Boston University Institute for Sustainable Energy

The Value of Diversifying Uncertain Renewable Generation through the Transmission System

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Acknowledgements

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Author bios

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With over twenty-five years of consulting experience, Pfeifenberger has authored and co-authored numerous industry reports and provided expert testimonies to courts, arbitration panels, and regulatory agencies throughout the U.S. and Canada. He works with a wide range of clients, including investor-owned utilities and public power companies, independent power system operators, transmission companies, generation and storage developers, large electricity customers, and regulatory agencies across North America and internationally. His recent experience includes wholesale electricity market design, renewable generation development, market-potential and cost-benefit analyses for battery storage and transmission investments; long-term power system planning, and electricity-industry regulation.

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Contents

Abstract

The integration of large-scale wind, solar, and other forms of variable renewable generation is a reality currently faced by many electricity grid operators, planners, and policymakers. These new sources of energy exhibit higher variability and uncertainty of supply than conventional sources of electricity—which requires operational adjustments, such as increased ramping requirements, the utilization of more flexible generation reserves, and employing new system control technologies and wholesale power market designs.

Broader geographic diversification through the transmission grid is widely recognized as a cost-effective approach to facilitate renewable integration. However, little work has been done to quantify (1) how the need to integrate growing amounts of renewable generation increases the benefit of expanding regional and interregional transmission capabilities; and (2) how the day-to-day renewable generation forecasting uncertainties further add to these benefits.

In this study, we estimate the magnitude of transmission-related benefits that can be attributed solely to the diversification of uncertain wind generation and load over a larger geographic footprint. The results of our analysis indicate that the benefits of transmission expansion between areas with diverse renewable generation resources are substantial, with significant reductions in system-wide costs and renewable generation curtailments. When real-time uncertainties of renewable generation are taken into consideration, the benefit of geographic diversification through the transmission grid are 2 to 20 times higher than benefits quantified only based on "perfect forecasts" under day-ahead market conditions.

Executive Summary

To isolate renewable generation diversification benefits of the transmission grid we use a case study with two neighboring power market subregions that are identical in every respect but the diversity of renewable generation outputs. They both have an identical load profile (with 14,000 MW annual peak load) and 16,000 MW of conventional generation, prior to adding the same amounts of renewable generation. Without diverging renewable generation profiles, both submarkets would yield exactly the same hourly dispatch and market prices—which means that there would be very little value of transmitting energy between the subregions.[1] Consequently, investing in transmission links between the two subregions likely would not be justified economically.

To study the diversification value of transmission in this setting, we relied on publicly-available historical data of both (1) day-ahead load and wind forecasts (hourly) and (2) actual real-time load and wind generation (subhourly). The wind generation data is for the western (inland) and southern (coastal) portions of ERCOT.[2] The differences in the day-ahead and real-time wind generation profiles and the associated diversity of generation output makes it valuable to add transmission in order to transfer energy between the two regions and diversify the two areas' renewable generation patterns.

The result of our market simulations show that, for identical renewable generation penetrations from 10% to 60% of annual energy consumption, interconnecting the two submarkets with different wind regimes through transmission investments:

- reduces annual production costs by between 2% and 23% and
- reduces annual renewable curtailments by 45% to 90%,

Furthermore, we find that the benefits of adding transmission between the markets are not only a function of the diversity of hourly renewable generation profiles, but also depend significantly on the uncertainty between day- and hour-ahead scheduling and sub-hourly real-time operations. Our simulation results show that, depending on the level of renewable generation installed:

- the annual reductions in real-time production cost from the transmission additions are between 2 to 20 times higher than those in the day-ahead market;

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1 The transmission capacity between the areas could increase economic efficiency to a limited extent by reducing unit commitment costs even if the two areas are identical; for example by allowing a single incremental unit to be committed under some conditions when two such units would be needed without the transmission capacity. Combining the two areas also reduces the need for operating reserves.

2 The correlation between the DA wind forecasts for the two regions used in the study is approximately 0.3. This relatively low but realistic correlation implies a complementarity between the two regions' wind regimes that is the source of geographic diversification benefits. A higher correlation would imply lower complementarity and would thus tend to reduce geographic diversification benefits.

- the reductions in annual real-time renewable curtailment (and associated negative market prices) are 2 to 40 times higher than those in the day-ahead market; and
- the difference between day-ahead and real-time market benefits is most pronounced at the lower (10-20%) levels of renewable generation shares; as the share of renewable generation increases, total transmission benefits grow but an increasingly higher portion of that value is captured in the day-ahead market.

In addition, our analysis shows that the majority of these benefits can be captured with transmission investments accommodating only 50% of the maximum unconstrained flow that would occur between the interconnected systems. In applying our results to transmission development in any particular real-world power system, the benefits discussed here would need to be combined with other transmission-related benefits, such that total benefits can be compared against the costs of transmission facilities needed to achieve different transfer capabilities to determine the optimal level of investment.

While the scope of this case study was limited to analyzing the diversification value for two wind generation regimes for which both hourly day-ahead forecast and actual real-time intra-hour generation was publicly available, the results have important generalizable implications for transmission planning, energy policy, and electricity market design. First, existing transmission planning models—which do not typically simulate sub-hourly real-time markets with load and renewable generation forecasting uncertainty—significantly understate transmission benefits related to the geographic diversification of variable renewable generation. Second, energy policies that encourage the development of a highly-diverse portfolio of renewable generation will be more cost effective than policies that do not consider the benefits of broad geographical and technological resource diversity. Third, at low levels of renewable generation, much of the geographic diversification benefits of transmission can be captured if the interconnected regions operate in a real-time energy market. As the share of renewable generation grows, however, the benefit of a geographically-integrated day-ahead market increases.

I. Introduction

The integration of large-scale wind, solar, and other forms of variable renewable generation is a reality currently faced by grid operators, planners, and policymakers. These sources of energy, while virtually emissions-free and with low variable cost, exhibit higher variability and uncertainty of supply than conventional sources of electricity, such as, hydro and thermal power plants. This additional variability and uncertainty brings with it the need for operational adjustments, such as increased ramping requirements, the utilization of more flexible generation reserves, and employing new system control technologies and wholesale power market designs. It also brings with it increased cycling of conventional power plants[3] and, in cases in which the renewable output simply cannot be injected into the system without jeopardizing reliability, the curtailment of renewable generation.

Transmission between markets with different patterns of variable renewable generation has long been recognized as a cost-effective approach to facilitate renewable integration in a decarbonizing electricity industry.[4] However, little work has been done to quantify the magnitude of this diversification value of transmission investments and the full benefits of being able to diversify uncertain variable generation are rarely included in the cost-benefit analyses used to analyze the viability of candidate transmission projects. Further, transmission benefits studies have typically employed only deterministic simulations of hourly wholesale power markets—akin to "day-ahead" markets that are based on an assumption of perfect foresight.[5] A deterministic market simulation cannot fully account for the uncertainty between the day-ahead timeframe (which is typically settled on an hourly basis) and the real-time operation of the system (which is typically settled on a 5- to 10-minute basis). The challenges associated with these uncertainties include the need to adjust unit commitment decisions due to inaccurate day-ahead forecasts and significant real-time price spikes and negative prices that can result from large forecast errors and sub-hourly variability. As a result, transmission investments that may be justified on the basis of a more holistic benefit-cost analysis that includes accounting for real-time uncertainties cannot be supported through deterministic hourly market simulations.[6]

In this study, we investigate and quantify the magnitude of the benefits associated with interconnecting systems with high penetrations of wind generation. Our aim is to provide

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[3] A detailed discussion of the cycling costs of renewable integration can be found in NREL (2013)

[4] See, for example, US DOE (2008), NREL (2010), NREL (2011), NREL (2015), SPP (2016).

[5] For example, in NREL (2011), p. 146, "the average price for energy in the subhourly market was assumed not to diverge from the day-ahead price." For additional examples of broadly-used transmission benefits calculation approaches based on hourly, perfect foresight conditions, see, e.g., CAISO (2017), MISO (2018).

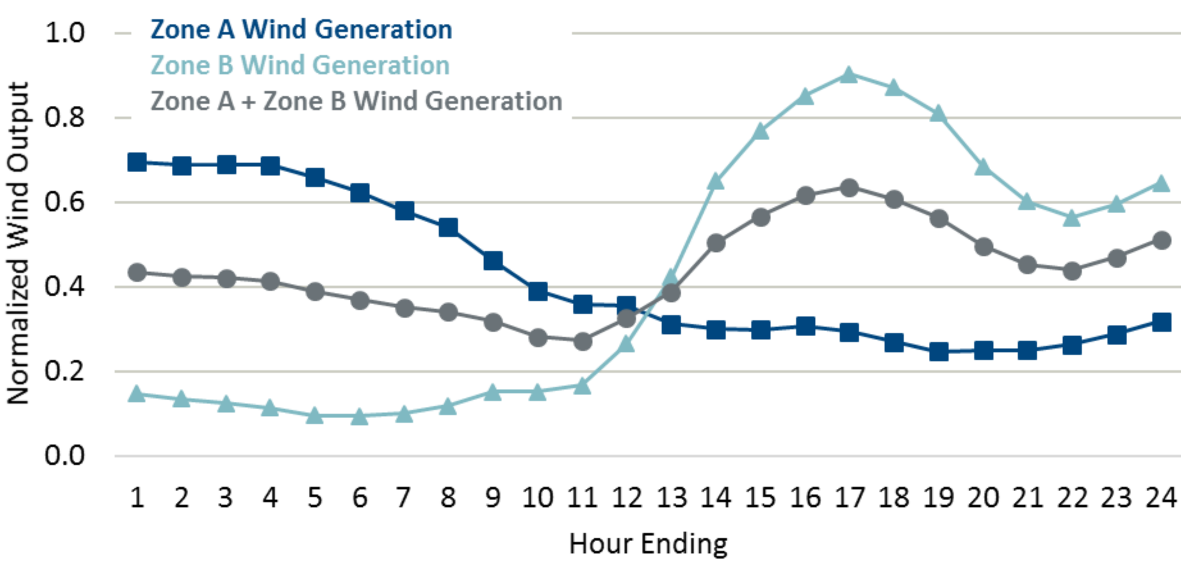
[6] For a more complete discussion of the broad range of transmission investment benefits and how to quantify them, see Chang, Pfeifenberger and Haggerty (2013). For examples of quantifying a broad range of transmisison benefits see Newell et al. (2015), SPP (2016), and MISO (2017).

concrete analytical support for the notion of considering of a broader range of benefits, and specifically the interconnection benefits, in transmission planning and cost-benefit analyses.

