The Eastern Renewable Generation Integration Study: Insights on System Stress

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The Eastern Renewable Generation Integration Study: Insights on System Stress

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***Abstract*— The Eastern Renewable Generation Integration Study (ERGIS) explores the operational impacts of the wide spread adoption of wind and solar photovoltaics (PV) resources in North America's Eastern and Québec Interconnections. We explore the impact of large scale adoption of wind and solar generation on the unit commitment and economic dispatch of the largest coordinated power system in the world by simulating hourly and five-minute operations. Using NREL's high-performance computing capabilities and new methodologies to model operations, we found that the modeled system, as simulated with evolutionary change in 2026, could balance the variability and uncertainty of wind and solar PV at a five-minute level under a variety of conditions. Our simulations achieve instantaneous penetrations that exceed 50% of load while meeting an annual penetration of 30% on an energy basis. The system meets balanced load and supply in all intervals, with modest curtailment, using technologies and practices that are widely available today. However, a variety of the conditions present in these simulations deviate substantially from historical practice. In this work, we analyze potentially stressful system conditions that occur in the simulations and identify opportunities for innovation, regulatory reform, and changes in operating practices that require further analysis to enable the transition to a system with more wind and solar PV.**

Keywords-component; wind, solar, grid integration, production cost modelling, North American Eastern Interconnection, Québec Interconnection

I. OVERVIEW

Wind, solar, and natural gas generation are the fastest growing electric generation resources in the United States. As capital costs of wind and solar decline, and both international and domestic polices continue to push the power system toward lower carbon generating resources, new questions are emerging about the ability to balance hundreds of gigawatts of wind and solar capacity. The Eastern Interconnection, which is highly coordinated with the Québec Interconnection, is one of the largest power systems in the world, and regularly facilitates trade across thousands of kilometers. Collectively, we refer to the two systems as the EI. The study domain is presented in Figure 1. In this work, we model the unit commitment and economic dispatch (UC&ED) of the entire system under four scenarios, two of which have an annual penetration of 30% and deliver nearly 1,000 TWh of carbon-free generation to the system. To aid in this analysis a technical review committee (TRC) composed of over 30 industry participants met on a quarterly basis to review assumptions, methods, and resource results in the most open and transparent integration study ever conducted.[1]

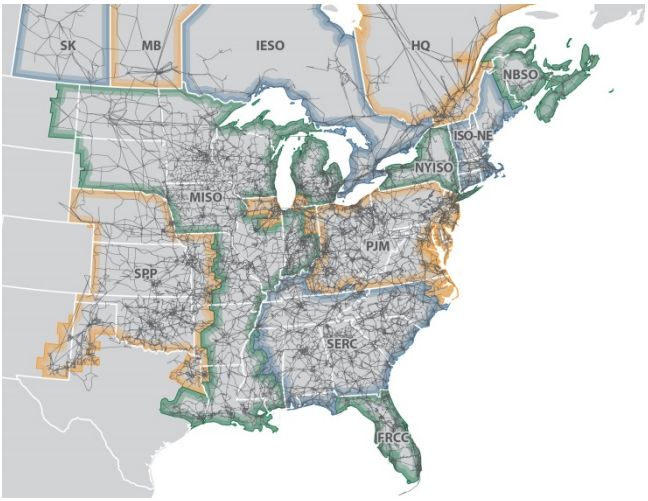

Figure 1. The transmission network and system regions

The ERGIS study joins a growing list of variable generation (VG) integration studies that have examined part or all of the EI. One of the goals of ERGIS was to add enhanced simulation methods to increase confidence in the ability of the system to handle increased amounts of VG. To provide a brief overview of modeling enhancements, Table 1 lists several assumptions used in this study, as well as five previous studies: the Eastern Wind Integration and Transmission Study (EWITS) (Enernex 2011), The Manitoba Hydro Wind Synergy Study (Bakke, Zhou, and Mudgal, n.d.), The Eastern Interconnection Planning Collaborative Phase 2 Report (EIPC 2012), the Minnesota Renewable Integration and Transmission Study (MRITS)(GE 2014b), and PJM Renewable Generation Integration Study (PRIS) (GE 2014a) projects. We reviewed published reports for each project and worked with TRC members and authors to verify the listed information. In aggregate, the improvements in the ERGIS study represent an increase in temporal, geographic, and technical fidelity. First, ERGIS expands the range of resources analyzed by simulating large-scale adoption of PV in addition to wind in the U.S. EI. This increases the number

[1] The production cost model, underlying data, and visualization tools can be obtained at www.nrel.gov/ERGIS.

