

Advanced Hydropower and PSH Capacity Expansion Modeling

Final Report on HydroWIRE
D1 Improvements to Capacity
Expansion Modeling

July 2022

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HydroWIRES

In April 2019, the U.S. Department of Energy Water Power Technologies Office launched the HydroWIRES Initiative¹ to understand, enable, and improve hydropower and pumped storage hydropower's (PSH's) contributions to reliability, resilience, and integration in the rapidly evolving U.S. electricity system. The unique characteristics of hydropower, including PSH, make it well suited to provide a range of storage, generation flexibility, and other grid services to support the cost-effective integration of variable renewable resources.

The U.S. electricity system is rapidly evolving, bringing both opportunities and challenges for the hydropower sector. Though increasing deployment of variable renewables such as wind and solar have enabled low-cost, clean energy in many U.S. regions, it has also created a need for resources that can store energy or quickly change their operations to ensure a reliable and resilient grid. Hydropower (including PSH) is not only a supplier of bulk, low-cost, renewable energy but also a source of large-scale flexibility and a force multiplier for other renewable power generation sources. Realizing this potential requires innovation in several areas: understanding value drivers for hydropower and PSH under evolving system conditions, describing flexible capabilities and trade-offs associated with hydropower meeting system needs, optimizing hydropower operations and planning, and developing innovative technologies that enable hydropower to operate more flexibly.

HydroWIRES is distinguished in its close engagement with the DOE national laboratories. Five national laboratories—Argonne National Laboratory, Idaho National Laboratory, the National Renewable Energy Laboratory, Oak Ridge National Laboratory, and Pacific Northwest National Laboratory—work as a team to provide strategic insight and develop connections across the HydroWIRES portfolio as well as broader DOE and national laboratory efforts such as the Grid Modernization Initiative.

Research efforts under the HydroWIRES Initiative are designed to benefit hydropower owners and operators, independent system operators, regional transmission organizations, regulators, original equipment manufacturers, and environmental organizations by developing data, analysis, models, and technology research and development that can improve their capabilities and inform their decisions.

More information about HydroWIRES is available at energy.gov/hydrowires.

¹ Hydropower and Water Innovation for a Resilient Electricity System (HydroWIRES)

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Executive Summary

Hydropower and pumped storage hydropower (PSH) have played a key role in providing flexible, low-carbon electricity to the U.S. electricity system for over a century. As deployment of variable generation (VG) increases the demand for flexible, dispatchable generation, it is important to understand all options for providing this flexibility. Hydropower and PSH are two such options, and, given their established and potential future role in the U.S. electricity system, it is critical to use all available methods for understanding how hydropower and PSH interface with VG and other technologies in a future low-carbon grid. Hydropower and PSH flexibility are challenged by site-specific requirements for environmental flows, irrigation, navigation, recreation, flood control, and other services that often take priority over power production, and these constraints highlight the importance of a holistic approach to studying future hydropower roles in the grid.

Capacity expansion models (CEMs) of electricity systems are often used to study future electricity scenarios, but these tools can have difficulty representing site-specific and other technology details of hydropower and PSH because of limited spatial, temporal, or process resolution. As a result, CEMs have historically failed to characterize hydropower and PSH technology and operational characteristics with sufficient detail to answer focused questions about future deployment and operation. To improve the state-of-the-art for hydropower and PSH modeling with CEMs and other analytical tools, this report demonstrates a set of model advancements that could be implemented in CEMs and other models to more accurately represent hydropower and PSH and their role in electricity systems. These new capabilities are implemented in the Regional Energy Deployment System (ReEDS), the flagship national electricity system CEM at the National Renewable Energy Laboratory (NREL). Model advancements include new data integration to define closed-loop PSH resource availability and cost, along with site-level parameterizations of existing PSH capacity and energy storage specifications. Existing model structures only allow storage energy arbitrage over diurnal and seasonal timescales, and we implement the new capability to shift energy across seasons for both hydropower and PSH to conduct a bounding exploration of the potential value of long-duration storage and demonstrate how it might be studied. New representations of hydropower upgrades offer opportunities to increase operating flexibility (i.e., dispatchability), add pumps to allow hydropower to perform energy arbitrage, or independently add capacity or energy depending on which is most valuable. While some of these opportunities will be difficult to realize in practice, this set of new capabilities allows an expansive exploration of hydropower and PSH flexibility, from the standpoint of investment options as well as operational characteristics.

In this report, new model structures and data are demonstrated individually and in combination to observe their impact on model results and provide initial insights into what is most important for analysts, electricity system planners, and hydropower decision makers to consider when assessing future roles of hydropower and PSH. New features are tested under two underlying future electric sector projections: (1) a reference scenario (Ref) and (2) a scenario requiring 100% renewable electricity by 2050 (RE100). Model outcomes with new features are compared to baseline (Base) versions of these scenarios without the new features. Data limitations often preclude accurate, site-specific estimations of flexibility and upgrade cost and potential, so bounding sensitivity analysis is often used to present possible outcomes under a range of input assumptions.

This exploratory analysis resulted in several key observations.

New PSH resource supply curves indicate the potential for new deployment at low-cost closed-loop PSH sites. When implementing new PSH supply curves defined for 8–10-hour storage duration before a cost-calibration procedure, the 22-GW existing PSH fleet grows by 6.5–8.6 GW through 2050 in the Ref scenarios, and 13.4–15.8 GW of new PSH is deployed through 2050 in the RE100 scenarios (Figure ES

1). Deployment in these scenarios is driven strongly by firm capacity value of PSH, with diurnal energy arbitrage playing a smaller role. New PSH deployment is highly sensitive to the costs of PSH and competing storage technologies (e.g., batteries), with negligible new PSH deployment after cost calibration that adds 51% to new PSH capital costs. Nevertheless, pre-calibration PSH deployment can help identify lower-cost sites for more rigorous evaluation. PSH competitiveness could also be greater in scenarios with higher VG shares, where flexible technologies such as batteries and PV-battery hybrids are also deployed to a greater extent.

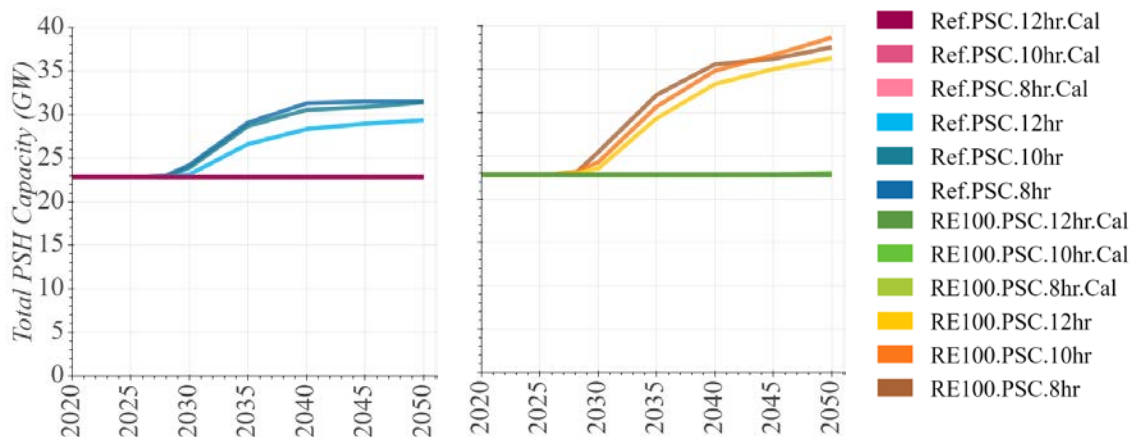


Figure ES 1. Total PSH capacity deployment including the existing fleet is plotted through 2050 in reference scenarios [Ref] (left panel) and scenarios requiring 100% renewables by 2050 [RE100] (right panel). Results include PSH supply curves assuming 8-, 10-, and 12-hour storage durations as well as pre- and post-calibration [Cal] of site capacity costs. Results demonstrate the potential for new closed-loop PSH deployment in the United States at lower costs, with high-RE scenarios providing a greater deployment incentive.

Where practical, it appears valuable to consider shifting available hydropower energy across long-duration timescales up to a season. However, it is unclear how this value compares to any associated costs to environmental and other water management requirements. Although practical limitations of non-power constraints and planning horizons can prohibit major changes to inter-seasonal hydropower and PSH operating plans, exploratory scenarios demonstrate there is value to the grid in shifting hydropower energy to winter periods, which has implications for other long-duration storage technologies. In the scenarios modeled herein, this seasonal shifting primarily helps balance seasonal availability of solar PV resources, which could become increasingly important if flexible fossil-generation is less available and electrification leads to higher winter load. We observe this behavior both when relaxing constraints on hydropower seasonal energy allocations and when allowing PSH to perform energy arbitrage across seasons. This bounding case indicates there is value in seasonal storage and demonstrates a framework that could be expanded to explore energy allocation and arbitrage at timescales between diurnal and seasonal.

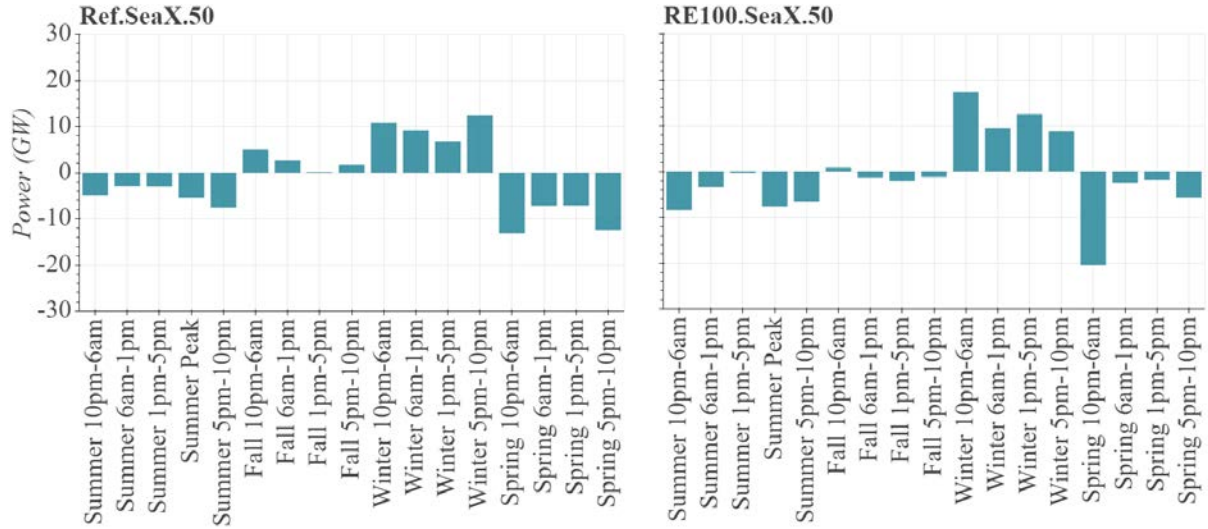


Figure ES 2. This plot shows the change to the U.S. hydropower fleet generation for ReEDS time-slices in Ref and RE100 scenarios when energy is allowed to be shifted across seasons. When 50% of available hydropower energy is permitted to shift across seasons, energy is typically shifted from the spring and sometimes the summer to the winter, which helps balance seasonal availability of solar PV resource.

Improving flexibility of existing hydropower assets has the potential to reduce CO₂ emissions and improve electricity system economics (Figure ES 3 and Figure ES 4). This can occur because flexible hydropower can complement VG technologies and reduce the need to deploy new flexible technologies that are higher-emitting, higher-cost, or both. Though we do not impose realistic practical limits on upgrading hydropower flexibility, demonstrative scenarios allowing existing hydropower to invest in upgraded flexibility has the greatest overall impact on the U.S. electricity system outcomes. These flexibility upgrade opportunities included allowing existing flexible hydropower to add pumps and allowing existing inflexible (i.e., run-of-river) hydropower to invest and enable flexible dispatch in response to electricity market requirements within minimum and maximum capacity limits. In scenarios where these upgrades and all other new features are enabled at relatively low cost (AllFlex), dispatchability and add-pump upgrades occur on most of the existing hydropower fleet. In the Reference scenario, hydropower flexibility upgrades help facilitate greater PV deployment (155 GW in 2050), which supports 35% lower CO₂ emissions in 2050 and 7% lower electricity costs. In the RE100 scenario, hydropower flexibility reduces the need for new construction of other flexible technologies (289 GW less total capacity in 2050), allowing decarbonization at lower electricity costs (12% in 2050).

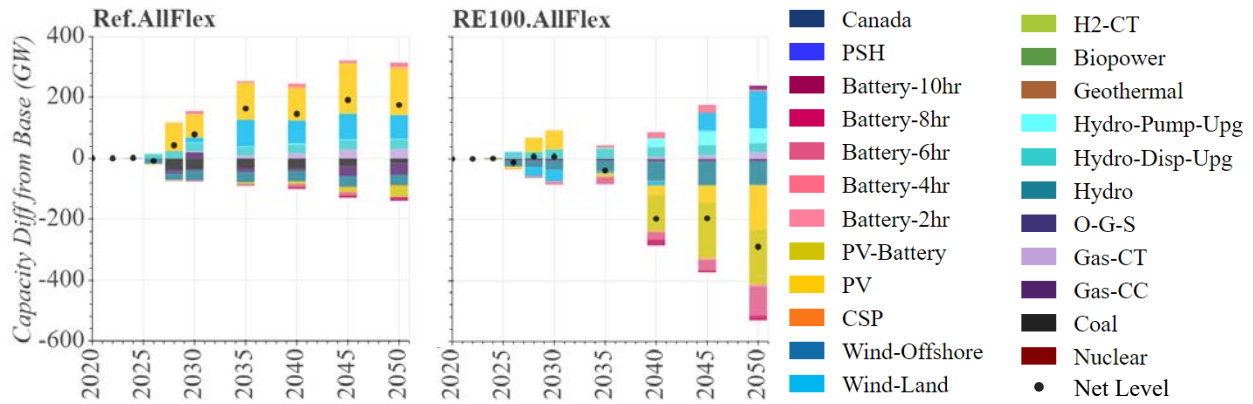


Figure ES 3. The change to the national capacity mix is shown for Ref and RE100 scenarios with and without the full array of new hydropower and PSH capabilities permitted by new model developments. Increased hydropower and PSH flexibility and upgradeability substantively change the national capacity mix in a Ref scenario and a RE100 scenario where hydropower and PSH improvements are given favorable costs and operability parameters relative to their respective base scenarios with default costs and operability.

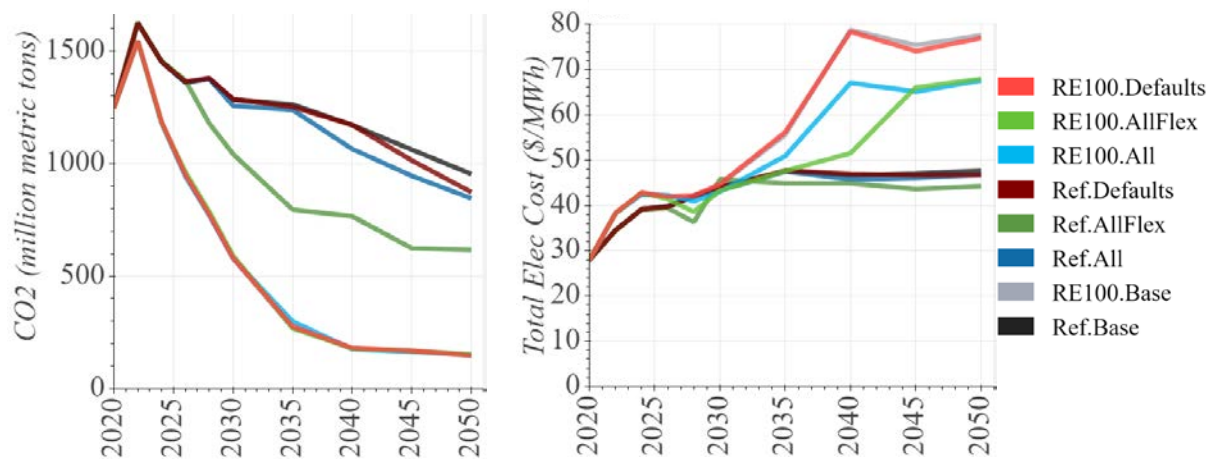


Figure ES 4. CO₂ emissions (left) and total marginal electricity cost (right panel) under Ref and RE100 scenarios that vary the extent that hydropower and PSH upgrades and improved flexibility is available (Base < Defaults < All < AllFlex) and show that these changes can reduce CO₂ emissions and electricity costs. The electricity cost metric includes energy, capacity, and policy cost components.

Future analysis and modeling of hydropower and PSH's role in electricity systems could benefit from improved data and modeling methods, particularly for defining the potential to deploy new closed-loop PSH and enhance the operating flexibility of the existing hydropower fleet. Improvements to geospatial and site-level data could enable a more accurate assessment of these opportunities, but valuable conclusions could be drawn with expanded scenario sensitivity analysis using new methods described herein. Expanded scenario analysis could also be coupled with continued model improvements to represent operating flexibility and long-duration storage opportunities for hydropower, PSH, and other technologies to best understand competition among technologies in a low-carbon grid.

This report lays the groundwork to use advanced planning models to explore the range of roles hydropower and PSH can play in the grid of the future. The report can help both analysts and decision makers better identify key opportunities for hydropower and PSH investment when deciding how to decarbonize the electricity system and broader economy.

Acronyms and Abbreviations

AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
BA	balancing area
CEM	capacity expansion model
CO ₂	carbon dioxide
CSP/csp	concentrating solar power
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
Gas-CC	[Natural] gas combined cycle
Gas-CT	[Natural] gas combustion turbine
H2-CT	hydrogen-fueled combustion turbine
hr	hour
Hydro-Disp-Upg	hydropower that has upgraded from nondispatchable to dispatchable
Hydro-Pump-Upg	hydropower that has been upgraded by adding a pump
IHA	International Hydropower Association
kW	kilowatt
MWh	megawatt-hour
NPD	non-powered dam
NREL	National Renewable Energy Laboratory
NSD	new stream-reach development
O-G-S/ o-g-s	oil-gas-steam
ORNL	Oak Ridge National Laboratory
PCM	production cost models
PSH	pumped storage hydropower
PV	[solar] photovoltaic
PV-Battery	[solar] photovoltaic battery [hybrid]
RE	renewable energy
ReEDS	Regional Energy Deployment System
RTO	regional transmission operator
TEPPC	Transmission Expansion Planning Policy Committee
TWh	terawatt-hour
USD	U.S. dollars
US-REGEN	Regional Economy, Greenhouse Gas, and Energy [model]
VG	variable generation

WECC	Western Electricity Coordinating Council
Wind-Land	land-based (onshore) wind
yr	year

Scenario Nomenclature

This section describes shorthand and abbreviations used in naming scenarios that are described in detail in within the report. Sections 1.4, 2.4, 3.5, 4.4, and 5.1 include full scenario definitions, and this table can be used as a reference beyond scenario definition tables in those sections.

Ref	Reference case data and assumptions for all information that does not involve hydropower and PSH technologies
RE100	Scenario enforces a linear path to 100% renewable energy in 2050, with reference data and assumptions for all information that does not involve hydropower and PSH technologies
Base	Base representation of hydropower and PSH prior to any model improvements
PSC.#hr	Scenario uses a new PSH Supply Curve (PSC) where the “#” specifies the assumed storage duration in hours (hr)
Cal	Scenario uses new PSH supply curves after implementing a cost calibration procedure
PFix	Scenario enforces additional constraints on PSH to represent fixed-speed operation
PCap	Scenario uses plant-level PSH capacity data
SeaX.[<i>fx</i>]	Scenario allows interseason energy transfers for existing dispatchable hydropower (not PSH), and <i>fx</i> is the fraction of energy originally allocated to each season that must remain allocated to that season
SeaA.[<i>fa</i>]	Scenario allows interseason energy arbitrage for existing PSH, and <i>fa</i> is the fraction of energy input (stored) in a season that must be used for generation in that season
Dur	Scenario uses plant-specific PSH storage duration data for the existing PSH fleet
UD.[<i>dc</i>]	Scenario allows upgrades of dispatchability for existing nondispatchable hydropower, and <i>dc</i> is the dispatchability upgrade capital cost in \$/kW
UP.[<i>pc</i>]	Scenario allows upgrades that add pumps to existing dispatchable hydropower, and <i>pc</i> is the pump upgrade capital cost in \$/kW
UC.[<i>fcc</i>]	Scenario allows upgrades of capacity for existing hydropower, and <i>fcc</i> is the fractional multiplier applied to the combined capacity-plus-energy capital cost to define the capacity-only upgrade capital cost
UE.[<i>fec</i>]	Scenario allows upgrades of energy for existing hydropower, and <i>fec</i> is the fractional multiplier applied to the combined capacity-plus-energy capital cost to define the energy-only upgrade capital cost
UCE.[<i>fcc</i>].[<i>fec</i>]	Scenario allows independent upgrades of capacity and/or energy for existing hydropower, with <i>fcc</i> and <i>fec</i> defined as above
Default	Scenario uses a combination of new hydropower and PSH assumptions that will become default assumptions in the ReEDS model version 2021
All	Scenario uses a combination of new hydropower and PSH assumptions that enables all new hydropower and PSH features and data with relatively conservative assumptions for cost and flexibility
AllFlex	Scenario uses a combination of new hydropower and PSH assumptions that enables all new hydropower and PSH features and data with relatively aggressive assumptions for cost and flexibility

Equation Terms

Sets and Subsets

<i>i</i>	technology
<i>PSH</i>	subset of <i>i</i> including all PSH technologies
<i>Pump upgrades</i>	subset of <i>i</i> including all upgrade technologies containing pump additions to hydropower
<i>dispatchable hydro</i>	subset of <i>i</i> including all dispatchable hydropower technologies
<i>v</i>	technology vintage
<i>r</i>	region
<i>h</i>	time-slice
<i>hh</i>	duplicate time-slice set
<i>szn</i>	subset of <i>h</i> including all time-slices in a season
<i>t</i>	year
<i>t'</i>	duplicate year set
<i>eligible</i>	subset of <i>t</i> including all eligible model years
<i>bin</i>	resource bin

Variables

<i>CAP</i>	generator or pump capacity
<i>GEN</i>	generator power output
<i>STORAGE_IN</i>	power input to storage
<i>STORAGE_LEVEL</i>	stored energy level
<i>INV_CAP_UP</i>	new capacity investment for capacity-only upgrades
<i>INV_ENER_UP</i>	new capacity investment for energy-only upgrades

Parameters

<i>H</i>	total number of hours represented by a time-slice
<i>hours_daily</i>	number of hours per day represented by a time-slice
<i>minstorfrac</i>	minimum power input to storage as a fraction of maximum power input to storage in a season
<i>storinmaxfrac</i>	ratio of pump capacity to generator capacity
<i>avail</i>	availability factor
<i>m_cf_szn</i>	seasonal average capacity factor used in the model
<i>within_seas_frac</i>	fraction of originally allocated seasonal energy that must be used within that season (hydropower) or fraction of storage input across a season that must be used to generate power in that season (PSH)
<i>storage_eff</i>	energy storage round-trip efficiency
<i>cap_cap_up</i>	upper limit on capacity upgrades
<i>cap_ener_up</i>	upper limit on capacity upgrades