The extent to which renewable integration can be operationally challenging and the magnitude of the potential benefits of transmission additions depends on (a) the type (renewable, thermal, etc.) and amount of installed generating capacity in the system, (b) the geographical scope of the system, and (c) the capability of its transmission network. The benefits of transmission investments related to renewable integration arise from the observed decrease in renewable resource aggregate output volatility that results from an increase in the geographic area from which such resources are drawn.[7]

Figure 1 demonstrates this principle at work for two adjacent areas of an electricity grid (which we will refer to in this report as Zone A and Zone B, respectively) over a typical 24-hour period. As noted, the two wind regimes used in this case study are from ERCOT's coastal southern and its western interior regions with a correlation factor of 0.3. It is clear from Figure 1 that Zone A wind output tends to be high when Zone B wind output tends to be low in the first 12 hours of the day and vice versa for the rest of the day. Overall, when the wind output from Zones A and B is aggregated in this particularly example, the "lows" are not so low and the "highs" are not so high. This means the aggregate wind volatility is less than the wind volatility of each individual zone.

Figure 1: Interconnection Impact on Aggregate Renewable Generator Output[8]



Source: This illustrative example represents a historical day during which the divergence of wind in the two subregions (the coastal ERCOT south and inland ERCOT west) is particularly pronounced, based on wind generation data made available by ERCOT. While this case study is limited to analyzing the diversity of different wind regimes, a similar divergence of renewable generation patterns is also experienced between wind- and solar-rich areas.

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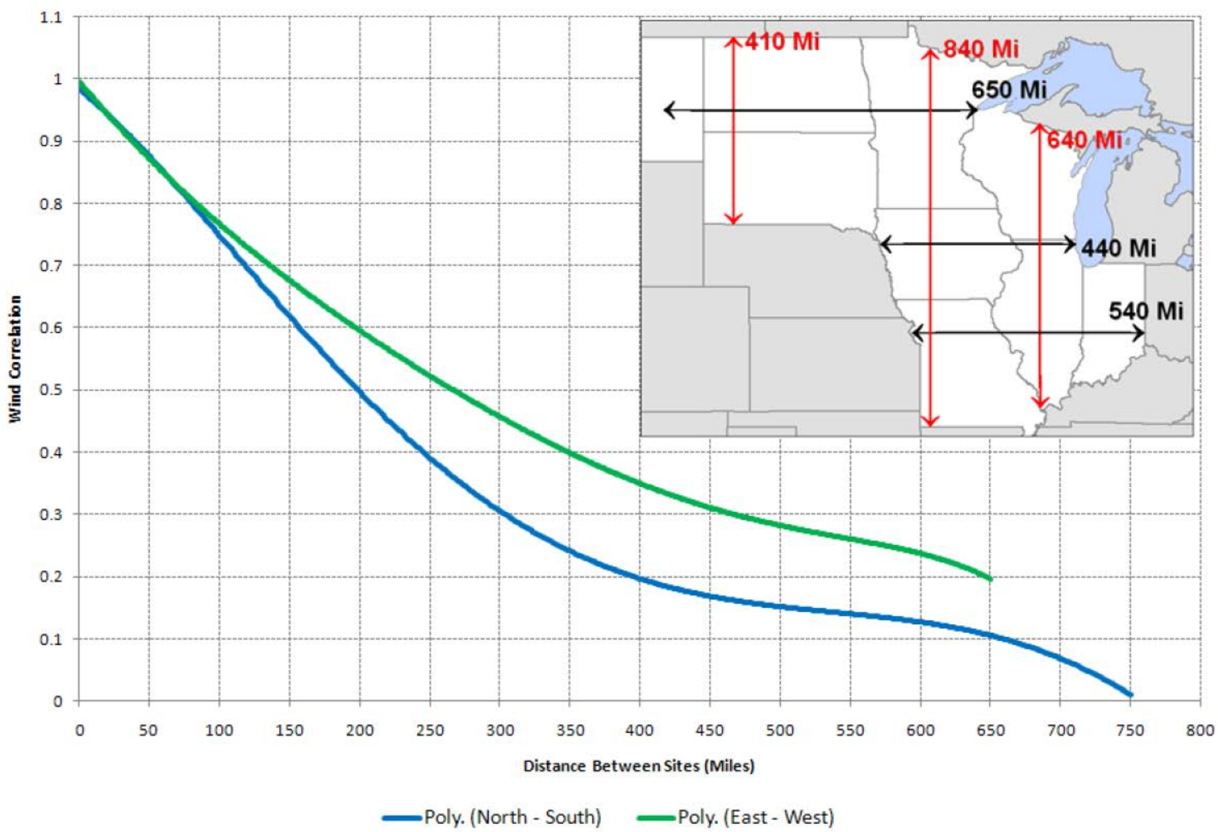
7 See US DOE (2008), pp. 100.

8 The wind output in Zone A, Zone B, and Zone A + Zone B is normalized to their respective annual maximum wind output.

As illustrated in Figure 2, prior studies have shown that wind generation correlations in the midwestern U.S. fall with increasing distance between facilities. The largest diversity benefit exists for over broad geographic regions. As shown, the correlation factors of wind regimes drop to a range of 0.2 to 0.35 at distances of 400 miles. The reduction in aggregate wind generation variability resulting from diversification through the transmission system has substantial benefits, as we quantify in this report.[9]

Figure 2: Geographical Diversity is Substantial over Broad Regions



Source: MISO (2013)

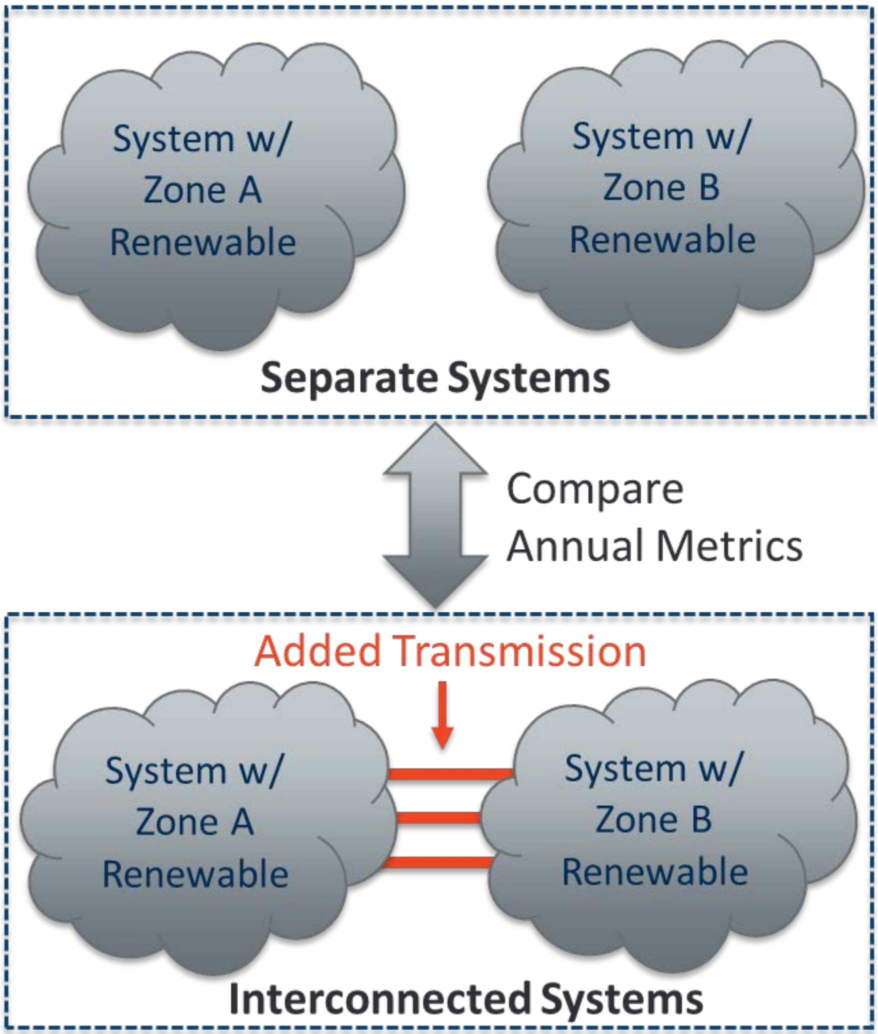
A. Study Approach

In this work, we isolate the benefits of transmission associated with interconnecting regions with diverse renewable resources. To do so, we constructed two systems (Zone A and Zone B) identical in every way except for the renewable generation profiles. As such, the differences between their respective renewable generation profiles is the primary driver of the observed differences in operational outcomes, such as the unit dispatch and production costs. As shown graphically in

9 For additional studies highlighting the impacts of renewables geographical diversity, see e.g., MISO (2017), MacDonald, A. E., Clack, C. T., et al (2016), NESCOE (2015), SPP (2016) and Charles River Associates (2010).

Figure 3, we analyze the benefits of operating these systems first as "separate", i.e., without any transmission linking them, and then as "interconnected" systems. We assume no limits on transfers within each zone.

Figure 3: Study Approach to Capture Renewable Integration Transmission Benefits



The primary metrics we quantified are the production costs, wind curtailments, and CO_2 emissions. To evaluate these metrics, we performed production cost simulations using the Power System Optimizer (PSO) package[10] and employing a three-cycle representation of the system scheduling decision-making process.[11] The three-cycle representation consists of:

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10 PSO is a product of Polaris Optimization Systems. For an overview of PSO, see Polaris Systems Optimization (2020).