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of generators on the system considerably compared to previous studies, and thus increases the complexity of the UC&ED. Next, the study narrows the temporal resolution to 5 minutes in order to understand the sub-hourly impact of these resources on system operations. This time resolution reflects the dispatch interval of existing regional transmission organizations and independent system operators (RTOs/ISOs). ERGIS also increases the spatial resolution of the model to include all synchronous components of the EI, on a comparable basis. This increases the number of transmission facilities and generators in the model significantly. Previous work by Dean, Drayton, and Gallachóir (2014) indicates that sub-hourly modeling is an important factor in accurately characterizing the impact of wind on production costs and thermal plant operations. Further work by Stoll et al. (2016) analyzed the effects of optimization technique, temporal resolution, and intra-day commitment on several key metrics for integration studies. They found that operational metrics such as starts, time online, and ramping were significantly impacted by the use of continuous linear optimization and hourly temporal resolutions.

II. Scenarios

We developed the four study scenarios through a consensus process with the TRC. With their assistance, we identified a variety of qualitative characteristics to include in framing potential power system conditions in the next 10–15 years. All scenarios assume two key elements: (1) modest load growth and (2) significant retirements of coal and natural gas generation. These scenarios were developed to create bookend cases for studying 30% wind and PV that could reflect how inter-regional and regional policy decisions could drive wind and PV development. The qualitative characteristics of the four generation and transmission scenarios are outlined in Table 1. The transmission assumptions are adopted from the Eastern Interconnection Planning Collaborative (EIPC) (EIPC 2012). The Regional Energy Deployment System (ReEDS) capacity expansion model was used to determine the location, type, and capacity for every generator added to the model (Short et al. 2011).

Table 1. ERGIS Scenarios.

Scenario	Wind	PV	Attributes
LowVG	3%	0%	• No new wind or PV generation installations after the year 2012. • Minimal transmission expansion.
RTx10 (Regional Transmission and ~10% VG)	12%	0.25 %	• An approximately 10% VG penetration as reflected in state RPS and interconnection queues as of 2012.[b] • Intra-regional transmission expansion.
RTx30 (Regional Transmission and 30% VG)	20%	10%	• Approximately 30% combined VG, with an emphasis on within-region wind and PV resources. • Identical transmission expansion to RTx10.
ITx30 (Inter-regional transmission and 30% VG)	25%	5%	• Approximately 30% combined VG, with an emphasis on the best wind and PV resources in the U.S. EI. • Interregional transmission expansion with 6 large high-voltage direct current (HVDC) lines.

III. UC&ED Model Setup and Execution

The UC&ED model replicates both the day-ahead and real-time operational phases of the electric power sector. The 2026 EI model was simulated for an entire year in 8,760 one-hour time steps in the day-ahead phase of operations and 105,120 five-minute steps in the real-time phase of operations. We configured the UC&ED model using hurdle rates to reflect elements of market friction between the ERGIS regions. Hurdle rates of $10/MWh were applied to any power transferred between the larger ERGIS regions shown in Figure 1. Wind and solar resources were assumed to have zero variable costs. Furthermore, the model did not include any production-tax credits. All wind and solar resources were assumed to be dispatchable up to their maximum available output. This means that the UC&ED model could dispatch down wind and solar resources, otherwise known as VG curtailment, in order to balance system demands and respect a variety of other generation and transmission constraints. The UC&ED model represents all of the transmission elements and uses DC power flow, which is a linearized approximation of AC power flow. Enforcing all of the transmission constraints was infeasible because doing so caused the simulation times to be intractable.

To keep simulation times reasonable, the number of transmission constraints was substantially reduced and transmission constraints were modeled as soft constraints with penalty prices for exceeding the flow limits. To limit the number of transmission constraints in the model, the ERGIS team solicited and received feedback from the TRC on sub-regions within which transmission limits would not be enforced. Approximations of existing transmission or capacity zone boundaries were used for each region, resulting in the creation of 33 sub-regions. After establishing the sub-regions, transmission lines that crossed each of the sub-region boundaries were identified. These transmission lines were grouped by geographic proximity into flowgates. Figure 2 shows all of the lines that were included in a flowgate. The sum of the flows on the lines in the flowgate was then constrained rather than the flows on individual lines. This resulted in a significant reduction in the number of transmission constraints in the model. We limited inter-sub-regional transfers (between sub-regions) but not intra-sub-regional (within sub-regions) transfers. In order to reflect contingency limits, each flowgate was assigned a flow limit defined by the maximum of: half of the sum of the thermal ratings of the lines in the flowgate lines or the sum of the thermal ratings of the flowgate lines minus the largest thermal rating in the flowgate lines.

