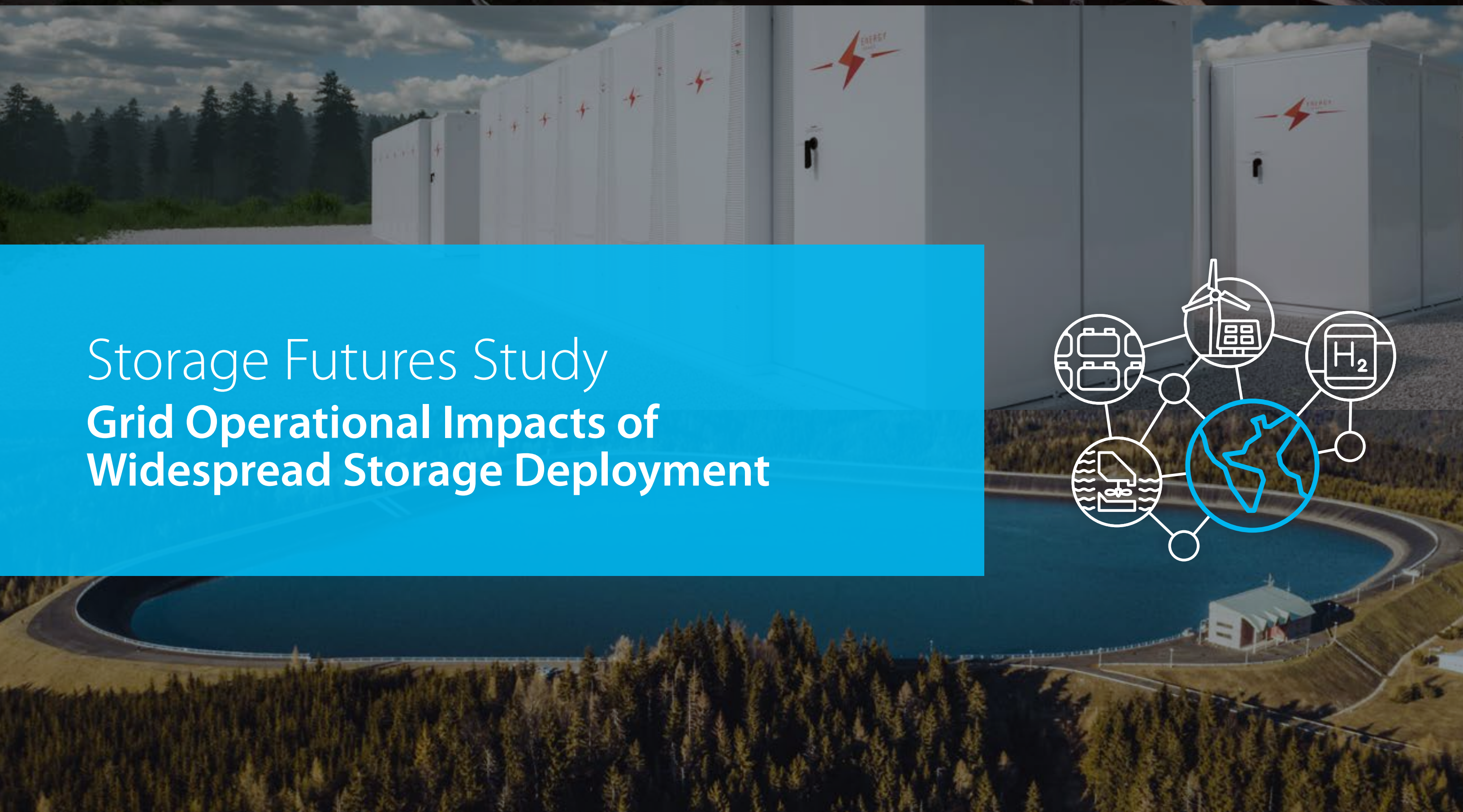
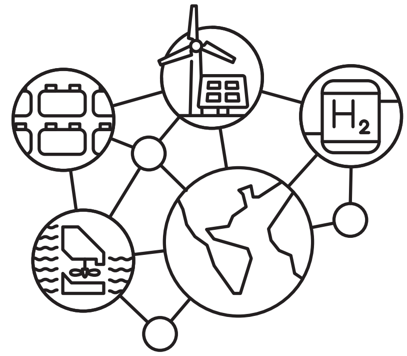


Storage Futures Study

Grid Operational Impacts of Widespread Storage Deployment

Jennie Jorgenson, A. Will Frazier, Paul Denholm, and Nate Blair



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NOTICE

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Preface

This report is one in a series of the National Renewable Energy Laboratory's Storage Futures Study (SFS) publications. The SFS is a multiyear research project that explores the role and impact of energy storage in the evolution and operation of the U.S. power sector. The SFS is designed to examine the potential impact of energy storage technology advancement on the deployment of utility-scale storage and the adoption of distributed storage, and the implications for future power system infrastructure investment and operations. The research findings and supporting data will be published as a series of publications. The table on the next page lists the planned publications and specific research topics they will examine under the SFS.

This report, the sixth in the SFS series, uses cost-driven scenarios from NREL's Regional Energy Deployment System (ReEDS) model as a starting point to examine the operational impacts of grid-scale storage deployment and relationships between this deployment and the contribution of variable renewable energy. We use commercial production cost modeling software to evaluate hourly operation of five scenarios that reach between 210 gigawatts (GW) and 930 GW of installed storage by 2050. We find that storage plays an important role in these power systems between now and 2050—by storing the lowest-marginal cost generation (often, overgeneration from solar or wind plants) and generating energy during the highest net load periods of the day and year. Storage helps with the integration of variable renewable energy and by providing an important resource to provide continued reliable power.

The SFS series provides data and analysis in support of the U.S. Department of Energy's Energy Storage Grand Challenge, a comprehensive program to accelerate the development, commercialization, and utilization of next-generation energy storage technologies and sustain American global leadership in energy storage. The Energy Storage Grand Challenge employs a use case framework to ensure storage technologies can cost-effectively meet specific needs, and it incorporates a broad range of technologies in several categories: electrochemical, electromechanical, thermal, flexible generation, flexible buildings, and power electronics.

More information, any supporting data associated with this report, links to other reports in the series, and other information about the broader study are available at https://www.nrel.gov/analysis/storage-futures.html.

Title[a]	Description	Relation to this Report
The Four Phases of Storage Deployment: A Framework for the Expanding Role of Storage in the U.S. Power System	Explores the roles and opportunities for new, cost-competitive stationary energy storage with a conceptual framework based on four phases of current and potential future storage deployment, and presents a value proposition for energy storage that could result in cost-effective deployments reaching hundreds of gigawatts (GW) of installed capacity	Provides broader context on the implications of the cost and performance characteristics discussed in this report, including the specific grid services they may enable in various phases of storage deployment. This framework is supported by the results of scenarios in this report.
Energy Storage Technology Modeling Input Data Report	Reviews the current characteristics of a broad range of mechanical, thermal, and electrochemical storage technologies with application to the power sector. Provides current and future projections of cost, performance characteristics, and locational availability of specific commercial technologies already deployed, including lithium-ion battery systems and pumped storage hydropower.	Provides detailed background about the battery and pumped storage hydropower cost and performance values used as inputs to the modeling performed in this report.
Economic Potential of Diurnal Storage in the U.S. Power Sector	Assesses the economic potential for utility-scale diurnal storage and the effects that storage capacity additions could have on power system evolution and operations	Analyzes utility-scale storage deployment and grid evolution scenarios and provides the input scenarios for this report.
Distributed Storage Customer Adoption Scenarios	Assesses the customer adoption of distributed diurnal storage for several future scenarios and the implications for the deployment of distributed generation and power system evolution	Analyzes distributed storage adoption scenarios to test the various cost trajectories and assumptions in parallel to the grid storage deployments modeled in this report.
The Challenge of Defining Long-Duration Energy Storage	Describes the challenge of a single uniform definition for long-duration energy storage to reflect both duration and application of the stored energy.	Thought piece to support the larger discussion about the role, value, and impact of storage on the grid.
Grid Operational Implications of Widespread Storage Deployment	Assesses the operation and associated value of energy storage for several power system evolution scenarios and explores the implications of diurnal storage on grid operations	This report.
Key Learnings About the Coming Wave of Energy Storage Deployment	Synthesizes and summarizes findings from the entire series and related analyses and reports, and identifies topics for further research	Includes a discussion of all other aspects of the study and provides context for the results of this report

Acknowledgments

We would like to acknowledge the contributions of the entire Storage Futures Study team as well as our U.S. Department of Energy (DOE) Office of Strategic Analysis colleagues as core contributors to this document. Those contributors include Wesley Cole, Chad Augustine, Kevin McCabe, Ben Sigrin, Ashreeta Prasanna, Jessica Lau, and Madeline Geocaris from the National Renewable Energy Laboratory (NREL) and Kara Podkaminer, Paul Spitsen, and Zachary Eldredge from DOE.

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List of Acronyms

CAISO	California Independent System Operator
DOE	U.S. Department of Energy
GW	gigawatts
MISO	Midcontinent Independent System Operator
MW	megawatts
MWh	megawatt-hours
NREL	National Renewable Energy Laboratory’s
PSH	pumped storage hydropower
PV	photovoltaics
TWh	terawatt-hours

Executive Summary

Due to rapid technology cost declines and significant potential value of energy storage, we could see hundreds of gigawatts of storage on the future grid. The Storage Futures Study (SFS) is designed to explore the potential role and impact of energy storage in the evolving electricity sector of the United States, specifically how energy storage technology advancement could impact the deployment of utility-scale and distributed storage, and the implications for future power system infrastructure investment and operations. This report—the sixth in the series—assesses the hourly operations of high storage power systems in the U.S., with storage capacities ranging from 213 GW to 932 GW.

The assessment builds upon a previously published report in the Storage Futures Study in which NREL added new capabilities to its publicly available Regional Energy Deployment System (ReEDS) model to build least-cost scenarios for a range of cost and performance assumptions for energy storage (A. W. Frazier et al. 2021). Scenarios showed the potential for U.S. storage capacity to exceed 125 gigawatts (GW) by the end of 2050, even in the most conservative estimates—a more than a fivefold increase over current U.S. storage capacity (A. W. Frazier et al. 2021).

This analysis returns to the ReEDS high storage scenarios with detailed production cost modeling to observe the hourly, daily, and annual operations and associated value of storage. Overall, we find that the high storage (and often high variable generation) power system scenarios envisioned in ReEDS successfully operate with no unserved energy and low reserve violations,[1] showing no concerns about hourly load balancing through the end of 2050. The successful hourly load balancing indicates the various improvements to ReEDS in previous work are effective in envisioning these future scenarios.

On a daily basis, we find storage operations are heavily aligned with the availability of solar photovoltaics (PV), which has a predictable daily on and off cycle that aligns well with the need for storage to charge and discharge. Wind, on the other hand, has a less apparent daily cycle and often experiences long periods of overgeneration stretching for many hours or days, which is much longer than the duration of storage we explore here[2]. Although storage can play a key role in utilizing energy from both PV and wind, the synergies with PV are more consistent. On an annual basis, storage effectively provides time-shifting and peak-load reduction services in all configurations and grid mixes. Although storage has a low annual capacity factor, which is inherently limited by its need to charge, it has a very high utilization (in many cases over 75%) during the top 10 net load hours across scenarios and years—when the system needs capacity and energy the most—indicating a strong contribution to the system's resource adequacy.

Lastly, we also find that storage increases the efficiency of many types of power system assets. For instance, we find that in these future grid scenarios, storage reduces total electricity system carbon dioxide emissions by utilizing overgeneration from zero-marginal emissions sources like wind and solar to displace generation from the coal and natural gas fleet. In addition, storage

[1] The scenario with the largest reserve shortages experiences a 0.3% shortfall of all required reserves.
[2] These ReEDS scenarios consider battery deployment with up to 10 hours of duration, and pumped storage hydropower with up to 12 hours of duration.

can prevent start-ups of those generators and thus reduce emissions of criteria pollutants, which can disproportionally impact those in poor health with low income, particularly those living near thermal power plants. Storage also impacts the operation of the transmission grid. We find that storage increases utilization of some transmission lines (quantified by the amount of observed congestion) while reducing the congestion observed on other lines. Exactly how storage impacts nearby transmission by either increasing or decreasing usage depends on the local conditions, but we find that more often than not, storage encourages higher utilization of transmission assets. These findings indicate that further analysis should consider the unique interaction of storage and transmission when both deploying and operating the assets together.

Collectively, the results of this and previous Storage Futures Study analysis show the growing opportunity for diurnal storage (that is, storage with up to 12 hours of duration) to play an important role in future power systems. This analysis shows how greater deployment of diurnal storage can increase efficiency of operations by reducing overgeneration, decreasing generator starts and emissions, and increasing utilization of the transmission system. Furthermore, storage plays an important role in providing capacity during the top net load hours. Future work could examine the role of longer-duration storage resources, especially under highly decarbonized grid conditions, such as those approaching 100% clean energy.

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1 Introduction

Deployment of variable generation sources such as solar and wind are increasing worldwide, driven by declining costs and renewable energy targets (Barbose 2021; Feldman and Margolis 2020; NREL 2020). In parallel, declining costs of batteries have led to a growing interest in deployment of energy storage to provide many grid services, including energy shifting and peak shaving (EIA 2019; Augustine and Blair 2021). The National Renewable Energy Laboratory's (NREL's) Storage Futures Study has evaluated pathways to storage deployment through 2050 and has found that storage will become an important contributor to the bulk power system, reaching 132 GW of deployed storage capacity in the United States by 2050 even with conservative storage cost assumptions (A. W. Frazier et al. 2021). This storage deployment is driven primarily by a combination of energy value (shifting energy over time) and capacity value (providing generation capacity during times of system need).

When deployed on the bulk power system, energy storage can provide numerous benefits, including energy shifting, avoided generator starts and stops, provision of ancillary services, contributing to the resource adequacy of the system, and possible deferral of transmission or other system upgrades (P. Denholm et al. 2013; Bistline et al. 2021). In providing energy shifting (arbitrage), storage, which is a net energy consumer, stores energy available at lower price to be discharged when the price is higher. As the share of zero-marginal cost variable generation resources continues to grow on the system, one well-documented use for storage is consuming energy during times of overgeneration (Paul Denholm et al. 2015). Another benefit of energy storage is to use stored energy to avoid costly start-ups of other generator types (Jorgenson et al. 2013). Energy storage can also provide ancillary services or operating reserves, which provide important reliability sources to the power system (Taylor, Bradshaw, and Hoagland 2002). Also, energy storage can provide peaking capacity to the system by discharging during times of system need, often during times of peak net load (demand minus contributions from variable generation) (W. Frazier et al. 2020). And finally, storage can provide other harder-to-quantify benefits, such as avoiding or deferring upgrades on the transmission or distribution system, particularly in areas where it may be hard to site traditional generation resources (P. Denholm et al. 2013).

