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Solar and Storage Integration in the Southeastern United States

Economics, Reliability, and Operations

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Solar and Storage Integration in the Southeastern United States: Economics, Reliability, and Operations

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Executive Summary

Solar energy has the potential to be a core energy resource for the southeastern United States. This study analyzed the implications of significantly higher levels of solar photovoltaic (PV) generation and electricity storage in the U.S. Southeast, focusing on five regions that cover Alabama, Georgia, Kentucky, North Carolina, South Carolina, Tennessee, and parts of Mississippi and Missouri.

The study sought to address two main questions. First, how would higher levels of solar PV and electricity storage impact the costs, reliability, and operations of electricity systems in the Southeast in 2035? Second, at different levels of solar PV and electricity storage, what are the benefits of operational coordination among utilities in the Southeast, through more efficient regional dispatch and sharing operating reserves?

To answer these questions, the study used detailed capacity expansion and dispatch modeling to develop and examine 15 scenarios with different levels of solar PV, electricity storage, and operational coordination, focusing on the year 2035. The 15 scenarios included low solar (LP, where the "P" refers to "PV"), medium solar (MP), and high solar (HP) scenarios. The MP and HP scenarios each had a low storage (LS) and high storage (HS) scenario, in which we held the solar cost assumptions in our capacity expansion modeling constant and changed electricity storage cost assumptions. Each resource (solar and storage) scenario had three coordination scenarios (lower coordination, higher coordination, single balancing region), in which we kept the resource portfolio constant and varied barriers to electricity trade (dispatch efficiency) and the kinds of operating reserves that could be shared among balancing regions. Table ES-1 shows how these 15 scenarios were organized and the shorthand used for each.

Table ES-1. Organization and Shorthand for Scenarios Examined in this Study

Coordination Scenario	Resource Scenario				
	Base Solar	Medium Solar		High Solar	
	Base Storage	Low Storage	High Storage	Low Storage	High Storage
Lower Coordination	BPBS_LC	MPLS_LC	MPHS_LC	HPLS_LC	HPHS_LC
Higher Coordination	BPBS_HC	MPLS_HC	MPHS_HC	HPLS_HC	HPHS_HC
Single Balancing Region	BPBS_SB	MPLS_SB	MPHS_SB	HPLS_SB	HPHS_SB

Note: The scenario shorthand is resource scenario_coordination scenario

The analysis explored levels of solar and storage that are higher than what has been examined in most Southeastern utility integrated resource plans (Table ES-2; see also Section 5.2). Across the resource scenarios in this study, the share of utility-scale solar PV generation capacity in the Southeast region ranged from 27% to 43% of total generation capacity. Electricity storage capacity ranged from 13% to 49% of total peak load. The analysis focused on operations—how the five different resource portfolios performed in detailed dispatch modeling under different assumptions about operational coordination. It did not attempt to identify an optimal resource portfolio or an optimal level of solar or storage capacity. This report does not contain estimates of investment costs or total costs for the different resource portfolios.

Table ES-2. Utility-Scale Solar PV Share of Total Generation Capacity and Electricity Storage Share of Peak Load *(parentheses show total installed capacity for both solar PV and storage)*

	Resource Scenario				
	BPBS	MPLS	MPHS	HPLS	HPHS
Solar PV Shares	27% (76 GW)	33% (100 GW)	39% (133 GW)	42% (174 GW)	43% (182 GW)
Electricity Storage Shares	13% (19 GW)	18% (25 GW)	32% (46 GW)	40% (57 GW)	49% (71 GW)

Note: Electricity storage includes 2-hour, 4-hour, 6-hour, 8-hour, and 10-hour battery storage, pumped hydropower storage, and compressed air energy storage.

The 15 scenarios encompassed a wide and almost continuous range of both solar generation (23% to 46% of total energy generation) and nonfossil fuel generation—solar, wind, hydro, nuclear, and biomass generation (69% to 99% of total generation) (Figure ES-1). The results thus provide useful benchmarks for changes in carbon dioxide emissions, production costs, and operations with higher levels of solar generation.

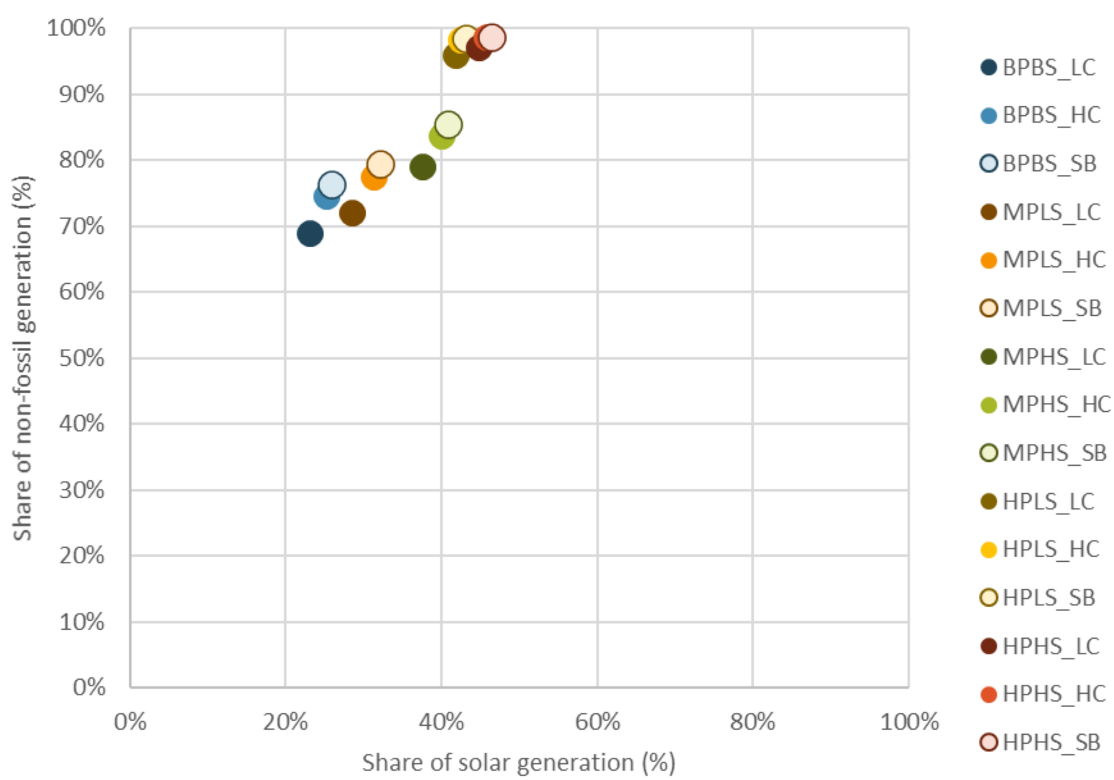

Figure ES-1. Shares of solar and nonfossil fuel generation in the U.S. Southeast region by scenario

The analysis did not include the effects of higher load growth and electrification or the potential for more demand-side flexibility to manage operational challenges in higher solar electricity systems. At the time that the study began, we did not have sufficient confidence in the data to do so. Incorporating emerging changes in load growth, load shapes, and demand-side flexibility in electricity planning studies is an important area of work going forward.

High-Level Takeaways

The remainder of this summary describes key takeaways from the analysis, organized in terms of:

- **Reliability**: Could resource portfolios with higher levels of solar and storage be reliably operated, and how did the nature and timing of system stress change with higher levels of solar and storage?
- **Coordination:** How did assumptions about operational coordination affect the results?
- **Planning:** What do the results imply for resource and transmission planning?
- **Emissions:** How much did higher levels of solar and storage reduce carbon dioxide emissions, and what are the implications for resource planning and policy?
- **Costs:** How did production costs change across the different scenarios, and what does this imply for planning and wholesale markets?
- **Modeling:** Is more modeling detail always necessary to address the kinds of questions posed in this study?

Reliability. Detailed operational (day-ahead and real-time) modeling of a range of higher solar and storage resource portfolios did not result in significant reliability issues in the Southeast, measured in terms of lost load and reserve shortages. However, the nature and timing of operating challenges changed with different levels of solar and storage—for instance, in a few cases reserve shortfalls occurred in the early morning hours following low solar days. Some of these new challenges could be addressed through demand-side flexibility and changes in operating practices, including how storage is operated and a shift from hourly to sub-hourly day-ahead scheduling. (*Section 3.5, Section 3.6.4*)

Coordination. Higher levels of operational coordination (more efficient dispatch, reserve sharing) among balancing regions were not necessary to reliably operate electricity systems with more solar and storage, though higher coordination reduced costs and emissions and helped to address operational challenges. More efficient regional dispatch and reserve sharing reduced CO_2 emissions in the Southeast and neighboring regions by 3%–7% and reduced production costs by 1%–2%, on par with cost savings from the creation of wholesale markets in the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP) regions. Sharing reserves to manage solar and wind forecast errors reduced day-ahead reserve requirements in the Southeast by 5%–23%, depending on reserve sharing assumptions. In all scenarios, the cost and dispatch results for the Southeast region were sensitive to changes in the resource mix of neighboring regions, underscoring the importance of accounting for changes in other regions in resource planning, transmission planning, and operations, regardless of the level of coordination in operations. (*Section 3*)

Planning. Storage technology decisions and new transmission investments in the resource portfolio (capacity expansion) modeling had path dependence, meaning that in some cases the model built more of certain technologies in lower solar scenarios—such as 4-hour battery storage or local transmission—

relative to what it built in higher solar scenarios. This suggests that planners building for a system with lower solar generation in the nearer term might "overshoot" the optimal level of some technologies relative to a longer-term future with higher levels of solar. The combination of high uncertainty and the potential for overshoot in some technologies highlights the importance of using transparent, carefully designed scenarios in resource and transmission planning. (*Section 3.1*)

Emissions. Across the 15 scenarios, carbon dioxide emissions in the Southeast region declined by 65% to 99% relative to 2022 levels. At a level of about 75% to 80% reductions in emissions, solar generation in the study region reached an economic saturation point—potentially related to the region's relatively high share (around 30%) of nuclear generation—where additional reductions in solar and storage costs in the capacity expansion modeling did not lead to significant additions of new solar capacity. Beyond this point, onshore wind was the most cost-effective resource for reducing emissions in the region. More significant changes in expected solar and storage costs, different assumptions about solar plant performance, limits on wind development and procurement, and changes in assumptions about load growth and load shapes would likely change the level at which solar saturates. Nevertheless, it would be beneficial to explore onshore wind availability within the Southeast region and the feasibility of out-of-state wind procurement. (*Section 3.4*)

Costs. Production costs and market (modeled) prices in the Southeast region declined significantly with higher amounts of solar and, in the HP scenarios, wind generation due to lower fuel costs and an increase in the frequency with which solar, storage, and wind generation was on the margin. Lower production costs and market prices reduced the absolute (total dollar) cost savings from more efficient regional dispatch and reserve sharing. Declines in production costs and market prices with higher levels of solar suggest that, in addition to operating costs, it may be beneficial to explore alternative metrics, such as capacity cost (fixed cost) savings, for evaluating the benefits of operational coordination and transmission investments. That being said, the decline in market prices may not accurately reflect market prices with higher levels of storage, because current models do not adequately capture storage opportunity costs. (*Section 3.3, Section 3.8*)

Modeling. As a research project, this study used complex models with detailed solar and wind data and a detailed representation of generator and transmission constraints. Many of the questions that utilities, commissions, and stakeholders are asking around higher solar and storage systems may not require this level of complexity or detail to accurately answer. For instance, subhourly dispatch modeling is useful for understanding the adjustment between day-ahead forecasts and schedules and real-time dispatch, along with potential real-time reliability concerns that may result from those adjustments, but may not be necessary for understanding the value of operational coordination or the cost or emissions impacts of higher levels of solar. As the industry moves toward more complex, detailed modeling tools, there is a need to right-size analysis to the questions being asked, to develop new rules of thumb for when models can be simplified, and to continue to use simple calculations to verify model results. (*Overarching*)

1. Introduction

Solar energy has the potential to supply a large share of energy demand in the southeastern United States. The region has abundant, low-cost solar resources.[1] Solar generation is growing rapidly in the U.S. Southeast, and some utility integrated resource plans (IRPs) are considering scenarios in which solar photovoltaic (PV) generation accounts for as much as 40% of total generation by the mid-2030s, accompanied by gigawatts (GW) of energy storage.[2] Growth in solar PV and storage on this scale could lead to significant changes in the region's electricity system, particularly given its relatively high reliance on nuclear power. High solar-storage systems have been studied in some individual utility IRPs but have not been studied for the Southeast region as a whole.

This report examines the economic, reliability, and operational implications of higher levels of solar generation (27%-43% of total generation capacity) and energy storage (up to 13%-49% of peak load) on electricity systems in the Southeast. The report explores two main questions:

- How would higher levels of solar generation and energy storage impact electricity system reliability, operating costs, and operations in the Southeast in 2035?
- What are the benefits of closer operational coordination among utilities ("regional coordination") in the Southeast, and how do those benefits change with higher levels of solar and storage?

The analysis seeks to provide general insights without being prescriptive. It focuses on how different resource portfolios affect reliability, operating costs, and operations rather than which portfolio might be preferred due to cost or other considerations. It examines how reserve sharing and more efficient dispatch through regional coordination might impact the results but does not seek to assess the benefits of specific regional market designs or contribute to ongoing regulatory proceedings around regional markets.[3] The analysis uses publicly available data and aims to help build a foundation for regional modeling work in the Southeast.

This report is the first in a series of three studies on solar and storage integration in the Southeast. The second study will examine the impact of improvements in solar forecasting on system operations,

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[1] Most of the region has daily solar global horizontal irradiance exceeding 4.5 kWh/m^2-day. See NREL's Global Horizontal Solar Irradiance map for the U.S., https://www.nrel.gov/gis/assets/images/solar-annual-ghi-2018-usa-scale-01.jpg. The average price of Lawrence Berkeley National Laboratory (LBNL)'s sample of solar power purchase agreements in the Southeast was $21/MWh (2022$) in 2019 and 2020 (Bolinger et al., 2023). The LBNL data do not include solar projects in the Southeast in 2021 or 2022.

[2] Solar generation in the Southeast (Alabama, Florida, Georgia, Mississippi, North Carolina, South Carolina, and Tennessee) quadrupled from 2017 to 2022, rising from 1% to 4% of total generation in the region. Data are from the U.S. Energy Information Administration's (EIA's) *Electric Power Monthly*, https://www.eia.gov/electricity/monthly/. Duke Energy Carolinas' 2020 IRP (Duke Energy Carolinas, 2020) studied three scenarios in which solar accounted for 40% of generation by 2035. Georgia Power's 2022 IRP (Georgia Power Company, 2023) studied scenarios in which solar PV accounts for 40% to 45% of generation by 2041 (see Section 5.2).

[3] See Section 5.1.2 for a brief history of operational coordination among balancing area authorities in the Southeast.

including changes in energy storage operations. The third study will explore the implications of higher levels of energy-limited resources, such as solar and energy storage, on resource adequacy and on the value of demand-side management programs.

The remainder of the report is organized around three sections:

- **Methods** provides an overview of the methods used in this study, including scenario development, data sources and development, model architecture, and reserve calculations.
- **Results** describes the study's results, organized into four sections: economics, reliability, operations, and modeling issues.
- **Conclusions** distills key conclusions from the analysis and identifies priority areas for additional research.

The analysis addresses a broad range of questions across multiple dimensions: solar and storage scenarios, coordination scenarios, and day-ahead and real-time operations. To facilitate ease of reading and navigation, each section is designed to stand alone and is extensively linked to other sections.

2. Methods

This study used a two-step modeling process to develop and dispatch resource portfolios. In the first step, we used a capacity expansion model (Regional Energy Deployment System, or ReEDS)[4] to develop consistent, least-cost resource portfolios with different levels of solar and storage. In the second step, we examined the economics, reliability, and operations of each resource portfolio using a detailed dispatch model (PLEXOS).[5]
This section provides an overview of the methods used in this two-step process, including geographic definitions, resource and coordination scenarios, reserve requirement calculations, and dispatch methods.

2.1 Geographic Definitions

The Southeast region has hundreds of electric utilities but a small number of balancing area authorities (BAAs).[6] To match the level at which system operators make operating decisions, we aggregated transmission zones from the ReEDS model into balancing regions (Figure 1). These balancing regions approximately capture five BAAs that are participating in the Southeast Energy Exchange Market (SEEM):

- Associated Electric Cooperative Incorporated (AECI in Figure 1),
- Duke Energy Carolinas and Duke Energy Progress (DUK),
- Louisville Gas & Electric and Kentucky Utilities (LGEE),
- Southern Company (SOCO), and
- Tennessee Valley Authority (TVA).

These balancing regions do not correspond perfectly with physical BAA territories and should be thought of as regions rather than individual BAAs. We refer to them as "balancing regions" rather than BAAs throughout the report. Some of these regions include other, smaller BAAs.[7] This definition of the Southeast does not include Florida.

[4] For an overview and documentation of the ReEDS model, see Ho et al. (2021).
[5] For an overview of PLEXOS, see https://www.energyexemplar.com/plexos.
[6] See Section 5.1.1 for an overview of BAAs and utilities in the Southeast region.
[7] For instance, the DUK region also includes the Dominion Energy South Carolina and Santee Cooper BAAs.

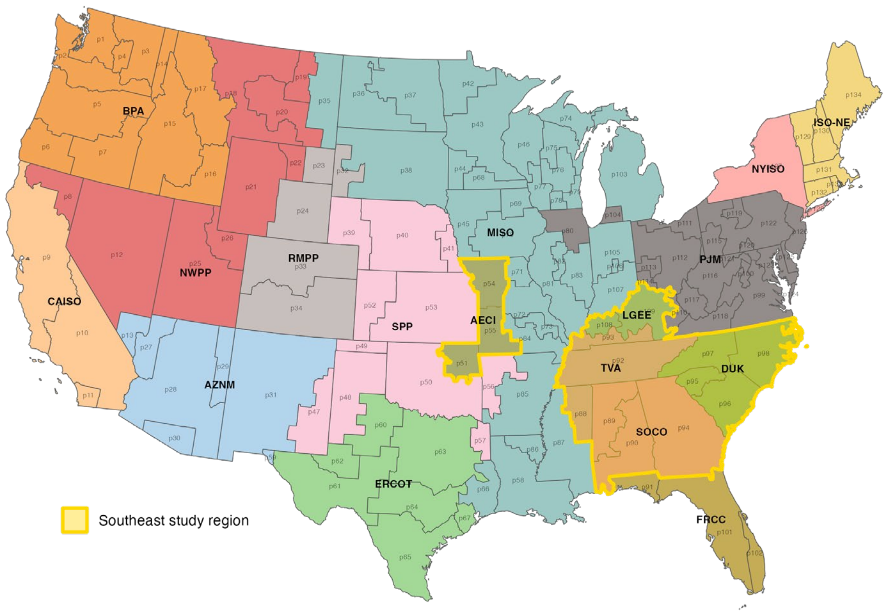

Figure 1. Boundary for the Southeast region used in this study

Although the study focuses on the Southeast region, both the capacity expansion and production simulation modeling include the rest of the United States. Interactions between the Southeast and neighboring regions are important for understanding the results. Neighbors for the Southeast region, as defined for this study, include the Midcontinent Independent System Operator (MISO) and PJM Interconnection (PJM) in the North, MISO and the Southwest Power Pool (SPP) in the West, and the Florida Reliability Coordinating Council (FRCC) in the South. The Southeast region's size, in terms of annual electricity demand, was on par with MISO and PJM, nearly five times larger than SPP, and more than three times larger than FRCC.[8] As described in the following sections, many of the modeling assumptions for the Southeast region were the same as those for the rest of the United States.

2.2 Modeling Scenarios

The analysis examined 15 total scenarios: five resource scenarios with progressively higher levels of solar PV and battery storage, and, for each resource scenario, three regional coordination scenarios reflecting different levels of operational coordination among balancing regions. The resource scenarios include a base solar PV (BP) base storage (BS) scenario, medium solar PV (MP) with low storage (LS) and high storage (HS) scenarios, and high solar PV (HP) with low storage (LS) and high storage (HS) scenarios. The coordination scenarios include lower coordination (LC) among balancing regions, higher coordination (HC) among balancing regions, and a single balancing region (SB). Table 1 shows the

[8] Our projected 2035 annual electricity demand for these five regions was 742 TWh in the Southeast, 719 TWh in MISO, 765 TWh in PJM, 165 TWh in SPP, and 243 TWh in FRCC.

organization of resource and coordination scenarios and the shorthand for each scenario that we use in the rest of the report.

Table 1. Organization of Modeling Scenarios and Shorthand for Scenarios

Regional Coordination	Base Solar PV Scenario	Medium Solar PV Scenario		High Solar PV Scenario	
		Low Storage	High Storage	Low Storage	High Storage
Lower Coordination	BPBS_LC	MPLS_LC	MPHS_LC	HPLS_LC	HPHS_LC
Higher Coordination	BPBS_HC	MPLS_HC	MPHS_HC	HPLS_HC	HPHS_HC
Single Balancing Region	BPBS_SB	MPLS_SB	MPHS_SB	HPLS_SB	HPHS_SB

We developed resource portfolios using ReEDS, with a focus on the year 2035. For the resource scenarios, we toggled four key assumptions in each scenario—utility-scale PV costs, battery costs, distributed PV (DPV) adoption, and a carbon tax—to target higher levels of utility-scale PV as a share of total generation and higher levels of battery storage ratios with PV for the Southeast region (Table 2), including for the BPBS scenario. The BPBS scenario is a future (2035) scenario with more moderate assumptions about PV and storage costs (see Section 5.3), but it still had significantly more solar and storage than is currently installed in the Southeast. Portfolios for a resource scenario were identical across all regional coordination scenarios. All scenarios incorporated the Inflation Reduction Act's (IRA's) clean energy tax credits. For consistency and accuracy in terms of how the Southeast region interacts (imports/exports) with neighboring regions, we applied cost and other ReEDS input assumptions uniformly across the United States, rather than more narrowly to the Southeast region. Other sections of this report describe the assumptions behind these scenarios (Section 5.3) and the results of the capacity expansion modeling (Section 3.1) in greater detail.

Table 2. Utility-Scale Solar PV and Energy Storage Metrics (ReEDS Outputs for 2035) for the Southeast Region by Resource Scenario

Resource Scenario	Description	Utility-Scale PV Installed Capacity	Utility-Scale PV Share of Generation Capacity	Energy Storage Installed Capacity	PV-to-Storage Capacity Ratio
BPBS	Base solar, base storage	76 GW	27%	19 GW	4.0
MPLS	Medium solar, low storage	100 GW	33%	25 GW	4.0
MPHS	Medium solar, high storage	133 GW	39%	46 GW	2.9
HPLS	High solar, low storage	174 GW	42%	57 GW	3.0
HPHS	High solar, high storage	182 GW	43%	71 GW	2.6

Notes: See Section 5.2 for a description of how these storage-to-PV capacity ratios compare against recent IRPs for utilities in the Southeast.

In both the capacity expansion and production simulation modeling, we assumed a business-as-usual load forecast, based on projections from the U.S. Energy Information Administration's (EIA's) *Annual Energy Outlook 2022*.[9] This means that the analysis does not incorporate the impacts of electrification or increased demand-side flexibility on load shapes. At the time this study commenced (2022), we

[9] See https://www.eia.gov/outlooks/aeo/narrative/introduction/sub-topic-02.php. This project began in 2022 and, in most cases, uses 2022 input data.

determined that we did not have the data to rigorously include above-trend load growth or potential changes in 2035 load shapes.

In developing resource portfolios, we assumed that each balancing region optimizes its portfolio independently to meet a local resource adequacy constraint, incorporating import opportunities, market barriers, and transmission limits. In other words, we did not assume that balancing regions cooperate to reduce their resource adequacy requirements through region-wide resource adequacy planning. However, we did assume that balancing regions can apply imports to their resource adequacy requirements, subject to an import cost adder ("hurdle rate") of $11.55 per megawatt-hour (MWh) that is consistent with the hurdle rate used in our lower coordination scenario.[10] Additionally, we allowed ReEDS to build transmission both within and between balancing regions when cost-effective.

After developing the five resource portfolios in ReEDS, we then modeled each portfolio in PLEXOS under the three different regional coordination scenarios (LC, HC, SB). Table 3 shows the assumptions for each coordination scenario, with progressively higher levels of reserve sharing and lower barriers to trade (transmission "hurdle rates") in higher coordination scenarios. Hurdle rates are virtual cost adders ($/MWh) that determine the ease with which power can flow economically between balancing regions, but they are not included in the tally of total costs.[11]

Table 3. Description of Regional Coordination Scenarios

Coordination Scenario	Reserve Sharing	Reserve Location	Hurdle Rates Day-Ahead (Real-Time)
LC	Spinning and nonspinning contingency reserves	Each balancing region must hold its own reserves	$15/MWh ($8/MWh)
HC	Spinning and nonspinning contingency reserves, spinning load following reserves	Each balancing region must hold its own reserves	$8/MWh ($0/MWh)
SB	Spinning and nonspinning contingency reserves, spinning and nonspinning load following reserves, regulation reserves	Reserves can be held anywhere in the Southeast region	$0/MWh ($0/MWh)

Notes: Hurdle rate values were based on Energy and Environmental Economics (E3) (2011) and Chang et al. (2016a). We used illustrative hurdle rates rather than trying to benchmark against historical transmission flows, due in part to data limitations. The hurdle rates were implemented as $10/MWh and $5/MWh (2004$) in PLEXOS; the values here are inflated to 2022$.

In the LC scenarios, we only allowed balancing regions to share contingency reserves, required each balancing region to hold its own reserves, and imposed $15/MWh and $8/MWh hurdle rates between

[10] Hurdle rates are described in the next paragraph. This hurdle rate was implemented in ReEDS as $7.50/MWh in 2004$. 'Consistent' here means that it is in the range of day-ahead and real-time hurdle rates used in the lower coordination scenario. We did not attempt to maintain consistency between hurdle rates in ReEDS and PLEXOS.

[11] For instance, with a $15/MWh hurdle rate, a generator with $35/MWh operating costs will look like it costs $50/MWh to another region. The actual cost of operating the generator will still be $35/MWh.

balancing regions in day-ahead and real-time PLEXOS runs, respectively.[12] In the HC scenarios, we allowed balancing regions to share contingency and spinning load following reserves, required each balancing region to hold its own reserves, and imposed $8/MWh and $0/MWh hurdle rates. In the SB scenarios, we allowed balancing regions to share all reserves (contingency, load following, regulation), allowed reserves to be held anywhere in the Southeast region, and removed all hurdle rates in both day-ahead and real-time.

These coordination scenarios are intended to be illustrative, approximately capturing different kinds of institutional arrangements and market designs. They are not intended to evaluate specific market designs that exist or have been proposed for the Southeast.[13] The LC scenario is consistent with a bilateral market, with relatively high levels of trade friction and a contingency reserve sharing group. The HC scenario might be consistent with an organized exchange market and a mechanism for sharing forecast error reserves, but more likely would require a centralized real-time market, such as an energy imbalance market. The SB scenario is consistent with some form of regional system operator, such as a regional transmission organization (RTO).

Nuances in our hurdle rate assumptions reflect these differences. For instance, the rationale for using lower hurdle rates in the real-time model runs vis-à-vis those used in day-ahead runs (LC and HC scenarios) is that day-ahead scheduling in bilateral markets typically involves physical transmission rights, and that market participants can use unscheduled transmission capacity within the operating day for lower-cost transactions that do not require paying the full fixed costs of transmission. We also apply the same hurdle rates between the Southeast region and neighboring regions, assuming that progressively higher levels of price discovery within the Southeast would increase transactions between the Southeast and its neighbors as well.

2.3 Reserve Requirement Calculations

BAAs in North America typically hold three kinds of operating reserves:[14]

- Regulation reserves, to manage ramp and forecast error within the dispatch interval
- Load following reserves, to manage load, wind, solar, and hydro variability within the operating day and load, wind, and solar forecast error[15]

[12] See Section 2.3 and Kahrl et al. (forthcoming) for an overview and longer description, respectively, of reserve requirement calculations.

[13] See Section 5.1.2 for a brief history of regional coordination in the Southeast.

[14] For an overview, see Ela et al. (2011).

[15] Most ISOs do not currently hold load following reserves, though ERCOT does hold reserves to manage wind and solar forecast error, and the California Independent System Operator's (CAISO's) and MISO's ramping products have some similarities to load following reserves. Most ISOs instead deal with load and resource forecast errors through intraday unit commitment processes. Outside of ISOs, utilities and generation and transmission providers often hold load following reserves. For instance, the Bonneville Power Administration holds following reserves to cover minute-by-minute differences between an hourly average schedule and 10-minute net load (addressing variability) and imbalance reserves to cover the difference between forecasted and actual net load (addressing uncertainty) (Bonneville Power Administration 2021). In the SB scenario in this analysis, load following reserves would thus be a proxy for intraday unit commitment.

- Contingency reserves, to manage the loss of generation or transmission.

In the PLEXOS modeling, we assumed that balancing regions hold all three categories of reserves on a day-ahead timescale, but that in real-time they only hold regulation and contingency reserves. In other words, resources that provided load following reserves day-ahead were released and able to provide energy in real-time dispatch. We did not attempt to ensure consistency between the operating reserves held in ReEDS (capacity expansion) and PLEXOS. Average reserve levels were comparable between the two, but the timing of reserves differed significantly, and ReEDS did not incorporate nonspinning reserves to manage larger, infrequent solar and wind forecast errors (see Section 5.3).

Higher levels of solar and wind generation will tend to increase regulation and load following reserve requirements, though impacts on reserve requirements will depend on scheduling and dispatch practices that are specific to BAAs. This study took a more general approach, by assuming that all balancing regions in the Southeast use a similar approach for calculating reserve requirements.

Solar and wind forecast errors are specific to locations and resource profiles. To incorporate location-specific forecast errors in reserve requirements, we calculated reserve requirements exogenously. The details of these calculations are described in a separate component study that evaluated reserve sharing for forecast error reserves.[16] Table 4 summarizes the overall approach to calculating reserves and the table notes provide additional detail. We used the same annual solar and wind profiles to calculate forecast errors that we used in the ReEDS and PLEXOS modeling.[17] For all of these uses, we developed concurrent, zone-specific solar and wind profiles using ReEDS and the Renewable Energy Potential (reV) model, based on data from the National Solar Radiation Database and Wind Integration National Dataset Toolkit.[18]

[16] Kahrl et al. (forthcoming). Our approach borrowed heavily from earlier studies, in particular GE Energy (2010) and EnerNex (2011).
[17] Given the breadth of this study and uncertainty around how using solar and wind profiles from multiple weather years might affect the results, we chose to use on a single weather year to calculate forecast errors. Ideally, however, forecast errors used to calculate reserve requirements would be based on data from multiple weather years.
[18] For more on reV, see Maclaurin et al. (2021).

Table 4. Summary of Reserve Requirement Calculation Methods

Reserve	Type	Requirement
Contingency	Spinning	Balancing regions hold spinning contingency reserves equivalent to 3% of load
	Nonspinning	Balancing regions hold nonspinning contingency reserves equivalent to 3% of load
Regulation	Bidirectional	Balancing regions hold bidirectional regulation to cover 1% of load and three standard deviations of real-time solar and wind forecast errors $3 \times \sqrt{\left(\frac{l_t \times 1\%}{3}\right)^2 + s.\sigma_t{}^2 + w.\sigma_t{}^2}$
Load Following	Spinning	Balancing regions hold upward spinning load following reserves to cover one standard deviation of day-ahead solar and wind forecast errors $\sqrt{s.\sigma_t{}^2 + w.\sigma_t{}^2}$
	Nonspinning	Balancing regions hold nonspinning load following reserves to cover two standard deviations of day-ahead solar and wind forecast errors $2 \times \sqrt{s.\sigma_t{}^2 + w.\sigma_t{}^2}$

Notes: In the single balancing region scenario, balancing region refers to a single balancing region with a regional system operator. l_t is load at time t, $s.\sigma_t$ is the standard deviation of solar forecast errors projected for time t, and $w.\sigma_t$ is the standard deviation of wind forecast errors projected for time t. We used hourly load to calculate day-ahead contingency reserves and 15-minute load to calculate real-time contingency reserves. We calculated solar and wind forecast errors for regulation reserves using 15-minute profiles and 15-minute persistence forecasts. Day-ahead regulation reserves were the maximum 15-minute regulation reserve requirement in each hour. We calculated solar and wind forecast errors for load following reserves using hourly profiles and hourly persistence forecasts, rather than day-ahead persistence forecasts. Day-ahead persistence forecasts resulted in forecast errors that were unreasonably large relative to what should be achievable in 2035 (see Section 2.4). See Kahrl et al. (forthcoming) for more detail on forecast error and reserve requirement calculations in this study.

The approach in Table 4 already incorporates contingency reserve sharing.[19] To incorporate reserve sharing related to solar and wind forecast errors, we calculated forecast errors either for each individual balancing region (no reserve sharing) or for the Southeast region as a whole (reserve sharing). Because local solar and wind forecast errors tend to offset over a larger geographic area, reserve requirements

[19] Contingency reserve requirements are typically based on single largest contingencies. Requirements based on percent load rather than single largest contingencies assume that any differences between the two would be made up via imports from neighboring regions.

will be lower using the latter approach.[20] We used regional forecast errors to calculate spinning load following reserve requirements in both the HC and SB scenarios and regulation and nonspinning load following reserve requirements in the SB scenario.

2.4 Production Simulation

We used the PLEXOS model for all production simulation modeling. The PLEXOS modeling had two stages, resembling the scheduling and dispatch process used by most system operators.[21] In the first (day-ahead) stage, PLEXOS scheduled units to meet hourly demand based on expected available generation, including hourly solar and wind forecasts. In the second (real-time) stage, PLEXOS committed and dispatched generators to meet 15-minute demand using 15-minute actual solar and wind profiles and incorporating intertemporal operating constraints on generators.