Contents

Acknowledgments.....	i
Executive Summary.....	iii
Acronyms and Abbreviations	1.1
Scenario Nomenclature.....	1.3
Equation Terms.....	1.4
Contents.....	1.5
Figures.....	1.7
Tables.....	1.10
1.0 Introduction: Projecting the Future of Hydropower and PSH with Capacity Expansion Modeling	1.11
1.1 The Evolving Role of Hydropower and PSH in the Electricity System.....	1.11
1.2 Hydropower and PSH Modeling Challenges in Expansion Planning	1.12
1.3 The Regional Energy Deployment System (ReEDS) Modeling Platform	1.13
1.3.1 Model Overview.....	1.13
1.3.2 Baseline Hydropower and PSH Representation.....	1.14
1.3.3 Hydropower and PSH Modeling Improvements	1.16
1.4 Demonstrative Scenario Design.....	1.17
2.0 Pumped Storage Hydropower Resource Data and Pump Characteristics.....	2.19
2.1 Integrating a New National Closed-Loop PSH Resource Assessment	2.20
2.2 Distinguishing Pumping Technologies	2.22
2.3 Differentiating Pump and Generator Capacity.....	2.23
2.4 Scenario Results.....	2.24
2.4.1 New PSH Supply Curves	2.24
2.4.2 Fixed-Speed versus Adjustable-Speed Pumps	2.28
2.4.3 Pump Capacity Data.....	2.28
3.0 Valuing Long-Duration Energy Storage.....	3.30
3.1 Interseasonal Energy Transfers with Hydropower Generation	3.30
3.2 Interseasonal Energy Arbitrage with PSH.....	3.31
3.3 Plant-Level Storage Duration Data	3.31
3.4 Intermediate-Duration Storage Valuation Using Hourly Dispatch Module.....	3.32
3.5 Scenario Results.....	3.33
3.5.1 Interseasonal Energy Transfers	3.34
3.5.2 Interseasonal Arbitrage with PSH.....	3.38
3.5.3 Storage Duration Data.....	3.42
3.5.4 Valuing Intermediate-Duration Storage	3.45
4.0 Upgrading Hydropower Systems.....	4.46
4.1 Improving Dispatchability of Hydropower Generation	4.46

4.2	Adding Pumping	4.47
4.3	Increasing Generating Capacity or Stored Energy	4.48
4.4	Scenario Results	4.49
4.4.1	Upgrading Hydropower Generation Dispatchability.....	4.50
4.4.2	Adding Pumps to Hydropower Generation	4.55
4.4.3	Increasing Capacity or Energy	4.62
5.0	Broader Modeling Implications.....	5.67
5.1	Scenario Comparison with All Changes	5.67
5.2	Adapting Methods to Other Capacity Expansion Models.....	5.75
5.3	Application to Other Model Types.....	5.76
5.4	Future Research and Applications.....	5.77
6.0	Summary and Recommendations	6.78
7.0	References	7.80

Figures

- Figure 1.1. National capacity and generation in Base scenarios. Ref projects a mix of fossil and renewable generation sources, where RE100 invests heavily in variable renewables and storage. 1.18
- Figure 1.2. 2050 power generation by time-slice in Base scenarios. Black circles show net power generation. Ref balances VG with natural gas and some energy storage, where RE100 relies more heavily on storage. 1.19
- Figure 2.1. Comparison of the Base PSH supply curve created for the DOE *Hydropower Vision* (black) and alternative PSH supply curves using new resource assessment data with three possible assumed storage durations. New resource estimates include lower-cost sites and far greater resource. 2.21
- Figure 2.2. Comparison of BA-level distribution of prior (Base) PSH resource and the new PSH supply curve for 10-hr storage duration. Both follow similar regional distributions, but new data has more resource, especially in the west. 2.21
- Figure 2.3. Total PSH capacity deployment across Ref (left panel) and RE100 scenarios (right panel), including the existing fleet, demonstrates the potential for new closed-loop PSH deployment in the United States at lower costs, with high-RE scenarios providing a greater deployment incentive... 2.25
- Figure 2.4. Difference in energy storage capacity by technology relative to the respective Base case with the new PSH supply curves before cost calibration. New PSH deployment typically displaces longer-duration batteries but can correspond to greater short-duration battery deployment. 2.26
- Figure 2.5. New PSH capacity by state through 2050 for the 10-hr duration supply curve before cost calibration. Most new PSH is deployed in California and the southwestern United States. 2.27
- Figure 2.6. Net discounted value of new PSH capacity deployed with the 10-hr duration supply curve, with arrows indicating that the actual value is beyond the y-scale shown. New PSH is most valuable for providing planning reserves, with curtailment reduction and energy arbitrage providing smaller value streams. 2.28
- Figure 2.7. National power output from the U.S. PSH fleet by time-slice in 2050 in Base scenarios and in Pcap scenarios that incorporate plant-level pump capacity data. Pump capacity data has a negligible cumulative impact on national PSH operation. 2.29
- Figure 2.8. Power output by time-slice in 2050 for PSH capacity in Georgia in RE100.Base and in the RE100.Pcap scenario that incorporates plant-level pump capacity data. Pump input capacity data has a notable impact on PSH dispatch in Georgia. 2.29
- Figure 3.1. IHA data for storage duration versus generating capacity at three different y-axis scales to view progressively smaller storage durations. While some facilities have hundreds to thousands of hours of energy storage, most are 12 hours or less. 3.32
- Figure 3.2. Changes to 2050 time-slice generation relative to Base scenarios for hydropower. Hydropower energy tends to shift to the winter to help balance PV. 3.35
- Figure 3.3. Changes to 2050 time-slice generation relative to Base scenarios for all technologies. Shifting hydropower to the winter enables greater PV generation in Ref scenarios. 3.36
- Figure 3.4. Change to the national capacity and generation mix with interseasonal energy shifting. Ref scenarios have increased PV capacity and energy, but RE100 scenarios have mostly inconsistent technology-specific impacts. 3.37
- Figure 3.5. Sum of the discounted energy value across 2020–2050 model years for existing dispatchable hydropower in the Base scenarios and scenarios with the ability to transfer energy across seasons. Quantities are normalized by generation, and other value streams (e.g., capacity) are not shown.

Seasonal shifting has little effect on energy value in Ref scenarios but increases energy value in RE100 scenarios.	3.38
Figure 3.6. Changes to 2050 time-slice generation relative to Base scenarios for PSH. PSH tends to shift energy from Spring to Winter when able, which can help balance PV.	3.39
Figure 3.7. Changes to 2050 time-slice generation relative to Base scenarios for all technologies. Shifting PSH from Spring to Winter can increase PV generation and reduce fossil generation, depending on the scenario.	3.40
Figure 3.8. Change to the national capacity and generation mix with interseasonal energy arbitrage, relative to the corresponding Base scenario. Interseasonal energy arbitrage facilitates increased PV use and complements short-duration battery deployment in RE100 scenarios.....	3.41
Figure 3.9. Sum of the discounted energy value across 2020–2050 model years for existing PSH in the Base scenarios and scenarios allowing interseasonal energy arbitrage. Quantities are normalized by capacity; other value streams (e.g., capacity) are not shown. Interseasonal arbitrage increases energy value, particularly in the RE100 scenarios.....	3.42
Figure 3.10. 2050 time-slice generation for Ref scenarios with and without plant-level PSH storage duration data, for varying degrees of seasonal energy arbitrage. Storage duration data has negligible impact on nationally aggregated PSH dispatch.....	3.43
Figure 3.11. 2050 time-slice generation for RE100 scenarios with and without plant-level PSH storage duration data, for varying degrees of seasonal energy arbitrage. Storage duration data has negligible impact on nationally aggregated PSH dispatch.....	3.44
Figure 3.12. 2050 time-slice generation for PSH in Arizona for the RE100.SeaA.0 scenario with and without plant-level PSH storage duration data. Arizona has a 60-MW facility with 46 hours of storage and a 130-MW facility with 182 hours of storage, and plant-level storage duration data substantially affects how these systems operate in the model.	3.45
Figure 3.13. Minimum and maximum energy arbitrage value (2020\$) across balancing areas in several states, as a function of storage duration, in a Mid Case scenario in 2026 and a High RE scenario in 2050 (Georgia has only 1 ReEDS BA). Arbitrage value varies across regions and increases with storage duration, and the value of longer storage durations is higher in a high-RE grid.....	3.46
Figure 4.1. Upgrades over time from nondispatchable to dispatchable hydropower.....	4.51
Figure 4.2. Cumulative dispatchability upgrades by state in the RE100.UD.500 scenario in model years 2026, 2035, 2040, and 2050. Dispatchability upgrades are geographically dispersed and tend to occur later in areas with existing flexible hydropower (e.g., the Pacific Northwest).....	4.51
Figure 4.3. Fraction of eligible capacity that upgrades dispatchability by state in the RE100.UD.500 scenario in model years 2026, 2035, 2040, and 2050. Florida is the first to upgrade all capacity where regions in the Midwest and west do not upgrade all eligible capacity in this scenario.....	4.52
Figure 4.4. Change in national non-PSH hydropower power output in each ReEDS time-slice in 2050 relative to the corresponding Base scenario without flexibility upgrades available. When hydropower is more dispatchable, generation shifts to time periods when VG is less available.....	4.53
Figure 4.5. Change to the national capacity mix with flexibility upgrades (Hydro-Disp-Upg). Increased hydropower flexibility can substantially influence the deployment of RE, battery, and natural gas-based technologies, with the technology-specific impacts being scenario dependent.	4.54
Figure 4.6. Discounted value streams for hydropower with dispatchability upgrades over time for select scenarios, normalized by energy production. Dispatchability upgrades are driven by energy, capacity (reserve margin), and policy (national RPS) value.	4.55
Figure 4.7. Capacity upgraded over time by adding pumps to dispatchable hydropower. With 43.3 GW eligible for this upgrade, pump upgrades are far more attractive in high-RE scenarios.....	4.56

Figure 4.8. Cumulative pump upgrades by state in the RE100.UP.10 scenario in model years 2026, 2040, 2045, and 2050. These pump upgrades occur initially in Texas, neighboring states, and the southern Atlantic coast but eventually become regionally dispersed.	4.56
Figure 4.9. Fraction of eligible capacity that adds pumping by state in the RE100.UP.10 scenario in model years 2026, 2040, 2045, and 2050. When pump upgrades are competitive, they often deploy on 100% of the capacity in a given state.....	4.57
Figure 4.10. Power output from hydropower without pumping (Hydro) and hydropower with added pumps (Hydro-Pump-Upg) in each ReEDS time-slice in 2050 for Base scenarios and lowest-cost pump upgrade scenarios. Ref scenarios do not use pump upgrades for energy arbitrage, while RE100 scenarios do.....	4.58
Figure 4.11. Operating reserve provision from hydropower without pumping (Hydro) and hydropower with added pumps (Hydro-Pump-Upg) in each ReEDS time-slice in 2050 for Base scenarios and lowest-cost pump upgrade scenarios. Ref scenarios use pump upgrades to provide operating reserves, while RE100 scenarios do not.	4.59
Figure 4.12. Change to the national capacity mix with pump upgrades. Pump upgrades can help facilitate RE deployment and reduce the need for alternative flexible technologies (e.g., PV-battery).	4.60
Figure 4.13. Discounted energy and operating reserves value streams for hydropower with pump upgrades over time for select scenarios, normalized by energy production. Operating reserves is a key value stream in Ref scenarios, with energy arbitrage having some value in RE100 scenarios.	4.61
Figure 4.14. Discounted reserve margin value streams for hydropower with pump upgrades over time for select scenarios, normalized by energy production. Reserve margin value of pump upgrades is high in many years in Ref scenarios.	4.61
Figure 4.15. Change in total hydropower capacity over time with capacity-only upgrades (UC, left panel), independent capacity and energy upgrades (UCE, right panel), and Base configurations with the prior formulation having combined capacity-plus-energy upgrades. Capacity upgrades vary by cost and scenario but are largely a similar magnitude as the Base scenarios. Note that the figure axis does not start at zero.....	4.62
Figure 4.16. Cumulative capacity upgraded through 2050 by state for scenarios with capacity-only upgrades available (UC) and the Base scenarios with combined capacity-plus-energy upgrades. Capacity upgrades are initially attractive in the western United States but occur throughout the United States in scenarios with more capacity upgrades.	4.63
Figure 4.17. Change in total hydropower generation over time with energy-only upgrades (UE), independent capacity and energy upgrades (UCE), and Base configurations with the prior formulation having combined capacity-plus-energy upgrades. Independent capacity and energy upgrades lead to the greatest overall hydropower generation, but results are similar to Base scenarios. Note that the figure axis does not start at zero.	4.64
Figure 4.18. Additional 2050 generation from hydropower relative to a “no upgrade” case in Ref scenarios with energy-only upgrades available (UC), independent capacity and energy upgrades (UCE), and the Base scenarios with combined capacity-plus-energy upgrades. Upgrading hydropower energy availability is most attractive in the western United States but becomes more geographically dispersed as more capacity upgrades.	4.65
Figure 4.19. Additional 2050 generation from hydropower relative to a “no upgrade” case in RE100 scenarios with energy-only upgrades available (UC), independent capacity and energy upgrades (UCE), and the Base scenarios with combined capacity-plus-energy upgrades. Additional hydropower energy is very geographically dispersed in RE100 scenarios.....	4.66
Figure 5.1. Capacity of each hydropower and PSH technology type over time for Ref scenarios, showing PSH deployment and upgrades from hydropower to add flexibility (Hydro-Disp-Upg) or pumping	

(Hydro-Pump-Upg) as well as the sum of hydropower plus all upgrade types (bottom-left panel). Dispatchability upgrades are more prevalent than pumping upgrades, and low-cost PSH is deployed. 5.69

Figure 5.2. Capacity of each hydropower and PSH technology type over time for RE100 scenarios, showing PSH deployment and upgrades from hydropower to add flexibility (Hydro-Disp-Upg) or pumping (Hydro-Pump-Upg) as well as the sum of hydropower plus all upgrade types (bottom-left panel). Some RE100 scenarios increase flexibility of nearly all hydropower, and high-flexibility hydropower can compete with new PSH deployment. 5.70

Figure 5.3. Generation of each hydropower and PSH technology type over time, showing PSH deployment and upgrades from hydropower to add flexibility (Hydro-Disp-Upg) or pumping (Hydro-Pump-Upg) as well as total net generation of hydropower, upgrades, and PSH (bottom-left). Pump efficiency losses and displacement by other low-cost technologies sometimes results in reduced generation. 5.71

than in Figure 5.4. This is also true for Ref.All relative to Ref.UD.500, but Ref.AllFlex has slightly smaller magnitude changes than Ref.UD.10..... 5.71

Figure 5.5. Change to the national capacity mix relative to Base in scenarios with combined new features and data. Increased hydropower and PSH flexibility and upgradability supports greater wind and PV capacity in Ref scenarios and reduces system capacity needs in RE100 scenarios. 5.72

Figure 5.6. Change to the national generation mix relative to Base in scenarios with combined new features and data. Increased hydropower and PSH flexibility and upgradability reduces fossil fuel use in Ref scenarios and decreases net electricity demands from PV-battery storage losses in RE100 scenarios. 5.73

Figure 5.7. CO₂ emissions over time in scenarios with combined new features and data. Increased hydropower and PSH flexibility and upgradability can facilitate lower CO₂ emissions. 5.73

Figure 5.8. Total marginal cost of electricity over time in scenarios with combined new features and data. This metric includes all marginal cost components, including those from energy, capacity, and policy requirements. (2020 USD). Increased hydropower and PSH flexibility and upgradability can reduce electricity costs, particularly in low-carbon scenarios. 5.74

Figure A.1. National power output from the U.S. PSH fleet by time-slice in 2050 when all capacity is represented as fixed-speed versus adjustable-speed pumps. The model representation of fixed-speed pumps nearly negates energy arbitrage opportunities and is thus overly restrictive..... 1

Tables

Table 1.1. Baseline Scenarios for Demonstrating Model Improvements 1.18

Table 2.1. Generator and Pump Capacity Data for Units with Unequal Pump and Generator Capacity. 2.23

Table 2.2. Scenarios for Demonstrating PSH Improvements 2.24

Table 3.1. Scenarios for Demonstrating Long-Duration Energy Storage Valuation 3.33

Table 4.1. Scenarios for Demonstrating New Hydropower Upgrade Options..... 4.50

Table 5.1. Scenario Specifications for Scenarios that Combine New Model Features..... 5.68

Table 5.2. Present Value of Total System Cost from 2020 to 2050 for Base Scenarios and Each Scenario with Combined Features and Data, Showing Absolute and Relative Differences from Base Scenarios 5.75

1.0 Introduction: Projecting the Future of Hydropower and PSH with Capacity Expansion Modeling

Capacity expansion models (CEMs) are a class of analytic tools used to project future investment decisions under one or more guiding objectives, given a set of decision variables and constraints on the systems being modeled. CEMs often include a representation of operational decisions to better represent how operational outcomes drive investment decisions. In the electric sector, CEMs are commonly used to understand the future mix of generation, storage, and transmission technologies that meet future system performance, environmental, and policy objectives at the minimum cost or maximum welfare, or other overarching aims. Examples of CEMs include the:

- Electricity module of the National Energy Modeling System, which is used for U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) scenarios (EIA 2020b; 2021a)
- Integrated Planning Model, which is used for U.S. Environmental Protection Agency (EPA) regulatory analysis (US EPA 2018; EPA 2011)
- Electric Power Research Institute’s U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model, which is used for industry stakeholder-driven analysis (EPRI 2020; 2018; 2021)
- National Renewable Energy Laboratory’s (NREL’s) Regional Energy Deployment System (ReEDS), which used in the exploratory analysis reported in this document and has been used to explore an array of electricity futures for various purposes (DOE 2016; Hamm et al. 2019; Murphy and Mai 2021; DOE 2021; W. Cole et al. 2021).

Some CEM analyses such as that included in the DOE *Hydropower Vision* focus specifically on hydropower¹ and pumped storage hydropower (PSH) technologies, exploring hydropower and PSH deployment and operating potential across a range of technology and policy scenarios (DOE 2016; Barros et al. 2003; Ralston Fonseca et al. 2021; Gyanwali, Komiyama, and Fujii 2020). In the dynamic and ever-evolving landscape of electricity systems in the United States and beyond, CEMs are an important tool for understanding the future roles of all electricity system technologies, and hydropower and PSH are not exceptions.

1.1 The Evolving Role of Hydropower and PSH in the Electricity System

Hydropower and PSH have played a variety of roles in the electricity system for many decades, with the first PSH facility in operation in 1930 and the first hydropower facilities coming online before 1900 (USDOE n.d.; n.d.). In addition to providing low-marginal-cost energy, hydropower and PSH are often flexible enough to dispatch in response to real-time grid needs and provide ancillary services such as operating reserves, frequency response, and voltage support with high reliability. These capabilities have long allowed hydropower and PSH to play a key role in providing grid reliability and resilience.

Multiple electric sector trends suggest a growing need for low-cost, flexible, reliable power. Variable generation (VG) is poised to meet an increasing share of electricity demand, and its lower dispatchability than other generation technologies could increase the need for flexible grid technologies of all types. This

¹ Throughout this report, “hydropower” is most often used to refer to systems that do not have pumping capabilities, though it is sometimes used to refer more broadly to all hydropower generation and storage technologies.

trend along with increasingly electrified transportation and building loads creates further uncertainty about electricity demand, including both the quantity demanded and its timing at diurnal to interannual scales. Uncertainty in Earth systems over both long and short timescales will also compound uncertainty about both supply and demand, raising the importance of flexible, reliable electricity systems. Emerging contributions of batteries, demand response, and distributed energy systems contribute to a dynamic landscape of electric sector trends that could create both challenges and opportunities for hydropower and PSH.

Hydropower's ability to respond to future grid needs is affected by the prioritization of hydropower among other water management functions of dams, which often include environmental flows, irrigation, navigation, recreation, flood control, and other services. This large set of requirements can create challenges for hydropower flexibility while also incentivizing innovative approaches to enhancing flexibility of existing and future hydropower systems. Cascading multifacility hydropower systems also constrain operation, but they offer the possibility of coordinated operation for greater overall flexibility. Closed-loop, off-river PSH is an example of how future hydropower could prioritize electricity services with fewer environmental constraints (Saulsbury 2020). Hydropower is technically capable of fast ramping between minimum and maximum output within a few minutes (Mongird et al. 2020), possibly meaning some existing facilities could become more flexible with technological upgrades or revised operating plans, and new facilities could be built with low environmental impact and with electricity designated as a higher priority. Large hydropower reservoirs, particularly among the existing hydropower fleet, could provide flexibility over longer timescales than many other energy storage technologies currently being considered, potentially allowing hydropower to fulfill long-duration storage needs associated with very high VG penetration.

Competition with other storage technologies is one example of how the future role of hydropower and PSH in the grid will depend on complex interactions with other supply, demand, and storage technologies. It is thus important to study future hydropower and PSH in the grid using an approach that explicitly represents the complexities of hydropower and PSH operation along with other electricity supply, demand, and transmission characteristics. And this should be done in a grid-level context with sufficient fidelity to capture important operational and investment decision drivers. CEMs are designed specifically to address these types of problems; however, hydropower and PSH representations in electricity CEMs have historically failed to effectively characterize technology and operational characteristics with sufficient detail to answer focused questions about future deployment and operation. These modeling challenges, which are discussed in the next section, are the primary motivator of this work.

1.2 Hydropower and PSH Modeling Challenges in Expansion Planning

Several common structural characteristics of CEMs create difficulties for representing realistic hydropower and PSH characteristics (Stoll et al. 2017; PNNL 2021; Koritarov et al. 2021; Harby et al. 2019). First, these models are often spatially aggregated such that individual plants are not explicitly represented, making it difficult to account for site-specific characteristics and constraints. CEMs do not always have chronological intra-annual time resolution, severely limiting their ability to represent time-variant water availability and operating constraints. CEMs with higher intra-annual time resolution still typically use characteristic 24-hr periods rather than a full hourly or subhourly time series for each model year. Challenges with temporal resolution and chronology limit CEM capabilities to represent energy storage and flexibility in general, impacting their utility in studies of hydropower and PSH technologies, which can have complex complementary or competitive relationships with other storage and flexible technologies (J. Bistline et al. 2020). Even with plant-level resolution and hourly time resolution,

computational and data limitations prevent a complete characterization of hydropower and PSH operating characteristics, which strongly depend on non-power components of water management plans. This limitation is further reflected in the solution algorithms, which typically use a cost- or profit-optimizing approach without directly representing other non-power and nonmarket objectives.

Beyond challenges representing today's hydropower and PSH systems, CEMs have not been used extensively to understand how hydropower and PSH technologies and operating plans could adapt and change over time in response to system needs and external influences such as climate change. Though there can be barriers to changing characteristics of the existing fleet, no work has used a detailed national-scale CEM to systematically enumerate the value of changing alternative hydropower and PSH technology and operating characteristics. Similarly, there has been limited capability to examine how improved flexibility could change economic competitiveness of new hydropower and PSH while also satisfying ecosystem needs. Valuing flexibility for all technologies has been a broader challenge, particularly when aiming to differentiate between flexibility of various generation and storage technologies.

This report describes the outcomes of a 2-year effort to address some of these limitations by developing advanced methods for representing hydropower and PSH in CEMs, it specifically focuses on improving technology and operating detail. These new capabilities aim to improve our understanding of the future role of hydropower and PSH in electricity systems. The work reported herein uses the ReEDS model, a CEM built to explore the contiguous U.S. electric system to 2050 and beyond. However, the techniques described herein could be adapted to other models and tools that explore hydropower and PSH deployment and operation anywhere in the world.

1.3 The Regional Energy Deployment System (ReEDS) Modeling Platform

ReEDS, NREL's flagship electricity CEM, has been used for several notable analyses for DOE and others, including the 2016 DOE *Hydropower Vision* (W. Cole et al. 2020; DOE 2016; Murphy and Mai 2021; Hamm et al. 2019). The model undergoes continual improvement with annually released versions, and ReEDS v2021 is the basis of all analysis in this report (NREL 2021b). The documentation for ReEDS v2021 is forthcoming, but the v2020 documentation (Ho et al. 2021) contains a thorough discussion of the model formulation and data. Rather than describe all model components, this report briefly describes key model characteristics relevant to hydropower and PSH before discussing innovations to improve the ReEDS representation of these technologies.

