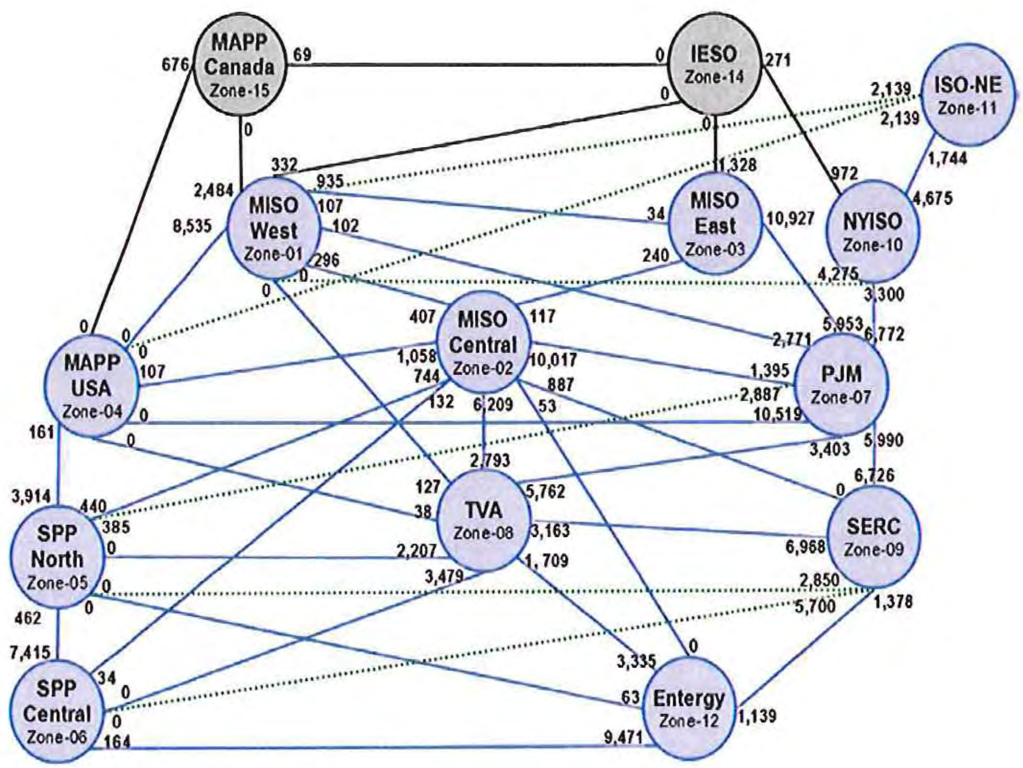


Figure 7-10. Scenario 4, conceptual transmission overlay August interface limits (MW)

RESULTS

ISOLATED SYSTEM

Table 7-2 shows the ELCC results summed over the entire Eastern Interconnection study system on an isolated system basis for the four wind penetration scenarios and three different profiles studied. "On an isolated system basis" means that there is no transfer capability or ties between any of the zones and thus no ability to share the wind resource with the rest of the system. This transmission sensitivity limits the wind capacity to serving load only in the zone where the wind resource is actually located.

TABLE 7-2. ELCC RESULTS FOR ISOLATED SYSTEM (NO TIES)

RESULTS	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4
Nameplate Wind (MW)	223,609	225,902	230,299	337,708
2004 Profile-ELCC (MW)	32,144	35,868	41,264	54,408
2004 Profile-ELCC (%)	14.4	15.9	17.9	16.1
2005 Profile-ELCC (MW)	31,433	40,322	46,484	54,218
2005 Profile-ELCC (%)	14.1	17.8	20.2	16.1
2006 Profile-ELCC (MW)	36,126	43,986	53,375	63,586
2006 Profile-ELCC (%)	16.2	19.5	23.2	18.8

EXISTING TRANSMISSION

Table 7-3 shows the ELCC results under the transmission sensitivity of using only the existing transmission system. This allows for transfer capability and ties between zones at levels of today's existing infrastructure. Figures 7-3 through 7-6 show these tie configurations and interface limits for all four scenarios.

TABLE 7-3. ELCC RESULTS FOR EXISTING TRANSMISSION SYSTEM

RESULTS	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4
Nameplate Wind (MW)	223,609	225,902	230,299	337,708
2004 Profile-ELCC (MW)	35,708	42,468	52,286	68,932
2004 Profile-ELCC (%)	16.0	18.8	22.7	20.4
2005 Profile-ELCC (MW)	45,216	54,764	60,765	69,655
2005 Profile-ELCC (%)	20.2	24.2	26.4	20.6
2006 Profile-ELCC (MW)	44,560	53,864	70,155	83,007
2006 Profile-ELCC (%)	19.9	23.8	30.5	24.6

OVERLAY TRANSMISSION

Table 7-4 shows the ELCC values calculated for the transmission sensitivity case of the conceptual transmission overlay system. The overlay transmission system increases the transfer capability between zones and allows more of the wind capacity to serve load outside the zone where it is physically located. The transmission overlay consists of multiple new DC and AC lines in various different configurations in each of the four scenarios; these lines both increase the transfer limits and add new interfaces between the zones. These changes in interface limits and new ties can be seen in Figures 7-7 through 7-10.

TABLE 7-4. ELCC RESULTS FOR OVERLAY TRANSMISSION SYSTEM				
RESULTS	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4
Nameplate Wind (MW)	223,609	225,902	230,299	337,708
2004 Profile-ELCC (MW)	61,884	61,655	65,205	89,763
2004 Profile-ELCC (%)	27.7	27.3	28.3	26.6
2005 Profile-ELCC (MW)	56,737	63,248	64,711	83,807
2005 Profile-ELCC (%)	25.4	28.0	28.1	24.8
2006 Profile-ELCC (MW)	53,956	60,913	75,552	100,680
2006 Profile-ELCC (%)	24.1	27.0	32.8	29.8

Figure 7-11 shows the ELCC results for both the existing and the overlay transmission systems. The figure also illustrates how the ELCC increased in the overlay system because the conceptual overlay increased the transfer capability between zones. These results are depicted for the four scenarios, and the different colors represent the three yearly profiles studied.

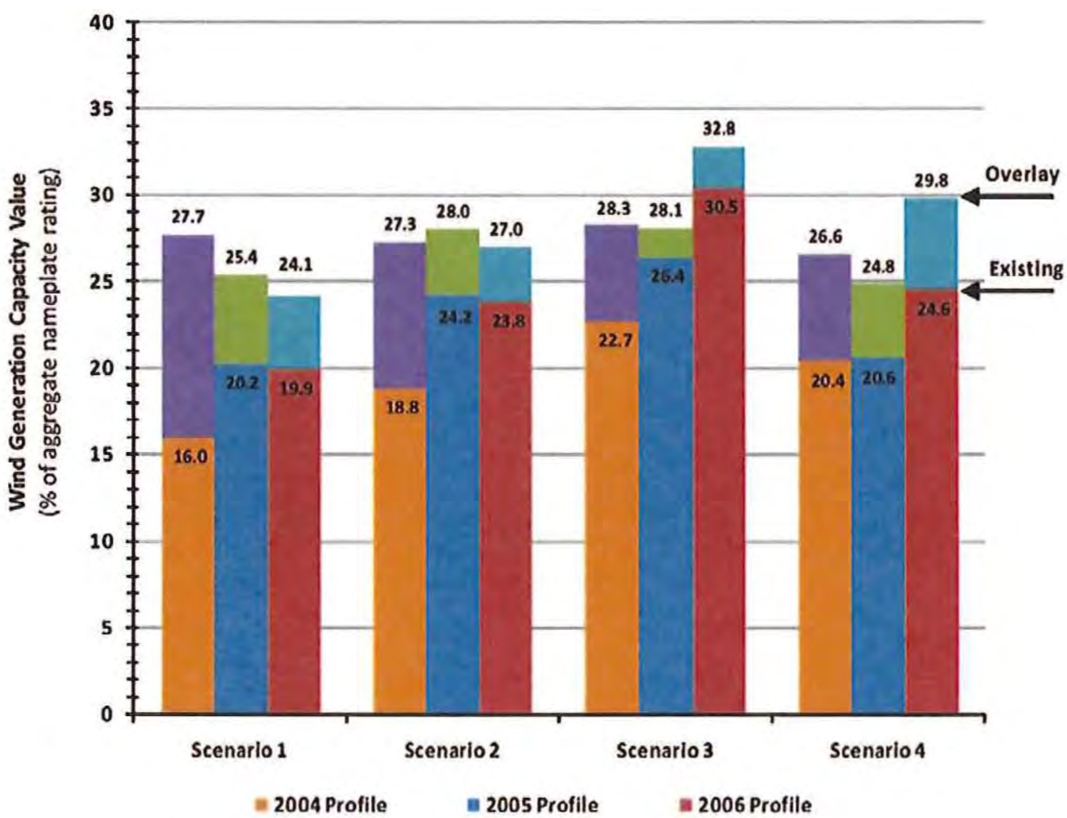


Figure 7-11. ELCC results for existing and overlay transmission

TIE-ONLY BENEFITS

Figure 7-12 and Table 7-5 show the total and incremental benefits gained from including ties in the system, without including any of the benefits from wind. These tie-only LOLE benefits are calculated by looking only at the cases without any wind resources modeled and then comparing the isolated system results with those of an interconnected system such as the existing and overlay transmission systems. Clearly, significant benefits are gained from an interconnected system. These results show that roughly 50,000 MW of benefits in the Eastern Interconnection system are gained from the existing transmission system because it operates as an interconnected system. These benefits would not be realized if each of the zones were not part of an interconnected system, meaning that they would function like an isolated system.