All load data were from publicly available sources.[22] We did not include day-ahead load forecasts in the day-ahead PLEXOS runs, due to a lack of accurate data.[23] As discussed earlier, we used hourly persistence rather than day-ahead persistence forecasts to calculate wind and solar forecast errors used in the day-ahead modeling runs, because forecasts based on day-ahead persistence led to unreasonably large forecast errors.[24] Across scenarios, day-ahead forecast errors (installed capacity-normalized) were 1.6%–1.7% for solar and 2.9%–3.4% for wind.[25]

In the real-time runs, we did not allow coal and other steam units to be turned on or off but allowed them to be re-dispatched within operating constraints. We allowed gas and storage units to be fully re-dispatched, including turned on or off (committed or decommitted), in real-time. This approach assumes that there would be processes within the operating day—between the day-ahead and real-time stages that we modeled—to commit and decommit combined cycle gas units with longer start times. We did not allow hydro units to be re-dispatched in real-time, outside of curtailment. We did not

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[20] See Focken et al. (2002) and Katzenstein et al. (2010) for more on the correlation of solar and wind forecast errors across space. See GE Energy (2010), EnerNex (2011), King et al. (2011), and E3 (2013) for studies illustrating that handling forecast errors at a regional, as opposed to local, level can reduce reserve requirements.

[21] We ran the day-ahead and real-time simulations separately rather than solving day by day. In other words, we first ran PLEXOS for the first stage (day-ahead) for all days in the year and then subsequently ran all days for the second stage (real-time). An alternative is to run in "interleaved" mode, which solves the day-ahead stage and real-time stage for each day sequentially before proceeding to the next day. Interleaved simulations are closer to actual practice but can raise computational challenges.

[22] ReEDS uses a combination of Federal Energy Regulatory Commission (FERC) Form 714 hourly load data and load growth projections from the EIA's *Annual Energy Outlook* (Ho et al., 2021). Our 15-minute load data were linearly interpolated from hourly data.

[23] Both EIA-930 (reported) and persistence-based load forecast errors were large relative to typical day-ahead load forecast errors, and with large load forecast errors the real-time model was unable to solve.

[24] Forecast errors using simple day-ahead persistence solar and wind forecasts were 8% and 13%–19%, respectively. As a reference, the CAISO's monthly capacity-weighted solar and wind forecast errors (normalized mean absolute error) ranged from approximately 2%–3.5% and 2%–6%, respectively, in 2022 (CAISO, 2023).

[25] These forecast errors are likely lower than what is currently achievable but are significantly closer to currently achievable levels than using a daily persistence forecast. Given that the analysis year is 2035, this level of forecast accuracy reflects what might be possible in 2035.

allow nuclear units to be committed, decommitted, or ramped in day-ahead or real-time; nuclear units were only offline for planned or forced outages.

We used scarcity prices for reserve shortages in PLEXOS that reflect the value of unmet reserves and lost load, rising from $2,500/MWh (2004$, nonspinning reserve) to $5,000/MWh (spinning reserve) to $7,500/MWh (regulation reserve) and finally to $10,000/MWh (lost load).[26] Because PLEXOS co-optimizes energy and reserves, reserve scarcity prices also affected modeled energy prices.

We allowed almost all generation, except for nuclear and distributed PV generation, to provide operating reserves. We allowed wind generation, utility-scale solar generation, and energy storage to provide spinning load following and regulation reserves as long as they satisfied rules for response time (20 minutes for load following, 5 minutes for contingency and regulation) and, for energy storage, duration (60 minutes). We also allowed energy storage to provide all contingency and nonspinning load following reserves. We did not consider scenarios in which solar and wind generation are unable to provide reserves. By 2035 and with much higher levels of solar and wind generation online, it is unlikely that solar and wind generators would not be able to do so.[27]

The heat rates and fuel prices (biomass, coal, natural gas, and uranium) that we used in PLEXOS were consistent with those in ReEDS. Heat rates for existing units in ReEDS are based on the EIA's National Energy Modeling System database, and ReEDS uses a clustering algorithm to aggregate heat rates by technology and region.[28] In PLEXOS, heat rates vary by generator loading. In this study, the resulting average heat rates for natural gas generation were relatively similar across regions in most scenarios, but heat rates for coal generation varied more significantly across regions.[29] Fuel prices varied more significantly across regions.[30] ReEDS uses base fuel prices from the EIA's *Annual Energy Outlook* and, for natural gas prices, an endogenous demand curve to calculate regional fuel prices. This means that natural gas fuel prices were different in each of our scenarios. We used price projections from the *Annual Energy Outlook* 2022 in this study. All prices and costs in this report are in 2022 dollars (2022$), unless otherwise noted.[31]

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26 In 2022 dollars, these penalty prices are $3,873/MWh, $7,746/MWh, $11,619/MWh, and $15,493/MWh, respectively.

27 For more on participation by solar and wind generation in reserve markets, see Kim et al. (2023).

28 See Ho et al. (2021) for a more detailed description of how ReEDS does this aggregation.

29 In the BPBS and MP scenarios, average gas heat rates for the Southeast balancing regions, FRCC, and MISO-PJM-SPP (MPS) were within 6% of a simple average over the entire Southeast-FRCC, MPS footprint. In the HP scenarios, in which gas units were more seldomly used, gas heat rates varied more significantly within and across regions. Average coal heat rates ranged from 9,197 Btu/kWh in MISO-S (MPLS LC scenario) to 12,183 Btu/kWh in TVA (BPBS scenarios).

30 Coal prices were lowest in SPP and AECI ($1.8/MMBtu), slightly higher ($2.0–$2.1/MMBtu) in LGEE, TVA, MISO-E, and MISO-S, and highest ($2.7/MMBtu) in DUK, FRCC, and PJM-W. Natural gas prices were higher in the Southeast and FRCC ($3.6–$4.2/MMBtu across scenarios) and lower in MISO, PJM, and SPP ($3.3–$3.6/MMBtu). Differences in prices reflect resource endowments and differences in transport costs. All prices are in 2022$.

31 We inflated 2004 dollars to 2022 dollars using the consumer price index for all urban consumers (CPI-U), which resulted in an inflation factor of 1.55. We chose 2022 as the base price year because it was the year in which the study began, though using 2022 dollars results in higher dollar values due to higher than trend inflation between 2020 and 2022.

Due to regional differences in fuel prices and, to a lesser extent, heat rates, the fuel cost of generating electricity (heat rate multiplied by fuel price) varied across regions. The two most important generation fuel costs were coal and natural gas. For both, average fuel costs were lower in the MISO-PJM-SPP regions than in the Southeast region (SER) or in FRCC (Figure 2). Coal fuel costs were lower than natural gas fuel costs (Figure 2). Regional differences in heat rates and generation fuel costs played an important role in the production cost (Section 3.3.1), carbon dioxide (CO_2) emissions (Section 3.4), and transmission flow (Section 3.6.2) results.

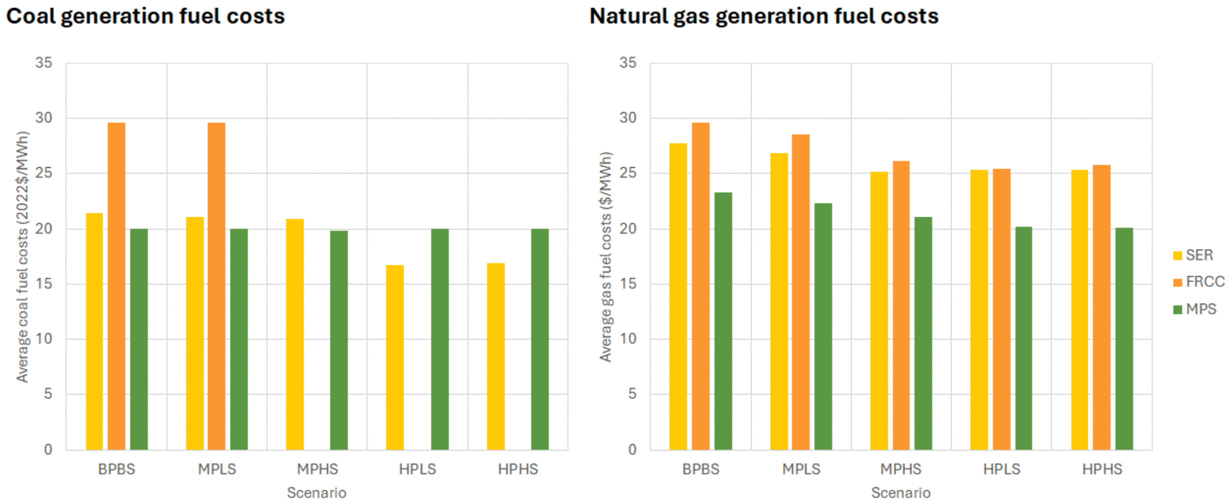


Figure 2. Average coal and natural gas generation fuel costs by region and scenario

Notes: For this figure, we averaged fuel generation costs across regions and regional coordination scenarios. Input fuel prices were held constant across regional coordination scenarios, but output fuel costs may vary based on dispatch efficiency.

3. Results

The results are organized into eight sections:

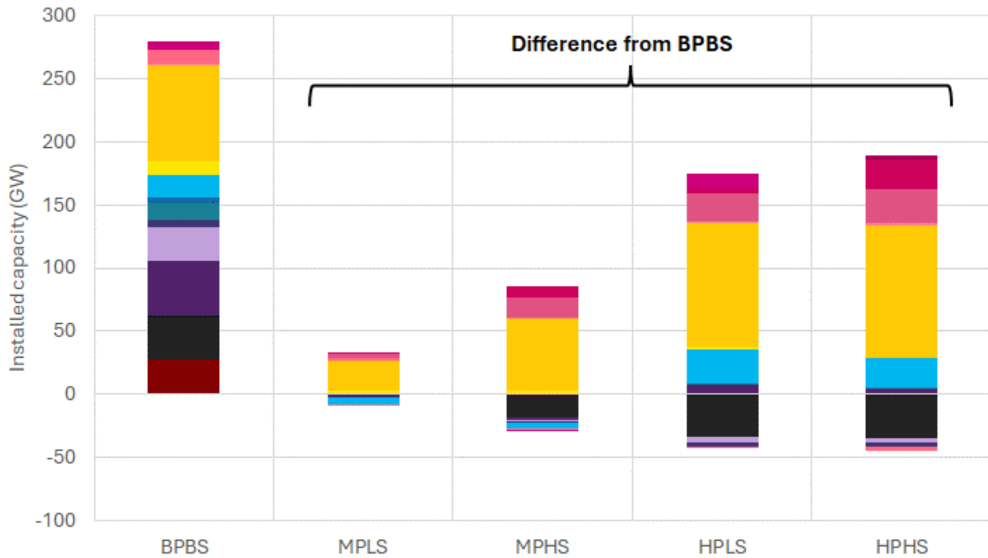
- **Generation and transmission expansion**, which describes results from the capacity expansion in ReEDS
- **Dispatch results**, which compares annual, daily average, and monthly generation across the scenarios
- **Economics**, which analyzes production costs and market costs
- **CO_2 emissions**, which describes carbon dioxide emissions across regions and scenarios
- **Reliability**, which examines load and reserve violations and reliability issues around multiday energy adequacy and real-time imbalances
- **Operations**, which describes changes in generation, curtailment, transmission flows, reserve requirements and provision, storage operations, and gas generation operations
- **Sensitivities**, which explores sensitivities for the PLEXOS modeling
- **Modeling issues**, which describes several modeling issues that arose during the course of this study.

For the Southeast region, production cost and CO_2 emission results are closely tied to assumptions about hurdle rates with neighboring regions. To capture these effects, we include results from neighboring regions (FRCC, MISO-PJM-SPP) in some sections. Unless specified, however, the results are limited to the Southeast region.

3.1 Generation and Transmission Expansion

The capacity expansion modeling results are helpful for understanding the production simulation results. Although we sought to independently increase levels of solar PV and storage across our resource scenarios while holding most other resources constant, in fact solar, storage, and wind resources are highly interactive. In all scenarios, the ReEDS model also built a significant amount of new transmission, both within the Southeast region and between the Southeast and neighboring regions.

Figure 3 shows, for the Southeast region, the BPBS scenario's installed capacity mix and the changes in installed capacity in other scenarios relative to the BPBS scenario. (Negative changes relative to the BPBS scenario in Figure 3 could reflect retirement, as with coal, or less growth, as with wind in the MP scenarios.) As described in Table 2 (Section 2.2), the MPLS scenario had more utility-scale solar PV capacity than the BPBS scenario (+24 GW) but was otherwise relatively similar. The MPHS scenario had significantly more solar PV capacity (+57 GW) and battery storage capacity (+26 GW) than the BPBS scenario, as well as significantly less coal capacity (-17 GW). The HPLS and HPHS scenarios had much more solar PV (+98–106 GW), energy storage (+38–51 GW), and onshore wind (+23–27 GW) capacity than the BPBS scenario, with almost no coal generation capacity remaining. Most additional energy storage capacity in the MPHS, HPLS, and HPHS scenarios, relative to the BPBS scenario, had at least 6-hour duration. The HPLS scenario, which had higher battery costs, had less 8-hour battery storage and more pumped hydro storage. In all scenarios, ReEDS maintained approximately the same amount of total natural gas generation capacity (68–75 GW). The HP scenarios had the most gas capacity (71–75 GW), with more combined cycle and less combustion turbine capacity than the BPBS scenario.



Key

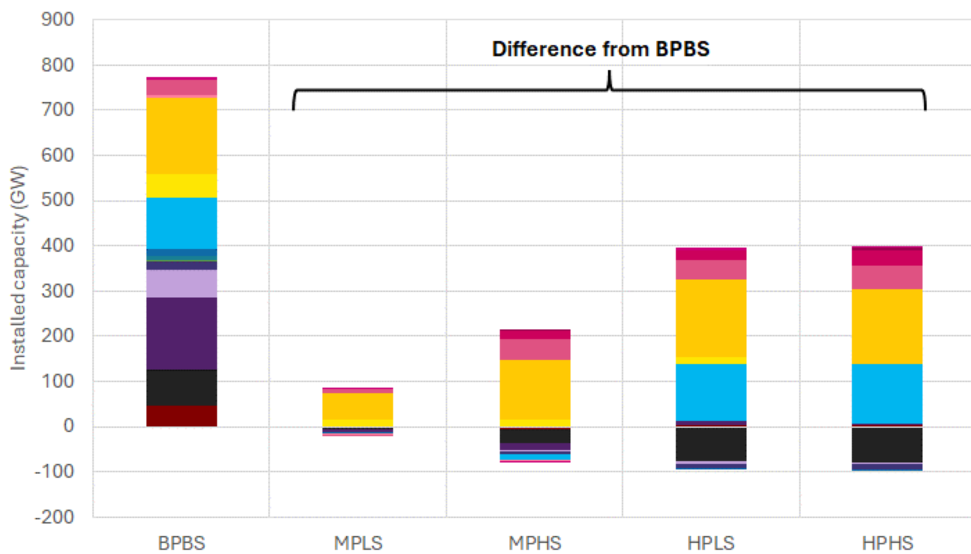
	Nuclear		Coal		Combined cycle gas		Gas turbine
	Oil & gas steam		Biomass		Hydro		Offshore wind
	Onshore wind		Distributed PV		Utility-scale PV		2-hour battery
	4-hour battery		6-hour battery		8-hour battery		10-hour battery
	Pumped hydro						

Figure 3. Installed capacity (BPBS) and change in installed capacity (MPLS, MPHS, HPLS, HPHS) relative to the BPBS scenario, Southeast region

Two interactions in Figure 3 are worth highlighting. First, in the medium solar (MP) scenarios, more battery storage enabled higher levels of solar PV capacity: Lower battery costs and 19 GW of additional battery storage enabled 33 GW of additional utility-scale solar PV in the MPHS scenario, relative to the MPLS scenario. Aside from battery costs, all other assumptions were identical between the MPLS and MPHS scenarios (see Section 5.3). However, in the higher solar (HP) scenarios, this relationship between solar PV and storage showed signs of leveling off: 14 GW of additional battery storage enabled only 8 GW of additional utility-scale solar PV in the HPHS scenario, relative to the HPLS scenario. As a result, the MPLS and MPHS differed in both the amount of solar and storage capacity, whereas the main difference between the HPLS and HPHS scenarios was the amount of storage capacity.

The second interaction to note is among solar PV, battery storage, and wind resources. In the MP scenarios, solar PV and wind were substitutes: Lower solar PV costs (MPLS and MPHS scenarios) and battery costs (MPHS scenario) that increased solar capacity reduced wind capacity, relative to the BPBS scenario. In the HP scenarios, solar PV and wind were complements: Using a carbon tax to increase solar PV generation relative to the MP scenarios also increased wind capacity. As a result, changes in the results between the MP and HP scenarios were more dramatic than changes between the BPBS and MP scenarios because the HP scenarios included a significant amount of new wind generation.

Changes in installed capacity in neighboring regions (FRCC, MISO, PJM, SPP) were similar to those in the Southeast region. Most new generation in neighboring regions was solar PV, onshore wind, and battery storage, nearly all coal generation was retired, and there were similar interactions between wind, solar, and storage in the MP and HP scenarios (Figure 4). However, in neighboring regions, the shares of wind and solar in the BPBS scenario (33%, 7%) were almost mirror opposites of those in the Southeast region (7%, 28%), and wind was a larger share of new generation capacity in the HP scenarios—approximately 40% relative to around 20% in the Southeast region. The Southeast's western neighbors (MISO, SPP) have the best quality wind resources in the United States.[32] The Southeast also had higher shares of nuclear generation capacity (30%–31%) than either FRCC (11%–12%) or MISO-PJM-SPP (17%–21%).



Key

	Nuclear		Coal		Combined cycle gas		Gas turbine
	Oil & gas steam		Biomass		Hydro		Offshore wind
	Onshore wind		Distributed PV		Utility-scale PV		2-hour battery
	4-hour battery		6-hour battery		8-hour battery		10-hour battery
	Pumped hydro						

Figure 4. Installed capacity (BPBS) and change in installed capacity (MPLS, MPHS, HPLS, HPHS) relative to the BPBS scenario, neighboring regions

32 For wind resource maps of the U.S., see https://www.nrel.gov/gis/wind-resource-maps.html.

The battery duration mix varied significantly across scenarios, and differences among scenarios were complex. The higher solar scenarios had more longer duration battery storage than the lower solar scenarios, but higher levels of solar capacity did not result in a simple shift from shorter to longer duration storage. Additionally, in some instances, ReEDS built less of a given battery storage technology in higher than in lower solar and storage scenarios. In the MP scenarios, ReEDS built less 2-hour battery storage (1 GW less, across the Southeast-FRCC-MISO-PJM-SPP footprint) and more 4-hour (13–20 GW more) and 6-hour storage (2–40 GW more) relative to the BPBS scenario. In the HPLS scenario, ReEDS built less 4-hour (6 GW less) and 8-hour (4 GW less) storage and more 6-hour (9 GW more) and 10-hour (2 GW more) storage than in the MPHS scenario. In the HPHS scenario, ReEDS built less 4-hour storage (7 GW less) and more of all other battery storage durations than in the HPLS scenario. Differences in battery duration and storage technologies among resource portfolios suggest that storage investments are sensitive to longer-term resource portfolios.

New transmission investments in ReEDS differed significantly across scenarios. ReEDS built more new transmission across the Southeast, FRCC, and MISO-PJM-SPP in the BPBS scenario (15 GW) than in the MPLS (12 GW) or MPHS (11 GW) scenarios. It built much more new transmission in the HPLS (37 GW) and HPHS (29 GW) scenarios than in the BPBS or MP scenarios. In the BPBS and MP scenarios, most of the new transmission capacity was within the Southeast region, whereas in the HP scenarios, most new transmission was between the Southeast region and neighboring regions (Figure 5). The high storage scenarios (MPHS and HPHS) illustrate the substitution effects between storage and transmission, and their interaction with higher levels of solar PV: 19 GW of additional storage in the MPHS scenario, relative to MPLS, offset 1 GW of new transmission capacity; 14 GW of additional storage in the HPHS scenario, relative to HPLS, offset 8 GW of new transmission capacity.

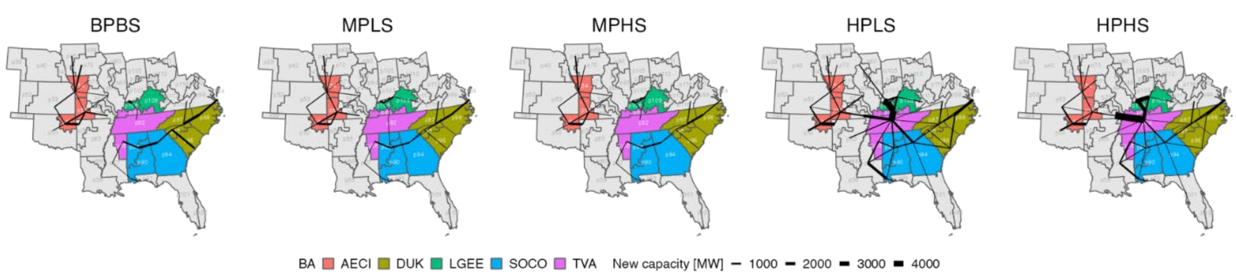


Figure 5. Transmission expansion in ReEDS by resource scenario

3.2 Dispatch Results

Dispatch results provide helpful context for understanding the other results. This section compares annual generation, daily average dispatch, and monthly generation across the resource and coordination scenarios.

3.2.1 Annual Generation

Higher levels of solar generation and higher levels of coordination both led to significant changes in generation in the Southeast across scenarios. Annual solar generation (nonfossil generation shares in parentheses) in the region increased from 23%–26% (69%–76%) of total generation in the BPBS scenarios, to 29%–32% (72%–80%) in the MPLS scenarios, 37%–41% (79%–85%) in the MPHS scenarios, 42%–43% (96%–98%) in the HPLS scenarios, and 45%–46% (97%–99%) in the HPHS scenarios. The resource scenarios thus capture an almost continuous range of solar and nonfossil fuel generation in the Southeast from a base of just over 20% solar (70% nonfossil) to around 45% (99%) (Figure 6).

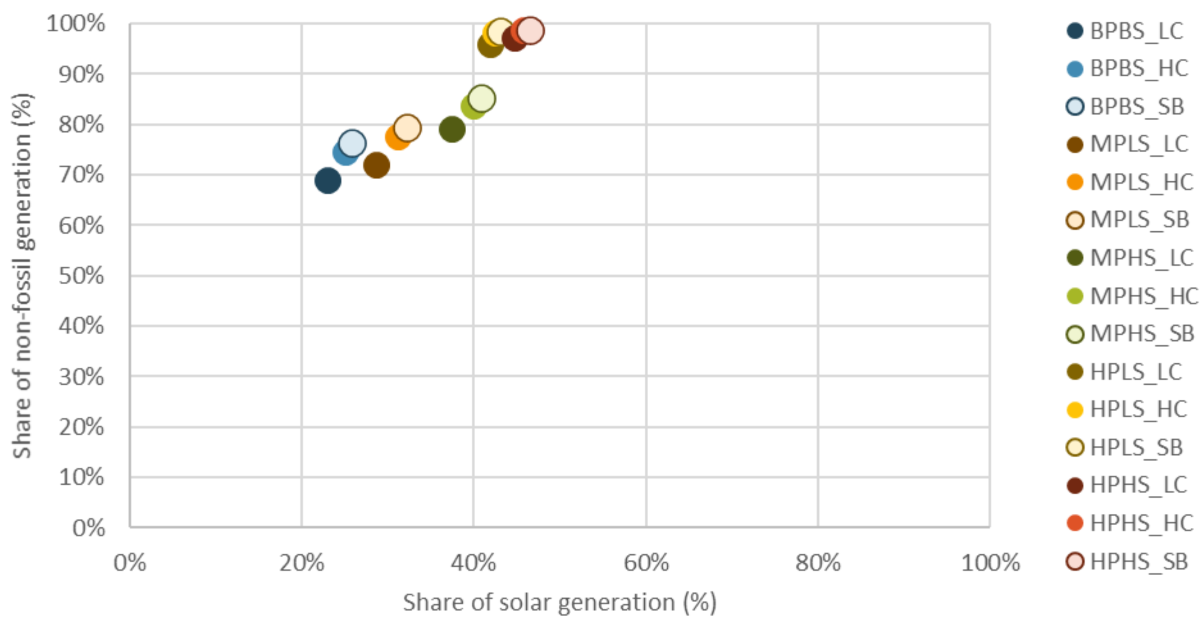


Figure 6. Solar generation and nonfossil fuel generation shares of total generation by scenarios

Notes: The format for scenarios in the legend is resource scenario_coordination scenario. For a review of scenario descriptions, see Section 2.2.

Annual generation in the Southeast's neighbors—Florida (FRCC), MISO, PJM, and SPP—resembled that in the Southeast because these regions were subject to a similar set of economic and policy assumptions in the national capacity expansion modeling we used to develop resource portfolios (see Section 2.2). In the larger region—the Southeast region (SER), FRCC, and the combined MISO, PJM, and SPP (MPS) regions—nonfossil generation increased from 70% in the BPBS LC scenario to 96% in the HPHS SB scenario. The FRCC generation mix resembled that in the Southeast, though with proportionately less nuclear and wind generation. MPS had proportionately less nuclear but more wind generation.

Figure 7 summarizes annual generation by region across resource scenarios for the LC scenarios, with aggregated generation technologies for ease of interpretation. Figure 7 also shows annual discharge of energy storage. Energy storage is not a primary energy resource, but including it with other primary energy resources in Figure 7 illustrates the increasingly important role that storage plays as more solar energy is added to the generation mix in the MP and HP scenarios. At its highest (HPHS HC and SB scenarios), energy storage discharge is equivalent to 17% of total generation from primary energy resources. We show energy storage discharge in several of the figures in this section for illustrative purposes.

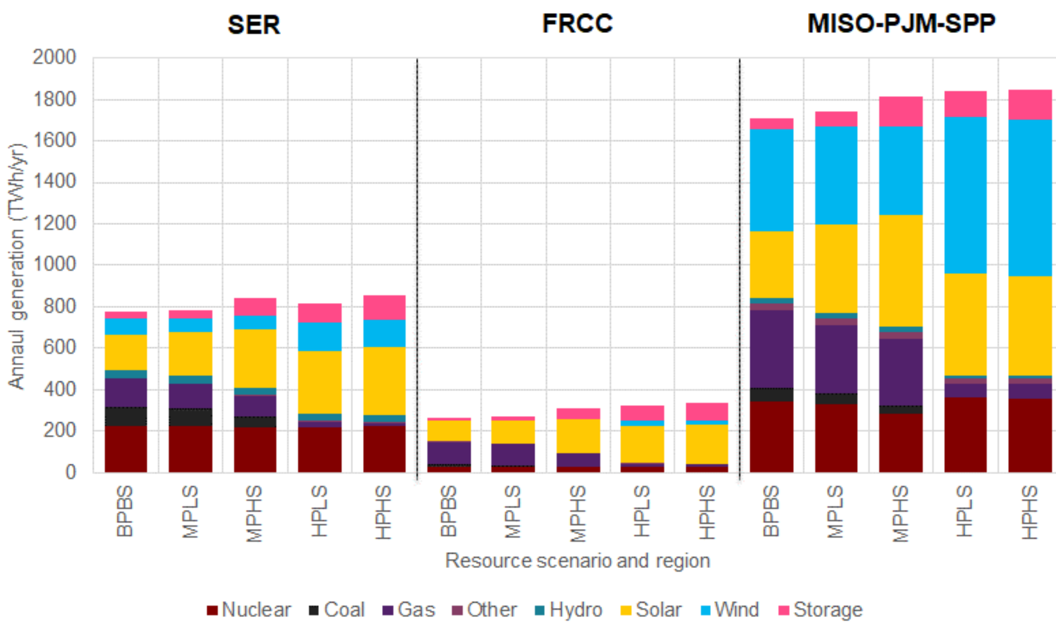


Figure 7. Annual generation in the Southeast and neighboring regions, lower coordination scenarios

Higher levels of coordination affected annual generation differently in different resource scenarios, both within the Southeast region and between the Southeast and its neighbors. Figure 8 shows changes in annual generation by region (SER, FRCC, MPS) and net total across all regions between the LC and HC scenarios. In the BP and MP scenarios, higher coordination (LC to HC) led to significant shifting of gas and coal generation within the larger SER-FRCC-MPS footprint, with smaller changes in solar and wind generation and storage discharge. To provide a relative sense of scale for the results in Figure 8, in the BPBS scenario, coal generation in SER declined 16%, gas generation declined 29%, and wind and solar generation increased by 5%; in the MPS region, gas generation increased by 22% and wind and solar generation declined by less than 1%. For the larger footprint (net total), the net result was a decrease in coal generation, a small decrease in wind generation (BPBS and MPLS scenarios only), an increase in gas and solar generation, and higher storage discharge. In the HP scenarios, across the larger footprint, higher coordination (LC to HC) led to a reduction in gas generation and increases in solar and wind generation and storage discharge.

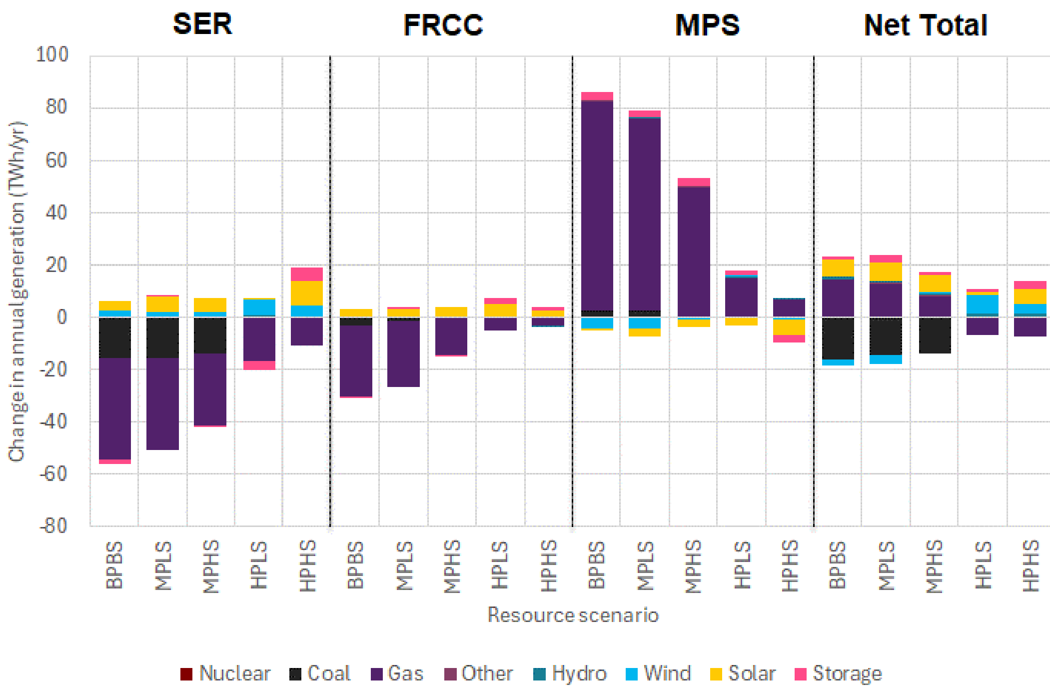


Figure 8. Change in annual generation in the HC scenarios relative to the LC scenarios, by region and net total

Changes in natural gas and coal generation from the LC to HC scenarios were driven by two main factors: (1) differences in natural gas generation fuel costs ($/MWh) and (2) decommitment of coal generation to absorb additional solar generation. For (1), differences in natural gas generation fuel costs between MPS and the Southeast region and FRCC were $4–$5/MWh across scenarios (see Section 2.4), which meant that reducing hurdle rates from $8/MWh to $0/MWh led to large changes in dispatch among these three regions. For (2), lower day-ahead hurdle rates made it economic to decommit coal generation day-ahead and replace its energy with a combination of solar, storage, and natural gas, even though natural gas generation fuel costs were generally more expensive than coal generation fuel costs (see Section 2.4).[33]

Figure 9 shows changes in annual generation by region and in aggregate between the HC and SB scenarios. The HC and SB coordination scenarios had the same real-time hurdle rates ($0/MWh) but differed in day-ahead hurdle rates ($8/MWh versus $0/MWh) and reserve sharing rules. Because these scenarios had the same real-time hurdle rates, changes in generation between them were smaller than changes between the LC and HC scenarios. The main net change across regions (net total) in the BPBS, MPLS, and MPHS scenarios was a reduction in coal generation and an increase in gas generation, with a smaller reduction in hydropower and an increase in wind and solar generation. In the HPLS and HPHS scenarios, the main net result was a reduction in hydropower generation and an increase in wind and solar generation.

[33] The exception to this was FRCC. Average coal generation fuel costs in FRCC ($30/MWh) were higher than average natural gas generation fuel costs in SER ($25–$28/MWh) or MPS ($20–$23/MWh).

