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PLANNING AND OPERATIONS IN ELECTRICITY MARKETS UNDER SYSTEM TRANSFORMATION

Key Findings

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BACKGROUND AND INTRODUCTION

United States electricity markets, planning mechanisms, and operational procedures are currently evolving in concert with three key trends. First, a range of new resources—solar, wind, energy storage, hybrid co-located storage, and distributed energy—are coming online and require new solutions to ensure they are efficiently integrated into existing systems. Second, consumers now face more opportunities to participate in markets by providing demand response and engaging in two-way interactions with the grid. Third, there is an increasing need for enhanced coordination between generation and transmission planning as well as across transmission and distribution systems.

Many of these factors are themselves driven by emerging decarbonization objectives, changing policy paradigms, and the decreasing costs of clean energy technologies. Wholesale electricity markets are operated in regions with over two-thirds of the U.S. population, and therefore it is crucial to ensure that these markets are designed and operated so as to ensure efficient, reliable, affordable, and just outcomes for all consumers.

This report summarizes 13 key findings that have emerged from the interconnected research of five institutions between January 2020 and December 2023. The project team, comprising Argonne National Laboratory, the National Renewable Energy Laboratory, Lawrence Berkeley National Laboratory, the Electric Power Research Institute, and Johns Hopkins University, collectively engaged with the North American Independent System Operators and Regional Transmission Operators (ISOs/RTOs) to identify the important challenges they are facing and the opportunities for the project team to provide technical assistance in meeting several high-priority challenges. Table 1 outlines each of the 13 key findings and provides a reference to the publication where the finding is discussed in more detail. We elaborate briefly on these findings throughout the remainder of this report.

Engagement with ISOs/RTOs began with a workshop held in April 2020 that helped identify an initial set of key research needs and priorities that were summarized in an initial report [10]. The project team drew upon these findings as well as further engagement with stakeholders to establish three distinct but coordinated technical workstreams that were implemented to help address a range of technical challenges that are currently facing ISOs/RTOs as power systems continue to evolve rapidly. These three workstreams were 1) operational reliability and flexibility, 2) resource adequacy, and 3) long-term market entry and exit. The project team then developed and implemented a technical workplan to address one or more specific research questions associated with each workstream. Stakeholder engagement continued throughout the project period through meetings between the project team and designated ISO/RTO advisors that were held regularly for each of these three workstreams.

The objective of this report is to briefly synthesize and highlight several key findings across this broad research portfolio and establish future needs and opportunities for planning and operations in electricity markets in system transformation. These findings are organized into the following categories: 1) market evolution, 2) system operations, 3) price formation, 4) resource adequacy, 5) long-term planning, and 6) transmission planning. Note that some findings could have been assigned to more than one category. For a more nuanced treatment of each finding, as well as detailed methodological descriptions and analytical results, readers should refer to the individual project publications that are cited throughout this report and listed in the references.

Table 1: Summary of 13 key research findings that have been identified throughout work conducted by the project team.

WHOLESALE ELECTRICITY MARKET CONSIDERATIONS	
1	Power systems are going through rapid transitions that will spur changes to wholesale electricity market design [10].
SYSTEM OPERATIONS	
2	System flexibility can be efficiently increased by introducing new flexibility into reserve products or appending ORDCs to existing reserve services to value flexibility beyond minimum requirements [1].
3	ORDCs can provide operational price signals that more efficiently incentivize day-ahead resource commitments to mitigate forecast uncertainty than capacity markets can [2].
PRICE FORMATION	
4	Reserve shortage pricing mechanisms create effective composite ORDCs that can improve pricing and ensure that operational capacity has a value commensurate with its reliability contribution. This creates effective short- and long-term incentives for a resource mix that achieves short-term reliability objectives [3].
5	Power market models need to improve representation of ancillary service price formation to capture operational reliability and revenue sufficiency implications [4].
RESOURCE ADEQUACY	
6	Simplified and/or deterministic modeling representations can overestimate the reliability of future power systems, as demonstrated in a system with a mix of thermal, storage, and variable renewable resources [5].
7	Uncertainty about thermal generator availability can impact resource adequacy significantly more than uncertainty about solar resource availability [5].
8	Simplified storage dispatch representation can overestimate the reliability contributions of these resources [6].
LONG-TERM PLANNING	
9	The investment decisions made by profit-seeking entities can differ from the idealized least-cost simulation outcomes using the same market design and system operating conditions [7].
10	It is important to implement and examine market designs that are incentive-compatible with the social objectives and support competitive market entry and exit to minimize the potential for the exertion of market power [7].
11	Annual variations in weather conditions affect cost-optimal resource mixes, resource adequacy, and total system costs, and these effects may be greater than those from changes in market design [2].
TRANSMISSION PLANNING	
12	Improved coordination and/or co-optimization of generation and transmission investments can lead to significant economic and technical benefits [8].
13	Energy storage can improve systemwide and zonal reliability when operated as a transmission asset; however, these benefits are not always captured by generation expansion models [9].

KEY FINDINGS

ELECTRICITY SYSTEM TRANSFORMATION

Finding 1. Power systems are going through rapid transitions that will spur changes to wholesale electricity market design.

Electricity systems in the United States and around the world are in a state of rapid transition due to growth in renewable resources, increasing consumer participation, expansion of distributed energy resources, and increasing deployment of energy storage resources. We conducted a survey of current research priorities related to wholesale electricity markets across North American ISOs/RTOs to prioritize specific challenges in six topic areas [10]. A synthesis of this feedback and an in-depth survey of current market rules, market enhancements currently under consideration, and forward-looking market proposals identified four broad and unifying themes.

Finding 1.1. As resource mixes evolve to include more weather-dependent generation, market design enhancements may be needed to ensure long-term resource adequacy and short-term operational reliability.

Finding 1.2. Resources must be appropriately incentivized to provide grid services that are valuable to the system. Specifically, markets may benefit from introducing new products and services, updating current definitions, and implementing enhancements to ensure effective deployment of services to meet system needs.

Finding 1.3. Well-designed pricing and resource adequacy mechanisms are crucial to ensuring revenue sufficiency for resources that provide value to the system. This is particularly true in futures with high penetrations of resources with zero fuel costs that may contribute to reductions and/or increased volatility in short-term price signals.

Finding 1.4. Improving transmission planning processes and enhancing coordination between the transmission and distribution systems will be increasingly important as generation resources are increasingly located either distant from loads or on the distribution system.

SYSTEM OPERATIONS

Finding 2. System flexibility can be efficiently increased by introducing new flexibility into reserve products or appending ORDCs to existing reserve services to value flexibility beyond minimum requirements.