Most power systems models can represent only a few of these potential benefits simultaneously, as the benefits are distributed widely across scale and time. System planning or capacity expansion models consider these various value streams as much as possible against upfront costs when considering future investments (A. W. Frazier et al. 2021; Brown et al. 2020). However, planning models often cannot consider detailed operational parameters or fully capture all services that storage (or other assets) may provide. Operational analysis typically requires the use of multiple models with different objective functions and temporal resolutions. For example, production cost modeling is one such tool that can provide detailed insight into the operation of the power grid, including hypothetical future systems that may look substantially different from today's system. For example, in some of the Storage Futures Study scenarios, deployment of storage reaches hundreds of gigawatts (GW), compared to the 23 GW of energy storage in the United States as of 2021, which is almost entirely pumped storage hydropower. What will the operation of a storage-heavy system look like, and how will it differ from today? How will different types of storage interact with each other, and other generating resources? How does that operation vary by season, scenario, and storage configuration?

To begin answering these questions, this work evaluates detailed operations of scenarios identified by the Regional Energy Deployment System (ReEDS) model to explicitly capture the operations of high storage scenarios on an hourly basis using a commercial production cost model, PLEXOS. We use a range of scenarios to examine the role storage may play on daily, seasonal, and annual bases and how that role varies by storage configuration and system resource mix.

2 Methods and Data

The main objective of the Storage Futures Study is to examine future electricity pathways that see a substantial and sustained deployment of energy storage in the United States. Understanding how the bulk-scale transmission and generation system may evolve with energy storage is at the heart of the study. The objective of this modeling is to identify and evaluate the costs and benefits of various storage pathways. Given the complexity of the power system, this cannot be achieved with a single model bulk-system model. To that end, we employ two bulk-system models[3] that in combination (1) identify least-cost investments pathways and (2) simulate the operations of projected future systems in detail.

In the first step in the analysis, we use a capacity expansion model (ReEDS) to identify the set of least-cost investments in transmission and generating assets under various evolutions of technology cost and performance. ReEDS is used for long-term power system planning efforts, as it synthesizes the many different constraints and drivers of change and investment in the power sector, including prices of technologies and fuels, policies and regulations, technology performance and constraints, fuel supply constraints, and changes in load shape and total demand, to identify investment pathways. In the second step, we use a production cost model (PLEXOS) to simulate the hourly chronological operation of the projected systems (under given scenarios) from present day to 2050. The results of PLEXOS can be used to evaluate whether the future projected system balances supply and demand without any major challenges on the hourly timescale.

2.1 Analysis Scenarios

This analysis is based on scenarios generated by NREL's ReEDS capacity expansion model, which represents the U.S. power system in 134 regions connected by aggregated transmission corridors, to perform least-cost system-wide optimization of power system retirements and investments in generation, transmission, and storage capacity through 2050 (Brown et al. 2020; A. W. Frazier et al. 2021). The model optimizes investments in the power system, including power system operation in each time-step with limited temporal resolution. Other reports in the Storage Future Study contain a full discussion of the ReEDS model, its inputs, and the various improvements associated with this work (Augustine and Blair 2021; A. W. Frazier et al. 2021).

This analysis focuses on the following five key scenarios implemented in ReEDS (A. W. Frazier et al. 2021; U.S. Department of Energy 2021). See the appendix for details.

[3] The Storage Futures Study also used a third model (dGen) to study adoption of customer-sited storage (Prasanna et al. 2021). However, the dGen model was not directly used as part of this analysis.

- **Reference scenario (Ref):** This scenario follows all reference assumptions for cost and technology evolution through 2050 (NREL 2020).
- **Low-Cost Battery scenario (Low-Cost Batt):** This scenario adopts the lowest-cost trajectory for batteries (Augustine and Blair 2021).
- **Low-Cost PV scenario (Low-Cost PV):** This scenario adopts the lowest-cost trajectory for solar photovoltaics (PV) (NREL 2020).
- **High Natural Gas Cost, Low-Cost Battery scenario (High NG Cost/Low-Cost Batt):** This scenario adopts the high-cost trajectory for natural gas fuel (EIA 2019) and battery technologies (Augustine and Blair 2021).
- **Zero Carbon scenario:** This scenario reflects the Zero Carbon Energy scenario from the *Solar* Futures Study,[4] which achieves even higher deployment of storage technologies (in megawatts) than the four scenarios above (U.S. Department of Energy 2021).[5]

Figure 1 shows the shows the capacity and annual generation broken down by generator type for each of the five scenarios for 2020–2050. All scenarios show expansion in solar PV, wind, and storage capacity, which is due in large part to declining technology costs for these three resources. These sources replace nuclear, coal, and in some cases gas generation. The displacement of gas generation and capacity is most obvious in the High NG Cost/Low-Cost Batt scenario, which uses a high natural gas price trajectory as well as the Zero Carbon scenario, which requires replacement of all coal and natural gas fueled generation by the end-year of 2050. The three other scenarios (Ref, Low-Cost Batt, and Low-Cost PV) follow a mid-case for a natural gas price trajectory, resulting in continued substantial natural gas generation and capacity through 2050.

[4] For information, see "Solar Futures Study," NREL, https://www.nrel.gov/analysis/solar-futures.html.
[5] The Zero Carbon Energy scenario, which is known as the Decarb scenario in the *Solar* Futures Study, achieves 95% decarbonization by 2035 and 100% carbon-free generation by 2050 with moderate load growth and demand response assumptions.

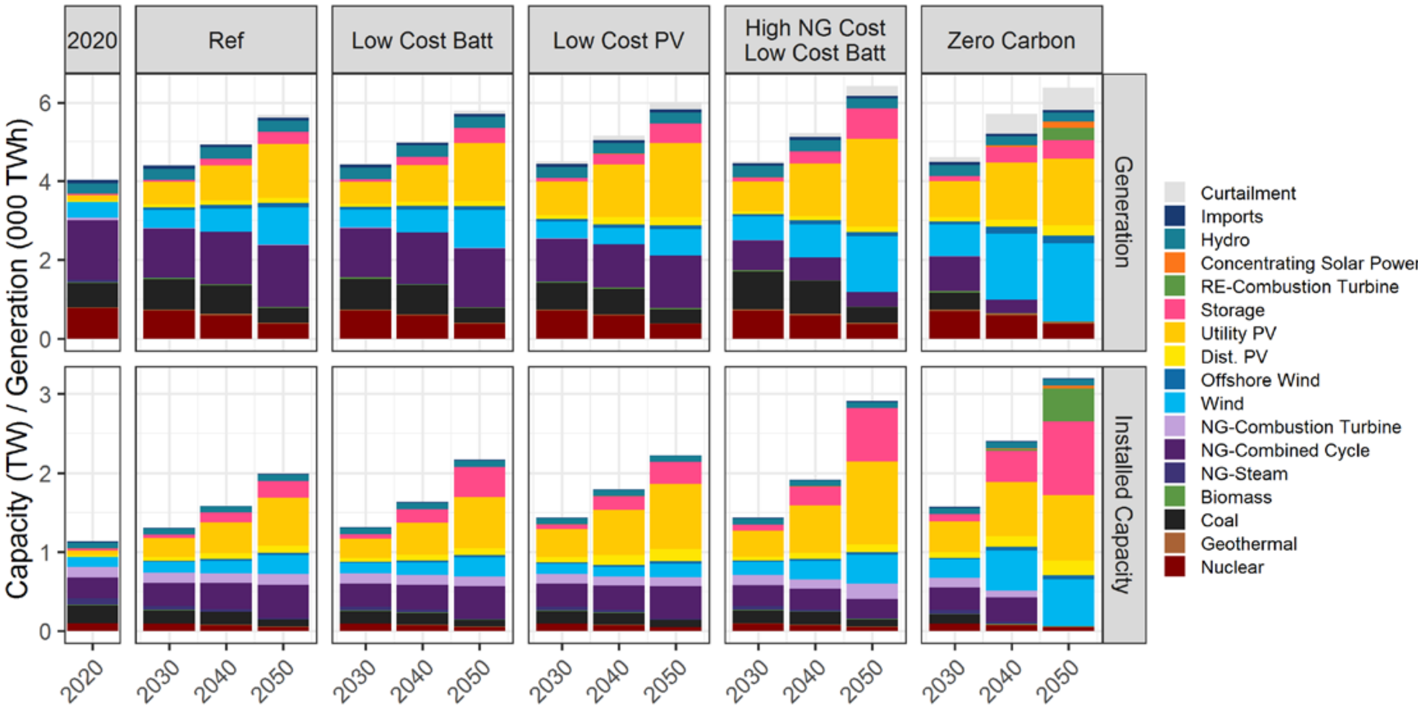

Figure 1. Total generation and capacity mix in five scenarios evaluated

Figure 2 shows the installed storage capacity broken down by technology type for the same scenarios and years. Note that storage durations greater than 12 hours were not considered for deployment in the larger Storage Futures Study (A. W. Frazier et al. 2021). In 2020, nearly all storage is existing pumped storage hydropower.[6] By 2030, we see a dramatic increase in the deployment of the lower-duration battery storage technologies (2- and 4-hr battery configurations), as those are assumed to have the lowest cost given their smaller energy capacity. In 2040, 4-hr batteries continue to dominate, but we start to see deployment of 6-hr battery technologies. By 2050, 4-hr batteries are still the most dominant storage technology in all scenarios, but some scenarios (particularly the Zero Carbon scenario) show deployment of longer-duration batteries such as 8- and 10-hr batteries. The longer-duration batteries become more cost-competitive in future years as a result of price declines. In the case of the Zero Carbon scenario, longer-duration batteries are also more valuable because of their ability to shift energy over longer periods and to provide a higher capacity credit. And finally, even the case with the least deployment of storage over the modeled time horizon (the Ref scenario) depicts a roughly tenfold increase in storage capacity through 2050.

[6] Although pumped storage hydropower is included in the ReEDS model, the technology was not substantially deployed in these scenarios because of the technology's assumed costs (Augustine and Blair 2021).

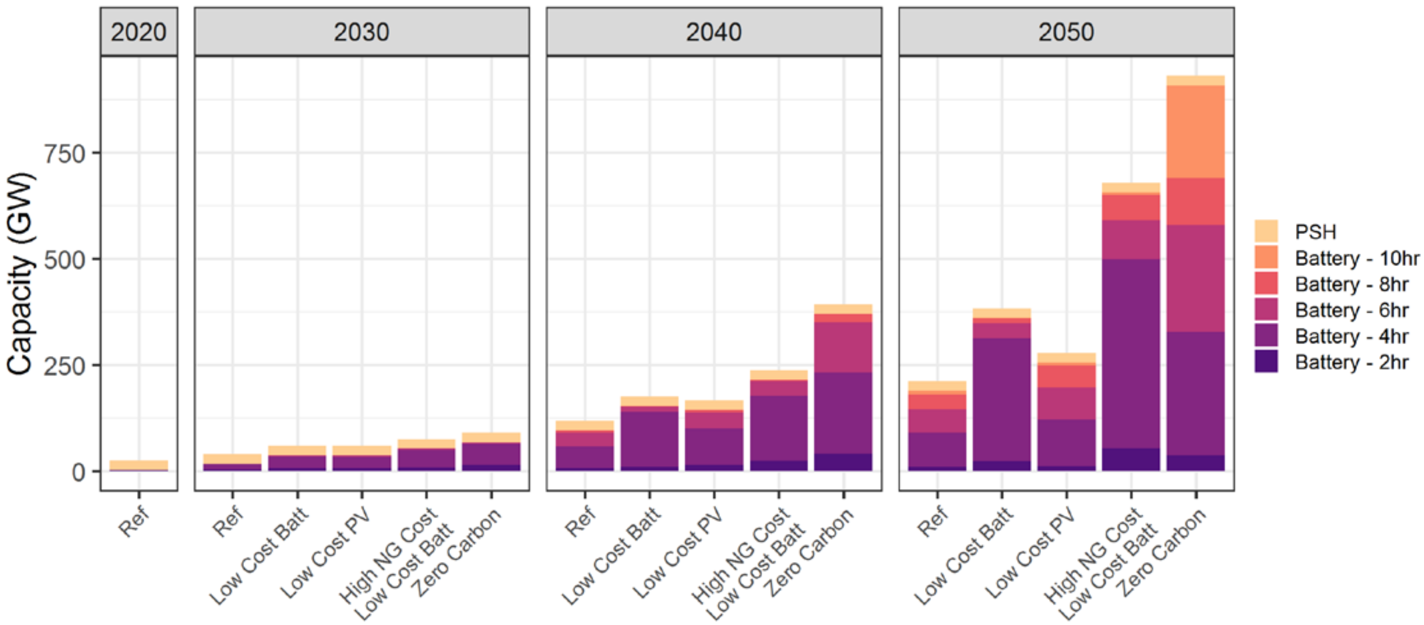

Figure 2. ReEDS storage capacity by technology type across time for five scenarios considered in this analysis

2.2 Formulation of PLEXOS

The production cost modeling begins with the system generated by ReEDS, including the types, capacities, and locations of transmission, renewable generation, and conventional generation, along with hourly load and variable generation data. These data are passed to the production cost model, along with hourly operating reserve requirements. We use PLEXOS,[7] a commercially available production cost model (sometimes referred to as a unit commitment and economic dispatch model) to simulate the hourly operations of the future systems identified by ReEDS. The objective of a production cost model is to optimize the scheduling and dispatch of generation resources to meet load most cost-effectively, subject to all constraints (e.g., renewable resource, transmission availability, and operational practices).

ReEDS conducts a simplified dispatch in its algorithm to inform investment decisions decades into the future. This allows the model to consider key operational constraints and challenges but remain simple enough to maintain computational tractability. However, because ReEDS does not explicitly simulate all 8,760 hours of dispatch for each year within the time horizon, nor does it account for unit commitment, it is unable to resolve many operational constraints key to ensuring energy balance and optimal operation of storage. So, PLEXOS simulates hourly operation of the ReEDS-determined build-out of the grid to measure operational costs and validate the balance of supply and demand, check for reserve violations, measure basic transmission adequacy using a simplified zonal approximation of the transmission network, and evaluate the dispatch of storage. Storage is defined in PLEXOS with the capacity (megawatts [MW]), duration (megawatt-hours

[7] "PLEXOS Market Simulation Software," Energy Exemplar, https://energyexemplar.com/products/plexos-simulation-software/.

[MWh]) and location determined by ReEDS. Consistent with the ReEDS All Services assumption, storage devices are co-optimized to provide both energy and ancillary services.

This analysis covers the entire conterminous United States, which encompasses all or part of three independent synchronous interconnections: the Eastern Interconnection, the Western Interconnection, and the Texas Interconnection. Because this geographic footprint is extensive, the capacity expansion modeling and the production cost modeling simplifies the transmission representation. For this modeling, the U.S. power system is represented by 134 regions connected with aggregated transmission corridors. Thus, both ReEDS and PLEXOS will constrain flow *between* (subject to the physical limits) but not *within* those regions.[8]

The goals of the production cost modeling step are to test the operational impacts of capacity expansion scenarios, offer a detailed picture of hourly dispatch across scenarios, and give insight regarding the optimization of storage dispatch.