11 PSO uses a state-of-the-at unit commitment and dispatch engine to cooptimize commitment, energy, reserve decisions, consistent with the algorithms used in ISO/RTO markets.

- The first cycle, reflecting a "day-ahead market," (DA) in which day-ahead unit commitment decisions are made for each hour of the following day with a two-day look-ahead based on load and wind forecasts.
- The second cycle, reflecting an "hour-ahead scheduling process," (HA) in which fast start units are committed at each hour for the following hour with a six-hour look-ahead and day-ahead dispatch decisions are updated for the same period based on updated load and wind forecasts.
- The third cycle, reflecting a "real-time market," (RT) in which unit dispatch decisions from the day-ahead and hour-ahead scheduling processes are updated at each ten-minute period with a 30-minute look ahead based on the realizations of real-time load and wind output.

Our three-cycle approach with sub-hourly real-time granularity enables us to capture the uncertainty associated with the transition from a day-ahead scheduling view of the system to the conditions faced in real-time operations.[12] To further emulate real power system operations, we enforce in all cycles spinning, intra-day commitment option, and regulating reserve requirements, which we compute based on the volatility of system net load (load minus wind).[13]

B. Overview of Study System

The models developed for this study are generally representative of the thermal fleet and load characteristics of a large midwestern ISO/RTO. The generation and load profile data in each system (Zone A and Zone B) are based on the resource mix and load of the SPP market footprint, reduced in size and aggregated to reduce the computational burden of the simulations. The assumed composition and characteristics of the generating fleets are shown in Table 1.

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[12] Generator forced outages between day-ahead scheduling and real-time operations are an important source of uncertainty in real-world system operations. However, to better isolate the renewables diversity benefits and avoid analytical "noise" related to the "lumpiness" of such outages, we do not model generator forced outages in this study. Capturing forced outages would likely increase the transmission interconnection benefits further due to the additional flexibility that the combined system provides to respond to such outages.

[13] For additional description of the reserve calculation methodology, see Appendix B.

Table 1: Generator Capacity and Characteristics Assumptions

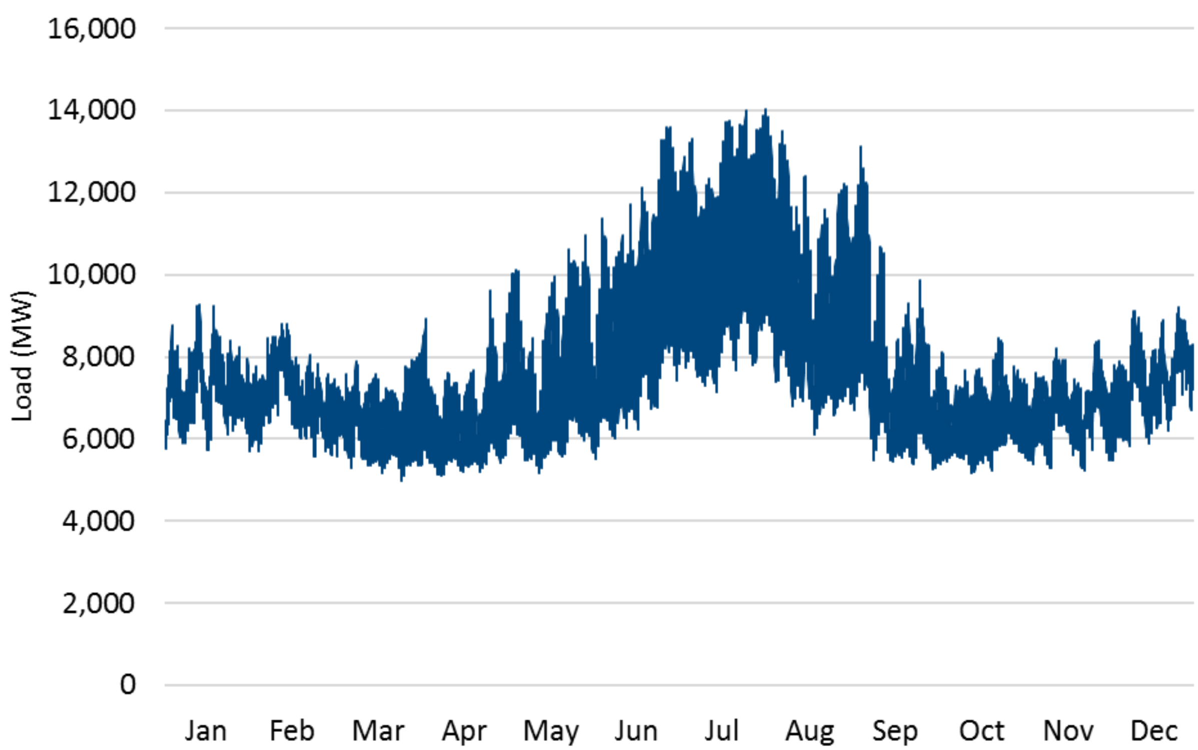
Technology	Nameplate Capacity (MW)	Fraction of Total Capacity (%)	Min Up/Dn Time (hrs)	Min Output (% of nameplate)	Ramp Rate (MW/min)**
Gas CC	3,328	20%	3/4	50%	10
Gas ST	2,420	15%	10/8	30%	6
Gas Peaker	1,967	12%	-	80%	-
ICE	300	2%	-	1%	-
Nuclear	793	5%	N/A	100%	N/A
Coal ST	7,488	46%	24/12	30, 50%*	3
Total	16,296				

* Coal ST units with capacity >=600 MW were assigned min outputs of 30%

** Ramp rates were used in the model only to determine the quantity of reserves units can provide. Gas Peakers and ICE units were assumed to be able to ramp over their entire operating range.

We use forecast and actual 2012 load from SPP, scaled down for the study system. The real-time load shape over the simulated year is shown in Figure 4. The system is summer peaking with an annual load factor of 55%. We report day-ahead and hour-ahead forecast as well as actual load annual consumption, peak, and minimum in Table 2.

Figure 4: Ten-minute Real-time Load Used in the Study



Notes: We use the load shown in both Zone A and Zone B. The load used in the interconnected systems case is exactly twice the load shown.

To model the geographic diversity of wind generation, we utilized two sets of wind forecast and actual wind production profiles from ERCOT, as they were readily available, time-synchronized with the SPP actual and forecasted load data, provided at the granularity required for the study, and are geographically proximate to SPP. We provide a summary of the day-ahead and hour-ahead forecasts as well as the real-time actual wind generation data in Table 2.

Table 2: Summary of Metrics for Load and Wind Generation Forecast and Actual Timeseries Data

Load and Wind Profile Metrics	DA	HA	RT
Total Annual Consumption (GWh)	67,981	67,982	67,979
Peak Load (MW)	14,100	14,003	14,048
Minimum Load (MW)	5,071	4,983	4,965
Zone A Annual Wind Generation (GWh)	6,798	6,798	6,798
Zone A Capacity Factor	0.36	0.36	0.35
Zone B Annual Wind Generation (GWh)	6,798	6,798	6,798
Zone B Capacity Factor	0.38	0.38	0.37

Note: wind generation shown is for the 10% penetration scenario.

We construct scenarios of increasing wind development (from 0% to 60% of the region's annual generation) by multiplying each zone's real-time actual wind generation timeseries by a factor such that the total annual wind generation matches the desired total level (as a fraction of real-time load). We then apply these same factors to the day-ahead and hour-ahead forecasts to construct the timeseries required for pre-real-time cycles.[14]

Simulating the system with the assumed mix of non-renewable generation, load, and without any added wind yields baseline CO_2 emissions of 98 million metric tons per year across zones A and B.[15] We provide additional details on the model and study system in Appendix A.

[14] Renewables siting is typically an important assumption in studies of systems with high renewables penetrations. However, to focus on the benefits of inter-regional transmission, we assume that no intra-zonal transmission limitations exist and thus siting assumptions were not required for this study.

[15] This level of CO_2 emissions is roughly in line with that in SPP, which has had CO_2 emissions of between 134 and 170 million metric tons per year over the last 6 years, has wind generation levels that increased from 12% to 27% over the same period, and is approximately twice the size of our combined zones A and B on a total load basis. For an overview of the SPP market, see SPP 101.

II. The Benefits of Transmission for Renewable Generation Integration

Transmission interconnection that enables the deployment of renewables at geographically diverse locations has a number of benefits. Foremost are the benefits of reduced production costs and reduced renewable curtailments, which can in turn reduce the investment costs associated with achieving climate and renewables policy goals. Further, interconnection can decrease the required levels of regulation and spinning reserve, reducing the number units that must be committed to provide these services and the associated costs. An additional and increasingly important benefit of interconnection is system-wide emissions reductions. In this section, we describe our findings on the magnitude of these benefits. We focus our discussion on the real time benefits and discuss the relationship between the real-time and day-ahead benefits in the following section.

A. Production Cost Reductions

The primary driver of reduced production costs with system interconnection is increased flexibility. Reduced reserve requirements and the larger pool of resources resulting from interconnection opens up additional flexibility in the existing generation fleets that can be harnessed to more efficiently operate the systems and reduce production costs. This increased access to operational flexibility additionally reduces wind curtailments, which reduces the energy produced by thermal generation and associated production costs.