De Mello et al. [1] find that either a new flexibility product or an operating reserve demand curve (ORDC) can successfully increase system reliability, and they may perform in similar ways, depending on the details of their specific designs and implementations. This analysis found that these strategies can reduce shortages by 60%-99% at a cost ranging from $65 to $195 per MWh of avoided reserve shortage, with the specific values heavily dependent on the quantities of additional reserves that are procured. These costs are all less than the lowest administrative reserve shortage penalty cost considered. Ultimately, the choice between these two approaches depends on system objectives, existing market design and operational rules, and the specific parameters that are being considered (Table 2).

One important distinction is that providers of multiple separate reserve products that include a flexibility reserve may be allowed to share ramp rates across products, for example between flexible reserves and regulation reserves, whereas this is typically not possible when an ORDC is implemented and extended as part of a single existing product. Therefore, introducing a flexible reserve product would allow resources to potentially offer more reserve capacity in the market than implementing an ORDC would. However, this may in fact lead to less flexibility and reserve availability if a single resource is called upon to deliver two or more of these products simultaneously. Market operators should examine the goals of introducing either mechanism, how the specific design of each can help meet them, and any other consequences so that they can effectively bring more efficient flexibility onto their system and incentivize resources to provide that flexibility.

Table 2: Summary of key pros and cons of establishing a new flexible reserve product or implementing an ORDC as part of an existing product. Adapted from de Mello et al. [1].

	FLEXIBLE RESERVE	ORDC
PROS	◻ Reserve can be tailored to meet specific system flexibility needs. ◻ Resources can qualify to provide reserves independent of their provision of other products. ◻ Requirements can be easily adjusted to achieve target procurement levels.	◻ No new products are needed. ◻ No additional certification is needed. ◻ Requirements can be easily adjusted to achieve target procurement levels.
CONS	◻ Resources need to be certified specifically for providing flexible reserves. ◻ A new product must be designed. ◻ Resources can share ramp rates with other products, although this may introduce deliverability issues. ◻ Computational complexity of market clearing may increase.	◻ Reserve products might not be tailored to meet specific system flexibility needs. ◻ Resources must qualify to provide the existing reserve product. ◻ Availability may be limited if linked to a contingency product. ◻ Difficult to redesign to address changing objectives.

Finding 3. ORDCs can provide operational price signals that more efficiently incentivize day-ahead resource commitments to mitigate forecast uncertainty than capacity markets can.

Sun et al. [2] explored interactions between operational incentives and supply-side investment decisions made over longer time periods. This work compared the effectiveness of ORDCs to capacity markets in incentivizing investments to support resource adequacy. The study found that an ORDC and a capacity market can both support resource adequacy by incentivizing investment in supply-side resources, with some notable differences [2].

Specifically, the analysis suggests that a capacity market may incentivize more overall capacity investment than an ORDC alone. However, an ORDC can more efficiently incentivize capacity availability by efficiently committing resources in the day-ahead market to be available in real-time operations. Further, markets without either mechanism were observed to be unlikely to attract sufficient investment to achieve resource adequacy objectives. Significantly, even when each approach achieves comparable resource adequacy levels, total system costs and market revenues may differ. These results are particularly sensitive to changes in weather conditions. Figure 1 demonstrates that implementing an ORDC leads to an increase in the availability of firm capacity resources in the real-time market (via day-ahead commitments) when hourly locational marginal prices are high, in this case more than $1,000/MWh. The analysis assumes that firm capacity resources include coal, nuclear, natural gas combined cycle, natural gas combustion turbine, and renewable energy combustion turbine resources.

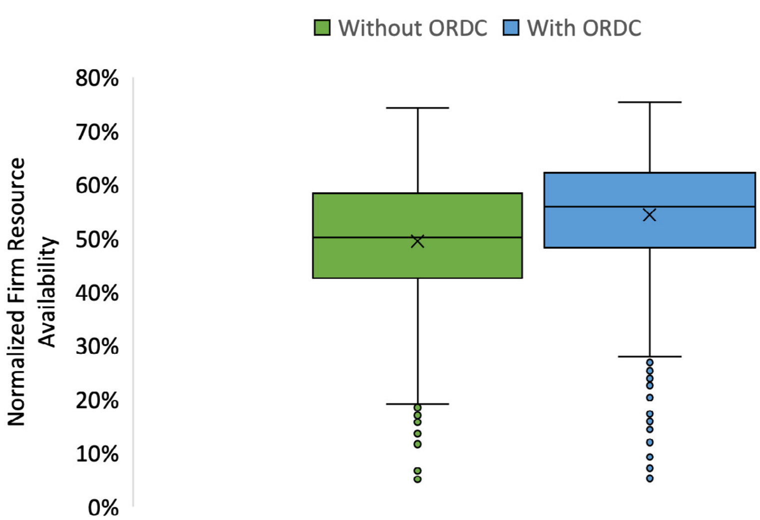

Figure 1: The distribution of normalized dispatchable thermal resource availability across 736 simulation periods with and without an ORDC during hours when locational marginal prices are more than $1,000/MWh. Each data point is calculated by dividing the maximum online system generation capacity during that simulation by the total system generation capacity [3]. Availability is based on the real-time capacity from day-ahead commitment outcomes, and dispatchable thermal resources consist of all generation resources excluding hydropower, wind, solar, and battery

PRICE FORMATION

Finding 4. Reserve shortage pricing mechanisms create effective composite ORDCs that can improve pricing and ensure that operational capacity has a value commensurate with its reliability contribution. This creates effective short- and long-term incentives for a resource mix that achieves short-term reliability objectives.

All ISOs/RTOs in the U.S. use administrative shortage pricing for their operating reserve products. This design causes high prices when the system does not have enough reserve capacity or when achieving more capacity is not cost effective. As the ISOs/RTOs all have or have proposed co-optimization between energy and ancillary service markets in their market design, these prices almost always influence the energy price as well, which leads to short-term incentives to supply energy and long-term incentives to invest in particular locations when these prices can help recover capital costs.

The shortage prices for different reserve products can be single values, multi-step functions, or full robust demand curves. The determination of the values for each of these prices is based on a number of factors, such as the value of loss load (VOLL), costs of other mitigation actions, such as commitment costs of expensive generators, costs of penalties from reliability organizations for not meeting reliability standards, or simply stakeholder input and ranking of product value from lowest to highest.

While many operators are exploring the differences between new products and extended ORDCs, Mehrtash et al. [3] found that combining the numerous ancillary service products in the order in which products are expected to be deficient first creates an effective extended ORDC. Such composite demand curves are shown for all seven U.S. ISOs/RTOs in Figure 2. This demand curve can effectively price reserve and energy in a way that is commensurate with increasing value as reserves become scarce, which can lead to short- and long-term incentives that can be effective without the volatility of extremely high price spikes that are politically not acceptable. Market operators should therefore consider the shortage values of all their products and contributions to holistically create incentives that balance reliability and economic efficiency.

