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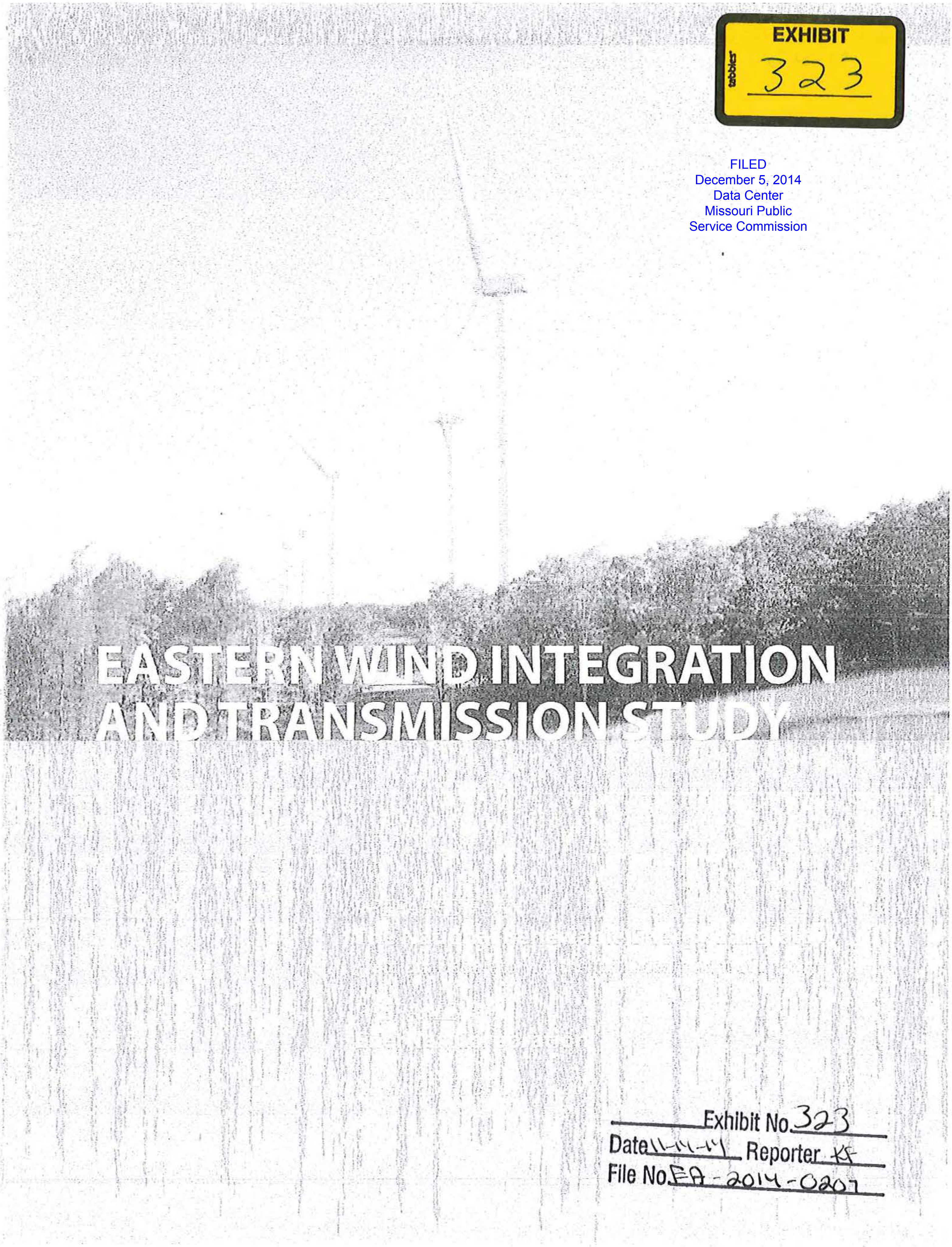

EASTERN WIND INTEGRATION AND TRANSMISSION STUDY

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EWITS was the first of its kind in terms of scope, scale, and process. Initiated in 2007, the study was designed to examine the operational impact of up to 20% to 30% wind energy penetration on the bulk power system in the Eastern Interconnection of the United States.