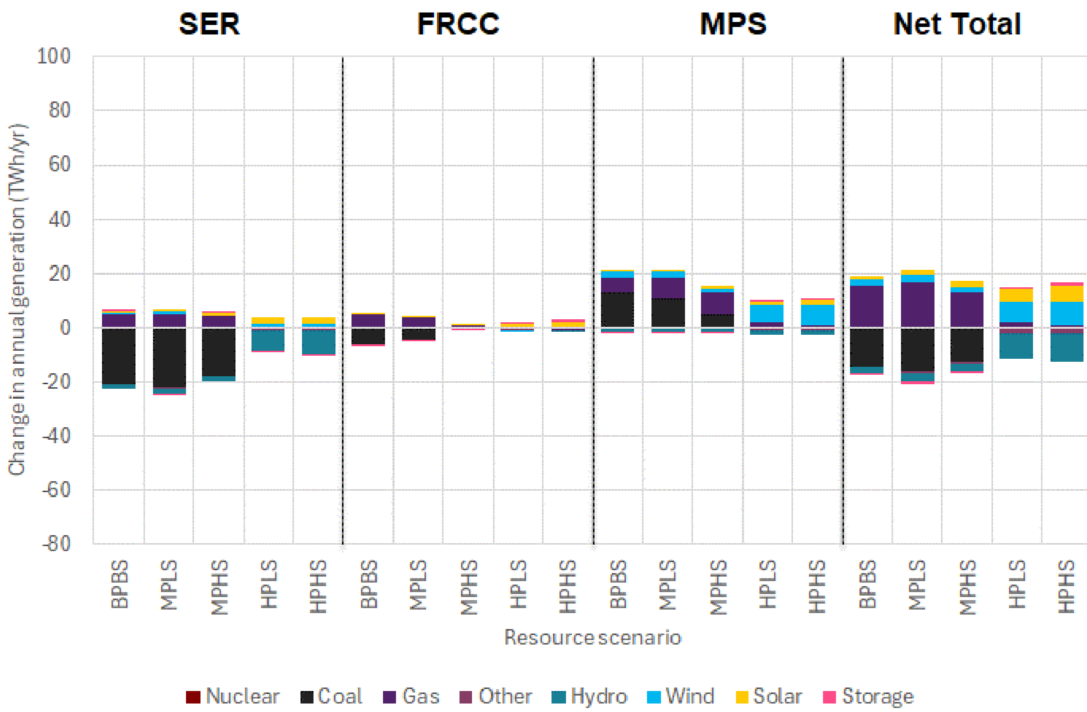


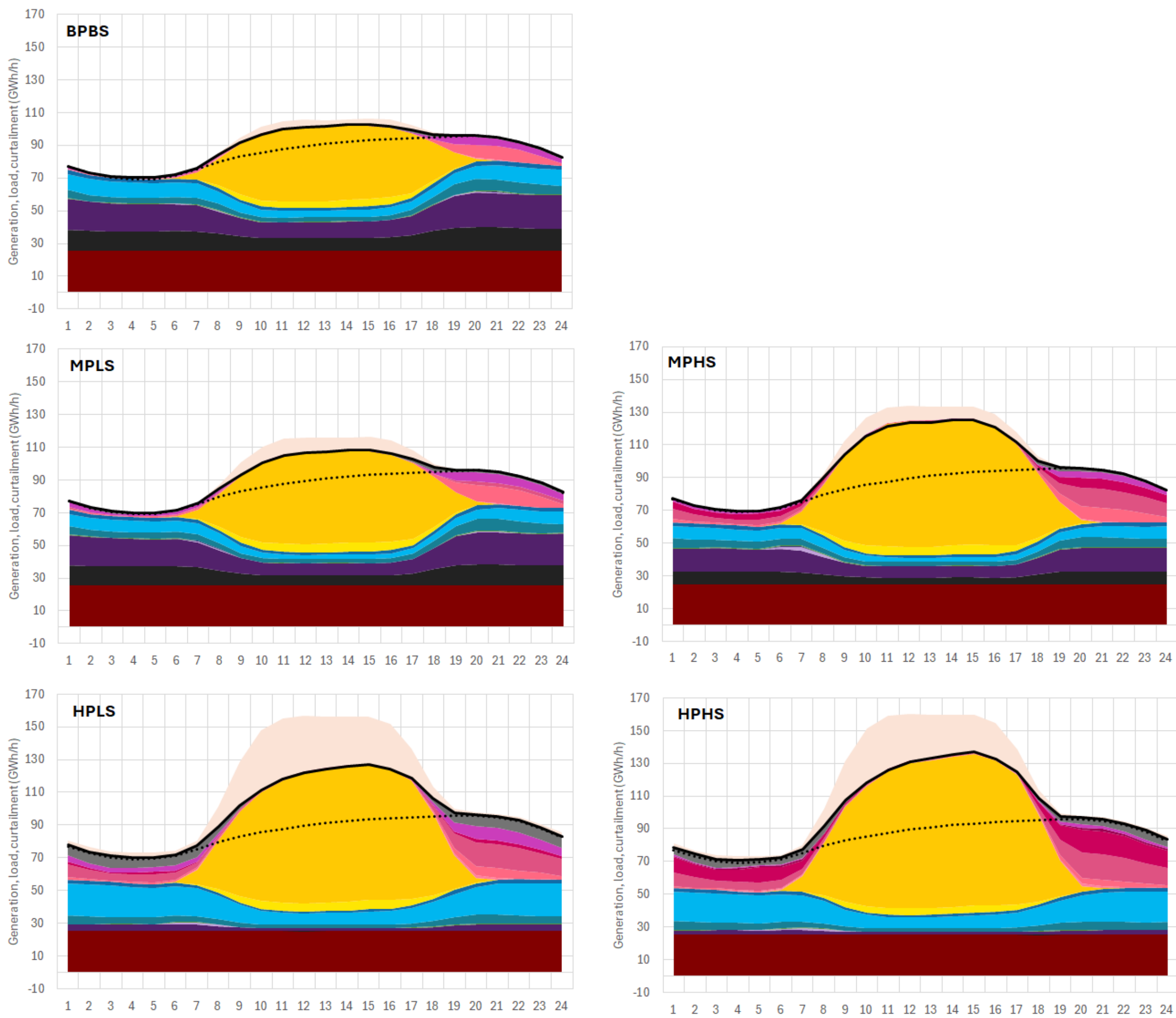
Figure 9. Change in annual generation in the SB scenarios relative to the HC scenarios, by region and net total

Real-time curtailment of hydropower generation occurred in all SB scenarios, but particularly in the two HP scenarios. Hydropower curtailment was, to some extent, an artifact of our modeling assumptions. Hydropower had higher variable operations and maintenance costs than wind and solar generation, and PLEXOS curtailed hydropower day-ahead to absorb more wind and solar generation. Because we limited the ability of hydropower to re-dispatch from a day-ahead schedule in real-time, PLEXOS was unable to increment hydropower dispatch from its day-ahead schedule to address real-time energy shortfalls and dispatched gas generation instead. We discuss the implications of this result for production costs in Section 3.3. We discuss a sensitivity in which we allowed hydropower more real-time dispatch flexibility in Section 3.7.

To summarize, the largest changes in dispatch from higher coordination were for gas and coal generation, particularly in the BPBS, MPLS, and MPHS scenarios. Generation that had lower fuel costs (heat rate multiplied by fuel price) displaced generation with higher fuel costs, and changes in natural gas and coal generation between regions mainly reflected regional differences in fuel prices. To a lesser extent, higher coordination allowed solar and wind generation that would have been curtailed to be consumed instead. In most cases, higher efficiency and lower curtailment led to lower production costs (Section 3.3) and CO_2 emissions (Section 3.4). We discuss changes in operations that result from higher coordination in more detail in Section 3.6.

3.2.2 Daily Average Dispatch

Daily average dispatch provides insight on how the timing of generation changes across resource and coordination scenarios. Figure 10 shows the evolution of daily average dispatch in the Southeast region across the five resource scenarios for the LC scenarios. Across resource scenarios, this evolution consists of two main changes. First, higher amounts of solar generation during the middle of the day were stored and discharged during the evenings and, beginning in the MPHS scenarios (37%–41% solar), mornings. Second, this shifted solar generation, and additional wind and net imports in the HPLS and HPHS scenarios, displaced almost all gas and coal generation in the evenings. Changes in daily average dispatch between the coordination scenarios are more difficult to see in dispatch plots, and thus we do not show them here. We discuss changes in operations with higher levels of coordination in Section 3.6



Key

	Nuclear		Coal		Combined cycle gas		Gas turbine		Oil & gas steam
	Biomass		Hydro		Offshore wind		Onshore wind		Distributed PV
	Utility-scale PV		2-hour battery		4-hour battery		6-hour battery		8-hour battery
	10-hour battery		Pumped hydro		Net imports		Curtail-ment		
…………	Load	________	Load plus storage charge						

Figure 10. Evolution of daily average dispatch in the Southeast from lower to higher solar scenarios (LC scenarios)

Figure 10 illustrates the complementarity between solar and storage. As more solar generation was added in the MP and HP scenarios, most incremental solar generation during the middle of the day was stored and shifted to other time periods rather than used to meet load. As an illustration, the lowest average amount of nonsolar generation during the day (12:00–13:00) declined from 51% of load in the

BPBS LC scenario to 42% in the HPHS LC scenario, but the average solar share of load in this hour increased from 54% in the BPBS scenario to 104% in the HPHS scenario. In this hour, on average, around 70% of incremental (HPHS relative to BPBS) solar generation was stored and shifted rather than used to meet demand in that hour.[34]

For the entire year, the amount of incremental (relative to BPBS) solar generation stored and shifted to another time period rather than used to meet energy demand in that period was 42% in the MPLS scenario, 60% in the MPHS scenario, 55% in the HPLS scenario, and 63% in the HPHS scenario.[35] In average rather than incremental terms, the share of solar that was stored and shifted rather than directly used to meet load increased from 19%–23% in the BPBS and MPLS scenarios to 34%–40% in the MPHS and HP scenarios.[36] Longer-duration storage in the MPHS, HPLS, and HPHS scenarios allowed solar generated in the day to be shifted to the early morning hours. Figure 10 also shows the Southeast region's increased reliance on net imports during the evenings in the two HP scenarios, a subject that we explore in more detail in the next section.

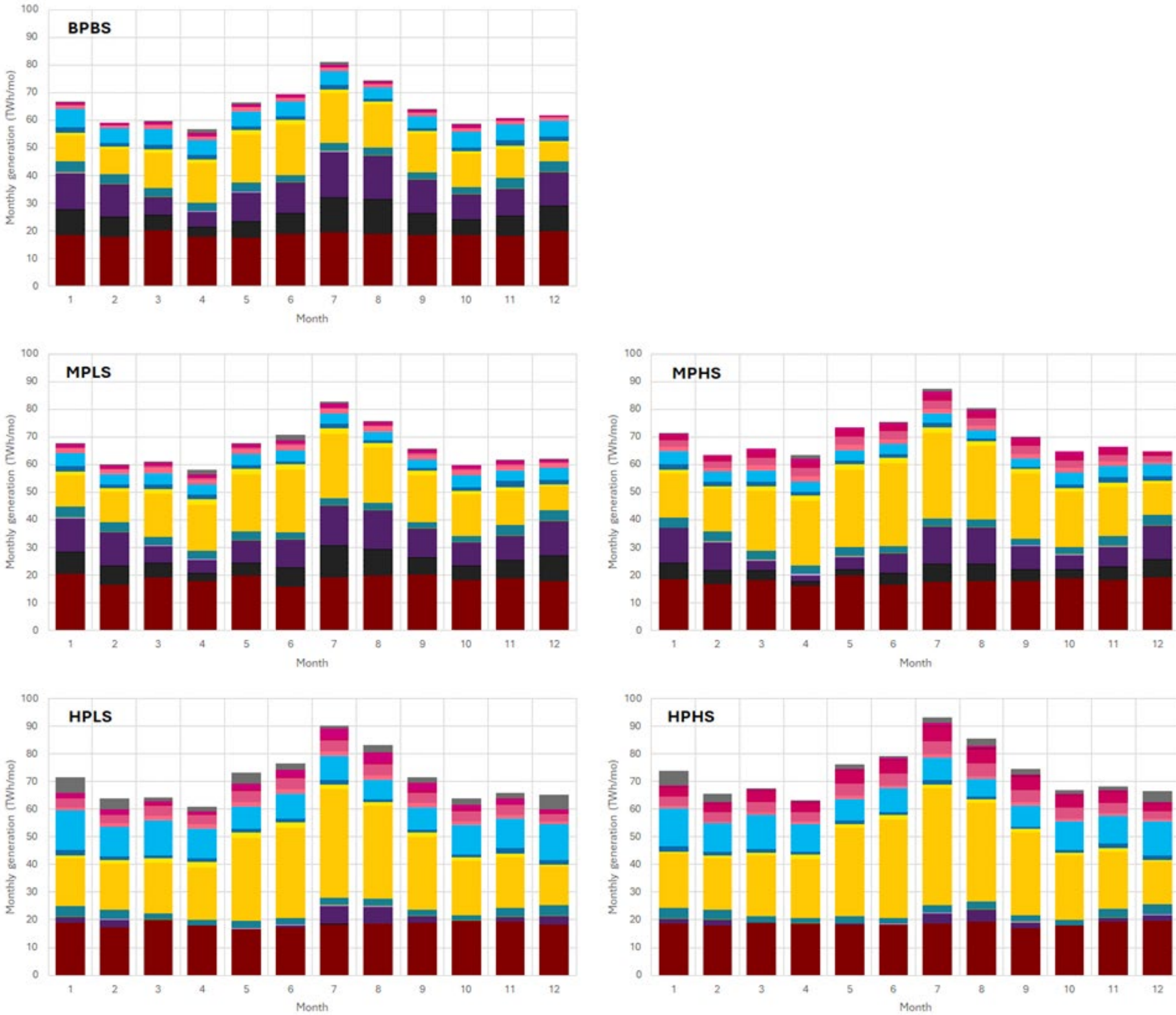
3.2.3 Monthly Generation

Monthly generation illustrates how the generation mix changed to match changes in load and wind and solar generation in different seasons. Load in the Southeast region was highest in July and August. Winter load in January was still relatively high; January monthly energy demand was on par with that in September. Solar generation in the winter was less than half of its maximum levels in July. In the HP scenarios, for instance, solar met 52% to 56% of energy demand in July but only 25% to 27% of demand in December. Wind generation in the winter was more than twice as large as its lowest point in August, but wind supplied at most 25% of monthly energy demand (January, HP scenarios). Figure 11 illustrates these patterns for the LC scenarios.

[34] The incremental average share of solar generation stored rather than used to meet energy demand in period t will be $1 - \frac{\Delta MIN_t}{-\Delta INC_t}$, where ΔMIN_t is the change in minimum nonsolar generation share of load at time t and ΔINC_t is the change in incremental solar generation share of load at time t. In the example in the text, $1 - \frac{0.51-0.42}{-(0.54-1.04)} = 0.69$.

[35] Across time periods, the incremental share of solar that is stored rather than consumed in the time period in which it is generated can be equivalently calculated as $\frac{\sum_t \Delta S_t + \Delta NS_t}{\sum_t \Delta S_t}$, where ΔS_t is the change in solar generation at time t and ΔNS_t is the change in nonsolar generation (including net imports) at time t and where values are zero if $\Delta S_t < \Delta NS_t$. ΔNS_t will be negative if minimum nonsolar generation levels decline from the base scenario. We include net exports in the definition of energy demand.

[36] The average share of solar generation consumed by load in period t can be estimated as $\alpha = L_t - NS_t$, where L is load and NS is nonsolar generation (including net imports). The share of solar generation not consumed by load will be $1 - \alpha$. Solar generation here is already adjusted for curtailment.



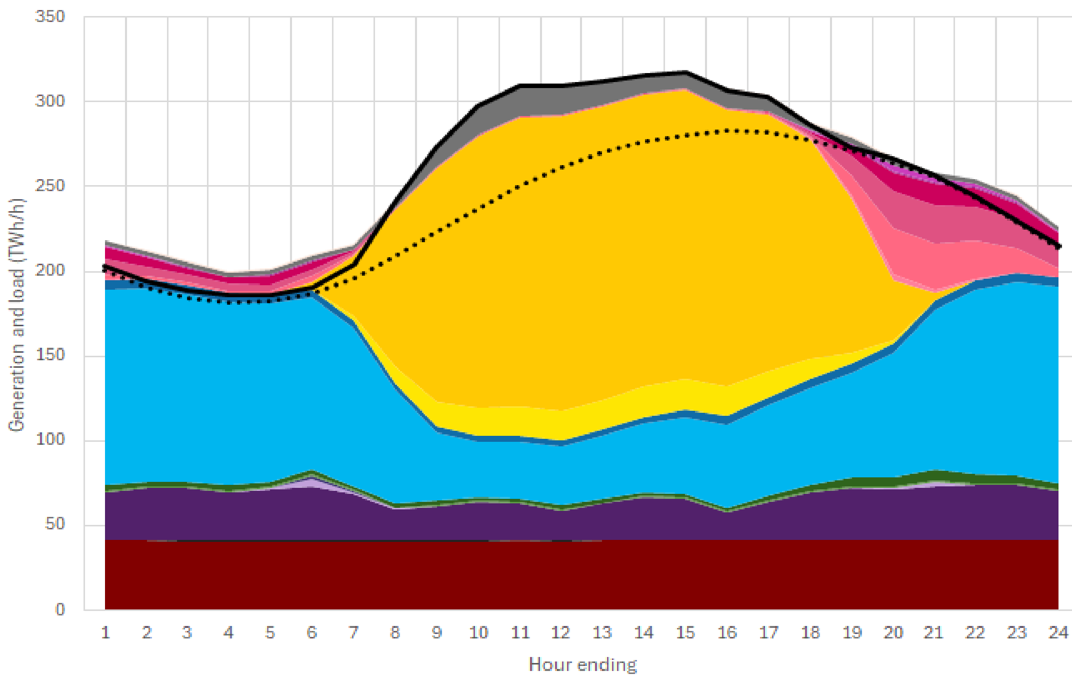
Key

	Nuclear		Coal		Combined cycle gas		Gas turbine		Oil & gas steam
	Biomass		Hydro		Offshore wind		Onshore wind		Distributed PV
	Utility-scale PV		2-hour battery		4-hour battery		6-hour battery		8-hour battery
	10-hour battery		Pumped hydro		Net imports				

Figure 11. Monthly generation mix, LC scenarios

Changes in monthly thermal generation and energy storage matched seasonal patterns in demand and solar and wind availability. In the BPBS and two MP scenarios, gas and coal generation increased during the summer (July–August) to meet peak demand, and during the winter (December–February) when demand was still high but solar generation was low. In the two HP scenarios, gas generation was only used during the summer and winter. Storage discharge peaked in the summer but was at its lowest levels in the winter due to limited solar generation. In both HP scenarios, net imports were highest in winter to make up for the shortfall in solar generation.

The Southeast region had ample gas generation (71–74 GW) in the two HP scenarios to provide both capacity and energy during the winter. Imports during the winter to fill in the decline in solar generation in the winter were driven by economics and not capacity or energy adequacy. As Figure 12 illustrates (for December), the MISO-PJM-SPP (MPS) region had abundant wind and available storage during winter evenings and mornings and exported low-cost energy to the Southeast region. We discuss the implications of limiting transmission capacity on this complementarity between the Southeast region and the MPS region in Section 3.7.



Key

	Nuclear		Coal		Combined cycle gas		Gas turbine		Oil & gas steam
	Biomass		Hydro		Offshore wind		Onshore wind		Distributed PV
	Utility-scale PV		2-hour battery		4-hour battery		6-hour battery		8-hour battery
	10-hour battery		Pumped hydro		Net imports		Curtail-ment		
....	Load	________	Load plus storage charge						

Figure 12. Daily average dispatch in MISO, PJM, and SPP for December, HPHS SB scenario

3.3 Economics

This section describes production cost and market cost results. We discuss the economics of reserve sharing in Section 3.6.3, as it requires more context on reserve requirements and the physical (MW) reserve savings that result from reserve sharing.

3.3.1 Production Costs

Figure 13 shows production cost results for the Southeast region (SER), MISO-PJM-SPP (MPS), and Florida (FRCC). In Figure 13, production costs include real-time fuel, variable operations and maintenance, and real-time and day-ahead startup costs.[37] Across these three regions and across coordination scenarios, increasing levels of solar generation capacity drove large reductions in production costs. Relative to the BPBS LC scenario ($29 billion per year, $11/MWh average costs), annual production costs declined by 10%–12% (by $3 billion per year, $1/MWh reduction in average costs) in the MPLS scenarios, 26%–27% (by $7–$8 billion per year, $3/MWh reduction) in the MPHS scenarios, 67%–68% in the HPLS scenarios (by $20 billion per year, $7–$8/MWh reduction), and 69%–70% (by $20 billion per year, $8/MWh reduction) in the HPHS scenarios.[38]

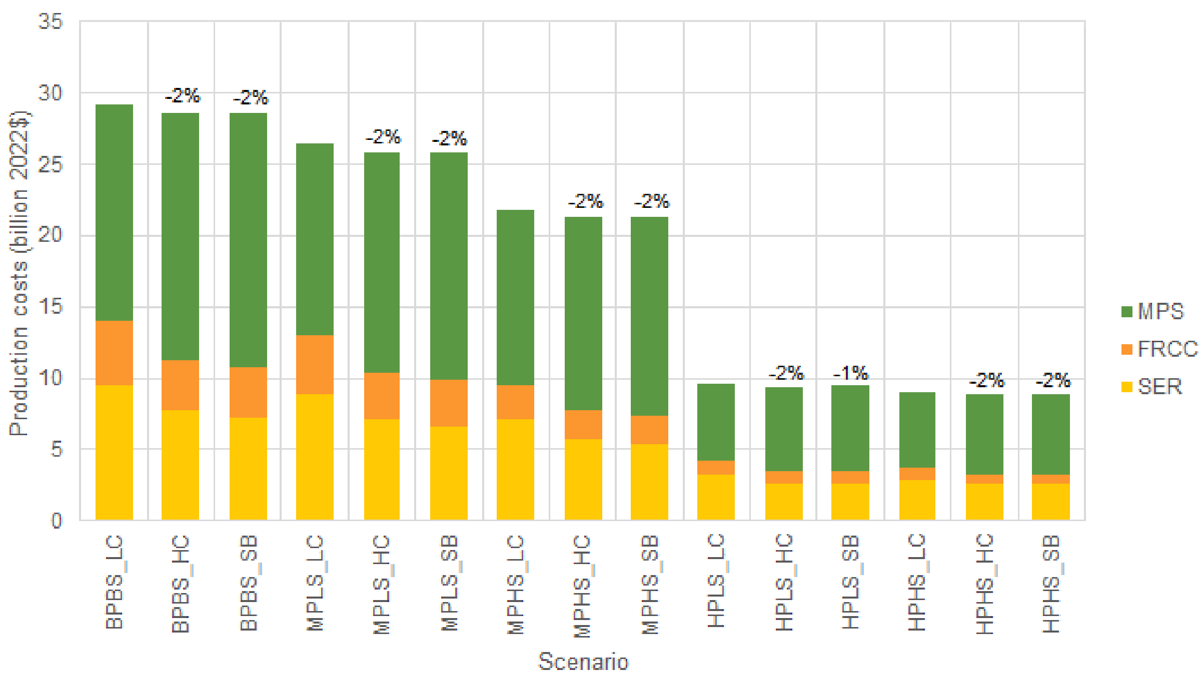


Figure 13. Production costs by region and percent change from LC scenarios

[37] PLEXOS tracks units that are online in real time and includes their day-ahead start costs in its tabulation total start and production costs. However, it does not track units that have been started day-ahead and are decommitted in real time due, for instance, to forecast error. The estimates here thus may be a slight underestimate of total production costs and production cost savings.

[38] $/MWh average costs here are in terms of MWh load. For the SER-FRCC-MPS region, total annual energy demand was 2,634 TWh.

In most cases, higher levels of coordination led to large reductions in production costs in the SER and FRCC regions but an increase in production costs in MPS. This regional shifting of production costs occurred primarily due to two main changes in dispatch across the Eastern Interconnection: (1) lower cost natural gas and coal generation in MPS displacing higher cost generation in SER and FRCC (see Section 3.2.1), and (2) higher wind and solar curtailment in MISO (+3.4–6.0 terawatt-hours [TWh] relative to LC across scenarios), and PJM (+1.4–6.4 TWh). It is unclear why higher coordination would increase solar and wind curtailment in MISO and PJM, but this increase in curtailment occurred in all scenarios and was consistent with a multiregion optimization that lowered total annual costs, curtailment, and CO_2 emissions (Section 3.5). Changes in inter-regional dispatch were most pronounced when hurdle rates declined from $8/MWh to $0/MWh.[39]

For the SER-FRCC-MPS regions in aggregate, production costs in all of the HC and SB scenarios declined by around 2% (the percentages shown at the top of the columns in Figure 13) relative to the LC scenarios. In percentage terms, these results are consistent with production cost savings from the creation of organized regional markets in MISO and SPP.[40] Lower overall production costs were the result of lower total wind and solar curtailment, which displaced thermal generation, and displacement of less efficient thermal generation with more efficient thermal generation.

Production cost savings declined in absolute terms with higher levels of solar and, in most cases, storage. For instance, annual production cost savings in the BPBS SB scenario, relative to the LC scenario, were $610 million per year, but in the MPHS and HPHS scenarios, SB scenario cost savings were $420 million and $160 million per year, respectively, relative the LC scenario. Lower cost savings, in absolute terms, were consistent with steep declines in production costs in the higher solar scenarios. However, this result also suggests that total production cost savings and other traditional metrics for assessing the benefits of regional coordination will decline in importance in scenarios in which resources with no fuel costs make up a larger share of the generation mix. Alternatively, fixed cost and opportunity cost savings will increase in importance. We discuss this issue in more detail in the conclusions.

In all scenarios, production costs were higher (+0.01% to +1.0%) in the SB scenarios than the HC scenarios. This result was unexpected. Both the real-time HC and SB scenarios had $0/MWh hurdle rates, but the SB scenarios allowed more reserve sharing, which in principle should have freed up lower marginal cost resources to provide energy rather than reserves and reduced production costs relative to the HC scenarios. Higher costs in the SB scenarios may have been related to hydropower dispatch. In all of the SB scenarios but particularly in the HPLS and HPHS SB scenarios, PLEXOS curtailed hydropower day-ahead, potentially due to lower spinning reserve requirements. Because of the limits on real-time hydropower re-dispatch, PLEXOS was unable to increment hydropower in real time and instead dispatched natural gas generation to cover solar and wind forecast error and 15-minute ramps, leading

[39] In day-ahead, the change from a $8/MWh to a $0/MWh hurdle rate was between the HC and SB scenarios. In real time, it was between the LC and HC scenarios.
[40] Reitzes et al. (2009); Chang et al. (2016b).

to higher fuel and startup costs in the SB scenarios relative to the HC scenarios. Section 3.7 explores how allowing more real-time flexibility for hydropower might affect these results.

In general, the difference between day-ahead and real-time production costs was shaped by the balance between lower real-time hurdle rates in many scenarios (day-ahead in the HC and SB scenarios, real-time in the HC scenarios), which tended to reduce overall production costs, and the inflexibility introduced by day-ahead scheduling and commitment, which tended to increase startup—and, in some instances, fuel—costs. In almost all scenarios,[41] the latter effect was larger, and real-time production costs were higher than day-ahead costs for the aggregate SER-FRCC-MPS region. Beginning with the MPHS scenarios, higher solar-storage scenarios had much higher (+4%–17%) real-time production costs relative to day-ahead.

This increase in real-time production costs was almost entirely—or, in some scenarios, entirely—driven by higher real-time startup costs. Figure 14 shows the change in production cost components between day-ahead and real-time runs. Adding more battery storage (HS scenarios) did not reduce startup costs or overall real-time production costs relative to day-ahead costs, for reasons that we explore in Section 3.6.5. Despite increases in real-time startup costs, fuel costs still accounted for the bulk of production costs in both the day-ahead (84%–92% of total production costs across all scenarios) and real-time (81%–85% of costs) runs.

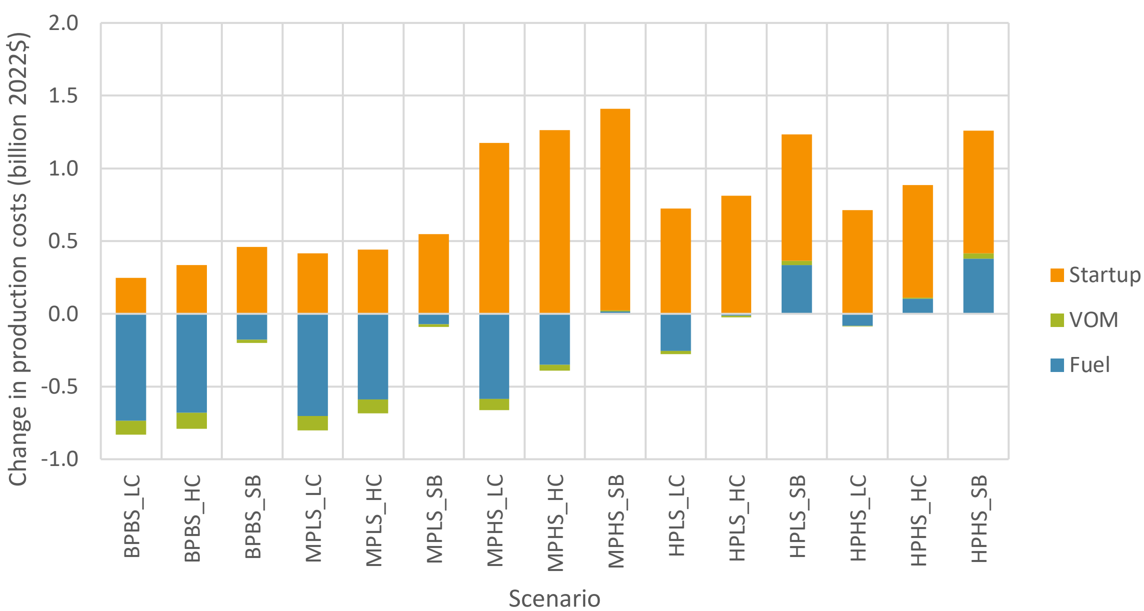


Figure 14. Changes in production costs between real-time and day-ahead by production cost component, aggregate SER-FRCC-MPS region

Notes: Startup is startup costs. VOM is variable operations and maintenance costs. Fuel is fuel costs.

[41] The exceptions to this were the BPBS and MPLS LC and HC scenarios, in which real-time production costs were 1%–2% lower than day-ahead production costs.

3.3.2 Market Costs

Figure 15 shows total energy and reserve market costs for the Southeast region. Energy and market costs are quantities multiplied by nodal prices.[42] They are not net costs—market costs are significantly higher than production costs due to the difference between market prices and costs (inframarginal rents).[43] The market costs in Figure 15 have a similar general pattern with production costs in Figure 13, declining with higher levels of solar generation, but are more variable between coordination scenarios. They illustrate both the importance of scarcity pricing and the relative size of energy and reserve costs.

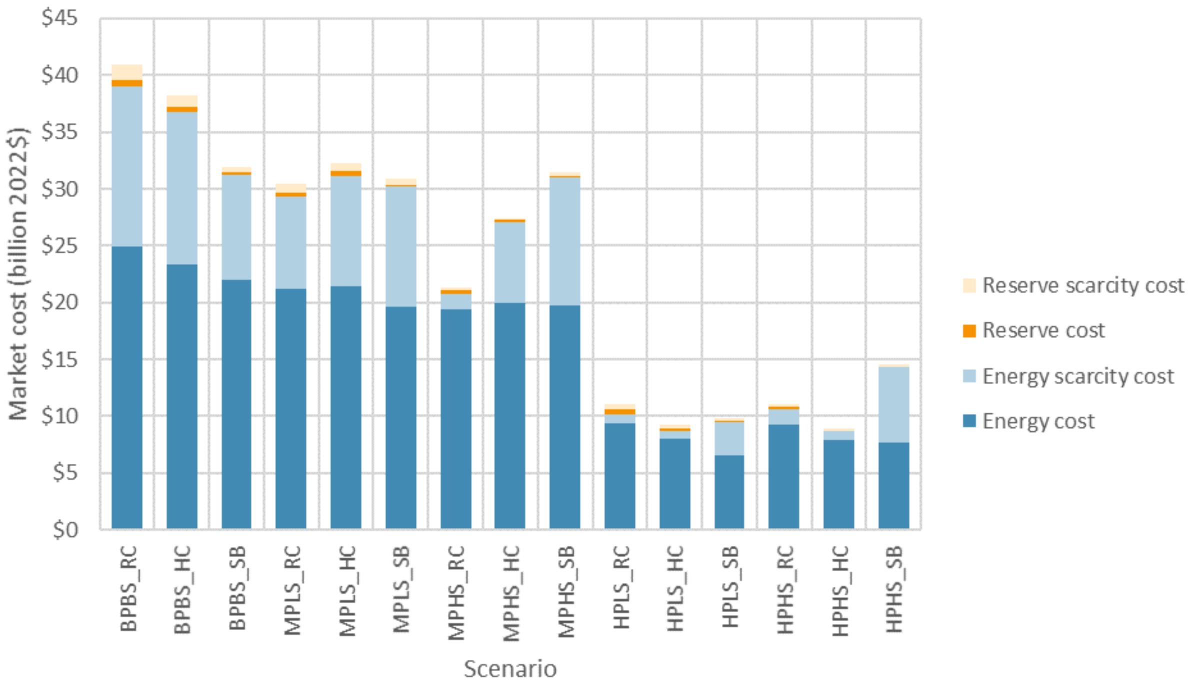


Figure 15. Market costs by cost component

Scarcity costs—defined here as energy and reserve costs at model prices over $1,000/MWh (2004$, $1,549/MWh in 2022$)—can occur either due to resource inadequacy or generator constraints. In the latter case, the system has sufficient total capacity but is unable to schedule or dispatch it to ensure that energy and reserve requirements can be met in a specific time period due to constraints like ramp

[42] For market cost calculations, we used a nodal two-settlement approach, in which the real-time cost is incremental to day-ahead cost

$$C = \sum_n \sum_t Q_{nt}^{DA} \times P_{nt}^{DA} + (Q_{nt}^{RT} - Q_{nt}^{DA}) \times P_{nt}^{RT}$$

where C is total cost or value, Q_{nt} is the quantity of supply or demand at transmission node n at time t, P_{nt} is the price at node n at time t, and the DA and RT superscripts refer to day-ahead and real-time stages. In a two-settlement system, most cost and value will typically be driven by day-ahead quantities.