For the purposes of this analysis, key outputs of the production cost model include:

- Identification of any unserved load or unserved reserve, which might signal resource adequacy concerns
- Generation composition at different timescales, from hourly to annual
- Total variable operating cost of generating electricity (including fuel costs, startup and shutdown costs, and variable O&M costs)
- Dispatch and utilization of energy-constrained resources such as hydropower, pumped storage hydropower, and batteries
- Resource mix providing reserve on an annual basis and at any given time
- Usage and congestion of the simplified representation of the transmission system
- Dispatch during periods of interest (e.g., high renewables/low load periods and low renewables/high load periods).

[8] The exact implications of simplistic transmission representation on the value of storage are unclear; the value of storage could be either overestimated or underestimated. For instance, under our modeling assumptions, storage could take advantage of the best opportunities for arbitrage within a region, whereas actual transmission constraints might inhibit those opportunities in the real world, thus *over*valuing storage. On the other hand, real world congestion could drive up regional prices at various places within the region, which our modeling would not capture, thus *under*valuing storage.

3 Operational Results for High Storage Futures Scenarios

In this section, we discuss the operation of the storage deployed in five Storage Futures Study scenarios, examining the role that storage plays on daily, seasonal, and annual bases. We also examine the changing role of storage over time, starting with a representation of the 2020 system through the modeling end-year of 2050.

3.1 Role of Energy Storage in Annual Operations

Storage is inherently different from most generators on the bulk power system as it is not technically a generation resource. To provide energy to the system, it must first *consume* energy to store, with an efficiency loss due to the conversion. Because of the requirement to charge and associated storage efficiency losses, the capacity factor[9] of storage is inherently limited[10]. Figure 3 indicates the average annual capacity factor for storage in each scenario with dots. In all years and scenarios, the annual capacity factor stays below 25% (and in some cases below 10%). To understand the capacity factor trends in Figure 3, we first consider the reasons storage is deployed in the capacity expansion model, which include as both:

- An Energy-Shifting Resource: Diurnally cycled storage performs energy arbitrage, especially with increasing amounts of low-cost resources to charge on, such as solar PV. And as battery costs drop, more energy-shifting opportunities become economical.
- A Capacity Resource: Energy storage is a dependable resource to help meet times of peak net demand.

The capacity factor slightly increases over time in some scenarios (Ref and Low-Cost PV) as a result of (1) the relative increase of deployment of longer-duration batteries, which can discharge for longer, giving a higher average capacity factor, as well as (2) higher deployment of zero-marginal cost resources (PV and wind) to arbitrage. In the other cases (Low-Cost Batt and High NG Cost/Low-Cost Batt), the average storage capacity factor drops after 2030 despite (in some cases) increased deployment of longer duration batteries; this occurs in the scenarios that have Low-Cost battery assumptions, as lower-cost batteries can be economic even with fewer opportunities for arbitrage. In these four scenarios, the capacity factor trends are largely driven by the first role of storage—as an energy-shifting device. The fifth scenario (Zero Carbon), however, shows annual capacity factors that are the lowest by 2050. In this scenario, the 2050 end year has nearly 200 days with curtailment in all 24 hours, compared to around only 55 days in the High NG Cost/Low-Cost Batt case. Given the significant round-the-clock curtailment in the Zero Carbon scenario, storage has less to do on a daily basis, reducing the average capacity factor. In this case, storage is primarily fulfilling the second role of storage—as a capacity resource—similar to a gas-fired peaking plant, which rarely runs.[11] Of course, storage in this

[9] The capacity factor is defined as the actual energy output over a given time relative to the maximum possible energy output over the same period.

[10] For a fictitious device with 100% round-trip efficiency, the capacity factor would be limited to 50%. For real devices with less than 100% efficiency, the capacity factor is even less than 50%.

[11] Comparatively, a recent analysis of combustion turbine generators (which are often referred to as peaking plants) in the United States finds that they had an average fleet capacity factor of 11% in 2019 (Brinkman, Novacheck, and

case is still providing the first role (energy shifting). The arbitrage opportunities in Zero Carbon, although they occur less frequently, are lucrative, because storage is charging on zero-marginal cost overgeneration and displacing expensive generation by renewable energy combustion turbines (which have marginal costs of around $200/MWh).

Although Figure 3 shows low annual capacity factors, the triangles, which show storage capacity factor averaged over only the top 10 net load hours in each region, tell a different story. This calculation reveals high capacity factors during those hours that are often much higher than 75%. These hours represent times of system stress and storage contributes greatly during these periods.[12] In most scenarios, the capacity factor for storage during the top 10 net load hours is the lowest in 2050 as a results of high storage deployment. With more storage capacity on the system, there are diminishing returns for *new* storage, indicating saturation. Similar to the annual capacity factor, the average capacity factor during the top 10 net load hours is the lowest in the 2050 Zero Carbon scenario for the same reasons that the *annual* capacity factor is the lowest in that scenario.

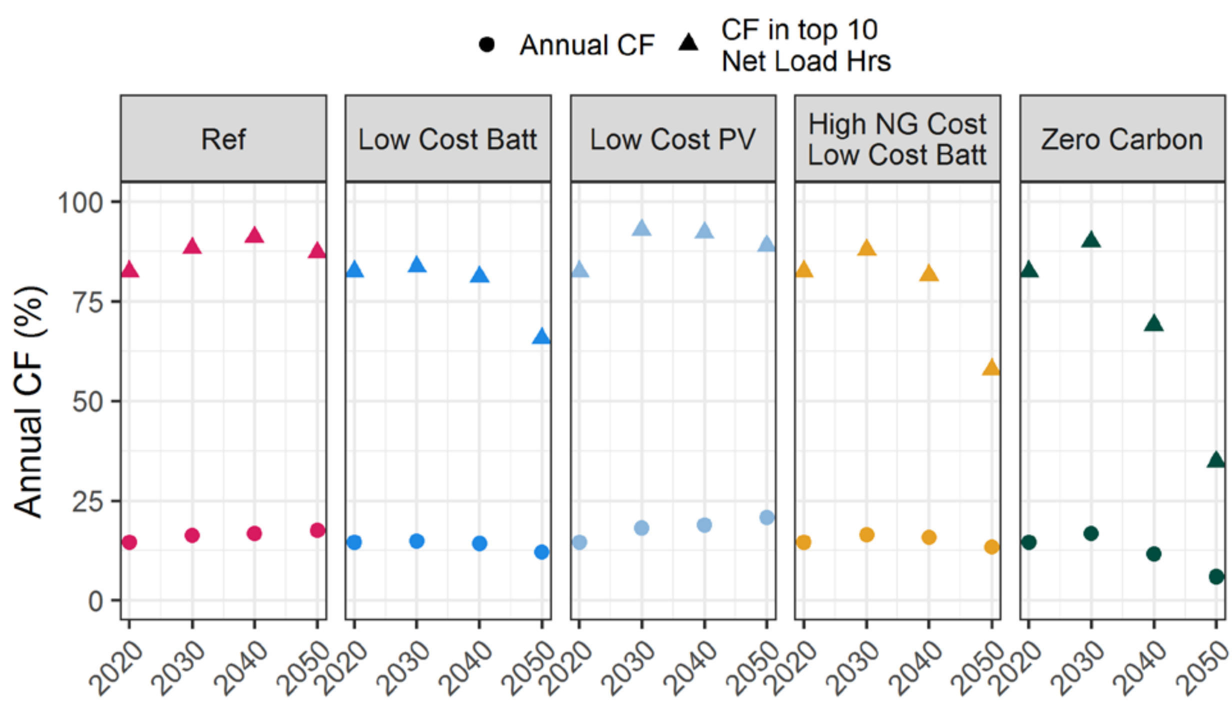

Figure 3. Annual capacity factor for storage assets across year and scenario, computed as an annual average (top panel) and during the top 10 net load hours (by region)

Ho 2021). In the Zero Carbon Energy scenario, which does not allow gas-fired generation by the end year, diurnal storage at least partially fulfills a similar role of providing generation at times of system need.

[12] The average capacity factor during the top hours of net load is often used as a simple calculation of capacity credit or firm capacity (Jorgenson et al. 2021).

Figure 4 shows annual capacity factor and the percentage storage duration discharged daily by storage type in 2050. The percentage of storage discharged daily is an alternative metric that represents the number of operational cycles per day.[13] These values are *usually* greater than 50%, indicating storage is being used heavily diurnally (or, on a daily basis) even in 2050, which sees the lowest annual capacity factors for most scenarios. Note that lowest duration storage has the highest percentage of energy utilized, despite the lowest capacity factors. As duration increases, the fraction decreases as there are fewer hours in a day to fully utilize it and lower chances that the full capacity will be needed. In addition, pumped storage hydropower has the lowest efficiency and so provides fewer opportunities for arbitrage, lowering its utilization. The Low-Cost PV scenario has the highest overall percentages (and capacity factors) because it has a combination of the highest PV deployment with the lowest amount of storage. The Zero Carbon scenario has the lowest overall percentages (and capacity factors) for reasons discussed above (i.e., it highest overall storage deployment combined with highest frequency of overgeneration conditions leading to fewer opportunities for storage to discharge).

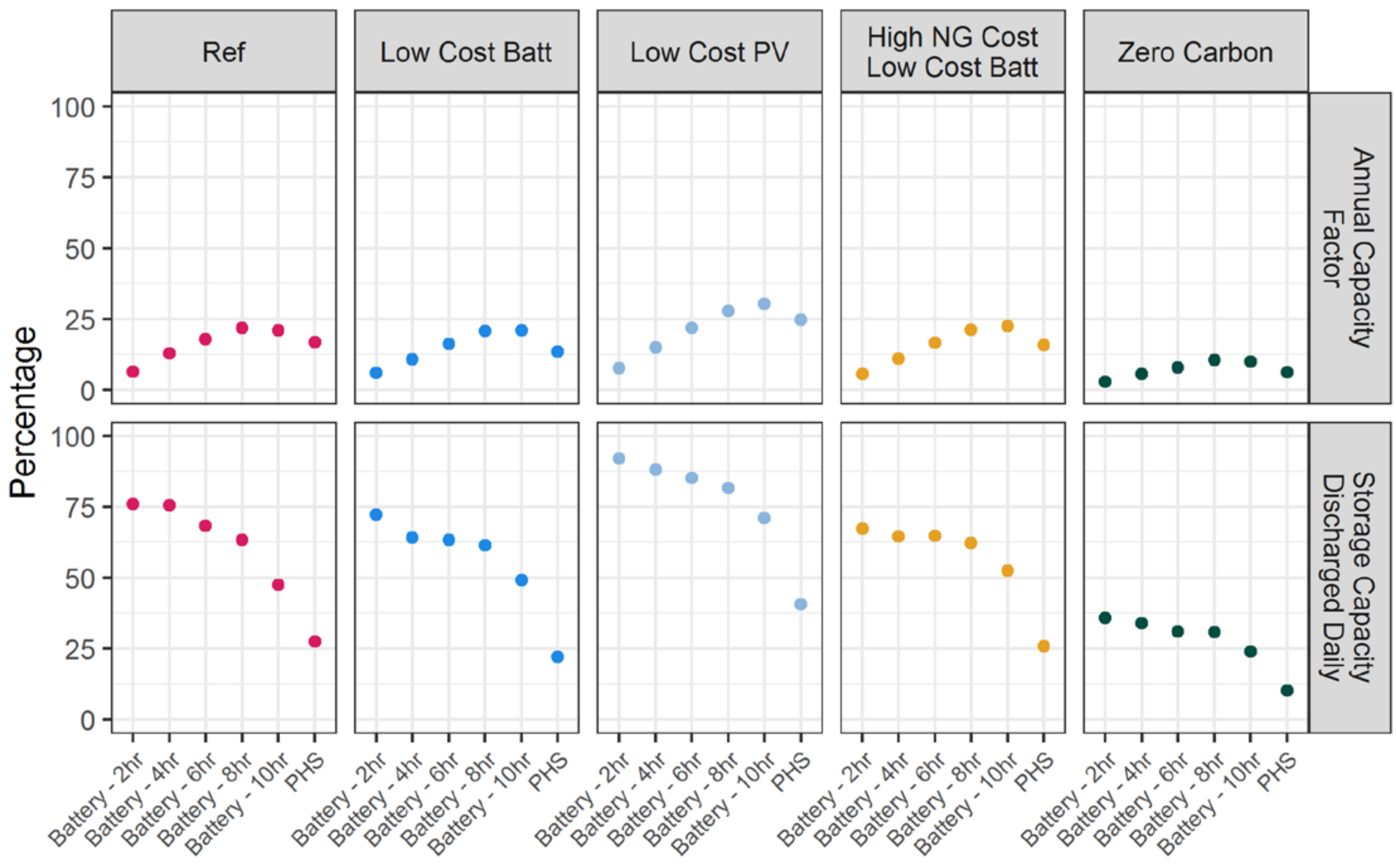

Figure 4. Annual capacity factor for each technology of storage (top panel) and percentage storage capacity discharged daily (bottom panel) for all scenarios in 2050

[13] Because cycles are tied to storage degradation, metrics of cycling are of particular interest to storage developers, operators, and researchers.

Finally, we examine the relationship of the percentage of storage capacity discharged daily for the High NG Cost/Low-Cost Batt scenario in 2050 with variable generation contribution (Figure 5). Here, we plot collections of ReEDS regions as individual points; doing so divides the footprint into 18 regions across the United States, somewhat approximating regional transmission organization/independent system operator footprints or market regions.[14] Each region is a point, with the percentage of capacity discharged daily versus solar as a percentage of total generation (left panel) or wind as a percentage of total generation (right panel). Although the plot exhibits substantial variation, there is a clear relationship between increasing solar contribution with increasing percentage of capacity discharged daily (or daily energy cycles) and a relationship between increasing wind contribution with *decreasing* percentage of capacity discharged daily. The positive relationship for PV indicates that as solar contribution rises, there is an increased need for diurnal cycling of storage—charging on overgeneration during daylight hours and discharging during the morning and evening peak. On the other hand, we see the opposite relationship for wind. Previous analysis has shown that wind overgeneration generally occurs for hours or even days on end, far longer than duration of storage deployed in this analysis (Jorgenson, Denholm, and Mai 2018). During these periods of wind overgeneration, once the storage is fully charged, the storage device cannot discharge until overgeneration conditions desist, thus lowering average diurnal capacity used.

[14] For purposes of plotting, these regions represent collections of the 134 original ReEDS transmission regions. The regions are broadly: Bonneville Power Association, the California Independent System Operator (CAISO), PJM West, PJM East, Florida Reliability Coordinating Council, Midcontinent Independent System Operator (MISO) East, MISO West, MISO South, Northwest Power Pool, New York Independent System Operator, Independent System Operator of New England, Arizona/New Mexico, Rocky Mountain Power Pool, Southwest Power Pool, Electricity Reliability Corporation of Texas, Tennessee Valley Authority, the Southeast, and Virginia and the Carolinas.