To set an appropriate backdrop for addressing the key study questions, the EWITS project team—with input from a wide range of project stakeholders including the Technical Review Committee (TRC)—carefully constructed four high-penetration scenarios to represent different wind generation development possibilities in the Eastern Interconnection. Three of these scenarios delivered wind energy equivalent to 20% of the projected annual electrical energy requirements in 2024; the fourth scenario increased the amount of wind energy to 30%.

In each scenario, individual wind plants from the Eastern Wind Data Study database (see sidebar) were selected to reach the target energy level. The wind data consisted of hourly and 10-minute wind plant data for each of three years: 2004, 2005, and 2006. Wind plants were available in all geographic locations within the Eastern Interconnection except off the shore of the southeastern United States and Canada (because of limitations on the scope of work for the wind modeling). Approximately 4 GW of new Canadian renewable generation was modeled to cover imports of new Canadian wind and hydro to the northeast.

The Eastern Wind Data Study

A precursor to EWITS known as the Eastern Wind Data Study (AWS Truewind 2009) identified more than 700 GW of potential future wind plant sites for the eastern United States. All the major analytical elements of EWITS relied on the time series wind generation production data synthesized in this earlier effort. The data cover three historical years—2004, 2005, and 2006—at high spatial (2-kilometer [km]) and temporal (10-minute) resolution. On- and offshore resources are included, along with wind resources for all states.

A brief description of each scenario follows:

- **Scenario 1, 20% penetration** – High Capacity Factor, Onshore: Utilizes high-quality wind resources in the Great Plains, with other development in the eastern United States where good wind resources exist.
- **Scenario 2, 20% penetration** – Hybrid with Offshore: Some wind generation in the Great Plains is moved east. Some East Coast offshore development is included.
- **Scenario 3, 20% penetration** – Local with Aggressive Offshore: More wind generation is moved east toward load centers, necessitating broader use of offshore resources. The offshore wind assumptions represent an uppermost limit of what could be developed by 2024 under an aggressive technology-push scenario.

PROJECT OVERVIEW

This section describes the transmission requirements, wind operational impacts, production-cost modeling results, wind integration costs, carbon sensitivity analysis, and the wind contribution to resource adequacy for EWITS.

TRANSMISSION REQUIREMENTS

EWITS uses a deterministic, chronological production-cost model (PROMOD IV®)[1] for evaluating transmission requirements. The study process began with locating wind generation across the interconnection, and then determining what additional nonwind capacity would be required in each region to maintain reliability for the projected energy demand in the study year. No new transmission was considered at this stage. This step allowed the study analysts to identify the locations of electrical energy supply and locate the loads or demand for the energy. To develop the transmission overlays, then, the project team used economic signals to connect the "sources" (supply) to the "sinks" (loads).

The study team used an economics-based expansion planning methodology to develop transmission requirements for each scenario based on the output of the different production simulations. Before each set of simulations, the additional nonwind capacity required to reliably serve the projected load was determined using traditional generation expansion methodologies. Wind generation was assigned a firm capacity value of 20%. Next, wind generation and the indicated conventional expansion were added to the production-cost model that contained the existing transmission network.

After simulating system operation over an entire year of hourly data, study analysts then compared the results of this modeling simulation to those from a similar simulation in which constraints on the transmission system were removed. The comparison indicates how regional or interconnection-wide production costs increase because of transmission congestion, or put another way, what value could be achieved by eliminating or reducing transmission constraints. Differences between the "constrained" case and the "unconstrained" case yield the following information:

- The areas of economic energy sources and sinks
- The interface flow changes to determine the incremental transfer capacity needs
- The total benefit savings, which in turn gives a rough estimate of a potential budget for building transmission to relieve constraints and reduce congestion costs

[1] PROMOD IV (developed by Ventyx) is an integrated electric generation and transmission market simulation system that incorporates extensive details of generating unit operating characteristics and constraints, transmission constraints, generation analysis, unit commitment/operating conditions, and market system operations. PROMOD IV performs an 8,760-hour commitment and dispatch recognizing both generation and transmission impacts at the bus-bar level. (Bus-bar refers to the point at which power is available for transmission.)