Figure 5: Annual Real-Time Production Cost Savings and Percentage Savings Resulting from the Interconnection of Systems with 10% to 60% Renewable Energy Annually

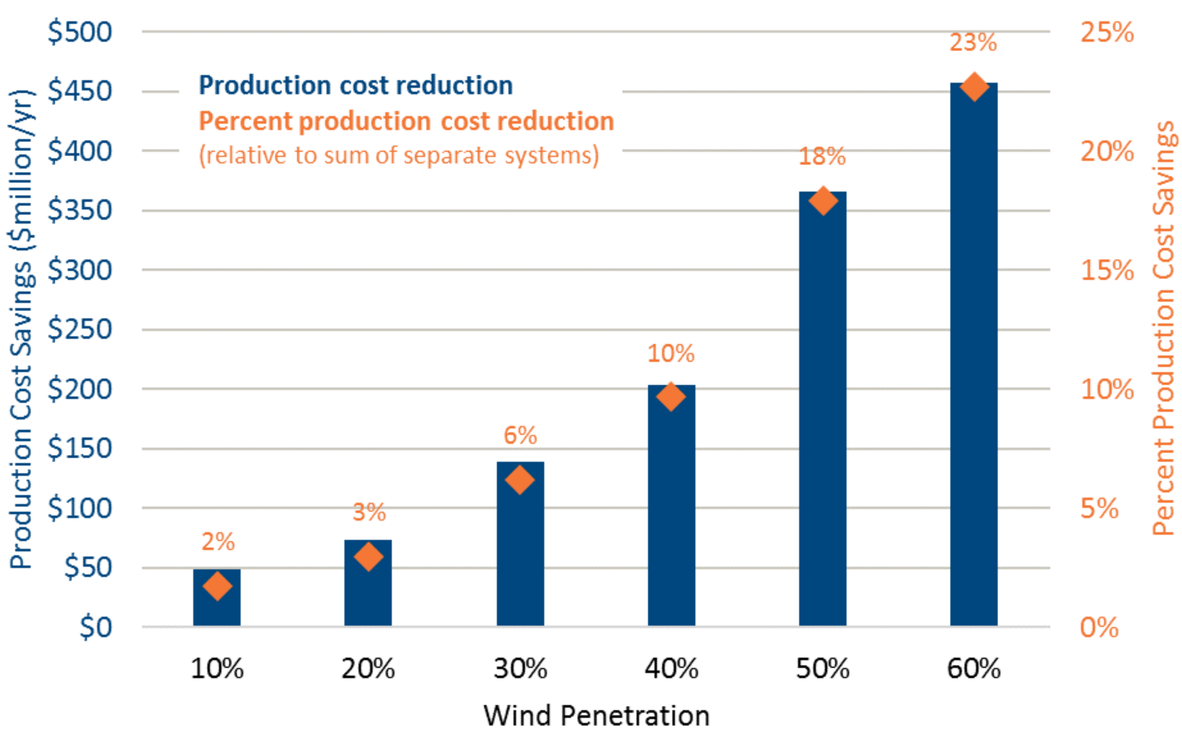


Figure 5 shows the production cost benefits of interconnecting the two systems with between 10% and 60% renewable generation. The results of our studies showed that interconnecting the two areas results in $49 million to $460 million in annual production cost savings (out of total production costs of between $2 and $3 billion), with both the absolute magnitude and percentage of savings increasing with the level of renewable generation. Marginal production cost savings rise until 50% of annual energy is sourced from renewable generation, after which they appear to begin to saturate. The high renewable generation levels at which this saturation effect occurs suggests that interconnections between neighboring regions become increasingly valuable as renewable generation levels increases. The production cost savings are driven principally by substantial renewable generation curtailments reductions enabled by transmission interconnections.

B. Curtailment Reductions

System operators are primarily concerned with maintaining the system reliability at the lowest cost. At times, it is not possible to utilize wind-generated electricity without compromising system reliability, due in large part to transmission limitations and a lack of available conventional generator flexibility. As such, the reduced volatility of aggregate wind output and additional flexibility of the conventional generation fleet that result from system interconnection drive reductions in wind curtailment.[16]

[16] Note that this case study assumes sufficient transmission capability within each market area. Thus the curtailments analyzed in this study are the result of over-generation conditions caused by limited dispatch-down flexibility. Renewable curtailments caused by intra-regional transmission constraints would be additional to those reported here.

Figure 6: Annual Real-Time Renewable Energy Curtailment Reduction Resulting from the Interconnection of Systems with 10% to 60% Renewable Generation Annually

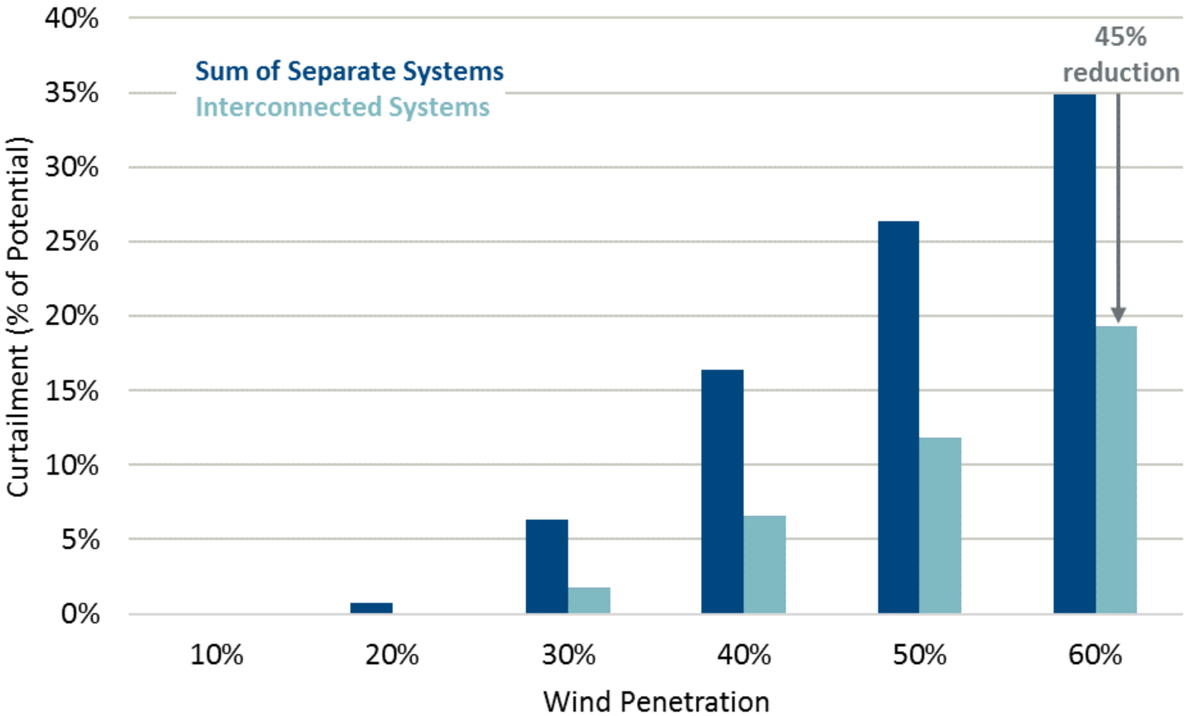


Figure 6 shows the total annual real-time curtailments that occur at wind penetrations from 10% to 60% in both the interconnected and separate systems. As the wind penetration increases, so too does the level of curtailment as the system flexibility is utilized to its limit. In the separated case, as much as 35% of the potential wind generation is curtailed. However, when we interconnect the two systems, the curtailments are reduced considerably—in the 60% renewable energy scenario, the curtailment is reduced from 35% to 20% of potential annual wind generation, a 45% reduction. The reduced renewable generation variability combined with additional flexibility of the larger system that contributes to the curtailment reductions shown in Figure 4 is a direct result of interconnection, amplified by the benefit of reduced regulation reserve requirements.

C. Reduced Regulation Reserve Requirements

Regulation reserve requirements are designed to provide system operators with adequate capacity to compensate for volatility and uncertainty in the net load.[17] Regulation reserve requirements are time-varying and are typically calculated using statistical models of wind and load variability based on historical data.[18] Expanding the system size through transmission interconnections plays a role

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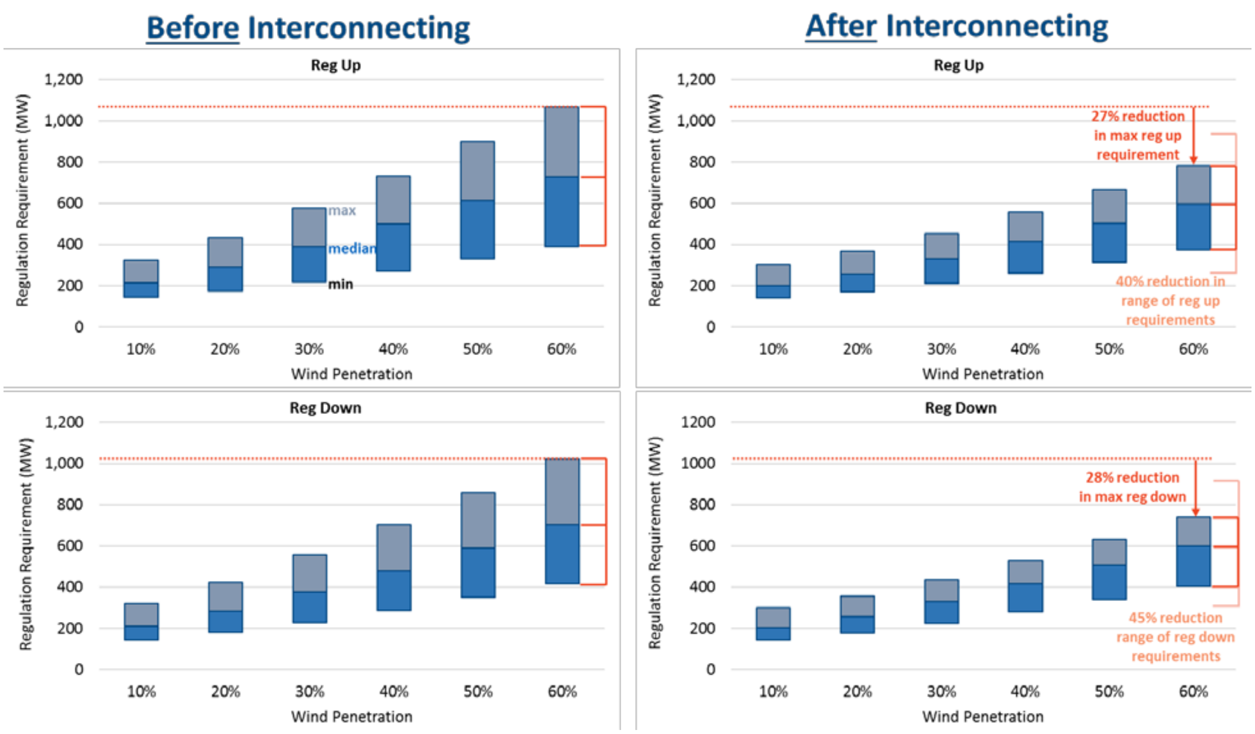
17 Reliability standards, including reserve requirements, are maintained by the North American Electric Reliability Corporation (NERC). For a complete set of standards, see NERC (2015).