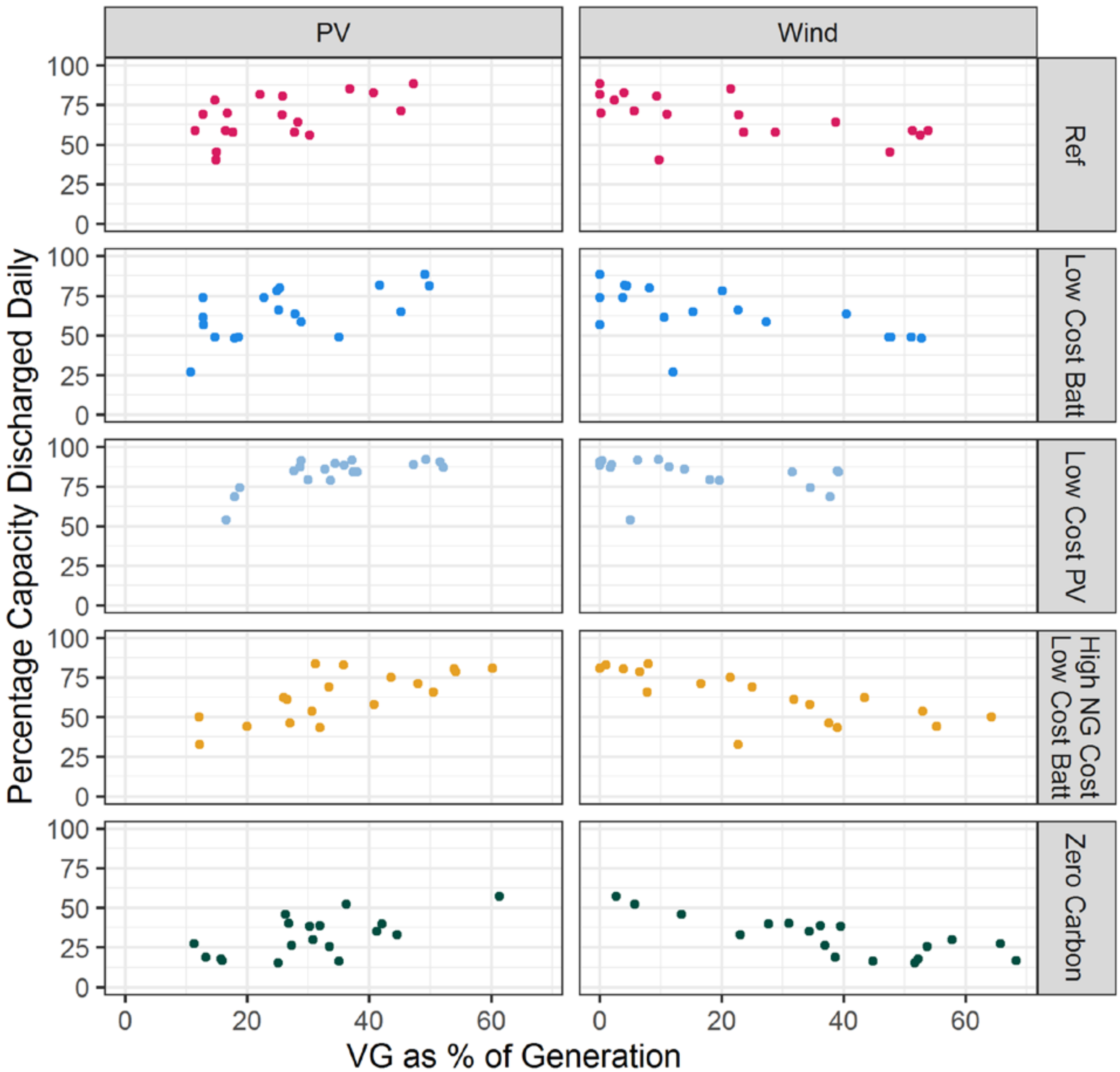

Figure 5. Percentage storage capacity discharged daily for 2050 for each of 18 regions in this analysis, plotted against variable generation as percentage of generation

This section illustrates how storage effectively provides peak-load reduction services (alongside time-shifting shifting), in all configurations and grid mixes. Although storage has a low annual capacity factor that is inherently limited by its need to charge, it has a very high utilization (in many cases, over 75%) during the top 10 net load hours across scenarios and years, when the system needs capacity and energy the most.

3.2 Role of Energy Storage in Hourly and Seasonal Operations

To demonstrate the changing role of energy storage across the analysis time-frame, we first look at other drivers of system change. For example, the recent rapid deployment of PV and wind technologies represent a dramatic factor in the changing landscape of generation technologies. Figure 6 shows average diurnal (daily) net load (demand minus variable generation) for the High NG Cost/Low-Cost Batt case through 2050. In 2020, we see a historically typical load curve that is generally lowest overnight and highest in the early evening during the summer. By 2030, substantial deployment of PV (14% contribution by generation) has already changed the shape of the net load curve, by reducing net load in the middle of the day and shifting the evening peak later in the day after the sun has set (Paul Denholm et al. 2015). All seasons show a secondary morning peak that occurs just before sunrise. These features persist and intensify in 2040 and 2050, as PV contribution continues to increase to 20% and 23% respectively.

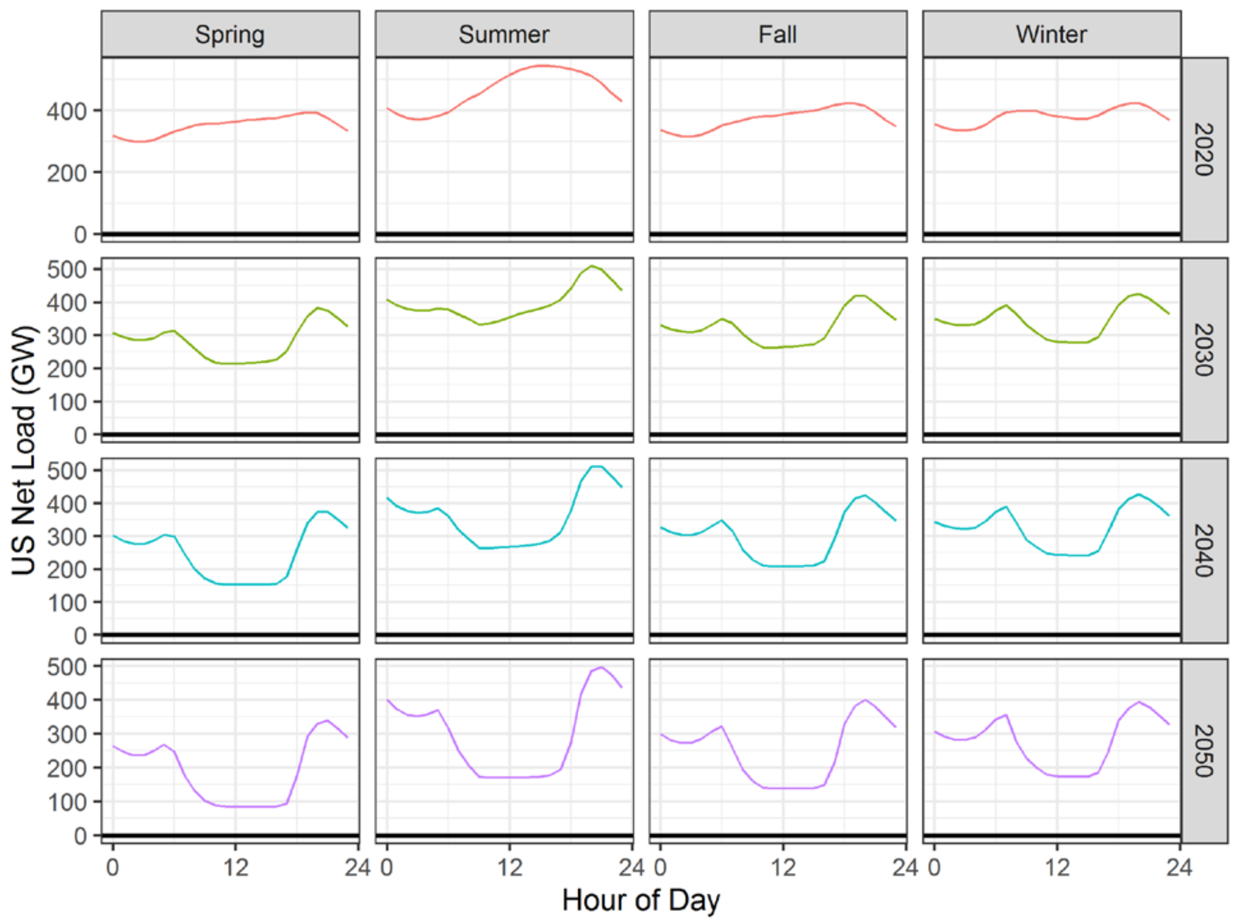

Figure 6. Average diurnal net load curves for 2020, 2030, 2040, and 2050 for High NG Cost/Low-Cost Batt case (shown *after* curtailment)

As net load changes across years, the operation of storage shifts as well (Figure 7). On the top panel showing 2020, storage charges mostly at night, which corresponds to the lowest net load levels in Figure 7 and thus lowest marginal generation costs. During all seasons in 2020, storage discharges mostly in the afternoon and in the early evening during peak net load. By 2030, however, storage has shifted to almost completely charging during the middle of the day to correspond with PV generation. Storage discharges in the evening but often slightly later in the evening relative to 2030 as solar shifts the peak later in the day. We also begin to see some generation during the morning shoulder peak. The same pattern persists and intensifies in 2040 and 2050 with storage charging in the middle of the day and discharging before solar comes online and after the sun sets for the day.

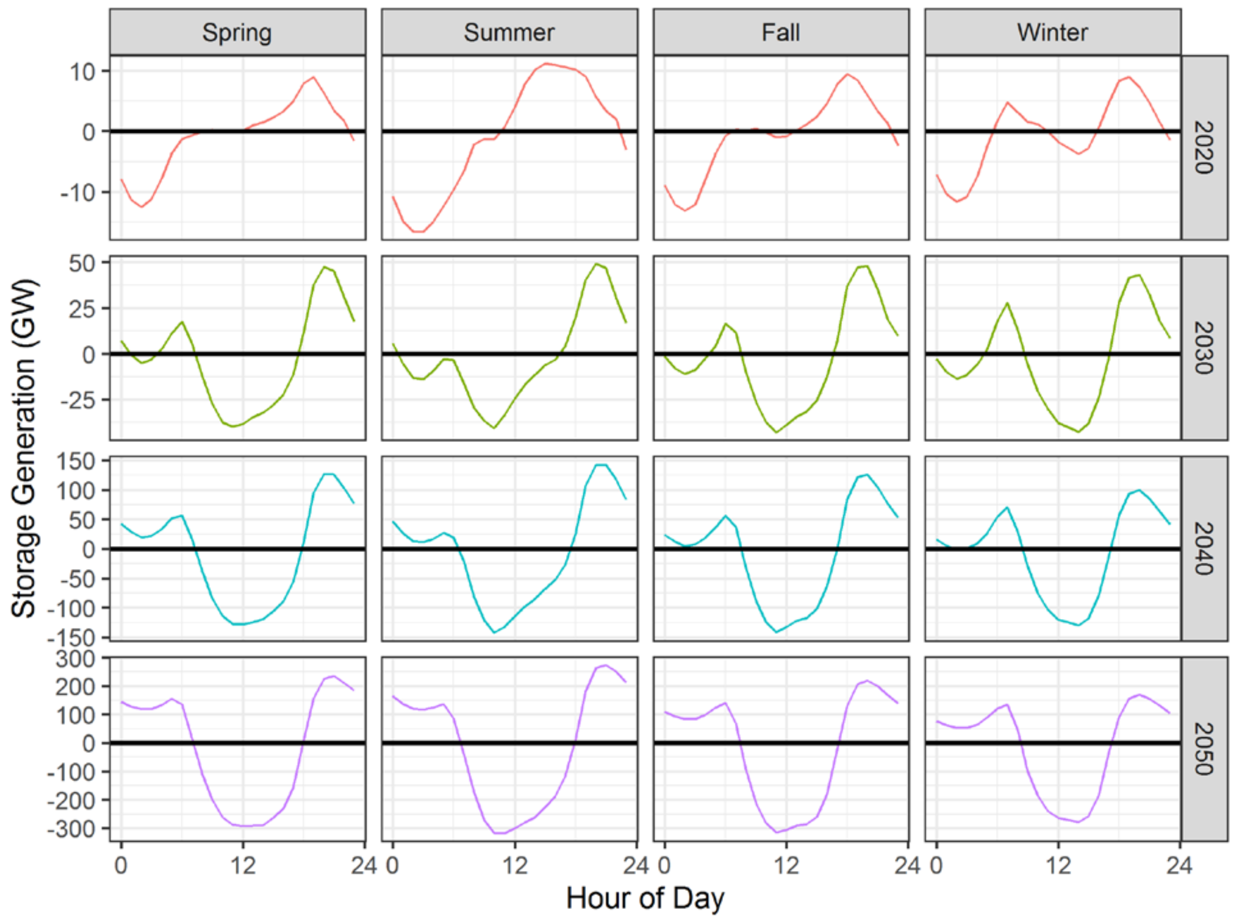

Figure 7. Average diurnal storage generation profile for 2020, 2030, 2040, and 2050 under High NG Cost/Low-Cost Batt scenario

As Figure 7 indicated, there is little difference in average diurnal storage usage across the four seasons, particularly non-summer months. This observation generally holds in Figure 8, which illustrates the percentage of full energy capacity used daily for all five scenarios for each month of the year. However, we observe several interesting trends. First, the average percentage utilized goes slightly above 100% for some scenarios (Zero Carbon and Low-Cost PV) in 2030 for most non-summer months. In these cases, shorter duration (2- and 4-hr) storage charges overnight (on wind or cheap nuclear/coal, depending on region) and discharges during the morning peak, and then charges again during the day on solar and discharges during the evening peak as well. Figure 9 (page 15) illustrates this with five sample days in January 2030 in the Low-Cost PV scenario. The top panel shows the daily generation profile of 2-hr battery storage, which shows generally two daily cycles. The longer-duration storage configurations (pumped storage hydropower and 6-hr batteries in this case) show typically one daily cycle. On the whole, however, most years and scenarios indicate the fraction of full energy capacity using less than 100% of the full capacity per day—so, more than one daily cycle remains rare.