[43] For instance, a utility with 500 MW of load and 600 MW of generation facing a market clearing price of $100/MWh in a given time period will have $50,000/h in costs for its load (= -500 MW × $100/MWh), $60,000/h in revenues for its generation (= +600 MW × $100/MWh), and net revenues of $10,000/h (= $60,000/h + -$50,000/h). In this case, the market costs to the utility are negative (net savings).

rates, minimum generation, startup times, or battery state-of-charge. PLEXOS co-optimizes energy and reserves, and thus energy and reserve prices in this study were interlinked. Reserve shortages that triggered reserve scarcity prices propagated to energy prices as well, triggering higher scarcity costs. Scarcity prices in one region also propagated to other regions as long as transmission capacity was available, raising scarcity costs for multiple regions.[44]

For the Southeast region, the share of scarcity costs in total costs was relatively high (27%–47%) in most scenarios, in part due to the high levels at which we set administrative scarcity prices for reserve shortfalls in PLEXOS (Section 2.4).[45] However, it does not appear from the results that higher levels of solar necessarily increase scarcity costs, and in fact, in the HP scenarios, the share of scarcity costs declined relative to the BPBS and MP scenarios.[46]

In the Southeast region, reserve costs were a relatively small share of total market costs, ranging from 1% (MPHS HC scenario) to 8% (HPLS LC scenario) of total market costs across scenarios and on par with the current share of reserve costs in ISO/RTO markets.[47] Reserve costs remained relatively low, even as the amount of reserves to manage solar and wind forecast error grew significantly in higher solar scenarios (Section 3.7.3). This was due to declining energy prices with higher levels of solar and wind, which also pulled down reserve prices. In this study, downward pressure on prices outweighed the impact of scarcity pricing.[48]

3.4 CO2 Emissions

Figure 16 shows CO_2 emissions for the Southeast region (SER), FRCC, and MISO-PJM-SPP (MPS) for each scenario. Total CO_2 emissions for the SER-FRCC-MPS region declined across scenarios. In the MPLS scenarios, total emissions declined by 13%–18% relative to the BPBS scenario and further by 31%–36% in the MPHS scenarios and 90%–91% in the HPLS and HPHS scenarios. Although we did not attempt to benchmark CO_2 emissions for this study, based on EIA estimates the BPBS scenarios likely represent a

44 Scarcity price propagation occurred either when reserve shortages in one region triggered shortages in other regions or when reserve shortages in one region could not be mitigated through imports.

45 To illustrate why very high prices in a limited number of hours can have a large impact on market costs, consider that a $2,500/MWh price in 10 hours ($25,000/MW cost) is equivalent to a $25/MWh for 1,000 hours (also $25,000/MW cost).

46 The larger share of scarcity costs in the BPBS and MPLS scenarios may be due to the higher prevalence of generator operating constraints in these scenarios, due to the fact that we left battery storage relatively unconstrained.

47 Reserve costs were 2%–5% of total market costs in the BPBS scenarios (LC, HC, and SB), 2%–4% of costs in the MPLS scenarios, 1%–2% of costs in the MPHS scenarios, 3%–8% of costs in the HPLS scenarios, and 2%–4% of costs in the HPHS scenarios. In most years, ISO/RTO ancillary services costs tend to be around 1%–3% of total market costs. See Potomac Economics (2023).

48 In principle, this means that our resource portfolio (supply) was adequate, or perhaps over-adequate, to meet demand. Reducing the planning reserve margin (15%) in ReEDS or setting a resource adequacy constraint based on regional coincident peak rather than local (noncoincident) peak would presumably have led to more system stress and more frequent scarcity prices. For reference, there was a 2% (2.7 GW) difference between the sum of noncoincident peaks for individual balancing regions and the regional coincident peak in the Southeast.

65–70% reduction in total SER-FRCC-MPS CO_2 emission relative to 2022 levels.[49] The MPLS scenarios would thus be a 70%–71% reduction in CO_2 emissions, the MPHS scenarios a 76%–78% reduction, and the HPLS and HPHS scenarios a 97% reduction relative to 2022 CO_2 emissions for the total SER-FRCC-MPS region.[50]

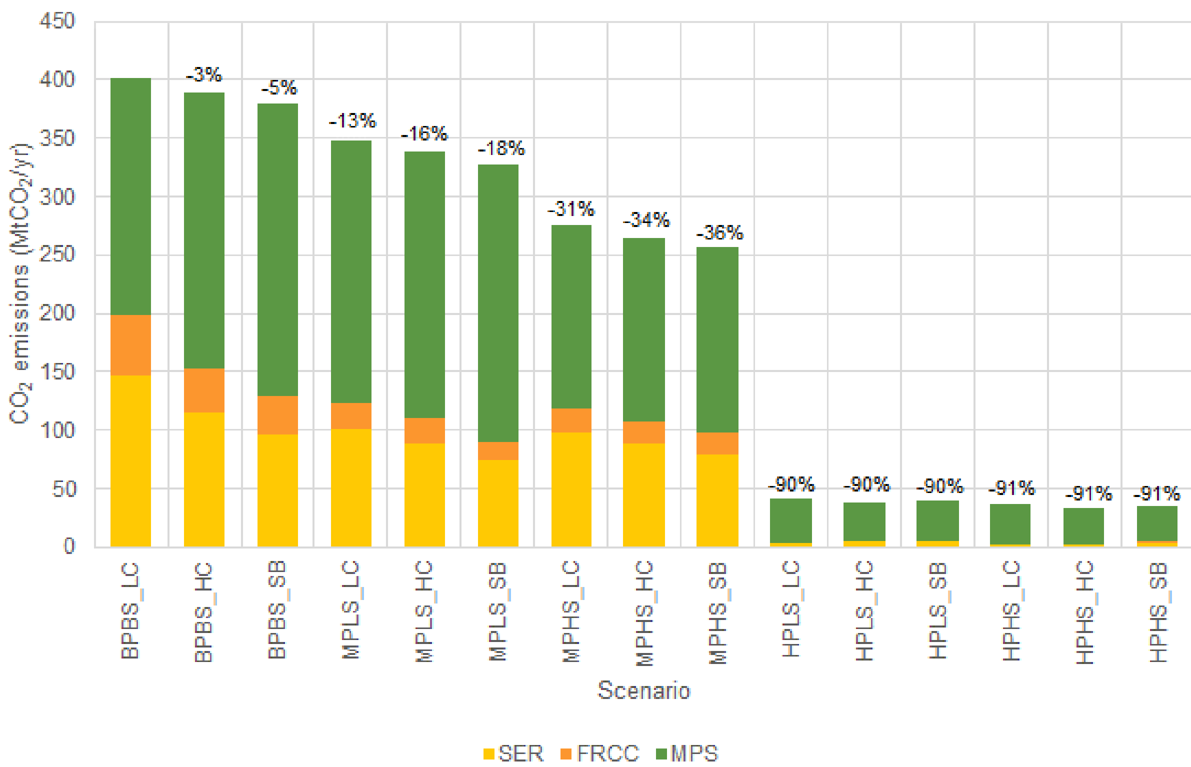


Figure 16. CO_2 emissions by region and percent change from the BPBS LC scenario

The steep drop in CO_2 emissions between the MPHS and HPLS and HPHS scenarios was mainly the result of large wind capacity additions (+156–165 GW for the SER-FRCC-MPS region) and retirement of almost all coal capacity (-60–62 GW for the SER-FRCC-MPS region) in the HPLS and HPHS scenarios relative to the MPHS scenario. As described in Section 3.1, in developing resource portfolios for the analysis we imposed a carbon tax in the HPLS and HPHS scenarios to obtain portfolios with higher shares of solar generation. The carbon tax also led to significant additional wind generation and retirement of coal generation.

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49 The U.S. EIA estimates that, in 2022, CO_2 emissions in the Midwest Reliability Organization (MRO, MISO and SPP) and Reliability First Corporation (RFC, most of PJM) NERC regions were 612 million metric tons of CO_2 ($MTCO_2$) and CO_2 emissions in the Southeast Reliability Corporation (SERC, some of PJM, Southeast region in this study, and FRCC) were 557 $MtCO_2$, implying total emissions of 1,169 $MtCO_2$ for the SER-FRCC-MPS region. CO_2 emissions in the BPBS scenarios were 380–401 $MtCO_2$. EIA data are from "Emissions by plant and by region," https://www.eia.gov/electricity/data/emissions/.

50 This total reduction in CO_2 emissions relative to 2022 will be $(1-\alpha_A)\times(1-\alpha_B)-1$, where α_A is the reduction in CO_2 emissions between the BPBS LC scenario and 2022 emissions and α_B is the reduction in emissions in a scenario relative to the BPBS LC scenario.

Higher coordination reduced total CO_2 emissions for the SER-FRCC-MPS region by 3%–7% across scenarios. However, as with production costs, higher coordination led to significant shifting of CO_2 emissions between regions. In the BPBS and MP scenarios, higher coordination led to lower emissions in SER-FRCC (decrease of 11–69 $MtCO_2$, or 9%–35%) but higher emissions in MPS (increase of 3–48 $MtCO_2$, or 1%–24%).[51] In the HP scenarios, in which CO_2 emissions were already very low, higher coordination led to higher emissions in SER-FRCC (increase of 1–4 $MtCO_2$, or 4%–210%) and lower emissions in MPS (decrease of 2–3 $MtCO_2$, or 4%–7%).[52] Regional shifting of CO_2 emissions in the BPBS and MP scenarios is likely due to changes in coal and natural gas generation (Section 3.2). The drivers behind regional shifting of emissions in the HP scenarios are not as clear. In both cases, they are part of a larger cost optimization in PLEXOS that does reduce CO_2 emissions for the SER-FRCC-MPS region as a whole.

In some cases, changes in CO_2 emissions between scenarios were nonintuitive and the result of geographic definitions or PLEXOS' region-wide optimization. For instance, CO_2 emissions in the Southeast region were higher in the MPHS SB scenario than in the MPLS SB scenario, due to higher levels of coal generation in AECI. As an additional example, CO_2 emissions were higher in the HPLS SB scenario than in the HC scenario, likely due to day-ahead hydropower curtailment and limits on hydropower re-dispatch in real-time (see Section 3.2).

3.5 Reliability

Load and reserve violations were our two primary metrics for examining the impact of higher levels of solar and storage on reliability. Changes in the nature and timing of reserve violations also provide insight into the changing nature of reliability issues with higher levels of solar and storage.

3.5.1 Load and Reserve Violations

Load and reserve violations refer to conditions in which PLEXOS sheds load or is unable to meet operating reserve requirements due to insufficient available generation. Within the Southeast region, load violations did not occur in any scenarios.[53] Table 5 and Table 6 show the frequency (count) and average (avg) and maximum (max) extent (see table notes) of reserve violations in day-ahead and real-time, respectively, for the Southeast region. Day-ahead (real-time) reserve violations occurred in less

[51] The exception to this pattern is the MPHS HC scenario, in which CO_2 emissions decline for SER, FRCC, and MPS relative to the MPHS LC scenario.

[52] In the HP scenarios, annual CO_2 emissions in SER-FRCC were only 2 $MtCO_2$ in the LC scenario and increased to 6 $MtCO_2$ in the SB scenario, which explains the large percentage increase in the text.

[53] Load violations did occur outside of the Southeast region. In real time, SPP (eastern New Mexico, p47 in ReEDS) had one to five small (< 1 MWh) load violations that occurred in almost all scenarios (except BPBS SB) and four slightly larger violations (41 MWh total) that occurred in the MPHS SB scenario. FRCC had one small load violation (< 1 MWh) in the MPLS, HPLS, and HPHS SB scenarios and three to seven larger violations (2.0–2.7 GWh total) in the HPLS and HPHS LC scenarios. All of the real-time FRCC violations occurred between 06:30 and 08:30. Half of the SPP load violations occurred between 07:00 and 10:00 but otherwise did not have a clear pattern. The frequency of day-ahead load violations was smaller, with one occurring in FRCC in the HPHS SB scenario (5 MWh) and five in FRCC in the MPLS SB scenario (147 MWh). Five of the six day-ahead violations occurred at 00:00, which may be related to day-ahead lookahead in PLEXOS. For more discussion on reliability issues in FRCC see Section 3.6.2.

than 3% (0.5%) of time intervals (hourly intervals in day-ahead and 15-minute intervals in real-time) and resulted in reserve shortages equivalent to an average of 3%–5% (0%–10%) and at most 50% (40%) of total reserves in each balancing region. Larger reserve violations (violations greater than 20% of total reserves in a time interval) were infrequent; across scenarios, they occurred in at most six time intervals in day-ahead (in the BPBS_HC scenario) and at most 14 time intervals in real time (BPBS_HC scenario).

Table 5. Day-Ahead Reserve Violations in the Southeast Region, Total Count, Average Shortage (Avg Short, % Total Reserves), and Maximum Shortage (Max Short, % Total Reserves)

	BPBS	MPLS	MPHS	HPLS	HPHS
LC	Count: 125 Avg short: 3% Max short: 18%	Count: 123 Avg short: 3% Max short: 19%	Count: 78 Avg short: 2% Max short: 11%	Count: 296 Avg short: 2% Max short: 15%	Count: 101 Avg short: 1% Max short: 5%
HC	Count: 99 Avg short: 5% Max short: 50%	Count: 114 Avg short: 3% Max short: 46%	Count: 42 Avg short: 2% Max short: 12%	Count: 236 Avg short: 1% Max short: 5%	Count: 80 Avg short: 2% Max short: 11%
SB	Count: 3 Avg short: 3% Max short: 9%	Count: 5 Avg short: 3% Max short: 5%	Count: 1 Avg short: 1% Max short: 1%	Count: 2 Avg short: 4% Max short: 6%	Count: 2 Avg short: 5% Max short: 9%

Table 6. Real-Time Reserve Violations in the Southeast Region, Total Count, Average Shortage (Avg Short, % Total Reserves), and Maximum Shortage (Max Short, % Total Reserves)

	BPBS	MPLS	MPHS	HPLS	HPHS
LC	Count: 135 Avg short: 10% Max short: 40%	Count: 92 Avg short: 10% Max short: 43%	Count: 41 Avg short: 7% Max short: 24%	Count: 144 Avg short: 3% Max short: 14%	Count: 50 Avg short: 3% Max short: 14%
HC	Count: 67 Avg short: 11% Max short: 33%	Count: 78 Avg short: 10% Max short: 38%	Count: 51 Avg short: 8% Max short: 34%	Count: 187 Avg short: 3% Max short: 17%	Count: 55 Avg short: 3% Max short: 11%
SB	Count: 28 Avg short: 2% Max share: 4%	Count: 5 Avg short: 2% Max short: 3%	Count: 6 Avg short: 1% Max short: 2%	Count: 4 Avg short: 0% Max short: 1%	Count: 5 Avg short: 1% Max short: 2%

Notes: Counts are the number of time intervals in which there is an operating (load following, contingency, regulation) reserve violation in a balancing region. This means that a balancing region that has shortages of multiple types of reserves in a time interval will have a count of 1 (rather than 1 for each reserve type) in that interval. It also means that when multiple balancing regions have reserve shortages in a time interval, each balancing region is counted toward the total count. Average reserve shortages (avg short) are the average amount of reserves lost in reserve shortage events for all balancing regions, calculated as the average of reserve shortage amount (MW) divided by total reserves (MW) in each interval for each balancing region. Maximum reserve shortages (max short) are the maximum amount of reserves lost in reserve shortage events, calculated as the maximum of reserve shortage amount divided by total reserves across all balancing regions. For the LC and HC scenarios, the balancing region will be the five individual balancing regions (AECI, DUK, LGEE, SOCO, TVA), whereas for the SB scenario, it will be the Southeast region as an aggregate. Because PLEXOS held different kinds of reserves in day-ahead and real time and because the number of time intervals in real time is four times larger than the number of intervals in day-ahead, the day-ahead (Table 5) and real-time (Table 6) reserve violation results are not comparable.

Most day-ahead and almost all real-time reserve violations in the Southeast region were for spinning contingency reserves.[54] This was expected—spinning contingency reserves had more stringent requirements than nonspinning contingency or load following reserves, and they were curtailed before regulation reserves. However, in the day-ahead time frame, there were also a significant number of shortfalls of both nonspinning contingency and nonspinning load following reserves. This was not expected. Production simulation modeling often excludes nonspinning reserves based on the assumption that constraints for these reserves will seldom, if ever, bind. In fact, however, nonspinning reserve constraints did bind and were important in our analysis of reserve sharing (Section 3.6.3).

The frequency of spinning reserve violations was significantly lower in the SB than in the LC or HC scenarios, and the SB scenarios had no nonspinning reserve violations. The main difference between the SB and the HC scenarios was the ability to share regulation and nonspinning load following reserves and the ability to hold reserves anywhere in the Southeast region. Given that reserve sharing between the SB and HC scenarios was the same, this suggests that the reduction in spinning reserve violations was due to being able to hold reserves anywhere in the region.

In the LC and HC scenarios, most day-ahead reserve violations in the Southeast region were in the AECI balancing region.[55] AECI was a relatively small balancing region (12 GW peak), and even in the BPBS scenarios onshore wind and solar generation comprised almost 90% of its generation, which means that its day-ahead operating reserve requirements were high relative to load. Reserve sharing in the HC scenarios marginally reduced the share of AECI's day-ahead reserve violations, but allowing forecast error-related reserves to be held outside of the AECI balancing region in the SB scenarios entirely resolved issues around reserve adequacy in AECI because it allowed most day-ahead reserves to be held outside of the AECI balancing region (see Figure 32 in Section 3.6.3). The AECI example illustrates that, for smaller utilities, reserves needed to manage day-ahead solar and wind forecast error can be high relative to load and available resources, requiring either large local reserves (over-building of supply) or some form of reserve sharing that allows reserves to be held outside of the utility's footprint.[56] Real-time reserve violations were more evenly spread throughout the Southeast region.[57] The next section describes potential causes behind real-time reserve violations.

The limited frequency of reserve violations in Table 5 and Table 6 suggests that, even when capacity expansion models and production simulation models are not perfectly coordinated, it is possible to develop and reliably operate portfolios with much higher levels of solar and storage—including systems that are supplied almost entirely by nonfossil energy resources (HP scenarios)—in both day-ahead and

[54] Spinning reserve violations were largest in both frequency (59%–98%) and magnitude (43%–94%).
[55] With the exception of the BPBS MC scenario, in which AECI accounted for 48% of day-ahead reserve violations, 68%–100% of day-ahead reserve violations occurred in AECI.
[56] See Hale and Zhou (2021) for an analysis of municipal utilities in Florida that had similar findings. This study suggests that reserve sharing alone may not address day-ahead reserve adequacy issues without the ability to hold reserves in other regions.
[57] In the BPBS and MP LC and HC scenarios, most (65%–95%) real-time reserve violations occurred in the DUK and LGEE balancing regions, whereas in the HP scenarios, violations were less concentrated. In all scenarios, the share of reserve violations in the SOCO balancing region was below 15%.

real-time using detailed operating constraints. Section 3.8 provides more discussion of issues around consistency between operating reserves in capacity expansion and production simulation models.

3.5.2 Reserve Violations and Operating Constraints

The nature and timing of reserve violations changed across scenarios, shifting from mostly evening hours to a broader range of evening and morning hours. For the Southeast region, in the BPBS scenarios, 64%–92% of day-ahead and real-time reserve violations occurred during 19:00–22:00, whereas in the MP scenarios, this fell to 24%–65% and in the HP scenarios fell further to 12%–31%. Figure 17 shows heat maps for total real-time reserve violations in the BPBS, MPHS, and HPHS LC scenarios, illustrating changes in the timing of reserve violations.

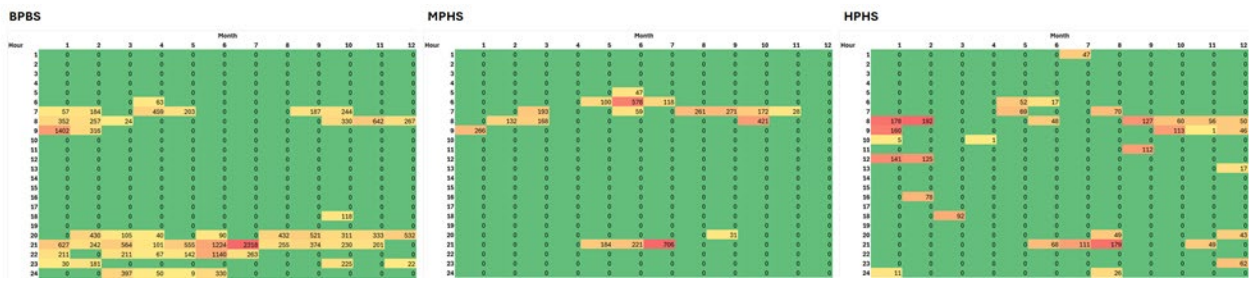


Figure 17. Heat map of total real-time reserve violations (GW-h/yr) in the BPBS, MPHS, and HPHS LC scenarios by hour (rows) and month (columns)

In electricity systems with higher levels of solar, such as in California, the window between 19:00 and 22:00 often has the highest net peak demands—demand minus solar and wind generation. During net peak in higher solar systems, solar generation ramps down and other resources must ramp up to replace it, making this a period of resource adequacy concern.[58] In this study, reserve violations occurred during the 19:00–22:00 window throughout the year, even with seasonal changes in solar generation. For the Southeast region, the 19:00–22:00 net peak window in winter and summer would likely be a new focus area for reliability concerns relative to the present. In the load data used in this study, system peaks for the different balancing regions within the Southeast region occurred in late June (SOCO, TVA) or in July (AECI, DUK, LGEE) between 15:00 and 19:00, and the coincident peak for the Southeast region occurred on June 30 at 18:00.[59]

As Figure 17 illustrates, the BPBS scenario had some reserve violations in the early morning (05:00–09:00), but the higher solar scenarios had more real-time reserve violations in this time period. In the MPHS LC and HC scenarios, 68%–70% of real-time violations occurred in this period, and 32%–50% of violations in the MPLS, HPLS, and HPHS LC and HC scenarios did. Reserve violations in this period may

[58] As a reference point, 17% of California's total electricity supply came from solar generation in 2022. Resource adequacy planning issues for net peak demand were one driver of outages in the California ISO footprint that occurred during a heat wave in August 2020 (CAISO et al., 2021). California electricity supply data is from the California Energy Commission, "2022 Total System Electric Generation," https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2022-total-system-electric-generation.

[59] See Section 2.1 for a map of the balancing regions included in this study.

have occurred for two related reasons: (1) 05:00–09:00 is part of the morning solar ramp, with large 15-minute deviations from day-ahead schedules (Section 3.6.4); (2) following low-solar days, battery storage state-of-charge was depleted by early morning, and PLEXOS did not have adequate resources online to address 15-minute imbalances.

Figure 18 and Figure 19 provide an illustration of an early morning reserve violation for the DUK balancing region, which occurred in the MPHS LC scenario on June 13 at 05:00. Figure 18 shows battery state-of-charge (SOC) for DUK from June 11 to June 15. On June 12, the DUK balancing region had low solar generation, resulting in a lower SOC relative to other days. By 01:00 on June 13, battery SOC had largely been depleted. As Figure 19 shows, PLEXOS mainly used hydropower and unloaded coal and gas capacity to provide spinning reserves during the early morning. From 04:15–04:45, PLEXOS charged batteries to provide reserves but ran out of battery SOC at 05:00 and was unable to commit a gas combustion turbine (GCT) quickly enough, resulting in a violation at 05:00. At 05:00 PLEXOS charged batteries again and had enough battery SOC to provide reserves at 05:15 and 05:30 and committed GCT resources at 05:45 to shore up reserves. In this example, the reserve violation occurred because of a lack of resources that could change output quickly enough to provide reserves on a 15-minute time interval rather than a lack of available capacity and energy resources per se.

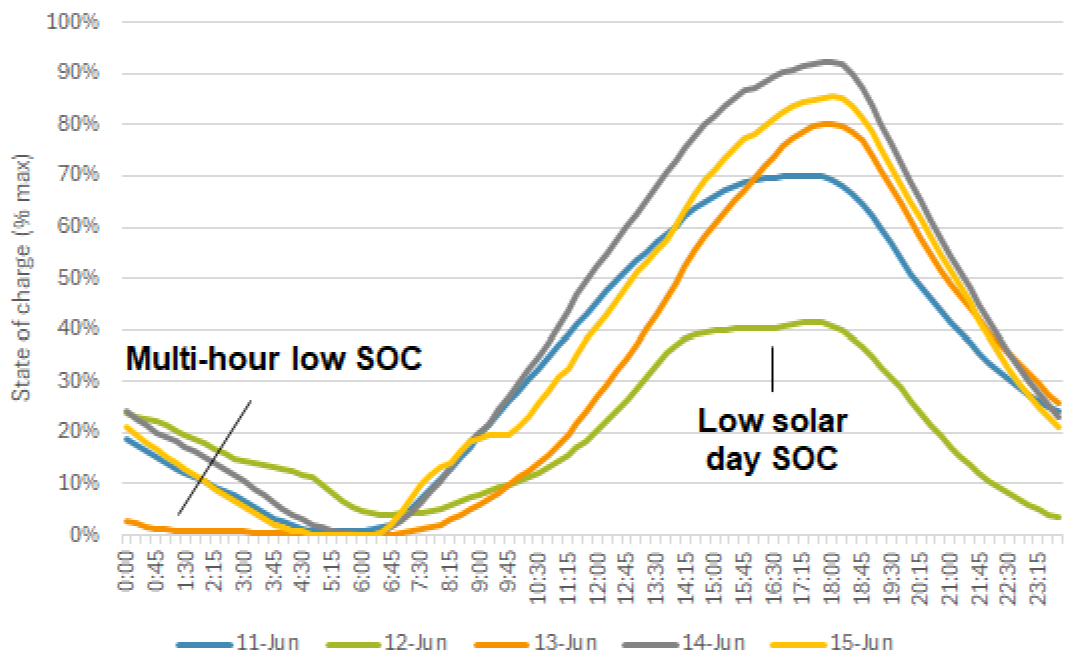


Figure 18. Total storage state-of-charge from June 11 to June 15 in DUK balancing region

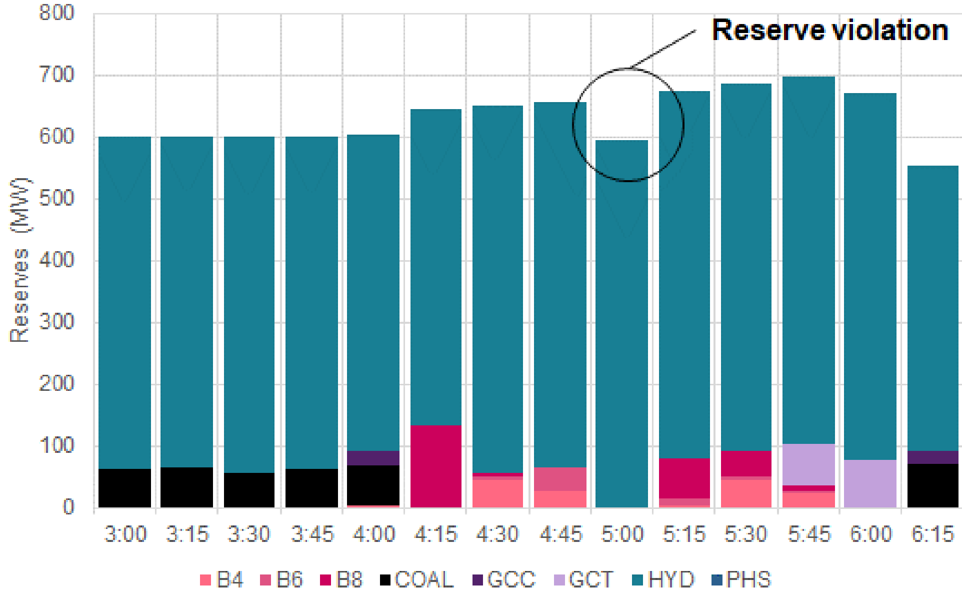


Figure 19. Reserve provision by resource during a reserve violation (05:00) in DUK balancing region on June 13

Notes: B4 is 4-hour battery storage; B6 is 6-hour battery storage; B8 is 8-hour battery storage; COAL is coal generation; GCC is combined cycle natural gas; GCT is simple cycle gas turbine; HYD is hydropower; PHS is pumped hydro storage.

In many scenarios, the largest number of real-time spinning reserve violations across the larger Southeast-FRCC-MISO-PJM-SPP region occurred in FRCC. FRCC had very high levels of solar (39%–76% of generation across scenarios) and storage—in the HPHS LC scenario, for instance, storage discharge in FRCC was on average more than 70% of load between 20:00 and 24:00. Like load violations in FRCC (Section 3.5.1), spinning reserve violations occurred almost exclusively in the morning and, interestingly, often increased with higher coordination.[60] These violations may have also been related to the interplay between solar generation and storage SOC management. The second study in this series (solar forecasting) will explore issues around solar generation, solar forecasting, storage operations, and reliability in more detail.

3.6 Operations

This section describes how higher levels of solar and storage affected electricity system operations. It covers solar, wind, and hydropower curtailment, transmission flows, reserve requirements and provision, real-time operations, storage operations, and gas operations.

[60] The only exceptions to this were the HPLS and HPHS HC scenarios, in which FRCC had a lower share of violations than in the LC scenarios. In all other scenarios, FRCC's share of spinning reserves increased with higher coordination.

3.6.1 Curtailment

Curtailment of solar, wind, and hydropower generation in the Southeast region was below 9% of available generation in the BPBS, MPLS, and MPHS scenarios but increased to 14%–20% in the HPLS and HPHS scenarios. Figure 20 shows solar, wind, and hydropower curtailment rates as a function of installed solar and wind generation capacity. Across scenarios, higher levels of storage and coordination reduced curtailment rates. In the coordination scenarios, the largest reduction in curtailment rates was between the LC and HC scenarios. Reductions between the HC and SB scenarios were significantly smaller.[61]

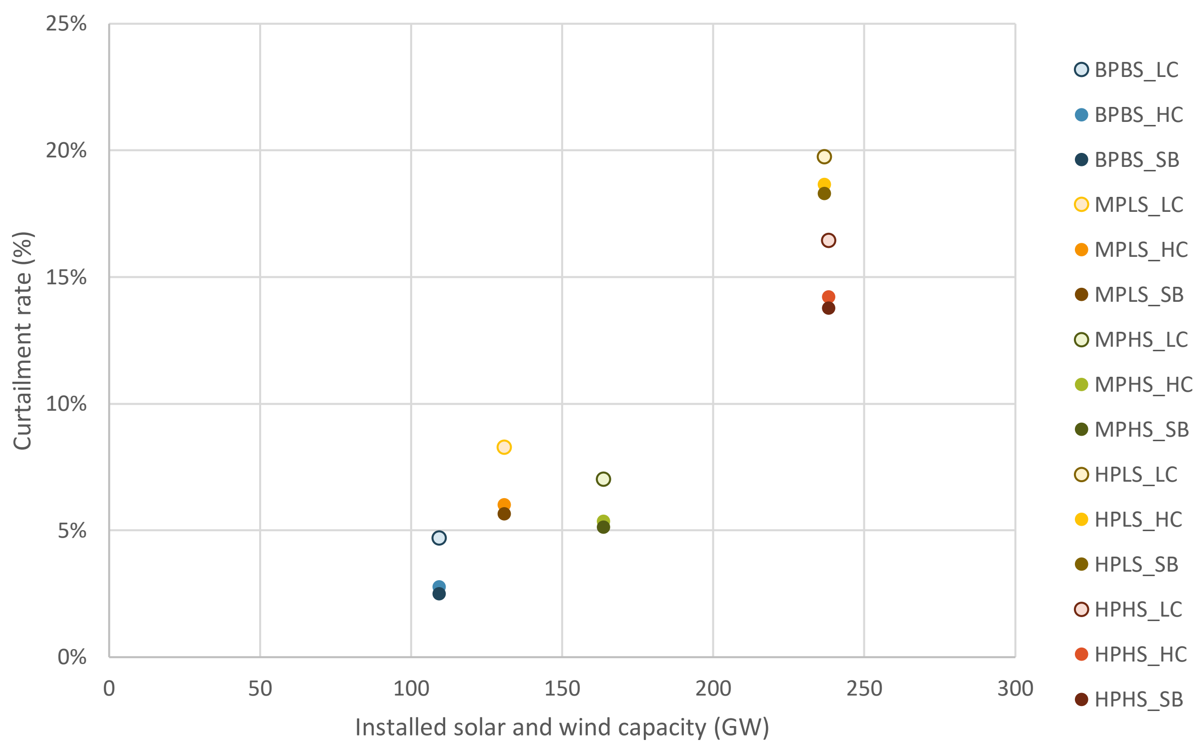


Figure 20. Curtailment rates by scenario as a function of solar and wind installed capacity

Across scenarios, more than 75% of total annual curtailment occurred during March–May (48%–61%) and September–November (19%–26%) (Table 7). Figure 21 (shares of total curtailment by hour and month) illustrates diurnal and seasonal patterns for curtailment for the lower coordination scenarios. Most curtailment occurred during daytime hours (8:00 to 17:00), though in the HPLS and HPHS scenarios an increasing share of curtailment was in the spring, fall, and winter evenings.

[61] More specifically, this suggests that the changes in assumptions between the lower and higher coordination scenarios (reduction in day-ahead [real-time] hurdle rates from $15/MWh [$8/MWh] to $8/MWh [$0/MWh], sharing of day-ahead spinning load following reserves) had a larger impact on curtailment rates than changes from the HC to SB coordination scenarios (reduction in day-ahead hurdle rates from $8/MWh to $0/MWh, $0/MWh real-time hurdle rates in both scenarios, sharing of all load following and regulation reserves, ability to hold reserves anywhere in the Southeast region).