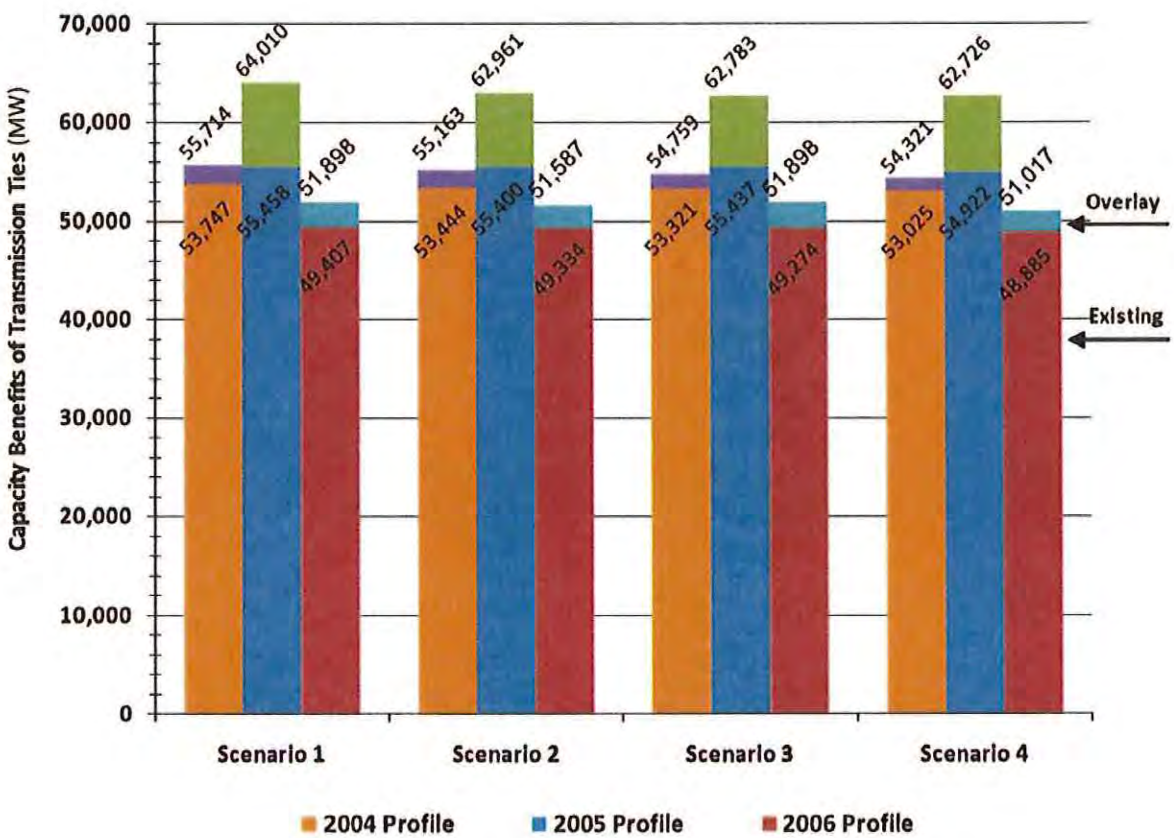


Figure 7-12. Tie benefit results for existing and overlay transmission

TABLE 7-5. BENEFITS FROM OVERLAY						
		LOLE TIE BENEFITS (MW)	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4
PROFILE	2004	Existing Transmission System	53,747	53,444	53,321	53,025
		Conceptual Overlay System	55,714	55,163	54,759	54,321
		LOLE Tie Benefits from Overlay	**1,967**	**1,719**	**1,438**	**1,296**
	2005	Existing Transmission System	55,458	55,400	55,437	54,922
		Conceptual Overlay System	64,010	62,961	62,783	62,726
		LOLE Tie Benefits from Overlay	**8,552**	**7,561**	**7,346**	**7,804**
	2006	Existing Transmission System	49,407	49,334	49,274	48,885
		Conceptual Overlay System	51,898	51,587	51,898	51,017
		LOLE Tie Benefits from Overlay	**2,491**	**2,253**	**2,624**	**2,132**

ANALYSIS

WIND CONTRIBUTION

The ELCC results from this analysis based on the four wind penetration scenarios and three simulated wind output and historical load profiles (2004, 2005, and 2006) show that the wind resource can achieve >24% capacity contribution to serving load with the conceptual transmission overlay added. The existing transmission system without the transmission overlay could expect to achieve 16% or greater capacity contribution. The findings discussed here are the conservative lower bounds of the overall study results because of the risk associated with overestimating the capacity contribution of wind.

Discretion and prudence must be practiced when considering these results. This analysis looked at only three different yearly profiles, and the results vary year by year. Many more profiles would need to be simulated and studied to begin to form statistically based confidence levels around these results. Another thing to consider is the limitation of using a transportation-style model. Although there are interface limits and ties between study zones, it is still assumed that there are no internal constraints or deliverability issues within the study zones. When splitting and dividing a system of this size and magnitude into a configuration of study zones, some liberties must be exercised when defining large zones.

OVERLAY CONTRIBUTION

The LOLE-based tie benefits illustrate that the conceptual transmission overlay incrementally adds to the tie benefits of the existing transmission system. The overlay adds from 1,200 to 8,500 MW of tie benefits to the Eastern Interconnection system. These benefits indicate that the conceptual transmission overlay would help move capacity needed for resource adequacy out of one area where it is not particularly needed into another area where it is needed. With the conceptual transmission overlay in place, there is less need for new power plants.

As with the ELCC results, discretion must be practiced when looking at these results. These values can vary greatly among the historical profiles studied. The LOLE tie benefits depend greatly on the amount of capacity a particular area needs at a specific time and simultaneously on how much reserve is available in the rest of the system. The tie benefits, then, depend on the overall diversity of a system, which can vary greatly and yearly throughout the entire Eastern Interconnection.

SECTION 8: SYNTHESIS AND IMPLICATIONS

NOTES ON THE ANALYTICAL METHODOLOGY

The analytical methodology used in the Eastern Wind Integration and Transmission Study (EWITS) conforms to the economic transmission expansion procedure illustrated in Figure 8-1. The National Renewable Energy Laboratory's (NREL) mesoscale data set for the eastern United States was the starting point for EWITS. After doing some initial characterization, the study team defined four wind generation scenarios by selecting specific wind plants from the database. Wind plant locations in each scenario were mapped into a generation expansion model that estimated the amount of new conventional generation that would be required across the Eastern Interconnection in 2024 to serve load and ensure a sufficient level of resource adequacy.

To begin the transmission overlay development process, the EWITS team incorporated new generation from the expansion process and wind from the defined scenarios into a chronological production simulation model. Comparing a case with transmission constraints enforced to one with no transmission constraints allowed calculation of annual congestion charges over constrained interfaces in the production model. The congestion charges then served as the basis for the design of overlay transmission and regional transmission upgrades to move energy from sources to sinks.

Hourly and subhourly profile data corresponding to the selected wind plants and 2024 load data were also used in various statistical analyses. These analyses were designed to determine the requirements for regulation and operating reserves that would be needed in each of the operating areas to manage the incremental variability and uncertainty introduced by wind generation.

Wind generation, new nonwind generation, transmission overlay designs, and results of the statistical analysis were merged into a new set of annual production simulations. The objective here was to simulate as closely as possible the operation of individual operating pools or markets in the Eastern Interconnection, along with their economic interactions. The same approach was used to estimate the operating cost of the incremental variability and uncertainty introduced by wind generation.

The production model was also the basis for analyzing resource adequacy. The comprehensive loss of load expectation (LOLE) analysis looked at the contribution of wind generation to resource adequacy for individual regions in isolation, with existing transmission ties, and with the transmission overlays developed in the earlier step. Running cases with and without wind generation allowed the project team to calculate the effective load-carrying capability (ELCC) of wind generation in each scenario. Figure 8-1 clearly shows that the procedure was intended to be iterative. In other words, more than one pass through the analyses that make up the process would allow for reconciliation of inconsistencies among interim results and for improvement of subsequent outcomes. In EWITS, only a single pass was possible because of the very large study scope and schedule limitations.

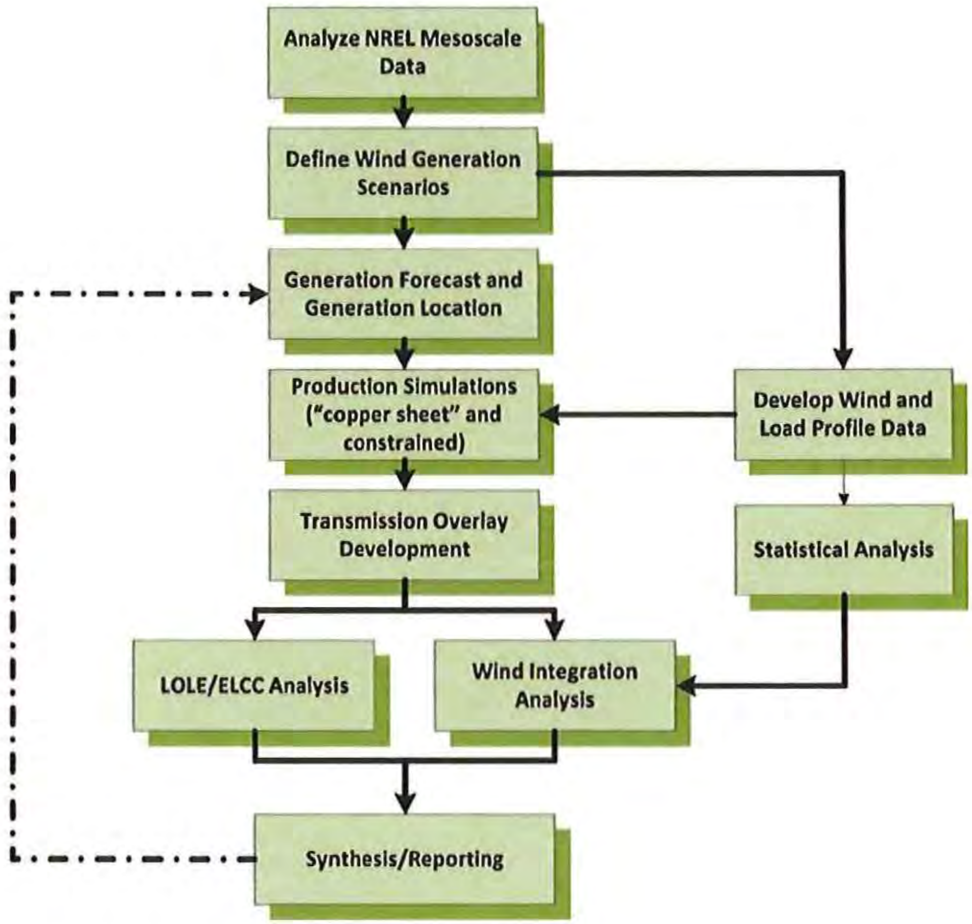


Figure 8-1. Flow diagram for study analytical methodology

Bottom-up processes make decisions from the present to the future based on annual incremental expansions. Most previous transmission expansions used bottom-up processes; most states, for example, use such a process for approval of projects from a list of alternatives. Each transmission line is decided one at a time to meet near-term resource adequacy or delivery requirements. Bottom-up processes are usually based on resolving line-loading or voltage-level problems associated with reliability criteria.

The EWITS study team used top-down economic methods to design the conceptual transmission expansion. These methods tend to create transmission designs with more transmission than bottom-up transmission methods, primarily because the total economic potential of increasing the economic efficiency of the generation fleet, including wind generation in the Eastern Interconnection, is used to justify transmission. The combination of capturing the economic potential of nonwind and wind generation loads transmission lines to high load factors, resulting in more efficient use of the transmission. The transmission requirements are mainly off peak for the wind generation and on peak for the nonwind generation.

Previous sections of this report focused on results from the individual analytical steps of the process. This section brings together the various results of the analyses for an overall perspective.