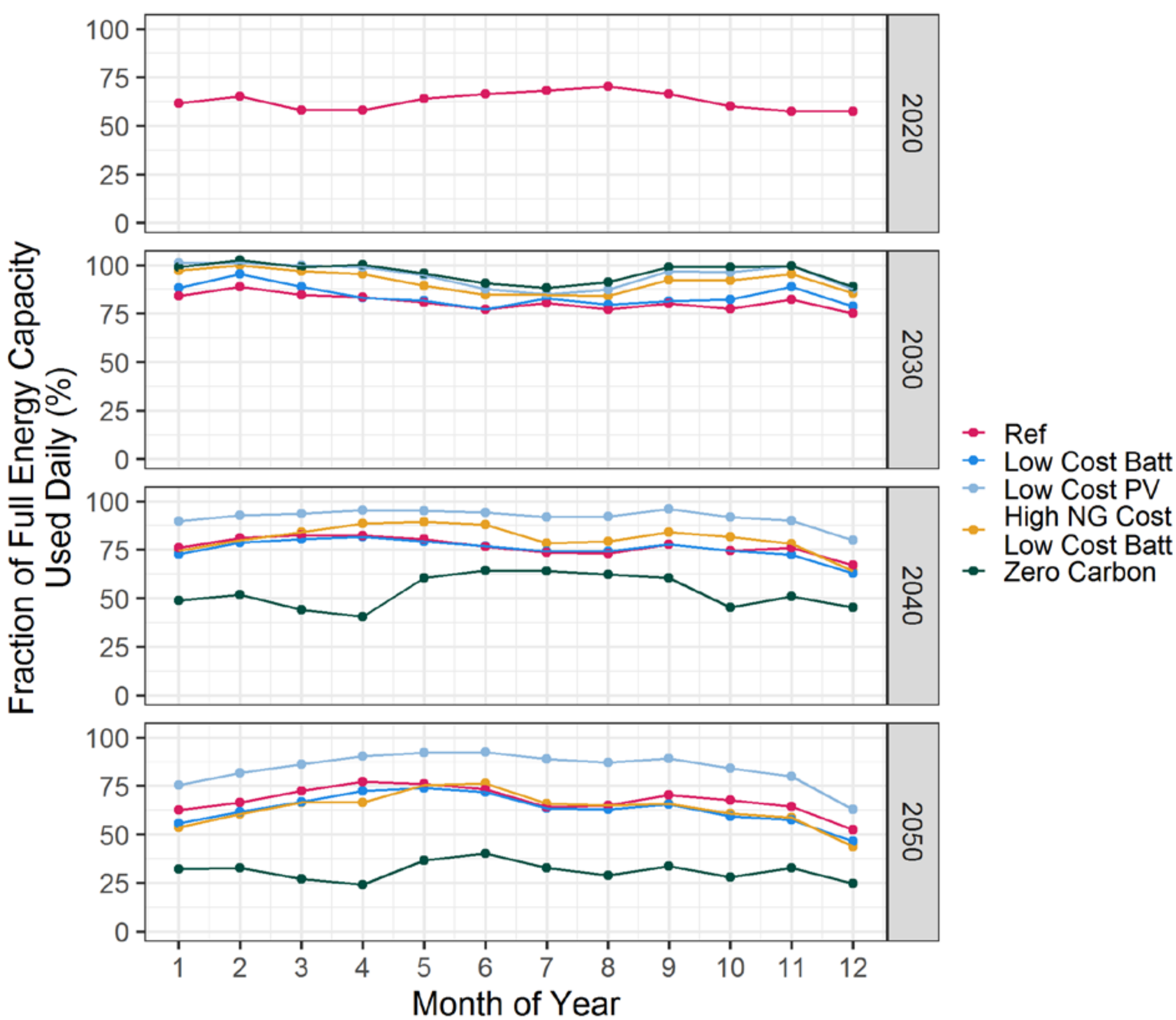

Figure 8. Percentage storage capacity discharged daily, shown for each month and scenario

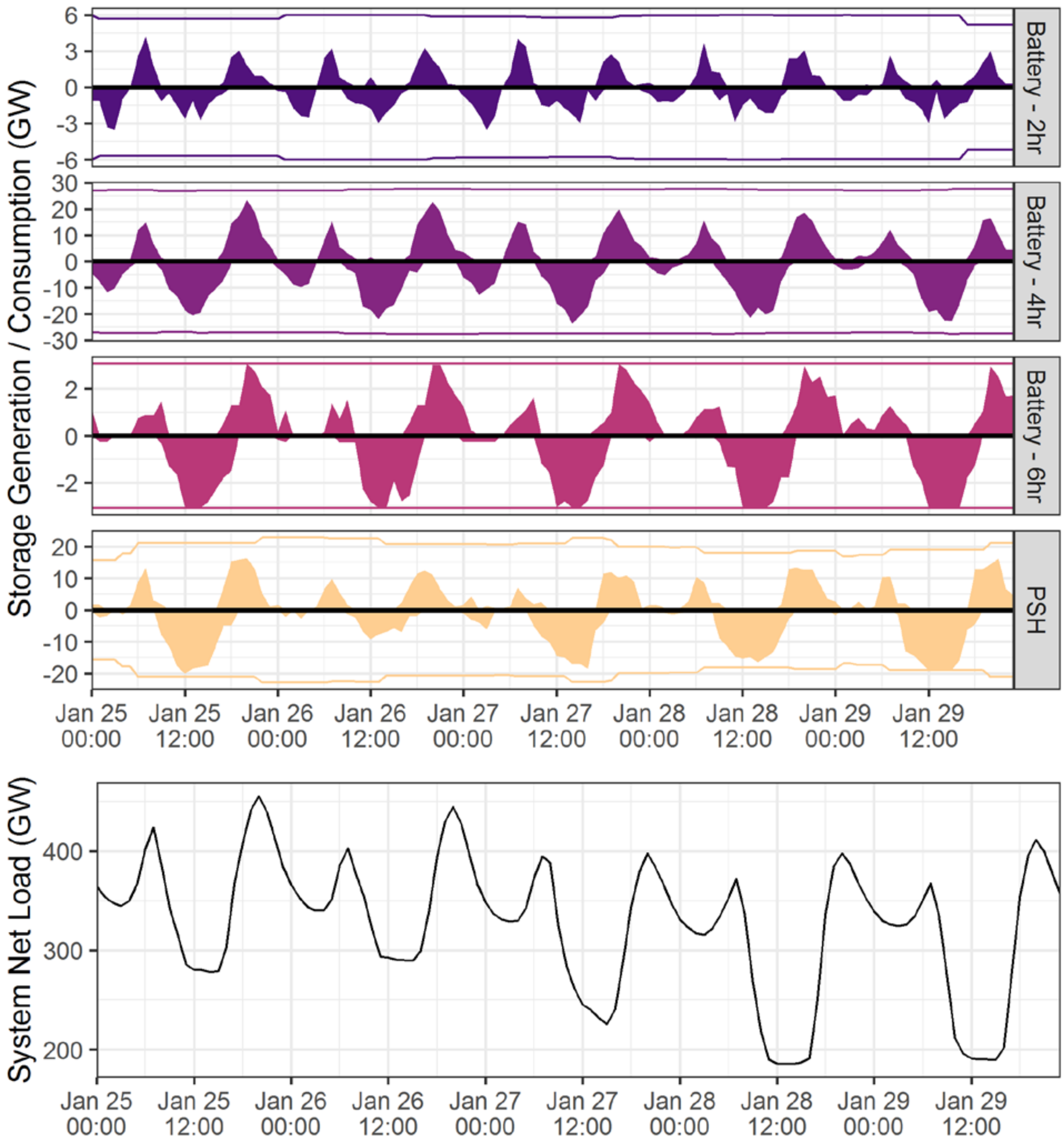

Figure 9. Utilization of various technologies of storages during winter in the Low-Cost PV scenario, 2030 (top panel), along with system net load (bottom panel). For the top panel, the filled area represents storage dispatch and the solid line indicates total available capacity[15]

The plot only displays the configurations of storage deployed in this year and scenario (omitting 8- and 10-hr batteries). PSH is pumped storage hydropower.

[15] Total available capacity varies over time due to outages from individual storage plants.

We also note that in 2030, the utilization of storage is lowest during the summer months. The net load is less "duck-shaped" (i.e., the net load in the middle of the day remains high) due to the higher overall demand driven by additional cooling loads. These midday and afternoon loads are largely coincident with solar availability, resulting in slightly less overgeneration for charging storage. Figure 10 (page 17) illustrates this with 5 sample days in July 2030 for the Low-Cost PV scenario (the same scenario shown in Figure 10). In the summer, we note generally just one daily cycle even for the lower-duration storage configurations. We also note less need for storage generation during the morning (relative to the winter period), with virtually all storage discharge occurring during the evening peak.

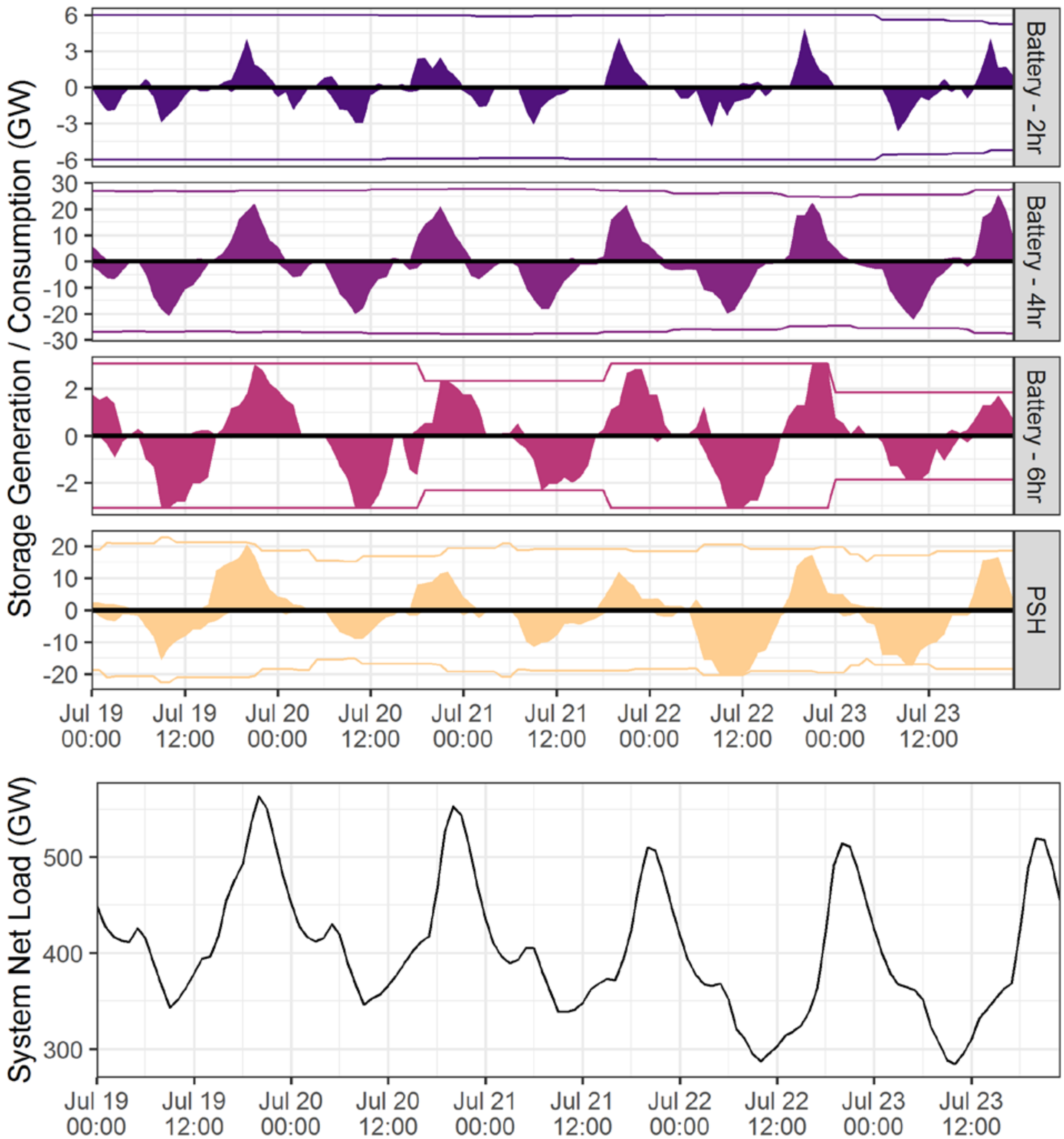

Figure 10. Utilization of various technologies of storages during summer in the Low-Cost PV scenario, 2030 (top panel), along with system net load (bottom panel). For the top panel, the filled area represents storage dispatch and the solid line indicates total available capacity[16]

In 2040 and 2050, there is overall less utilization of storage (as was discussed in Section 3.2) due to increased storage deployment and very little seasonal variance—apart from perhaps more storage usage in the early summer months in some seasons. The early summer months typically

[16] Total available capacity varies over time due to outages from individual storage plants.

demonstrate strong wind and PV generation, combined with moderate load from more mild temperatures than late summer months.

Overall, the diurnal operation profiles in this section illustrate that storage operation is tightly aligned with PV availability and less so with wind generation. This conclusion remains consistent among scenarios, resource mixes, and seasons. PV has a predictable daily on and off cycle that aligns well with the need for storage to charge and discharge. Wind, on the other hand, has a less apparent daily cycle and often experiences long periods of overgeneration stretching for hours or days, much longer than the duration of storage we explore here. Though storage can play a key role in utilizing storage from both PV and wind, the synergies with PV are more consistent.

3.3 Storage Sensitivities

So far, we have discussed the role of storage for future power systems on daily, seasonal, and annual bases. However, we can also gain meaningful insight by assessing the role of *incremental* storage. Until this point, we have considered the "optimal" amount of storage that had been deployed by the cost optimization in the capacity expansion model (ReEDS). For the set of sensitivities described in this section, we vary the amount of storage in the 2050 High NG Cost/Low-Cost Batt case to observe the impacts on the value of storage, the interaction of transmission and storage, and the impacts on the dispatch of the conventional generator fleet.

For the sensitivities we describe in this section, we begin with the 660 GW of storage deployed in the 2050 High NG Cost/Low-Cost Batt case. From there, we adjust the storage fleet by +/-5% increments of 80%–120%. Each sensitivity changes the amount of storage by about 33 GW. We emphasize that removing and adding storage from the ReEDS deployed generation mix results in build-outs that are no longer "optimal." One implication of this might be reduced reliability in cases with less than 100% storage. Although none of the cases had substantial observed dropped load, the lower storage cases did have an increased incidence of dropped reserve relative to the 100% Storage sensitivity. So, these sensitivities on storage amount are counterfactual but still instructive.

3.3.1 Incremental Operational Value of Storage

Figure 11 shows four days of system-wide generation dispatch for three of these sensitivities (80% Storage, 100% Storage minus the original High NG Cost/Low-Cost Batt case, and 120% Storage) for May of 2050. The 80% Storage sensitivity indicates a large amount of curtailment (particularly on May 6 at around noon, when over 150 GW of curtailment is occurring). The curtailment goes down in both the 100% Storage sensitivity and the 120% Storage sensitivity, and it is just less than 100 GW in the 120% Storage sensitivity. The daily dispatch also shows less natural gas generation (most NG-Combined Cycle) in the shoulder hours between daily solar hours as storage displaces it in the 100% and 120% scenarios relative to the 80% Storage sensitivity.