Transmission flows between regions in EWITS are determined in part by the differences between production simulations using a "copper sheet" (i.e., no transmission constraints, no congestion) versus the existing transmission system. Transmission capacity is designed to deliver 80% of the desired energy flow. Figure 6 shows the annual generation differences between the unconstrained and constrained cases for Scenario 2. This helps to define the energy source and sink areas and gives insight into the optimal locations for potential transmission lines and substations. Red represents the energy source areas; blue signifies the energy sink areas. As Figure 7 illustrates, the price signal drives energy from low-cost source areas to high-cost sink areas if the transmission system is not constrained across the study footprint.

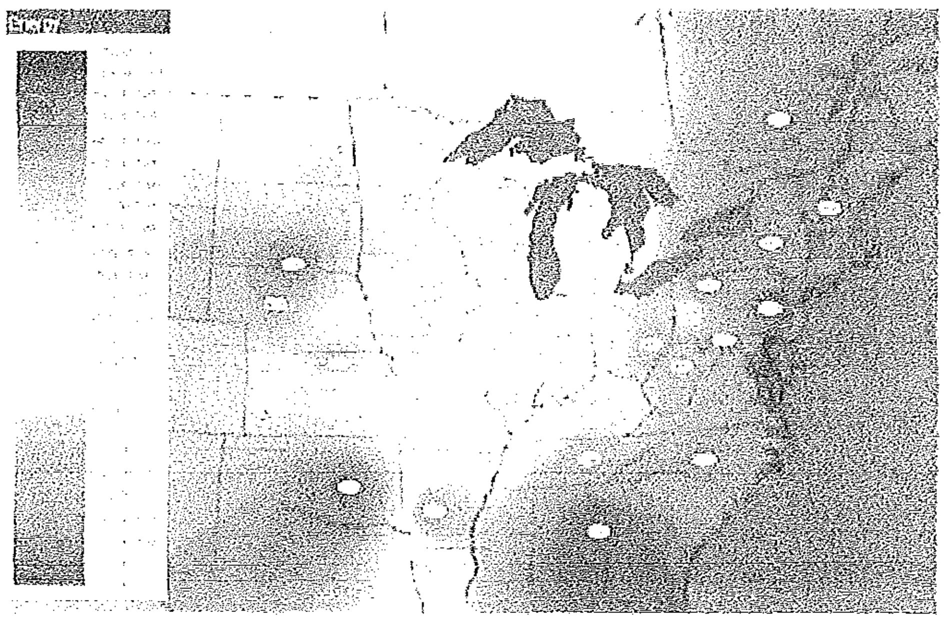

Figure 6. Scenario 2, annual generation differences between unconstrained case and constrained case (Note: Because price contours developed from defined pricing hubs, they do not correspond exactly to geography.)

Figure 7. Scenario 2, annual generation weighted locational marginal price (LMP) for constrained case

Using these comparative results as a guide, and with input from the TRC, the study team developed transmission overlays for each scenario.

The conceptual transmission overlays, shown in Figure 8, consist of multiple 800-kilovolt (kV) high-voltage direct current (HVDC) and extra-high voltage (EHV) AC lines with similar levels of new transmission and common elements for all four scenarios. Tapping the most high-quality wind resources for all three 20% scenarios, the project team arrived at a transmission overlay for Scenario 1 that consists of nine 800-kV HVDC lines and one 400-kV HVDC line. For Scenario 2, analysts moved some wind generation eastward, resulting in a reduced transmission overlay with seven 800-kV HVDC lines and one 400-kV HVDC line. As more wind generation is moved toward the east and more offshore resources are used in Scenario 3, the resulting transmission overlay has the fewest number of HVDC lines, with a total number of five 800-kV HVDC lines and one 400-kV HVDC line. To accommodate the aggressive 30% wind target and deliver a significant amount of offshore wind along the East Coast in Scenario 4, the overlay must be expanded to include ten 800-kV HVDC lines and one 400-kV HVDC line.