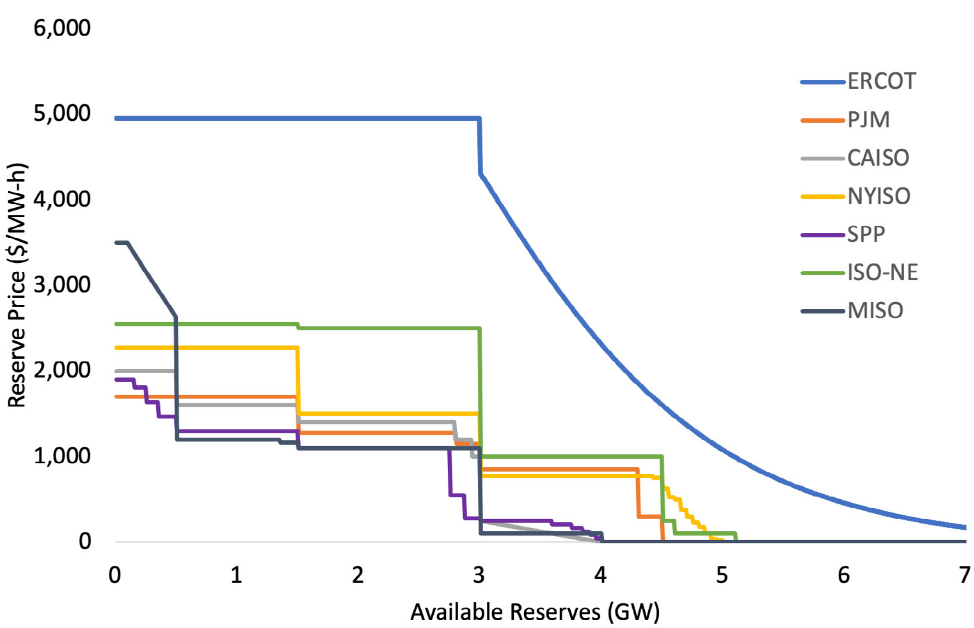

Figure 2: Composite operating reserve demand curves for each ISO/RTO as generated in [3]. This approach uses actual ISO/RTO shortage prices with reserve quantity points that are modified to create a consistent comparison.

Finding 5. Power market models need to improve representation of ancillary service price formation to capture operational reliability and revenue sufficiency implications.

Power market models simulate electricity prices by calculating the shadow price[1] of the demand balance constraint in the security-constrained economic dispatch optimization problem. This is essentially the same process used to determine prices in real-world practical market operations. Given the increasingly important role of ancillary services in modern power systems, many power market models are now able to perform similar calculations to simulate prices for ancillary service products that are procured in wholesale markets, such as regulation reserves or spinning reserves. The mathematical theory behind these calculations is the same as it is for energy; however, modeled prices are only as accurate as the cost and performance assumptions that are used as inputs to the power market models. That is, it is currently common practice to not directly consider any physical costs that resources incur from providing ancillary services due to, for example, increased wear and tear and maintenance requirements. It is also common to ignore several categories of costs that are not directly captured through co-optimization with energy markets, such as financial replacement risk, real-time optionality, and intertemporal opportunity costs.

Noll et al. [4] analyzed data from Electric Reliability Council of Texas (ERCOT) operating reserve markets in 2022 and found that most offers for regulation reserves indicated non-zero costs of provision, and a majority of resources also vary their offers over time. Furthermore, resources owned by municipal utilities (munis) and utility cooperatives (coops) generally have lower and less variable offers than those owned by other entities, such as independent power producers. Figure 3 shows the distribution of regulation reserve offers for four different technology types and two different ownership classes. For all technologies classes, resources owned by munis or coops have lower median offers as well as less variability in their offer prices than those owned by other entities. Such temporal variation and ownership heterogeneity are not commonly captured in market simulation studies, and improving the representation of this data is important for accurately identifying future price trends for operating reserves.

1 The shadow price is the additional cost incurred by the system if electricity demand were to increase by one unit (e.g., 1 MWh) during a specified time interval and at a specified location.

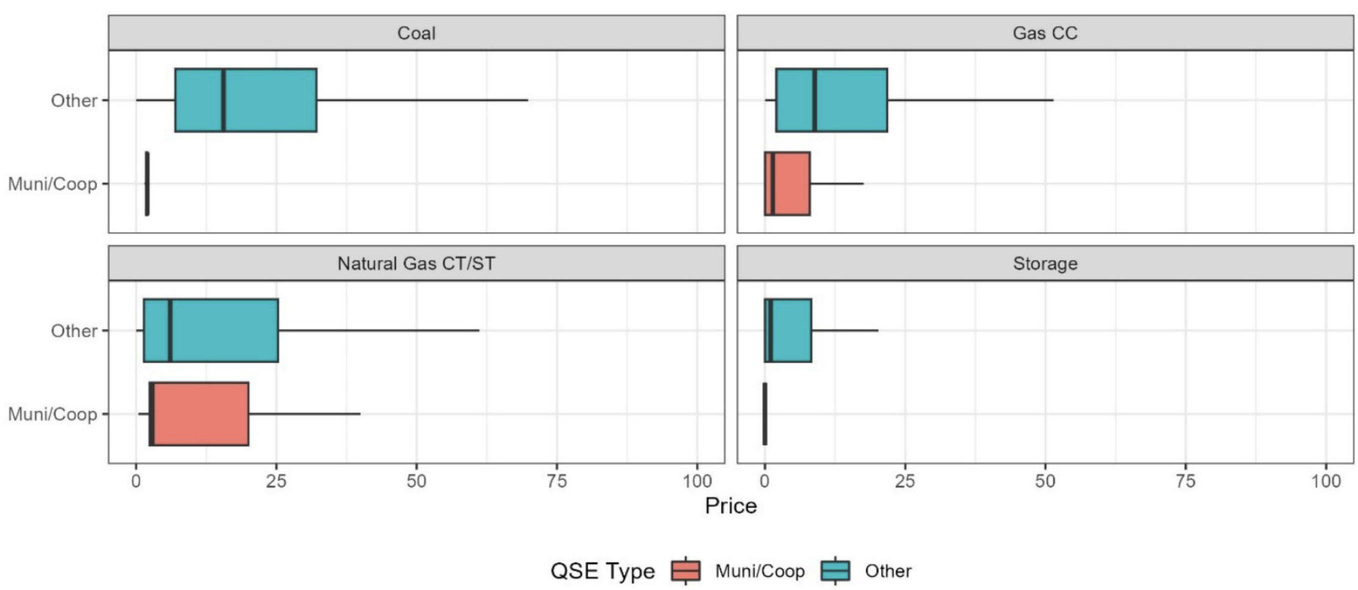

Figure 3: The distribution of representative offer prices for regulation reserves by technology type and ownership class in ERCOT in 2022 [4].

RESOURCE ADEQUACY

Finding 6. Simplified and/or deterministic modeling representations can overestimate the reliability of future power systems, as demonstrated in a system with a mix of thermal, storage, and variable renewable resources.