Table 7. Shares of Total Curtailment by Month and Scenario

	Month											
Scenario	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
BPBS_LC	4%	6%	19%	28%	11%	7%	1%	1%	8%	9%	6%	1%
BPBS_HC	4%	6%	19%	32%	9%	7%	1%	1%	7%	8%	5%	1%
BPBS_SB	3%	7%	20%	32%	9%	7%	1%	1%	7%	8%	5%	1%
MPLS_LC	5%	5%	14%	23%	14%	11%	1%	1%	10%	7%	7%	1%
MPLS_HC	4%	5%	15%	26%	13%	10%	1%	1%	11%	7%	7%	1%
MPLS_SB	4%	5%	15%	27%	13%	10%	1%	1%	11%	7%	6%	1%
MPHS_LC	3%	5%	15%	29%	15%	12%	1%	1%	10%	7%	3%	0%
MPHS_HC	3%	5%	15%	28%	15%	13%	1%	1%	10%	7%	4%	0%
MPHS_SB	3%	5%	15%	29%	15%	12%	1%	1%	10%	7%	3%	0%
HPLS_LC	6%	6%	15%	20%	13%	11%	2%	2%	7%	11%	7%	2%
HPLS_HC	6%	5%	15%	21%	13%	11%	1%	1%	7%	11%	7%	2%
HPLS_SB	5%	5%	15%	21%	13%	11%	1%	1%	8%	11%	7%	2%
HPHS_LC	5%	5%	15%	23%	14%	11%	1%	1%	6%	10%	7%	2%
HPHS_HC	5%	5%	15%	25%	13%	11%	0%	1%	7%	10%	6%	1%
HPHS_SB	5%	5%	15%	26%	13%	12%	0%	0%	7%	10%	6%	1%

BPBS

Hour	Month 1	2	3	4	5	6	7	8	9	10	11	12
1	0.0%	0.0%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
2	0.0%	0.0%	0.3%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
3	0.0%	0.0%	0.3%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
4	0.0%	0.0%	0.3%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
5	0.0%	0.0%	0.3%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
6	0.0%	0.0%	0.2%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%
7	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%
8	0.0%	0.0%	0.1%	0.9%	0.8%	0.7%	0.0%	0.0%	0.3%	0.1%	0.1%	0.0%
9	0.0%	0.1%	1.0%	2.5%	1.2%	1.2%	0.0%	0.0%	1.3%	1.0%	0.2%	0.0%
10	0.2%	0.4%	1.6%	2.8%	1.3%	1.2%	0.0%	0.0%	1.3%	1.0%	0.5%	0.0%
11	0.4%	0.4%	1.7%	2.8%	1.2%	0.9%	0.0%	0.0%	1.2%	1.0%	0.5%	0.1%
12	0.5%	0.6%	2.0%	2.9%	1.2%	0.7%	0.0%	0.0%	1.0%	1.0%	0.6%	0.1%
13	0.4%	0.7%	2.0%	2.9%	1.0%	0.5%	0.0%	0.0%	0.7%	0.8%	0.4%	0.0%
14	0.2%	0.7%	1.6%	2.9%	0.9%	0.5%	0.0%	0.0%	0.4%	0.6%	0.4%	0.0%
15	0.7%	0.7%	1.8%	2.7%	0.9%	0.4%	0.0%	0.0%	0.7%	0.9%	0.9%	0.2%
16	1.0%	1.0%	2.0%	2.6%	0.8%	0.4%	0.1%	0.1%	0.7%	1.1%	1.0%	0.3%
17	0.5%	0.8%	1.8%	2.3%	0.6%	0.3%	0.1%	0.1%	0.4%	0.6%	0.4%	0.1%
18	0.1%	0.2%	0.7%	1.0%	0.4%	0.2%	0.1%	0.1%	0.2%	0.2%	0.1%	0.0%
19	0.0%	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%
20	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
21	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
23	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
24	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%

MPLS

Hour	Month 1	2	3	4	5	6	7	8	9	10	11	12
1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
7	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
8	0.0%	0.0%	0.1%	0.7%	0.9%	1.1%	0.1%	0.0%	0.3%	0.1%	0.0%	0.0%
9	0.0%	0.1%	0.8%	2.1%	1.8%	1.6%	0.2%	0.2%	1.4%	0.8%	0.3%	0.0%
10	0.3%	0.4%	1.5%	2.7%	2.1%	1.6%	0.2%	0.2%	1.5%	1.0%	0.6%	0.0%
11	0.4%	0.5%	1.6%	2.5%	1.9%	1.5%	0.1%	0.2%	1.4%	0.9%	0.9%	0.0%
12	0.6%	0.7%	1.8%	2.4%	1.6%	1.1%	0.0%	0.1%	1.3%	0.9%	0.9%	0.1%
13	0.6%	0.7%	1.7%	2.5%	1.5%	1.0%	0.0%	0.0%	1.0%	0.8%	0.7%	0.0%
14	0.4%	0.6%	1.4%	2.6%	1.2%	0.9%	0.0%	0.0%	0.8%	0.6%	0.6%	0.0%
15	0.8%	0.7%	1.4%	2.3%	1.1%	0.7%	0.0%	0.0%	0.8%	0.8%	1.2%	0.2%
16	1.0%	0.9%	1.6%	2.0%	1.0%	0.6%	0.0%	0.1%	0.8%	0.9%	1.4%	0.2%
17	0.4%	0.7%	1.3%	1.8%	0.7%	0.4%	0.1%	0.1%	0.5%	0.4%	0.3%	0.1%
18	0.1%	0.2%	0.4%	0.8%	0.4%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%
19	0.0%	0.0%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
20	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
21	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
23	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
24	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

MPHS

Hour	Month 1	2	3	4	5	6	7	8	9	10	11	12
1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
7	0.0%	0.0%	0.0%	0.0%	0.2%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
8	0.0%	0.0%	0.1%	0.7%	0.9%	1.0%	0.0%	0.0%	0.2%	0.1%	0.0%	0.0%
9	0.0%	0.1%	0.7%	2.5%	1.9%	1.9%	0.1%	0.1%	1.2%	0.8%	0.2%	0.0%
10	0.2%	0.4%	1.7%	3.3%	2.4%	2.1%	0.1%	0.1%	1.5%	1.0%	0.4%	0.0%
11	0.3%	0.4%	1.7%	3.0%	2.0%	1.8%	0.1%	0.1%	1.3%	0.8%	0.4%	0.0%
12	0.3%	0.5%	1.6%	2.6%	1.7%	1.3%	0.1%	0.1%	1.2%	0.9%	0.5%	0.0%
13	0.4%	0.5%	1.6%	2.7%	1.6%	1.3%	0.0%	0.1%	1.0%	0.9%	0.5%	0.0%
14	0.3%	0.6%	1.6%	3.0%	1.5%	1.0%	0.0%	0.0%	0.8%	0.7%	0.3%	0.0%
15	0.5%	0.6%	1.3%	2.4%	1.0%	0.8%	0.0%	0.0%	0.6%	0.7%	0.9%	0.1%
16	0.9%	0.8%	1.4%	2.3%	0.9%	0.7%	0.1%	0.1%	0.7%	0.9%	1.0%	0.2%
17	0.4%	0.6%	1.3%	2.1%	1.0%	0.7%	0.1%	0.1%	0.5%	0.5%	0.2%	0.1%
18	0.1%	0.1%	0.5%	1.0%	0.6%	0.4%	0.1%	0.1%	0.2%	0.1%	0.0%	0.0%
19	0.0%	0.0%	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
20	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
21	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
23	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
24	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

HPLS

Hour	Month 1	2	3	4	5	6	7	8	9	10	11	12
1	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%
2	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%
3	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%
4	0.1%	0.0%	0.1%	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
5	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
6	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
7	0.1%	0.0%	0.1%	0.2%	0.2%	0.2%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%
8	0.0%	0.0%	0.3%	0.9%	0.9%	0.8%	0.1%	0.1%	0.3%	0.3%	0.1%	0.0%
9	0.1%	0.2%	1.0%	1.7%	1.4%	1.3%	0.2%	0.2%	0.8%	0.9%	0.5%	0.1%
10	0.5%	0.5%	1.6%	2.0%	1.5%	1.4%	0.3%	0.3%	1.0%	1.3%	0.9%	0.2%
11	0.6%	0.6%	1.8%	2.1%	1.5%	1.2%	0.2%	0.3%	0.9%	1.2%	0.8%	0.2%
12	0.5%	0.5%	1.7%	2.1%	1.3%	1.1%	0.2%	0.2%	0.9%	1.1%	0.7%	0.2%
13	0.5%	0.6%	1.6%	1.9%	1.1%	0.9%	0.2%	0.2%	0.7%	1.1%	0.7%	0.2%
14	0.6%	0.6%	1.6%	1.9%	1.0%	0.8%	0.1%	0.1%	0.6%	1.0%	0.8%	0.2%
15	0.7%	0.7%	1.5%	1.9%	0.9%	0.7%	0.0%	0.1%	0.5%	1.0%	0.8%	0.2%
16	0.7%	0.6%	1.4%	1.8%	0.9%	0.7%	0.1%	0.1%	0.6%	0.8%	0.7%	0.2%
17	0.3%	0.5%	1.1%	1.4%	0.6%	0.5%	0.1%	0.1%	0.4%	0.5%	0.2%	0.1%
18	0.1%	0.1%	0.4%	0.7%	0.3%	0.2%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%
19	0.0%	0.1%	0.1%	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%
20	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%
21	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
22	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
23	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
24	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%

HPHS

Hour	Month 1	2	3	4	5	6	7	8	9	10	11	12
1	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
2	0.1%	0.0%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
3	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
4	0.1%	0.0%	0.1%	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
5	0.1%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
6	0.1%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
7	0.0%	0.0%	0.1%	0.2%	0.3%	0.3%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%
8	0.0%	0.0%	0.3%	1.1%	1.1%	1.0%	0.0%	0.0%	0.2%	0.2%	0.1%	0.0%
9	0.1%	0.2%	1.1%	2.1%	1.6%	1.5%	0.1%	0.2%	0.8%	0.9%	0.5%	0.0%
10	0.5%	0.5%	1.9%	2.4%	1.9%	1.5%	0.1%	0.2%	1.0%	1.3%	0.9%	0.2%
11	0.5%	0.6%	2.0%	2.6%	1.7%	1.4%	0.0%	0.1%	0.9%	1.2%	0.8%	0.2%
12	0.5%	0.4%	1.7%	2.5%	1.6%	1.3%	0.0%	0.1%	0.8%	1.0%	0.6%	0.2%
13	0.5%	0.5%	1.7%	2.3%	1.3%	1.0%	0.0%	0.1%	0.7%	1.0%	0.7%	0.1%
14	0.6%	0.5%	1.6%	2.1%	1.1%	0.8%	0.0%	0.1%	0.5%	1.0%	0.8%	0.2%
15	0.6%	0.6%	1.4%	2.1%	0.9%	0.7%	0.0%	0.0%	0.4%	0.8%	0.7%	0.2%
16	0.6%	0.5%	1.2%	2.2%	0.9%	0.7%	0.0%	0.1%	0.5%	0.7%	0.6%	0.2%
17	0.3%	0.4%	1.0%	1.5%	0.5%	0.4%	0.0%	0.1%	0.3%	0.4%	0.2%	0.1%
18	0.1%	0.1%	0.4%	0.7%	0.2%	0.2%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%
19	0.0%	0.0%	0.1%	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
20	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%
21	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
22	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
23	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%
24	0.0%	0.0%	0.1%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%

Figure 21. Curtailment rates by hour, month, and resource scenario for lower-coordination scenarios

In the BPBS, MPLS, and MPHS scenarios, most (56% to 76%) curtailment occurred in 500 hours (6% of the year) (Figure 22). In the HPLS and HPHS scenarios, curtailment was less concentrated in time; 37% to 50% of curtailment occurred in the top 500 curtailment hours, but most (61% to 76%) occurred in the top 1,000 hours. Higher levels of storage (HS scenarios) and coordination (HC and SB scenarios) bend the curtailment duration curves inward but have less impact on curtailment in the highest curtailment hours.

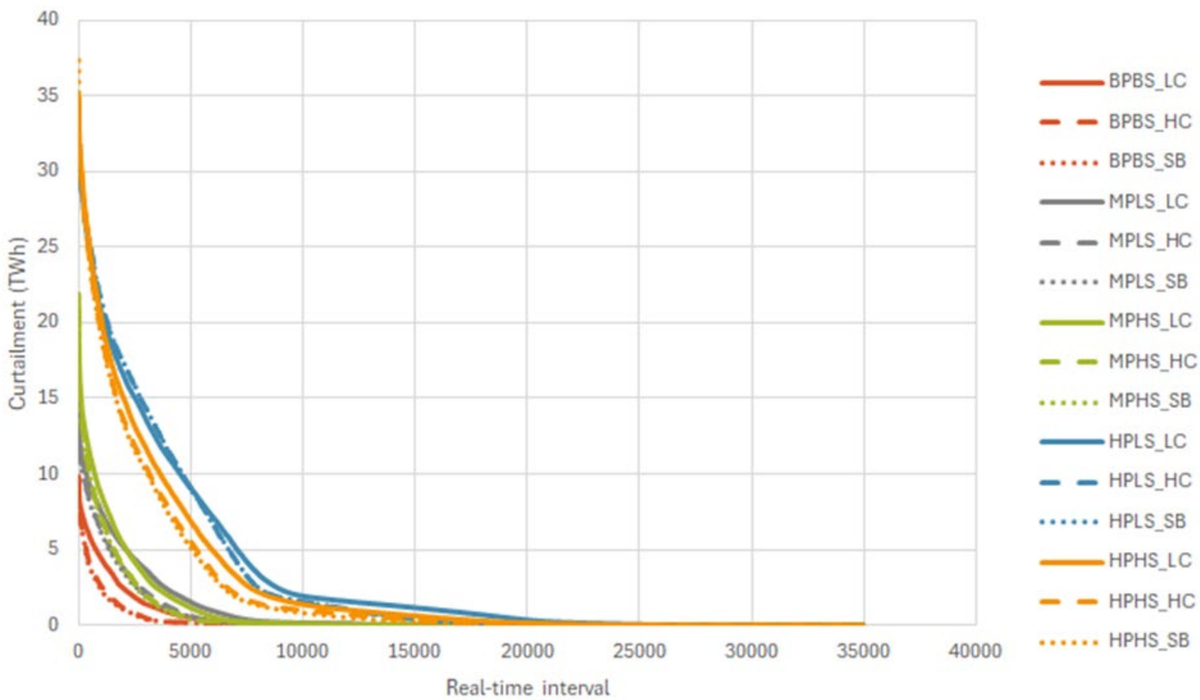


Figure 22. Curtailment duration curves by scenario

The magnitude, timing, and concentration of solar, wind, and hydro curtailment in this study is consistent with other studies and other regions.[62] The concentration of curtailment in a relatively small number of hours in the spring and fall suggests that a large driver of curtailment was the mismatch between sizing resources to meet summer peak demand and lower demand in spring and fall months. This mismatch, and the presence of large-scale economic curtailment, has important implications for procurement and structuring contracts. In many ways, these issues around sizing are not dissimilar from those related to natural gas combustion turbines and other seasonal resources.

3.6.2 Transmission Flows

The production simulation modeling included many transmission connections within and between balancing regions (see Section 3.1 for an overview of transmission expansion in this study). To simplify, we aggregated these to a regional level in reporting the results. 'Intraregional' refers to transmission flows within the Southeast region. 'Inter-regional' refers to transmission flows between the Southeast region and its neighbors. 'Total interchange' or 'total transfer' refers to the total transfer of power between regions, in both directions. 'Net interchange' or 'net transfers' refer to the net transfer of power between regions.[63]

[62] See, for instance, Brinkman et al. (2021).

[63] For instance, if flows from region A to region B were 50 TWh and flows from region B to region A were 25 TWh, the total transfer would be 75 TWh and the net transfer would be 25 TWh in the A to B direction.

Higher levels of coordination (HC, SB scenarios) led to a large increase in total transfers both within the Southeast region (intraregional) and between the Southeast region and neighboring regions (inter-regional) (Figure 23). This increase in transfers was primarily due to re-dispatch of natural gas and coal generation, taking advantage of lower fuel costs (see Section 3.2.1). In the HC and SB scenarios, total annual energy transfers decreased as more solar and storage capacity were added in the MP and HP scenarios, whereas in the LC scenarios, total transfers remained relatively constant across solar and storage scenarios. While intraregional and inter-regional transfers were of similar magnitude in the LC scenarios, inter-regional transfers were larger than intraregional transfers in the HC and SB scenarios even though intraregional and inter-regional hurdle rates were the same. Intuitively, this result may have been due to more energy resource complementarity among more distant regions, though we did not attempt to prove that this was the case.

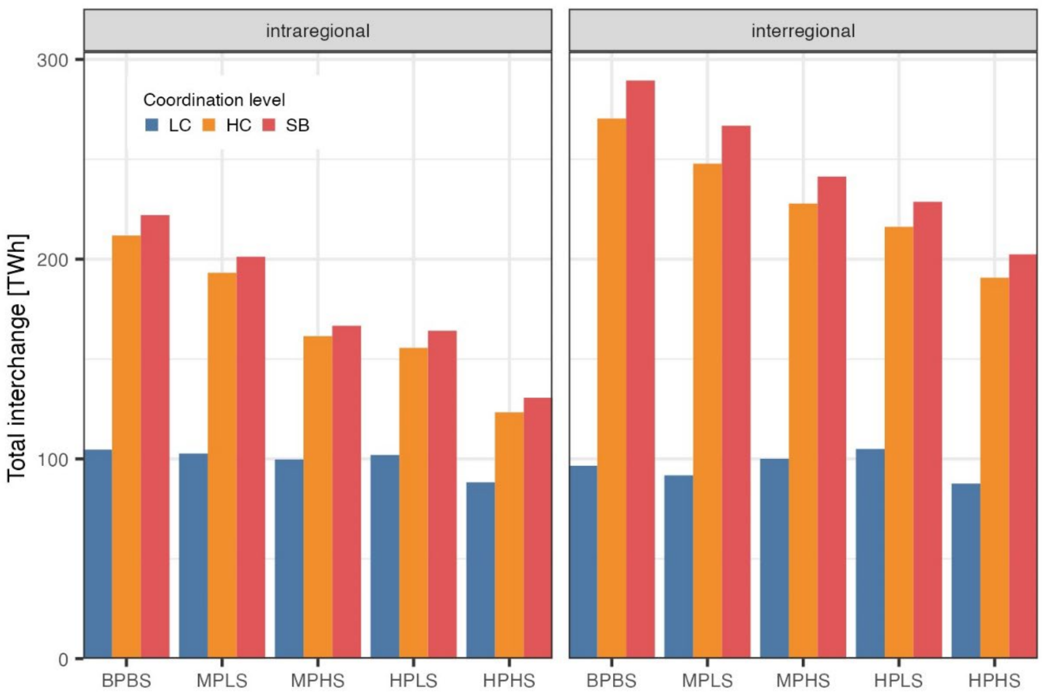


Figure 23. Total intraregional and inter-regional interchange by resource and coordination scenario

Transmission flows increased region-wide in the HC and SB scenarios relative to the LC scenarios, with particularly large increases between the Southeast region and MISO (MISO-TVA interface), the Southeast and PJM (PJM-DUK interface), and the Southeast and FRCC (SOCO-FRCC interface).[64] As an illustration, Figure 24 shows the topography and magnitude of gross transmission flows in the BPBS and HPHS LC and SB scenarios. Changes in flows were consistent with the location of large centers of electricity demand (DUK, SOCO, FRCC). Figure 24 also illustrates that transmission flows declined with higher levels of solar (HPHS vis-à-vis BPBS in this case) but the topography of transmission flows did not significantly change.

[64] PLEXOS includes transmission losses that vary according to distance and voltage level.

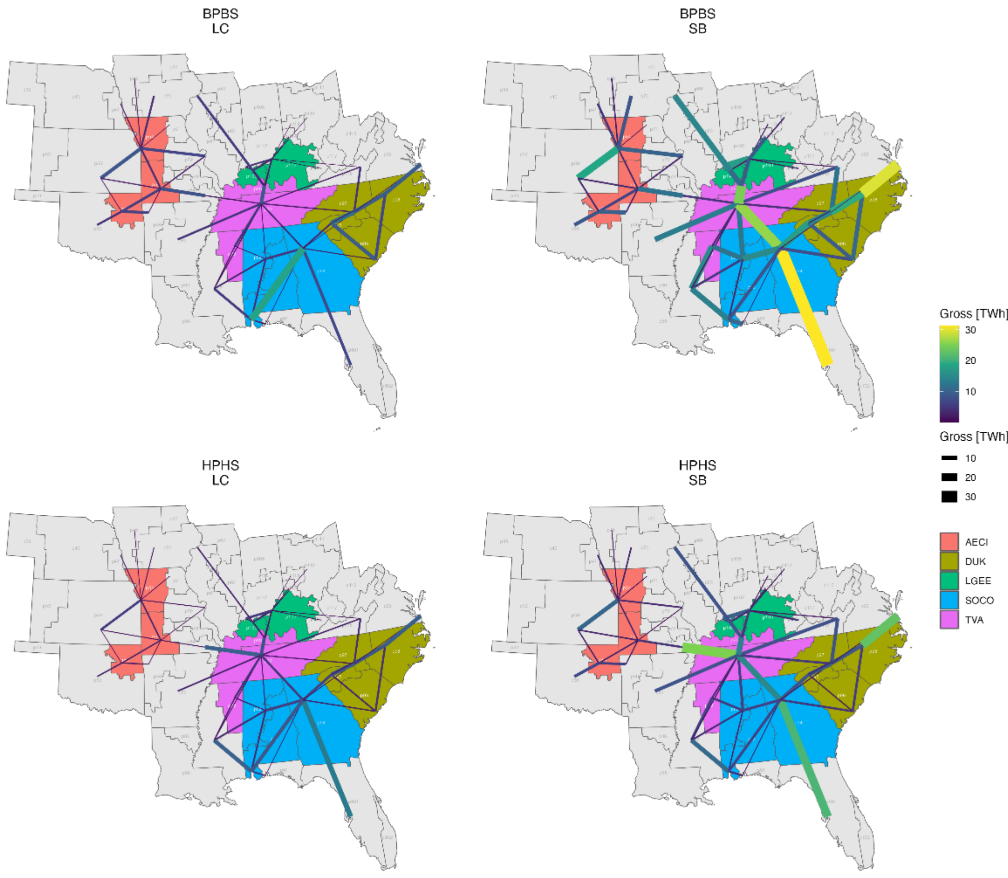


Figure 24. Gross transmission flows, BPBS and HPHS LC and SB scenarios

Figure 25 shows transfers to and from the Southeast region, as well as net transfers. Changes in transmission flows in the HC scenarios (relative to the LC scenarios) were much larger than those in the SB scenarios (relative to the HC scenarios). In the HC scenario, higher levels of imports and exports were driven mainly by differences in real-time hurdle rates (real-time dispatch), whereas in the SB scenarios, they were driven by differences in day-ahead hurdle rates (day-ahead commitment and scheduling). In the BPBS, MPLS, and MPHS LC scenarios, the Southeast region was a small net energy importer but became a larger net importer (black diamonds in Figure 25) in the HPLS and HPHS LC scenarios due to winter imports (Section 3.2.3). In the HC and SB scenarios, net imports to the Southeast region increased significantly, though higher levels of solar tended to decrease net imports within a coordination scenario.[65] In the HPLS and HPHS scenarios, differences in net imports across coordination scenarios were relatively small.

[65] The exception to this pattern was the HPLS scenario, which may have been due to lower storage capacity relative to the HPHS scenario.

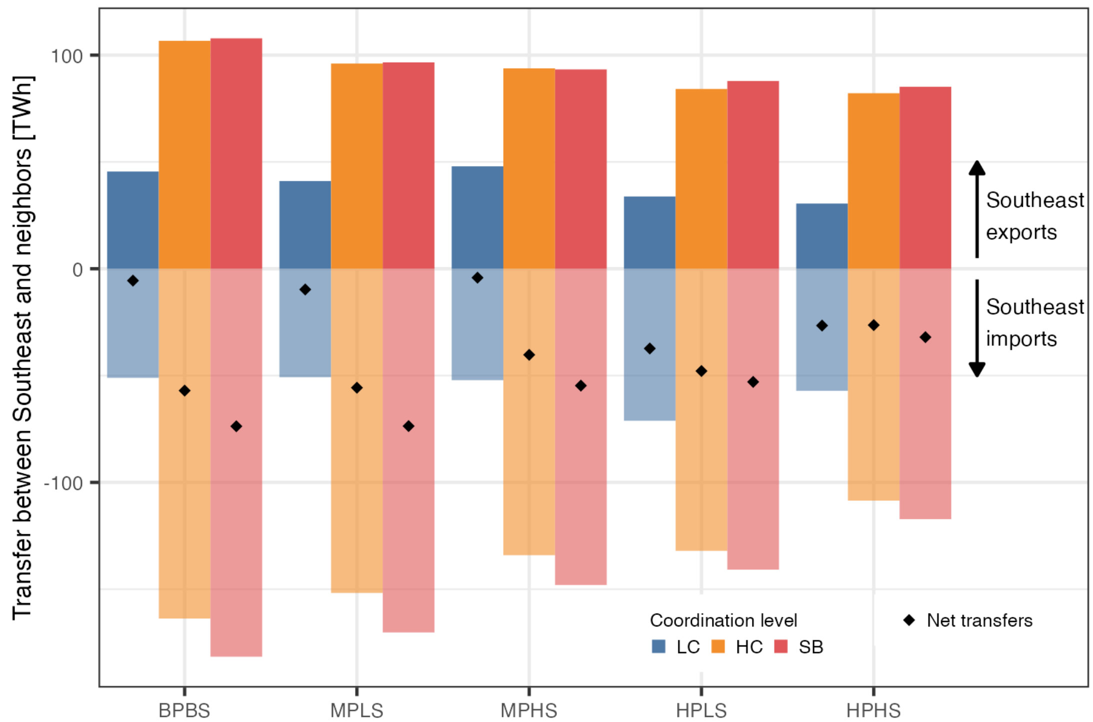


Figure 25. Transfers between the Southeast region and neighboring regions by resource and coordination scenario

Figure 26 shows transmission flow duration curves for each resource and coordination scenario (positive numbers are exports, negative numbers are imports). Higher levels of solar reduced the utilization of transmission infrastructure, with "peakier" transmission flows in the MP and HP scenarios relative to the BPBS scenario. More than half of interfaces within the Southeast region and between the Southeast region and its neighbors were used at maximum capacity at least once during the year. In all resource scenarios, higher coordination (HC and SB scenarios) shifted most of the duration curve downward (higher imports) but did not significantly change maximum export levels.

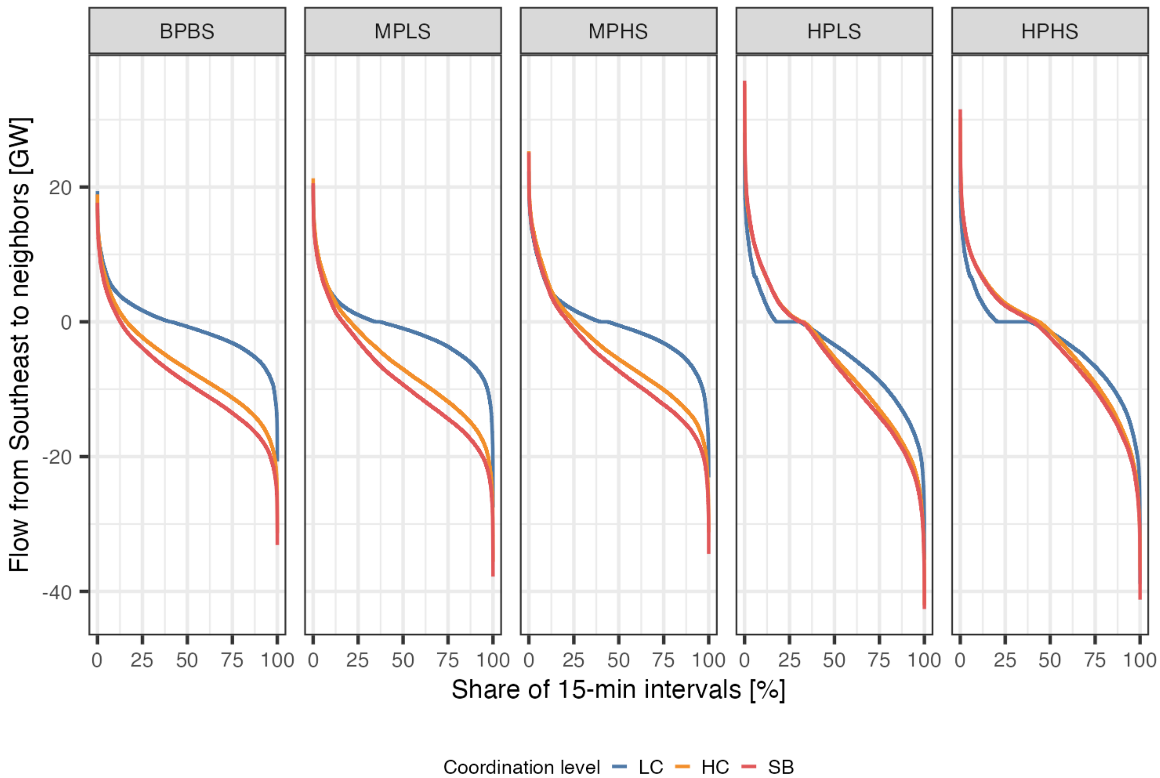


Figure 26. Transmission flow duration curves between the Southeast region and neighboring regions

Figure 27 and Figure 28 show the highest (top 5% of real-time intervals) net exports from and net imports to the Southeast region by hour and season. The highest net exports tended to be concentrated in the morning solar ramp in the summer and spring and in the evening solar ramp in the fall and winter (BPBS and MP scenarios), but in the HP scenarios they were concentrated in the morning solar ramp. The highest net imports were more evenly distributed in the BPBS and MP scenarios but were mainly in winter evening hours in the HP scenarios.

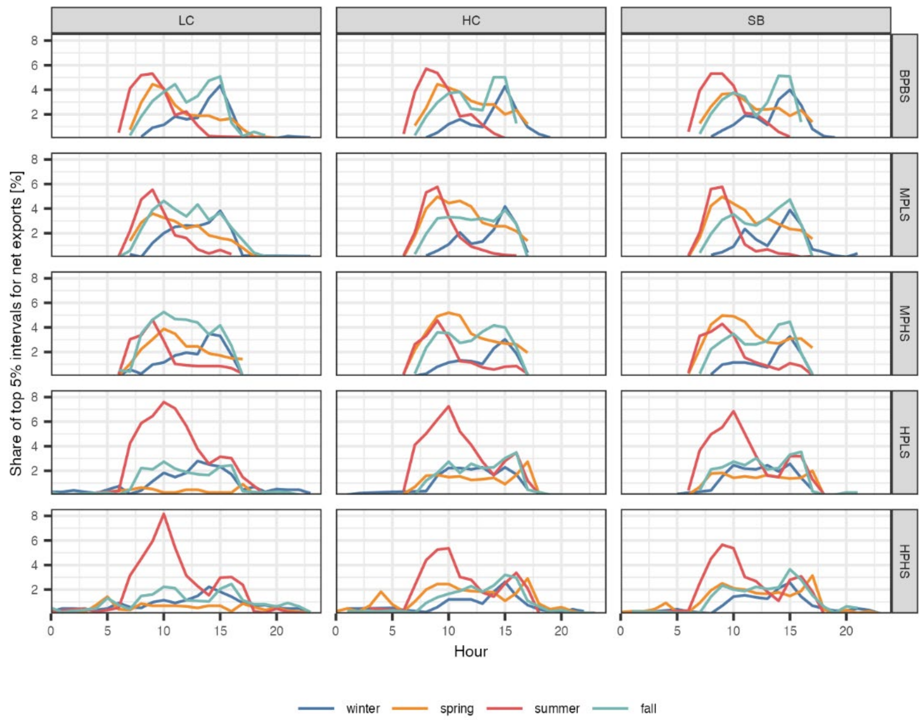


Figure 27. Top 5% of net export (Southeast region to neighboring regions) intervals by hour, season, and scenario

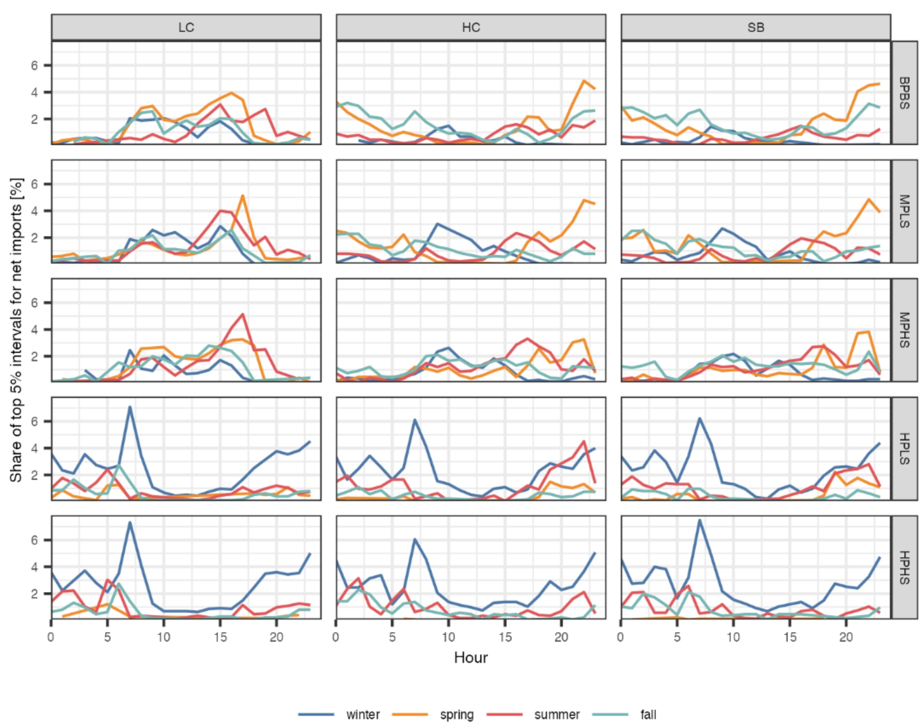


Figure 28. Top 5% of net import (Southeast region from neighboring regions) intervals by hour, season, and scenario

Figure 29 shows daily average net transmission flows to (imports, negative number) and from (exports, positive number) the Southeast region by season for the SB scenario throughout the year, rather than for just the highest flow hours as in Figure 27 and Figure 28. In all seasons, net exports from the region were concentrated in solar hours, whereas net imports to the region were concentrated in evening hours.