TOTAL COSTS

Each EWITS scenario created for 2024 results in a picture of the Eastern Interconnection that is substantially different from what is in place today. The changes made include adding very large amounts of wind, regional and overlay transmission, and conventional generation. As described earlier, the top-down method leads to a snapshot of 2024; it does not consider the evolution of today's power system through time to get to 2024. After refining each scenario through additional iterations of the study process, more conventional planning methods would be employed to fill in the details of the evolution over time, along with even further refinement.

Components of cost and the approaches for tabulating them are described next.

ASSUMPTIONS

Costs for each scenario comprise both capital investment and production-related costs. To better compare between scenarios, the team annualized capital costs. Table 8-1 gives the assumptions used for capital costs.

TABLE 8-1. ASSUMPTIONS USED IN SCENARIO COST CALCULATIONS

TYPE	LEVELIZED FIXED CHARGE RATE (%)	CAPITAL COST, US$2008 ($/kW[a])
COAL	12.50	1,833
COMBUSTION TURBINE (CT)	12.43	597
COMBINED CYCLE (CC)	12.50	857
NUCLEAR	12.53	2,928
ONSHORE WIND	11.92	1,875
OFFSHORE WIND	11.92	3,700
TRANSMISSION	15	NOT APPLICABLE
ESCALATION	3	NOT APPLICABLE

[a] *kW = kilowatt*

CAPITAL COSTS—NEW GENERATION

The economic transmission development process began with a conventional generation expansion exercise. Its purpose was to ensure that there is adequate generation in the case to meet the load reliably in the future year being studied. For this study, the expansion was performed by first siting the wind generation for each scenario, then determining what new generation would be required to maintain regional resource adequacy.

Wind generation was assigned a capacity value of 20% of nameplate for the generation expansion runs. The LOLE analysis described in Section 7 revealed that the actual capacity value with the overlay transmission was higher than 20% for all scenarios. To compensate, the original conventional generation expansion could be adjusted downward to reflect the fact that, with wind generation and transmission, a certain amount of that capacity would not be needed for resource adequacy. Given that capital costs for conventional generation technologies vary widely, the adjustment cannot be done without further iterations of the generation expansion model. Consequently, the conventional generation capital costs in EWITS are based on a wind generation capacity value of 20%.

CAPITAL COSTS—NEW TRANSMISSION

Section 4 covered the cost of regional and overlay transmission for each scenario. Here, the amounts are capitalized using a fixed charge rate of 15%. The transmission capital costs include estimates for the extra-high voltage (EHV) overlays, the identified regional upgrades, and the associated terminal/substation equipment.

Some regional or local upgrades would be necessary for moving energy to or from the transmission backbone, and cost estimates for these upgrades are not included in EWITS. Because of related internal work in operating areas covered by the Midwest Independent System Operator (Midwest ISO) and the Southwest Power Pool (SPP), some detail was available for regional upgrades in these areas. Much less information was available for the other operating areas, and the transmission capital costs may be understated as a result. The overlay transmission makes up the majority of the transmission capital cost, however, and the results are from a single iteration of the top-down economics-based analysis. Refinements from further iterations would presumably work to reduce capital costs.

PRODUCTION COSTS

Production costs for each scenario were extracted from the annual PROMOD IV simulations. Fuel and operating costs, along with variable operations and maintenance (O&M) costs, make up production costs.

TOTAL COSTS

Figure 8-2 shows the total costs for each scenario.

Costs for each scenario are calculated as the sum of production-related costs plus annualized amounts for capital investments in new conventional generation, wind plants, and transmission. The results for the Reference Scenario and the four EWITS high-penetration scenarios (Figure 8-2) show that Scenario 1 is the least costly of the 20% scenarios and that the increased cost of offshore wind is a major cost element of Scenarios 3 and 4.

Transmission costs are a relatively small fraction for all scenarios, with only a small absolute difference in this component in the 20% cases.

None of the scenarios includes any costs associated with carbon.

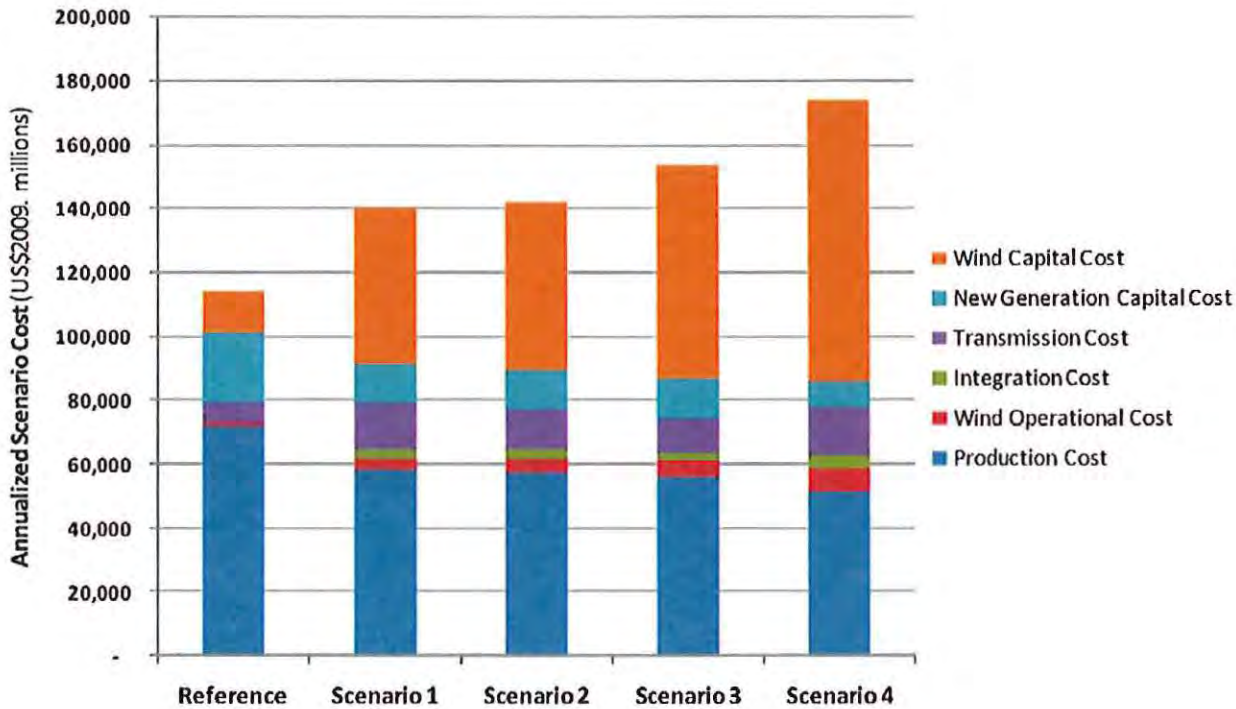


Figure 8-2. Costs by scenario

IMPLICATIONS OF THIS STUDY

EWITS is the first study that considered three geographic generation scenarios for the 20% wind energy level for the Eastern Interconnection. All costs for integrating wind—costs for generation expansion, transmission expansion, production, and operations—were calculated based on defined assumptions for the study.

GENERAL OBSERVATIONS

Based on the work done in this study, the EWITS team can make a number of general observations. The wind generation does not need 100% transmission for the rated wind generation connected to the transmission system. The geographic diversity of wind generation produces a coincident peak capacity of 80%–90% of the total rated wind generation. Transmission does not need to be sized to handle all the wind generation at its maximum coincident output. Some wind can be curtailed for some hours more economically than building transmission that would be loaded only for those few hours. Adding more generation with small curtailments to meet the renewable energy standards can be more cost-effective than designing a transmission system for the peak coincident output of the generation. The top-down economic process used for EWITS determines the curtailment energy for wind and also the potential benefit of adding transmission compared to the cost.

The combination of large pools of low-cost energy delivered to higher priced areas and the abundance of generation capacity off peak creates a large market price signal that drives the justification of economic transmission expansion at the 20% wind energy level. The price signal is quite sensitive to the price of natural gas. Natural gas-fired generation sets the marginal price on the energy market. The difference in marginal prices across the Eastern Interconnection drives the need for transmission. The assumed price of \$8/MBtu (millions of British thermal units) translates to a significant differential in marginal prices across the interconnection.

At the US\$2009 price of natural gas in the \$3–\$4/MBtu range, the energy market prices are already level and the difference in energy price across the Eastern Interconnection is reduced. Less transmission can be justified at lower gas prices that reduce the differential pricing across the Eastern Interconnection.

At 30% wind energy, energy market prices are practically level across the Eastern Interconnection. The energy market no longer gives a signal to justify additional transmission expansion based on marginal prices.

Wind generation generally does not appear on peak and contributes less to serving load on peak than off peak. Wind generation on the peak hour in the Midwest ISO for the last 5 years has been 1.2%, 11.4%, 1.2%, 11.8%, and 56%, respectively. Currently, wind generation in the Midwest ISO area is concentrated in a small geographic area in southwestern Minnesota and northern Iowa. Wind generation potential exists in much of the Midwest ISO's footprint. Geographic diversity is expected to increase the capacity contribution of wind on the peak period.

The EWITS LOLE studies show that when the geographic diversity of the Eastern Interconnection is considered, the capacity credit could increase to 25%. The capacity credit given to wind reduces the amount of other generation that must be constructed. The incremental economic value of the diversity factor (the capacity factor owing to diversity) can be estimated by running a case with an assumed wind capacity credit such as the 20% used in EWITS, then running the EWITS process again using the ELCC wind energy capacity credit. In this example, an 8% reduction in other generation would apply to about 30% of the total cost of the wholesale price energy.

POLICY IMPLICATIONS

Although EWITS is a technical study that examines future wind scenarios, the results of this study pose some interesting policy and technology development questions:

- Could the levels of transmission, including the Reference Case, ever be permitted and built, and if so, what is a realistic time frame?
- Could the level of offshore wind energy infrastructure be ramped up fast enough to meet the aggressive offshore wind assumption in the EWITS scenarios?
- Would a different renewable profile or transmission overlay arise from a bottom-up process with more stakeholders involved?
- How can states and the federal government best work together on regional transmission expansion and the massive development of onshore and offshore wind infrastructure?
- What is the best way for regional entities to collaborate to make sure wind is optimally and reliably integrated into the bulk electrical grid?
- What is the difference between applying a carbon price instead of mandating and giving incentives for additional wind?

SECTION 9: FINDINGS, CONCLUSIONS, AND RECOMMENDATIONS

The analytical modeling of the operational impacts of wind generation in the Eastern Wind Integration and Transmission Study (EWITS) was conducted on a scale and at a level of detail not previously attempted for this type of analysis. The volume of raw results is immense—hourly data for any generator or monitored interface in the Eastern Interconnection for four scenarios of wind generation over three annual periods.

This section describes the key findings and conclusions of the project, and recommends follow-up actions or further investigation.

KEY FINDINGS AND CONCLUSIONS

A number of conclusions can be drawn from the process and results of the analytical work in this study. These are summarized by topical category in the following subsections.