Sun et al. [5] show that multi-stage probabilistic assessments will provide a more robust evaluation of resource adequacy by capturing a wider range of operational and system interactions than traditional Monte Carlo simulation of thermal generator outages or single stage unit commitment and economic dispatch methods. However, such assessments can increase computational costs by 1-2 orders of magnitude over traditional methods.

This study explored several different methods for simulating system operations to project the frequency of lost load events in different conditions. The study system included a mix of thermal, storage, and variable renewable resources, each of which represented different sources of uncertainty and/or operational considerations. Figure 4 shows the average frequency of lost load events across 1000 simulations (i.e., outage draws) each, with increasing levels of operational detail across the set of operational modeling representations. The tools that explicitly represent multi-stage unit commitment (UC) and economic dispatch (ED) capture more total lost load event hours (LOLH) than the ones representing only a single UC or ED stage due to uncertainty in resource availability. This suggests that lower fidelity in traditional and single-stage tools can overestimate the reliability of a system and therefore may lead to inadequate resource portfolios in practice.

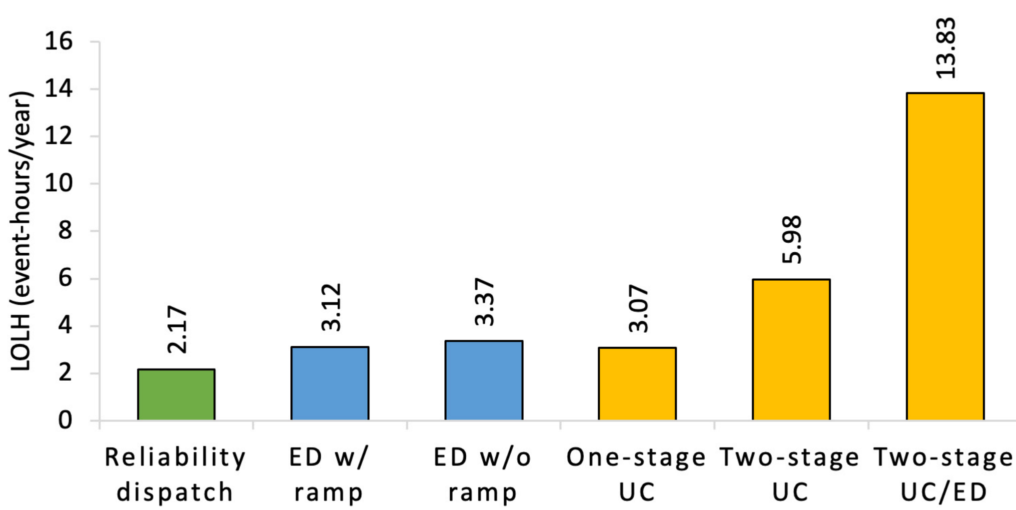

Figure 4: Average frequency of lost load events across 1000 samples of six different modeling representations of system operations with increasing operational detail [5].

Finding 7. Uncertainty about thermal generator availability can impact resource adequacy significantly more than uncertainty about solar resource availability.

Sun et al. [5] also found a difference in the impact on resource adequacy from various sources of uncertainty. Notably, thermal generator availability forecast accuracy was found to impact resource adequacy performance significantly more than solar forecast accuracy in this system with a mix of thermal and variable renewable (solar and wind) resources. This is captured in Figure 5, which shows the normalized expected unserved energy (NEUE) for scenarios with different levels of forecast accuracy of thermal general availability and solar resource availability. These can be viewed as proxies for different types of unavailability sources, such as forced outages for thermal generators or forecast errors for solar. This is driven by the comparatively larger magnitude of thermal outages compared to solar forecast errors in the test system used here, which had approximately 60% thermal resources and 20% solar resources on a capacity basis. Results may differ with different systems and buildouts.

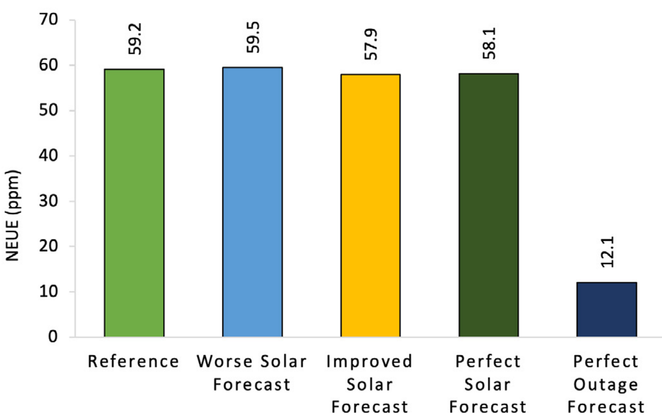

Figure 5: Average expected unserved energy across 1,000 simulations of system operations for each of five forecast qualities [5] considered.

Finding 8. Simplified storage dispatch representation can overestimate the reliability contributions of these resources.

Stephen et al. [6] analyzed two different approaches to representing storage dispatch in resource adequacy assessments: 1) a "reliability" approach in which a storage resource charges whenever excess energy is available and discharges only to avoid unserved energy, and 2) an "economic" approach based on limited-horizon (with options of a 12, 24, or 48 hour horizon) intertemporal system cost minimization, which is a more realistic representation of operational practices in restructured wholesale electricity markets. These four resulting storage dispatch representations (i.e., reliability, economic-12 hr, economic-24 hr, and economic-48 hr) were compared across three different systems, as described in Table 2. All three systems are modified from the same Reliability Test System Grid Modernization Lab Consortium (RTS-GMLC) test system [11] by removing different amounts of thermal capacity and then adding enough storage to reliably meet load for a target of just under 20 ppm NEUE.

The study found that that the reliability approach does not accurately represent real-world operating conditions and generally overestimates the actual resource adequacy contributions of energy-limited resources like storage. This is because the economic dispatch approach seeks to minimize system costs by providing short-term balancing and does not withhold state-of-charge to help mitigate unforeseen periods with potential lost load events.

These effects are particularly pronounced in systems B and C, where the economic approach leads to approximately 300 and 3,000 times as much NEUE, respectively (Figure 6). Increasing the foresight period of the economic dispatch approach from 12 to 48 hours does increase system reliability and the resource adequacy contribution of the storage resource. Similarly, estimated storage capacity credits are substantially lower when the economic dispatch methodology is used (Figure 7).

Collectively, these results suggest that the most robust resource adequacy (RA) assessment includes probabilistic-based approaches that account for the impact of economic-driven arbitrage and resource availability uncertainty, including those from both thermal and variable renewable energy (VRE) resources. Methods that apply simplifications to these aspects may overestimate the reliability of a system, especially in systems with storage resources.