1.3.1 Model Overview

ReEDS uses linear programming to minimize the 20-year present value of all investment and operating costs in the contiguous U.S. electricity system in one or more model years starting with 2010 as a base year. Scenarios are typically explored using sequential model-year solution increments of 2 years through 2030 and 5 years through 2050, though the model can solve any set of years, continue beyond 2050, and optimize multiple model years simultaneously. The least-cost objective function includes costs of capital, fuel, fixed operation and maintenance, and variable operation and maintenance for each generation, storage, and transmission technology, along with any applicable policy costs and incentives.

Model constraints represent energy demand requirements and capacity needs to maintain adequacy and operating reserves, with three types of operating reserve products: spinning, flexibility, and regulation. Adequacy reserve requirements are defined using regional transmission organization reserve margins, and operating reserve requirements are a function of load as well as VG penetration, meaning they change

over time and with the generation mix. The ability of a given technology to provide operating reserves depends on its ramp rate and the necessary time-frame for providing each operating reserve product.

ReEDS represents the supply and demand of these grid services with high spatial, temporal, and process resolution for its model class and scope. The contiguous United States is resolved into 134 balancing areas (BAs) for electricity demand and generation, with the wind and concentrating solar power (CSP) resource further resolved by 356 resource regions. Demand for energy and capacity can be met by a full suite of generation and storage technologies, many of which are further distinguished by technology subcategories, resource classes, and vintages to differentiate the cost and performance of generation and storage technologies. Electricity flows between BAs are represented using an aggregated inter-BA transmission system with capacity limits and pipe flow constraints. In addition to deploying generation and storage, the model can choose to expand transmission capacity along existing inter-BA transmission corridors to meet system needs at the least cost. Within each model year, the core optimization balances electricity supply and demand and operating reserves in 17 intra-annual time-slices while interfacing with an hourly dispatch model that uses 7 years of hourly data to calculate VG curtailment, capacity credit for VG and storage, and diurnal energy arbitrage value for storage technologies. The aggregated time-slices include chronological morning, afternoon, evening, and night time-slice for each season plus a peak time-slice averaging the top 40 load hours in a year, allowing investment decisions to be made while capturing resource and load profile coincidence along with diurnal and seasonal operating flexibility. The additional module employs a simplified 8,760-hr dispatch optimization to dynamically update VG and storage characteristics across model years depending on how the system evolves in that scenario.

ReEDS uses unit-level characteristics of generation and storage resources from the EIA, including cost and performance, planned and lifetime retirements, and prescribed expansion of near-term known construction. Electricity load and fossil fuel price projections are derived from the EIA AEO2021, and technology cost and performance projections are taken from the NREL 2021 Annual Technology Baseline (ATB) (NREL 2021a; EIA 2021a). PSH capital costs are not yet included in the 2021 ATB, so its capital costs and resource availability are derived from either the *Hydropower Vision* (DOE 2016) or the new PSH supply curves described in Section 2.1.

The model also represents existing electricity policies including renewable portfolio standards, storage capacity mandates, tax credit incentives, air pollution limits, and regional carbon dioxide (CO₂) emissions policies (e.g., the California and the Regional Greenhouse Gas Initiative). Where appropriate, hydropower and PSH are made eligible for these policies.

1.3.2 Baseline Hydropower and PSH Representation

The baseline representation of hydropower and PSH technologies in ReEDS is largely a product of work conducted for the DOE *Hydropower Vision* and is documented in detail in Chapter 3 and Appendix B of the *Hydropower Vision* report (DOE 2016). The formulation of hydropower and PSH technologies, described in this section, is used as a reference point for comparison of the new model and data changes described in subsequent sections of the report.

The *Hydropower Vision* work added new categories of hydropower resource potential and cost, including upgrades to the existing (non-pumped) fleet, powering non-powered dams and new stream-reach development. Binned regional supply curves for these technologies were developed by Oak Ridge National Laboratory (ORNL) using existing literature and geospatial analysis and resulting in the model including 6.9 GW of upgrade potential with 27 TWh/yr energy potential, 5.0 GW of non-powered dams (27 TWh/yr), and 30.7 GW of new stream-reach development (176 TWh/yr (ORNL n.d.; Hadjerioua, Wei, and Kao 2012; DOE 2016; Bureau of Reclamation 2011; Montgomery, Watson, and Harza 2009).

The existing hydropower generation fleet capacity and energy availability are based on historical data from the Western Electricity Coordinating Council’s Transmission Expansion Planning Policy Committee (TEPPC) 2024 Common Case and the ORNL HydroSource database (formerly the National Hydropower Asset Assessment Program) (WECC 2013; NHAAP, n.d.; Rocío Uría-Martínez, Patrick W. O’Connor, and Megan M. Johnson 2015). Maximum available capacity is adjusted seasonally in WECC regions using available monthly data. Generation in historical years is calibrated to match historical generation, and future years define energy availability using average capacity factors for 2006–2015.

One limitation of the baseline technology representation is that the existing fleet is dispatched in the model independently of any upgrades that are optimally deployed, as the upgrades are treated as a separate technology resource. In addition, upgrades are generic in that they always entail both an energy and a capacity increase, with the energy increase being proportional to the capacity factor of the existing fleet in that region. This simple representation of upgrades allowed prior work to identify opportunities for upgrade deployment, but it offers limited insights into what might drive decisions for different types of upgrades under different future grid conditions.

PSH is represented in the baseline as a single technology category, so there is no distinction between the existing fleet and new potential and no differentiation between pump types for existing or new capacity. Existing fleet capacity is defined using EIA data, and new resource potential includes capacity identified in a 30-year history of Federal Energy Regulatory Commission (FERC) license applications and preliminary permits as well as 750 MW of additional resource in each ReEDS BA to provide an outlet for storage deployment if storage is particularly valuable in a region (EIA 2021a; FERC, n.d.). New PSH costs are a function of capacity regressed from limited cost data in FERC applications, and artificial resource is assigned a high cost at the 90th percentile of all resource, so in practice it is not deployed unless deep cost reductions are assumed.

This PSH representation limits the model’s ability to consider trade-offs between alternative pump technologies and resource types. Also, while FERC applications and permits are useful for identifying some attractive PSH resources, they are inherently inconsistent and incomplete, unlike the national technical resource potential estimates used for wind, solar, and geothermal resources. Also, limited cost data are not generated using a consistent bottom-up approach.

Baseline operability of hydropower generation is characterized first by categorizing the existing fleet and its associated upgrades as either dispatchable or nondispatchable. This categorization is made using WECC operating classes for the Western Interconnection and ORNL operating modes for the rest of the contiguous United States (WECC 2013; Rocío Uría-Martínez, Patrick W. O’Connor, and Megan M. Johnson 2015; NHAAP, n.d.). In the model, the nondispatchable portion of the fleet is required to generate constant power output across all time-slices in each season such that it uses 100% of its seasonal energy budget. This nondispatchable hydropower has a flat generation profile in each season that is most often below 100% of its rated capacity. Even when not generating at 100% its rated capacity, nondispatchable hydropower is prohibited from providing operating reserves, and its contribution to firm capacity (i.e., capacity credit) is assumed to equal its power output in a season. On the other hand, dispatchable hydropower can optimize its power output within minimum and maximum output limits across time-slices within a season, within its seasonal energy budget. Any excess available capacity can be used to provide operating reserves, and the full rated capacity is applied toward adequacy reserve requirements. All non-powered dam and new stream-reach development resource is conservatively assumed to be nondispatchable based on how those resource assessments were conducted (ORNL n.d.; Hadjerioua, Wei, and Kao 2012; DOE 2016).

PSH flexibility is characterized both within the ReEDS optimization and in the 8,760-hr dispatch module that runs external to the main optimization. Within the ReEDS optimization, PSH is subject to an energy

balance over diurnal time-slices in a season, meaning it can perform diurnal energy arbitrage. Output and input capacity are assumed to be equal, and the energy balance assumes an 80% round-trip efficiency. The baseline model assumes all PSH, existing and new, has 12 hours of storage capacity. PSH can also dispatch pumps to help reduce VG curtailment. Any available PSH generation capacity can supply operating reserves. The 8,760-hr dispatch module also uses the 12-hour assumed storage duration to characterize capacity credit and diurnal arbitrage value (Ho et al. 2021; Frazier et al. 2020). Though this representation allows an understanding of the value of PSH for load-following, curtailment reduction, and reserve provision, the inputs are not necessarily representative of existing and potential new PSH capacity; the representation ignores possible benefits of long-duration storage beyond diurnal timescales, along with site-specific constraints on capacity and energy. Improving both the model formulation and data for PSH are thus important to better understand its role in future electric sector scenarios.

1.3.3 Hydropower and PSH Modeling Improvements

The limitations identified above inspired a broad array of hydropower and PSH modeling improvements implemented in ReEDS v2021. These advances in data and model formulation fall into three categories: (1) PSH data and operability, (2) long-duration energy storage valuation, and (3) upgrades. These categories reflect known data and methodology gaps described above and in Stoll et al. (2017), as well as emerging trends and interests within the U.S. electricity system. Growth in VG and interest in deep decarbonization (W. Cole et al. 2021) have driven increased attention to how hydropower and PSH can adapt to a changing grid through upgrades and increased flexibility. Existing and new PSH could be used for energy and other services across many timescales, making it increasingly important to incorporate best available PSH data and study its contribution as a long-duration storage device. We briefly introduce these new capabilities in this section, and methodical details follow in subsequent sections of the report.

A companion effort to ReEDS model improvements created a first-of-its-kind national resource assessment and supply curve for closed-loop PSH in the United States, which is documented by Rosenlieb and Heimiller (Rosenlieb and Heimiller 2022). These resource and cost data are implemented in the ReEDS model to improve on the prior data based on FERC license applications and permits, laying the groundwork for an expanded exploration of PSH resource and cost assumptions and their impact on long-term deployment. For existing PSH, we also use International Hydropower Association (IHA) data to account for differences in pump versus generating capacity where applicable (IHA 2021). We also explore ways to differentiate different pumping technologies (i.e., differences in operating flexibility between fixed-speed and variable-speed or ternary pumps). These features allow a more accurate depiction of the capabilities of the existing fleet and the ability to consider how CEMs might differentiate different PSH pump types that might provide different value streams and investment opportunities.

New features in ReEDS improve capabilities for representing long-duration energy storage for both hydropower generation and PSH. Where the baseline representation of hydropower generation includes a fixed quantity of energy available each season, we add the capability to transfer a fraction of that energy between seasons to study the value of reallocating hydropower energy across seasons to respond to changes in electricity system needs. Similarly, where PSH was previously limited to diurnal energy arbitrage, we add the capability to use a fraction of energy pumped in one season for generation in another season, allowing PSH to perform seasonal energy arbitrage. Plant-level storage duration data from IHA are also used to constrain seasonal energy arbitrage capabilities for existing PSH. The time resolution in ReEDS represents only diurnal and seasonal dynamics, but we also use the 8,760-hr dispatch module to explore the value of energy arbitrage at intermediate timescales. This value assessment considers energy arbitrage opportunities for storage durations beyond 12 hours and sets the stage for valuing and incentivizing longer storage durations in ReEDS. These new capabilities collectively advance the ability to understand the role of long-duration storage in the future electric grid.

Upgrade opportunities are expanded to allow detailed examination of which key performance characteristics are most valuable to upgrade under different circumstances, allowing the choice to upgrade capacity, energy, and flexibility independently of each other. The baseline formulation allows only a fixed capacity-energy upgrade for existing hydropower generation, which reflects the typical practice of choosing upgrades that increase both capacity and energy to some extent (e.g., re-winding a generator). However, it is possible to choose upgrades that emphasize capacity (e.g., adding a turbine-generator unit) or energy (e.g., raising a dam), so modeling capacity and energy upgrades independently allows us to assess the relative value of these characteristics for a given scenario. Further, these upgrades are represented in the model as improved performance characteristics rather than a separate hydropower subcategory as in the baseline formulation, meaning the operation of existing hydropower is now correctly coupled to any upgrades of that capacity. We also allow the existing hydropower generation fleet to upgrade its flexibility by changing its designation from nondispatchable to dispatchable hydropower at a cost. Doing so affords the benefits described in the baseline hydropower discussion and creates a way to study how the changing value of flexibility could incentivize hydropower to modernize and optimize technology and operation to become more flexible in the future. Lastly, we create a pathway for existing hydropower to increase flexibility by adding pumping capacity. Though doing so is not practical at many plants, this model capability can be used to find locations where adding pumps to existing hydropower could be an attractive future investment.

These new capabilities allow a more detailed exploration of hydropower investment and operational opportunities and advance CEM capabilities for identifying the potential future role of hydropower in the electric grid. Each feature is studied methodically using a scenario design that helps determine the importance of that feature in a CEM model, ultimately allowing us to identify model improvement and analysis priorities.

1.4 Demonstrative Scenario Design

The impacts of each new ReEDS feature on model outcomes are demonstrated using two scenarios that vary in the degree to which hydropower and PSH is expected to be competitive (Table 1.1). These scenarios include (1) a reference [Ref] scenario with all default model assumptions from the 2021 ReEDS model version (NREL 2021b), and (2) a scenario that requires 100% electricity demand be supplied by renewable energy sources in 2050, linearly increasing from 20% in 2020 [RE100] (W. J. Cole et al. 2021). The Base versions of these scenarios have none of the hydropower and PSH improvements described in this report and serve as baselines for comparing the effects of those improvements. Though these scenarios are not comprehensive, they offer a broad but manageable set of electricity futures for understanding the importance of the model and data improvements.

In Sections 2.0 through 4.0, we compare outcomes in these two scenarios with and without each model or data change to isolate their effects and draw insights about how and when each improvement is important. For some improvements, there are additional parameter sensitivity scenarios, particularly when key input parameters are highly uncertain. Then, in Section 5.0, we compare scenarios with and without all improvements to examine their aggregate impacts. We do not study all possible combinations of new features to maintain a reasonable scope, but this aggregated comparison shows how new model features interact and advises on the importance of their inclusion in electricity planning analysis. The Base scenario capacity and generation mixes over time is shown in Figure 1.1, and Figure 1.2 shows the Base scenario power generation mix in each ReEDS time-slice in 2050. Together these figures provide a graphical reference point from which to compare many subsequent plots of differences relative to these results.

Table 1.1. Baseline Scenarios for Demonstrating Model Improvements

Scenario Name (abbreviation)	Scenario Description	Technology Costs	Demand and Fuel Prices	Renewable Energy Requirements
Reference Base (Ref.Base)	ReEDS v2021 reference assumptions without hydropower and PSH model improvements	2021 ATB Mid	AEO2021 Ref	Current policies as of November 2021
100% Renewables in 2050 Base (RE100.Base)	ReEDS v2021 reference assumptions with requirement for 100% renewables by 2050	2021 ATB Mid	AEO2021 Ref	Current policies and linear path to 100% renewables in 2050

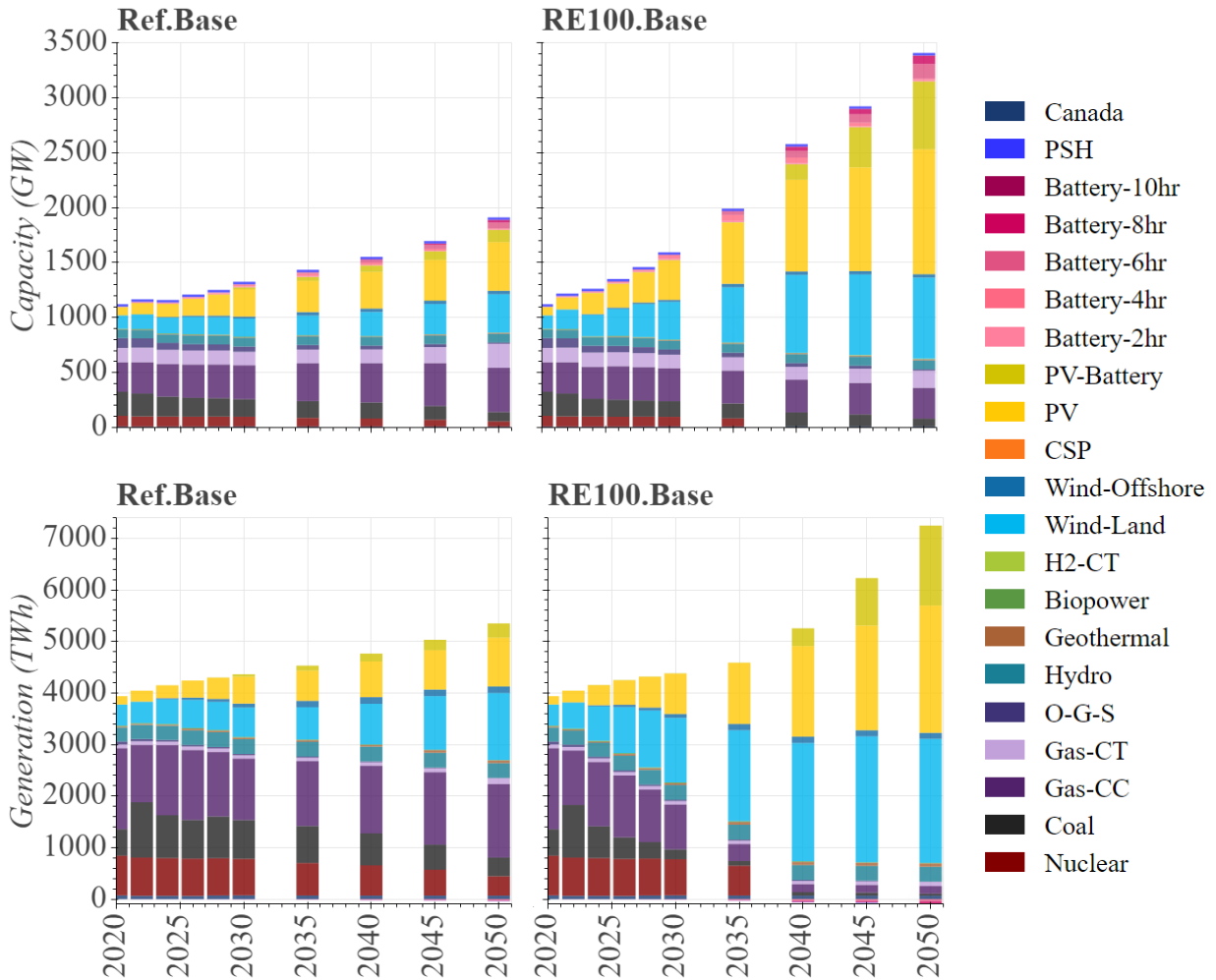


Figure 1.1. National capacity and generation in Base scenarios. Ref projects a mix of fossil and renewable generation sources, where RE100 invests heavily in variable renewables and storage.

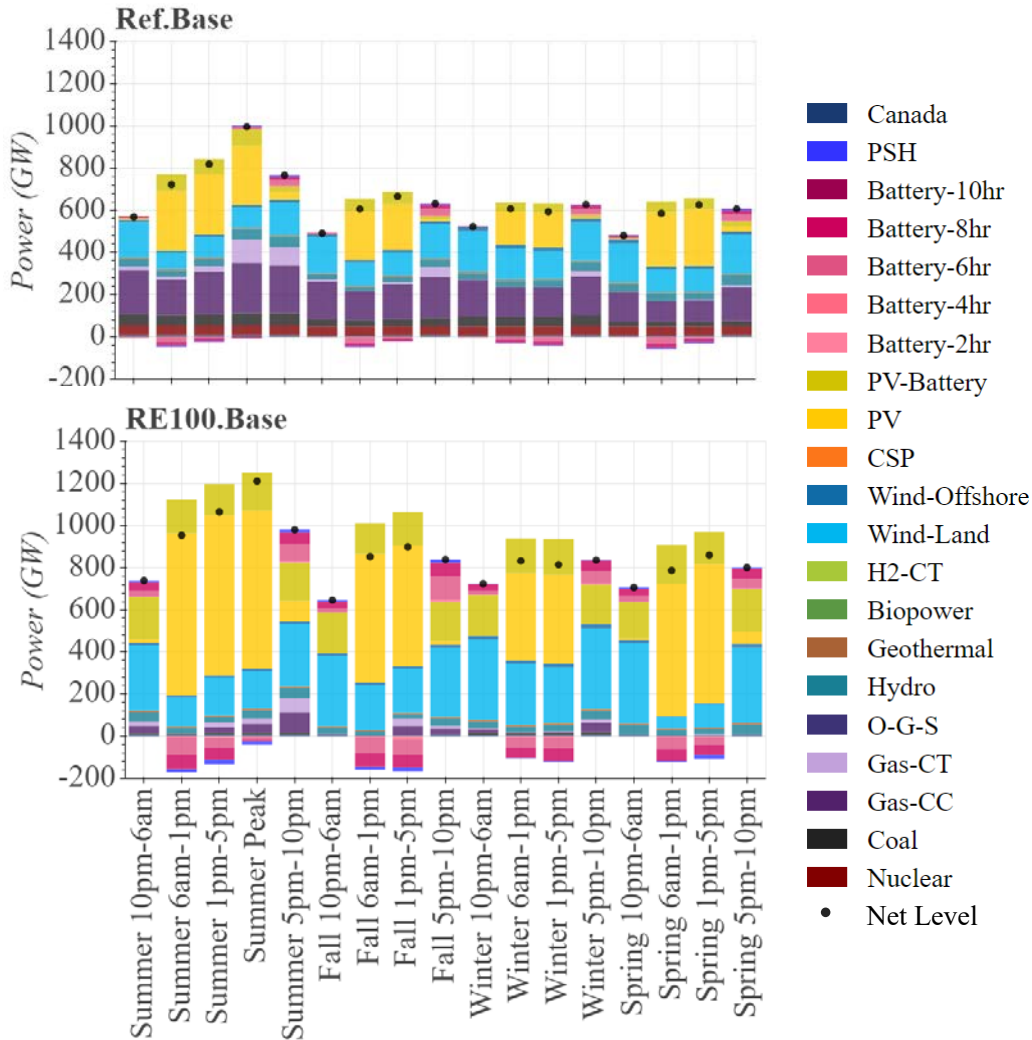


Figure 1.2. 2050 power generation by time-slice in Base scenarios. Black circles show net power generation. Ref balances VG with natural gas and some energy storage, where RE100 relies more heavily on storage.

2.0 Pumped Storage Hydropower Resource Data and Pump Characteristics

The implementation of new PSH resource and cost data in the ReEDS model represents an important PSH data advancement. The new data set, described in Rosenlieb and Heimiller (Rosenlieb and Heimiller 2022), is the first-ever comprehensive and consistent U.S.-focused assessment of closed-loop PSH resource and cost across the entire United States. We also explore new ways to differentiate PSH pumping technologies and site-level pump characteristics, because these specifications can affect how the model perceives how PSH can perform energy arbitrage and supply reserve products to the grid.

2.1 Integrating a New National Closed-Loop PSH Resource Assessment

Rosenlieb and Heimiller describe the new closed-loop PSH resource and cost assessment methodology in detail, so here we only include an overview (Rosenlieb and Heimiller 2022). Resource potential is defined by first identifying all possible locations for off-river reservoirs that could be used for a closed-loop PSH system, using adapted geospatial algorithms from Australia National University (Andrew Blakers et al. n.d.). For this first data set release, reservoirs exclusively include dry gully formations² with a 40-m dam height, along with constraints on head height and the distance between upper and lower reservoirs that are kept consistent with Blakers et al. based on their published methodological choices. Several technical potential criteria are then applied to eliminate reservoirs in areas such as critical habitats and urban areas, and then reservoirs are paired and optimized to eliminate overlapping reservoirs (e.g., where several possible reservoirs are located along the same dry gully).

The remaining set of nonoverlapping reservoir pairs defines the quantity of water storage at each site, which is fixed in this first release of NREL’s closed-loop PSH resource data set. Given the quantity of water storage, the corresponding quantity of energy storage is defined by choosing a storage duration upfront and then sizing a powerhouse for that storage duration given the reservoir size and head height. Once the powerhouse size is chosen, a cost model adapted from Australia National University (Blakers et al. 2019) is used to assign a capital cost for the closed-loop PSH site, and we add a grid interconnection cost based on the closest available transmission node. The resulting capital costs are then calibrated using recent cost estimates for new PSH in the United States for large (1000 MW, 10-hr) facilities (Mongird et al. 2020), and this calibration results in a 51% increase in capital costs. This process of choosing storage duration, sizing the powerhouse, and calculating costs is repeated for 8-hr, 10-hr, and 12-hr storage durations.