CONCEPTUAL TRANSMISSION OVERLAY

In contrast to previous wind integration studies, adding significant new transmission across an interconnection was a principal element of this study.

- The conceptual transmission overlays consist of multiple 800-kilovolt (kV) high-voltage DC (HVDC) and extra-high voltage (EHV) AC lines. HVDC is preferred if not required because of the volumes of energy that must be transported across and around the interconnection and the distances involved.
- Similar levels of new transmission are needed across the four scenarios, and certain major facilities appear in all of the scenarios. The study focused on a snapshot of four possible 2024 futures; how to get to any one of those futures was outside the scope of the study. The commonality of transmission elements across the four scenarios reveals important information should that effort be undertaken.
- The modeling indicates that a substantial amount of wind can be accommodated if adequate transmission is available.
- Transmission produces capacity benefits in its own right, and enhances the capacity credit contribution of wind generation by a measurable and significant amount.
- The EHV DC transmission that constitutes a major portion of the overlays designed for the EWITS scenarios has benefits beyond those evaluated here. For example, it would be possible to schedule reserves from one area

to another, effectively transporting variability caused by wind and load to areas that might be better equipped to handle it. And the transfer capability of the underlying AC network could be enhanced by using the DC terminals to mitigate limitations related to transient stability issues.

WIND GENERATION IMPACT ON RESERVES

Current operating experience gives little guidance on how to manage the incremental variability and uncertainty associated with large amounts of wind generation in the operating footprints defined for this study. The statistical analysis conducted on the time-series data from the scenarios, however, produced a very reasonable analytical foundation for the assumptions and reserve requirement results that were carried forward to the production simulations.

Study findings and conclusions relative to reserve requirements and impacts include the following:

- The assumptions made about how the Eastern Interconnection will be operated in 2024 played an important role in minimizing the additional amounts of spinning reserve that would be required to manage the variability of large amounts of wind generation.
- The geographic size of the market areas assumed in EWITS allows substantial benefits of geographic diversity to be realized.
- The pooling of larger amounts of load and discrete generating resources via regional markets also realizes the benefits of diversity. The per-unit variability of load declines as the amount of load increases; larger markets also have more discrete generating units of diverse fuel types and capabilities to use for meeting load and managing variability.
- With real-time energy markets, changes in load and wind that can be forecast over a short interval—10 minutes in this study, 15 to 20 minutes in current practice—are compensated for in a very economic manner.
- Incremental spinning reserve requirements are driven by errors in short-term forecasts of wind generation.
- Both variability and uncertainty of aggregate wind decrease percentage-wise with more wind and larger geographic areas.
- Both variability and uncertainty can be characterized for a defined scenario using National Renewable Energy Laboratory (NREL) mesoscale data.
- Characterizations are useful for estimating incremental reserve requirements.
- Variations on a second-by-second basis are still dominated by load.
- Load changes over 10-minute intervals can be forecast well, and are therefore cleared in the regional transactions market.
- Current energy market performance shows that subhourly market prices, on average, do not command a premium over day-ahead prices. As a consequence, the hourly production simulation will capture most of the costs associated with units moving in subhourly markets, and the spinning

reserve requirements for regulation and contingency will appropriately constrain the unit commitment and dispatch.

OPERATIONAL IMPACTS

The detailed production modeling of a system of such size and scope reduces the number of assumptions and approximations required to obtain a solution. The extremely large volume of results is a disadvantage, but they do contain information that can be used to draw conclusions of relatively high confidence with respect to wind generation impacts on other system resources:

- Generation displacement depends on location and amount of wind generation.
- Fossil units are displaced because of the requirements for additional reserves and influences of day-ahead forecast error (ideal to actual cases).
- Wind generation reduces locational marginal price (LMP) in all operating regions.
- The effect appears to be greatest with local wind resources.
- Offshore wind has more effect on LMP in eastern load centers.

WIND GENERATION CURTAILMENT

In the production simulations, the EWITS team assigned a very low dispatch price to wind generation, so that other sources would first be redispatched to relieve congestion. Even so, a modest amount of curtailment was observed in some operating areas. Local or subregional transmission congestion is the probable cause because the production simulation results gave no clear evidence that the other likely causes—minimum generation levels, reserve requirements, or ramp limitations—were responsible.

A certain amount of wind generation curtailment was to be expected, based on the process by which the overlay transmission concepts were developed. Transmission was sized to accommodate a large fraction—but not 100%—of the transaction energy from the unconstrained production simulation case.

WIND GENERATION CONTRIBUTION TO RESOURCE ADEQUACY

Assessing the capacity value of wind generation has been a staple of most of the integration studies conducted over the past several years (see Bibliography). The approach taken in this project represents the most thorough and detailed investigation to date because of the size and scope of the model, the process by which areas transfer limits were determined, and the sensitivity analyses performed. The study team recognizes that the results represent a macro view and do not consider some important intraregional transmission constraints. Because of the project focus on transmission, however, the results represent a target resource adequacy contribution that could be achieved for the wind generation scenarios.

Specific findings and conclusions are as follows:

- The loss of load expectation (LOLE) analysis performed for this study shows that the existing transmission network in the Eastern Interconnection contributes roughly 50,000 megawatts (MW) of capacity benefits. With the transmission overlays developed for the wind scenarios, the benefit increases by up to 8,500 MW.
- LOLE analysis of the Eastern Interconnection with wind generation and the transmission overlays developed in this study estimates that the ELCC of the wind generation ranges from 24.1% to 32.8% of the rated installed capacity.
- The transmission overlays increase the ELCC of wind generation anywhere from a few to almost 10 percentage points (e.g., 18% to 28%).
- The ELCC of wind can vary greatly geographically depending on which historical load and wind profiles are being studied. The EWITS team observed interannual variations; these variations, however, were much smaller than had been observed in previous studies (e.g., EnerNex 2006).
- Characteristics of the zonal ELCC differences between profiles tended to be the same between all four scenarios.

WIND INTEGRATION COSTS AND IMPACTS

Assessing the costs and impacts of integrating large amounts of wind generation was another key aspect of this study. Methods and analytical approaches used in earlier integration studies were the starting point, but as interim results became available, nuances and challenges in those methods when they are applied to a large, multiarea production model became apparent. As a result of this project, then, the team learned a great deal of useful information about the total costs associated with managing the delivery of wind energy.

Despite the challenges, the study team has confidence in the results as applied over the entire model footprint. Salient points include the following:

- The conventional proxy resource assumption is not usable with very large amounts of wind generation.
- Because the production simulation model contains multiple operating areas, and transactions between these areas are determined on an economic basis, variability from wind in a given area will be carried through economic transactions to other areas.
- Earlier integration studies isolated the subject area by restricting transactions to predefined shapes based on historical contracts.
- The integration costs over the entire model are accurate because all transactions sum to (nearly) zero.
- Costs for integrating wind across the interconnection vary by scenario. For the 20% cases, Scenario 1 showed the highest cost at $8.00/MWh (megawatt-hour) of wind energy; Scenario 2 follows at $7.21/MWh. Scenario 3 shows the lowest integration costs at $5.77/MWh. These costs

are in US$2024; using the 3% escalation factor, the integration costs in US$2009 would be $5.13/MWh for Scenario 1, $4.63/MWh for Scenario 2, and $3.10/MWh for Scenario 3.

- The integration cost results for the 20% scenarios show that spreading the wind more evenly over the footprint reduces the cost of integration. Integration costs increase to $7.07/MWh for the 30% scenario, or $4.54/MWh in US$2009. This scenario is roughly a combination of Scenarios 1 and 3.
- Using the actual shape as the proxy resource (with no intrahour variability or uncertainty over any forward time frame) eliminates any issues related to the "value" of wind energy between the actual and ideal wind cases.
- The actual shape proxy, however, does potentially mask or leave out some true operational costs, for example, backing down or possibly even decommitting fossil-fuel units to accommodate wind generation.
- Wind generation reduces LMP in all operating regions.
- The reduction appears to be greatest with local wind resources.
- Offshore wind has more effects on LMP in eastern load centers.

SENSITIVITIES

PRODUCTION MODEL ASSUMPTIONS AND CURTAILMENT

The study team investigated the cause of wind generation curtailment by running additional production simulation cases. The results produced quantitative information about the causes, revealing the following:

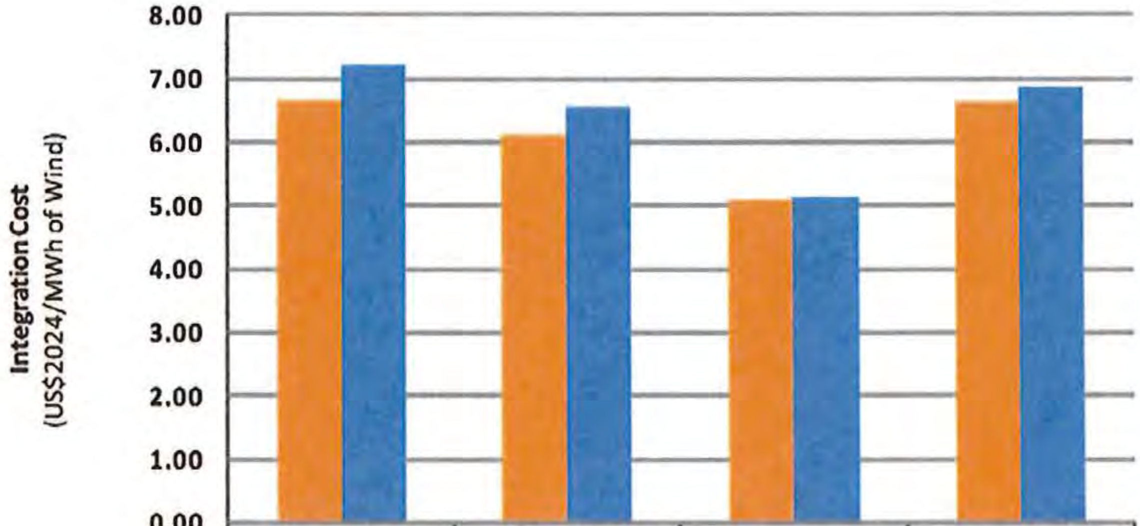
- Removing must-run flags from coal units had very little effect on wind generation curtailment (decrease of 0.27%).
- Setting the dispatch price of wind generation to negative $40/MWh reduced curtailment by just under 50% (6.38% to 3.51%).
- The copper sheet case shows a curtailment level of 0.12%, which is most likely because of minimum generation constraints.
- Increasing minimum generation levels to 50% on coal plants increased curtailment by only 2%.

This information led the team to conclude that transmission congestion is the primary cause of wind generation curtailment in Scenarios 1 through 4.

UNIT COMMITMENT WITH PROMOD IV BID LOGIC

PROMOD IV offers a more sophisticated security-constrained unit-commitment algorithm that was not used for the base production simulations in the study because it increases simulation time. A sensitivity case using wind and load profiles based on 2005 data was run to assess the performance of this alternative approach and the effect on production and integration costs.