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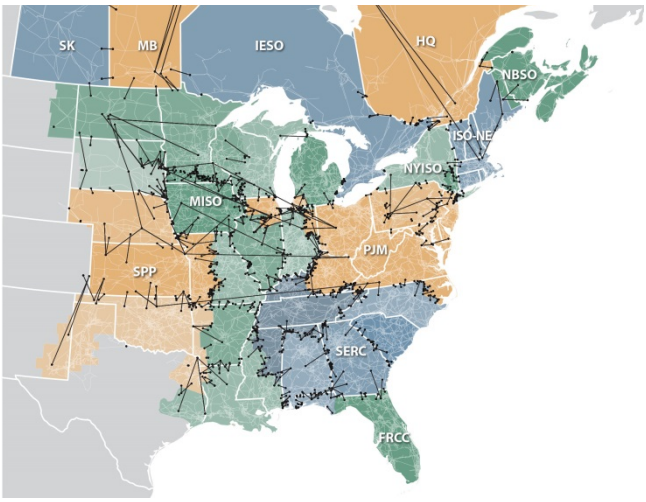

Figure 2. Map showing the transmission flowgates between the ERGIS sub-regions.

The model was executed using PLEXOS version 6.400 R02. The PLEXOS model for ERGIS includes over 5,600 generating units, 60,000 transmission nodes, and 50,000 transmission lines and transformers. As formulated by PLEXOS, each day-ahead optimization problem has about 73,000 integer variables, 1.2 million continuous variables, and 23 million non-zeros in the constraint matrix. Because of the size of the problem, runtimes would be infeasible if the model were run consecutively from January 1 through December 31 of the study year.

To address the extreme computational challenge presented by large UC&ED models, Barrows et al. (2014) developed methods to decompose annual UC&ED simulations into shorter time partitions while preserving the accuracy of simulation results. Applying these methods allowed us to reduce the simulation time from a theoretical 19 months to 19 days using NREL's Peregrine High Performance Computer (NREL 2015).

IV. Results

We analyzed the results of the UC&ED modeling using a variety of operational metrics (e.g. annual generation, ramping, capacity factor, VG curtailment) in order to understand how varying levels of wind and solar generation affect system operations. The metrics were then compared across scenarios at both an interconnection-wide and regional level. The simulations indicate that the RTx30 and ITx30 scenarios are both capable of meeting load with wind and solar generation, while reducing production costs by $30 billion and system wide carbon dioxide emissions by 600 million short tons. A detailed account of all of the study results can be found in Bloom et al. 2016, Here we focus on the results of UC&ED for a potentially challenging period of system operations.

Efficient operation of the power system requires operators to commit and dispatch the system under a variety of challenging conditions. We analyzed ten high net load ramps to identify potentially challenging conditions for the EI in the RTx30 and ITx30 scenarios. First, the ten largest positive net load ramps over an eight-hour period were identified for both scenarios. Next, both the absolute VG forecast error for each hour and the total ramp magnitude forecast error were plotted to determine which of the ten net load ramps had the largest forecast error. This analysis indicated the November 23-25 period had both a very large and quick ramp (i.e., had one of the largest positive net load ramps over an 8-hour period) as well as a large forecast error. We chose to analyze this period because the period includes three noteworthy events that occur within eight hours:

1. A significant wind forecast error
2. A solar ramp that results from the setting sun
3. Peak load coincident with sunset.

Taken together, these three events result in one of the most variable and uncertain periods of operation for the ERGIS simulations. While other periods of operation had high penetration of VG or more extreme differences in the peak and minimum load, this period is noteworthy because of the compounding of these three events.

The dispatch stacks for this time period are presented in Figure 3. In the LowVG we observe low load conditions throughout the period. The lowest load levels in the LowVG case occur after midnight, dropping to approximately 320 GW. In the RTx10 case, high winds in MISO and SPP decrease the net load and result in several hours of VG curtailment in excess of 15 GW. As the wind and PV penetration increase in the RTx30 and ITx30, the dispatch stacks for the system change considerably. The minimum net load at 12:00 pm for the RTx30 is ~170 GW while in the ITx30 the minimum net load is ~220 GW. We also note significant difference in the slope of the net load ramp between the scenarios.