Table 3: Description of the three systems explored by Stephen et al. [6] with each system's storage fleet configuration and resulting shortfall risk metrics

SYSTEM	DESCRIPTION	STORAGE CAPACITY *(MW)*	STORAGE DURATION *(hr)*	LOSS OF LOAD EXPECTATION *(LOLE; hr/yr)*	NEUE *(ppm)*
A	Least amount of thermal capacity removed, replaced with short-duration storage.	1,068	5.3	2.35 ± 0.002	19.0 ± 0.2
B	Moderate amount of thermal capacity removed, replaced with long-duration storage.	2,943	107.5	0.84 ± 0.003	18.7 ± 0.6
C	Most amount of thermal capacity removed, replaced with seasonal storage.	3,425	646.6	2.29 ± 0.002	19.5 ± 0.6

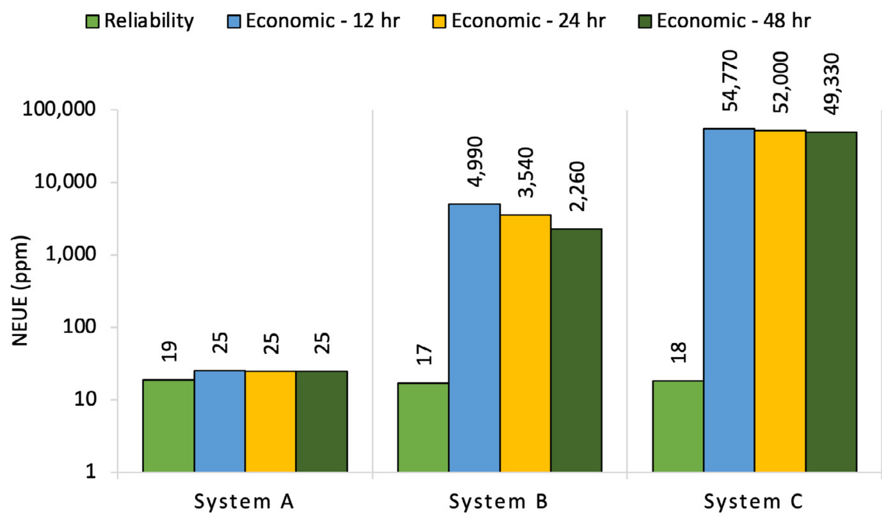

Figure 6: NEUE in four different modeling approaches in three different systems (note logarithmic scale on y-axis) [6].

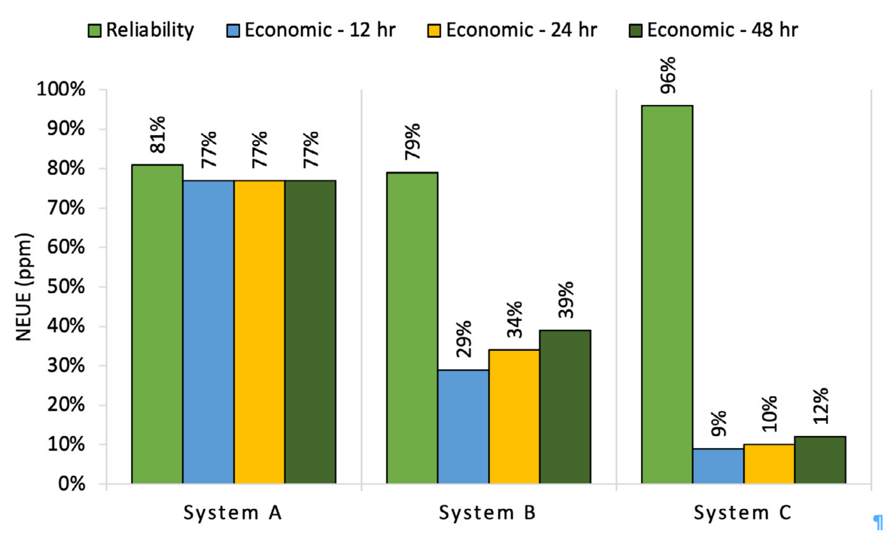

Figure 7: Capacity value of energy storage resources in four different modeling approaches in three different systems [6].

LONG-TERM GENERATION PLANNING

Finding 9. The investment decisions made by profit-seeking entities can differ from the idealized least-cost simulation outcomes using the same market design and system operating conditions.

Kwon et al. [7] highlights the importance of considering strategic profit-driven decision-making in capacity expansion planning studies in regions with organized wholesale electricity markets. The research investigates the impact of different market designs and clean energy incentive schemes on future generation portfolios using a game-theoretical approach where generation companies make investment decisions to maximize profits. The study shows that generation portfolios derived from strategic decision-making consistently have lower system-wide planning reserve margins compared to idealized least-cost generation expansion planning outcomes. This may imply that profit-seeking market participants have the ability to exert some level of market power in certain conditions; an effect that is not captured in least-cost capacity expansion modeling.

Specifically, generation portfolios from strategic investors were observed to include less new solar capacity and more new wind and storage capacity. This was likely observed because the strategic model places a higher priority on individual unit revenues rather than total system costs. Even when reserve margin levels align, the portfolios generated by each modeling approach differ significantly across five different market scenarios (Figure 8). This finding highlights the need to recognize the strategic perspectives of profit-seeking entities within generation expansion planning to enable more informed decision-making and electricity market design in an evolving power system landscape.

Table 4: Overview of scenarios considered in [7].

SCENARIO NAME	DESCRIPTION
E01	No capacity market, $5,000/MWh energy price cap
E02	No capacity market, $9,000/MWh energy price cap
CM1	Capacity market, $850/MWh energy price cap
CM2	Capacity market, $3,500/MWh energy price cap
CM3	Capacity market, $5,000/MWh energy price cap

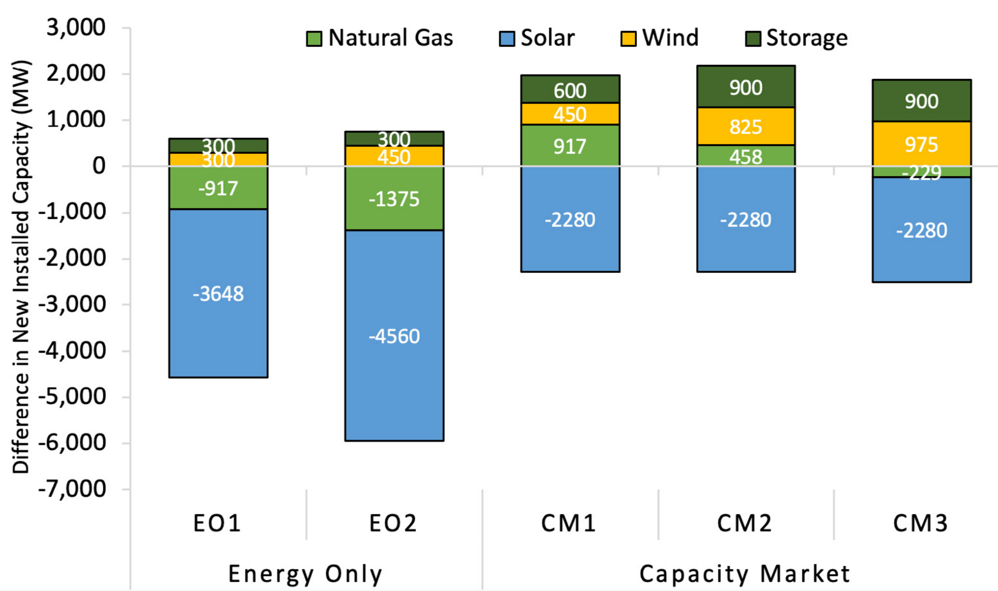

Figure 8: Differences in new investments in strategic models compared to least-cost generation expansion planning in different market design cases. The labels indicate the net change in unforced capacity obtained from the two models; i.e., a positive value indicates that the strategic model identified more new capacity than the least-cost one [7].