Figure 9-1 presents a comparison of the two approaches and shows that although the bid-logic approach does increase production and integration costs, the effects are relatively minor.



	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Original ($/MWh)	6.68	6.13	5.1	6.63
Bid-up Logic ($/MWh)	7.2	6.55	5.13	6.86

Figure 9-1. Comparison of production simulation results (integration cost) for base unit-commitment algorithm and more sophisticated "bid-logic" approach

INFLUENCE OF HURDLE RATES

Tariffs, or hurdle rates, are placed on transactions between defined regions in the model to simulate the economic inefficiency that results from independent commitment and dispatch of resources within each region. To assess the effect of these tariffs on production and integration cost, the study team ran production simulations again for two scenarios with hurdle rates set to zero. Under these conditions, the program optimizes the commitment and dispatch of resources across the entire model or, as in this study, the Eastern Interconnection.

Results from these simulations show that the hurdle rates have only a minor impact on production costs (shown in Figure 9-2) and integration costs.

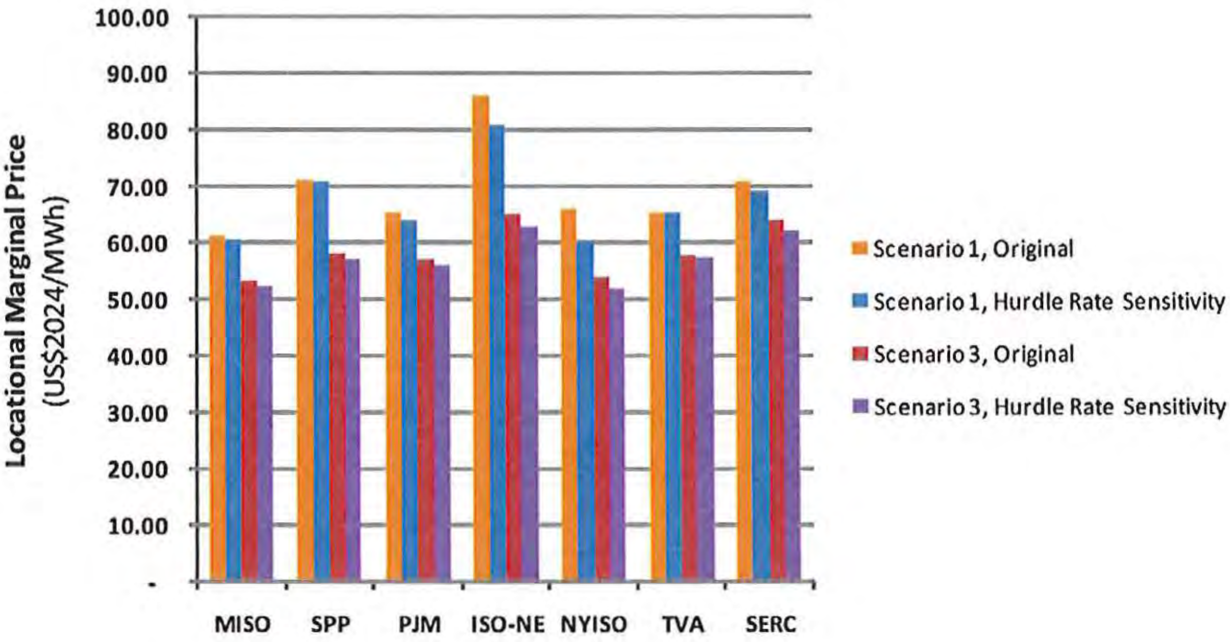


Figure 9-2. Comparison of LMPs for hurdle rate sensitivity

CARBON SENSITIVITY

No carbon penalties or limits were considered in the base set of assumptions for the study. A single formal sensitivity was defined in the original project scope—evaluating the impacts of carbon penalties or other limitations on the generation expansion, transmission overlay design, production costs, and integration costs associated with wind generation.

The entire analytical methodology, except for the LOLE analysis, was run for a scenario that considered a carbon price of $100/ton. The high price was determined to be necessary to bring about a significant change in the type of new generation built during the expansion process. Figure 9-3 shows the results of the expansion. Figure 9-4 gives more detail and compares the expansion for this case to the base scenarios and the existing Eastern Interconnection queue.

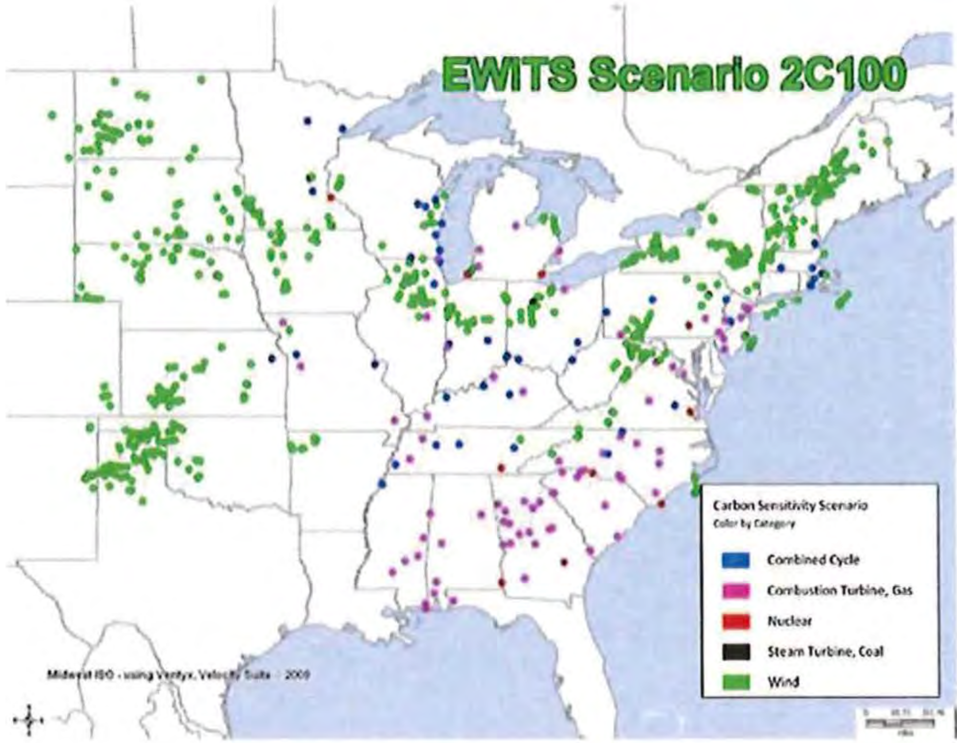
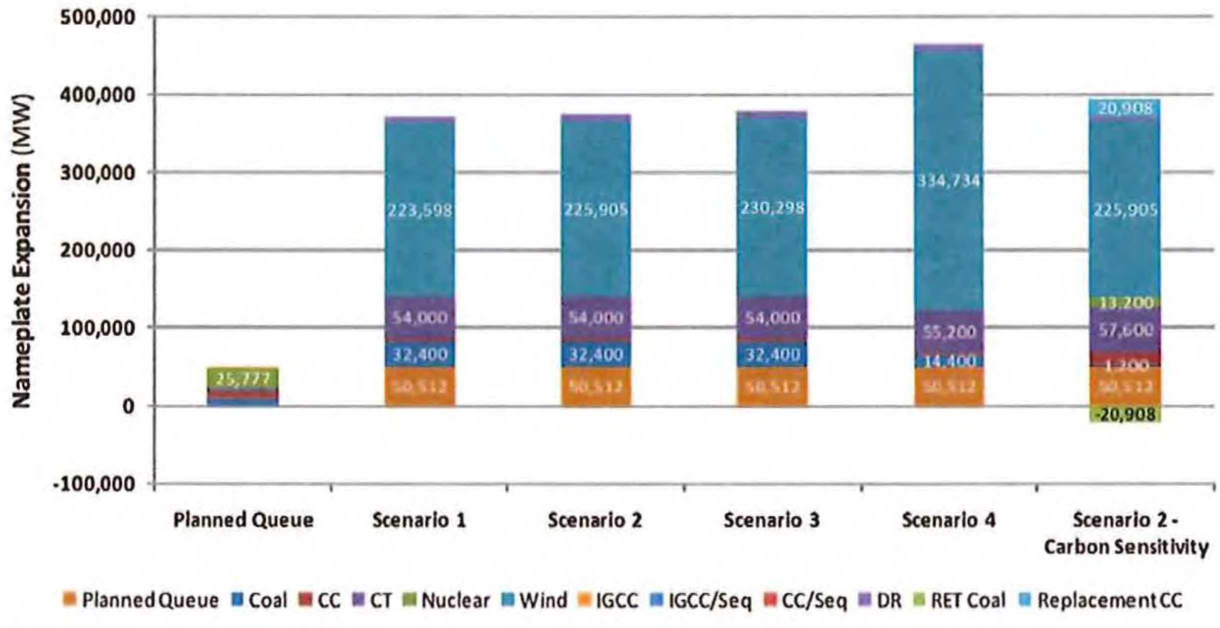


Figure 9-3. Scenario 2, carbon case generation expansion



Notes: CC = combined cycle; CT = combustion turbine; DR = demand response; IGCC = integrated gas combined cycle; IGCC/Seq = integrated gas combined cycle with sequestration; CC/Seq = combined cycle with sequestration; RET Coal = coal plant retirements; Replacement CC = replacement combined cycle

Figure 9-4. Generation expansion by scenario, 2008–2024

Results from the production simulations showed that the effect on carbon emissions was substantial. Even though the case was based on Scenario 2 and had wind generation delivering 20% of the Eastern Interconnection energy, carbon emissions were lower than those from Scenario 4 with 30% energy generated from wind (Figure 9-5).