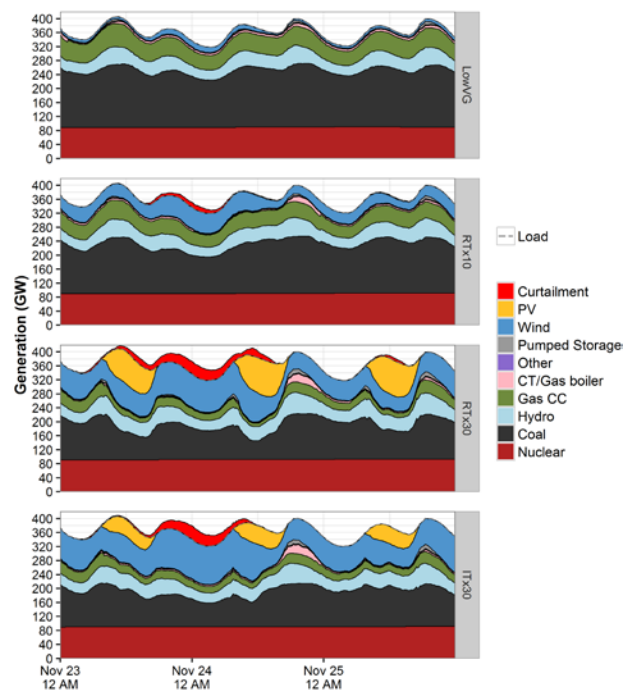

Figure 3. Dispatch stacks for November 23-25 across all 4 scenarios.

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In Figure 4 we provide the commitment and dispatch for the EI. This figure provides insights into the compounding impact of the wind forecast error, solar ramp, and growing load on the operation of the system. This figure connects Day-Ahead (DA) decisions and how they impact Real-Time (RT) operations. For wind and PV, the gray line indicates the DA generation forecast used to commit the system. Combined Cycles (CC) and Coal units are committed in the DA, and therefore the DA committed capacity and RT committed capacity are the same. Combustion Turbines (CT) are allowed to be recommitted in the RT. The difference between gray line and the pink line show the difference in the commitment decisions for CTs between the DA and RT. The shaded area for each generation technology is the total RT generation from that technology. For wind and PV, the difference between the solid colored line and the shaded area represents VG curtailment. For thermal generation, the difference between the colored line and shaded area are units operating bellow their maximum capacity.

In Figure 4 we see that the thermal commitment and dispatch for the RTx30 and ITx30 are very similar even though the amount of wind and PV on the system differs considerably across scenarios. For example, the combined penetration of wind and PV on November 24 at 12:00 PM in the RTx30 is more than 200 GW while in the ITx30 the combined generating capacity for wind and PV is 170 GW. Total commitment levels for CC and coal generation are very similar, though the RTx30 experiences deeper cycling of coal and CC plants as a result of daily PV patterns.

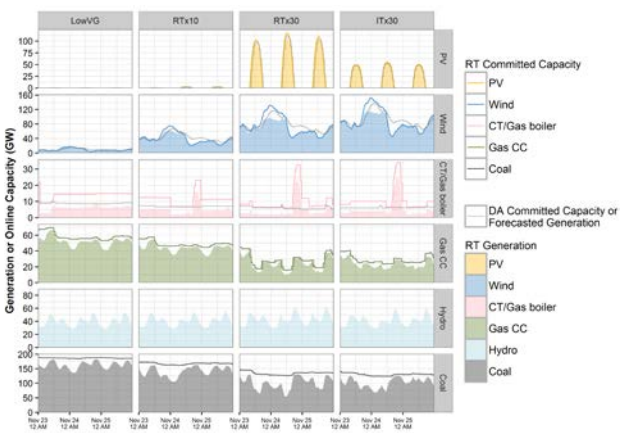

Figure 4 Comittment and dispatch for November 23-25 across all 4 scenarios.