18 See, for example, NERC (2011).

in the reduction of regulation reserve requirements by reducing the volatility of the aggregate load and wind, which impacts the volatility of the net load. Figure 5 shows the regulation reserve requirement statistics for upward and downward regulation with different wind generation shares and for the separate and interconnected systems. In our studies, the load of the two systems are identical (by study design), so the observed differences in regulation requirements can be attributed wholly to changes in the aggregate wind volatility through geographic diversification.

Figure 7: Regulation Reserve Requirement Statistics in Separate and Interconnected Systems with 10% to 60% Renewable Energy Annually



Note: statistics are calculated using the simulated 8760-hour regulation up/down time series for each wind penetration level

As shown in Figure 7, the level of regulation reserves required to accommodate the maximum historically observed net load volatility is considerably reduced by interconnecting the two systems. For example, the maximum reserve up/down requirement are reduced by ~120 MW in the 30% renewable energy scenario, around a 25% reduction. The reduction in reserve requirements releases additional conventional generation flexibility, which directly reduces production costs by decreasing the amount of online generation, and indirectly reduces production costs through the further reduction of wind curtailments. We summarize the regulation requirements and the interconnection-driven reductions in those requirements in Table 3.

Table 3: Interconnection-Driven Regulation Requirements

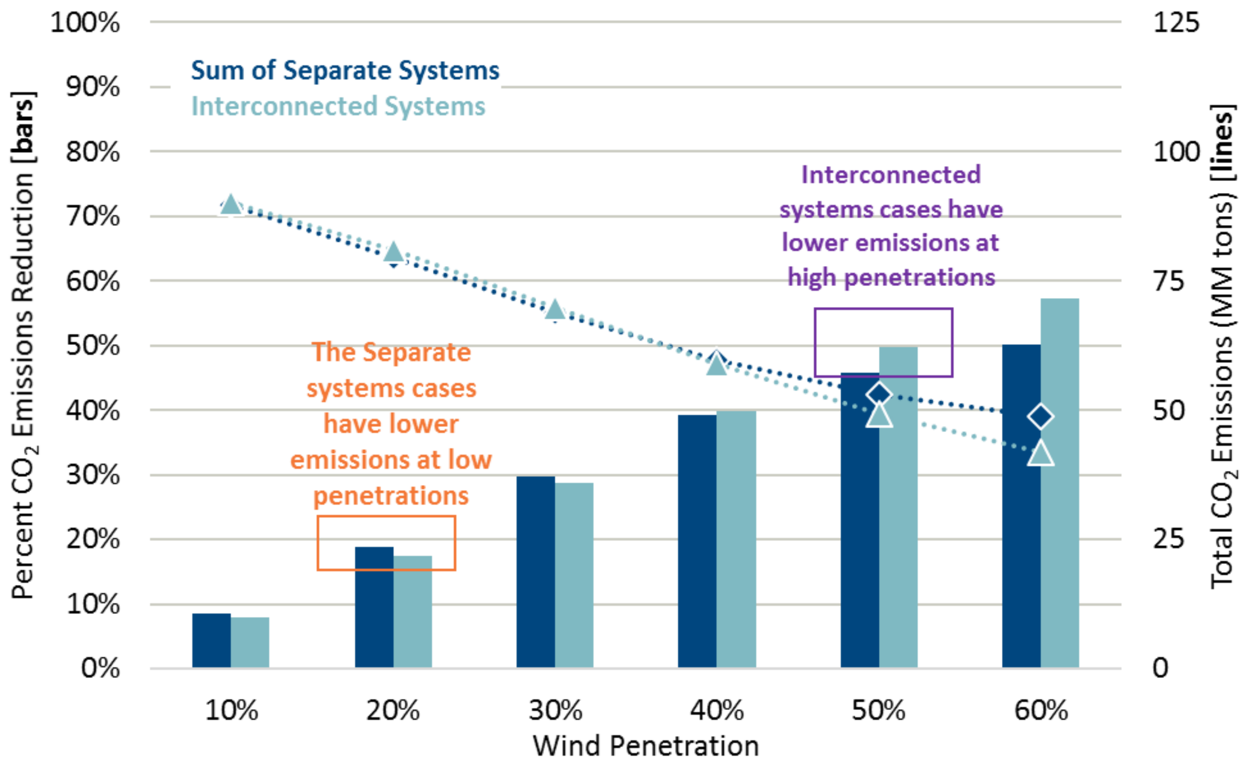
		Separate				Interconnected				% Delta		
	Pen.	Min	Med	Max		Min	Med	Max		Min	Med	Max
Reg Up	10%	143	214	324		142	202	303		-1%	-6%	-7%
	20%	174	292	434		170	256	365		-2%	-12%	-16%
	30%	219	390	576		211	329	453		-3%	-16%	-21%
	40%	271	498	734		261	413	555		-4%	-17%	-24%
	50%	329	612	900		315	502	666		-4%	-18%	-26%
	60%	391	730	1070		372	595	782		-5%	-18%	-27%
Reg Down	10%	144	211	321		143	202	301		-1%	-4%	-6%
	20%	179	284	422		176	257	357		-1%	-9%	-15%
	30%	228	377	555		224	331	436		-2%	-12%	-21%
	40%	286	481	704		279	416	530		-3%	-14%	-25%
	50%	349	591	861		340	507	632		-3%	-14%	-27%
	60%	416	704	1022		404	601	740		-3%	-15%	-28%

Note: % delta is the Interconnected system requirement minus the Separate system requirement expressed as a percentage of the Separate system requirement for each of the minimum, median, and maximum metrics.

D. CO_2 Emissions Reductions

The integration of large-scale renewable generation has been driven in large part by the policies aimed at reducing electricity sector CO_2 emissions. The CO_2 emissions reductions resulting from renewable integration are largely impacted by the composition of the conventional generation fleet—integrating renewables will results in higher emissions reductions in a system that still relies on coal-fired generation, such as SPP. The same can be said of the emissions reduction benefits of system interconnection—the magnitude of the reduction depends on the redispatch of the thermal units in response to wind generation as well as how much of the wind or other renewable generation can be reliably injected into the system.

Figure 8: Annual CO_2 Emissions and Emissions Reductions with and without System Interconnection for 10% to 60% Renewable Generation Relative to No Wind Scenario[19]



Note: emissions reductions measured relative to case with no wind (0% penetration)

Figure 8 shows the emissions reductions at the different shares of wind generation in our interconnected and separated cases. The reductions in each case are measured against the respective system annual emissions with no wind. From Figure 7 we see that addition of wind reduces system wide emissions and that the effect is more pronounced for the separated systems at low penetrations (10-30%) and for the interconnected system at high penetrations (40-60%). The more efficient dispatch of the system that results from interconnection results in a slightly increased utilization of the areas' coal generation. At low levels of wind penetrations development, the reduction in emissions from thermal generation displaced by the reduced wind curtailment when interconnecting the systems is insufficient to fully overcome the emissions due to the small increase in coal-fired dispatch. At high renewable generation shares, the significantly lower curtailments that occur in the interconnected system outweigh the emission impacts from small increases in the dispatch of coal-fired generation. As a result, even in systems with significant coal-fired generation (as simulated in this case study of SPP-like systems), the interconnected system has lower emissions than the separate systems as the level of wind generation increases.

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[19] Total CO_2 emissions across zones A and B in the no wind scenario are 98 million metric tons in both the separate and interconnected systems cases.

III. Geographic Diversification Benefits as a Function of Interconnection Capacity

The benefits reported up-to-now considered the interconnection of Zones A and B with transmission of sufficient (hurdle-free) capability to allow for all economic power flows. In this "copper sheet" scenario, the interconnection capability is sufficient to eliminate any and all intertie congestion. We now explore the sensitivity of the interconnection benefits to the total transfer capability of the assumed transmission system between the markets. As illustrated in Figure 9 (for the 30% renewable energy scenario), we consider total transmission capabilities between the two areas that are equal to the 50th, 70th, 90th percentile of the maximum area-to-area power flows experienced in the unconstrained, hurdle-free copper-sheet scenario.