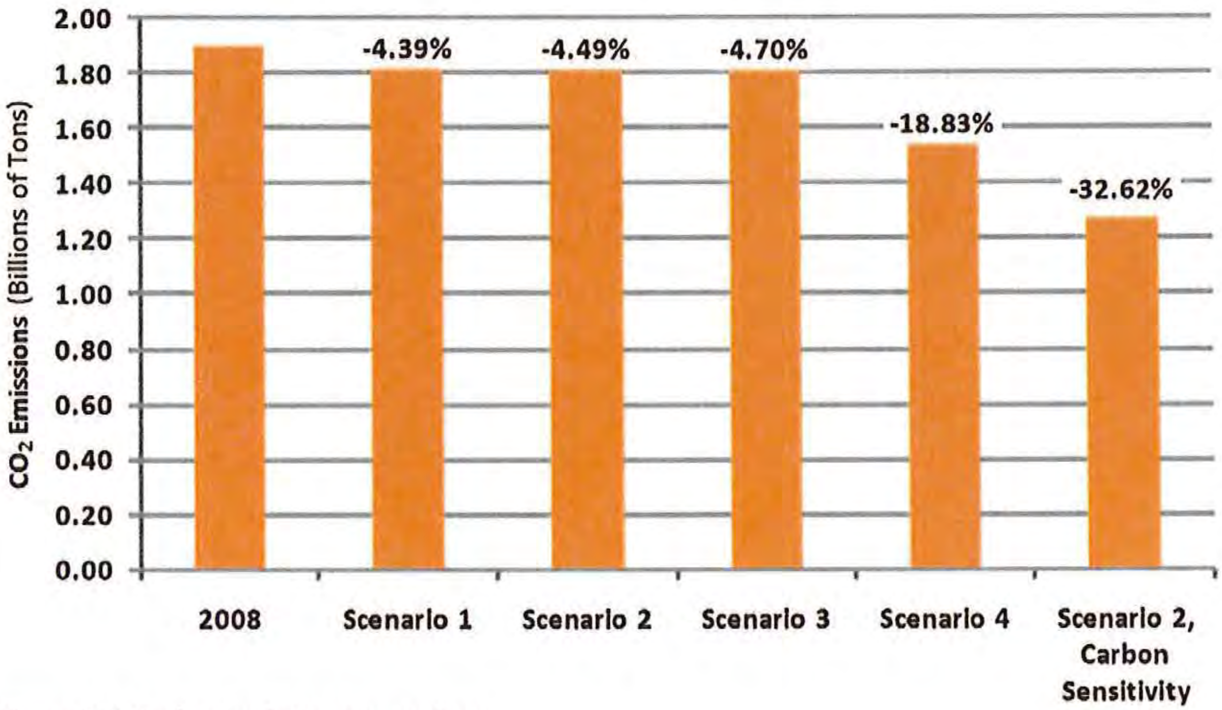
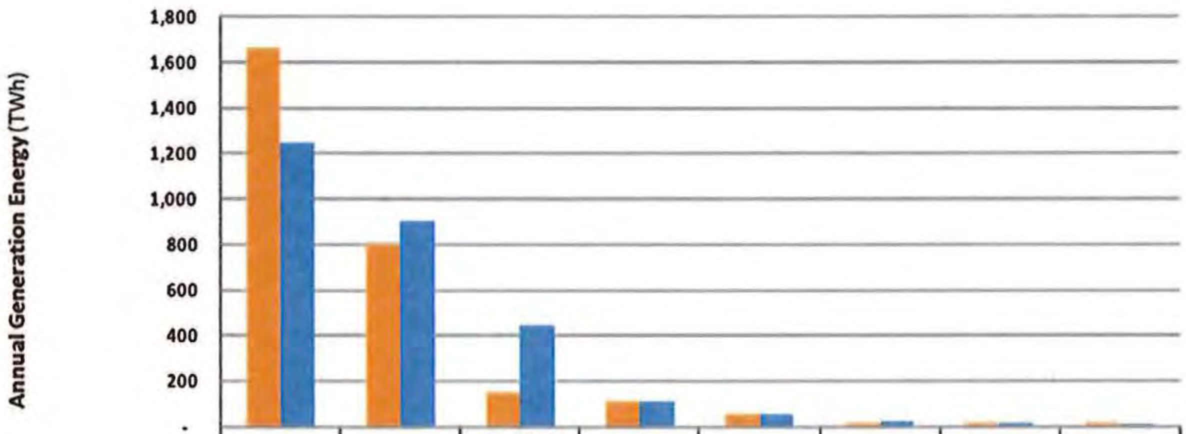


Figure 9-5. Carbon emission comparison

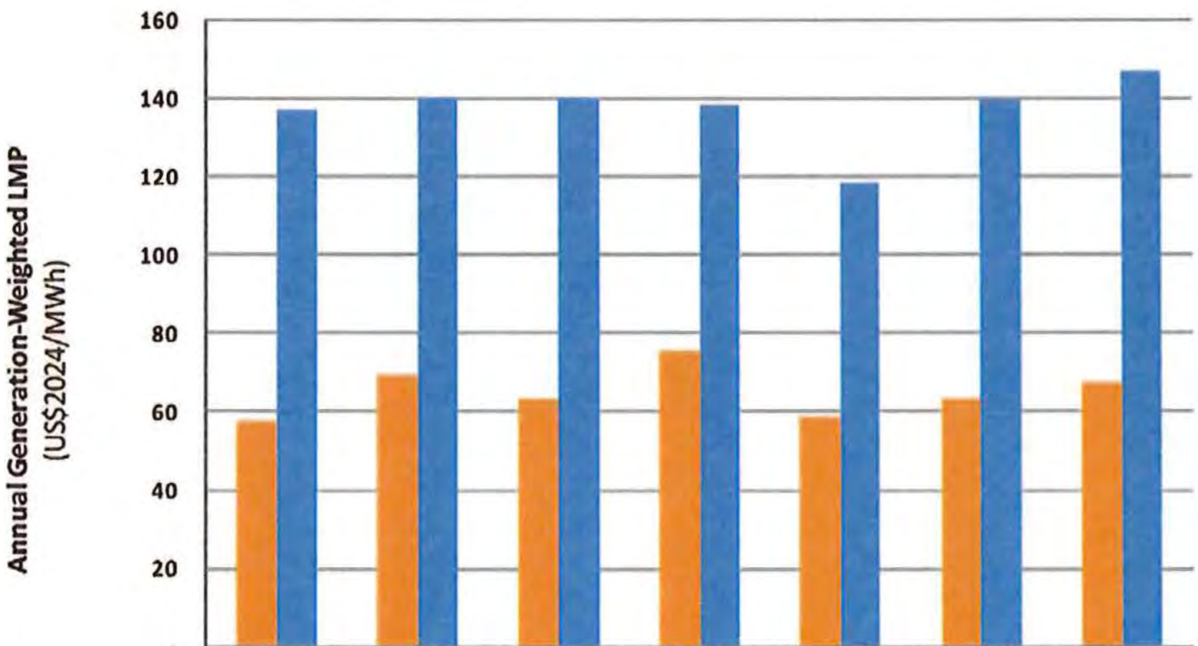
Little effect was observed on wind generation curtailment or integration cost. Fossil generation was reduced relative to the original Scenario 2 (Figure 9-6), and nuclear generation increased because the nuclear share of the new generation expansion was larger. Energy from combined cycle plants also increased as they became the preferred resource for managing variability.

Energy prices increased across the footprint (Figure 9-7).



	ST Coal	Nuclear	Combined Cycle	Hydro	CT Gas	IGCC	ST Gas	Other
Scenario 2	1,667	801	146	106	55	16	13	16
Scenario 2, Carbon 100$/Ton	1,249	906	444	106	53	18	14	5

Figure 9-6. Change in generation for carbon sensitivity



	MISO	SPP	PJM	ISO-NE	NYISO	TVA	SERC
Scenario 2	57.82	69.43	63.53	75.55	58.70	63.49	67.82
Scenario 2, Carbon 100 US$2024/Ton	136.87	140.47	140.54	138.51	118.75	140.12	147.07

Figure 9-7. Change in LMP for carbon sensitivity

SCENARIO COST COMPARISONS

Costs for each scenario were calculated as the sum of production-related costs plus annualized amounts for capital investments in new conventional generation, wind plants, and transmission. The results for the Reference Scenario and the four high-penetration scenarios developed in this study (Figure 9-8) show that Scenario 1 is the least costly of the 20% scenarios, and that the increased cost of offshore wind is a major cost element in Scenarios 3 and 4.

Transmission costs are a relatively small fraction for all scenarios, with only a small absolute difference in this component seen in the 20% scenarios.

None of the scenarios includes any costs associated with carbon.

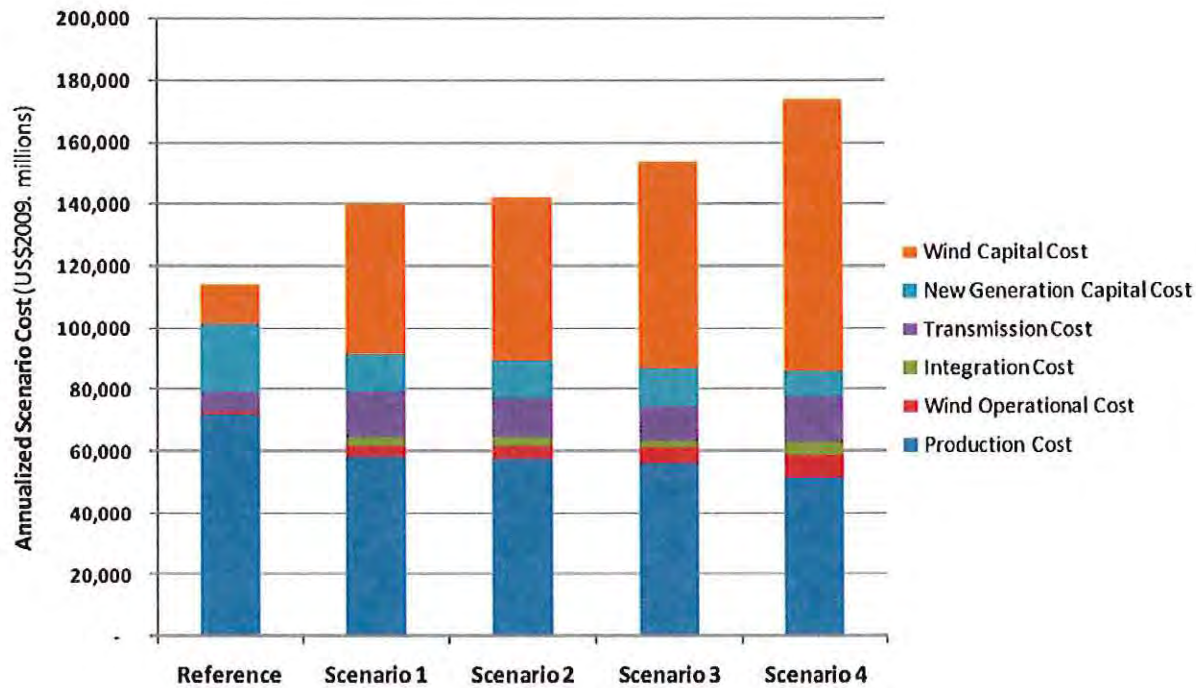


Figure 9-8. Scenario cost comparisons

Other findings and conclusions include the following:

- Achieving 20% wind energy penetration across the Eastern Interconnection will require very substantial wind development and therefore significant grid expansion.
- A single iteration of the economic transmission expansion methodology gives useful results and insights.
- Wind generation curtailment across the footprint ranges from a low of 3.9% in Scenario 3 to a high of 10.5% in Scenario 4.
- Further iterations would allow overlays to be improved and wind curtailment to be minimized.

SUMMARY

The significant amount of analytical work performed in this study answers the questions posed at the outset of the project:

1. What impacts and costs do wind generation variability and uncertainty impose on system operations? With large balancing areas and fully developed regional markets, the cost of integration for all scenarios is about $5/MWh of wind, or about $0.005 per kilowatt-hour (kWh) of electricity used by customers.