In both the RTx30 and ITx30 scenarios system commitment and dispatch are significantly impacted by uncertainty in wind generation. Figure 4 shows that the EI incorrectly forecasts wind generation for both scenarios. On November 23 between sunset and midnight the day-ahead forecast is lower than the available wind generation in the real time. Then, shortly after midnight on November 24, the system manages a steep unexpected down ramp in wind generation. The magnitude of the forecast error is greatest in the ITx30, as this scenario has a larger amount of wind installed on the system than the RTx30. However, by comparing the net load ramps for the RTx30 and ITx30 we observe that the steepest net load ramp occurs in the RTx30 on November 24. This difference is driven by the increased presence of PV in the RTx30. The RTx30 has nearly twice as much PV generation on peak. Most of this PV is in SERC and FRCC; however the commitment in nearly every region is impacted by the diurnal pattern caused by PV.

Managing the variable and uncertain conditions presented in this period requires the use of several sources of system flexibility to balance the net load. Initially, VG is curtailed to avoid over-generation and due to transmission congestion. As the net-load ramp approaches, committed thermal resources are redispatched based on operating constraints; large amounts of CTs are committed and dispatched in the real time; and interchange fluctuates rapidly before and after sunrise and sunset to manage regional offsets in VG availability. However, ERGIS demonstrates the system is technically able to handle these conditions, serving load and meeting reliability requirements. But, market incentives may be lacking for generators and transmission required for the system to handle these conditions.

To test the impact of reduced RT flexibility, we ran two sensitivities to RT operations. The first fixes the DA dispatch of coal generation in the RT. Coal is typically believed to be less flexible, and generators may be hesitant to significantly change their planned DA operation. The second sensitivity fixes RT interface flows between regions with their DA flow schedules. Due to the diversity of markets that currently exist, often the markets do not exist for flow schedules to change, or significant disincentives exist.

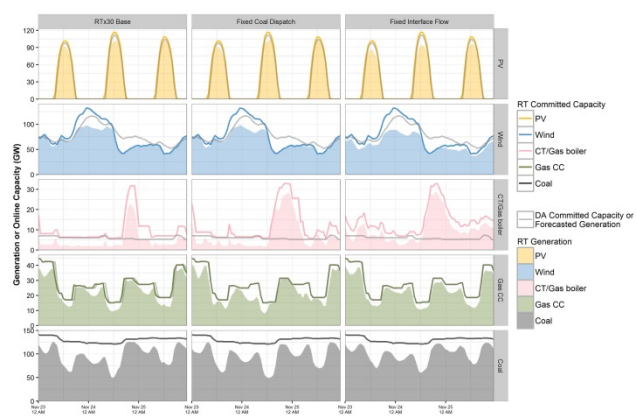

Figure 5 Comittment and dispatch for November 23-25 for the RTx30 scenario under base case assumptions and two real-time sensitivities.

Figure 5 and Figure 6 show how the commitment and dispatch change under these two RT sensitivities. Figure 5 shows the results for the RTx30, while Figure 6 shows the ITx30. For the RTx30, there is a significant increase in CT startups in RT when coal generation and interface flow are fixed in the DA. With coal generation fixed, CCs are also asked to ramp up once the wind begins to drop off at noon on Nov. 24. In the base case, coal provided this flexibility.

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When interface flows are fixed, the system relies much more heavily on the CTs. In the base case, most CTs not committed in the DA wait to turn on until after sunset. But with interface flows fixed, a large portion of CTs turn on well before sunset in response to the wind generation drop. In the base case, ramping coal and CCs provided this flexibility.

In the ITx30, the system exhibits different behavior in response to reduced RT flexibility. In fact, fixed coal dispatch has very little impact at all. The ITx30 system is more reliant on being able to transfer power across a larger transmission system, and therefore requires less flexibility from its coal fleet. On the other hand, fixing interface flows in the ITx30 has a much larger impact relative to the RTx30, which is more driven by local generation. With fixed interface flows, the ITx30 requires significant fast-start generation from its CT fleet. CTs must start more often and earlier, and stay on longer than either the base case or fixed coal dispatch.

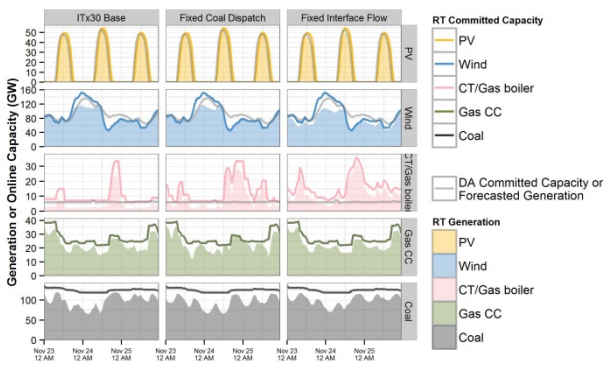

Figure 6 Comittment and dispatch for November 23-25 for the ITx30 scenario under base case assumptions and two real-time sensitivities.