Finding 10. It is important to implement and examine market designs that are incentive-compatible with the social objectives and support competitive market entry and exit to minimize the potential for the exertion of market power.

Kwon et al. [7] also found that in a strategic decision-making framework, energy-only market designs consistently resulted in lower system-wide planning reserve margins (PRMs) than designs with a capacity market. The analysis examined three classes of market design: (1) an energy-only market, (2) a capacity market, and (3) a clean energy market. It also explored two incentive schemes: a tax credit for renewables and carbon pricing.

This finding indicates that the presence of capacity markets may be able to attract new market entries and reduce the potential for exertion of market power in the energy market. Even when similar planning reserve margins result, the generation portfolios obtained from each model often differed (Figure 9), as did the respective system costs of each scenario (Figure 10). These results demonstrate that higher scarcity pricing in an energy-only market incentivizes additional investments. Finally, the design of capacity demand curves plays a crucial role in influencing investment outcomes and achieving the desired efficient and reliable resource mix.

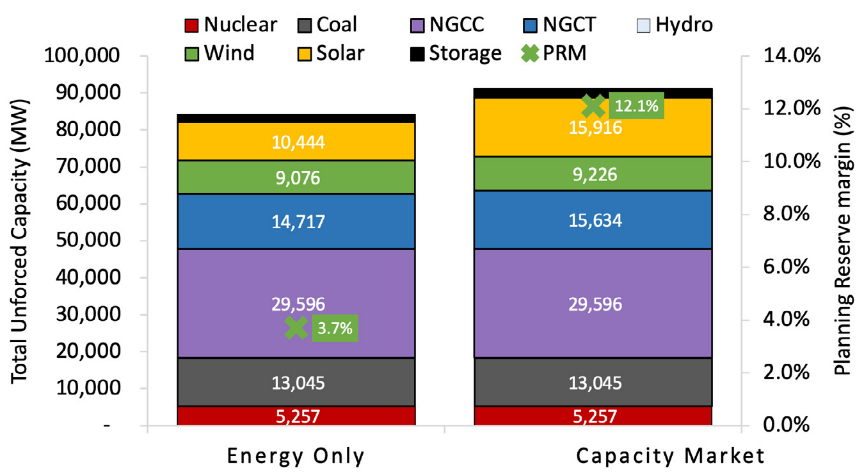

Figure 9: System-wide unforced capacity by technology and planning reserve margin in energy only and capacity market scenarios (NGCC: natural gas combined cycle, NGCT natural gas combustion turbine, PRM planning reserve margin).

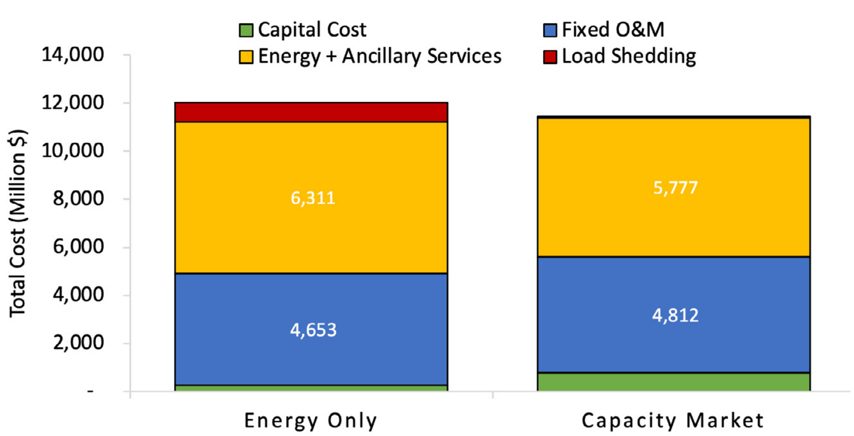

Figure 10: System-wide costs by category in energy only and capacity market scenario.

Finding 11. Annual variations in weather conditions affect cost-optimal resource mixes, resource adequacy, and total system costs, and these effects may be greater than those from changes in market design.

Sun et al. [2] show that capturing different weather years in expansion planning affects resource adequacy outcomes. This study also found that both ORDCs and/or capacity markets are able to attract sufficient investment to maintain targeted resource adequacy levels in different weather conditions. This analysis applied an agent-based capacity expansion model to an existing resource portfolio while assuming that either of two weather years would persist for 15 years. Figure 11 shows that in each case the system initially had adequate resources but experienced increased levels of NEUE in the third simulation year. However, in each weather scenario, the system was able to adapt to the conditions and reduce NEUE in subsequent years, regardless of the market designs that are implemented. In each case, the NEUE reaches zero for years 6 through 15 of the simulation.

Figure 12 shows how the weather assumptions impact the optimal generation portfolio. Weather year A generally has lower quality wind and solar resource availability than weather year B. This means that more wind and solar resources are developed when weather year A is assumed to persist. Conversely, battery storage investments are lower in the weather year A scenario because there is less net load volatility in these conditions. These differences are relatively consistent whether or not an ORDC is present. That is, the results are more sensitive to the weather year than the market design (ORDC vs. capacity market). These findings highlight the importance of evaluating market designs across a variety of weather conditions, especially forward-looking, climate-adjusted weather, to reflect additional extreme events.