For implementation in ReEDS, site-level resource and cost data are aggregated to the BA spatial resolution and grouped by capital cost into 15 cost bins for each BA. Binning puts an equal or nearly equal quantity of capacity in each bin (if the number of sites exceeds the number of bins) and calculates a capacity-weighted average capital cost for the bin that is unique to the BA. This method gives improved cost resolution, but bins do not correspond to any particular resource or site characteristics. As with all other technologies modeled with resource supply curves, ReEDS can invest in any quantity of capacity within each bin and does not select individual sites and locations. We tested 10-bin and 15-bin supply curves and chose to implement the higher-resolution 15-bin supply curves because they did not have a major computational impact, and they provided better resolution for capturing low-cost PSH opportunities.

Figure 2.1 shows the resulting binned supply curves for each storage duration before and after cost calibration, along with the Base supply curve that uses the data from the *Hydropower Vision* analysis (DOE 2016). As another point of reference, the 2021 ATB reports utility-scale battery costs as \$2,170/kWh for an 8-hr duration and \$2,650/kWh for 10-hr in the 2020 year, decreasing respectively to \$995/kWh and \$1,200/kWh in 2050 (NREL 2021a). The new data set has vastly more total potential given its comprehensive nature, even with the “artificial resource” shown in the flat section of the Base curve. The total resource potential scales proportionally with storage duration because of fixed reservoir volumes. The uncalibrated costs from Australia National University could be optimistic in its accounting for equipment, contingency, and indirect costs for deploying new PSH in the United States, so these costs are primarily considered here as a lower-cost scenario to study potential PSH deployment. Future work will

² A dry gully is a sloped channel in the topography whose characteristics help minimize the dam volume-to-water storage ratio, which is an important indicator of reservoir construction cost effectiveness.

improve cost characterization and further advance the ability of this data set to help identify economic PSH sites. Future work will also expand the range of possible technical specifications in the resource assessment (e.g., dam height, proximity to waterways, head height) and consider additional constraints on site availability (e.g. prime farmland, intersection of major roads, and water availability for filling reservoirs). Nevertheless, implementing this range of supply curves can help identify promising candidate locations for new closed-loop PSH and begin to establish the sensitivity of deployment to cost and technical specifications.

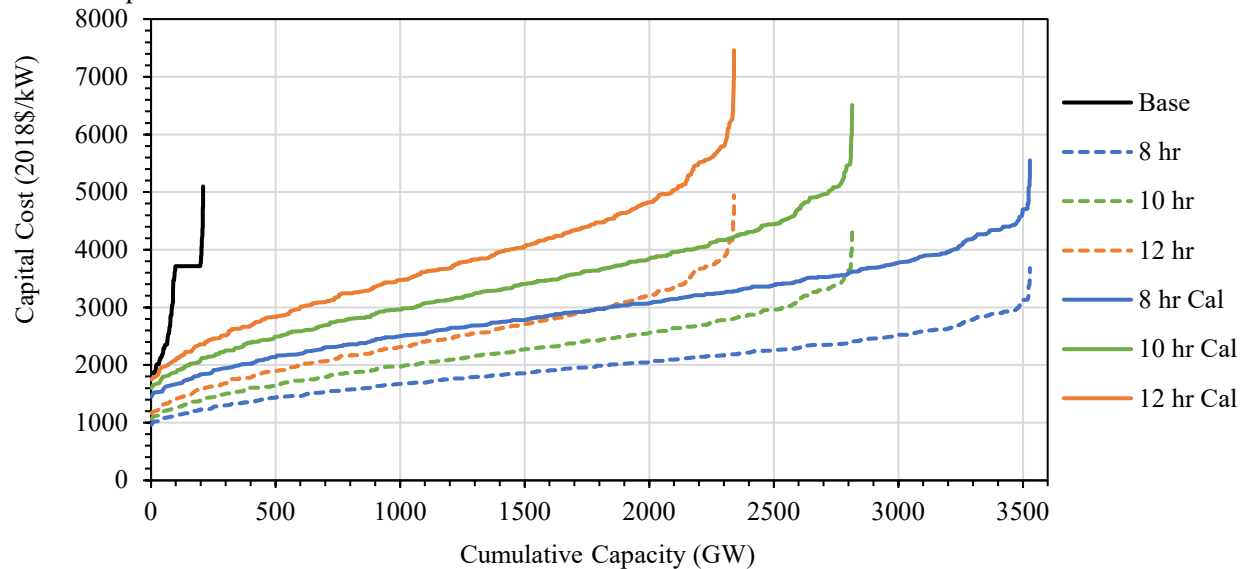


Figure 2.1. Comparison of the Base PSH supply curve created for the DOE *Hydropower Vision* (black) and alternative PSH supply curves using new resource assessment data with three possible assumed storage durations. New resource estimates include lower-cost sites and far greater resource.

The geographical distribution of Base and new PSH resource data is compared in Figure 2.2. Only the 10-hr data is shown because data is qualitatively similar for all three storage durations. Intuitively, resource potential is concentrated in mountainous regions of the United States, particularly in the West. This concentration existed in the Base data as well, but the new data set is much more comprehensive, particularly in Appalachia. Some regions in the Base data show resource potential where none exists in the new data set (e.g., South Dakota), and this result indicates alternative, less-restrictive site identification criteria might be worth considering (e.g., lower minimum head height). Though alternative storage durations result in different total resource, the spatial distribution of resource does not change substantively.

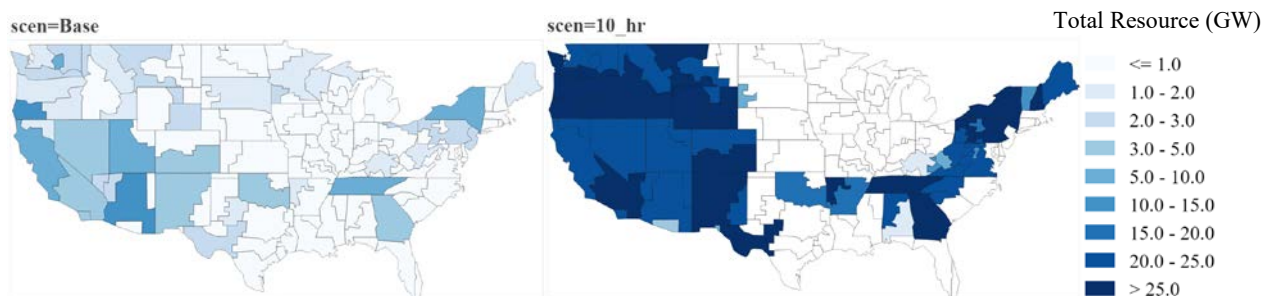


Figure 2.2. Comparison of BA-level distribution of prior (Base) PSH resource and the new PSH supply curve for 10-hr storage duration. Both follow similar regional distributions, but new data has more resource, especially in the west.

2.2 Distinguishing Pumping Technologies

The type of pump technology used in a PSH unit influences the overall operating flexibility of the unit and in part determines which grid services it may provide. All existing PSH facilities in the United States use fixed-speed pumps, which means they cannot ramp power input when in pumping mode, thus they also cannot supply operating reserves while pumping. In contrast, variable-speed, ternary, or quaternary pumps allow flexible operation by which the facility can ramp power input and provide reserve services while pumping.

The original ReEDS formulation of PSH operating constraints does not limit reserve provision while in pumping mode, and the linear, continuous structure of the model makes it difficult to do so. For example, it is not possible to define a constraint that says “reserve provision equals zero when power input to storage is nonzero” because doing so would require binary (i.e., on/off) variables that we prohibit in ReEDS to reduce computational complexity. Thus, baseline PSH operability in ReEDS could be considered generous.

Therefore, we tested a stylized way to differentiate fixed-speed pumps and other more-flexible pump types within the structural limitations of ReEDS. This was accomplished with a new constraint that places a minimum on the power input to storage for each time-slice, using a similar formulation that ReEDS uses for minimum power *output*. Because ReEDS does not generally distinguish individual units, the constraint must operate on all PSH capacity for each region (r) and vintage (v) combination³; in practice, this resolution could be nearly unit-level. Because of the continuous nature of capacity and generation variables, and the time-slice method of representing subannual time resolution, the constraint is defined so that power input to storage ($STORAGE_IN$) in each time-slice (h) must be greater than a specified fraction ($minstorfrac$) multiplied by power input to storage in all other time-slices in the characteristic day for that season ($h, hh \in szn$). The constraint can be written for all technologies (i) that are PSH ($i \in PSH$) in each model year (t) as:

$$\text{Equation 1: } \forall i \in PSH; h, hh \in szn; t: STORAGE_IN_{i,v,r,h,t} \geq minstorfrac_{i,v,r,hh} \times STORAGE_IN_{i,v,r,hh,t}$$

This constraint was tested by setting $minstorfrac = 1$ for all PSH to represent fixed-speed pumping that must be at the maximum pump capacity.

We also considered restricting reserve provision capabilities for fixed-speed PSH. However, we chose not to implement this practice because (1) fixed-speed PSH can provide reserve services in generating mode, and ReEDS cannot prohibit reserve provision during specific operating modes and (2) units could feasibly switch from pumping to generating mode fast enough to offer operating reserve services.

Structural limitations also prevent the model from differentiating between operational capabilities of variable-speed, ternary, and quaternary pumps, such as expanded operating range or faster ramping and mode switching. Comparing the relative cost and value of investing in different pump types is better suited for tools that have more detailed facility operating constraints.

³ Here, region is the BA. All existing PSH is assigned to a single vintage category, and the default formulation assigns a new PSH vintage for every future model year.

2.3 Differentiating Pump and Generator Capacity

Assuming pump capacity equals generator capacity is a simplification that is not appropriate for some facilities. The International Hydropower Association (IHA) publishes a data set and interactive web tool that lists pump capacity, generator capacity, and other characteristics for all operational and potential new PSH throughout the world, offering a key data set for improving PSH data accuracy among the existing U.S. PSH fleet (IHA 2021). In ReEDS, we use this data set to define a ratio (*storinmaxfrac*) of total pump capacity to generator capacity (*CAP*) for each balancing area, and this parameter is then used with the availability factor (*avail*)⁴ to limit the pump power (*STORAGE_IN*) in each PSH technology, vintage, region, time-slice, and model year.

$$\text{Equation 2: } \forall i \in \text{PSH}; h; t: \text{storinmaxfrac}_{i,v,r} \times \text{avail}_{i,v,h} \times \text{CAP}_{i,v,r,t} \geq \text{STORAGE_IN}_{i,v,r,h,t}$$

Table 2.1 reports capacity and duration data for all plants where pump and generator capacity are unequal. Only 11 facilities (of 39 total) have capacity ratios lower than 0.80, but some are 0.50 or lower, and given the size of these plants, it could be important for a model to capture the limitations on their operation if an analysis focuses on that region. Because most facilities *do* have equal or nearly equal pump and generator capacities, any new PSH deployment maintains the assumption that pump and generator capacity are equal. For all facilities, the storage rating and duration is taken as-is, assuming that sufficient upper and lower reservoir capacity exists. However, we acknowledge that some facilities might be part of cascading systems that constrain the effective storage duration to be below the values provided by the IHA.

Table 2.1. Generator and Pump Capacity Data for Units with Unequal Pump and Generator Capacity
Note: Some units lack storage duration data.

Plant Name	State	Generator Capacity (MW)	Pump Capacity	Pump/Generator Capacity Ratio	Estimated Energy Storage Rating (GWh)	Calc. Max Discharge Duration (hours)
Flatiron	Colorado	94.5	9	0.10	—	—
Smith Mountain	Virginia	560	100	0.18	3.33	6
Degray	Arkansas	68	28	0.41	0.19	3
Rocky River	Connecticut	29	12	0.41	26.79	924
Edward C Hyatt	California	819	390	0.48	1,858.481	2,269
Carters	Georgia	500	250	0.50	1.89	4
Richard B Russell	Georgia	600	300	0.50	—	—
Clarence Cannon	Missouri	58	31	0.53	0.28	5
Wallace Dam	Georgia	321	210	0.65	213	664
Thermalito hydropower plant	California	120	84	0.70	1.381	12
Horse Mesa	Arizona	130	97	0.75	23.6	182
Rocky Mountain	Georgia	1,095	903	0.82	6.08	6
Mormon Flat	Arizona	60	50	0.83	2.76	46
San Luis (W R Gianelli)	California	504	424	0.84	509.71	1011
Yards Creek	New Jersey	453	420	0.93	2.8	6
Seneca	Pennsylvania	469	440	0.94	3.92	8

⁴ The availability factor is a function of technology-specific average planned and forced outage rates.

Plant Name	State	Generator Capacity (MW)	Pump Capacity	Pump/Generator Capacity Ratio	Estimated Energy Storage Rating (GWh)	Calc. Max Discharge Duration (hours)
Bath County	Virginia	3,003	2,880	0.96	23.7	8
Northfield Mountain	Massachusetts	1,124	1,080	0.96	10.5	9
Castaic	California	1,556	1,500	0.96	—	—
Taum Sauk	Missouri	450	440	0.98	2.75	6

2.4 Scenario Results

Each baseline scenario (Ref.Base and RE100.Base) is compared with and without each data or formulation update as described in Table 2.2. There is an additional sensitivity dimension for the scenarios with new PSH supply curves (PSC scenarios) where the storage duration is varied.

Table 2.2. Scenarios for Demonstrating PSH Improvements
Each improvement is applied to each of the two Baseline scenarios in Table 1.1.

Scenario Name (abbreviation)	Scenario Description
New PSH Supply Curve (*.PSC.#hr)	Uses new PSH supply curve for resource availability and capital cost before calibration with “#” specifying the assumed storage duration
New PSH Supply Curve (*.PSC.#hr.Cal)	Uses new PSH supply curve for resource availability and capital cost after calibration with “#” specifying the assumed storage duration
Fixed Pumps (*.PFix)	Pump input power must equal the maximum power across time-slices in a season, effectively requiring fixed pump power across a given season
Accurate Pump Capacity (*.PCap)	Integrates plant-level pump capacity data for existing PSH

2.4.1 New PSH Supply Curves

Figure 2.3 shows total PSH capacity over time with the Base and PSC scenarios, with capacity starting with the existing 23-GW fleet. Base scenarios and scenarios using calibrated capital costs deploy little to no new PSH. However, scenarios with lower-cost resource before cost calibration deploy PSH over time, adding 6.5–8.6 GW of new PSH in the Ref cases and 13.4–15.8 GW in the RE100 cases. Overall, deployment in these scenarios is driven more strongly by the electricity scenario than storage duration, and higher PSH deployment in RE100 scenarios demonstrates PSH and VG complementarity. While the calibrated costs better match industry and literature expectations, PSH deployment with the lower-cost data can demonstrate what future PSH deployment pathways could look like in an environment where PSH is more competitive.

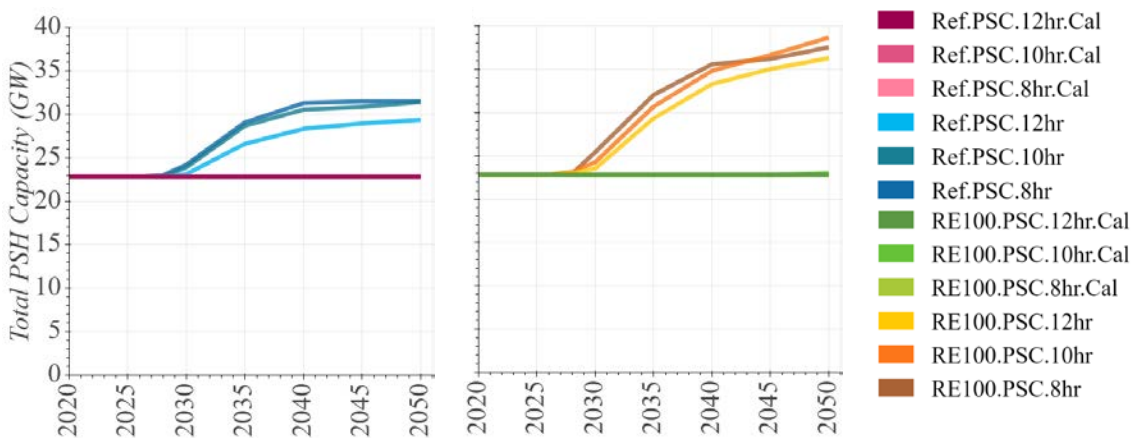


Figure 2.3. Total PSH capacity deployment across Ref (left panel) and RE100 scenarios (right panel), including the existing fleet, demonstrates the potential for new closed-loop PSH deployment in the United States at lower costs, with high-RE scenarios providing a greater deployment incentive

There is no clear relationship between PSH storage duration and total deployment. For the pre-calibration Ref cases, 2050 PSH capacity is in the order of 8-hr > 10-hr > 12-hr, and for RE100 results in the order of 10-hr > 8-hr > 12-hr. These differences reflect the complex relationships among PSH, VG, and other storage technologies. Figure 2.4 explores the relationship of PSH and other storage technologies by plotting the change in total PSH, battery, and PV-battery capacity relative to Base scenarios in the scenarios with non-negligible PSH deployment.

Generally, PSH displaces longer-duration 6-hr and 8-hr battery systems, but deployments of battery durations up to 4-hr are slightly higher by 2050 with additional PSH and thus exhibit some complementarity. Interactions with PV-battery hybrids are scenario-specific: new PSH corresponds to delayed or reduced PV-battery deployment in Ref scenarios, but PV-battery deployment is relatively unaffected by PSH deployment in RE100 scenarios where nominal PV-battery deployment is much higher. Despite interactions between competing storage technologies, a given electricity scenario (Ref or RE100) has relatively stable total deployment of storage capacity (the sum of PSH, battery, and PV-battery) across all PSH duration options. This result extends to the Cal scenarios, where additional battery storage is deployed instead of PSH.

Given the similar PSH deployment across durations and the interactions with battery storage up to 10 hours in duration using the pre-calibration supply curves, we decided to use the cost-calibrated 10-hr duration PSH supply curve as the default option for ReEDS. Different PSH duration scenarios have similar PSH deployment because there is a tradeoff between higher capital costs and increased arbitrage opportunity as duration increases, and future work could explore this tradeoff in greater detail to see if different PSH durations are more suitable to alternative electricity futures. No scenarios that deploy new PSH also deploy 10-hr batteries, so using the 10-hr PSH supply curve gives the model a more attractive 10-hr option and thus a more complete set of competitive storage options for exploring future electricity scenarios. Subsequent results in this section focus exclusively on results with the pre-calibration 10-hr duration PSH supply curves.

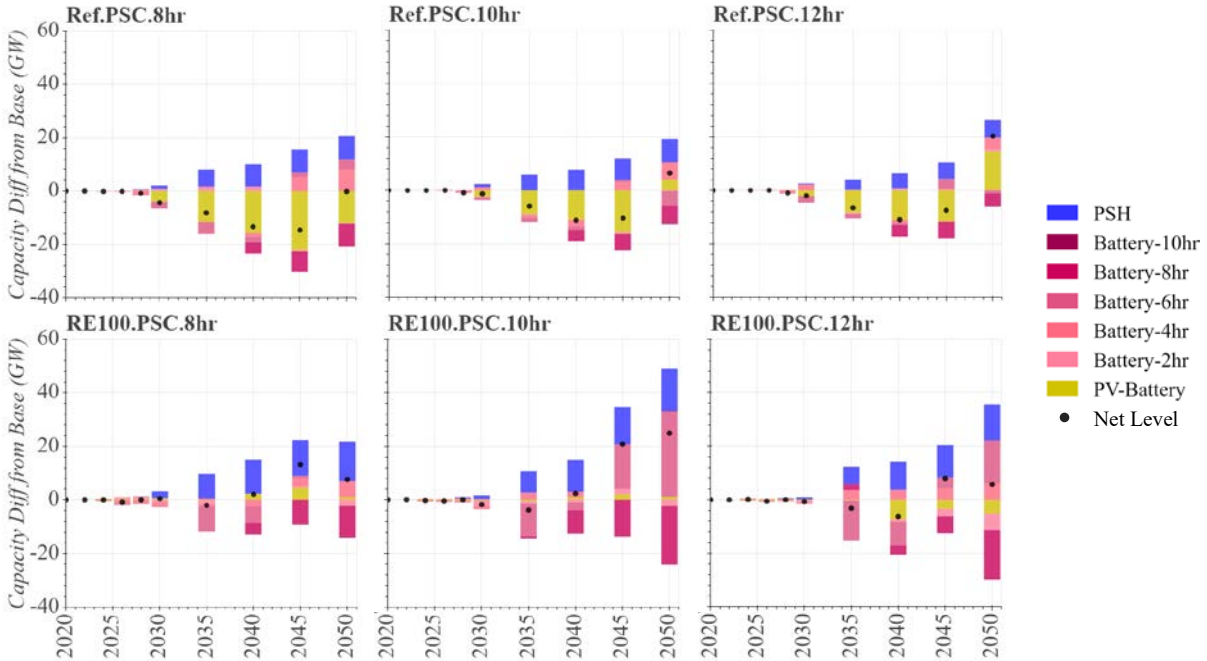


Figure 2.4. Difference in energy storage capacity by technology relative to the respective Base case with the new PSH supply curves before cost calibration. New PSH deployment typically displaces longer-duration batteries but can correspond to greater short-duration battery deployment.

Figure 2.5 shows where new PSH is installed through 2050 in cases with 10-hr storage duration before cost calibration. The Ref.PSC.10hr scenario results highlight nearer-term opportunities relative to the RE100.PSC.10hr scenario. PSH opportunities appear most attractive in California, with some deployment also occurring in Colorado, Arizona, Texas, South Carolina, and New York. These regions have a favorable combination of PSH resource cost and availability, electricity demand, and opportunities to balance VG that is bolstered by state-level decarbonization policies. The higher-deployment RE100 case further expands PSH deployment in the southwestern United States as well as in the Washington and Virginia.

Though these results can help identify promising PSH opportunities, it is important to emphasize that this first release of PSH supply curve data has several limitations. Geographical exclusions are largely taken from wind and solar resource assessment work, so other important considerations might not be included here. Also, we also use rigid design specifications that might not be appropriate for all sites. And the PSH cost model is subject to ongoing improvement, as evidenced by our exploration of results pre- and post-cost calibration. These and other limitations will be explored and addressed in ongoing work to improve our understanding of the future role of PSH in the U.S. electricity system.