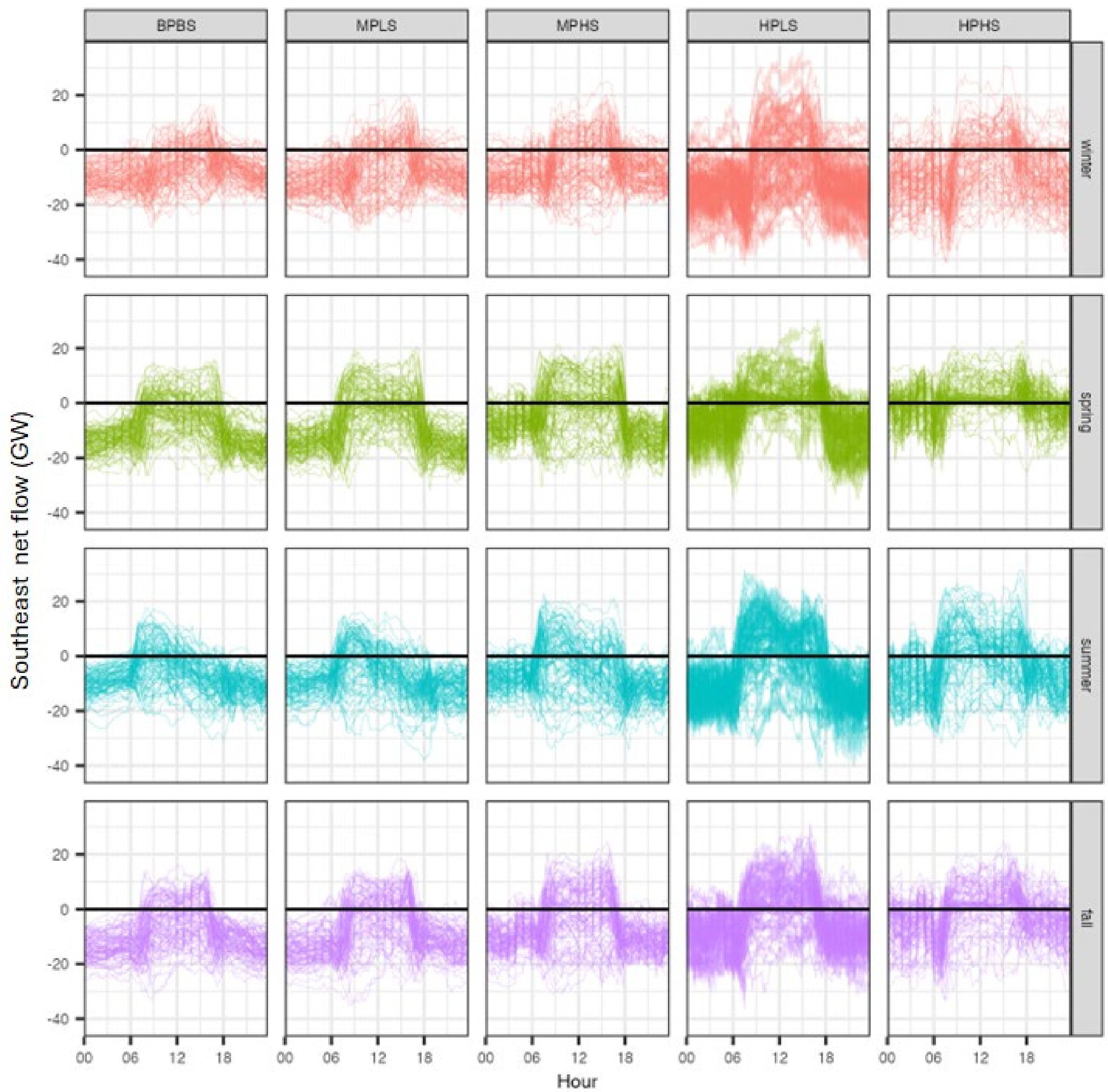


Figure 29. Average daily net transmission flows between the Southeast region and neighboring regions by hour, season, and resource scenario in the SB scenario

3.6.3 Reserve Requirements and Provision

Higher levels of solar and wind generation significantly increased day-ahead reserve requirements in the Southeast region, from 19% of average load in the BPBS LC scenario to 31% of average load in the HPHS LC scenario. As Figure 30 shows (red line), increases in reserves to manage solar and wind forecast error were approximately linear with solar and wind generation capacity (6%–10% of capacity across scenarios). In real-time, solar and wind forecast errors were only held to deal with short-term (15-minute-ahead, 15-minute interval) forecast errors. As a result, real-time reserve requirements were much lower than—generally less than half of—day-ahead reserve requirements (Figure 31).

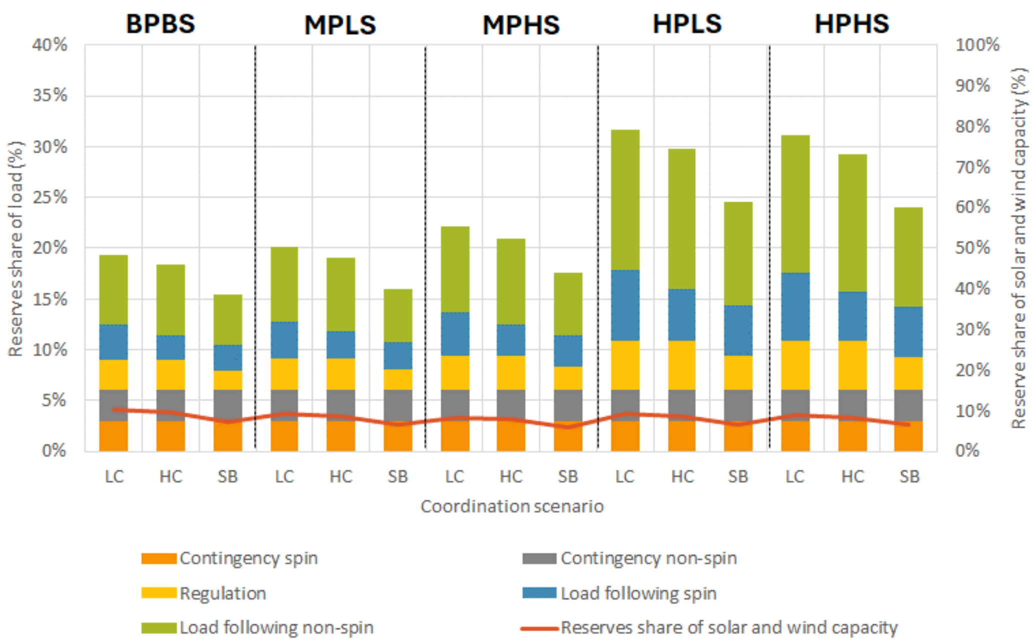


Figure 30. Average day-ahead reserves as share of average load by reserve category, and total forecast error-related reserves as a share of solar and wind generation capacity

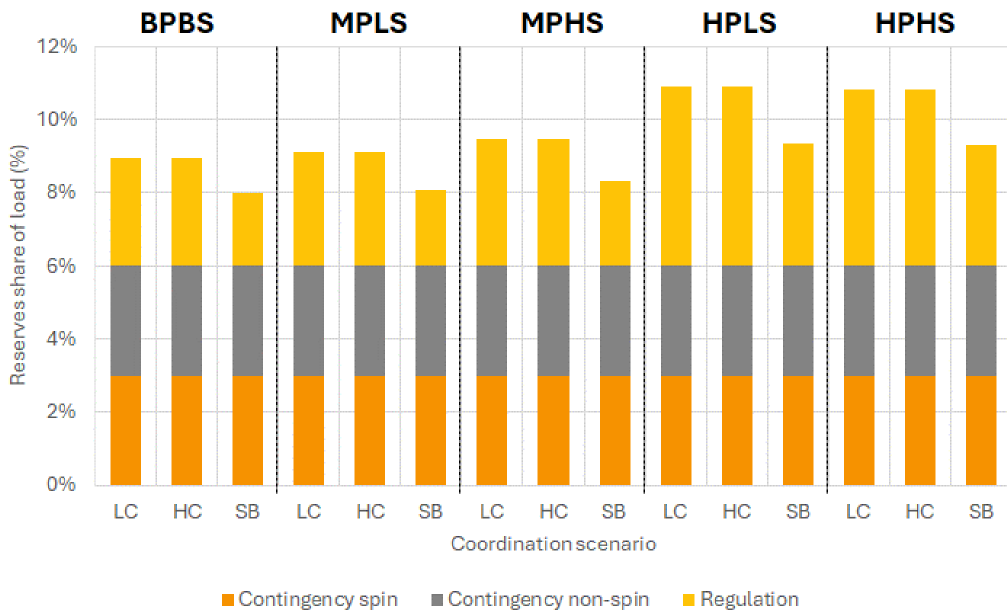


Figure 31. Average real-time reserves as a share of average load by reserve category

As Figure 30 shows, reserve sharing in the day-ahead HC and SB scenarios significantly reduced reserve requirements for the Southeast region, with more reserve savings at higher levels of solar. For instance, in the BPBS scenario, reserve requirements fell from 19% of average load in the LC scenario to 18% in the HC scenario and 16% in the SB scenario. In the HPHS scenario, they fell from 31% to 29% and 24%, respectively. Each percentage point reduction in reserve requirements as share of average load was equivalent to roughly 850 MW of reserves in all scenarios.[66] The largest reductions in reserve requirements were due to sharing of nonspinning load following reserves, which were held to manage larger, less frequently occurring solar and wind forecast errors. Reductions in real-time reserves from regulation reserve sharing in the SB scenarios, at around 1% to 2% of load, were significantly lower than those in day-ahead reserves.

We used modeled prices and a two-settlement approach (Section 3.3.2) to estimate the total reduction in reserve costs from sharing reserves in the Southeast region. In the HC scenarios, total reserve costs were $90 million ($0.12/MWh of load, MPLS scenario) to $474 million ($0.64/MWh, BPBS scenario) per year lower than the LC scenarios. In the SB scenarios, total reserve costs were $160 million ($0.21/MWh, MPHS scenario) to $1,244 million ($1.68/MWh, BPBS scenario) per year lower than the LC scenarios. In general, cost reductions from reserve sharing in the MP and HP scenarios declined in absolute terms relative to the BPBS scenario due to lower modeled energy and reserve prices. Cost savings from sharing nonspinning load following reserves (SB scenarios) unexpectedly accounted for a large share of cost savings.[67]

[66] In all scenarios, average load for the Southeast region was 84,990 MW.

[67] For more on this result and more detail on reserve sharing for solar and wind forecast errors in this study, see Kahrl et al. (forthcoming).

In the SB scenarios, we allowed PLEXOS to hold reserves anywhere in the Southeast region. This often led to significant changes in the location of reserves (Figure 32). In most scenarios, reserves shifted from other balancing regions to the SOCO balancing region. After examining changes in reserve capacity mix across different balancing regions, it was not clear why these changes occurred. The shifting of reserves from AECI to other regions in the SB scenarios, described earlier, is consistent across all resource scenarios.

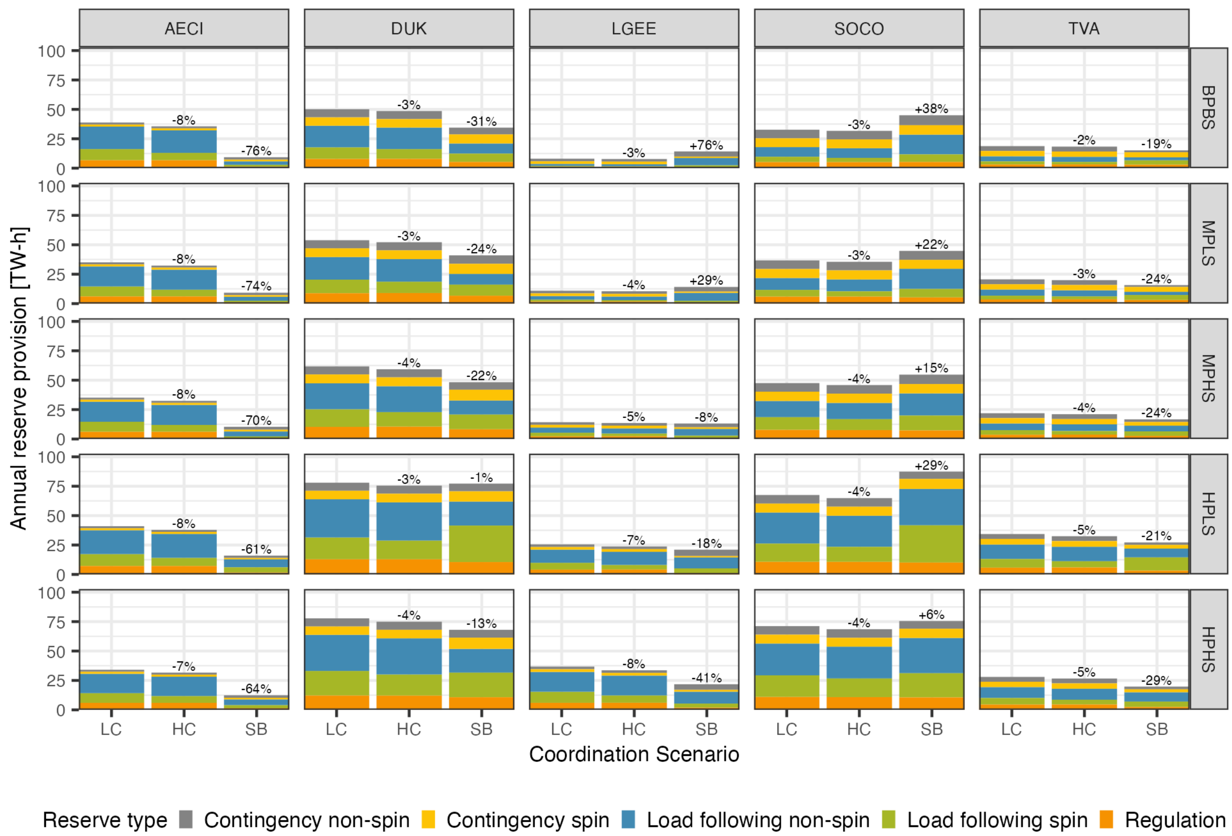


Figure 32. Reserves held in different southeast balancing regions by reserve type and scenario

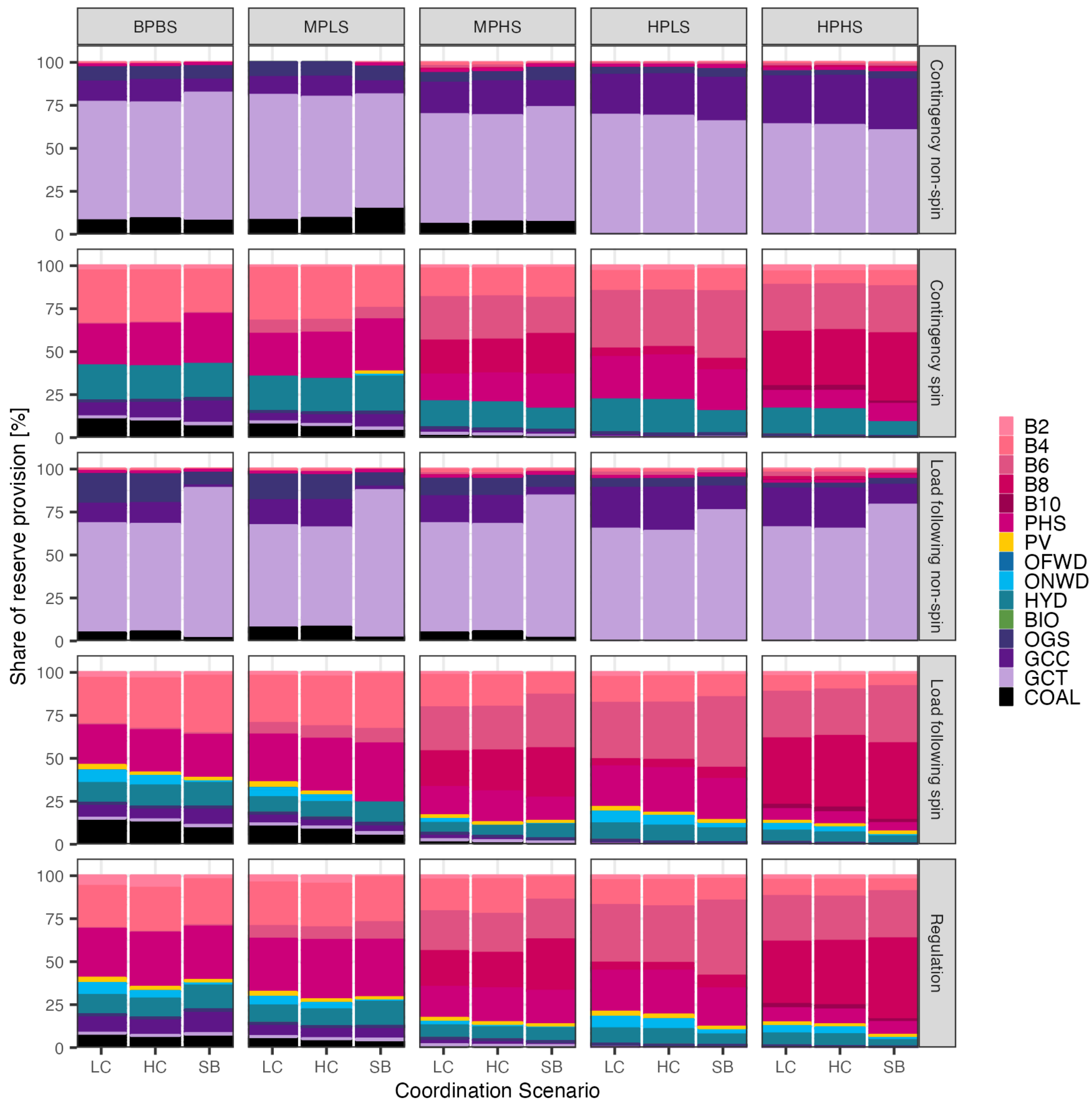
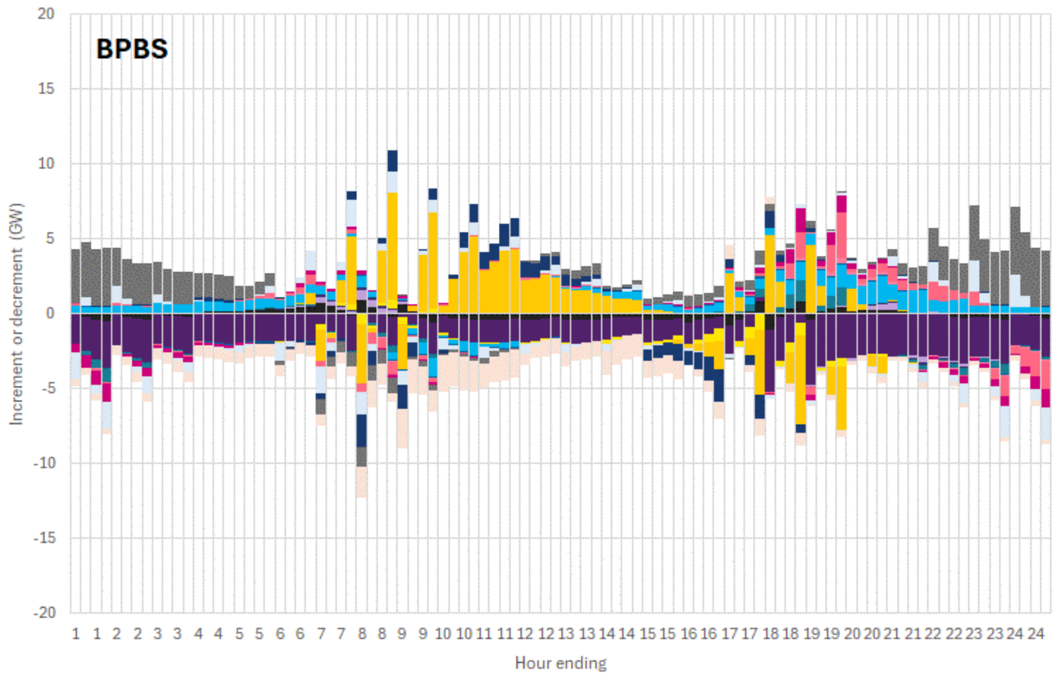


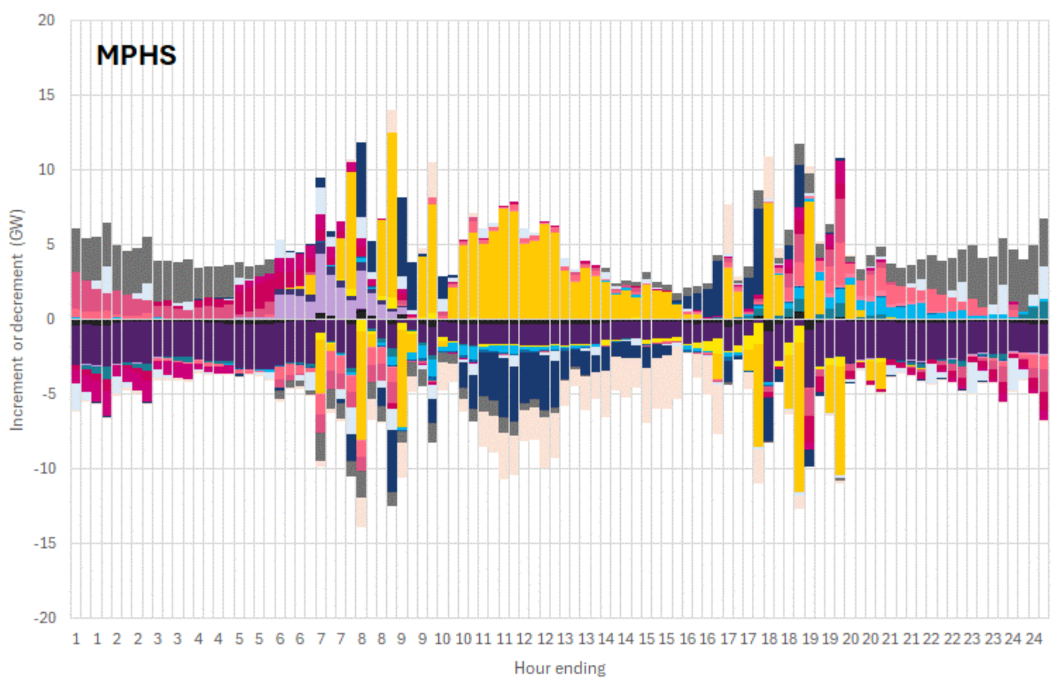
Figure 33. Reserve provision by reserve and technology type by scenario

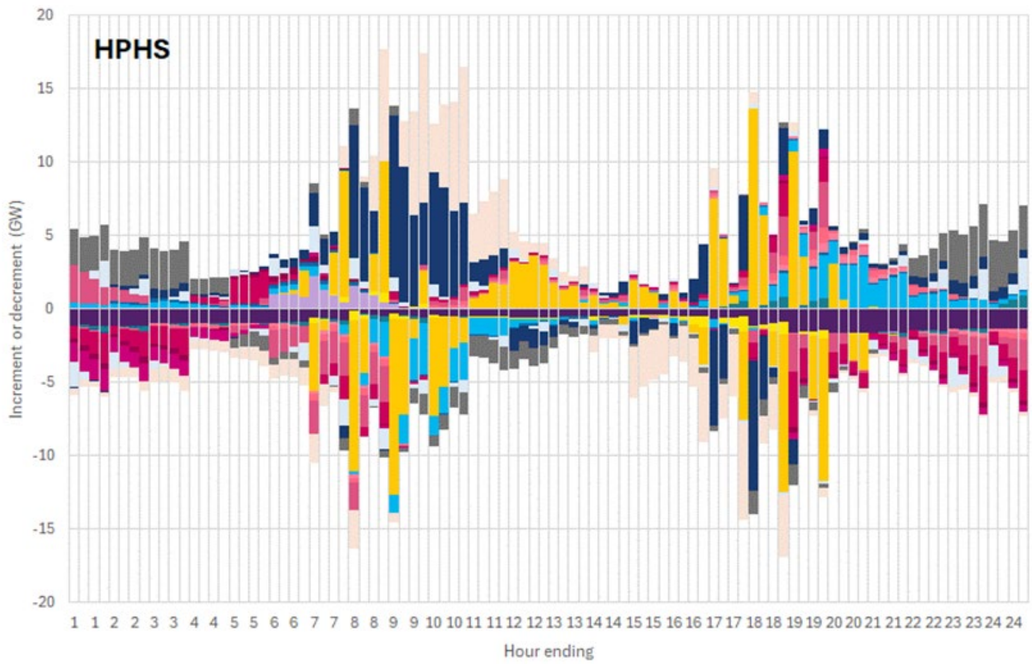
3.6.4 Real-Time Operations

Managing the difference between day-ahead schedules and real-time dispatch is important for maintaining system reliability. In this study, differences between the two were driven by several factors: differences between hourly day-ahead schedules and 15-minute real-time dispatch, day-ahead forecast error, changes in hurdle rates, and the release of load following reserves in real-time.

Figure 34 shows 15-minute daily average differences between day-ahead schedules and real-time dispatch for the BPBS, MPHS, and HPHS LC scenarios. An increase in storage charging is shown as an increase in load (generation decrement), which means that the total increments (increase in generation relative to day-ahead schedule) and decrements (decrease in generation relative to day-ahead schedule) are of the same magnitude. We include changes in curtailment in Figure 34 for illustrative purposes, though curtailment is not part of the increment-decrement balance.







Notes: x-axis shows hour ending rather than 15-minute intervals, to provide a sense of time during the day. Each 15-minute interval thus has multiple hour labels.

Key

	Nuclear		Coal		Combined cycle gas		Gas turbine		Oil & gas steam
	Biomass		Hydro		Offshore wind		Onshore wind		Distributed PV
	Utility-scale PV		2-hour battery		4-hour battery		6-hour battery		8-hour battery
	10-hour battery		Pumped hydro		Net imports		Curtail-ment		
	Load		Storage charge						

Figure 34. Fifteen-minute deviations between day-ahead and real-time generation, load, and curtailment in the BPBS, MPHS, and HPHS LC scenarios

In all scenarios, in real-time dispatch relative to day-ahead schedule, PLEXOS reduced combined cycle gas (GCC) generation throughout the day, increased net imports in the evening, and increased solar generation in the late morning and early afternoon. These three changes were likely interrelated. With lower real-time hurdle rates and lower cost imports available in the evenings, the Southeast region decommitted gas units that were primarily supplying energy in the evenings. Less gas generation running at minimum generation levels during the day allowed the region to reduce solar curtailment during the morning. This phenomenon was larger in the BPBS and MPHS scenarios, but much smaller in the HP scenarios because gas generation was smaller.

A second important area in Figure 34 is real-time adjustment to manage morning and evening solar ramps. Deviations between day-ahead and real-time during solar ramps include differences between hourly averaged and 15-minute solar profiles, solar forecast error, and curtailment. In the mornings, the difference between hourly averaged and 15-minute profiles will be positive (over-forecast, real-time decrement in solar generation) in the first 30 minutes and negative in the second 30 minutes; in the evenings, the reverse will be true. Forecast errors and curtailment may mean that deviations between day-ahead and real-time are not symmetric in some hours. Figure 35 illustrates how hourly scheduling and 15-minute dispatch leads to generation imbalances and the potential for forecast errors and curtailment to change the symmetry of those imbalances. In the figure, forecast error bias or ongoing curtailment during 08:00 to 10:00 (real-time interval 33–40) meant that imbalances during these hours were almost entirely upward (15-minute solar generation less than hourly forecast).

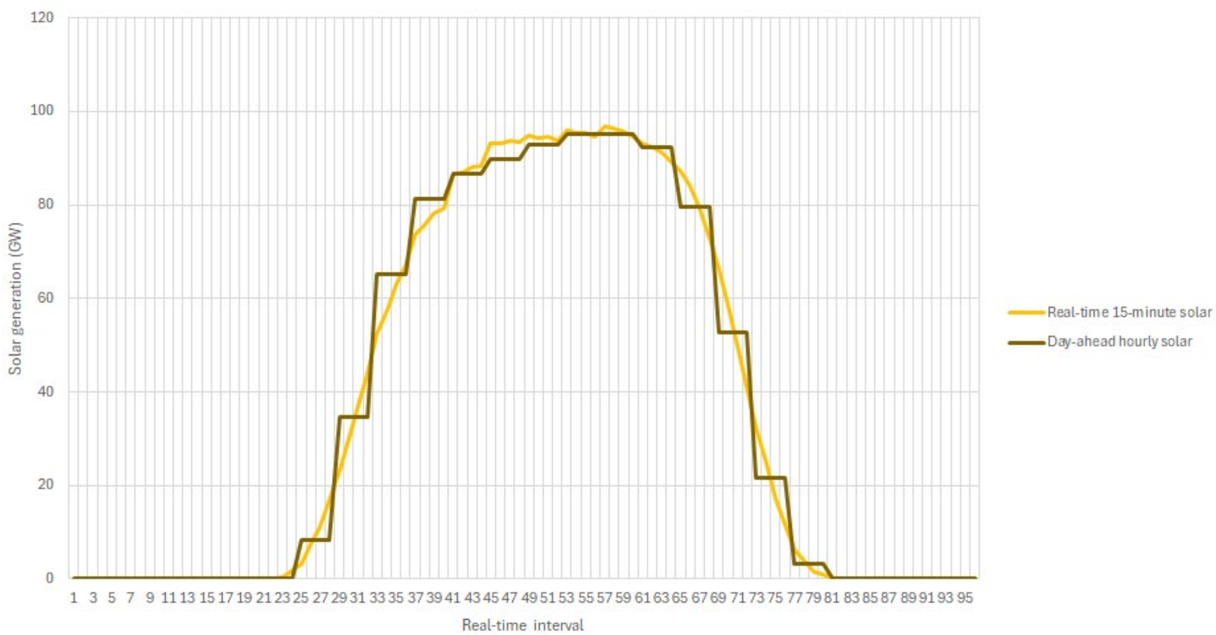


Figure 35. Average day-ahead (hourly averaged) and real-time (15-minute) solar generation in the HPHS SB scenario

As Figure 34 shows, the magnitude of solar ramp imbalances increased significantly with higher levels of solar generation. The general strategy that PLEXOS used to manage these imbalances—reducing GCC generation, dispatching GCTs, and changing storage charging and discharging—was common across all resource scenarios, but changes in generation, storage charging, and curtailment became larger and more visible in the higher solar scenarios. Beginning in the MPHS scenarios, average deviations during the solar ramp periods were more than 5 GW. Large deviations during solar ramp periods are mostly an artifact of hourly day-ahead scheduling and could be addressed by sub-hourly day-ahead forecasts and schedules.

3.6.5 Storage Operations

The daily solar cycle dominated storage operations. On average, PLEXOS charged all storage technologies during the day and discharged them during the evening and, in some cases, morning. In some scenarios (BPBS, MPLS), PLEXOS also charged shorter duration storage in the evenings. Figure 36 shows hourly averaged real-time daily charge (dotted line) and discharge (solid line) profiles, as a share of maximum discharge capacity, by storage technology for the LC scenarios. These profiles, including the uptick in storage discharge in the morning hours (05:00–09:00), are consistent with recent (2021–2022) storage dispatch in the California Independent System Operator (CAISO) region.[68]

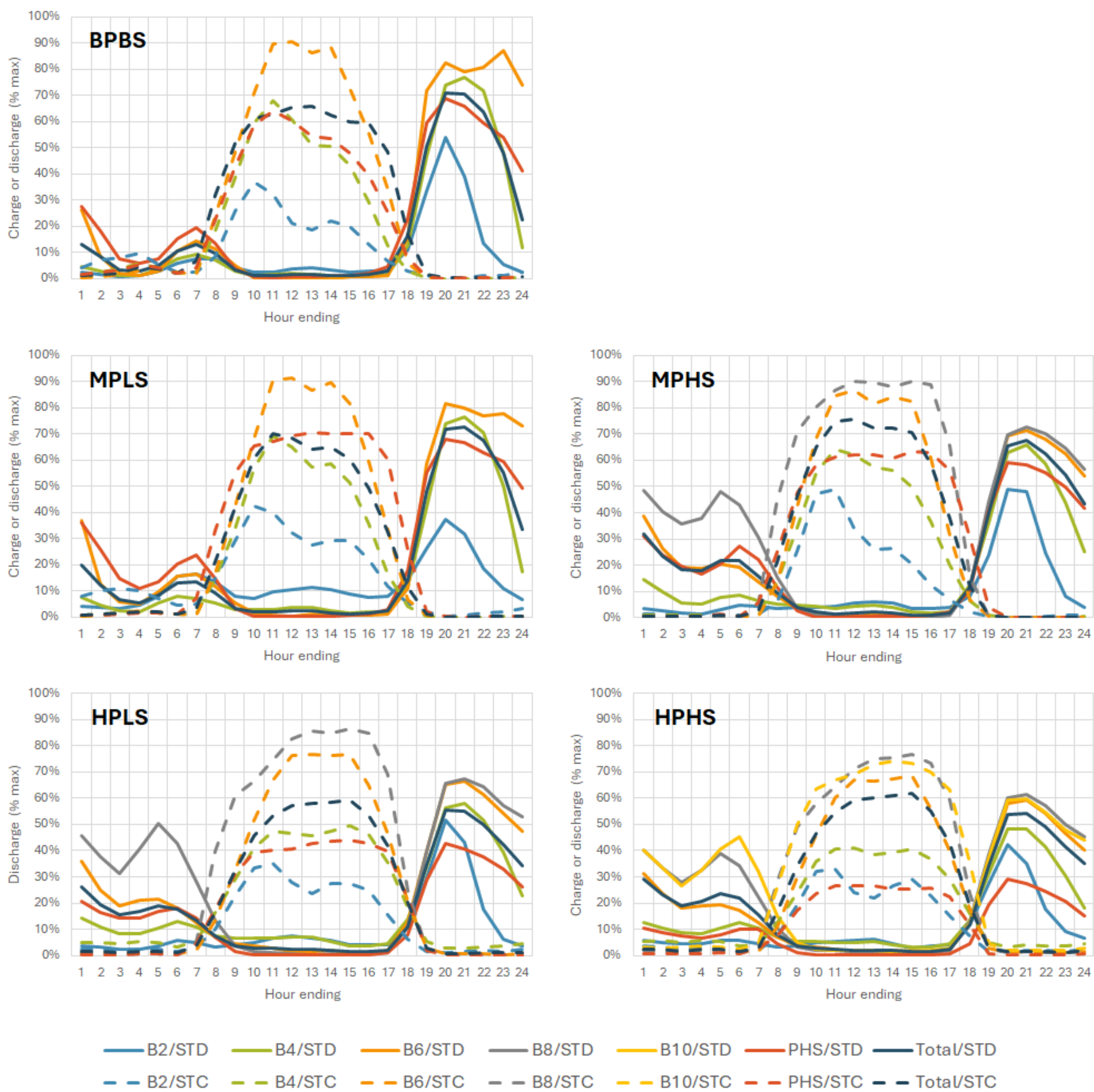


Figure 36. Energy storage charge (dotted line, STC) and discharge (solid line, STD) as a share of maximum charge or discharge capacity, by storage technology and average across technologies (total) in the LC scenarios

Figure 37 shows the average SOC profiles, as a share of maximum energy capacity, that correspond to the discharge and charge profiles in Figure 36. As expected, storage facilities increased SOC during the

68 CAISO DMM (2023).

day and mostly depleted it in the evenings. In general, it does not appear that there was a significant fundamental difference in how PLEXOS dispatched and managed different kinds of storage duration except for 2-hour battery storage (B2) and pumped hydro storage (PHS). For B2, PLEXOS charged and discharged it before other storage technologies and, in the BPBS and MPLS scenarios, charged it in the evening and discharged it in the early morning. For PHS, both charge and discharge and SOC declined in the HP scenarios, relative to the BPBS and MP scenarios, and PHS SOC was lower than other storage technologies in all scenarios.