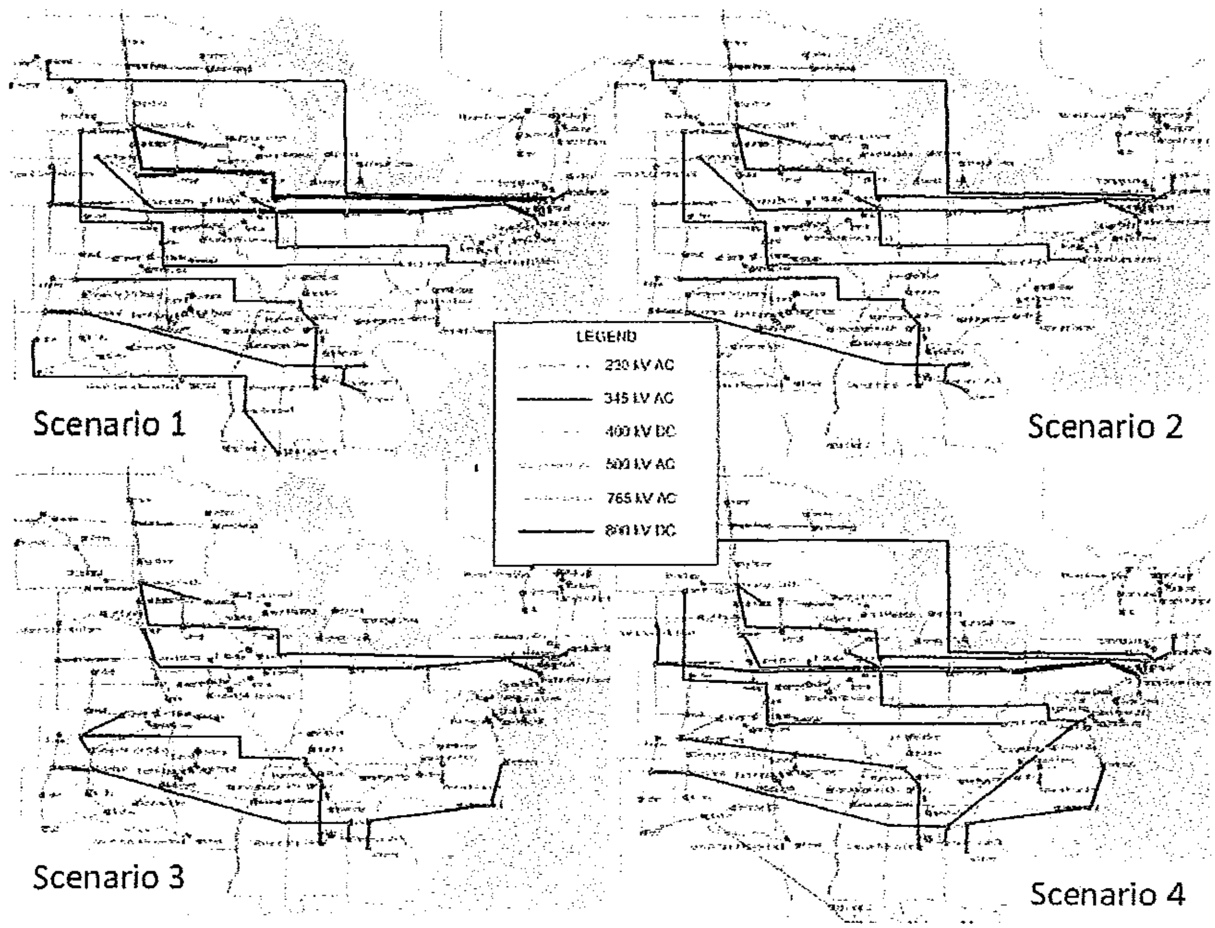

Figure 8. Conceptual EHV transmission overlays for each study scenario

Tables 2 through 4 summarize the transmission and construction cost-per-mile assumptions by voltage level, the estimated total line miles by voltage level, and the estimated cost in US$2024 for the four wind scenario conceptual overlays, respectively. In Table 4, the total AC line costs include a 25% margin to approximate the costs of substations and transformers. In addition, the total HVDC line costs include those for terminals, communications, and DC lines. Costs associated with an offshore wind collector system and those for some necessary regional transmission upgrades are not included in the total estimated cost and would increase total transmission costs. With approximately 22,697 miles of new EHV transmission lines, the transmission overlay for Scenario 1 has the highest estimated total cost at $93 billion (US$2009).