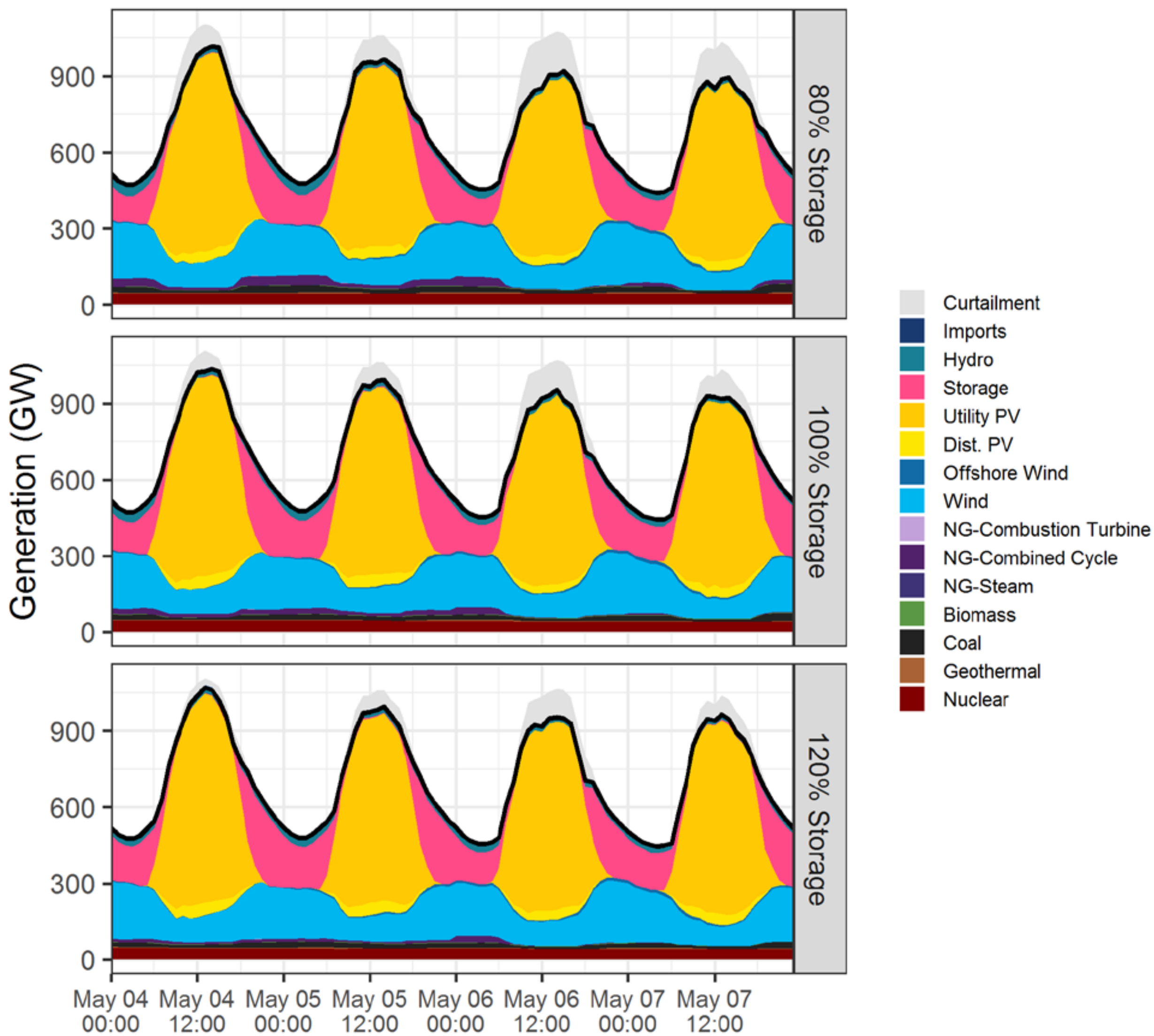

Figure 11. Total system generation dispatch for 4 example days in May 2050 in High NG Cost/Low-Cost Batt scenario

As indicated in Figure 11, storage can effectively use lower-marginal cost generation (e.g., curtailed solar) and can displace more expensive generation (e.g., natural gas-combined cycle generators). As a result, the higher storage sensitivities exhibit lower annual generation costs.

Figure 12 shows the total annual generation cost (in $ billion) for the storage sensitivities. The original 2050 High NG Cost/Low-Cost Batt case is shown in the middle as the 100% Storage sensitivity. Note that the annual generation cost increases as storage is removed from the 100% Storage sensitivity and decreases as storage is added beyond the 100% Storage sensitivity. The shape of this curve illustrates how the incremental value of storage decreases as more storage is added to the system. For instance, between the 80% and 85% Storage sensitivities, adding the 33 GW of storage reduces the annual generation cost by $732 million. In contrast, between 115% and 120% storage, adding those same 33 GWs reduce the total costs by only $248 million. This finding illustrates that as more storage is added, the opportunities for arbitrage go down. The first MW installed will take advantage of the most advantageous arbitrage, and the following MWs will have slightly less attractive options as additional storage flattens the shape of the net load. Figure 13, which shows the annualized marginal value of incremental storage relative to the original 100% Storage sensitivity, illustrates the same trend. Figure 13 shows that most of the value of storage comes from avoided fuel costs (by arbitraging more to less expensive fuel) with a substantial portion coming from avoided plant start and shutdowns.

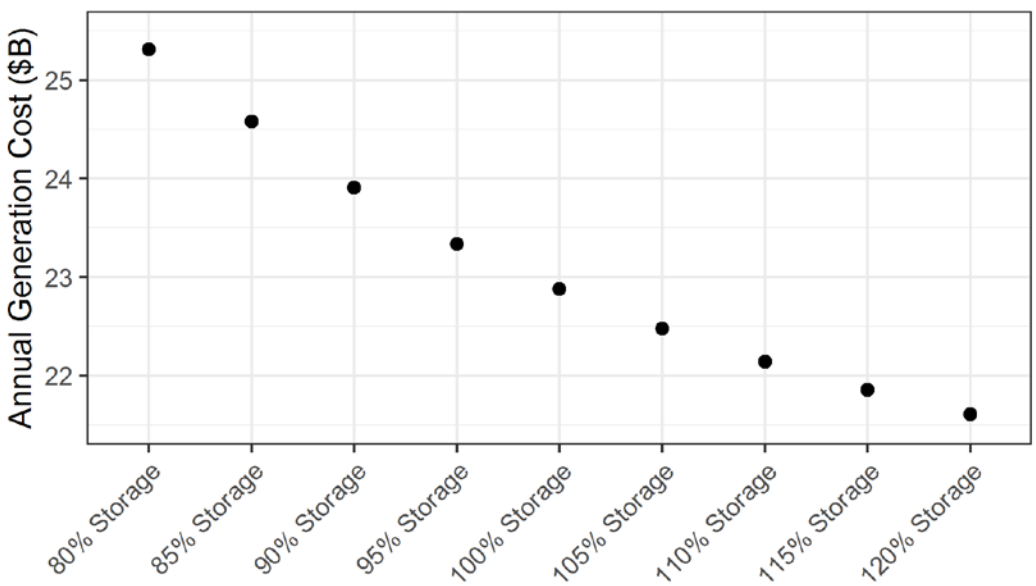

Figure 12. Total annual generation cost ($ billion) for storage sensitivities, with original 2050 High NG Cost/Low-Cost Batt case shown as 100% Storage

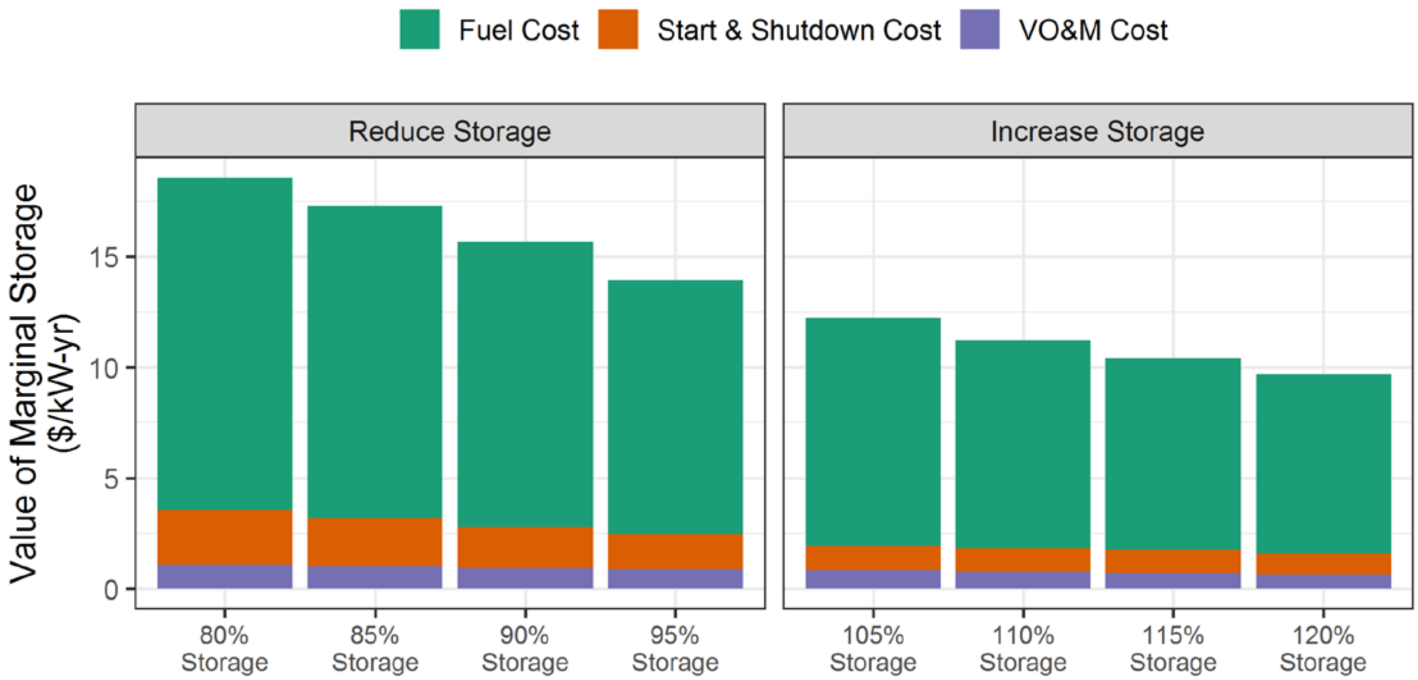

Figure 13. Value of marginal storage (relative to original 100% Storage sensitivity) normalized by installed capacity, broken down into variable cost category

Note that the incremental value of storage in Figure 13 is only a fraction of the total value of the incremental storage. As discussed in previous sections, storage also has capacity value. Although capacity value can be implied through production cost modeling (such as the availability of storage during the top 10 net load hours in Figure 3), the value of capacity and arbitrage will ultimately be weighted against the costs in capacity expansion models such as ReEDS.

3.3.2 Storage and the Thermal Fleet

Bulk power storage can not only increase the utilization of overgeneration from variable generation technologies, it can also increase the efficiency of thermal generators as well—whether by arbitraging more- to less-expensive thermal plants but also by avoiding start-ups of generators altogether (P. Denholm et al. 2013; Jorgenson et al. 2013). Avoided start-ups reduce the overall cost of providing energy, and they can also have a dramatic impact on total emissions from the power sector (Cochran and Denholm 2021). It is often simple to add emission-control technologies to generators; doing so can greatly reduce particulate emissions during normal operation, but it is often less straightforward to reduce emissions associated with generator start-ups. The additional air pollution resulting from generator starts can impact the health of already vulnerable populations—and the impacts are distributed inequitably (Tessum et al. 2021).

Figure 14 shows the impact of storage on generator stops for two of the Storage Futures Study scenarios (Ref and High NG Cost/Low-Cost Batt). The top panel shows the average amount of generator starts per day, across the entire footprint of the conterminous United States by generator type. In the Ref case, most starts are in the NG-Combustion Turbine category. Across the storage variation sensitivities (between 80% and 120% of the "optimal" starting build-out), the number of starts per day in that category is reduced from over 400 natural gas-combustion turbine starts per day to around 80. In the High NG Cost/Low-Cost Batt case, the reduction in the NG-Combustion Turbine category is 50 starts per day to around 5. Although the changes are dramatic in the NG-Combustion Turbine category in general, these plants tend to be smaller than, for example, coal or natural gas-combined cycle generators. The bottom panel of Figure 14 illustrates the average GW-starts per day, which normalizes by plant size. By this metric, there is still a dramatic reduction in GW-starts in both scenarios, particularly in the NG-Combined Cycle and NG-Combustion Turbine cases. One substantial benefit of storage may lie in its ability to reduce generator starts and thus criteria pollutants that harm human health. In fact, future work should examine the potential for storage to address health costs and premature mortality due to potential reduction in air pollution.

Reducing generator starts is one way to reduce emissions associated with detrimental human health impacts, such as those caused by nitrogen oxides and sulfur dioxide. Another important pollutant is carbon dioxide (CO_2). Storage can also have a measurable impact on the CO_2 emissions of the power sector. Figure 16 shows the impact of the storage sensitivities on the annual carbon dioxide emissions. In both scenarios, CO_2 emissions decline with increasing storage, because of reduced overgeneration from zero-carbon generation sources. The impact is more dramatic in the High NG Cost/Low-Cost Batt case, in which CO_2 decreases by 5% between the 80% Storage sensitivity and the 100% Storage sensitivity, and then another 3% between the 100% Storage and 120% Storage sensitivities. The impact is less dramatic in the Ref case in large part because of lower PV and wind deployment (and thus less overgeneration to begin with), but CO_2 emissions decline 0.5% between the 80% Storage sensitivity and the 100% Storage sensitivity, and 0.1% between the 100% and 120% Storage sensitivities.

Overall, these sensitivities indicate the important role storage can play in future power systems—by reducing generator starts (and associated emissions) and by increasing the use of zero-carbon resources such as existing curtailed PV or wind generation.