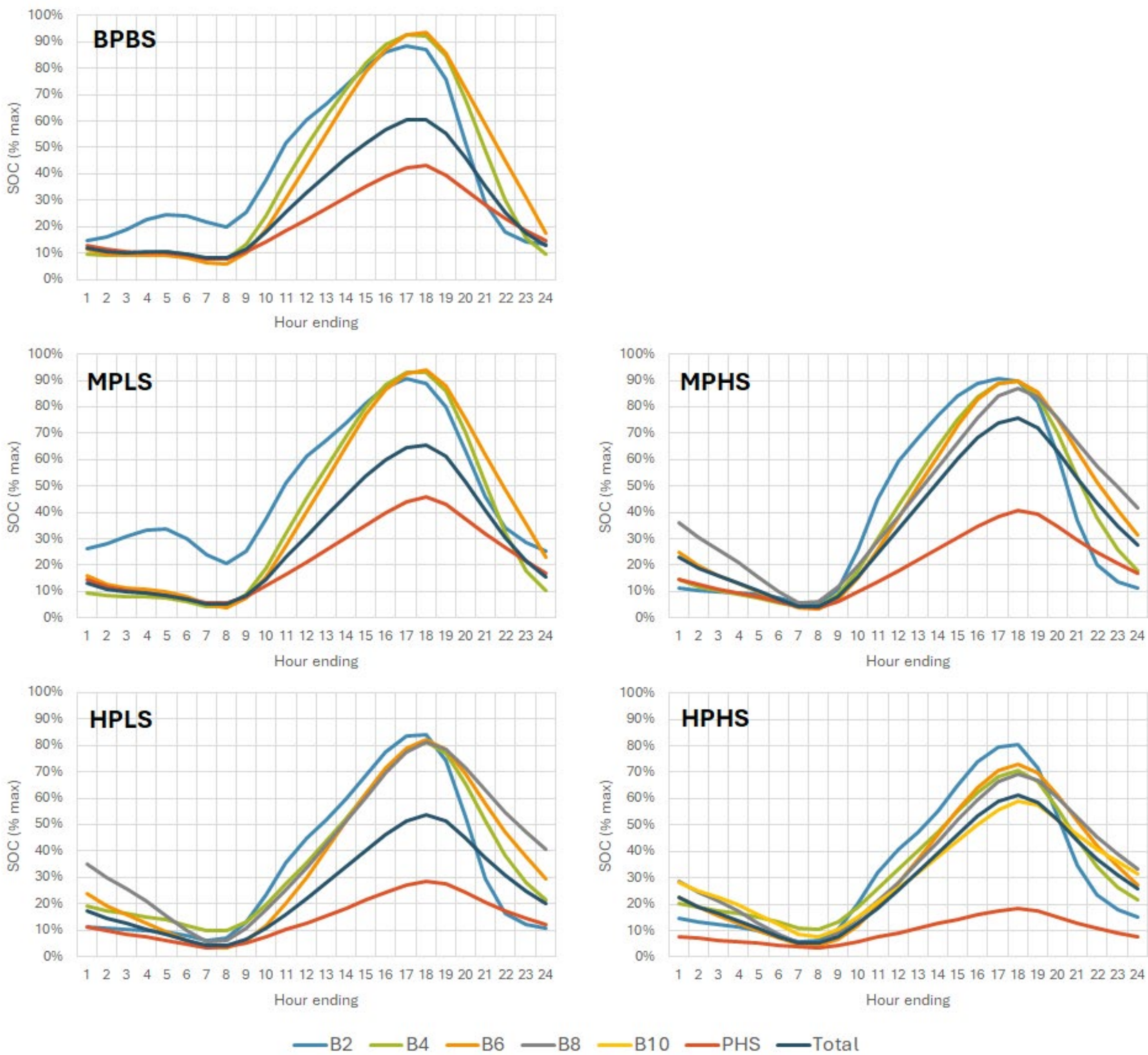


Figure 37. Energy storage SOC as a share of maximum energy storage capability, by storage technology and average across technologies (total) in the LC scenarios

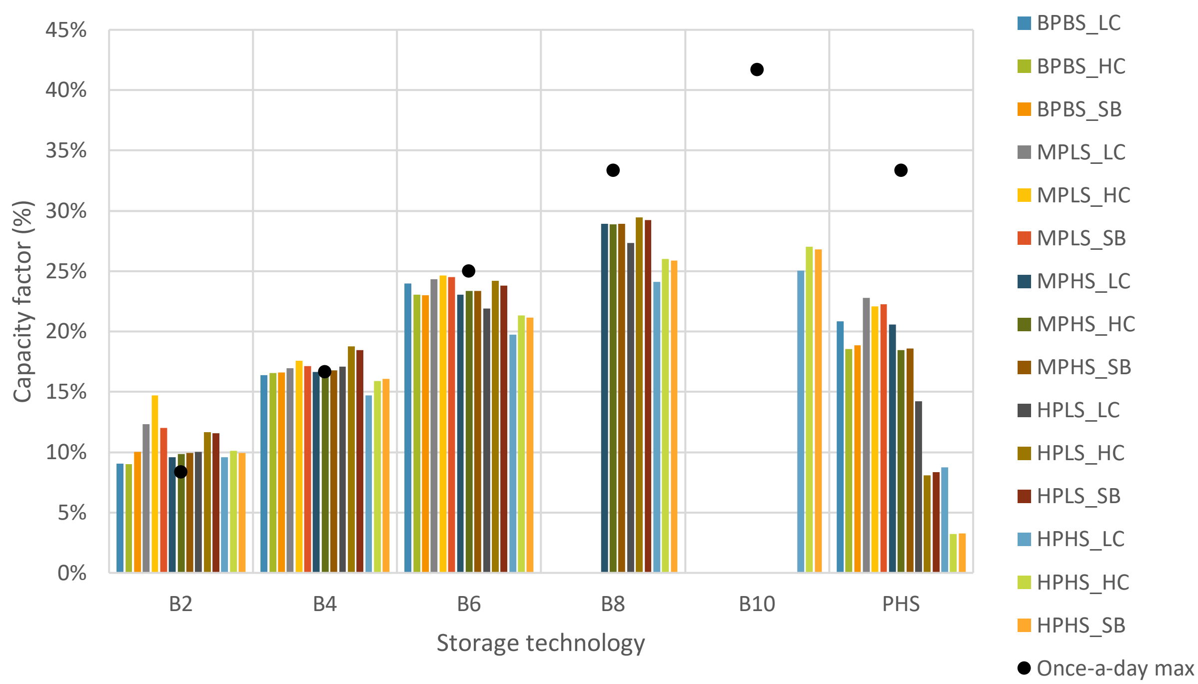


Figure 38. Annual capacity factors by storage technology and scenario (columns), and annual average capacity factor for once-a-day dispatch (black dots)

Seasonal storage could be storage that: (1) is used seasonally, (2) is unused during the season it is charged in, or (3) is charged and discharged based on seasonal differences in prices. Conventional production simulation models typically do not have the capability to optimize for (3), but short-term optimization may lead to outcomes that are strictly (2) but resemble (3). All storage technologies were used seasonally (1 above), as noted in the previous paragraph. However, PLEXOS did not charge and discharge storage seasonally (2 above) except for PHS in the HPHS scenarios. Figure 39 illustrates this seasonal usage for the HPHS SB scenario. In the summer months (July in particular), PHS "charge" exceeded discharged energy (plus losses, not shown). This energy was discharged over the winter and spring, so that in these months, discharged energy exceeded charged energy.

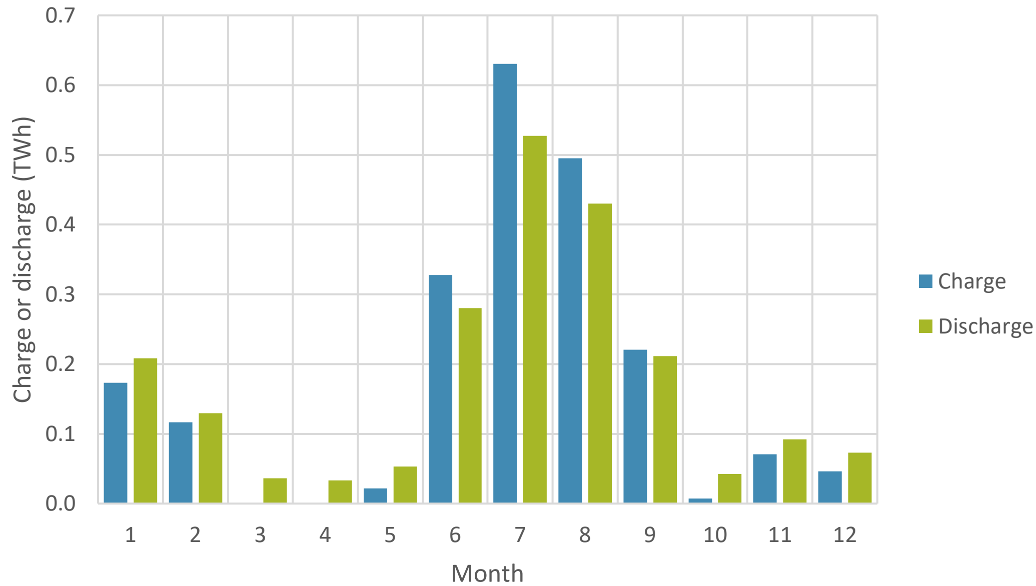


Figure 39. PHS total charge and discharge by month, HPHS SB scenario

In the Southeast region, annual differences between real-time and day-ahead storage charge and discharge were within 0.1%–5% in the BPBS and MP scenarios, and real-time charge and discharge were higher than day-ahead. However, in the HP scenarios, real-time charge and discharge were lower than day-ahead and annual differences between real-time and day-ahead were often larger (1%–11%). In MW terms, the largest deviations in storage charge-discharge between real-time and day-ahead were in the morning and evening solar ramp periods. In MWh terms, they were distributed over the day, clustered in three periods: (1) solar ramp periods (both charge and discharge deviations); (2) evening periods (discharge deviations); and (3) daytime (charge deviations) periods. Figure 40 shows average 15-minute real-time deviations for storage (total storage) for the MPHS LC scenario, illustrating these three periods. Several factors could be driving these deviations—hourly versus 15-minute, forecast versus actual, day-ahead versus real-time hurdle rates, release of load following reserves in real time.

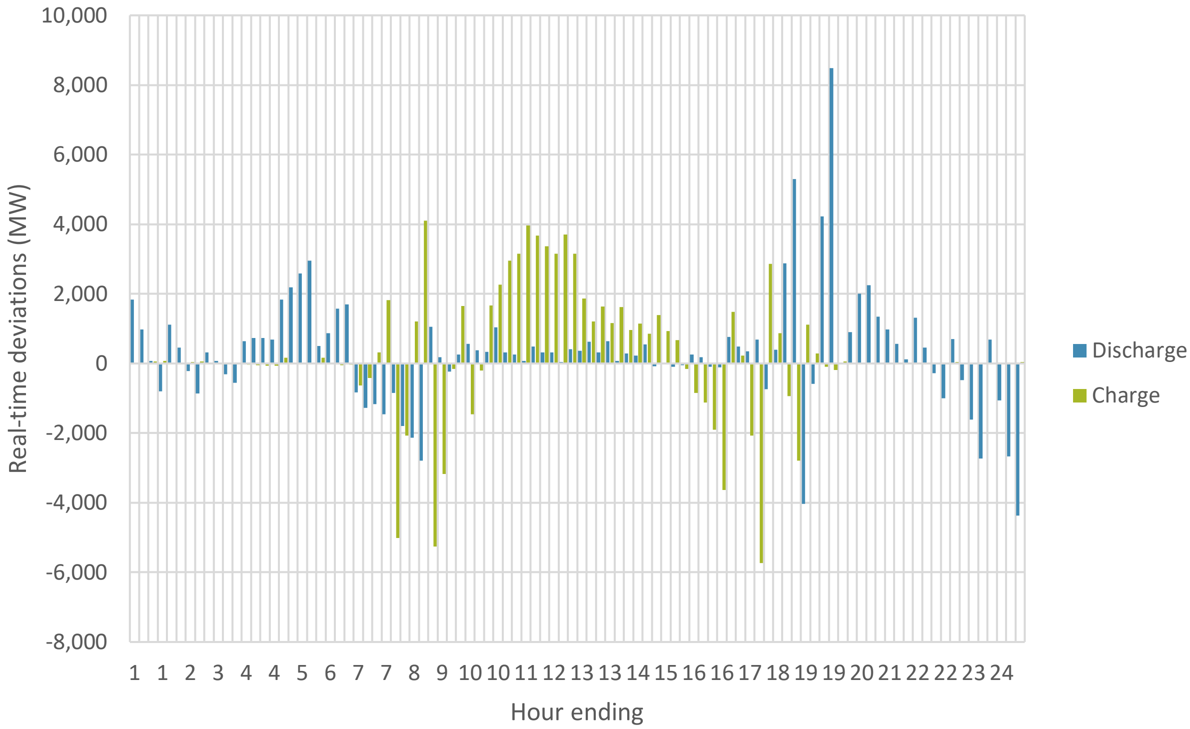


Figure 40. Average 15-Minute deviations between real-time and day-ahead for total storage charge and discharge, MPHS LC scenario

Notes: x-axis shows hour ending rather than 15-minute intervals, to provide a sense of time during the day. Each 15-minute interval thus has multiple hour labels.

3.6.6 Gas Operations

In all scenarios, ReEDS maintained a significant amount of natural gas generation capacity (see Section 3.1), both GCC and GCT. In the BPBS and MP scenarios, GCC capacity factors in the Southeast region remained between 20% and 35% but were much lower in the HP scenarios (2%–4%). In all scenarios, capacity factors for GCTs in the Southeast region were below 1%.

GCTs were almost exclusively used in real time and were primarily used during the morning and, to a lesser extent, evening solar ramps in all scenarios (Figure 41). The timing of GCT usage varied across scenarios. In the BPBS and MPLS scenarios, GCTs were used throughout the year; in the MPHS scenarios, usage was highest in the spring and fall (0.9%–1.4% monthly capacity factor) and lower in the summer and winter (0.5%–0.7%); and in the HP scenarios, usage was highest in the summer and winter (0.6%–1.0%) and fell in the spring (0.1%–0.4%) and fall (0.5%–0.6%).

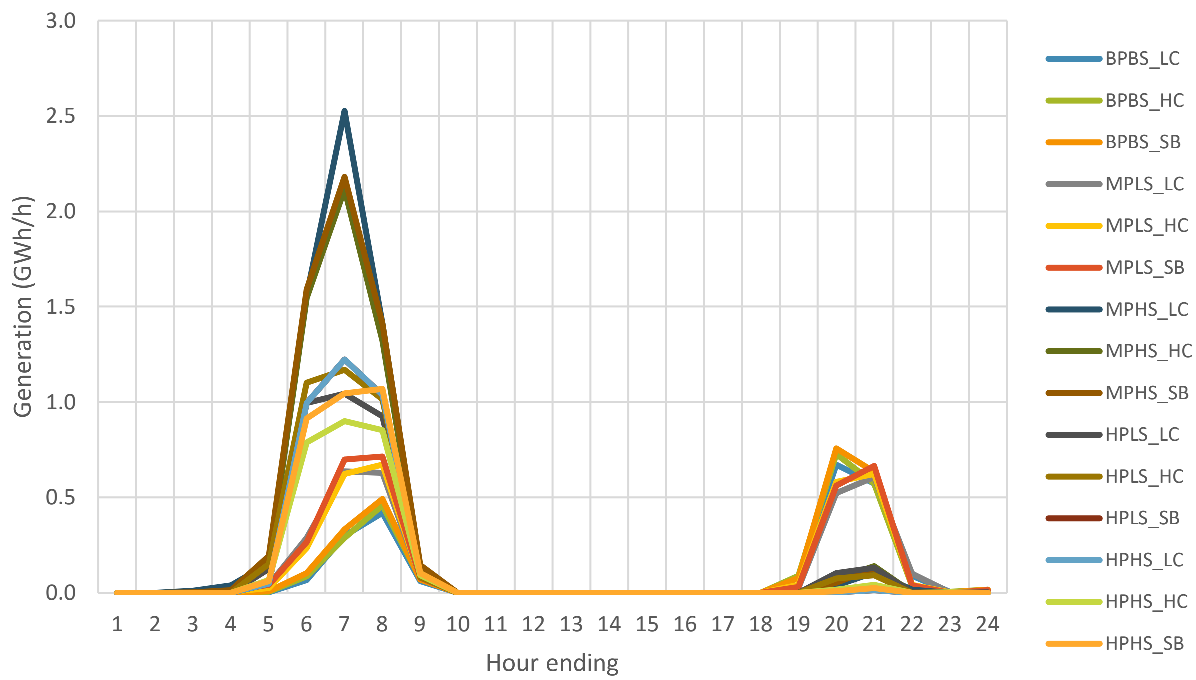


Figure 41. Average daily real-time dispatch for GCT generation by scenario

GCC daily and monthly usage followed a predictable pattern, ramping down during the day and up in the evenings (Figure 42). Average daily GCC ramps were higher in the LC scenarios. GCC units were used more frequently in the summer (29%–45% monthly capacity factors, BPBS and MP scenarios) and winter (31%–39%) than the spring (5%–23%) or fall (14%–32%).[69]

[69] GCC capacity factors were much lower in the HP scenarios. In these scenarios, GCC monthly capacity factors were 4%–8% in the summer, 1%–5% in the winter, 0% in the spring, and 1%–3% in the fall.

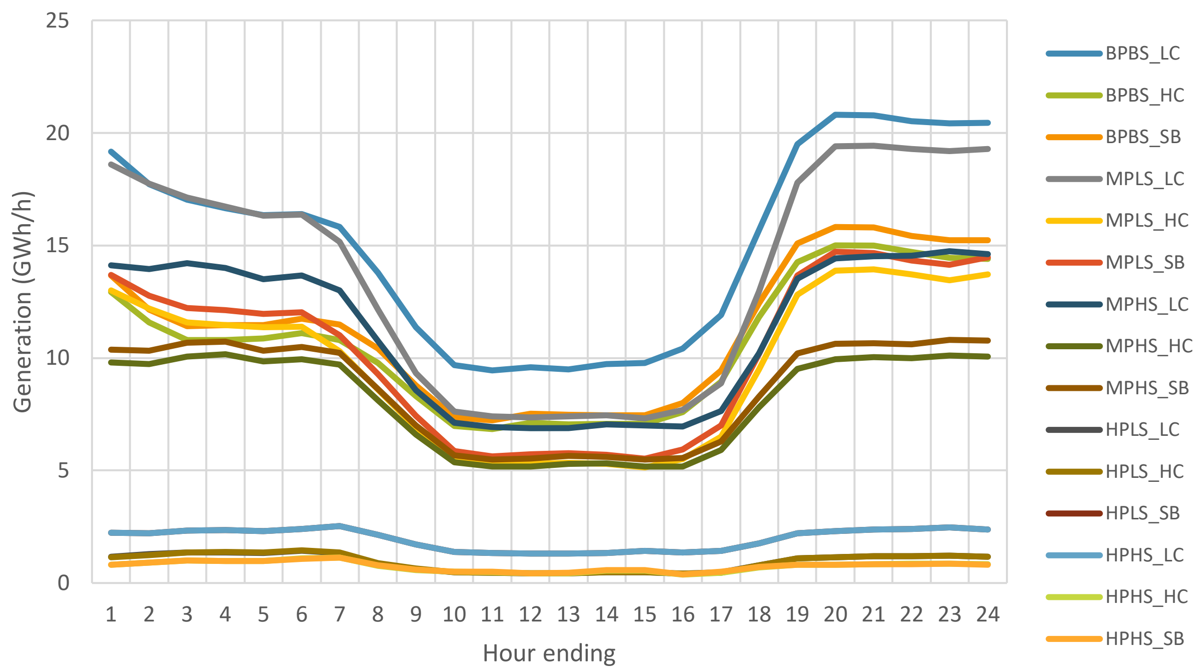


Figure 42. Average daily real-time dispatch for GCC generation by scenario

GCT generation was primarily used to manage short-term imbalances during morning and evening solar ramps and presumably as a low-cost resource for meeting resource adequacy constraints in ReEDS. Consistent with higher imbalances in the higher solar scenarios, in the BPBS and MPLS scenarios PLEXOS used 44% to 52% of available GCT capacity (maximum generation divided by installed capacity) but in the MPHS and HP scenarios it used 74% to 83% of available GCT capacity. Some of the operational need for GCT generation (imbalances) may have been addressed through sub-hourly day-ahead scheduling or changes in storage operations (Section 3.6.4).

GCC generation was mainly used as an energy and capacity resource to manage timing and sizing issues between solar and wind availability and storage operations. Maximum GCC use was higher in the BPBS, MPLS, and MPHS scenarios (69%–82% of installed capacity) than in the HP scenarios (34%–48%). Days with higher GCC generation tended to be more highly correlated with low wind days than low solar days. The SER-FRCC-MPS footprint had more than enough energy to meet demand without the need for gas generation—total curtailment in the HP scenarios ranged from 440–498 TWh, whereas total gas generation ranged from 91–109 TWh—but the timing of energy supply availability and demand were mismatched.

3.7 Sensitivities

We examined three main sensitivities to the core scenarios and methods: (1) a high solar scenario with less transmission, (2) turning off load following reserves, and (3) changing our approach to real-time hydropower dispatch.

3.7.1 Less Transmission

This sensitivity sought to better understand lower transmission utilization in the higher solar scenarios, and how not building as much transmission in these scenarios might affect the results. More specifically, we ran PLEXOS with the BPBS transmission system and the HPLS scenario resources, reducing total transmission capacity by 22 GW across the SER-FRCC-MPS footprint. Table 8 shows how constraining transmission affected the results. Production costs increased by around 10%–11%, relative to the base HPLS scenario, CO_2 emissions increased by 25%–29%, real-time reserve violations remained largely unchanged, and curtailment increased by 5%–6%.

Table 8. Comparison in Results Between the Transmission-Limited and Core HPLS Scenarios

Scenario	Annual Production Costs (billion $)	Annual Emissions ($MtCO_2$/yr)	Total Real-Time Reserve Violations (Count)	Curtailment (TWh/yr)
Transmission-limited HPLS sensitivity				
HPLS_LC	10.55	51.4	109	523
HPLS_HC	10.36	49.9	188	517
HPLS_SB	10.48	50.9	4	507
Base HPLS scenario				
HPLS_LC	9.60	41.2	144	498
HPLS_HC	9.38	38.7	187	489
HPLS_SB	9.47	39.5	4	477
Change in results, transmission-limited versus base scenario				
HPLS_LC	+0.96 (+10%)	+10.2 (+25%)	-35	+26 (+5%)
HPLS_HC	+0.98 (+10%)	+11.2 (+29%)	+1	+28 (+6%)
HPLS_SB	+1.01 (+11%)	+11.4 (+29%)	0	+31 (+6%)

Note: Real-time reserve violations here are a proxy for whether PLEXOS had adequate resources available in real-time.

In terms of dispatch, the main change between the transmission-limited and the core scenarios (SER-FRCC-MPS footprint-wide) was an increase in gas generation (+25 TWh, LC scenario), a decrease in wind generation (-29 TWh), and smaller increases in solar (+3 TWh) and pumped hydro discharge (+3 TWh). Figure 43 shows a comparison of imports, exports, and net transfers to and from the Southeast region in the limited transmission and core scenarios. Despite large differences in transmission capacity, the net transmission flows were relatively similar.

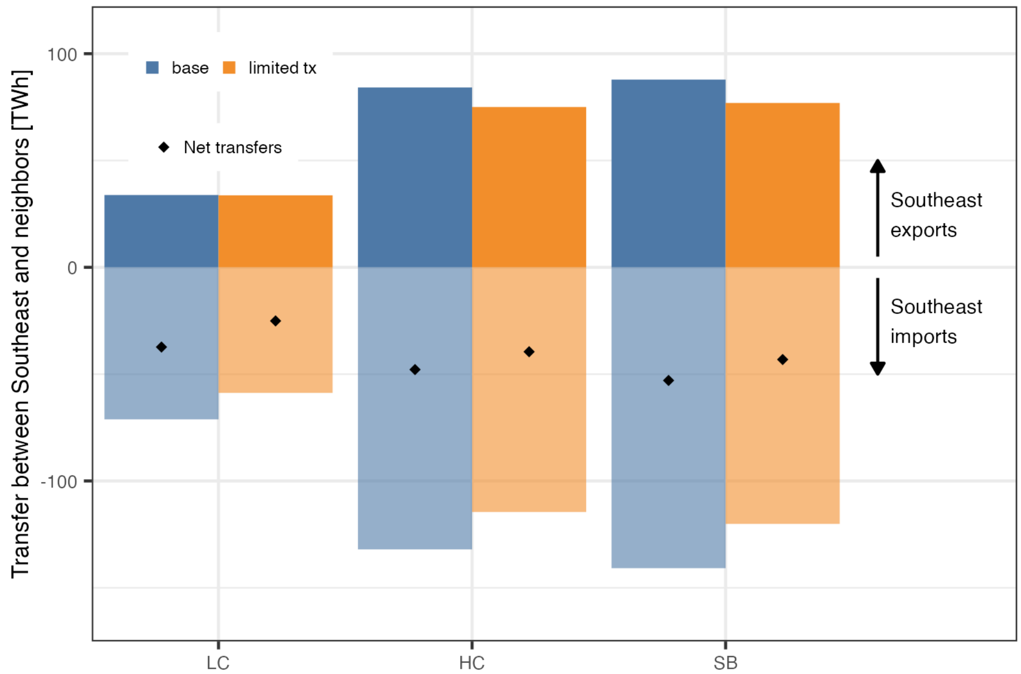


Figure 43. Comparison of imports, exports, and net transfers to and from the Southeast region in the transmission-limited HPLS sensitivity and base HPLS scenario

The results of this sensitivity suggest that the incremental transmission build in the HPLS scenario, relative to the BPBS scenario, may have been mostly driven by economics (cost savings) and emissions—and in particular the carbon tax assumptions in ReEDS (HPLS and HPHS scenarios) that were not carried over to PLEXOS—rather than reliability (load-resource balance constraint). For capacity expansion models like ReEDS, a carbon tax adder creates additional value for transmission that reduces CO_2 emissions. If the carbon tax were included in the production simulation model, this value would show up as a reduction in production costs.

3.7.2 No Load Following Reserves

Most system operators do not yet carry operating reserves to manage solar and wind forecast error. To assess how these reserves affect system operations, we ran PLEXOS in the HPLS scenario without load following reserves. Turning off these reserves had very little impact on production cost, CO_2 emissions results, or curtailment results—these were within 1% of the base scenario results. It did result in a small increase in real-time reserve violations, rising from 144, 187, and 4 (base LC, HC, and SB scenarios, respectively, from Table 8) to 187, 243, and 56 (LC, HC, and SB scenarios, respectively). Increased real-time reserve violations may have been due to insufficient capacity or energy held in reserve day-ahead. In terms of dispatch, turning off load following reserve resulted in a small decrease in gas (0.13 TWh) and wind (0.12 TWh) generation and a small increase in PV (0.25 TWh) generation, relative to base HPLS scenario generation of 2,691 TWh. That load following reserves did not significantly affect the results does not necessarily suggest that they are not needed. These reserves cover forecast error and contingency events that do not occur in production simulation models. However, it does suggest that there may still be scope for refining methods for calculating reserve requirements to cover solar and wind forecast errors to better align reserves with operating needs.

3.7.3 Real-Time Hydropower Re-Dispatch

To investigate the issues around day-ahead hydropower curtailment and limits on real-time re-dispatch described in Section 3.2.1, we conducted a limited sensitivity in which we allowed hydropower to be re-dispatched in real-time. In our base PLEXOS runs, we constrained hydropower dispatch using monthly energy budgets and did not allow it to be re-dispatched in real-time runs. As a result, hydropower was curtailed day-ahead in the HP SB scenarios and its energy was not available to manage imbalances in real time, contributing to higher production costs and emissions relative to the HC scenarios.

In the sensitivity, we selected one month (February) in the HPHS HC and SB scenarios and allowed hydropower to be re-dispatched in real time by using daily rather than monthly hydropower budgets. This approach resulted in 9% lower production costs in the Southeast region for both the HC and SB scenarios (decrease from $891 to $815 million in HPHS HC, decrease from $897 to $816 million in HPHS SB), but it did not resolve the underlying issue that lower hurdle rates and expanded reserve sharing (SB versus HC scenario) would lead to higher costs (the SB scenario still has costs $1.5 million higher than HC). We chose not to expand this sensitivity to the entire year. We discuss modeling issues around hydropower generation in the next section.

3.8 Modeling Issues

During this study, we encountered several modeling issues that may require more work to resolve going forward. In this section, we discuss a few of these issues and their implications for modeling.

- ***Coordination between operating reserves in capacity expansion and production simulation modeling***. We did not attempt to coordinate operating reserve requirements in ReEDS and PLEXOS. Our average reserve requirements in the two models were relatively similar though they differed significantly in the amount of reserves held in each time period. It was not clear from this study whether closer coordination between operating reserve requirements in capacity expansion and production simulation modeling—and the inclusion of reserves to manage larger, infrequent forecast errors in particular—would lead to significant changes in model results. Including forecast error reserves in capacity expansion models is challenging due to endogeneity problems: forecast errors depend on resource selection, but resource selection depends on forecast errors. The complexity of approaches to forecast error reserves in modeling should be consistent with the questions being asked. In this study, for instance, turning load following reserves (day-ahead forecast error) off had a relatively negligible impact on the results (Section 3.7.2), but detailed forecast error reserve calculations were important for the analysis of reserve-sharing (Section 3.6.3).
- ***Right-sizing the transmission network for dispatch modeling***. In this study, low transmission utilization (Section 3.6.2) and the results of the “less transmission” sensitivity (Section 3.7.1)

give a sense of the challenges in determining appropriate levels of transmission capacity in more detailed, forward-looking dispatch studies. Alternative approaches might include, for instance, developing transmission scenarios using capacity expansion models or iteration between capacity expansion and production simulation models to right-size transmission. In general, the electricity industry lacks standard methods for addressing uncertainty around transmission investments in forward-looking modeling.

- ***Rigorous load forecast error data***. We were not able to find reliable load forecast error data for this study. Developing rigorous publicly available data to parameterize load forecast errors, particularly in an era of electrification and new loads, would help to make production simulation results more realistic.
- ***More realistic solar and wind forecasts***. Many studies, including this study, use persistence solar and wind forecasts due to the challenges of developing more accurate forecasts that are consistent with solar and wind profile data. More work to develop rigorous solar and wind forecasts for use in planning models is needed.
- ***Reserve over-procurement***. PLEXOS "over-procured" reserves during time periods in which the marginal cost of supplying reserves was zero. We mostly addressed this problem via negligible but nonzero cost adders, but a more systematic approach may be needed. Better incorporation of opportunity costs in solar, wind, storage, and hydro dispatch may also help to resolve this issue.
- ***Intraday unit commitment and decommitment.*** We allowed all gas units, including combined cycle units, to be committed and decommitted in real-time, as a proxy for an intraday commitment process that would commit and decommit units based on changes in solar and wind forecasts and as an alternative to assuming that combined cycle gas units committed (or not committed) day-ahead could not be decommitted (or committed) during the operated day. Neither of these assumptions (full commitment flexibility in real time, no commitment flexibility during the operating day) is entirely satisfactory. Additionally, we discovered that with our approach it is currently not feasible to track the start costs of units that would have been started day-ahead but decommitted during the operating day. Adding in an entirely separate intraday stage to the production simulation process may not be practical due to computational concerns and data complexity. However, it may be possible to better incorporate intraday (e.g., hour-ahead) scheduling without having to include an entirely separate stage in models like PLEXOS.
- ***Hydropower modeling***. Hydropower has always been notoriously difficult to model due to uncertainty in expected water availability (e.g., drought) over time and the fact that competing water uses are often not straightforward or transparent. The accuracy of hydropower dispatch matters more in electricity systems with higher levels of variable renewable energy. Inaccurate dispatch can lead to an overbuild of other resources or, alternatively, give a false sense of security that a resource portfolio can meet reliability standards when it would not with realistic hydropower constraints.
- ***Energy storage modeling***. We used relatively minimal operating or economic constraints on energy storage operations. Specifically, we included SOC and capacity constraints and variable operations and maintenance costs in the PLEXOS modeling but did not include degradation

penalties ($/MWh cost adders to ensure that storage is not over-cycled) or otherwise limit storage SOC or dispatch using price curves or fixed constraints. Given recent experience in the CAISO market, minimally constrained battery operations may not be realistic, even if the final daily average dispatch from models resembles dispatch in practice.[70] Finding ways to mimic actual battery owner decision-making in production simulation models is an important task for researchers and model vendors.