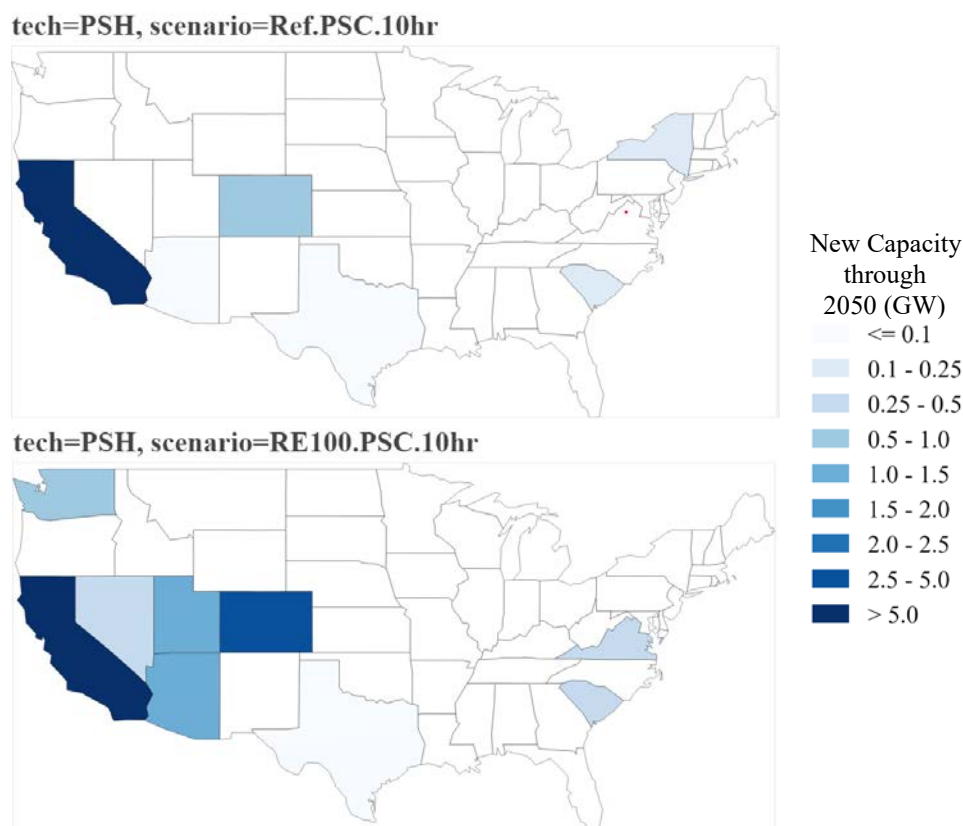


Figure 2.5. New PSH capacity by state through 2050 for the 10-hr duration supply curve before cost calibration. Most new PSH is deployed in California and the southwestern United States.

ReEDS can assess “value streams” that give insight into what grid services are providing value to a given technology in each region at any point in time. This result is derived using the shadow price from constraints that define system requirements for energy (to meet demand or reduce VG curtailment), capacity (reserve margin or operating reserves), or other policies (state renewable portfolio standards, renewable energy standards). These prices along with technology-specific provision of each service enable the value stream calculation. The absolute value of this metric is highly variable by technology, region, scenario, and year due to complex interactions between different system requirements (e.g., constraints) and the generation, transmission, and storage technologies available to meet those requirements (J. E. T. Bistline and Young 2020; Mai, Mowers, and Eurek 2021). Here we use value streams primarily for a qualitative discussion of the relative importance of different values towards hydropower and PSH investment decisions, and additional investigation would be required to fully understand numerical results in the context of the rest of the system.

PSH value streams over time for the 10-hr scenarios are shown in Figure 2.6. This result is a discounted 20-year present value for any new PSH deployed in that year,⁵ normalized by the newly deployed capacity in each model year. The capacity value for meeting reserve margin requirements (adequacy reserves) is the primary driver of new PSH deployment in these scenarios. Operating reserves are not a major contributor, and despite PSH being capable of energy arbitrage and curtailment reduction, these value streams are a minor portion of total value. Energy arbitrage does become more important in later years of the RE100 case, likely because of higher VG penetration. However, these results could change

⁵ The discounting calculation assumes constant operation over the 20-year economic life, which is identical to the ReEDS objective function.

under different scenarios and limited operating time resolution makes it difficult to assess the full value of energy arbitrage and operating reserves in ReEDS.

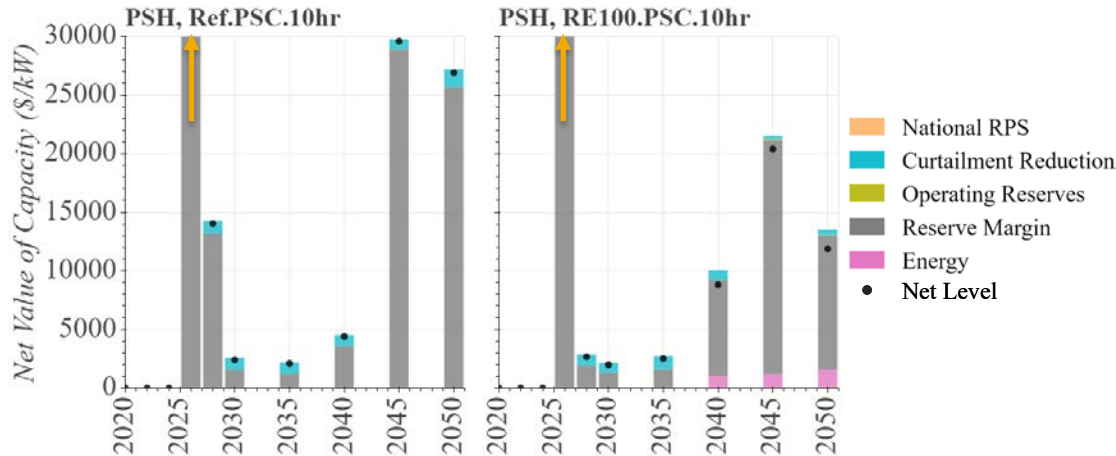


Figure 2.6. Net discounted value of new PSH capacity deployed with the 10-hr duration supply curve, with arrows indicating that the actual value is beyond the y-scale shown. New PSH is most valuable for providing planning reserves, with curtailment reduction and energy arbitrage providing smaller value streams.

2.4.2 Fixed-Speed versus Adjustable-Speed Pumps

The Pfix scenarios are an example of a model development that ultimately did not achieve its goal of improving the model representation of PSH technologies. The Pfix scenarios limited PSH energy arbitrage far below what is observed in today’s existing PSH fleet, it is not defensible to apply this change to the existing fleet or use it to differentiate between fixed- and adjustable-speed pumps. Thus no changes were made to ReEDS as a result of this investigation. Appendix A describes these results in detail.

2.4.3 Pump Capacity Data

Figure 2.7 shows 2050 PSH power output by time-slice for Base and Pcap scenarios that limit pump input power based on IHA data. At the national level, results are nearly identical between Base and Pcap scenarios. Facilities where pump capacity is less than generator capacity do not have enough cumulative impact on the national PSH fleet to change overall results. However, when plotting the same result for a region where pump capacity is much lower than generator capacity, such as Georgia (Figure 2.8), the RE100.Pcap scenario results clearly demonstrate the limit on pump input.⁶ This change not only reduces the pumping power in the daytime time-slices; it also results in less power output in evening and nighttime time-slices and shifts some energy output to the spring evening. The example of Georgia demonstrates that plant-level pump input capacity is not necessarily important to aggregate national impacts but could influence region-specific outcomes.

⁶ PSH is not used extensively for pumping or generation Georgia in Ref scenarios.

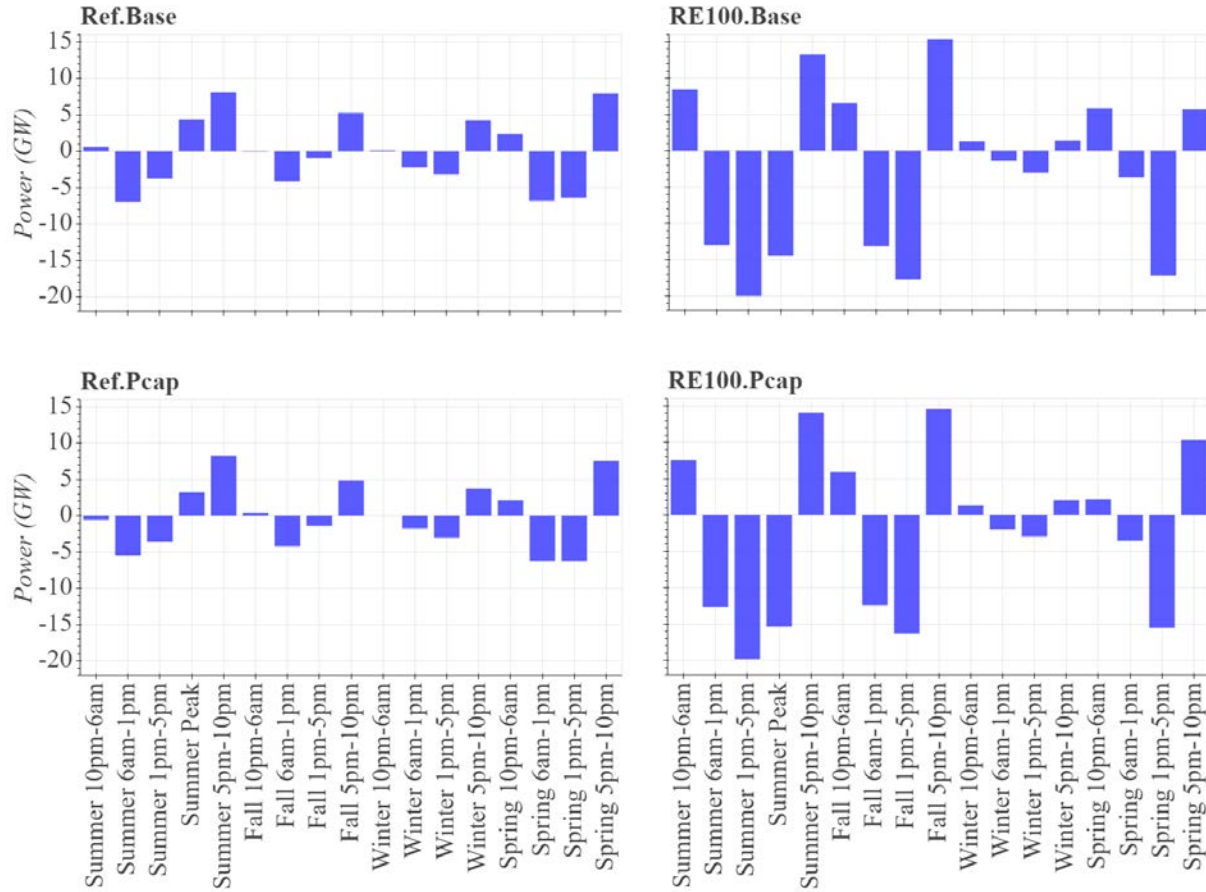


Figure 2.7. National power output from the U.S. PSH fleet by time-slice in 2050 in Base scenarios and in Pcap scenarios that incorporate plant-level pump capacity data. Pump capacity data has a negligible cumulative impact on national PSH operation.

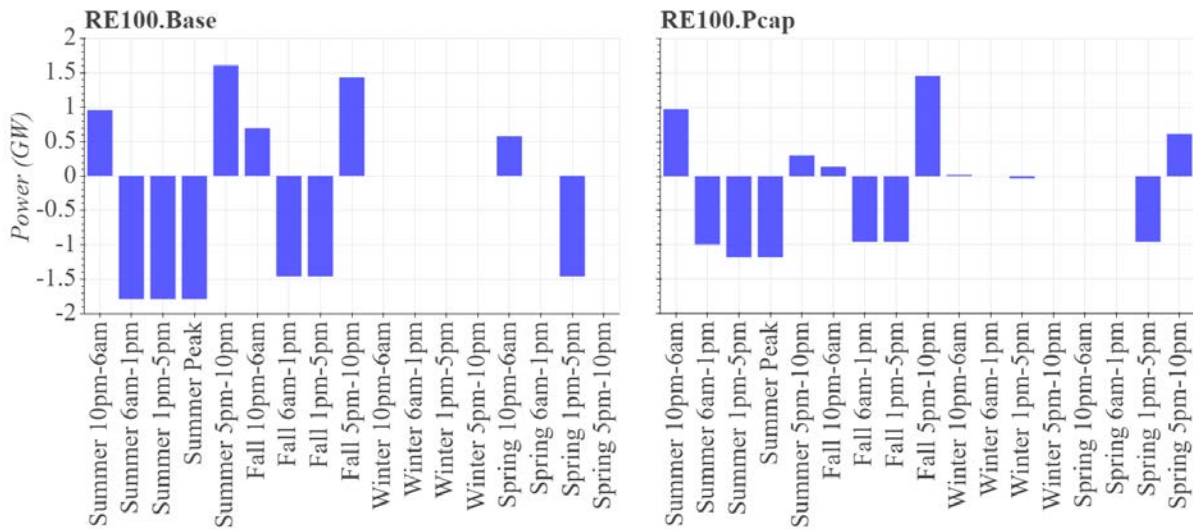


Figure 2.8. Power output by time-slice in 2050 for PSH capacity in Georgia in RE100.Base and in the RE100.Pcap scenario that incorporates plant-level pump capacity data. Pump input capacity data has a notable impact on PSH dispatch in Georgia.

3.0 Valuing Long-Duration Energy Storage

Long-duration energy storage is often difficult to represent in power system models due to limitations on time resolution, model structure, and computational resources. This can be especially true with CEMs that must inherently balance operational detail and investment decision drivers. Here we demonstrate ways to explore long-duration storage value and operation within the limitations of the ReEDS model structure. In this exercise, “long-duration” is anything beyond 12 hours of storage that could theoretically optimize operation along timescales longer than 24 hours. Given that ReEDS time-slices represent only one characteristic day per season, this long-duration storage exploration primarily consists of demonstrating the ability to optimize operation across seasons, either by shifting hydropower energy (water) storage across seasons or by using larger PSH facilities to pump energy in one season for use to generate electricity in another. We also test the value of including plant-specific storage duration data for the existing PSH fleet. Finally, the value of energy arbitrage between diurnal and seasonal timescales is studied by expanding the Augur hourly dispatch module used to characterize VG and storage to study arbitrage value across a broader range of storage durations. These model and data developments do not represent a comprehensive look at long-duration energy storage, but they can help identify promising areas of focus for future analysis, planning, and operation.

3.1 Interseasonal Energy Transfers with Hydropower Generation

This exercise allows interseasonal energy transfers for dispatchable hydropower capacity without pumps, which could allow hydropower to better match seasonal variations in net load given long-term changes to electricity demand and VG. Where the Base formulation imposes a strict seasonal energy budget, interseasonal energy transfers are allowed using two alternative constraints: (1) an annual energy balance to limit total *annual* hydropower generation and (2) a requirement that a specified fraction of the originally specified seasonal energy allocation (*within_seas_frac*) must remain within that season. Setting *within_seas_frac* to 1 is equivalent to the Base formulation.

Because seasons are already a coarse time resolution, we do not enforce any chronology such that interseasonal energy transfers must go in a certain direction (e.g., spring to summer, summer to fall). This representation implies there is some degree of annual planning for seasonal energy allocations, and these allocations can change over time with grid needs.

Equation 3 is the annual energy limit for dispatchable hydropower, where H_h is the number of hours associated with each time-slice, m_cf_szn is the seasonal average capacity factor, GEN is the generator power output, and $h \in szn$ refers to all time-slices in a season.⁷ Equation 4 is the constraint requiring some energy to be used in its original season.⁸

$$\text{Equation 3: } \forall i \in \text{dispatchable hydro}; v; r; t: \sum_{szn} \left(\left[\sum_{h \in szn} (avail_{i,v,h} \times H_h) \right] \times CAP_{i,v,r,t} \times m_cf_szn_{i,v,r,szn,t} \right) \geq \sum_{szn} \left(\sum_{h \in szn} (GEN_{i,v,r,h,t} \times H_h) \right)$$

$$\text{Equation 4: } \forall i \in \text{dispatchable hydro}; v; r; t: \sum_{h \in szn} (GEN_{i,v,r,h,t} \times H_h) \geq \text{within_seas_frac}_{i,v,r} \times \left[\sum_{h \in szn} (avail_{i,v,h} \times H_h) \right] \times CAP_{i,v,r,t} \times m_cf_szn_{i,v,r,szn,t}$$

⁷ The actual formulation of Equation 3 in ReEDS includes terms to adjust total capacity (CAP) for seasonal differences in rated hydropower capacity and a term on the right-hand side that includes a fraction of regulation reserve provision in the energy balance.

⁸ The actual formulation of Equation 3 in ReEDS includes terms on the left-hand side to include a fraction of regulation reserve provision in the energy balance.

As described in Section 3.5, we explore only demonstrative scenarios that specify *within_seas_frac* uniformly for all dispatchable hydropower capacity. In reality, practical limitations such as environmental constraints and cascading system operations will make it difficult to substantially change seasonal energy allocations for many facilities. Nevertheless, this feature allows us to explore the value of changing hydropower operating plans to respond to future net load profiles. Its accuracy and realism could be improved with plant-specific data on reservoir characteristics and operating constraints, along with a forward-looking assessment of how these might change in the future.

3.2 Interseasonal Energy Arbitrage with PSH

The representation of interseasonal energy arbitrage for PSH uses a similar framework as interseasonal energy transfers. Where the Base formulation enforces a PSH energy balance within each characteristic day in a season, the alternate formulation (1) enforces an *annual* energy balance between PSH input and output while accounting for round-trip efficiency (*storage_eff*) and (2) requires a specified fraction of energy input (pumped) in each season to be used for generation in the same season. Again, setting this *within_seas_frac* parameter for PSH to 1 is equivalent to the Base formulation. Setting *within_seas_frac* to 0 effectively allows PSH to remain in pump or generation mode for an entire season, which is likely unrealistic but represents an upper bound for comparison. Chronology across seasons is not enforced, again implying a degree of annual planning for which seasons to primarily pump rather than generate. Equation 5 is the annual energy balance for PSH, and Equation 6 requires some energy that is pumped in a season to be used for generation in that season.

$$\text{Equation 5: } \forall i \in PSH; v; r; t: \sum_h (\text{storage_eff}_{i,t} \times H_h \times \text{STORAGE_IN}_{i,v,r,h,t}) = \sum_h (\text{GEN}_{i,v,r,h,t} \times H_h)$$

$$\text{Equation 6: } \forall i \in PSH; v; r; szn; t: \sum_{h \in szn} (\text{GEN}_{i,v,r,h,t} \times H_h) \geq \text{within_seas_frac}_{i,v,r} \times \sum_{h \in szn} (\text{storage_eff}_{i,t} \times H_h \times \text{STORAGE_IN}_{i,v,r,h,t})$$

Similar to interseasonal energy transfers for hydropower, interseasonal energy arbitrage is not necessarily practical or possible for many PSH facilities, especially those with storage durations below 12 hours. Uncertainty over a multimonth time frame about water availability and other operational considerations make it difficult to truly perform annual planning. Nevertheless, this formulation allows us to demonstrate the value of considering alternative interseasonal PSH operation in response to multidecadal changes to the grid. It also helps identify the potential for new long-duration storage to help respond to seasonal profiles of load and other VG sources. Where there are practical limitations to hydropower PSH planning and dispatch at longer timescales, the value of other technologies such as hydrogen production and storage (which can be included in ReEDS) could be informed by this approach.

3.3 Plant-Level Storage Duration Data

Where the Base formulation uniformly assumes a 12-hr storage duration for all PSH, model accuracy can be improved by again using the IHA database, which includes plant-specific storage durations for most facilities. Many facilities have storage durations of less than 12 hours (Figure 3.1, right panel), meaning the Base formulation is too generous for these facilities. Conversely, several facilities have > 12 hours storage, and some have several hundred or thousands of hours of storage. These storage durations are taken as-is for the present work, but we suspect some of the longest durations are overstated based on the upper reservoir being larger than the lower, and future work could use reservoir data for cascading systems to further improve the accuracy of storage duration assumptions. While we have yet to integrate data describing the practical lengths of time these facilities could perform energy arbitrage, such large

storage durations cannot even be valued with the Base formulation that only enforces a diurnal energy balance. However, the constraints allowing interseasonal arbitrage could be used in combination with plant-level duration data to study the value of these larger-duration plants.

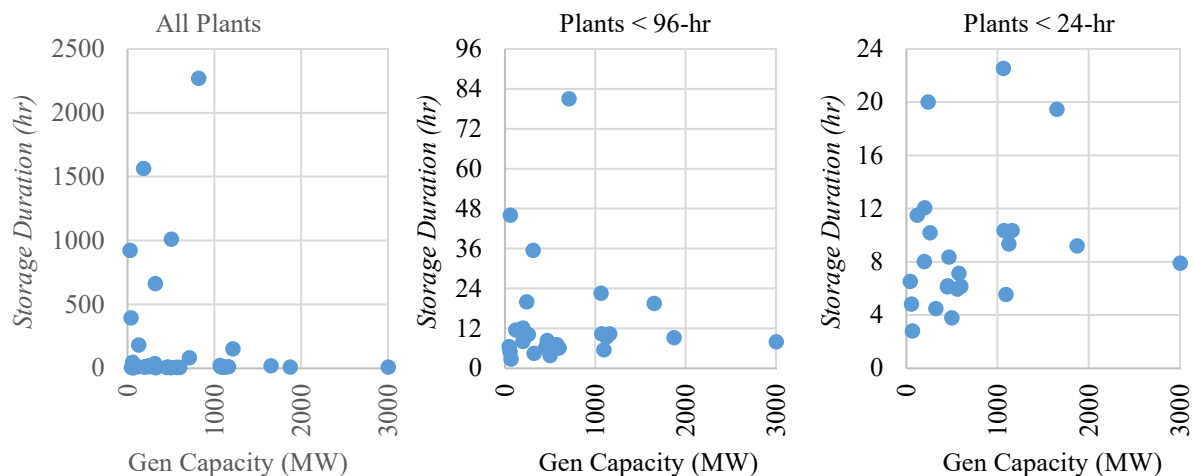


Figure 3.1. IHA data for storage duration versus generating capacity at three different y-axis scales to view progressively smaller storage durations. While some facilities have hundreds to thousands of hours of energy storage, most are 12 hours or less.

In ReEDS, plant-level storage duration data can allow a more accurate representation of existing fleet PSH capabilities using existing constraints that track stored energy over diurnal periods. These constraints track the storage level and ensure storage duration limits are not exceeded. Plant-specific durations are also implemented in the Augur module so that hourly dispatch and arbitrage valuation is done appropriately for facilities with < 12-hr duration. Beyond the seasonal arbitrage constraints, ReEDS does not currently have a way to dispatch and value storage durations beyond 12 hours, including within the Augur hourly dispatch. The exercise described in the next section lays the groundwork for improving that characterization, particularly for new construction of long-duration PSH or other storage technologies.

3.4 Intermediate-Duration Storage Valuation Using Hourly Dispatch Module

As described above, the time-slice representation in ReEDS creates structural challenges for valuing storage durations beyond diurnal and interseasonal timescales. Time-slice aggregation to four periods per day also prevents the core optimization from studying load and resource coincidence at high resolution, making it difficult to accurately represent energy arbitrage value even at diurnal timescales. In an effort to improve diurnal arbitrage valuation and VG characterization, the Augur model was developed for the 2020 ReEDS version (Ho et al. 2021). This module runs in between each ReEDS model year, allowing parameter updates as the generation and transmission system changes over time, and its output characteristics are used to inform the main ReEDS optimization in the subsequent solve year.

Augur begins by importing the generation and transmission fleet characteristics after a given solve year. It then uses hourly load and VG profiles to perform a rolling 24-hr dispatch that includes a 24-hr look-ahead. This dispatch is its own optimization problem, and it produces shadow prices for electricity at hourly resolution. These prices are then input to a dynamic program that optimizes storage operation assuming storage systems are price-takers (i.e., their operation does not influence prices themselves). With the resulting storage operating profiles and the input electricity prices, Augur then calculates the storage cost (from buying electricity to store energy) and revenue (from selling electricity during

discharge), which determines storage system profit. When normalized by storage capacity, the result is an arbitrage value for energy storage. This dollar-per-kilowatt (\$/kW) arbitrage value is then used in the ReEDS objective function as an incentive for investing in new storage in the following model year.

Typically the dynamic program is run with a diurnal timescale to assess arbitrage value for 2-hr to 12-hr storage durations. To explore longer-duration storage value, we use the existing dynamic program framework to optimize storage operation and calculate arbitrage value for hypothetical storage durations up to 168 hours. Lower hourly resolution was used with longer time horizons to maintain computational tractability. This calculation can be done for any ReEDS scenario and model year, and it can be explored for each BA as well.

This approach offers a first-order assessment of long-duration storage value, but it does not constitute a rigorous characterization. Increasing the time horizon of the hourly dispatch optimization and the dynamic program together would provide a more consistent result that endogenously considers price impacts of long-duration storage, but doing so would impose significant computational burden. Future work could explore additional adjustments to Augur or could take advantage of other recent ReEDS improvements that allow flexible time-slice definitions and higher subannual dispatch resolution in the main ReEDS optimization.