Figure 9: Interconnection Capacity Sensitivity Study: Limited Transfer Capability Approach
(for the 30% Renewable Energy Scenario)

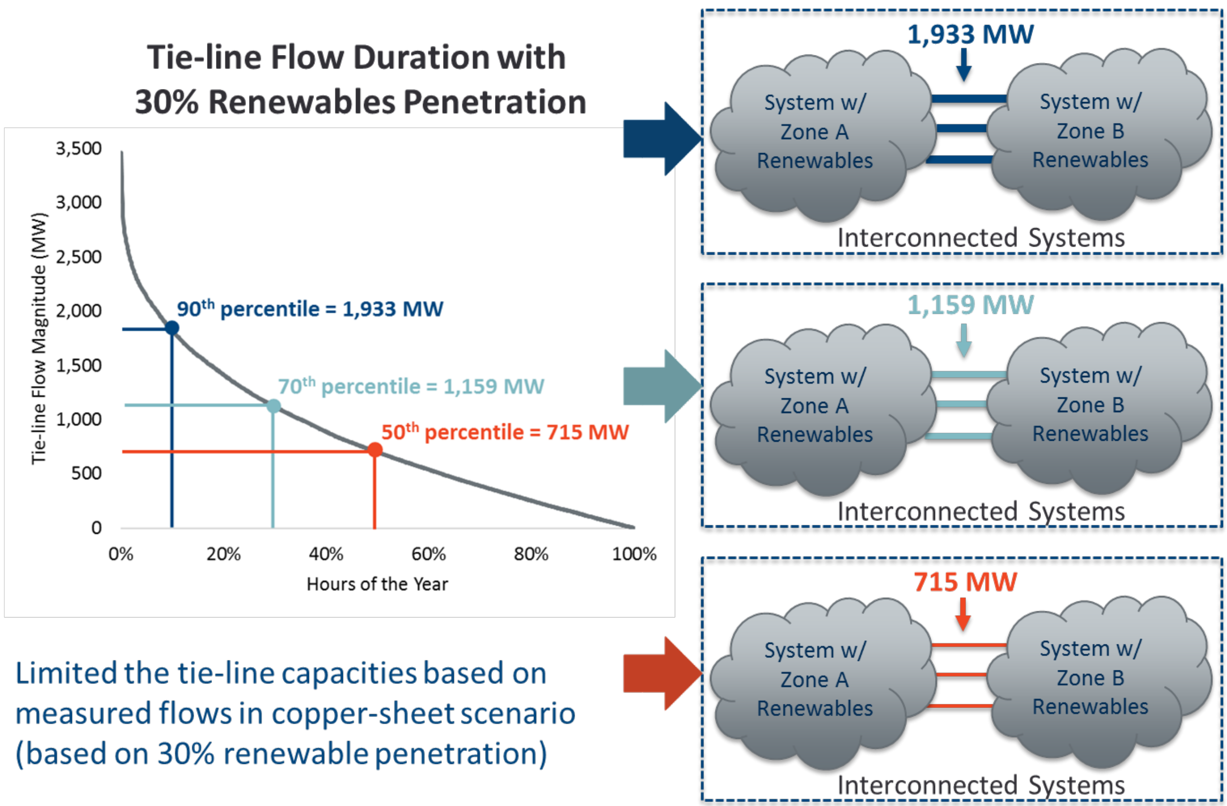
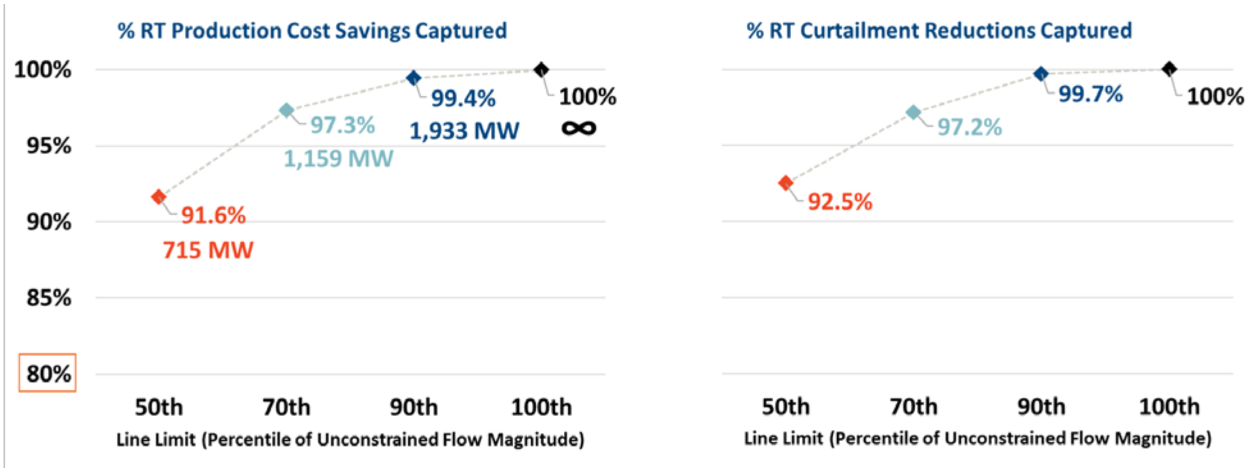


Figure 10 shows the production-cost and curtailment-reduction benefits for each level of interconnection capacity. We find that the incremental benefits of system interconnection are very large initially, but decline incrementally at increasing transfer capabilities. With a transfer capability equal to only the 50th percentile of the maximum unconstrained, hurdle-free flow, approximately 90% of the production cost savings and wind curtailment reduction benefits are captured.[20] In other words, building interconnections with half of the capacity that would be required to transmit all of the energy that could be transferred economically between systems captures nearly all of the benefits.

Figure 10: Real-Time Production Cost and Curtailment Reductions Captured at Various Interconnection Capacities from the Interconnection of Systems
(for the 30% Renewable Energy Scenario)



IV. Day-Ahead and Real-Time Market Benefits of Enabling Geographic Diversification through Transmission Investments

The results presented so far have reflected benefits for real-time market conditions with intra-hour dispatch optimization, hurdle-free transmission between the areas, and the need to balance deviations between forecast and actual load and renewables levels. This is in contrast to conventional planning studies, the majority of which do not reflect the uncertainties and intra-hour challenges faced by system operators. Rather, planning studies evaluating the economic benefits of transmission are based on simplified hourly simulations with perfect foresight of all system conditions, including renewable generation and load level. These "deterministic" hourly simulation of planning studies are akin to "day-ahead market" results, which similarly are based on hourly dispatch levels for forecast system conditions, without considering any uncertainties between day-ahead and real-time market conditions.

In this section, we compare the actual real-time benefits of geographic diversity discussed in the previous sections (based on optimal real-time dispatch of the combined system) to those that would be estimated considering only the day-ahead market outcomes without considering forecasting uncertainty and intra-hour variability. These conditions are simulated in the first cycle of the PSO model as described above.

20 This result suggests that reserve requirement reductions resulting from interconnection have a prominent role in the observed interconnection benefits. Preliminary analysis suggests that reduced reserve requirements may account for around 50% of the observed interconnection benefits.

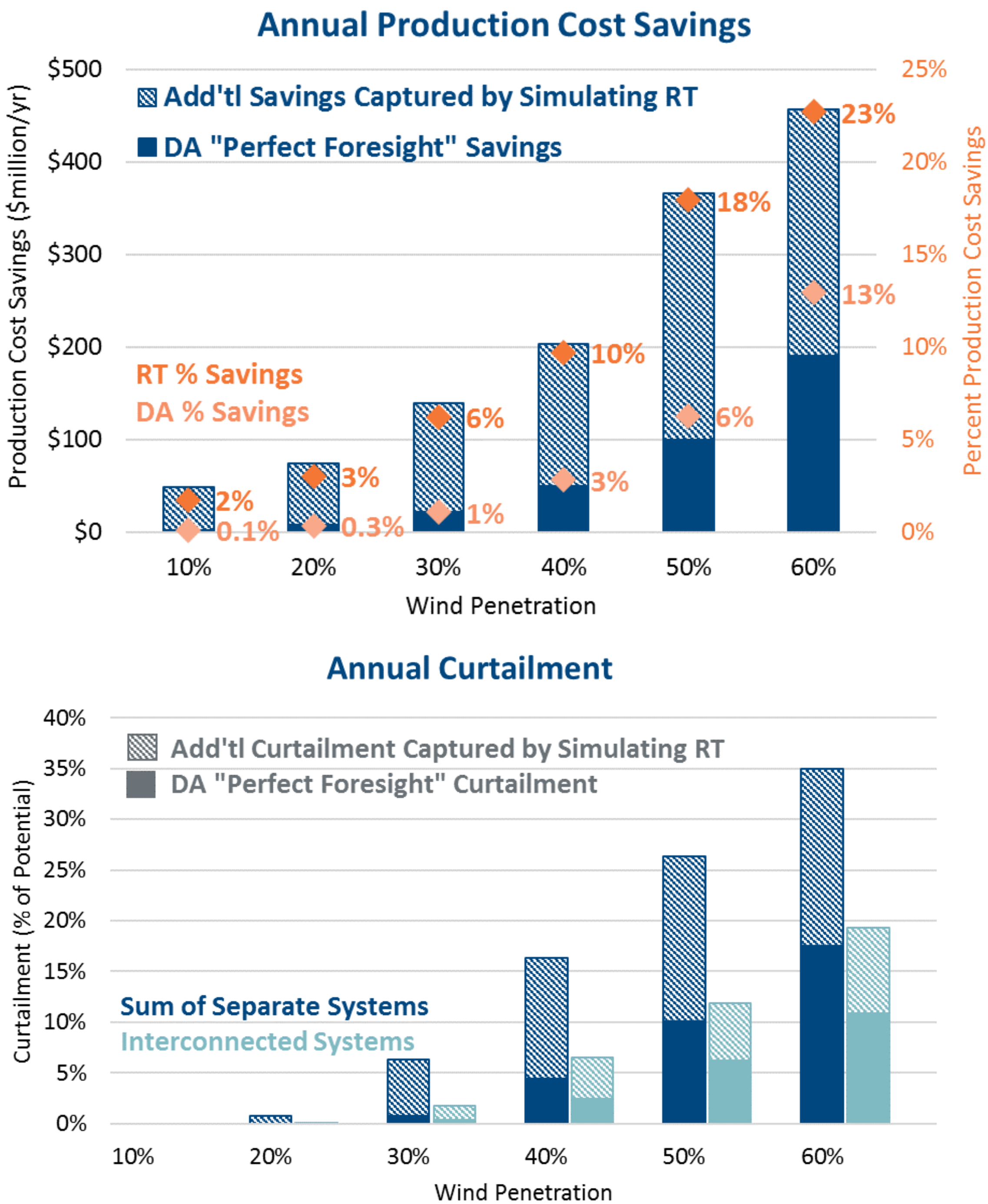
As shown in Figure 11, we find the real-time production cost savings are between 2 times to 20 times larger than those realized in day-ahead. The additional real-time relative benefits are the largest at the lower levels of renewable generation. Similarly, the wind curtailment benefits of interconnecting the two market areas are 2 to 40 times larger in real-time than those we observe in the day-ahead market.

These substantial differences in simulated day-ahead and real-time benefits and outcomes are driven by several factors. First, it's easier to optimize the system and minimize costs if there is perfect foresight (*i.e.*, no uncertainty) and there is enough time before scheduling decisions must be executed such that all unit-commitment decisions can be made based on that perfect foresight. This is the world assumed in most market simulation models (with hourly granularity) that are used for planning studies. Only the "day-ahead" markets fit these simulation assumptions.