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TABLE 2. TRANSMISSION COST ASSUMPTIONS							
COST-PER-MILE ASSUMPTION							
VOLTAGE LEVEL	345 KV	345 KV AC (DOUBLE UNIT)	500 KV	500 KV AC (DOUBLE CIRCUIT)	765 KV	400 KV DC	800 KV DC
US$2024 (MILLIONS)	2,250,000	3,750,000	2,875,00	4,792,00	5,125,000	3,800,000	6,000,000
US$2009 (MILLIONS)	1,440,000	2,410,000	1,850,00	3,080,00	3,290,000	2,440,000	3,850,000

TABLE 3. ESTIMATED LINE MILEAGE BY SCENARIO								
ESTIMATED LINE MILEAGE SUMMARY								
VOLTAGE LEVEL	345 KV	345 KV AC (DOUBLE CIRCUIT)	500 KV	500 KV AC (DOUBLE CIRCUIT)	765 KV	400 KV DC	800 KV DC	TOTAL
REFERENCE	3,106	292	593	494	2,624	470	2,400	9,979
SCENARIO 1	1,977	247	1,264	243	7,304	560	11,102	22,697
SCENARIO 2	1,977	247	1,264	243	7,304	560	8,352	19,947
SCENARIO 3	1,977	247	1,264	742	7,304	769	4,747	17,050
SCENARIO 4	1,977	247	1,264	742	7,304	560	10,573	22,667

TABLE 4. ESTIMATED COSTS BY SCENARIO (US$2009, MILLIONS)								
Estimated Cost Summary (US $2024, millions)								
VOLTAGE LEVEL	345 KV	345 KV AC (DOUBLE CIRCUIT)	500 KV	500 KV AC (DOUBLE CIRCUIT)	765 KV	400 KV DC	800 KV DC	TOTAL
Reference	5,607	880	1,367	1,900	10,790	1,383	9,243	31,170
Scenario 1	3,569	743	2,916	935	30,033	1,539	53,445	93,179
Scenario 2	3,569	743	2,916	935	30,033	1,539	40,206	79,941
Scenario 3	3,569	743	2,916	935	30,033	1,898	22,852	64,865
Scenario 4	3,569	743	2,916	935	30,033	1,539	50,898	92,551

Specific findings and conclusions from development of the transmission overlays for each scenario include the following:

- The 800-kV HVDC and EHV AC lines are preferred if not required because of the volumes of energy that must be transported across and around the interconnection, as well as the distances involved.
- Similar levels of new transmission are needed across the four scenarios, and certain major facilities appear in all the scenarios. This commonality is influenced by the top-down method used and the location of the wind generation in each scenario. The study focuses on four possible 2024 "futures." Determining a path for realizing one or more of those futures was outside the study scope. Large amounts of transmission are also required in the Reference Case.
- The modeling indicates that significant wind generation can be accommodated as long as adequate transmission capacity is available and market/operational rules facilitate close cooperation among the operating regions.

- Transmission offers capacity benefits in its own right, and enhances wind generation's contribution to reliability by a measurable and significant amount.
- The EHV DC transmission that constitutes a major portion of the overlays designed for the scenarios in EWITS has benefits beyond those evaluated here. For example, it would be possible to schedule reserves from one area to another, effectively transporting variability resulting from 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 caused by transient stability issues.

WIND OPERATIONAL IMPACTS

Reliable delivery of electrical energy to load centers entails a continuous process of scheduling and adjusting electric generation in response to constantly changing demand. Sufficient amounts of wind generation increase the variability and uncertainty in demand that power system operators face from day to day or even from minute to minute. Quantifying how the amounts of wind generation in each of the study scenarios would affect daily operations of the bulk system and estimating the costs of those effects were major components of EWITS.

Using detailed chronological production simulations for each scenario, the study team assessed impacts on power system operation. The objective of these simulations was to mimic how day-to-day operations of the Eastern Interconnection would be conducted in 2024 with the prescribed amounts of wind generation in each scenario, new conventional generation per the expansion study, and the transmission overlays the study team developed. Ways to manage the increased variability and uncertainty attributable to wind generation, along with the resulting effect on operational costs, were of primary interest.