Because the hourly arbitrage value from Augur has no effect on existing fleet operation, and storage durations for new closed-loop PSH resource are assumed to be 12-hr or less (Section 2.1), we did not incorporate the arbitrage value for > 12-hr storage durations into the ReEDS optimization. Future work might consider doing so to study longer-duration PSH or other storage technologies.

3.5 Scenario Results

Interseasonal effects are each examined with a sensitivity on the *within_seas_frac* parameter that defines how much hydropower energy must remain in its original season or how much PSH energy pumped in a season must be used for generation in that season. Scenarios set this parameter to 0, 0.5 (50%), and 0.9 (90%) for all dispatchable hydropower capacity in the seasonal transfer scenarios (SeaX) and all PSH in the seasonal arbitrage scenarios (SeaA). The Base scenarios are equivalent to setting this parameter to 1. The impact of plant-specific PSH storage duration data is studied using an additional sensitivity on all the seasonal arbitrage scenarios, because these scenarios provide a way for the model to take advantage of durations above 12 hours.

Table 3.1. Scenarios for Demonstrating Long-Duration Energy Storage Valuation
Each improvement is applied to each of the three Baseline scenarios in Table 1.1.

Scenario Name (abbreviation)	Scenario Description
Non-PSH Seasonal Transfers (*SeaX.[<i>f_x</i>])	Includes interseason energy transfers for existing dispatchable non-PSH at no incremental cost, with <i>f_x</i> being the fraction [0–1] of energy that must remain within the nominal season for which it is allocated
PSH Seasonal Arbitrage (*SeaA.[<i>f_a</i>])	Includes interseasonal energy arbitrage for existing PSH at no incremental cost, with <i>f_a</i> being the fraction [0–1] of energy input (stored) in a season that must be used for generation in that season
PSH Seasonal Arbitrage + Storage Duration Data (*SeaA.[<i>f_a</i>].Dur)	Includes interseasonal energy arbitrage for existing PSH with plant-specific storage durations and <i>f_a</i> defined as above

Intermediate storage valuation takes a unique approach because calculations using Augur can be done independently of any ReEDS simulation for intermediate ReEDS results from any model year, and this approach is a first step to determining Augur could assess energy arbitrage value for storage durations beyond 12 hours and use that information to inform ReEDS investment decisions. For this analysis, we use two scenario-year combinations from the NREL 2020 Standard Scenarios (W. Cole et al. 2020): (1) the Mid-Case in 2026, and (2) a High RE system based on the Low RE Cost, High Gas Price scenario in 2050, which uses the 2020 ATB Low Cost Case for wind and solar technologies and AEO2020 low oil and gas resource case for natural gas price assumptions (NREL 2020; EIA 2020a). These scenario-year combinations are chosen because they bound a range of VG penetration from low (Mid-Case 2026) to high (High RE 2050).

3.5.1 Interseasonal Energy Transfers

Figure 3.2 and Figure 3.3 show the impact of allowing interseasonal energy transfers by plotting the change relative to Base scenarios of 2050 hydropower time-slice generation and 2050 generation of all technologies. In all scenarios, shifting energy from spring to winter is the most prominent result when the existing seasonal water allocation (i.e., capacity factor) is relaxed. The 2050 capacity mix has significantly more PV in both Ref and RE100 cases, and seasonally shifting hydropower energy can complement PV generation profiles by providing more energy in the winter when load is higher and PV generation is lower. Energy is moved from the spring because net load is lowest when accounting for electricity demand and generation of wind and PV, and hydropower availability is relatively high. In scenarios with 50% or more energy available for seasonal shifting, there is also some tendency to shift energy from summer, when PV generation is highest. It is also important to note that these results use reference load and renewable energy profiles from 2012, so a future where electrified building and transportation loads further shifts peak net load to the winter could provide an even greater incentive for changing seasonal energy allocations.

Impacts on dispatch of other technologies are not always consistent, but seasonal shifting in the Ref scenarios tends to result in higher PV generation and lower fossil generation in many time-slices. Changes to dispatch in RE100 scenarios do not follow any obvious trends, perhaps because these systems include much higher battery and PV-battery storage penetration, so the increased availability of these flexible technologies makes the system less sensitive to hydropower dispatch. All of these changes represent a small (<10%) fraction of the total power output, making it difficult to discern the impact of hydropower dispatch changes relative to known variability in ReEDS solutions due to path-dependent myopic solutions.

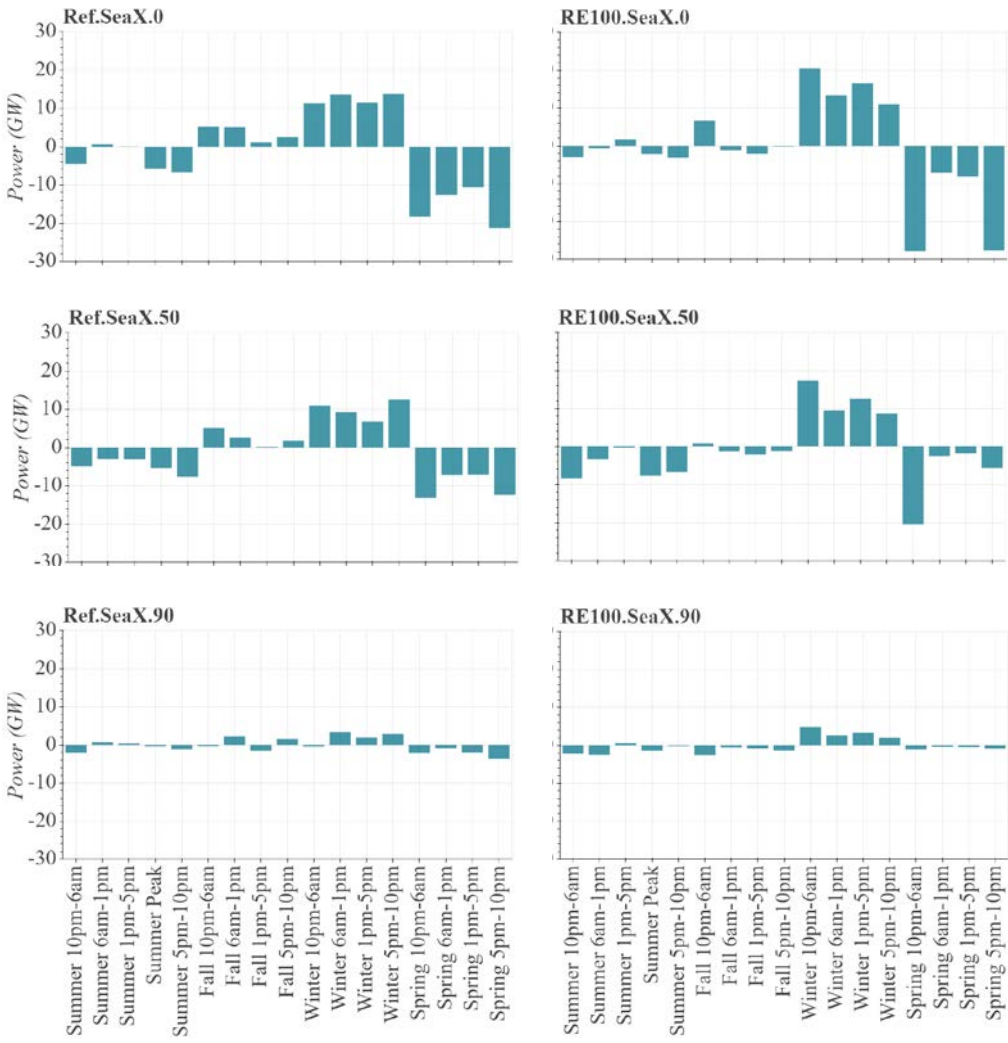


Figure 3.2. Changes to 2050 time-slice generation relative to Base scenarios for hydropower. Hydropower energy tends to shift to the winter to help balance PV.

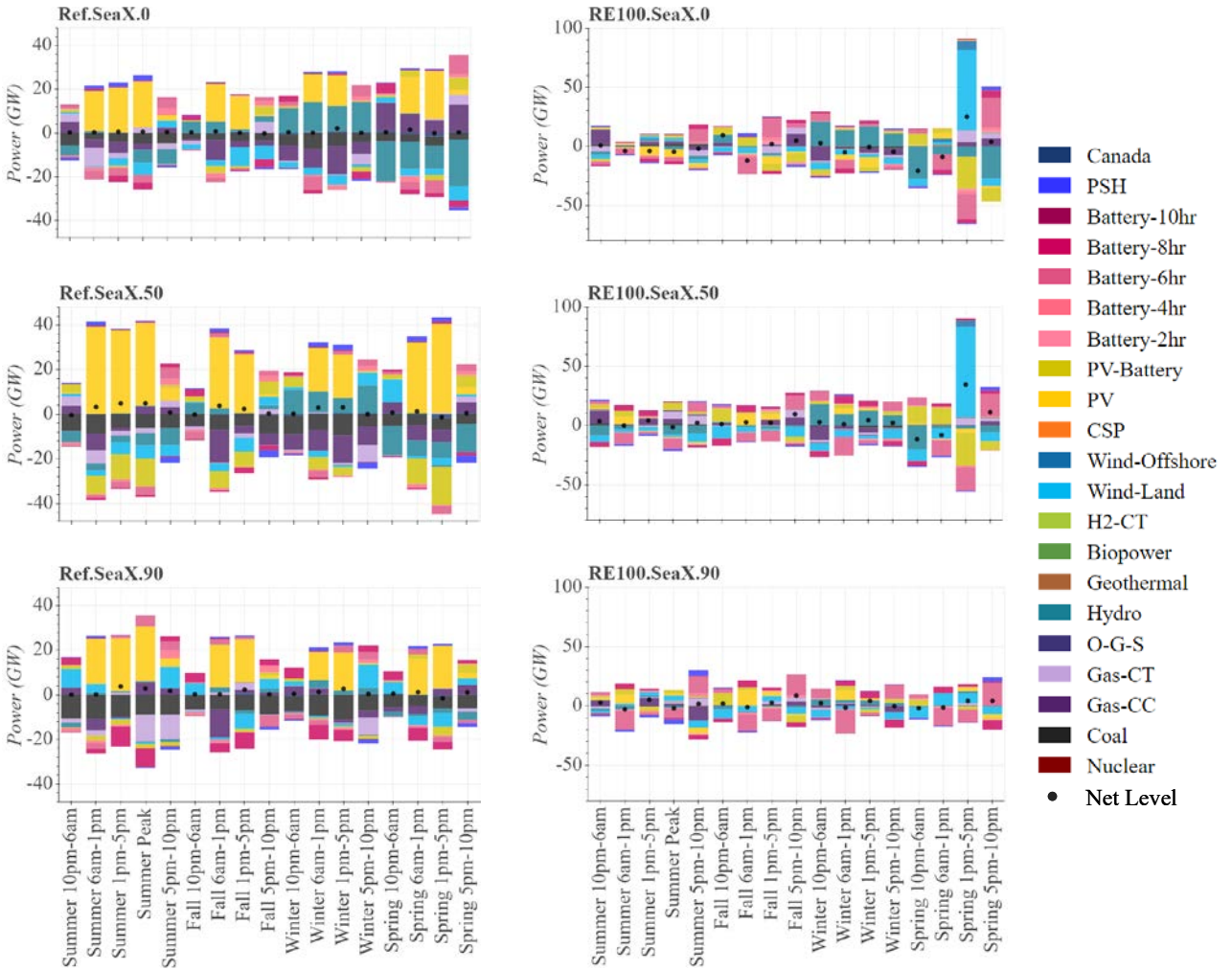


Figure 3.3. Changes to 2050 time-slice generation relative to Base scenarios for all technologies. Shifting hydropower to the winter enables greater PV generation in Ref scenarios.

Figure 3.4 shows the impact of allowing seasonal shifting on the aggregate capacity and generation mix in the contiguous United States. As indicated by the dispatch results, Ref.SeaX scenarios deploy additional PV capacity, thus PV generation increases. There is also a reduction of PV-battery hybrids in many years, indicating added hydropower flexibility reduces the incentive for other flexible technologies. Though fossil generation in 2050 is consistently lower under Ref.SeaX scenarios, this effect is not observed in all other model years. RE100.SeaX scenarios sometimes have additional PV and less wind capacity and generation through 2030, but PV capacity is lower in some years, and capacity and generation mix impacts are otherwise inconsistent. For example, wind capacity and generation changes differ in direction across years and scenarios. There does appear to be some net increase in battery deployment in later years, which could indicate some complementarity between technologies offers flexibility over different timescales.

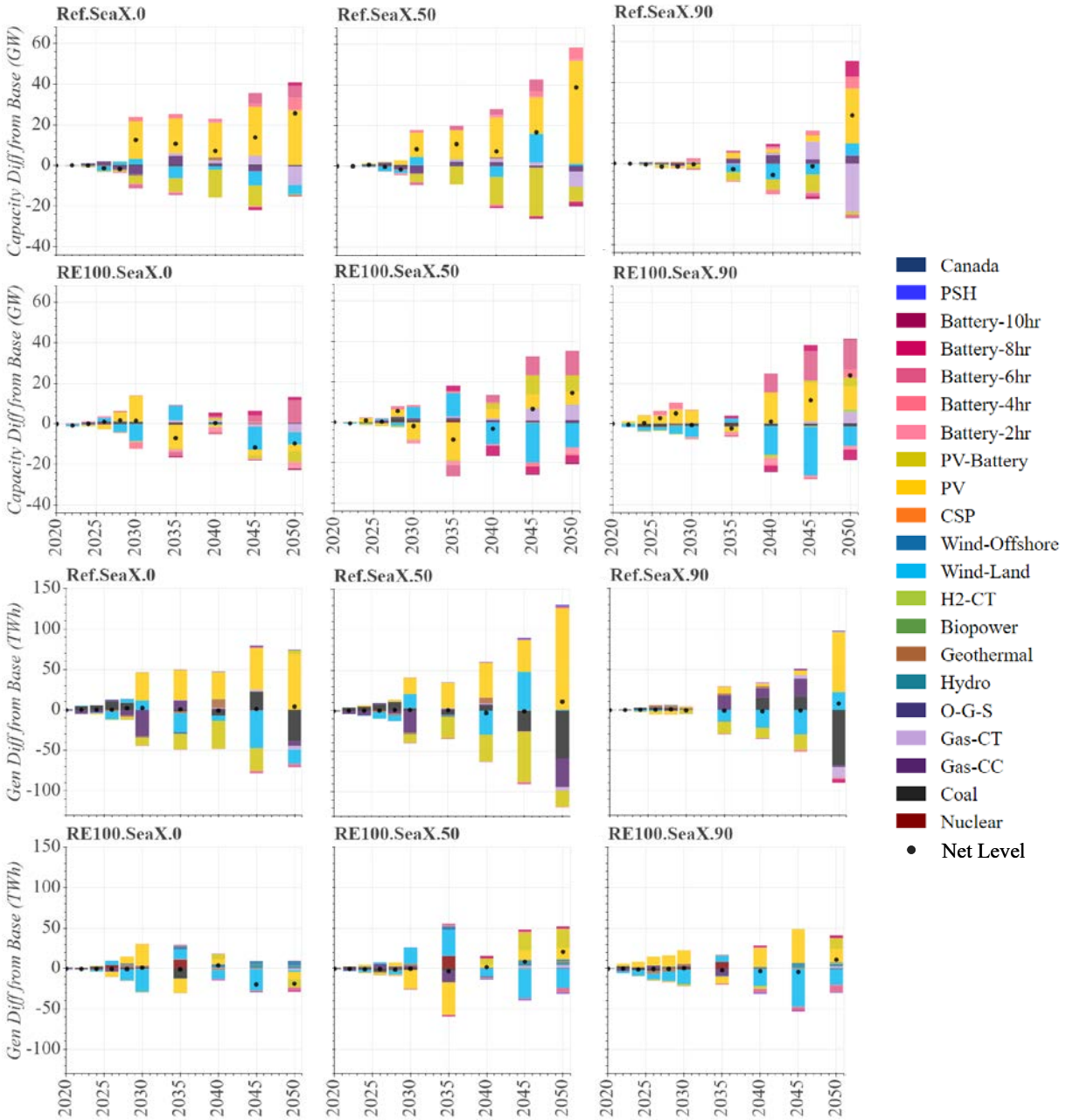


Figure 3.4. Change to the national capacity and generation mix with interseasonal energy shifting. Ref scenarios have increased PV capacity and energy, but RE100 scenarios have mostly inconsistent technology-specific impacts.

The ReEDS value stream outputs provide another way to observe the impact of interseasonal energy transfers. Figure 3.5 plots specifically the discounted energy value of existing dispatchable hydropower across the 2020 to 2050 model years, as this value stream metric is most relevant to seasonal energy shifting. Quantities are normalized by total energy production to report results as dollars per megawatt-hour (\$/MWh). The cumulative energy value is much higher in Ref scenarios than in the RE100 scenario. The energy value increases with seasonal shifting in all scenarios, but this change is only notable for a subset of the RE100.SeaX scenarios. The increase in energy value is highest for the RE100.SeaX.0 and RE100.SeaX.90 Scenarios, and the lack of a monotonic relationship between flexibility and value demonstrates the complexity of operating and valuing a particular type of flexibility.

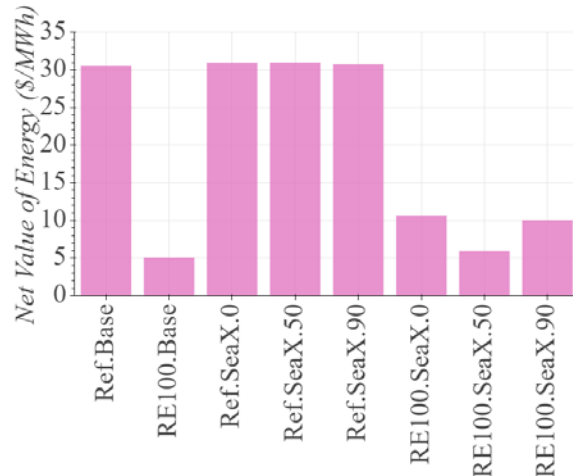


Figure 3.5. Sum of the discounted energy value across 2020–2050 model years for existing dispatchable hydropower in the Base scenarios and scenarios with the ability to transfer energy across seasons. Quantities are normalized by generation, and other value streams (e.g., capacity) are not shown. Seasonal shifting has little effect on energy value in Ref scenarios but increases energy value in RE100 scenarios.

This limited analysis demonstrates there is an opportunity for revised seasonal hydropower energy allocations to improve grid performance, particularly by helping balance seasonality of solar generation. However, reallocating energy across seasons could have negative impacts on ecology or other water management requirements, and these costs must be considered alongside any benefits of seasonal reallocation for power production. Though these generic scenarios do not reflect practical capabilities of existing hydropower, they are a step toward identifying the conditions where interseasonal shifting would be valuable and how it might be accomplished. Additional facility-level technical and operating data could offer an even clearer picture of how this capability could function in a future electricity system.

3.5.2 Interseasonal Arbitrage with PSH

Following a similar presentation as interseasonal energy transfers, Figure 3.6 and Figure 3.7 shows the change from Base dispatch of PSH only and all technologies in 2050. At moderate increases in flexibility (SeaA.90 and SeaA.50 scenarios), there is an increase in PSH usage for diurnal arbitrage, particularly in the spring. However, the highest flexibility SeaA.0 scenarios demonstrate a similar trend as interseasonal energy transfers for hydropower, with additional energy storage in the spring to be used for generation in the winter. Though SeaA.0 scenarios imply the unlikely practice of pumping or generating continuously for an entire season, they indicate how more realistic levels of interseasonal arbitrage might be utilized. Interseasonal arbitrage is used more extensively in RE100 scenarios than the Ref scenario, demonstrating the improved ability of PSH to complement VG in a higher-VG system with lower-cost renewable energy available for pumping.

The 2050 dispatch of other technologies also follows similar trends as hydropower with interseasonal energy shifting. Ref.SeaA scenarios have consistently more PV generation and less fossil generation, but the impacts on wind and battery storage are less clear. Again, dispatch in RE100.SeaA scenarios are noisy, with small changes to PV, battery, and PV-battery hybrid usage. These results, particularly in the Ref.SeaA scenarios, demonstrate changes to other technologies that are often much greater than to PSH, so it is possible that the differences are driven primarily by path-dependent solution variability that results from the lack of foresight in ReEDS.

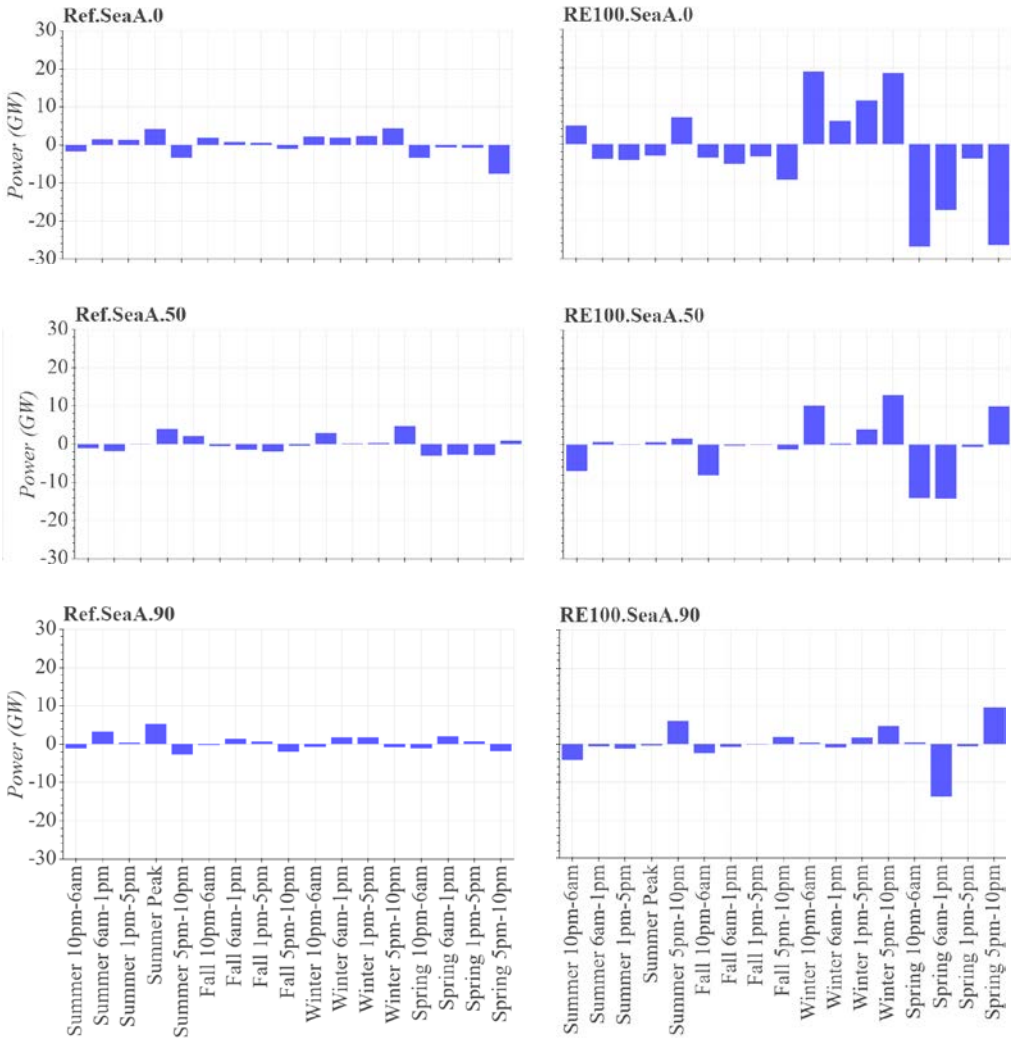


Figure 3.6. Changes to 2050 time-slice generation relative to Base scenarios for PSH. PSH tends to shift energy from Spring to Winter when able, which can help balance PV.