Second, the world is uncertain. For many power plants, unit-commitment (including fuel purchase) decisions have to be made well ahead of real-time market operations, such as on a day-ahead basis. The uncertainty between when many unit commitment decisions need to be made and real-time operations—such as load uncertainty, variable renewable generation, unexpected generation and transmission outages—creates a need for more flexibility (including intra-hour) to manage that uncertainty. The system operator must rely on a more restricted set of typically higher-cost resources (i.e., those still available and physically capable of delivering flexibility on short notice) to provide that flexibility, which is the primary driver of the costs. For example, a fast-start gas peaker that was not required to meet day-ahead forecast load may be required in real-time to respond to the intra-day loss of a large unit committed in day-ahead or a large day-ahead wind over-forecast deviation, creating additional costs relative to the day-ahead view of system needs. In real-time, the system cannot respond as optimally as would be the case with perfect day-ahead foresight.

Interconnecting markets through transmission diversifies and significantly reduces this uncertainty. It also gives the system operators access to additional flexibility from a broader fleet of resources, lowering the costs of managing uncertainty. Thus, considering this dynamic between day-ahead forecasts and real-time uncertainty and intra-hour market conditions is necessary if the total benefits of transmission are to be measured.

Figure 11: Real-Time and Day-Ahead Production Cost Savings and Renewable Curtailments Resulting from the Interconnection of Systems with 10% to 60% Renewable Energy



Note: for annual curtailment, solid bars of both colors represent curtailment with DA "Perfect Foresight"; hashed bars of both colors represent the additional curtailment captured by also simulating uncertainty between day-ahead and real-time.

V. Conclusions and Recommendations

Transmission expansion is a key component of the successful integration of large-scale renewable generation. Efficient transmission investment necessitates effective cost-benefit analyses that accurately account for both the costs and benefits of a project. Our study demonstrates that the benefits associated with transmission projects that facilitate geographic diversification of renewable generation variances are substantial. However, we also show that a large portion of the potential benefits of transmission will not be captured by the transmission planning models currently employed. This is because these deterministic hourly models—approximating day-ahead market conditions without consideration of forecasting uncertainty or intra-hour system conditions—do not capture the benefit of reduced real-time uncertainty in the larger geographic footprint. In other words, the planning models ignore the additional real-time benefits of the transmission system.

In light of the findings in this study, we offer the following recommendations:

- Building new and reinforcing existing transmission interconnections between regions to facilitate geographical diversification of renewable generation regimes should be explored more thoroughly when choosing cost-effective pathways to achieving large-scale-renewable-integration and decarbonization goals.
- Studies of systems with even modest renewable generation shares should not solely rely on deterministic hourly simulations, but take into account the value of transmission in managing and diversifying intra-hour real-time renewable generation variability and forecasting uncertainty.
- Benefit-cost analyses of proposed transmission projects should be carefully designed to capture the full range of benefits that transmission brings about, including the additional real-time benefits of renewable generation diversification documented in our case study.

Our case study also documents that the real-time optimization of interconnected power system is significantly more valuable than day-ahead optimization at low and modest shares of renewable generation. This is consistent with the experience of geographically-large real-time balancing markets, such as the Western Energy Imbalance market. However, as the share of renewable generation grows, an increasing proportion of these geographic diversification benefits is captured through optimizing day-ahead market operations across the combined power systems.

Appendix A: Model and Data Description

A. Model Description

The model used in this study is intended to generally represent the thermal fleet and load characteristics of a large midwestern ISO/RTO. The generation and load profile data are based on the resource mix and load of the SPP market footprint, reduced in size and aggregated to reduce the computational burden of the simulations. We utilized wind forecasts and actual wind production profiles from ERCOT, as they were readily available and time-synchronized with the SPP load data, provided at the granularity required for the study, and are geographically proximate to SPP.

For this study, we simulate three market timeframes or “cycles”:

1. A day-ahead (DA) cycle in which slow-start (steam turbines) unit commitment decisions are finalized and a provisional dispatch determined relative to day-ahead forecasts of load and renewables;
2. An hour-ahead (HA) cycle in which the combined-cycle commitment decisions are finalized and the system redispatched relative to more up-to-date forecasts;
3. A real-time (RT) cycle in which the gas turbine and internal combustion engine (ICE) unit commitment decisions are finalized, and dispatch decisions for all units are finalized relative to actual load and renewables output.

The time granularity of the day-ahead and hour-ahead cycles is one hour, while that of the real-time cycle is ten minutes. The DA cycle solves a unit commitment with a 48-hour window and keeps the solution for the first 24 hours. The HA cycle solves a unit commitment with a six-hour window and keeps the solution for the first hour. The RT cycle solves the dispatch for a 2-hour window and keeps the six 10-minute intervals from the first hour.

B. Simulated Scenarios

Each simulated scenario is one year in length and defined by two parameters: (1) the wind penetration, ranging from 10-60% in 10% increments[21]; and (2) the system configuration, from separate systems (no transmission capability) to interconnected systems (infinite “copper sheet” transmission). The wind capacity is scaled uniformly to achieve the desired penetration in each scenario. We derive the scaling factors using the real-time wind and load data, and apply those same scaling factors to construct the day-ahead and hour-ahead wind forecasts for the respective penetration scenario. We additionally ran transfer capability sensitivities, in which we restrict flow between the interconnected systems to be below a pre-specified maximum.

[21] The wind penetration is defined to be the annual wind output in GWh divided by the annual load consumption in GWh.

Each of the wind penetration scenarios are simulated on three systems. The systems are constructed using the data described in the following section. The first two systems have the same load and non-renewable generation resources; the systems differ only in their wind profiles ("Zone A" wind vs "Zone B" wind). The third system consists of the first two systems connected by transmission lines with infinite transfer capability (also referred to above as our "copper sheet" scenario). We assume in all scenarios that there are no transmission limitations within each system.

C. Time Series Data Description

The DA load forecast and RT actual load were obtained from SPP and the HA load forecast was synthesized from the RT load forecast. The wind time series are hourly day-ahead and hour-ahead forecasts and actual RT outputs obtained from ERCOT for the interior west and coastal south regions. All time series data are for the year 2012 (the year for which wind forecast data was available). Table A1 summarizes the key characteristics of the load and wind profiles.

Table A1: Load and Wind Time Series Metrics for the DA, HA and RT cycles

Load and Wind Profile Metrics	DA	HA	RT
Total Annual Consumption (GWh)	67,981	67,982	67,979
Peak Load (MW)	14,100	14,003	14,048
Minimum Load (MW)	5,071	4,983	4,965
Zone A Annual Wind Generation (GWh)	6,798	6,798	6,798
Zone A Capacity Factor	0.36	0.36	0.35
Zone B Annual Wind Generation (GWh)	6,798	6,798	6,798
Zone B Capacity Factor	0.38	0.38	0.37

Table A2 shows the correlation between the various load and wind time series in the DA and HA cycles for the 1 year study period. The relatively low (but realistic) correlation between zonal wind is a principal driver of the geographic diversity benefits.

Table A2: Time Series Correlations for the DA and HA cycles

Correlations	DA load	DA Zone A Wind	DA Zone B Wind	HA load	HA Zone A Wind	HA Zone B Wind
DA load	1	-0.004	-0.363	0.939	0.000	-0.315
DA Zone A Wind	-0.004	1	0.316	0.041	0.912	0.329
DA Zone B Wind	-0.363	0.316	1	-0.349	0.328	0.925
HA load	0.939	0.041	-0.349	1	0.052	-0.303
HA Zone A Wind	0.000	0.912	0.328	0.052	1	0.348
HA Zone B Wind	-0.315	0.329	0.925	-0.303	0.348	1

D. GENERATION DATA DESCRIPTION

The study generation fleet composition is based on the SPP generation fleet. Table A3 summarizes the study generation fleet metrics.

Table A3: Non-Renewable Generator Metrics by Technology Type

Technology	Number of Units	Total Capacity (MW)
Gas CC	14	3,328
Gas ST	9	2,420
Gas Peakers	25	1,967
Internal Combustion Engine (ICE)	2	300
Nuclear	1	793
Coal ST	37	7,488
Total:	88	16,296

The system reserve margin not including wind is 16%. If wind is credited at 10% of its nameplate capacity towards the system-wide firm capacity, the capacity margin rises by 2% for each additional 10% of wind penetration. For example, with 20% wind penetration, the capacity margin including wind is 20%.

Table A4 summarizes the generator operational characteristic assumptions used in the study.

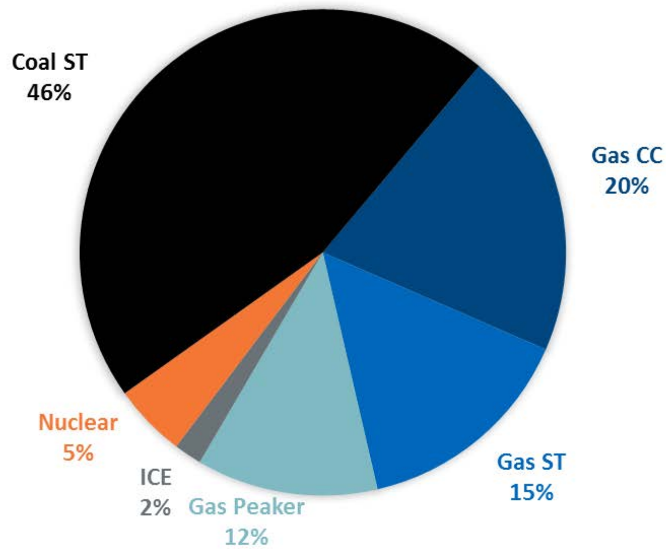
Table A4: Non-Renewable Generator Characteristics by Technology Type

Technology	Min Up/Dn Time (hrs)	Min Output (% of nameplate capacity)	Ramp Rate (MW/min)**
Gas CC	3/4	50%	10
Gas ST	10/8	30%	6
Gas Peaker	-	80%	-
ICE	-	1%	-
Nuclear	N/A	100%	N/A
Coal ST	24/12	30, 50%*	3

* Units with capacity >=600 MW were assigned min outputs of the lower of the two reported values
** Ramp rates were used in the model only to determine the quantity of reserves units can provide

Figure A1 shows the non-renewable generation mix by type. Natural gas-and coal-fired generation make up the bulk of capacity.