[70] For instance, in 2021 and 2022, average day-ahead offers (discharge) for battery storage in the CAISO market were mostly above $200/MWh and bids (charge) were negative in most nonsolar hours; real-time offers were above $100/MWh except for evening solar ramp hours and were above $150/MWh for all time periods in Q4, and real-time bids were negative or close to zero outside of solar hours (CAISO DMM 2023). These bids are very different than the implied prices (shadow prices on storage constraints) in this study.

4. Conclusions

This study examined the economic, reliability, and operational impacts of higher levels of solar PV and electricity storage in the Southeast in 2035, with different levels of operational coordination among system operators (balancing regions). The study analyzed 15 scenarios, with different levels of solar, storage, and coordination. The conclusions in this section are organized around report sections.

The 15 scenarios formed a near-continuous range of solar and nonfossil fuel generation in the Southeast region, from 23% to 46% solar and 69% to 99% nonfossil fuel generation. The results are thus useful for benchmarking estimates of costs, emissions, curtailment, and other variables.

Generation and Transmission Expansion (Section 3.1)

Solar PV and energy storage investments are complementary. Differences in electricity storage capacity across scenarios were driven in part by storage cost assumptions, but they were also strongly shaped by the economics of solar. Solar generation is concentrated during daytime hours, which means that it tends to lose its value as the level of solar generation increases relative to electricity demand. Electricity storage can preserve the value of solar by shifting it to other time periods where the level of demand supplied by solar is low or zero. The results of this study illustrate the economic interdependence between solar and storage. In the medium and high solar PV (MP and HP) scenarios (29%–46% solar PV share of total generation), most (42%–63%) incremental solar PV generation was stored and time shifted to evenings (all scenarios) and mornings (MPHS [high storage] and HP scenarios) rather than used to meet load when solar was available. The base solar base storage (BPBS) scenario (23% solar), which had 12 GW of new battery storage and in which an average of around 20% of solar PV was stored and shifted, suggests that solar and storage investments may be economically interdependent even at lower levels of solar PV generation—for instance, before solar reaches 20% of total generation.

Under some cost and technology assumptions, there may be economic limits to levels of solar PV generation in the Southeast region. In this study, solar PV in the Southeast region saturated at about 40% to 45% of total generation, meaning that additional reductions in solar and storage costs and the imposition of a carbon tax led to only marginal increases in solar PV capacity additions in the capacity expansion modeling. These were economic rather than physical limits, driven by declining capacity factors for both solar and storage. This saturation range was also likely related to the large share of nuclear generation (about 30%) in the Southeast region. As an illustration that these were economic rather than physical limits, the share of solar generation in Florida (FRCC)—which has higher quality solar, less nuclear, and limited wind resources—reached as high as 76% in one of the HP scenarios. Lower-than-assumed solar PV and battery costs, different technology assumptions about solar PV (e.g., tilt angles), different assumptions about load shapes, limits on wind resources or procurement, or retirement of nuclear generation could change solar saturation points in the Southeast region.

Determining the right level and kind of storage, gas, and transmission investment requires careful, scenario-based analysis. Storage technology choices were path-dependent. For instance, the HPHS scenario had the highest amount of both 2-hour and 10-hour storage but less 4-hour storage than the MPHS scenario, suggesting that different assumptions about solar costs and technologies in resource planning may lead to very different utility storage portfolios. Gas generation capacity was slightly (2–3 GW) lower in the MP scenarios, relative to the BPBS scenario (70 GW of total gas capacity), but higher

(2–5 GW) in the HP scenarios. Transmission expansion was closely tied to resource portfolios and assumptions in capacity expansion modeling (see also Section 3.7.1). The sensitivity of storage, gas, and transmission investments to modeling assumptions underscores the need for transparent, scenario-based analysis in resource and transmission planning.

Economics (Section 3.3)

Regional coordination lowers production costs at different levels of solar generation. In the higher coordination scenarios, total production costs in the Southeast region, Florida (FRCC), and MISO, PJM, and SPP (MPS) declined by about 2% in nearly all solar and storage scenarios, with significant shifting of costs across the larger region. Cost savings were consistent with cost savings from the formation of organized markets in other regions (MISO, SPP).

Higher levels of solar can lead to large reductions in production costs, requiring alternative approaches to evaluating operational coordination and transmission investments. In the higher solar scenarios, total Southeast-FRCC-MPS production costs declined by 10% (MPLS [low storage] lower coordination [LC] scenario) to 70% (HPHS single balancing region [SB] scenario) relative to the BPBS LC scenario. As a result, cost savings from higher coordination also declined in absolute terms, from a high of $610 million per year ($0.23/MWh) in the BPBS SB scenario (relative to BPBS LC) to a low of $160 million per year ($0.06/MWh) in the HPHS SB scenario (relative to HPHS LC). This suggests that, with higher levels of solar, additional approaches and metrics may be needed to evaluate the benefits of operational coordination and regional transmission investments—for instance, including capacity (fixed cost) savings in benefits calculations.[71]

Midwest wind can be a valuable winter resource for the Southeast. Monthly solar generation in the Southeast region during the summer was nearly twice as high as during the winter. In the HP scenarios, Midwest wind provided a low-cost resource for mitigating winter solar shortfalls in the Southeast region and FRCC.

CO_2 Emissions (Section 3.4)

Wind may provide lower cost CO_2 emission reductions for the Southeast if solar PV saturates. Most of the incremental emission reductions in the HP scenarios (97% reductions relative to 2022 emissions), vis-à-vis the MPHS scenarios (76%–78% reduction relative to 2022 emissions), was driven by additional wind generation. In considering larger reductions in CO_2 emissions for the Southeast region, it may be beneficial to assess the availability of wind within the region or the deliverability of wind from outside the region.

Higher operational coordination lowers total CO_2 emissions at different levels of solar generation. Total CO_2 emissions across the larger Southeast-FRCC-MPS footprint declined by 3%–7% with higher coordination, but higher coordination also led to significant CO_2 emissions shifting between regions, with lower emissions in the Southeast region and FRCC but higher emissions in MPS.

[71] As an additional illustration of this point, the *State-Led Market Study* for the Western U.S. (Energy Strategies 2021) found that most of the benefits of a west-wide RTO would be capacity savings by 2030.

Reliability (Section 3.5)

Higher levels of solar and wind may significantly increase the amount of reserves needed to manage solar and wind forecast errors. Forecast error-related reserves increased approximately linearly with solar and wind installed capacity (6%–10% of capacity, depending on reserve sharing). Total day-ahead reserves increased from 19% of load in the BPBS LC scenario to 31% of load in the HPHS LC scenario.

Reserve sharing reduces reserves required to manage solar and wind forecast errors. Sharing forecast error reserves over a wider geographic area reduced reserve requirements, as a result of solar and wind resource diversity. Forecast errors for the larger Southeast region were smaller than for each individual balancing region. Reserve sharing in the Southeast reduced day-ahead reserve requirements by 5% to 23%, depending on reserve sharing assumptions.

The value of reserve sharing may decline with more solar due to declines in reserve prices. Cost savings from reserve sharing tended to decline with higher levels of solar and wind generation due to lower reserve and energy prices. This result depends on scarcity prices and the extent to which an electricity system has adequate resources. It also depends on assumptions about storage opportunity costs and how they are modeled. Higher opportunity costs for storage may have limited the decline in reserve prices and reserve sharing value. If not, and with higher levels of solar, the benefits of reserve sharing may be better captured in capacity expansion rather than production simulation models.

Potential reliability (reserve shortage) issues change with different levels of solar. Reserve violations shifted from the evening solar ramp (19:00–22:00) in the BPBS scenarios to a broader range of time periods, including the morning solar ramp (05:00–09:00), in the MPLS, MPHS, HPLS, and HPHS scenarios.

Operations (Section 3.6)

The nature and timing of operational issues changes with different levels of solar and storage. As storage provided increasingly higher levels of reserves, storage state-of-charge management became a more critical part of operations. However, storage operations are often not well captured in current production simulation models, due to limited foresight over multiple days, disconnects between day-ahead and real-time storage operations, and under-constrained operations.

With higher levels of solar, system operators may need to transition to 15-minute day-ahead scheduling. The morning and evening solar ramp periods became a larger operational challenge in higher solar scenarios, as deviations from hourly solar forecasts and 15-minute actuals became much larger. Moving to 15-minute day-ahead scheduling could address a large part of the real-time imbalance challenges due to solar ramps.

The effects of higher coordination on operations also change with different levels of solar and storage. Dispatch changed in different ways when hurdle rates were lowered in the BP, MP, and HP scenarios. In the BPBS and MPLS scenarios, higher coordination (HC) led to large changes in dispatch, mainly gas-gas switching and displacement of coal with solar and gas. In the MPHS scenario, higher coordination led to smaller changes in dispatch, though they were similar in nature to those in the BPBS and MPLS scenarios. In the HP scenarios, higher coordination led to even smaller changes in dispatch, with solar and wind displacing gas (HC scenarios) and hydro (SB scenarios).

Higher levels of solar and operational coordination can lead to large changes in transmission flows. Higher levels of solar led to lower transmission flows and utilization. The shift from $8/MWh to $0/MWh hurdle rates (in real-time LC to HC scenarios, and in day-ahead HC to SB scenarios) significantly changed transmission flows across the broader SER-FRCC-MPS region.

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APPENDIX A.

A.1 Background on the Southeast

A.1.1 Industry Structure in the Southeast

The electricity industry in the U.S. Southeast[72] is composed of a diverse mix of investor-owned utilities, municipal utilities, rural cooperatives, federal and state agencies, and generation and transmission providers (Table A-1). In part due to the Tennessee Valley Authority (TVA), the density of municipal and cooperative utilities is relatively unique—no other region in the United States has such consistently large numbers of municipal utilities and cooperatives in each state.[73]

Table A-1. Number and Shares of Electricity Sales for Different Kinds of Electricity Providers in the Southeast Region, 2020

State	Number				Shares			
	IOU	MUNI	COOP	FED/STA	IOU	MUNI	COOP	FED/STA
AL	1	22	22	1	62%	18%	13%	7%
FL	5	17	15	0	76%	15%	9%	0%
GA	1	17	37	0	63%	6%	31%	0%
KY	4	17	24	1	52%	7%	36%	5%
MS	2	14	23	1	47%	6%	36%	10%
NC	3	20	29	1	76%	10%	14%	0%
SC	4	7	18	1	64%	4%	22%	10%
TN	2	59	25	1	2%	66%	26%	6%
Average	3	22	24	1	55%	17%	24%	5%

Notes and source: IOU refers to investor-owned utilities; MUNI refers to municipal utilities; COOP refers to rural cooperatives; FED/STA refers to federal and state agencies. Data are from EIA (2021). Electricity providers crossing multiple state lines are counted in each state.

Most of the region's municipal and cooperative utilities use the balancing services of a larger balancing area authority (BAA). A relatively small number of BAAs provide the majority of the region's balancing services; the five largest cover just over 70% of the electricity sales in the region, and the 10 largest account for 90% of sales (Table A-2). The exception to larger and fewer BAAs is Florida, which has 12 BAAs that range in size from Florida Power & Light (FPL) to Utilities Commission of New Smyrna Beach.

[72] In this section, we use a narrower definition of the Southeast than in the analysis, but we include Kentucky because it was an important part of the analysis and Florida for reference. We do not include Missouri and Arkansas, where Associated Electric Cooperative Incorporated's (AECI's) service territory is located, though we describe AECI's size relative to other BAAs below.

[73] Other individual states have larger numbers of non-investor-owned-utility electric providers, but no other region in the United States has as many municipal utilities and rural cooperatives in each state.

Table A-2. BAA Share of Sales and Number of Utilities in Each BAA in the Southeast Region

BAA	EIA Code	Share of Sales	Number of Utilities
Southern Company	SOCO	23%	64
TVA	TVA	17%	166
Florida Power & Light Co.	FPL	14%	8
Duke Energy Carolinas	DUK	11%	36
Duke Energy Progress East	CPLE	7%	26
Duke Energy Florida, Inc.	FPC	5%	9
Louisville Gas and Electric Company and Kentucky Utilities Company	LGEE	3%	7
Midcontinent Independent System Operator	MISO	3%	15
PJM	PJM	3%	27
Dominion Energy South Carolina	SCEG	3%	5
South Carolina Public Service Authority	SC	2%	15
Tampa Electric Company	TEC	2%	3
Seminole Electric Cooperative	SEC	2%	10
Florida Municipal Power Pool	FMPP	2%	9
JEA	JEA	1%	2
PowerSouth Energy Cooperative	AEC	1%	15
City of Tallahassee	TAL	0.3%	1
Gainesville Regional Utilities	GVL	0.2%	2
City of Homestead	HST	0.1%	1
Utilities Commission of New Smyrna Beach	NSB	0.1%	1
Southeastern Power Administration	SEPA	0.03%	2

Source: Data are from EIA (2021). This list does not include AECI, which operates in Missouri and Arkansas. In this list, AECI's share of sales would have been 1% and its number of utilities was 28

Some of the region's BAAs cross state lines, for historical reasons. Southern Company (then Commonwealth & Southern) was allowed to operate as a holding company following the Public Utility Holding Company Act of 1935, in recognition that four of its constituent utilities (Alabama Power, Georgia Power, Gulf Power, and Mississippi Power) were already operating as an integrated system. TVA, created in 1933, provides generation and transmission services to utilities and cooperatives across seven states.

The diversity and number of suppliers and the interstate nature of BAAs has important implications for this analysis. With such a large number of load serving entities, it was not practical to model individual contractual arrangements for generation and transmission. Because some BAAs cross state boundaries, it was also not practical to focus the analysis at a state level. Instead, the analysis focused at the BAA level.

A.1.2 A Brief History of Regional Coordination in the Southeast

Efforts to improve operational coordination among the Southeast region's utilities have waxed and waned over the past five decades.[74] These efforts often consisted of coordination among smaller numbers of utilities in subregions within the Southeast rather than attempts to facilitate coordination across the larger Southeast region.

In 1978, several Florida utilities created a "Florida Energy Broker" to facilitate voluntary, automated hour-ahead trading of nonfirm energy among utilities, using available transmission capacity.[75] The Florida Broker, whose design included high-low bid matching and split savings, was the earliest organized wholesale market in the United States and was in use for more than two decades.[76] During the 1970s, utilities also expanded inter-BAA interconnections, facilitating enhanced reliability and long-term power sales. For instance, Florida utilities (JEA, FPL) constructed two 500 kV (3,600 MW) interties with Southern Company, completed in 1982, that enabled long-term "coal-by-wire" sales.[77]

Following the Federal Energy Regulatory Commission's (FERC's) Order 2000 (1999), which encouraged all transmission owners to join a regional transmission organization (RTO), the Southeast region's utilities initially submitted four RTO proposals to FERC: GridSouth (Duke, Progress Energy, SCE&G), GridFlorida (Florida utilities), Southern Company's proposal to become a transco, and Entergy's proposal to become a transco within the Southwest Power Pool (SPP).[78] FERC conditionally accepted proposals from GridSouth and GridFlorida, but in 2001 directed utilities to form a single southeastern RTO: the Southeast Power Grid (SPG).[79] Neither the single RTO nor the subregional RTOs came to fruition.[80] All proposed RTOs had been abandoned by 2005.[81]

Despite the collapse of RTO development efforts, some of the region's utilities later joined existing RTOs over the 2000s and 2010s.[82] Entergy Mississippi joined MISO as part of Entergy utilities in 2013. Further afield, Big Rivers Electric Corp. (Kentucky) joined MISO in 2009. AEP Kentucky (2004), Dominion Power (2005), Duke Energy Kentucky (2012), and East Kentucky Power Cooperative (2013) joined PJM. These memberships set the current boundaries between the Southeast and PJM and MISO.

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74 This section focuses on operational coordination. The Southeast has also had successful efforts around transmission planning coordination that are not covered in this section.

75 For an analysis of the Florida Energy Broker, see Cohen (1982). The Florida Public Service Commission (FPSC) incentivized utilities to participate in the broker by allowing them to retain 20% of their energy cost savings (FPSC, 1997).

76 'High-low bid matching' refers to matching the highest demand (decrement) bids and lowest supply (increment) bids, until all possible trades are made. Matching bids were settled at an average of the two bids (e.g., a $20/MWh supply bid and $40/MWh demand bid would be settled at $30/MWh), allowing cost savings to be split. Over the 1990s, the Florida Energy Broker was eclipsed by wholesale bilateral markets and gradually fell out of use (FPSC, 1997).

77 FPSC (1997); FPSC (2007).

78 Konschnik (2019). Southern Company, Entergy, JEA, and others later proposed SeTrans.

79 *Ibid.*

80 Perceptions that FERC had "changed the rules midstream" may have negatively impacted efforts for both a region-wide RTO and the subregional RTOs (Konschnik, 2019, p. 4).

81 SeTrans was halted in 2003; GridSouth and GridFlorida were dissolved in 2005.

82 LG&E and KU joined MISO in 1998 but withdrew in 2006. See Kentucky Public Service Commission, 2006, "PSC Allows LG&E and KU to Leave MISO," https://psc.ky.gov/agencies/psc/press/052006/0531_r02.pdf.

Over the 2000s, less-consolidated parts of the Southeast developed reserve sharing agreements. These included the Virginia-Carolinas Electric Reliability Council reserve sharing agreement, which was developed in 2005 and covers Virginia and the Carolinas, and the Florida Reserve Sharing Group, which was created in 2008 and covers most of the Florida utilities. Both reserve sharing groups enable sharing of contingency reserves.

Two other important operational coordination mechanisms emerged in the Southeast over the late 2000s and early 2010s. In 2009, Southern Company created a day-ahead and hour-ahead energy auction in 2009 as part of a deal with FERC to obtain market-based rate authority.[83] In 2012, FERC required Duke Energy Corporation and Progress Energy (Carolina Power & Light) to develop, as part of their merger, a joint dispatch agreement with Duke Energy Carolinas.[84]

In late 2019, several southeastern utilities began discussions on a Southeast Energy Exchange Market (SEEM). SEEM would resemble the Florida Energy Broker in its design—a voluntary market for nonfirm energy with high-low bid matching and split savings. However, SEEM would be a 15-minute-ahead rather than an hour-ahead market. Additionally, whereas the Florida Energy Broker was limited to utilities within a single state, SEEM would also be the first organized, interstate, multi-utility market in the Southeast. SEEM began operations in November 2022.[85]

Beginning in 2019, legislators in the Carolinas put forward bills to either require utilities to join an RTO or to study the benefits and costs of them doing so. In North Carolina, House Bill 958 (2019) would have authorized the NC Utilities Commission to require larger investor-owned utilities to establish or join an RTO and would have required a study to be conducted on participation by those utilities in an RTO.[86] In South Carolina, House Bill 4940 (H4940) and Senate Bill 998 established a committee to study whether utilities should be required to join an RTO.[87]

A.2 Solar and Storage Planning in the Southeast

Most of the U.S. Southeast has abundant solar resources, with levels of solar insolation that rank only behind the Southwest (Figure A-1). Solar energy is expected to be a much larger part of the region's generation mix over the next two decades and an important part of utility strategies to achieve utilities' long-term plans for nearer-term emission reductions and longer-term carbon neutrality. Table A-3 describes emission reduction goals for three of the region's largest utilities.

83 For details, see https://www.southerncompany.com/about/energy-auction.html.
84 FERC (2012).
85 For more background and updates on SEEM, see https://southeastenergymarket.com/.
86 See "House Bill 958," https://www.ncleg.gov/BillLookup/2019/H958, https://www.ncleg.gov/Sessions/2019/Bills/House/PDF/H958v1.pdf.
87 See "S. 998," https://www.scstatehouse.gov/sess123_2019-2020/bills/998.htm.

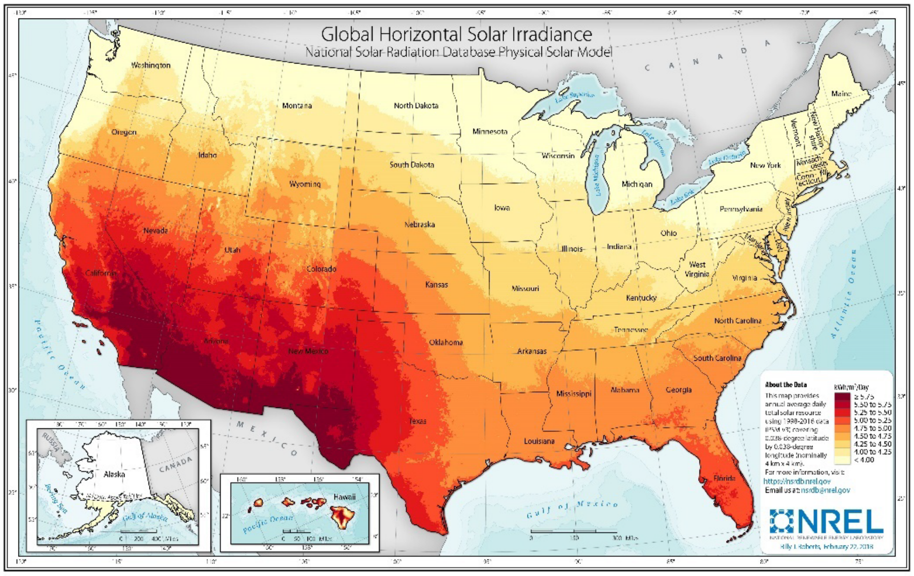

Figure A-1. Annual average daily total solar resources in the United States (1998–2016)

Figure from https://www.nrel.gov/gis/solar-resource-maps.html/

Table A-3. Nearer-Term and Longer-Term Emission Reduction Goals for Southern Company, TVA, and Duke Energy

Utility	Emissions Reduction Goals
Southern Company	50% reduction in year 2007 greenhouse gas emissions by 2030 Carbon neutral by 2050
TVA	70% reduction in year 2005 carbon intensity by 2030 80% reduction in year 2005 carbon intensity by 2035 Net zero carbon emissions by 2050
Duke Energy	50% reduction in year 2005 CO_2 emissions by 2030 Net zero carbon emissions by 2050

Sources and Notes: Targets are from Southern Company (2020), TVA (2021), and Duke Energy (2021). In the Carolinas, Duke Energy's target was a 70% reduction in carbon emissions by 2030 and net zero emissions by 2050, though this may be delayed due to recent above-trend load growth.

Table A-4 shows metrics for levels of solar and storage in recent utility integrated resource plans (IRPs) and market studies. These compare with a solar share of generation range of 23% to 46% and solar (utility-scale) to battery ratios of 2.9 to 6.3 used in this study.[88]

[88] Note that these ratios are lower than those in Table 2 because they do not include pumped hydro storage.

Table A-4. Solar and Storage in Recent Utility IRPs and Market Studies

Study	Year	Scenario	Solar Share	Solar to Battery Ratio
Guidehouse/CRA (2020), *Southeast EEM Benefits and Non-Centralized Costs*	2037	IRP Baseline Outlook	6%	25.0
		Carbon-Constrained Outlook	13%	4.0
Duke Energy Carolinas (DEC) (2020), *Duke Energy Carolinas 2020 Integrated Resource Plan*	2035	Base Without Carbon Policy	20%	8.3
		Base With Carbon Policy	30%	5.6
		Earliest Practicable Coal Retirements	30%	5.6
		70% CO_2 Reduction: High Wind	40%	3.7
		70% CO_2 Reduction: High SMR	40%	3.7
		No New Gas Generation	40%	2.1
Georgia Power (2021), *Georgia Power 2022 Integrated Resource Plan*	2041	Low Gas prices and Zero Carbon (LG0)	0%	N/A
		Low Gas Prices and $20 Carbon (LG20)	40%	5.0
		Moderate Gas Prices and $0 Carbon (MG0)	10%	5.0
		Moderate Gas Prices and $20 Carbon (MG20)	45%	2.5
TVA (2019), *2019 Integrated Resource Plan*	2038	Current Outlook, Base Case Strategy	10%	0.0
		Current Outlook, Promote Renewables Strategy	15%	10.0
		Current Outlook, Promote Efficient Load Shape Strategy	10%	2.5

Notes: All values that contain our estimates were rounded to the nearest five. Solar shares are the share of total or additional solar generation in total generation or annual sales. Battery/solar ratio is the ratio of additional battery capacity to total or additional solar capacity. Values in the table may not be strictly comparable among studies. See the notes below for each individual study for distinctions. The choice of utility IRP scenarios in this table is meant to be illustrative; Georgia Power and TVA explored additional scenarios in their IRPs.

Individual study notes: Solar to battery ratio for the Guidehouse/CRA (2020) study is cumulative battery capacity additions divided by cumulative solar additions, from 2020 to 2035 (Tables A-2 and A-3). Solar contribution in the DEC (2020) IRP is based on "Total Solar" (including 3,295 MW of existing capacity) in the DEC/Duke Energy Progress Combined System Portfolio Results Table multiplied by an assumed capacity factor of 0.28 and 8,760 hrs/yr and divided by total projected 2035 energy demand with energy efficiency programs but excluding impacts from demand reduction programs (Table C-12). The assumed capacity factor is based on Duke Energy (2021). Battery/storage ratio for the DEC (2020) IRP is "Incremental Storage Additions" divided by "Total Solar" in the DEC/DEP Combined System Portfolio Results Table. Solar share for the Georgia Power (2022) IRP is based on capacity additions in the B2022 Generic Expansion Plan Results figure (Figure 11) multiplied by an assumed capacity factor of 0.25 and 8,760 hrs/yr and divided by B22 Territorial Energy Sales (Figure 1.2.1-1) in the Budget 2022 Load and Energy Forecast 2022 to 2041. Solar to battery ratio for the Georgia Power (2021) IRP is based on solar and 4-hr and 8-hr battery capacity additions in the B2022 Generic Expansion Plan Results figure (Figure 11). We were not able to estimate the battery/solar ratio for the LG0 scenario (N/A in the table) because both capacities were too small. Solar share for the TVA (2019) IRP is based on nameplate solar capacity additions (Figure 7-7) multiplied by an assumed capacity factor of 0.25 and 8,760 hrs/yr, added on to an assumed 1.6 TWh of existing solar generation, and divided by the Current Outlook energy demand forecast from Figure 4-5. Solar to battery ratio for the TVA (2019) IRP is based on storage capacity additions in Figure 7-6 and nameplate solar capacity additions in Figure 7-7.

A.3 Capacity Expansion Model (ReEDS) Assumptions

We used the ReEDS capacity expansion model to develop resource portfolios for our five resource scenarios:

- Base solar base storage (BPBS)
- Medium solar low storage (MPLS)
- Medium solar high storage (MPHS)
- High solar low storage (HPLS)
- High solar high storage (HPHS)

To develop the portfolios, we adjusted five key assumptions, shown in Table 5. Costs in ReEDS were based on NREL's Annual Technology Baseline (ATB) 2022 projections. The high storage (HS) scenarios used more aggressive ("advanced") cost estimates from ATB.[89] The high solar (HP) scenarios used a carbon tax, beginning with \$46/tCO_2 in 2022 and increasing to \$88/tCO_2 by 2035 (2004\$). The carbon tax was applied to investment decisions in ReEDS but was not carried over to PLEXOS modeling. This approach would be similar to cases in which utilities include CO_2 costs in their IRP modeling but do not have actual limits or taxes on CO_2 emissions in practice.

Table A-5. Key ReEDS Input Assumptions for Developing Scenarios

Assumption	Resource Scenario				
	BPBS	**MPLS**	**MPHS**	**HPLS**	**HPHS**
Battery costs	conservative	conservative	advanced	conservative	advanced
Carbon tax	none	none	none	yes	yes
Coal retirements	accelerated	accelerated	accelerated	n/a*	n/a*
DPV adoption	mid case	low-cost case	low-cost case	low-cost case	mid case
Utility-scale PV costs	moderate	advanced	advanced	moderate	advanced

We used assumptions on distributed PV (DPV) adoption and utility-scale PV costs to adjust and differentiate the higher solar scenarios (MP and HP). DPV adoption was based on projections from NREL's dGen model.[90] Adoption scenarios varied with the cost of DPV, which were related to cost assumptions for utility-scale PV. For DPV adoption, we used low-cost cases for all higher solar scenarios except for HPHS, for which we used a mid case assumption to enable more utility-scale PV and better differentiate it from HPLS. For the HPLS case, we used moderate PV costs to better differentiate this scenario from HPHS but used advanced PV costs in all other solar scenarios. In all scenarios, we assumed accelerated retirements of coal units, consistent with trends within the Southeast region. Figure A-2 shows the ATB capital cost envelopes used in the analysis.

[89] Available at https://atb.nrel.gov/.
[90] See https://www.nrel.gov/analysis/dgen/.

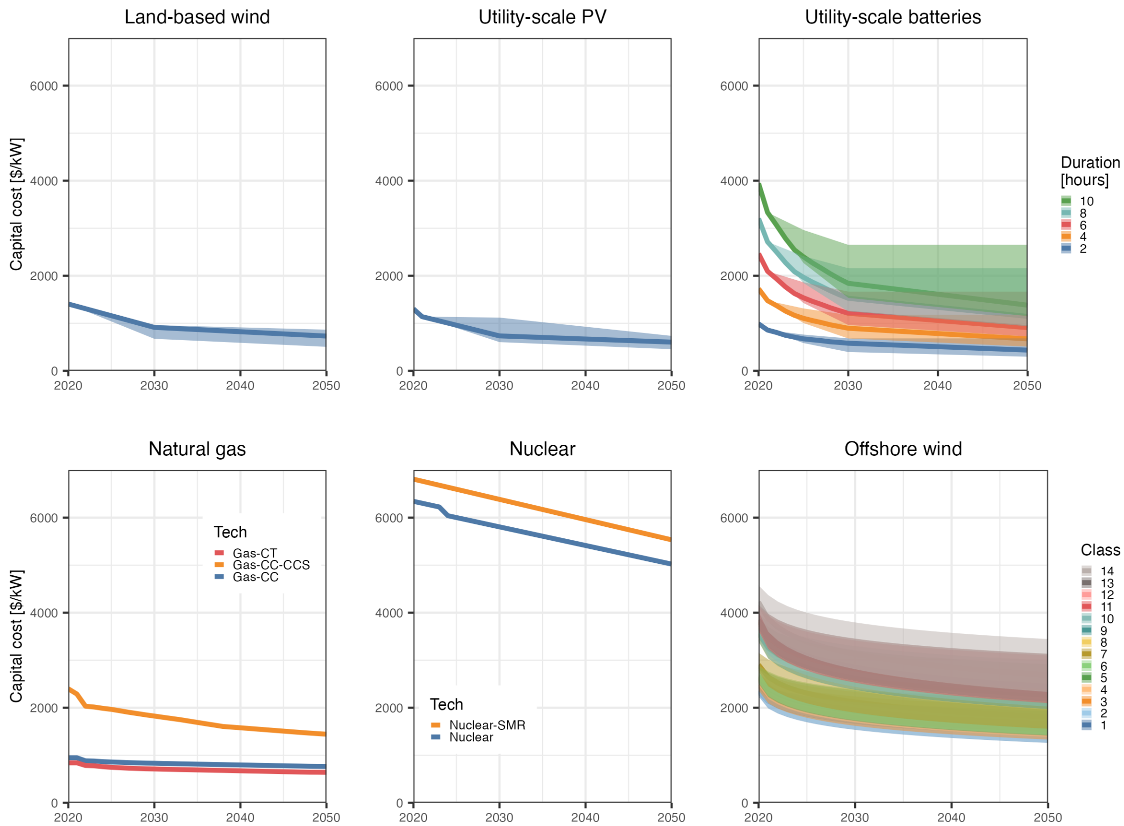

Figure A-2. ATB capital cost assumptions used in ReEDS

All scenarios included representation of Inflation Reduction Act (IRA) incentives. Utility PV projects are now eligible for up to a $28.60/MWh production tax credit (PTC) and can choose between the investment tax credit (ITC) and PTC. We assumed that solar projects choose the PTC given its higher lifetime value.[91] Incorporating IRA incentives into the model significantly increased the amount of "baseline" solar deployment in ReEDS. For instance, in the BPBS scenario, solar generation in ReEDS increased from 12% to 22% of total generation in 2035 after modeling IRA provisions. Note that not all IRA incentives are included in the ReEDS model (e.g., the 45V tax credit for hydrogen is not represented here).

We assumed that each balancing region must meet its own peak demand plus a planning reserve margin, rather than setting reserve requirements based on regionally coincident peak demand and allowing for planning reserve sharing. We allowed balancing regions to apply external resources toward local resource adequacy requirements. We used a hurdle rate of $7.5/MWh (2004$) to capture transmission friction between balancing regions.

Operating reserves held in ReEDS were on par with those held in PLEXOS. In general, ReEDS holds

[91] For more detail on the representation of IRA provisions in ReEDS and the impact on renewable deployment see https://www.nrel.gov/docs/fy23osti/85242.pdf.

regulation reserve requirements equivalent to 1% of load plus 0.5% of wind generation and 0.3% of solar generation capacity; it holds flex reserve (load following here) requirements of 10% of wind generation and 4% of PV generation; and it holds spinning contingency reserves equivalent to 3% of load.[92] ReEDS does not hold nonspinning reserves, but these may be captured within a planning reserve. For the Southeast region, regulation and spinning flex reserves in ReEDS would be equivalent to approximately 5% of solar and wind generation capacity, which is on par with the 3% to 5% range for regulation and spinning load following reserves used in this study (Section 3.6.3).[93] Operating reserves in ReEDS and PLEXOS differed mainly in the timing of reserves and in the inclusion of nonspinning reserves in PLEXOS.

92 See Sergi, B., W. Cole, 2021, "Operating Reserves in ReEDS," https://www.nrel.gov/docs/fy22osti/81706.pdf.

93 As long as there are no hours with zero wind generation, reserves as a share of wind generation can be converted to reserves as a share of wind capacity by multiplying the reserve requirement (10% of wind generation) by an average wind capacity factor (approximately 40% in this study). This implies solar and wind regulation reserves of 0.5% and spinning flex reserves of 4% of solar and wind generation capacity. Regulation reserves as a share of load can be converted to reserves as a share of solar and wind capacity by multiplying the reserve requirement (1% of load) by the ratio between average load (85 GW) and solar and wind capacity (109–238 GW), which results in a range of 0.4% to 0.8%. The resulting range of regulation and flex reserves in ReEDS, as a share of solar and wind capacity, is around 5%.