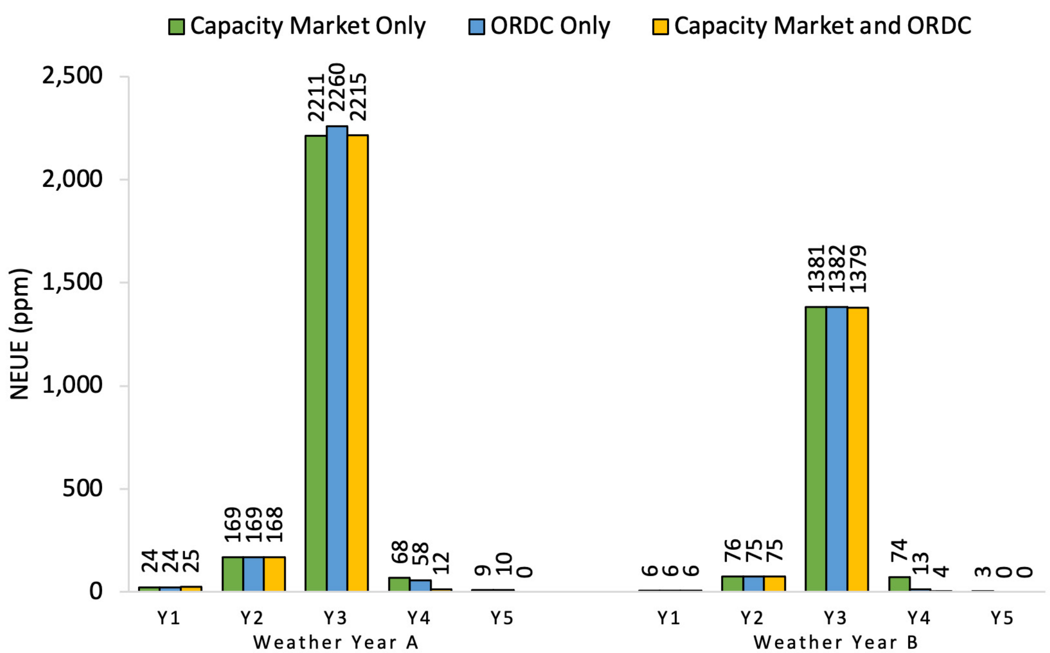

Figure 11: Normalized expected unserved energy resulting from capacity expansion scenarios that assume that each of two possible weather years persists for 15 years across three different market design scenarios [2].

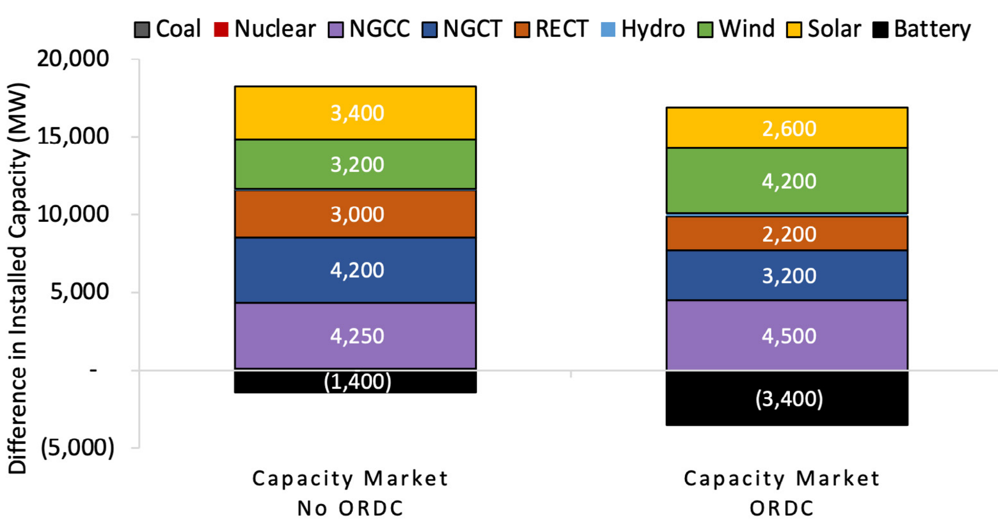

Figure 12: Differences in installed capacity after 15 years between cases with two different weather year assumptions (A and B). Positive values mean that capacity is greater in weather year A than in weather year B at the end of 15th year of the study [2].

TRANSMISSION PLANNING

Finding 12. Improved coordination and/or co-optimization of generation and transmission investments can lead to significant economic and technical benefits.

Mehrtash et al. [8] compared two different paradigms for transmission expansion: 1) a cohesive system least-cost optimization approach, and 2) individual project-by-project screening, which is more commonly used to evaluate transmission investments in practice. The study examined an "ERCOT-like" test system and established three significant conclusions. First, coordinated generation and transmission planning was found to reduce system costs and load shedding across four different scenarios compared with generation planning alone (Figure 13). Specifically, transmission investments can alleviate investments in both generation and storage resources. Second, while both a project-by-project transmission screening procedure and full transmission-generation co-optimization reduce system costs compared to generation expansion planning alone, cost reductions were twice as large when the optimization-based approach was utilized. Finally, storage and transmission investments are robust to changes in future conditions, while the optimal generation investment portfolio is more scenario dependent.

Table 5: Overview of scenarios considered in [8].

SCENARIO NAME	LOAD GROWTH	RETIREMENTS	POLICY
S1: Reference	10%	73% of coal, 18% of gas	None
S2: Carbon Policy	10%	73% of coal, 18% of gas	$50/ton carbon price
S3: Thermal Retirement	10%	100% of coal, 50% of gas	None
S4: High Load Growth	10%	73% of coal, 18% of gas	None

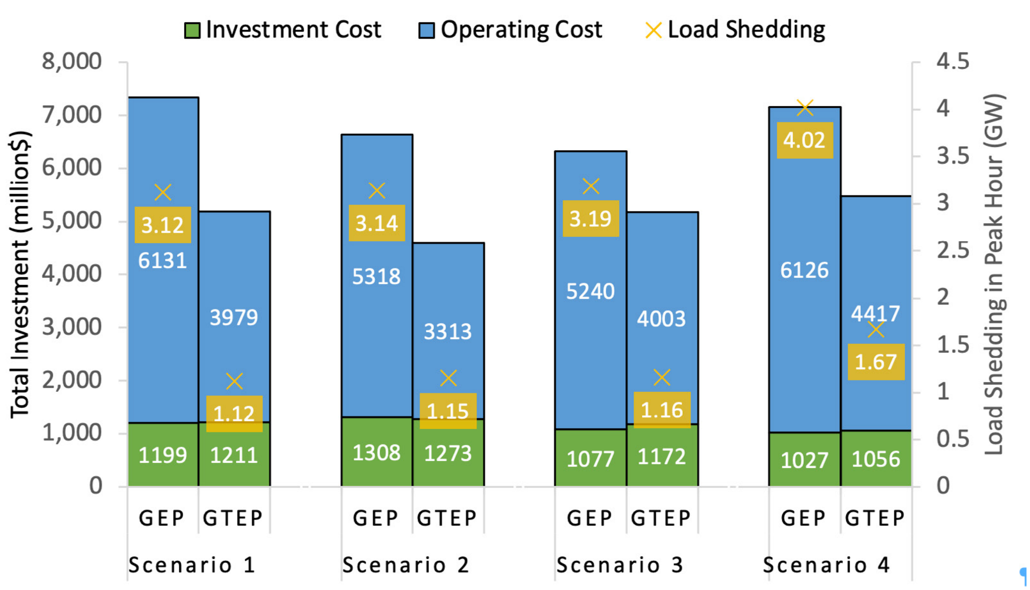

Figure 13: Total system costs and load shedding decrease when transmission expansion is considered as an investment option [8].