2. What benefits accrue from long-distance transmission that accesses multiple and geographically diverse wind resources? The study results show that long-distance (and high-capacity) transmission can assist smaller balancing areas with wind integration, allowing penetration levels that would not otherwise be feasible. Furthermore, all scenarios, including the Reference Case, made use of major transmission upgrades to better interconnect Eastern Interconnection markets for assisting with wind integration.

3. What benefits are realized from long-distance transmission that moves large quantities of remote wind energy to urban markets? Long-distance transmission, along with assumed modifications to market and system operations, contributes substantially to integrating large amounts of wind that local systems would have difficulty managing. In addition, long-distance transmission has other value in terms of system robustness that was not completely evaluated in EWITS.

4. How do remote wind resources compare to local wind resources? In the Eastern Interconnection, the Eastern Wind Data Study database (AWS Truewind 2009) shows that the higher quality winds in the Great Plains have capacity factors that are about 7%–9% higher than onshore wind resources near the high-load urban centers in the East. Offshore plants have capacity factors on par with Great Plains resources but the cost of energy is higher because capital costs are higher.

5. How much does geographical diversity, or spreading the wind out across a large area, help reduce system variability and uncertainty? Quite substantially.

6. What is the role and value of wind forecasting? With significant wind generation, forecasting will play a key role in keeping energy markets efficient and reducing the amount of reserves carried while maintaining system security.

7. What benefit does balancing area cooperation or consolidation bring to wind variability and uncertainty management? This and other recent studies (see Bibliography) reinforce the concept that large operating areas—in terms of load, generating units, and geography—combined with adequate transmission, are the most effective measures for managing wind generation.

8. How does wind generation capacity value affect supply resource adequacy? Wind generation can contribute to system adequacy, and additional transmission can enhance that contribution.

The scenarios developed for this study do not in any way constitute a plan; instead, they give a top-down, high-level view of four different 2024 futures. The transition over time from the current state of the bulk power system to any one of the scenarios would require much more technical and economic evaluation, including detailed modeling of power flows and a study of the effects on the underlying transmission systems. A more thorough evaluation of the sensitivity of the results from this study to changes in assumptions or scenarios would also be required to guide the development of any specific bottom-up plans.

RECOMMENDATIONS FOR FUTURE STUDY

The results of this study represent a first detailed look at a handful of future snapshots of the Eastern Interconnection as it could exist in 2024. The analysis was driven primarily through economics-based transmission expansion planning, resource adequacy studies, and hourly modeling simulations. Important technical aspects in the study related to bulk-power system reliability were not studied or were represented approximately or by means of best engineering judgments.

This study is an important step in the uncertain world of long-range planning because it addresses questions such as feasibility and total ultimate costs, and begins to uncover important additional questions that will require answers. Although the Technical Review Committee (TRC) that gave input to EWITS has extensive Eastern Interconnection representation, the study team recognizes that additional key stakeholders must be involved to further develop an interconnection-wide view of transmission system plans.

A complete evaluation of any of the scenarios would require a significant amount of additional technical analysis. The framework established by the scenario definitions and transmission overlay concepts in this study, however, offers a starting point for employing conventional power system planning to further evaluate the feasibility of these high-penetration scenarios and to improve the cost estimates.

Production simulation results from this study could be used to identify times of binding constraints. The EWITS results could also be used to explore other periods of interest, such as times when there are large changes in wind production, periods of minimum load, and conditions where loss of significant generation would raise questions about the security of the system. For such periods, the state of the system —in terms of, for example, loads, committed generation and dispatch level, and wind generation—would be transferred to an appropriate AC power system model. A variety of power system engineering analyses could then be conducted to determine what additional equipment or operating limitations would be necessary to maintain system reliability. Two examples follow:

- An AC analysis could examine in more detail the power transfer limitations assumed in the production modeling. The production simulations in EWITS used a DC power flow that does not consider the wide range of issues associated with voltage control and reactive power dispatch. This would involve power flows that look at voltage and reactive compensation issues, dynamic and transient stability, and HVDC terminal control. Local and regional transmission needs could then be analyzed in much greater detail.
- Longer term dynamic analysis would allow more detailed simulation and analysis. For example, the actions of automatic generation control (AGC), load tap changing on transformers, and capacitor or reactor switching for voltage control could be simulated and analyzed in much greater detail. This, in turn, would enable examination of subhourly market operation and the response of generation to either AGC or market dispatch instructions. And that examination would allow investigators to consider limitations caused by prime mover or governor response, HVDC control actions, or special protective schemes. These types of analyses could be used to zoom in on the operation of the system in real time, resulting in higher confidence estimates of the operating reserve requirements and policies needed to maintain performance and reliability.

The analysis suggested for the large footprint considered in EWITS would require participation and collaboration from a large number of entities across the interconnection. Personnel engaged in running similar studies with a regional focus would need to be involved, at a minimum, in a review capacity and for interpretation of results. National entities such as the North American Electric Reliability Corporation (NERC) would also need to be engaged to oversee the development of the data sets and models. The size and scope of the system models might also require computational power beyond what is used today in the power industry, and therefore could involve universities or national laboratories with appropriate resources.

The top-down views of the interconnection produced in this study constitute, in essence, the starting point for a significant amount of subsequent engineering analysis. The analysis would paint a more accurate picture of the total transmission investment necessary, and illuminate what would be required to preserve the security of the bulk power system. As with EWITS, such an effort would be beyond the scope of what has previously been attempted, and would require cooperation and coordination at many levels to succeed.

The results of this study pose some interesting policy and technology development questions:

- Could the levels of transmission, including the Reference Case, ever be permitted and built, and if so, what is a realistic time frame?
- Could the level of offshore wind energy infrastructure be ramped up fast enough to meet the aggressive offshore wind assumption in the EWITS scenarios?
- Would a different renewable profile or transmission overlay arise from a bottom-up process with more stakeholders involved?
- How can states and the federal government best work together on regional transmission expansion and the massive development of onshore and offshore wind infrastructure?
- What is the best way for regional entities to collaborate to make sure wind is integrated into the bulk electrical grid optimally and reliably?
- What is the difference between applying a carbon price versus mandating and giving incentives for additional wind?

As is expected in a study of this type, especially when a wide variety of technical experts and stakeholders are giving ongoing input, a number of important variations on the 2024 future scenario can be envisioned. In addition, a number of technical areas in the study present opportunities for further technical investigation that could deepen understanding or reveal new insights:

- Further analysis of production-cost simulation results: The output from the many annual production simulations performed in this study contains detail on every generator and monitored transmission interface in the Eastern Interconnection. Because of scope and schedule constraints, the analysis conducted in this study was necessarily limited to summary results. Further analysis of this output data would likely generate additional valuable insights on impacts of wind generation on the conventional generation fleet, and help define more detailed analyses that could be conducted going forward.
- Smart grid implications and demand response sensitivities: The Eastern Interconnection load considered in the study was based on regional projections out to the 2024 study year. For the most part, load was considered static. Major industry initiatives are currently exploring means by which at least a portion of the load might respond like a supply

resource, thereby relaxing the constraints on scheduling and dispatch of conventional generating units. The implications for wind generation are potentially very significant, which is why alternative 2024 scenarios that consider the range of smart grid implications for the bulk electric system merit further study.

- PHEVs (nighttime charging of plug-in electric vehicles): Widespread adoption of electric vehicles has the potential to alter the familiar diurnal shape of electric demand. Because the wind resource is abundant at night and during the low-load seasons, increases in electric demand during these times could ease some of the issues associated with integration.
- Commitment/optimization with high amounts of wind: The approach for scheduling and dispatching generating resources used in the production simulations was based on current practice. In the future, new operating practices and energy market structures might be implemented that take advantage of the fact that uncertainty declines as the forecast horizon is shortened (for both load and wind generation). Intraday energy markets that allow more frequent reoptimization of the supply resources could offer some advantage for accommodating large amounts of variable and uncertain wind energy.
- Fuel sensitivity: In this phase of EWITS, the study team considered a single "future" for prices of other fuels used for electric generation. As history attests, there is much uncertainty and volatility inherent in some fuel markets, especially for natural gas. Alternate scenarios that explore the impacts of other fuel price scenarios on integration impacts and overall costs would be valuable.
- The role and value of electric energy storage: With the substantial transmission overlays and the assumption of large regional markets, the EWITS results show that large amounts of wind generation might be accommodated without deploying additional energy storage resources. The ability to store large amounts of electric energy could potentially obviate the need for some of the transmission and reduce wind integration impacts, though. Analysis of bulk energy storage scenarios with generic storage technologies of varying capabilities would quantify the costs and benefits of an alternate means for achieving high penetrations of renewable energy.
- Transmission overlay enhancement: As described earlier, the analytical methodology was based on a single pass through what is considered an iterative process. Further analysis of the existing results could be used to refine the transmission overlays, which would then be tested in additional production simulations and LOLE analyses, along with AC power flow and stability analysis. This could reduce the estimated costs of the overlay, and bolster the view of the required regional transmission expansion that would be needed to deliver the large amounts of wind energy to load.

- Sequencing of overlay development: The EWITS team used a top-down perspective to focus on a snapshot of four 2024 scenarios. The resulting transmission overlays and very substantial wind generation would be developed over many years. An analysis over time—beginning now and extending to 2024—would yield important insights into the overall feasibility and costs of an aggressive transmission development future.
- Wind generation curtailment: Selective and appropriate use of wind generation curtailment could have high operational value. Although wind plants cannot increase their output at will without first spilling wind generation, downward movement is easily accomplished with today's wind generation technology, and could have very high economic value under certain circumstances. Wind generation is quite capable of providing "regulation down" (for example, in an ancillary services market where the regulation service is bifurcated, meaning that regulation up and regulation down are separate services). Additional analysis of the scenarios studied in EWITS could help quantify what such a service would be worth to wind plant operators.

The current installed capacity of wind generation in many areas of the United States, coupled with prospective development over the next several years, requires that assessments of the bulk electric power system take a much broader view than has been typically employed. In addition, the unique characteristics of wind generation as an electric energy supply resource are leading the power industry to new approaches for planning and analyzing the bulk electric power system.

Several of these techniques were demonstrated in this study, and are also being used in other large-scale wind integration analyses. The data sets compiled for the study represent the most detailed view to date of high-penetration wind energy futures. Given the significant changes coursing through the electric power industry, many alternative scenarios for the Eastern Interconnection in 2024 can be postulated. In that sense, EWITS is a solid first step in evaluating possibilities for the twenty-first-century grid in the United States, with many more to follow.

GLOSSARY

Area control error (ACE): The instantaneous difference between net actual and scheduled interchange within a control area on the power grid, taking into account the effects of frequency deviations.