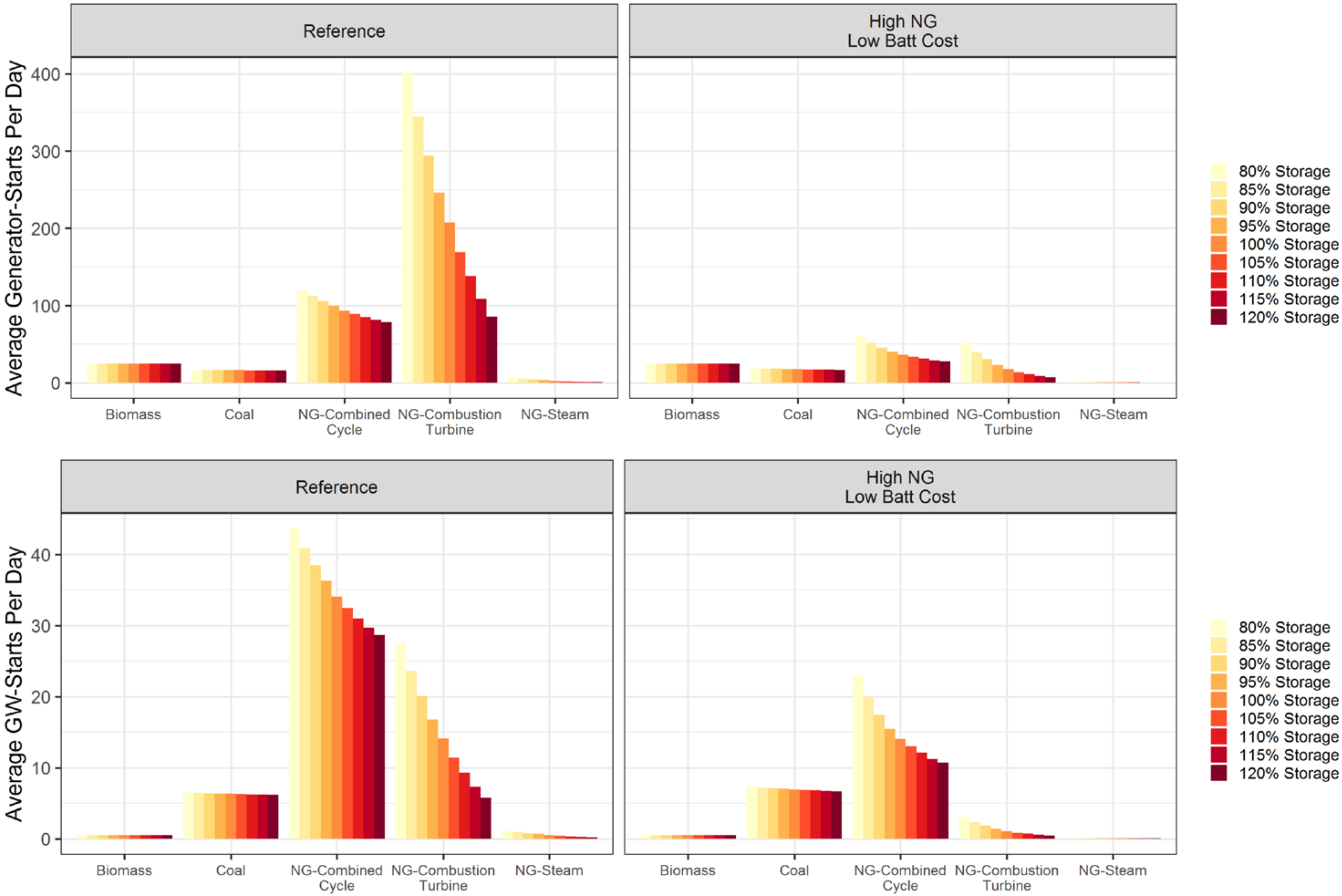

Figure 14. Reduction in generator start-up across two scenarios (Ref and High NG Cost/Low-Cost Batt scenarios) with additional storage

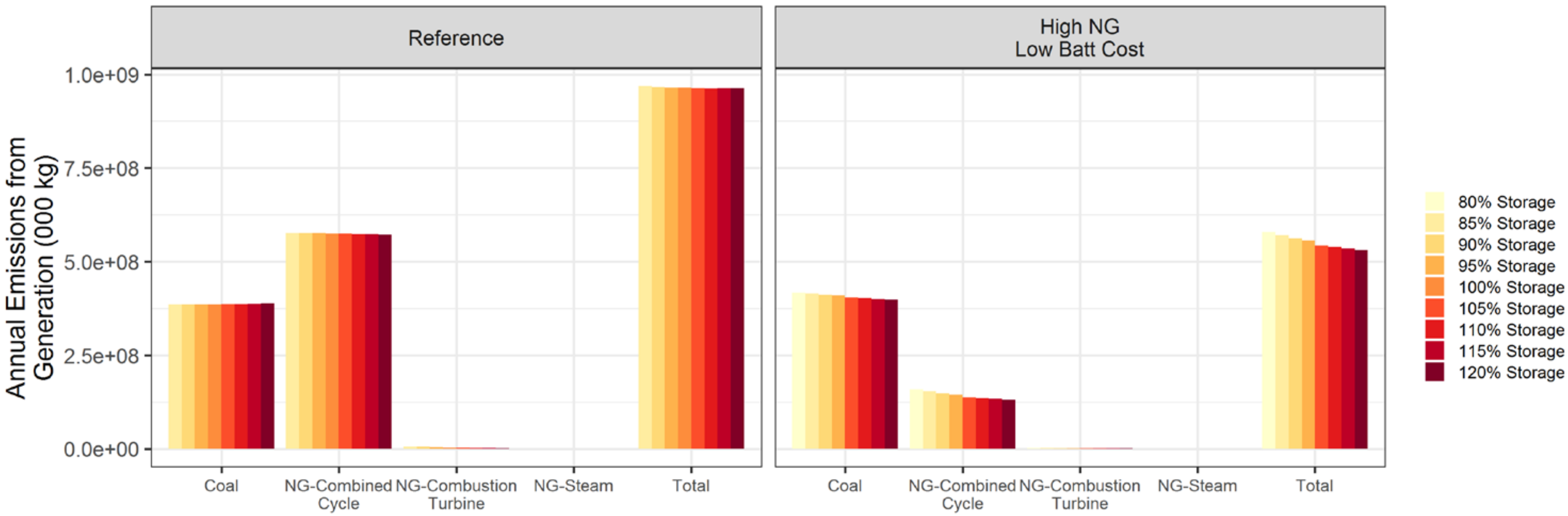

Figure 15. Annual emissions from generator types across scenarios

3.3.3 Storage and Transmission

Both transmission and energy storage can assist in integrating renewable energy onto the grid, but the relative merits of each enabling technology individually or when combined is complicated (Jorgenson, Denholm, and Mai 2018). For instance, transmission is well suited to deliver excess renewable energy from where it is generated to where it is needed while having much lower efficiency losses than storage. However, major transmission projects have proven challenging to build for myriad reasons (Brinkman, Novacheck, and Ho 2021).

We use the same storage sensitivity scenarios to give insight into the potential interaction of transmission and storage. We determine the frequency of congestion by showing the percentage of hours a year that a line is operating at its maximum thermal capacity. Figure 16 shows this metric between two sets of regions in this analysis: (1) the Midcontinent Independent System Operator-West (MISO-W) and MISO-E as well as (2) the Northwest (NW) region[17] to the California Independent System Operator (CAISO). As storage increases on the system from 80% storage to 120%s, congestion *increases* between the two MISO regions but *decreases* from the Northwest region to CAISO. In this section, we discuss why we see these two trends and the overall impacts of the difference.

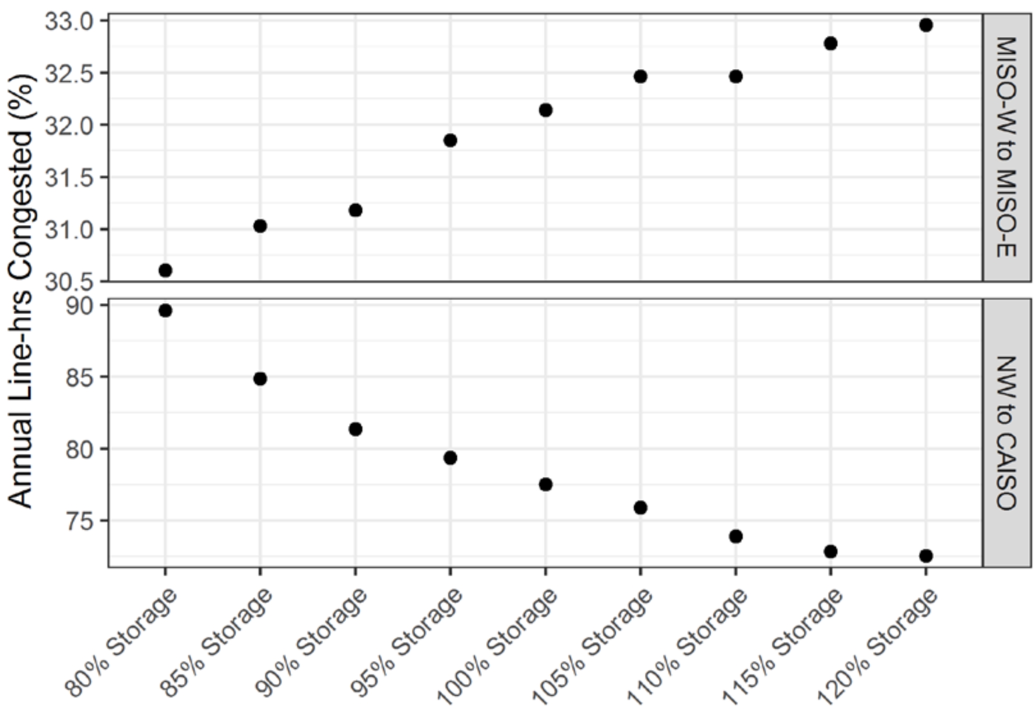

Figure 16. Annual congestion between two sets of regions in this analysis (MISO-W to MISO-E and Northwest (NW) to CAISO)

Note different scale on the y-axis.

[17] The Northwest region includes the footprint covered by the Northwest Power Pool as well as the Bonneville Power Association.

The bottom half of Figure 16 depicts how increasing storage results in a reduction of transmission congestion between the Northwest and CAISO. In the 100% Storage sensitivity, CAISO is a net importer of energy as shown in Figure 17 which depicts total annual generation from these two areas. Some of this energy comes either *from* or *through* the Northwest region. CAISO imports power during non-solar hours and often exports excess solar energy during daylight hours, but it imports more power on a net basis. An example of this is shown for four days on the left panel of Figure 18 (page 27). As storage increases (for example, from the 80% storage up to 120% storage scenario), the additional storage allows for better use of CAISO generation—specifically by storing solar overgeneration to displace imported power from the Northwest. This *reduces* the congestion or utilization of the transmission lines between the Northwest and CAISO during non-sunlight hours as local power is stored and dispatched more efficiently, as shown in Figure 19. Figure 18 shows how CAISO curtailment decreases from 80% storage to 100% storage to 120% storage, from 2.5% of total variable generation to 1.4% to 1.0%. Generation from Northwest region coal and natural gas-combined cycle technology also goes down, because this generation (likely previously imported by CAISO) has been displaced by local CAISO solar, delivered after sunset via storage. In this case, Northwest region coal reduces from 19.4 terawatt-hours (TWh) in the 80% Storage sensitivity to 18.9 TWh in the 120% Storage sensitivity, and Northwest NG-Combined Cycle reduces from 8.1 TWh to 7.4 TWh.

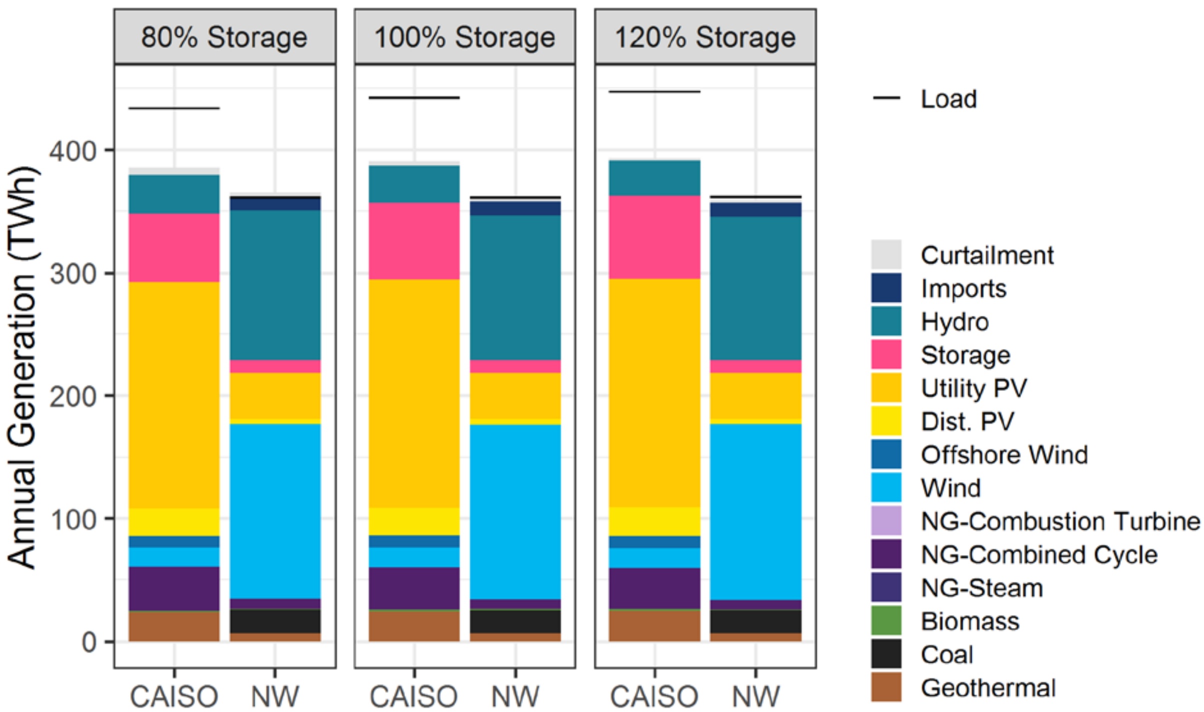

Figure 17. Annual generation from two regions in this analysis, CAISO and Northwest (NW) region.