Finding 13. Energy storage can improve systemwide and zonal reliability when operated as a transmission asset; however, these benefits are not always captured by generation expansion models.

Sehloff et al. [9] examined the reliability contributions of storage operated as a transmission asset (SATA) and compared these results to the reliability contributions of traditional wires transmission upgrades. In an application to an "ERCOT-like" zonal network, the study found that wires upgrades were consistently selected over SATA investments in a least-cost generation and transmission expansion model. However, more detailed reliability assessment of both the transmission upgrade and selected SATA assets of varying sizes demonstrated that appropriately sized SATA upgrades achieve comparable performance to wires upgrades in terms of reducing both expected unserved energy (EUE) and loss of load hours (LOLH). Specifically, SATA upgrades improve reliability in the region where the asset is located without impacting reliability in other regions, whereas wires upgrades may lead to changes in power flow dynamics that actually increase EUE in other regions (Figure 14).

Significantly, no unserved energy events were identified during the capacity and transmission expansion process due to its relatively coarse temporal resolution and omission of post-contingency operations. Such factors likely inhibit the ability of such expansion models to identify the value of SATA investments, since these assets may only provide services when reliability needs arise. These results suggest that capacity expansion processes may need to be revisited to capture the full range of system benefits provided by energy storage resources. This could be achieved by enhancing storage representation, increasing spatial and temporal resolution, and/or conducting contingency analysis in capacity expansion models, either directly or through iterative assessment with a higher fidelity reliability assessment tool. The differences in cost and cost recovery mechanisms between SATA and wires upgrades are also important considerations when evaluating investment opportunities. One strategy to aid in cost recovery without significantly compromising reliability benefits is to allow dual participation of storage as both a transmission asset and an energy market asset, a topic which requires additional study.

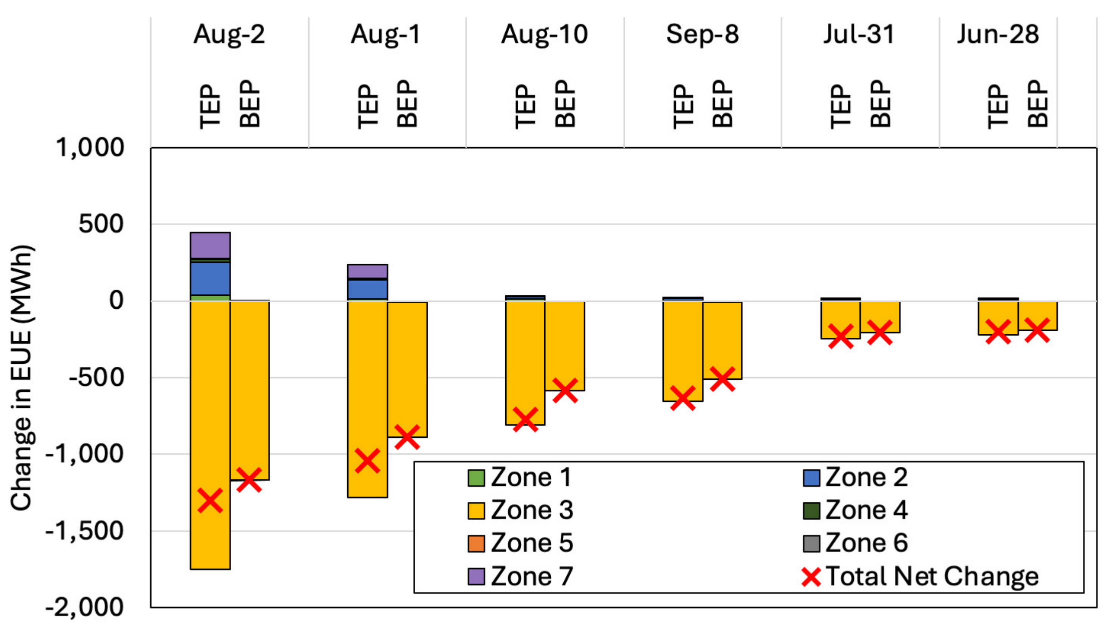

Figure 14: Change in expected EUE compared to the reference case for the seven days with the greatest EUE when either the transmission line between zone 7 and 3 is upgraded (TEP) or a 4h 1500MW battery storage transmission asset is located in zone 3 [9].

PATH FORWARD

This report summarizes 13 key findings that have emerged from the comprehensive set of research and stakeholder engagement activities performed by the project team between January 2020 and December 2023. These findings collectively point to several promising actions and research opportunities (Table 5) that can be undertaken to help ensure that wholesale electricity market processes continue to evolve to support efficient, reliable, affordable, and just system operations in electricity systems of the future. In a companion report to Sun et al. [10] authored by the same project team, Levin et al. provide an in-depth discussion of key electricity market research priorities and opportunities under deep decarbonization [12].

Table 6: Recommendations for future actions and research activities that have emerged from the stakeholder engagement and technical assistance performed by project partners between January 2020 and December 2023.

SYSTEM OPERATIONS
Enhance market participation models for energy storage resources to capture their full value in system operations and compensate them accordingly.
Consider using enhanced ORDCs, new flexibility products, look-ahead modeling, and/or enhanced reserve scarcity pricing mechanisms to increase system flexibility to maintain power balance efficiently.
PRICE FORMATION
Use efficient composite shortage/scarcity pricing demand curves through the whole set of grid services to value flexibility in a way that is commensurate with the contribution it can make to the system.
Better understand different resources’ participation models in energy and ancillary service markets and enhance the representation of incurred costs and/or offer behaviors in power system models.
RESOURCE ADEQUACY
Explore multi-stage operational modeling across thousands of outage states in resource adequacy modeling to more accurately capture the impact of operational constraints and uncertainty in systems with a mix of thermal, storage, and variable renewable resources.
Take outage uncertainty and common mode failures into consideration when determining the resource adequacy contributions of thermal resources.
Employ multiple weather years with varying types and degrees of weather events to ensure market designs are robust against inter-annual variations, especially with changing climatic conditions.
Apply chronological dispatch and state-of-charge tracking of storage in resource adequacy methods to ensure accurate representation of storage’s contribution to reliability.
LONG-TERM PLANNING
Improve the representation of future climate conditions in planning models to ensure that future power systems are resilient against macroscale climate trends and impacts.
Improve the representation of energy storage in planning models to fully capture the resource adequacy contributions of these resources.
TRANSMISSION PLANNING
Coordinate generation and transmission planning better and ensure that incentives and market signals are aligned across both domains to achieve system cost and reliability objectives.
Ensure that system cost reductions and reliability benefits of SATA are considered in transmission planning processes.

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