EWITS uses a deterministic production-cost model to run hourly power system operational simulations using the transmission overlays for each scenario and the wind plant outputs and actual load data for 2004, 2005, and 2006. The model takes the wind generation at each "injection bus" (i.e., the closest transmission connection to the wind plant) and dispatches nonwind generation units accordingly for each market region while solving at the model node for the LMP. The tool simulates actual power system operations by first solving the unit-commitment problem (i.e., what conventional generators will be dispatched to meet load), then using the wind power and load forecasts, and finally dispatching the units based on the actual modeled wind and load data. Obtaining realistic results is necessary because unit-commitment decisions must actually be made well in advance, allowing generators sufficient time to start up and synchronize to the grid. A hurdle rate accounts for hourly transactions among eight different market regions. The simulation is done over the entire study region and the wind plant and load time series data capture geographic diversity.

RESERVE REQUIREMENTS

With large amounts of wind generation, additional operating reserves (see sidebar) are needed to support interconnection frequency and maintain balance between generation and load. Because the amounts of wind generation in any of the operating areas, for any of the scenarios, dramatically exceed the levels for which appreciable operating experience exists, the study team conducted statistical and mathematical analyses of the wind generation and load profile data to estimate the additional requirements. These were used as inputs to the production-cost modeling. The analysis focused on the major categories of operating reserves, which included needs for regulation, load following, and contingencies.

In the production simulations for each scenario, study analysts took into account the additional uncertainty and variability resulting from wind generation by

- Incorporating the increased operating reserves as constraints on the commitment and dispatch of generating resources in each operating area
- Committing generating units for operation based on forecasts of load and wind generation, then dispatching the available units against actual quantities.

The levels of wind generation considered in EWITS increase the amount of operating reserves required to support interconnection frequency and balance the system in real time. Contingency reserves are not directly affected, but the amount of spinning reserves assigned to regulation duty must increase because of the additional variability and short-term uncertainty of the balancing area demand.

Types of Reserves

In bulk electric system operations, different types of generation reserves are maintained to support the delivery of capacity and energy from resources to loads in accordance with good utility practice.

Contingency Reserves

Reserves to mitigate a "contingency," which is defined as the unexpected failure or outage of a system component, such as a generator, a transmission line, a circuit breaker, a switch, or another electrical element. In the formal NERC definition, this term refers to 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 to provide 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.

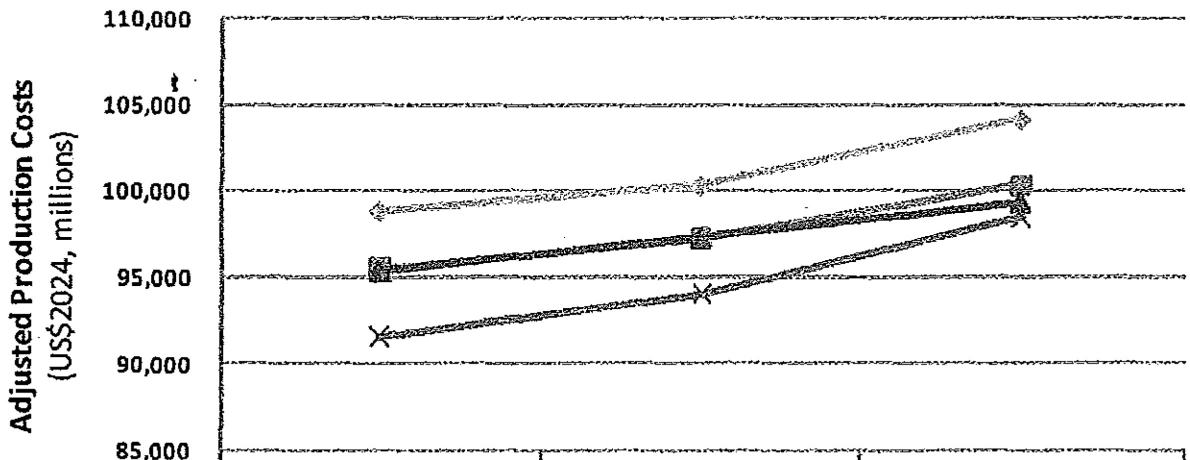
Regulating Reserves

An amount of reserve that is responsive to automatic generation control (AGC) and is sufficient to provide normal regulating margin. Regulating reserves 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 that follows a contingency event; or (2) load fully removable from the system within the disturbance recovery period after a contingency event.

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

Case

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

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.

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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.

Effective load-carrying capability

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.

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$5.13 in 2009
@ 3% / yr =
$5.95 in 2014

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.