Figure 7 shows the dispatch stacks for the same RT sensitivities. In both scenarios, fixing the interface flows causes a large increase in VG curtailment leading up to the net-load ramp on Nov. 24. This indicates that the main way for the system to deal with VG under-forecasts (DA believed there would be less VG generation than there actually was) is to export excess VG generation to neighboring regions that have more flexibility to ramp down thermal generation. Without that export flexibility, the only option to avoid over generation is VG curtailment.

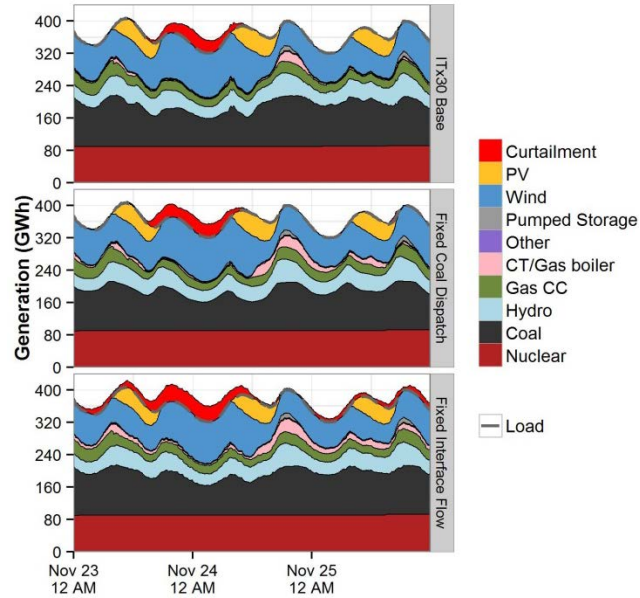

Figure 7 Dispatch stacks for November 23-25 for the RTx30 scenario under base case assumptions and two real-time sensitivities.

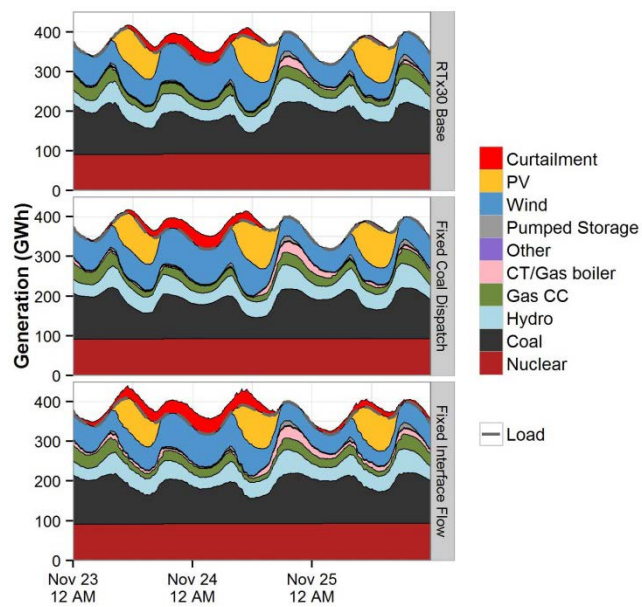

Figure 8 Dispatch stacks for November 23-25 for the ITx30 scenario under base case assumptions and two real-time sensitivities.

Unsurprisingly, in all cases production cost increased with less RT flexibility. However, costs were much more sensitive to interregional interface flow flexibility than coal redispatch flexibility. Increased costs were primarily due to the large increase in CT starts and generation over the net-load ramp period.

CONCLUSION

November 23-25 proved to be one of the more challenging periods from an operational perspective in the Eastern Renewable Generation Integration Study. At the beginning of the interval, nearly 50% of the load in the EI is met by wind

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and PV. However, in the course of 8 hours, total wind generation in the EI decreases by 50% along with a large wind DA over-forecast. This is followed by sunset, leading to the loss of all PV on the system, and peak load for the three-day period. Even during this stressful period, the system is able to react and handle the rapidly changing conditions. Even when RT flexibility is constrained from the base case assumptions, the system is able to meet load and reliability requirements, albeit in a different and more expensive manner.

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