Figure A1: Non-renewable generation capacity mix by fuel type



The nuclear unit is assumed to be "must run" and committed in all cycles. The ICE units are aggregations of many smaller units and so their dispatch range is assumed to be their entire capacity and their ramping capability assumed to be greater than their range for the time horizons of interest (10-minute and 20-minute reserve availability). The gas turbines are also assumed to be able to ramp over their entire range for the time horizons of interest.

E. Overview of Power System Optimizer (PSO)

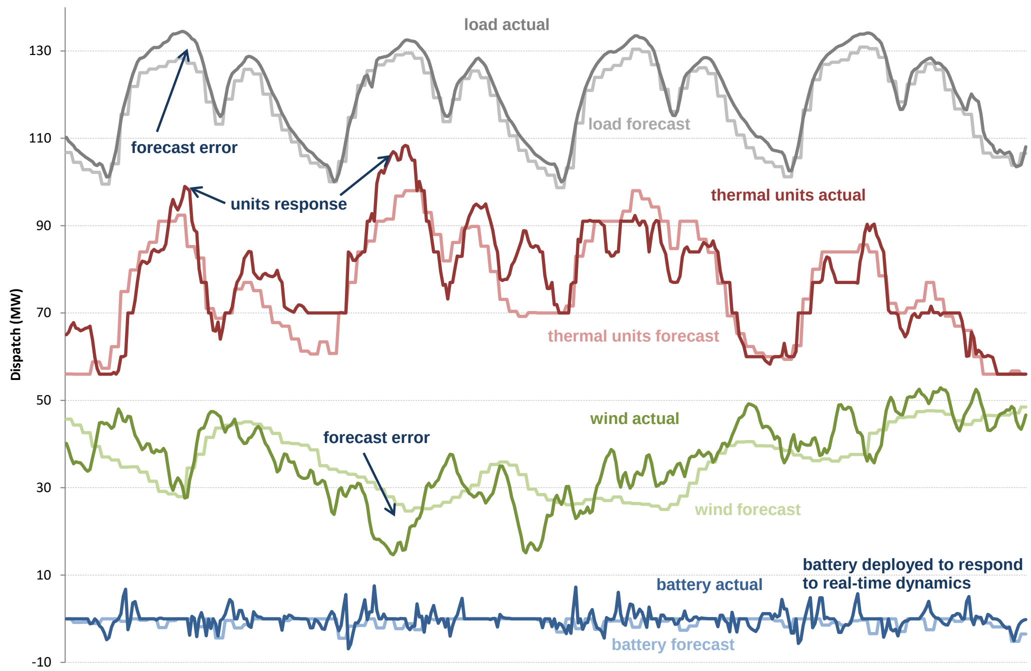
The study was conducted using PSO, a state-of-the-art production simulation tool. Polaris Systems Optimization has developed PSO to support the simulation of multi-level, nested time intervals that simultaneously optimize energy and ancillary services dispatch, and to simulate uncertainties. The model can:

- Simulate intra-hour operations and constraints (minute-to-minute or multiple seconds)
- Model dispatch decision at different time intervals and the impact of generation and load uncertainties on decision making
- Flexibly model new types of resources (generation, load, transmission, storage, services) without predetermined parameters – allows users to set operational assumptions
- Co-optimize across markets (energy and individual types of ancillary service markets)

- Support development of new modeling approaches (transmission switching, stochastic methods, multi-product models)

PSO simulates actual operations, not just setting reserves aside. This feature, illustrated in Figure A2, is critical to capture the actual effects of generation profile diversity core to this study.

Figure A2: Illustrative Example of PSO DA + RT Dispatch Capturing Uncertainty



Source: The Brattle Group

Appendix B: Reserves Requirement Calculation Methodology

In this study, we model four reserve types:

1. **Spinning reserves**: covering the need for the system to have online capacity to respond in the event of a large contingency. The spinning reserves have a 20-minute activation time requirement (i.e., the maximum capacity a unit can provide is 20 times its ramp rate)
2. **Regulation up**: covering the need to for upward capacity to cover mismatches between load and generation and maintain system frequency in between real-time market intervals. Regulation up as a 10-minute activation time requirement.
3. **Regulation down**: covering the need to for downward capacity to cover mismatches between load and generation and maintain system frequency in between real-time market intervals. Regulation up as a 10-minute activation time requirement.
4. **Intra-day commitment option (ICO) reserve**: retaining the option to utilize units that must be committed in the DA timeframe when moving into the HA and RT cycles. ICO

reserves cover forecast errors in load and renewables between DA and HA, and have a 20-minute activation time requirement.

The spinning and regulation reserve requirements were enforced in all model cycles. ICO reserve requirements were enforced only in the day-ahead and hour-ahead cycles.

A. Spinning Reserve Requirement

The spinning reserve requirement in each system (or the combined system) was assumed to be 850 MW—the largest potential single element contingency.

B. Regulation Up/Down Requirements

The regulation requirements are time-varying and based on the variability characteristics of the load and the wind. The methodology employed in the SPP wind integration study[22] was used to calculate the regulation up/down time series on a 10-minute basis for the Zone A, Zone B, and Zone A+B time series for wind penetrations of 10-60% in 10% increments. The 10-minute wind time series were divided into quintiles and the value of the wind component of the reserve calculation at each time point was based on the variability characteristics of the quintile into which the wind output fell at that time point. The equations used to calculate the regulation up (R_{up}) and regulation down (R_{dn}) are

$$R_{up} = \sqrt{\left(0.01 l_{peak} + L_{10}\right)^2 + a * \Delta W_{95}^2} - L_{10},$$

$$R_{dn} = \sqrt{\left(0.01 l_{peak} + L_{10}\right)^2 + a * \Delta W_{5}^2} - L_{10},$$

where l_{peak} is the daily peak load, L_{10} is a reliability-based parameter (assumed to be 125 MW in the SPP Wind Integration Study and scaled down by 70% to 37.5 MW (for each system, 75 MW for the combined system) for this study, a is a scaling factor (assumed to be 2, as in the SPP study), and ΔW_{95}, ΔW_5 are the 95th and 5th percentiles, respectively, of 10-minute wind increments for the quintile of the wind output at the time point for which the reserves are being calculated.

Table B1 shows representative regulation requirement statistics for the 30% renewable energy case. The values reported in Table B1 are the total requirement (wind component plus load component).

[22] See (SPP, Charles River Associates, 2010)

Table B1: Total regulation requirement statistics for 30% wind penetration with the Zone A, Zone B, and Zone A+B wind time series

Wind Time Series	Reserve Type	Min (MW)	Mean (MW)	Max (MW)
Zone A	R_{up}	115	211	320
	R_{dn}	117	202	308
Zone B	R_{up}	102	179	256
	R_{dn}	110	176	247
Total Separate Systems	R_{up}	217	390	576
	R_{dn}	227	388	555
Interconnected Systems	R_{up}	211	329	453
	R_{dn}	223	331	436

C. ICO Reserve Requirements

Intra-day commitment option (ICO) reserves are also time-varying and depend on the wind and load forecast errors and level of wind penetration. DA and HA ICO reserve time series were calculated on a 10-minute basis for the Zone A, Zone B, and Zone A+B time series for wind penetrations of 10-60% in 10% increments. The 10-minute wind and load time series were divided into 15 and 12 bins, respectively, and the value of the wind and load components of the reserve calculation at each time point is based on the variability characteristics of the wind and load forecast error of the bin into which the wind and load output fall at that time point. The DA and HA wind and load forecast errors for a 10-minute period are calculated as the difference between the hourly DA or HA scheduled wind and load values and the real-time wind and load realizations in the 10-minute period. Table B3 summarizes the ICO wind component bins for the 30% scenario.

Table B3: DA and HA wind bin cutoffs by wind time series for 30% wind

	Zone A		Zone B		Zone A+B	
Bin	DA cutoff (MW)	HA cutoff (MW)	DA cutoff (MW)	HA cutoff (MW)	DA cutoff (MW)	HA cutoff (MW)
1	1303	1300	1237	1217	2416	2427
2	2280	2274	2166	2130	4227	4247
3	2932	2924	2784	2739	5435	5460
4	3257	3249	3094	3043	6039	6067
5	3518	3509	3341	3286	6522	6552
6	3779	3769	3589	3530	7005	7038
7	4039	4029	3836	3773	7488	7523
8	4235	4224	4022	3956	7851	7887
9	4430	4419	4207	4138	8213	8251
10	4691	4678	4455	4382	8696	8737
11	4951	4938	4702	4625	9179	9222
12	5212	5198	4950	4869	9662	9707
13	5538	5523	5259	5173	10266	10314
14	5863	5848	5569	5477	10870	10921
15	6515	6498	6187	6086	12078	12134

For each bin, j, the 90th percentile of wind over-forecasts and the 90th percentile of load under-forecasts are the wind and load components, respectively, of the ICO reserve.

$$ICO_{DA}^{j} = \sqrt{\left(e_{l,90}^{da,j}\right)^2 + \left(e_{w,90}^{da,j}\right)^2}$$

$$ICO_{HA}^{j} = \sqrt{\left(e_{l,90}^{ha,j}\right)^2 + \left(e_{w,90}^{ha,j}\right)^2}$$

Where $e_{w,90}^{da/ha,j}$ and $e_{l,90}^{da/ha,j}$ are the 90th percentile of DA/HA load forecast errors for the jth bin of the wind and load output, respectively, at the time point for which the reserves are being calculated. The final reserves function is taken as the envelope of the reserves computed according to the above ICO equations. Figure B1 illustrates the wind component ICO calculation methodology for 60% wind penetration.

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