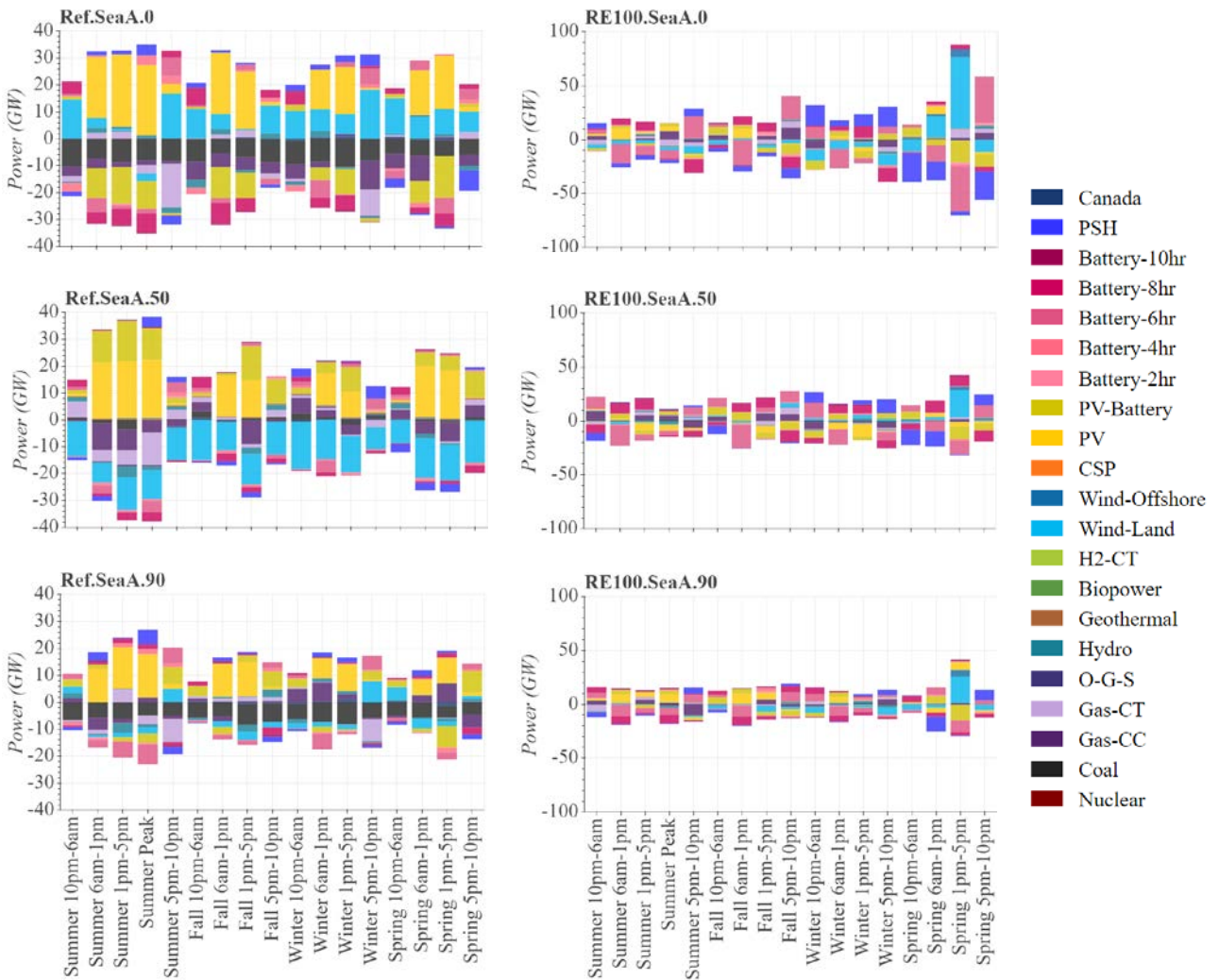


Figure 3.7. Changes to 2050 time-slice generation relative to Base scenarios for all technologies. Shifting PSH from Spring to Winter can increase PV generation and reduce fossil generation, depending on the scenario.

In Ref.SeaA scenarios, allowing 50% or 90% energy to move across seasons corresponds to higher PV capacity and generation across the United States (Figure 3.8), but the changes to nationally aggregated capacity and generation of other technologies are less consistent over time and across allowable levels of interseasonal arbitrage. RE100.SeaA scenarios often have consistently higher battery deployment, indicating some complementarity between the modeled long-duration storage capabilities of PSH and shorter-duration batteries. There is also a reduction in wind capacity and generation in many years for RE100.SeaA scenarios, but this outcome is not consistent across scenarios or over time for a given scenario.

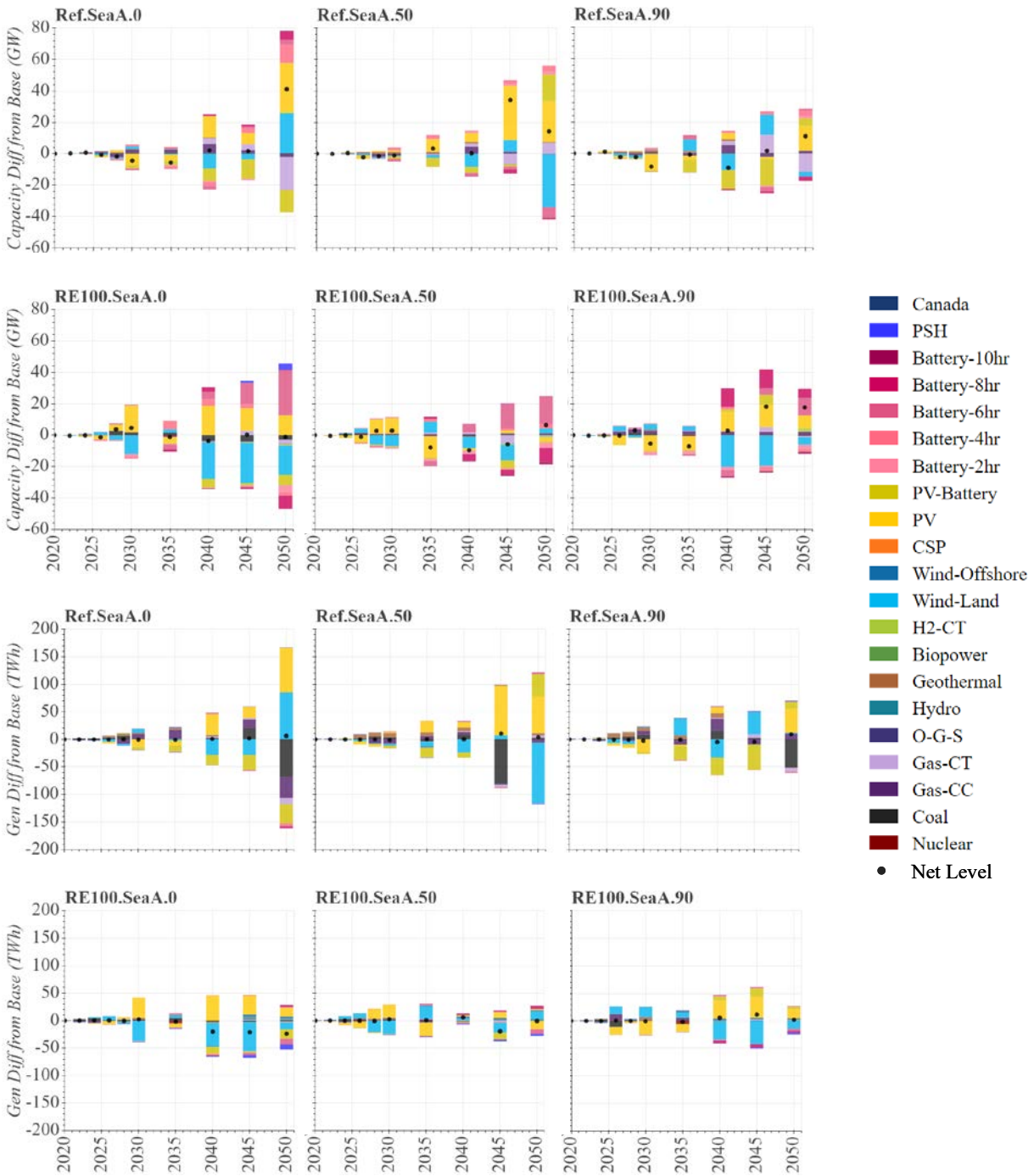


Figure 3.8. Change to the national capacity and generation mix with interseasonal energy arbitrage, relative to the corresponding Base scenario. Interseasonal energy arbitrage facilitates increased PV use and complements short-duration battery deployment in RE100 scenarios.

The total 2020–2050 discounted energy value stream for PSH in these scenarios (Figure 3.9) corroborates the dispatch observations from Figure 3.7. Values are normalized by PSH capacity rather than generation (as in Figure 3.5 with hydropower) because PSH is a net consumer of energy. Energy value is much higher for RE100 scenarios, as is the incremental value of interseasonal energy arbitrage. In contrast, the

energy value for PSH is negligible in this time frame for Ref scenarios except for the most flexible Ref.SeaA.0 scenario. Compared to Figure 3.5, Figure 3.6 indicates that while energy arbitrage is more valuable in the RE100 scenarios, low-marginal cost generation is more valuable in the Ref scenarios.

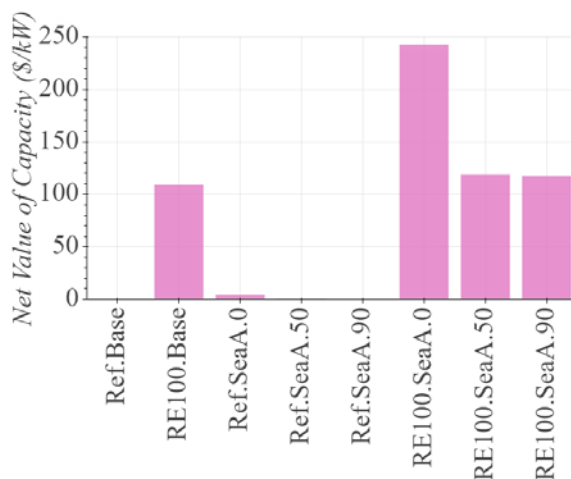


Figure 3.9. Sum of the discounted energy value across 2020–2050 model years for existing PSH in the Base scenarios and scenarios allowing interseasonal energy arbitrage. Quantities are normalized by capacity; other value streams (e.g., capacity) are not shown. Interseasonal arbitrage increases energy value, particularly in the RE100 scenarios.

This exploration of PSH interseasonal energy arbitrage ignores site-level feasibility challenges but again demonstrates the opportunity for complementing seasonal differences in VG availability. Future work could explore the true potential for storing energy across seasons for the existing fleet or new PSH capacity. Though arbitrage on a seasonal time frame might be impractical given uncertainty and operational planning horizons, this bounding case hints at the importance of understanding arbitrage opportunities beyond the diurnal timescale.

3.5.3 Storage Duration Data

The impact of plant-specific storage duration data is examined using 2050 time-slice power generation (net) for PSH. Figure 3.10 compares this result at a national level with and without duration data in Ref.SeaA scenarios, and Figure 3.11 does the same for RE100.SeaA scenarios. There are only minor quantitative changes to results when incorporating the duration data, and there is no qualitative effect on how PSH is used in aggregate throughout the United States. However, Figure 3.12 shows one example where storage duration data can have a notable regional impact, in this case for Arizona in 2050 for the Ref.SeaA.0 scenario. Arizona has two PSH facilities listed in the IHA database: a 60-MW facility with 46 hours of storage and a 130-MW facility with 182 hours of storage. Though downstream reservoir size and other constraints could reduce the effective available storage duration, when these longer durations are incorporated into ReEDS, seasonal arbitrage is used much more extensively.

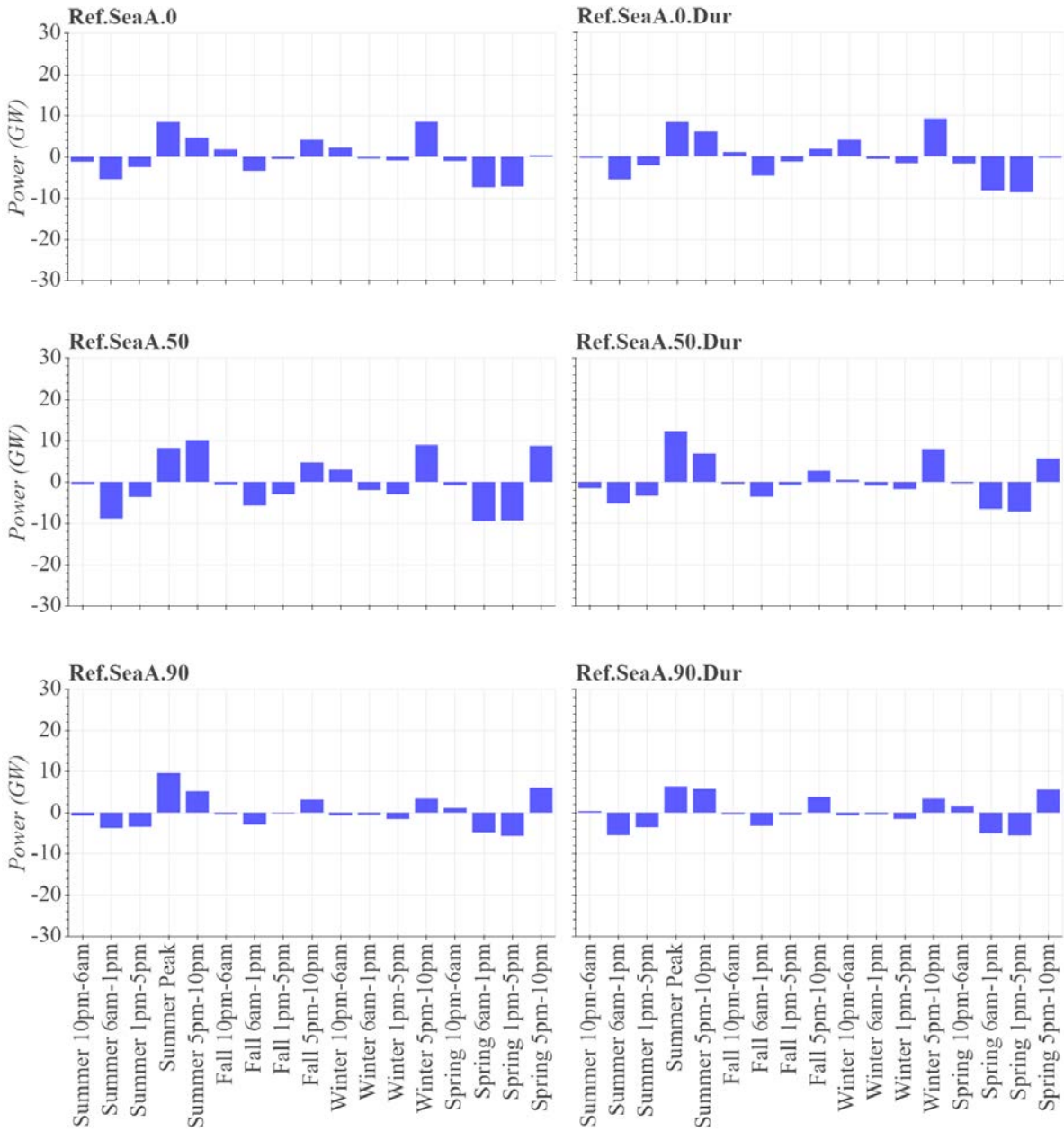


Figure 3.10. 2050 time-slice generation for Ref scenarios with and without plant-level PSH storage duration data, for varying degrees of seasonal energy arbitrage. Storage duration data has negligible impact on nationally aggregated PSH dispatch.

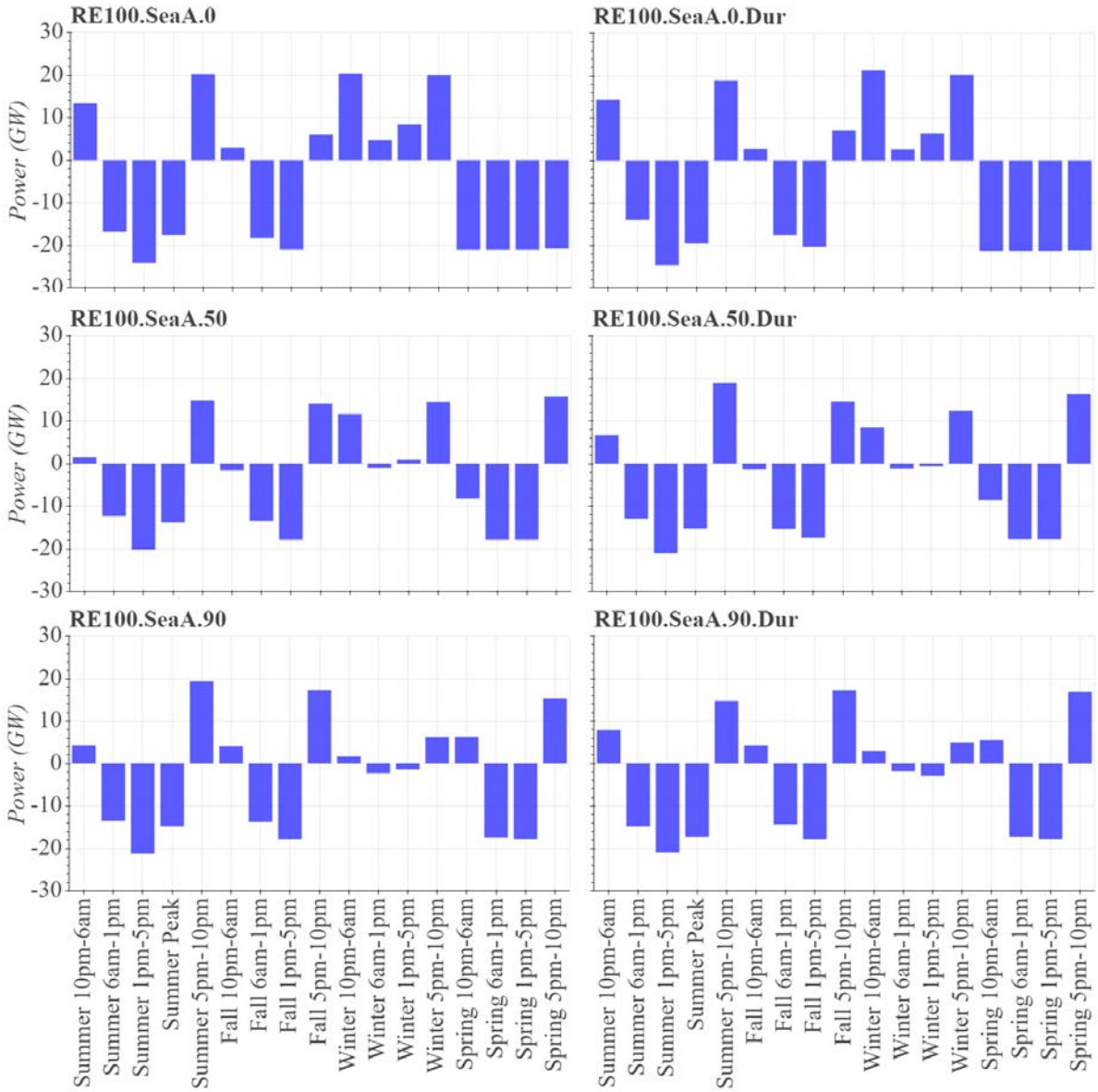


Figure 3.11. 2050 time-slice generation for RE100 scenarios with and without plant-level PSH storage duration data, for varying degrees of seasonal energy arbitrage. Storage duration data has negligible impact on nationally aggregated PSH dispatch.

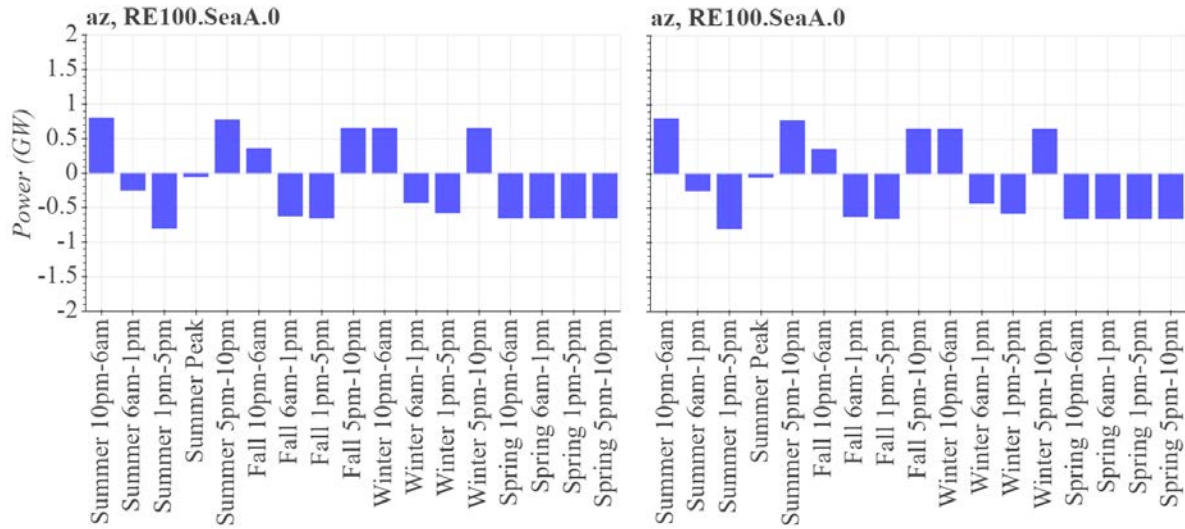


Figure 3.12. 2050 time-slice generation for PSH in Arizona for the RE100.SeaA.0 scenario with and without plant-level PSH storage duration data. Arizona has a 60-MW facility with 46 hours of storage and a 130-MW facility with 182 hours of storage, and plant-level storage duration data substantially affects how these systems operate in the model.

These results suggest a lower benefit for integrating plant-specific PSH duration data into ReEDS. However, this result is related to the time and plant resolution available in the model. Given higher time resolution or explicit representations of each PSH plant, accurate storage durations could have a greater influence on model results, especially in particular BAs, states, or regions. As models like ReEDS advance toward higher spatial, temporal, and process resolution, plant-level PSH duration data could be helpful to accurately depict the capabilities of the existing fleet.

3.5.4 Valuing Intermediate-Duration Storage

The results of the Augur intermediate-duration storage exploration are summarized in Figure 3.13. It plots the calculated energy arbitrage value as a function of hypothetical storage duration for several ReEDS BAs and lists the corresponding state in the legend. These BAs are chosen to represent a diverse set of geography, generation mix, and shares of hydropower. Both scenario-year combinations demonstrate that this spatial diversity is important to consider because arbitrage value is distributed widely across regions and the range of this distribution can change over time.

Both scenario-year combinations have an increasing arbitrage value with storage duration, but this increase is much greater in the High RE-2050 case, increasing arbitrage value by a factor of 1.5–2.2 relative to 12-hr duration for the regions shown. Arbitrage value increases very little beyond 48-hr durations for the Mid Case-2026, but higher renewable penetrations in High RE-2050 lead to greater arbitrage opportunities over longer timescales. This effect is also region-specific; in High RE-2050, the NC_p97 region does not have a similar increase in value with duration as other regions.

Though these value estimates are not yet integrated into the ReEDS model, this investigation signals the potential benefit of doing so. Where arbitrage across seasonal timescales is often impractical, PSH and other storage technologies with > 12-hr duration could provide increasing value to the grid with increasing VG deployment. A broader scenario analysis, including variations on demand flexibility, battery cost, policies, or other scenario variables could further evaluate the robustness of this result under alternative electricity futures.