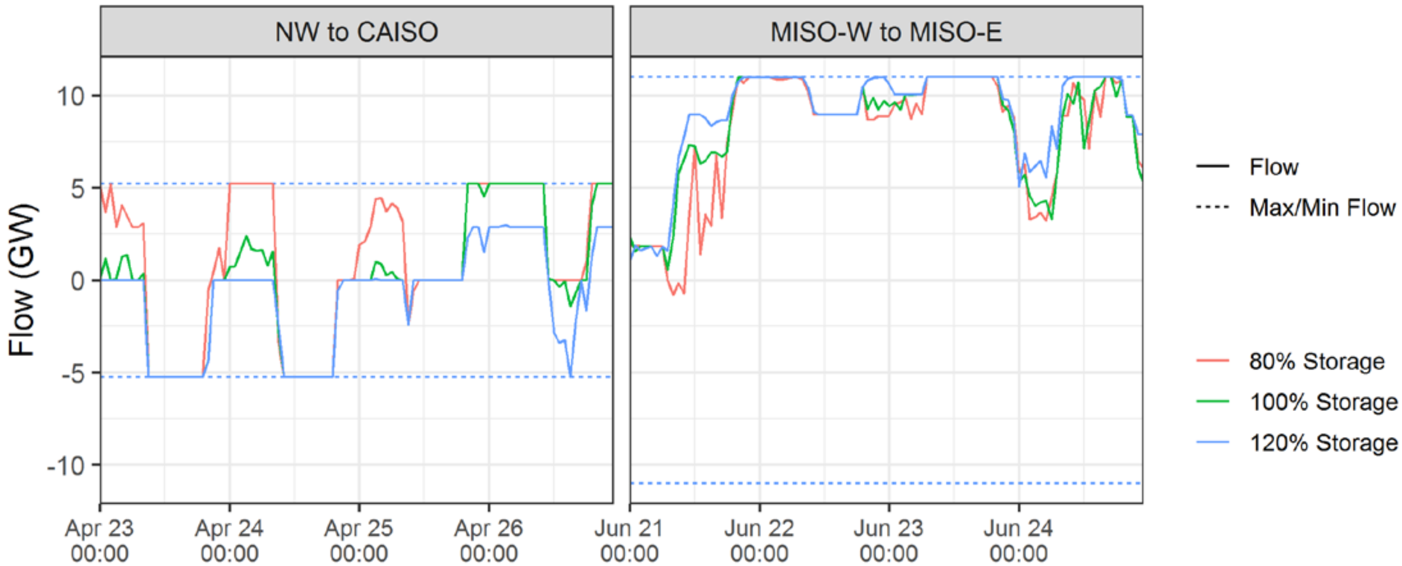

Figure 18. Flow between two sets of regions during examples of days in 2050 in the High NG Cost/Low-Cost Batt case

However, other regions see an *increase* in congestion with additional storage, including two subregions of the modeled Midcontinent Independent Service Operator (MISO), MISO-E and MISO-W as shown in the top panel of Figure 16. In this situation, MISO-W is a heavy exporter in the 100% Storage sensitivity as shown in Figure 19, which illustrates that the sum of all generation sources exceeds the total black load line. It can also be seen in an example of four days on the right side of Figure 18. When additional storage is added to regions that are *already* exporting power (such as MISO-W), there is nothing else to displace, so additional storage is used to store in-region overgeneration (usually solar) and then ship that power to neighboring regions to displace more expensive generation when it is needed. So, additional exports on already heavily utilized lines further increases congestion (or utilization) of transmission lines between the two regions. Although congestion does increase, this least-cost dispatch is exploited because the cost of generation from MISO-W (previously curtailed generation) is lower than the cost of generation from MISO-E (coal or natural gas).

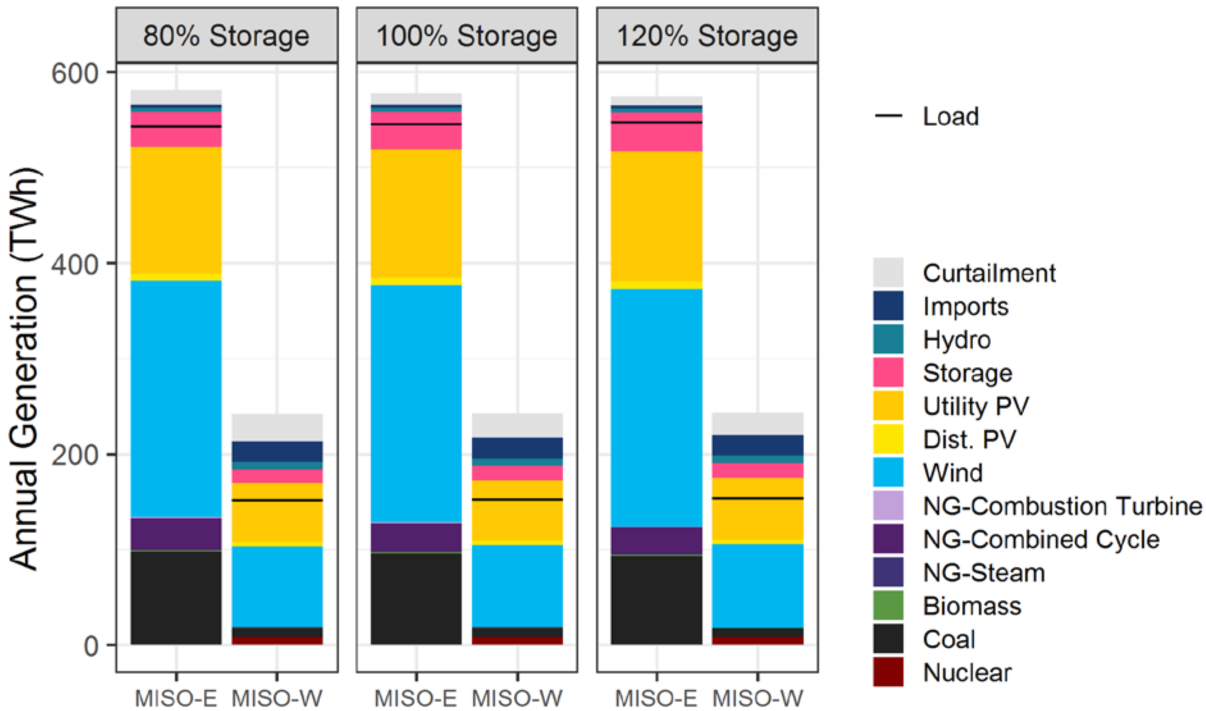

Figure 19. Annual generation from two regions in this analysis (MISO-E and MISO-W)

Overall, the interfaces of regions can experience either a decrease or an increase in utilization of transmission lines depending on local conditions, as demonstrated by the two sets of regions highlighted above. However, Figure 20 quantifies the total amount of average utilization (or congestion) on the transmission lines in each scenario, depicting an *overall* increase. This means the latter condition (in which stored energy is used to increase exports from an exporting region) is more common—and so the additional storage is generally increasing the utilization of the existing transmission system to reduce total costs and curtailment. In a sense, this is an example of storage and transmission working together (Jorgenson, Denholm, and Mai 2018).

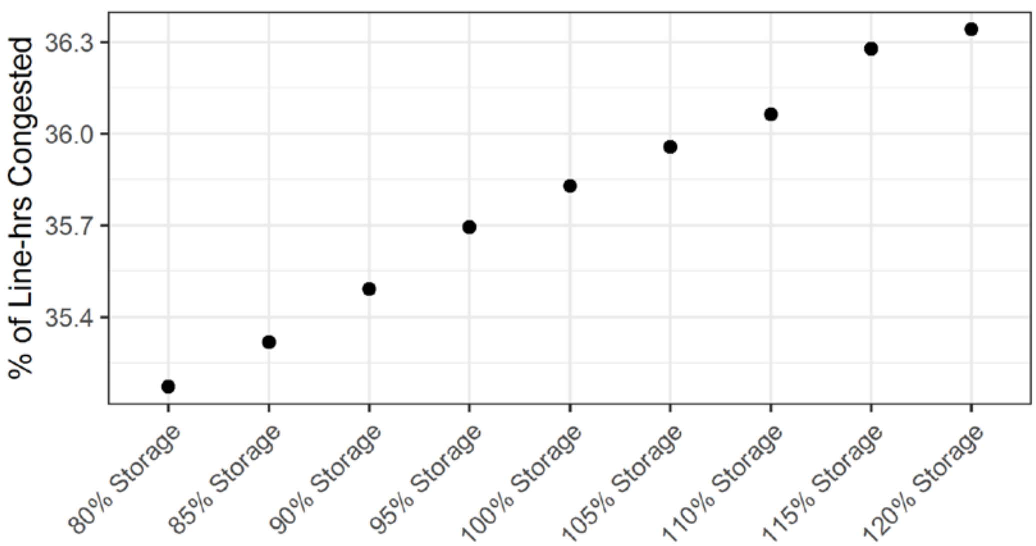

Figure 20. Annual % of line-hours congested (which represents the average percentage of hours in which a line is operating at its maximum thermal capacity)

4 Conclusions

This report, the sixth in the Storage Futures Study series, uses cost-optimized scenarios from the ReEDS model as a starting point to examine the operational impacts of grid-scale storage deployment and relationships between this deployment and contributions from variable generation. We use commercial production cost modeling software to evaluate hourly operation of five scenarios that reach 210 GW–930 GW of installed storage by the 2050. We find:

1. *The high storage (and often high variable generation, reaching up to 70% on an annual generation basis) scenarios developed by ReEDS indicate no unserved energy and low reserve violations,* indicating no concerns about hourly load balancing through the end-year of 2050. This result helps confirm that the ReEDS improvements for the Storage Futures Study are properly characterizing chronological operation of storage in various grid mixes. Even more in-depth modeling would be required to draw conclusions about subhourly load balancing, resource adequacy under various meteorological conditions, or power-flow or potential stability issues.
2. *Storage provides time-shifting and peak-load reduction services in all configurations and grid mixes.* Although storage has a low annual capacity factor, which is inherently limited by its need to charge, it has a very high utilization (in many cases, over 75%) during the top 10 net load hours across scenarios and years, when the system needs capacity and energy the most.
3. *Diurnal storage operation is tightly aligned with PV availability and less so with wind generation.* PV has a predictable daily on and off cycle, which aligns well with the need for storage to charge and discharge. Wind, on the other hand, has a less apparent daily cycle and often experiences long periods of overgeneration stretching for hours or days, which is much longer than the duration of storage we explore here. Though storage can play a key role in utilizing storage from both PV and wind, the synergies with PV are more consistent.
4. *Storage increases the efficiency of different types of generation assets, by reducing overgeneration PV and wind and reducing start-ups of the thermal generator fleet.* We find that in these future grid scenarios, storage reduces total electricity system carbon dioxide emissions by utilizing overgeneration from zero-marginal emissions sources like wind and solar to displace generation from the coal and natural gas fleet. In addition, storage can prevent start-ups of those generators, reducing emissions of criteria pollutants released during start-ups, which can disproportionally impact those in poor health, particularly those living near these thermal power plants.
5. *Storage increases the utilization of the transmission system.* By allowing arbitrage across regions, storage can increase the flow along transmission lines between regions, thus enabling the use of the lowest-cost resource mix. In other situations, storage may reduce transmission congestion by enabling local overgeneration. So, while storage and transmission can both assist with variable generation integration, they can often be complementary. The relationship between storage and transmission (in terms of both investment as well as operation) is complicated and merits further examination.

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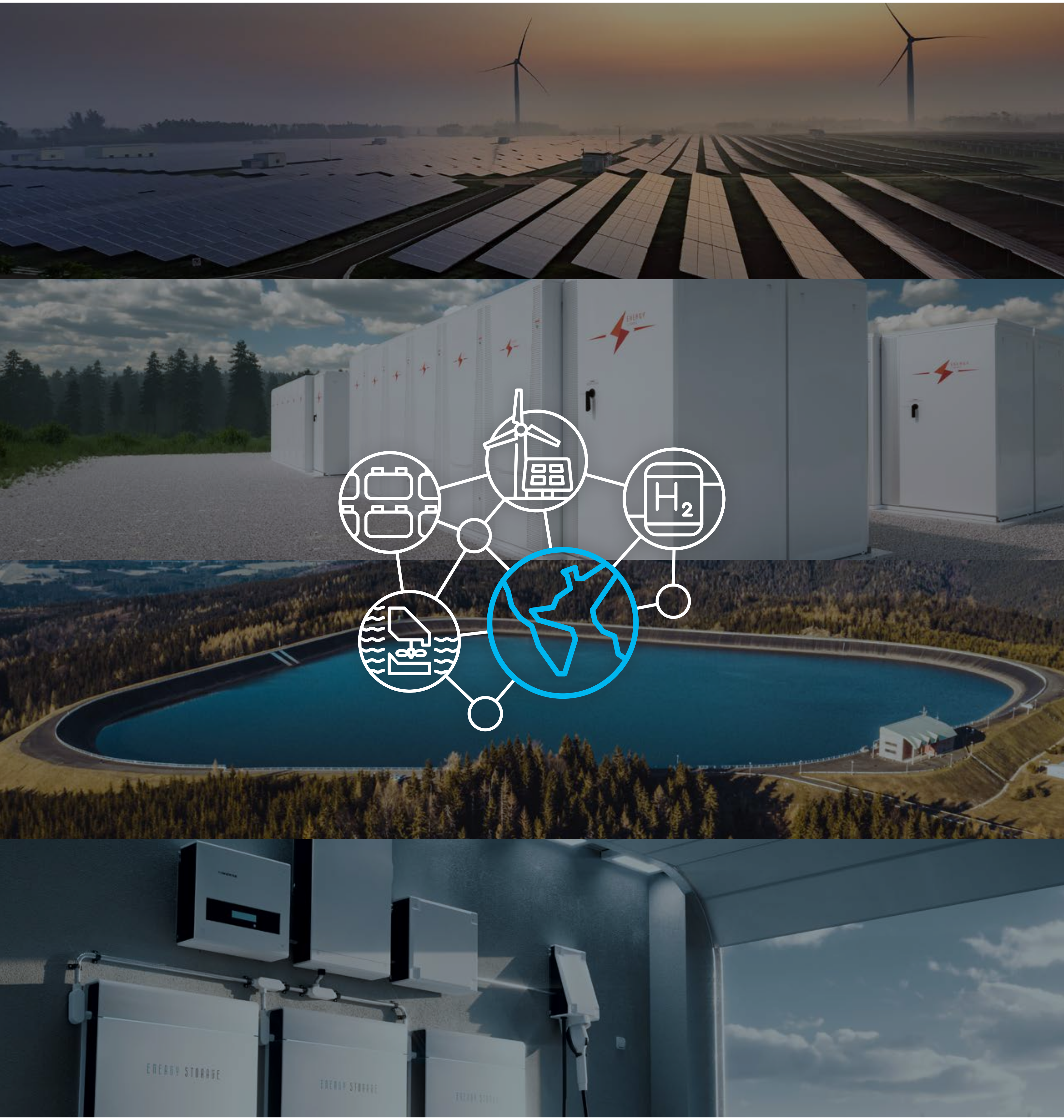
Appendix. Scenario Results

Table A-1 includes additional scenario results from the five Storage Future Study cases evaluated here.

Table A-1. Results for Wind, PV, and Total Renewable Energy Contribution in 2050 Across all Resource Sensitivity Scenarios

Scenario	Wind Generation (%)	PV Generation (%)	Renewable Energy Generation (%)	Storage (GW)	Storage (GW-h)	Storage duration (hrs)
Reference	20.4	28.8	56.4	213	1,318	6.2
Low-Cost Battery	20.2	30.6	58.0	384	1,792	4.7
Low-Cost PV	14.5	41.2	63.1	278	1,672	6.0
High Natural Gas Cost, Low-Cost Battery	27.7	46.0	80.8	679	3,242	4.8
Zero Carbon	37.3	33.4	94.0	932	6,097	6.5

Renewable energy includes biofuel, geothermal, hydropower, solar, and wind generation.



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