Automatic generation control (AGC): A control system that automatically adjusts generation units on regulation duty to compensate for random or sudden changes in demand. Depending on the characteristics of the balancing area, AGC adjustments occur over periods of tens of seconds to a minute.

Adjusted production cost (APC): Captures the actual cost of serving load. The cost of purchases or sales to the outside world is adjusted from the total production cost.

Balancing area (or balancing authority area [BAA]): The collection of generation, transmission, and loads within the metered boundaries of the balancing authority. The balancing authority maintains load–resource balance within this area.

Benefit/cost (B/C): Analysis of the benefits and costs of a given option. In this report, B/C is expressed as a ratio.

Bus-bar: The point at which power is available for transmission.

Capability: The maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved temperature and stress limits.

Capacity: The amount of electrical power delivered or required for which manufacturers rate a generator, turbine, transformer, transmission circuit, station, or system.

Capacity factor: The fraction of the nameplate rating of a wind power plant that can be counted as dependable or firm capacity, expressed as a percentage.

Capacity value: A measure of the productivity of a power plant, calculated as the amount of energy that the plant produces over a set time period, divided by the amount of energy that would have been produced if the plant had been running at full capacity during that same time interval. Most wind power plants operate at capacity factors ranging from 25% to 40%.

Capital costs: The total investment cost for a power plant, including auxiliary costs.

CAPX 2020: A joint initiative of 11 transmission-owning utilities in Minnesota and the surrounding region, designed to expand the electric transmission grid.

Copper sheet simulation: Sensitivity analysis with no transmission constraints in the system.

Control Performance Standards 1 and 2 (CPS1 and CPS2): The reliability standards that set the limits of a balancing authority's ACE over a specified time period. CPS1 is a statistical measure of the variability of the ACE and CPS2 is a measure of the magnitude of the ACE.

Curtailment: Shutting down or limiting the output of generators to mitigate a transmission constraint or other binding constraint such as excess electricity supply relative to demand and must-run generation (minimum generation limits); limitations in ramping capability; or availability of adequate operating reserves.

Dispatch: The physical inclusion of a generator's output onto the transmission grid by an authorized scheduling utility.

Distribution: The process of distributing electricity. Distribution usually refers to the series of power poles, wires, and transformers that run between a high-voltage transmission substation and a customer's point of connection.

Dump energy: A term representing the unavoidable surplus generation that cannot be used to serve load because of unit operating or transmission constraints. Dump energy is the result of negative bus locational marginal prices (LMPs). It is conceptual and used only for reporting purposes.

Effective load-carrying capability (ELCC): The amount of additional load that can be served at the target reliability level by adding a given amount of generation. For example, if adding 100 megawatts (MW) of wind could meet an increase of 20 MW of system load at the target reliability level, the turbine would have an ELCC of 20 MW, or a capacity value of 20% of its nameplate value.

Electric Generation Expansion Analysis System (EGEAS): Software from the Electric Power Research Institute (EPRI) that is used for long-term regional resource forecasting. EGEAS performs capacity expansions based on long-term, least-cost optimizations with multiple input variables and alternatives. The software can perform optimizations on a variety of constraints such as reliability (loss-of-load hours), reserve margins, or emissions.

Electricity generation: The process of producing electricity by transforming other forms or sources of energy into electrical energy. Electricity is measured in kilowatt-hours.

Energy penetration: The ratio of the amount of energy delivered from one type of resource to the total energy delivered. For example, if 200 megawatt-hours (MWh) of wind energy supplies 1,000 MWh of energy consumed, wind's energy penetration is 20%.

European Wind Integration Study (EWIS): An initiative established by the European transmission system operators in collaboration with the European Commission. EWIS partners are developing, where possible and appropriate, common solutions to wind integration challenges. They are also identifying arrangements that will best use the pan-European transmission network to deliver the benefits of wind generation across Europe.

Eastern Wind Integration and Transmission Study (EWITS): A project that evaluated the power system impacts, costs, and conceptual transmission overlays attendant with increasing wind generation capacity to 20% and 30% of retail electric energy sales in 2024 for the study area, which includes a large fraction of the U.S. Eastern Interconnection.

Federal Energy Regulatory Commission (FERC): An independent agency that regulates the interstate transmission of electricity, natural gas, and oil.

Financial transmission right (FTR): A right to congestion credits or charges along a specific path during a given time frame for a certain amount of power flow. FTRs are tradable financial instruments that allow market participants to hedge against the cost and uncertainty that can arise from congestion in the market.

GE Energy's Multi-Area Reliability Simulation (GE-MARS): A transportation-style model based on a sequential Monte Carlo simulation that steps through time chronologically and produces a detailed representation of the hourly loads and wind profiles, generating units, and interfaces between the interconnected areas.

Gigawatt (GW): A unit of power that is instantaneous capability equal to 1 million kilowatts.

Gigawatt-hour (GWh): A unit or measure of electricity supply or consumption of 1 million kilowatts over a period of 1 hour.

Grid: A common term for an electricity transmission and distribution system. See also power system and utility grid.

Hurdle rate: Rates used in the production-cost model to allow regional transactions during the security-constrained unit-commitment and dispatch process. Two separate hurdle rates are defined for dispatch and for unit commitment. The dispatch hurdle rates are the economic adders between applicable price zones to reflect either regulatory tariffs or market efficiency impacts. Within a regional transmission organization (RTO), there are no hurdle rates; the hurdle rates are between RTOs. The commitment hurdle rate is a mechanism to commit pool generation for pool load. Commitments to serve load outside the pool are made based on the price differentials.

Kilovolt (kV): One volt is the basic unit of electromotive force, or difference in potential, that causes a current of one ampere to flow through a conductor having a resistance of one ohm. One kilovolt is equal to 1,000 volts.

Kilowatt (kW): A standard unit of electrical power that is instantaneous capability equal to 1,000 watts.

Kilowatt-hour (kWh): A unit or measure of electricity supply or consumption of 1,000 watts over a period of one hour.

Load (electricity): The amount of electrical power delivered or required at any specific point or points on a system. The requirement originates at the consumer's energy-consuming equipment.

Load factor: The ratio of the average load to peak load during a specified time interval.

Load following: An electric system's process of adjusting its generation to follow changes in demand over periods of several minutes to hours. The goal of the practice is to ensure that generators are producing neither too little nor too much energy to supply the utility's customers.

Levelized cost of energy (LCOE): An important measure of wind-resource quality for each facility in the database and for the wind database as a whole. The LCOE allows for direct comparisons among the lifetime costs—on an energy-delivered basis—of facilities with different capital and maintenance costs.

Locational marginal price (LMP): The marginal cost of serving the next megawatt of demand. LMP depends on the system transmission constraints and the performance characteristics of generation resources.

Loss of energy expectation (LOEE): The expected unsupplied energy resulting from generating inadequacy. The LOEE incorporates the severity of the deficiencies.

Loss of load expectation (LOLE): The number of hours in a specified period in which the load exceeds the available generating capacity.

Loss of load probability (LOLP): The probability that the load will exceed the generation at a given time. When this probability is summed over a time frame (e.g., 1 year), it is known as LOLE.

Megawatt (MW): The standard measure of power plant electricity-generating capacity. One megawatt is equal to 1,000 kilowatts or 1 million watts.

Megawatt-hour (MWh): A unit of energy or work equal to1,000 kilowatt-hours or 1 million watt-hours.

Mesoscale: Atmospheric phenomena (temperature, pressure, precipitation, and wind, for example) on scales of several kilometers to several hundred kilometers.

Nameplate rating (or nameplate capacity): The maximum continuous output or consumption (in megawatts) of an item of equipment as specified by the manufacturer.

Power: The rate of production or consumption of energy.

Power system: A common term for an electricity transmission and distribution system. See also utility grid.

Production-cost model: A model that captures all the costs of operating a fleet of generators. The model has been developed into an hourly, security-constrained, economic commitment and dispatch simulation. It uses an hourly chronological dispatch algorithm that minimizes costs while simultaneously adhering to a number of operating constraints. It calculates hourly production costs and location-specific market-clearing prices.

Ramp rate: The rate of change in output from a power plant.

Regional Transmission Organization (RTO): An independent organization established to operate the transmission assets and deliver wholesale transmission services within a defined geographic region. Typically, the RTO does not own transmission facilities but operates them on behalf of the transmission-owning utilities. A RTO can operate a central energy market in addition to furnishing transmission services. (Note: RTO can sometimes stand for regional transmission operator, depending on context.)

Reserves

Contingency Reserves: Reserves to mitigate a contingency, which is defined as the unexpected failure or outage of a system component such as a generator, transmission line, circuit breaker, switch, or other electrical element. In the formal North American Electric Reliability Corporation (NERC) definition, this type of reserve is the provision of capacity deployed by the balancing authority to meet the disturbance control standard (DCS) and other NERC and regional reliability organization contingency requirements.

Operating Reserves: That capability above firm system demand required for regulation, load forecasting error, forced and scheduled equipment outages, and local area protection. This type of reserve consists of both generation synchronized to the grid and generation that can be synchronized and made capable of serving load within a specified period of time.

Regulating Reserves: An amount of reserve that is sufficient to allow for normal regulating margins. Regulating reserves, which are responsive to AGC, are the primary tool for maintaining the frequency of the bulk electric system at 60 Hz.

Spinning Reserves: The portion of operating reserve consisting of (1) generation synchronized to the system and fully available to serve load within the disturbance recovery period following the contingency event; or (2) load fully removable from the system within the disturbance recovery period following the contingency event.

Reserve margin: Percentage by which available generating capacity is expected to exceed forecast peak demand.

Security-constrained unit commitment (SCUC): An area-wide optimization process designed to meet electricity demand at the lowest cost, given the operational and reliability limitations of the area's generation fleet and transmission system.

Single largest hazard (SLH): Largest possible single loss of generating capacity resulting from either forced outage of generation or transmission equipment. Also called single largest contingency.

Utility grid: A common term for an electricity transmission and distribution system. See also power system.

Western Electricity Coordinating Council (WECC): The regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection.

Western Wind and Solar Integration Study (WWSIS): A study examining the planning and operational implications of adding up to 30% of wind and solar energy penetration to the WestConnect footprint in the WECC.

Wind integration costs: Incremental costs incurred in operational time frames that can be attributed to the variability and uncertainty introduced by wind generation.

Wind power: Power generated by using a wind turbine to convert the mechanical power of the wind into electrical power.

Wind power plant: A group of wind turbines interconnected to a common utility system.

Wind resource assessment: The process of characterizing the wind resource and its energy potential for a specific site or geographical area.

Wind speed: The rate of flow of wind when it blows undisturbed by obstacles.

Wind turbine: A device that converts wind energy to electricity.

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The Eastern Wind Integration and Transmission Study was designed to answer questions posed by a variety of stakeholders about a range of important and contemporary technical issues related to a 20% wind energy scenario for the large portion of the electric demand in the Eastern Interconnection.

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