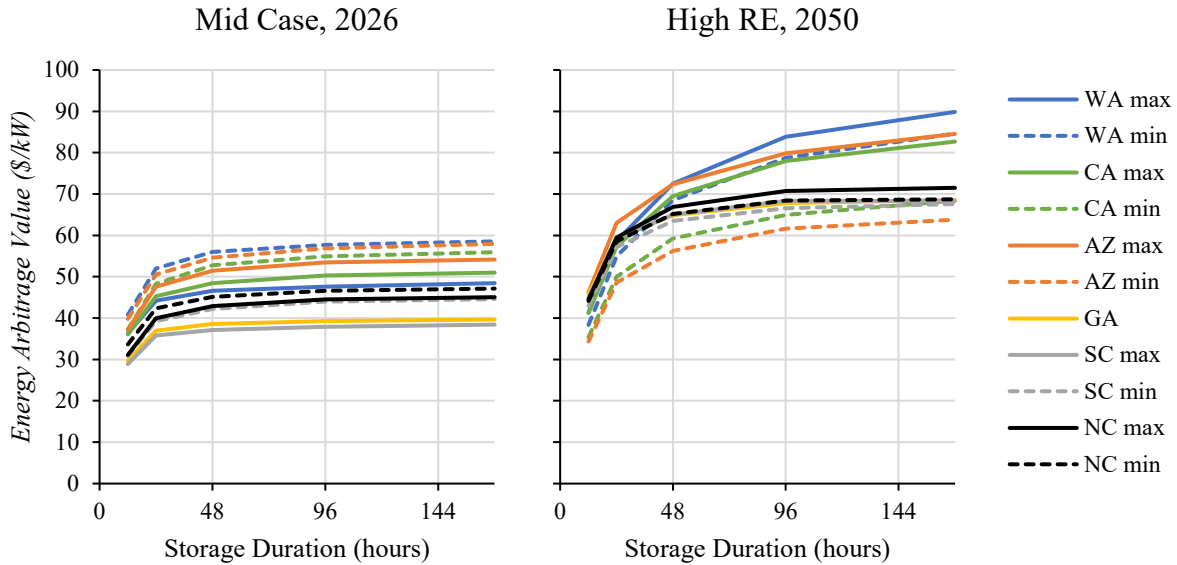


Figure 3.13. Minimum and maximum energy arbitrage value (2020\$) across balancing areas in several states, as a function of storage duration, in a Mid Case scenario in 2026 and a High RE scenario in 2050 (Georgia has only 1 ReEDS BA). Arbitrage value varies across regions and increases with storage duration, and the value of longer storage durations is higher in a high-RE grid.

4.0 Upgrading Hydropower Systems

Because of environmental, political, and social considerations, the opportunities for deploying new hydropower in the United States are limited, particularly on-river facilities that require new dam construction. However, the existing hydropower fleet could offer upgrade opportunities. ReEDS has been used to explore hydropower upgrades in the form of combined capacity-plus-energy additions to the existing fleet; ORNL researchers estimated the capacity cost (\$/kW) and availability of these upgrades as part of the DOE *Hydropower Vision* (DOE 2016), and they determined the corresponding energy addition using the capacity factor of the existing capacity being upgraded.

Here we expand hydropower upgrade opportunities by not only considering capacity and energy upgrades independently but also by offering ways to increase hydropower flexibility. Decoupling capacity and energy upgrades allows us to study which of the two is more valuable and how they complement each other. Flexibility upgrades are enabled by two pathways: (1) transitioning from highly constrained nondispatchable hydropower capacity to dispatchable hydropower and (2) adding pumps to existing dispatchable hydropower capacity. We acknowledge that upgrade opportunities could be limited in practice by a variety of unit-level technical considerations, environmental restrictions, or other investment and operating constraints. Nevertheless, the range of upgrade options examined here allows us to understand which characteristics are most attractive when considering hydropower upgrades, and how the value of these opportunities changes over time, throughout space, and across alternative electricity futures.

4.1 Improving Dispatchability of Hydropower Generation

In practice, hydropower flexibility is site-specific and depends on an individual facility operating plan. ReEDS abstracts this site-specific information by dividing the existing hydropower fleet into dispatchable

and nondispatchable categories based on data and operating mode classifications by the WECC and ORNL (WECC 2013; Rocío Uría-Martínez, Patrick W. O’Connor, and Megan M. Johnson 2015). Given this existing distinction in the model, a generalized upgrade pathway from nondispatchable to dispatchable hydropower can be easily defined in the model, provided an upgrade cost is defined. Then ReEDS can choose to invest in the upgrade if the additional energy and reserve provision capabilities result in lower overall system cost.

For this exploratory work, we allow all nondispatchable hydropower to upgrade to become dispatchable hydropower and perform a sensitivity analysis on the cost of this upgrade. In practice, increasing dispatchability could be infeasible for many facilities, so this analysis constitutes an upper bound of the availability of such upgrades. Significantly increasing dispatchability for non-federal hydropower would often require renegotiating a facility operating plan with FERC and other government agencies and would likely occur at the time of relicensing, but we do not restrict when dispatchability upgrades can occur for any hydropower capacity. This representation offers the opportunity to respond to grid flexibility needs whenever they may arise, better highlighting the potential future role of hydropower flexibility.

Assigning dispatchability upgrade costs is also difficult because the nature of the upgrade will be site-specific. Flexibility improvements could in some cases be possible under the existing license requirements; for example, operational changes enabling deeper ramping could be implemented if flow requirements are continued to be met. However, equipment and software modifications could be needed to enable faster responses to power system needs. A facility might also need to install environmental mitigation technologies. Given this uncertainty, dispatchability upgrades are explored for costs ranging from unrealistically low (to find an upper bound on what might be upgraded) to roughly the per-unit-capacity cost of new powerhouse and electromechanical construction and infrastructure for a 1,000-MW PSH facility (Mongird et al. 2020).⁹ This sensitivity analysis allows us to determine the role, value, and potential for hydropower dispatchability upgrades.

4.2 Adding Pumping

Another way to increase operating flexibility is to add pumping capability to hydropower generation facilities, converting an existing once-through facility to a pump-back facility. The facility could then augment the energy stored from inflow water with energy stored by pumping water to the upper reservoir. The facility would then have added flexibility to engage in energy arbitrage or use pumping to reduce VG curtailments. In the model, capacity that has added pumping can access all value streams available to standalone PSH.

We test this capability by allowing the entire existing dispatchable hydropower fleet to add pumps, implying there is downstream water storage that can function as a lower reservoir, such as a regulating or off stream reservoir. This upgrade is represented generically in the model by enabling pumping capabilities at a predefined capital cost, which would be site-dependent in practice depending on whether the upgrade involved replacing the turbine with a reversible pump-turbine, adding a separate conduit and pump, or something else. Such an upgrade would likely be infeasible at many existing facilities because of space constraints at the powerhouse, inadequate downstream water storage, environmental considerations, and cost; so this analysis is intended to place an upper bound on pump upgradability for existing hydropower. However, there could be opportunities for adding pumps to new generating capacity added by powering non-powered dams or building new low-head hydropower, and these pathways are not

⁹ Though this exercise considers hydropower generation and not PSH, this cost including pump equipment is used to provide a conservative upper bound.

considered here. Improved site-level data would help identify facilities more conducive to pump upgrades and would enable a more realistic analysis of these opportunities.

Upgrades are modeled such that generating capacity remains the same, but pump capacity does not have to equal generating capacity. This allows the model to optimize total pump capacity investment, even if that entails pump capacity greater than original generating capacity. We assume a generic 12-hr storage duration for any pump upgrades, although this assumption could be refined with site-level assessment.

This new capability is the first example in ReEDS where a generation-only technology is given a pathway to upgrade to a generation-plus-storage technology, making its capabilities similar to a PV-battery hybrid or CSP system. Thus, several model constraints had to be modified to (1) enable storage variables and constraints for the upgraded capacity and (2) account for pumping energy in system energy balance equations. To account for the inflow water energy in the constraint tracking stored energy levels, the final term had to be added to Equation 7:

$$\text{Equation 7: } \forall i \in \text{pump upgrades}; v; r; h; t: \sum_{h+1} (\text{STORAGE_LEVEL}_{i,v,r,h+1,t}) = \text{STORAGE_LEVEL}_{i,v,r,h,t} + (\text{storage_eff}_{i,t} \times \text{hours_daily}_h \times \text{STORAGE_IN}_{i,v,r,h,t}) - (\text{hours_daily}_h \times \text{GEN}_{i,v,r,h,t}) + (\text{avail}_{i,v,h} \times \text{hours_daily}_h \times \text{CAP}_{i,v,r,t} \times m_cf_szn_{i,v,r,szn \in h,t})$$

Uncertainty about the cost of adding a pump to a given facility is significant, but a recent report by Pacific Northwest National Laboratory and others offers a cost breakdown for new PSH facility cost categories (Mongird et al. 2020). If one conservatively assumes adding a pump requires rebuilding the powerhouse and electromechanical equipment and infrastructure, the total cost from this recent report is \$1,015/kW without contingency and \$1,354/kW with a 33% contingency factor (2020USD). We use the value with the contingency to define a conservative upper bound for cost sensitivity analysis, although it is certainly possible for costs to be higher if a new reservoir must be constructed as well. As a lower bound, an unrealistically low number is used to explore the upper limit on pump upgradability.

Though data limitations on feasibility and cost make an accurate depiction of pump upgrades difficult, here we demonstrate a new capability that enables such upgrades and helps identify locations and conditions where they might be valuable.

4.3 Increasing Generating Capacity or Stored Energy

Coupled capacity-plus-energy upgrade opportunities offer a first-order way to assess the economic potential for hydropower upgrades that could realistically occur via many upgrade mechanisms. It does not differentiate between upgrade options such as a generator rewind, a turbine refurbishment or addition, or a dam raise. Further, the Base ReEDS formulation treats upgrade potential and cost as a separate technology from the “existing hydro” technology in ReEDS, so nothing links the operation of upgraded capacity to the operation of the associated existing capacity (i.e., it can be dispatched independently).

The alternative upgrade formulation created for this work allows the model (1) to independently choose to upgrade hydropower capacity or energy or (2) to upgrade both depending on the relative value of capacity or energy in that region and year. The formulation also links any upgrades to the original hydropower capacity, so the original capacity plus its upgrade is dispatched together more realistically than the Base formulation. Though in practice, many hydropower upgrades (e.g., re-winding a generator) do result in both capacity and energy additions, decoupling them in the model helps identify the most valuable characteristics and how they complement each other and other grid technologies. Some upgrade options might prioritize capacity (e.g., adding a turbine-generator unit) or energy (e.g., raising a dam), so

modeling independent capacity and energy upgrades allows us to explore which characteristic is more important to prioritize and how that priority changes by region and scenario.

Decoupled capacity and energy upgrade potential remain limited by the Base hydropower upgrade supply curves. Capacity upgrade potential is equal to the region-specific quantity in the supply curves, and energy upgrade potential is equal to the upgrade capacity potential multiplied by the existing fleet capacity factor for that region. This keeps the resource base identical to the Base representation.

Given the uncertainty in the true nature of a given site upgrade, it is difficult to disentangle capacity and energy upgrade costs from the Base supply curve costs. Thus, we parameterize costs as a fraction of the total Base supply curve costs so that capacity and energy upgrades can be independently assigned 0%–100% or more of the original costs.

The model implementation of capacity and energy upgrades is unique in ReEDS because it constitutes a change to the performance specifications of an existing technology rather than a transformation from one technology to another (e.g., upgrading a natural gas-combined cycle unit to a natural gas-combined cycle unit with CO₂ capture and storage). This creates challenges for ensuring capacity upgrades *only* affect capacity and energy upgrades *only* affect energy.

Capacity upgrades require new investment variables (*INV_CAP_UP*) indexed not only by technology, vintage, region, and year but also by supply curve bin (*bin*) from the upgrade supply curves. Capacity upgrades are treated as a subset of the total capacity (*CAP*), so all capacity accounting constraints require an additional term with the new variable. A new constraint uses supply curve data to define the upper limit on capacity upgrades (*cap_cap_up*) for eligible capacity as shown in Equation 8, where *INV_CAP_UP* are single-year investment variables that are summed from the initial to current time periods for a given year. To prevent capacity upgrades from increasing available energy to nondispatchable hydropower, the product of *INV_CAP_UP* and the time-slice capacity factor *m_cf* must be subtracted from the product of *m_cf* and *CAP* in the constraint limiting power generation in each time-slice. For dispatchable hydropower, this product must be subtracted in any seasonal or annual energy limit constraints.

$$\text{Equation 8: } \forall i; v; r; bin; t \in \text{eligible: } cap_cap_up_{i,v,r,bin,t} \geq \sum_{t' \in [t'_{init}, t'_{current}]} INV_CAP_UP_{i,v,r,bin,t'}$$

Energy upgrades are formulated using new investment variables (*INV_ENER_UP*) that are in capacity units but affect only energy availability. An analogous constraint to Equation 8 uses a *cap_ener_up* parameter, defined as the product of upgrade capacity potential and the capacity factor of existing hydropower. The product of *INV_ENER_UP* and the capacity factor *m_cf* is then added to the total energy available to dispatchable hydropower, which allows for an increase in average output of nondispatchable hydropower. This flexible formulation offers a new way to explore upgrades in ReEDS that could be applied to other technologies in the future.

4.4 Scenario Results

Because of cost uncertainty for any of these upgrade options, each new feature is explored with an upgrade cost sensitivity. Dispatchability and pump upgrades are explored between \$10/kW and \$1,000/kW in the ReEDS native 2004 dollar year (\$14/kW and \$1,370/kW in 2020USD). Capacity and energy upgrade scenarios explore costs ranging from a 50% to 100% of the Base supply curve cost for each upgrade type, independently, and in combination.

Table 4.1. Scenarios for Demonstrating New Hydropower Upgrade Options
Each improvement is applied to each of the three Baseline scenarios in Table 1.1.

Scenario Name (abbreviation)	Scenario Description
Dispatchability Upgrades (*.UD.[<i>dc</i>])	Dispatchability upgrades available to existing nondispatchable hydropower, with <i>dc</i> being the capital cost (\$/kW) for the upgrade
Pumping Upgrades (*.UP.[<i>pc</i>])	Pumping upgrades available to existing dispatchable hydropower, with <i>pc</i> being the capital cost (\$/kW) for the upgrade
Capacity Upgrades (*.UC.[<i>fcc</i>])	Capacity-only upgrades available to existing hydropower, with <i>fcc</i> being the fraction of the upgrade supply curve capital cost attributed to the capacity-only upgrade
Energy Upgrades (*.UE.[<i>fec</i>])	Energy-only upgrades available to existing hydropower, with <i>fec</i> being the fraction of the upgrade supply curve capital cost attributed to the energy-only upgrade
Both Capacity and Energy Upgrades (*.UCE.[<i>fcc</i>].[<i>fec</i>])	Independent capacity and energy upgrades available to existing hydropower, with <i>fcc</i> and <i>fec</i> defined as above

4.4.1 Upgrading Hydropower Generation Dispatchability

Figure 4.1 (page 4.51) shows that dispatchability upgrades are sensitive both to cost and electricity scenario (Ref versus RE100 scenarios). Ref scenarios do not upgrade dispatchability at \$1,000/kW, but 12.4 GW upgrades at this cost in the RE100 scenario, more than with \$500/kW costs in Ref. At costs \$300/kW or below, upwards of 27 GW capacity upgrades dispatchability, and all the 32.5 GW of eligible capacity is upgraded at the negligible \$10/kW cost. These national-scale results indicate dispatchability upgrades are reasonably attractive, even in some scenarios where costs are higher.

The spatial distribution of these upgrades is shown in Figure 4.2 for several years in the RE100.UD.500 scenario to show a progression from the most-attractive to the least-attractive upgrade locations. Figure 4.3 uses the same information to plot the fraction of eligible capacity that has been upgraded for each year in the RE100.UD.500 scenario. Initial upgrades occur in Texas and Montana before expanding to other parts of the Rocky Mountain region, East Coast, and southern Mississippi River drainage basin states before eventually expanding to most U.S. states. On a fractional basis, Florida is first to upgrade all of its eligible capacity (albeit from only 12 MW), followed by a few other states across the eastern United States before eligible capacity is upgraded throughout the country. The specific reasons for this result are difficult to discern, but it is possible that firm capacity requirements play a major role in driving dispatchability upgrades in these regions, particularly in the southeast where high PV deployment can result in a more rapid erosion of PV capacity credit. Despite substantial hydropower capacity in the Pacific Northwest, dispatchability upgrades lag there because a substantial amount of flexible hydropower already exists there. States without any upgrades tend to have little hydropower capacity, low electricity demand, or both. The broad distribution of these upgrades demonstrates their potential value to a large portion of the United States.

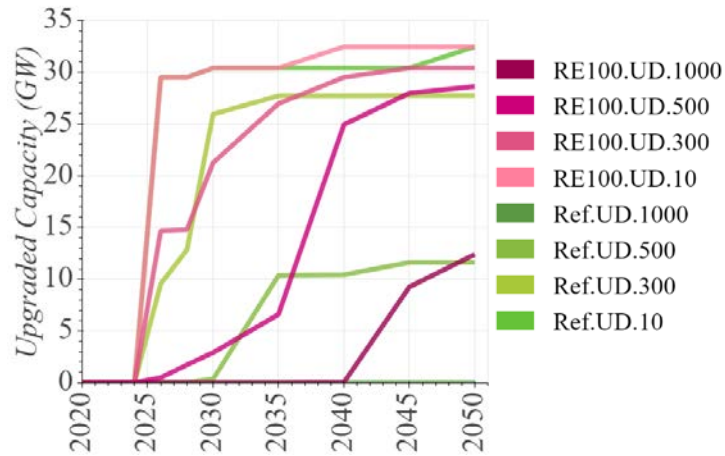


Figure 4.1. Upgrades over time from nondispatchable to dispatchable hydropower. Of the 32.5 GW eligible, dispatchability upgrades vary across scenarios but are higher with lower upgrade cost and a higher RE grid.

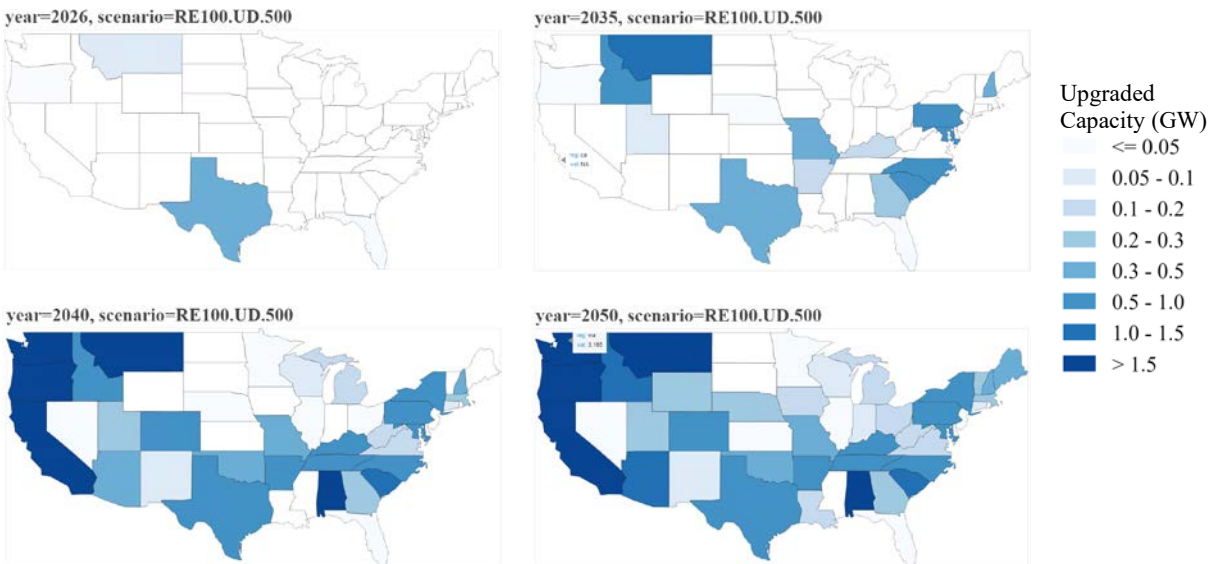


Figure 4.2. Cumulative dispatchability upgrades by state in the RE100.UD.500 scenario in model years 2026, 2035, 2040, and 2050. Dispatchability upgrades are geographically dispersed and tend to occur later in areas with existing flexible hydropower (e.g., the Pacific Northwest).

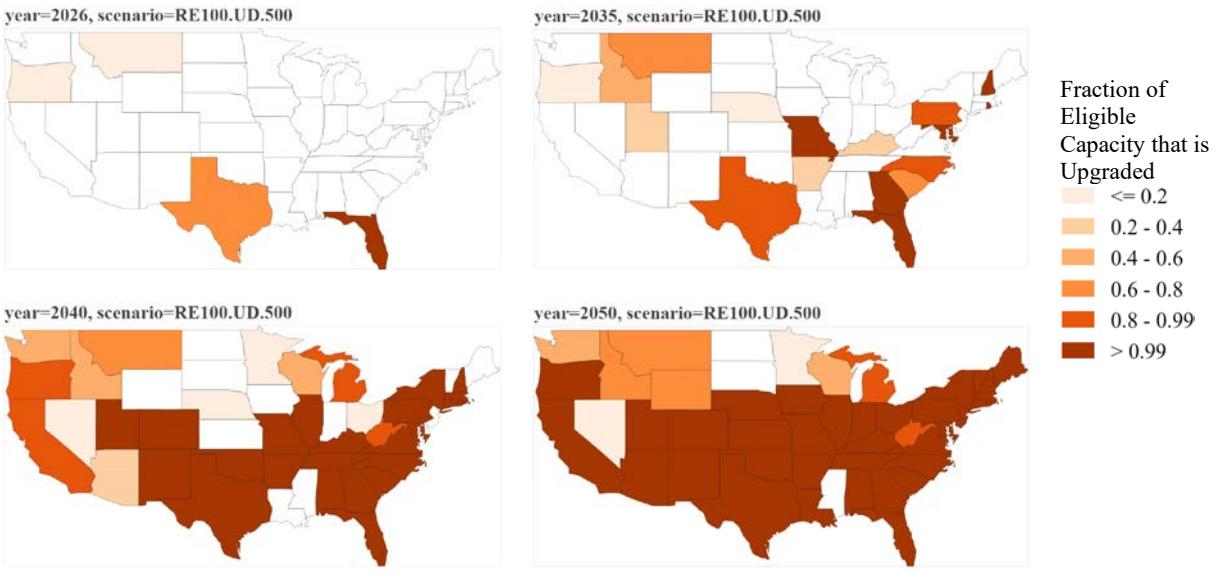


Figure 4.3. Fraction of eligible capacity that upgrades dispatchability by state in the RE100.UD.500 scenario in model years 2026, 2035, 2040, and 2050. Florida is the first to upgrade all capacity where regions in the Midwest and west do not upgrade all eligible capacity in this scenario.

Figure 4.4 plots the change from Base scenarios of total (non-PSH) hydropower power generation in each 2050 time-slice. In Ref scenarios, increasing deployment of dispatchability upgrades enables hydropower to shift generation from daytime to nighttime periods, largely to complement solar PV generation profiles. Dispatch changes with RE100 scenarios are less intuitive. There is little change in how hydropower is dispatched in RE100.UD.1000 despite the 12.4 GW of upgrades, suggesting dispatchability upgrades in this scenario primarily serve to increase the capacity value of these facilities for providing adequacy and operating reserves. In the RE100 scenarios with lower upgrade costs, some generation shifts to nighttime, but notably, generation is lower in all spring time-slices. This result represents available hydropower energy that is not being utilized because its marginal cost, albeit low, is still assumed to be slightly higher than wind and PV generation. If all technologies were given zero marginal operating cost, the spring dispatch solution would be indifferent to which technology is used.

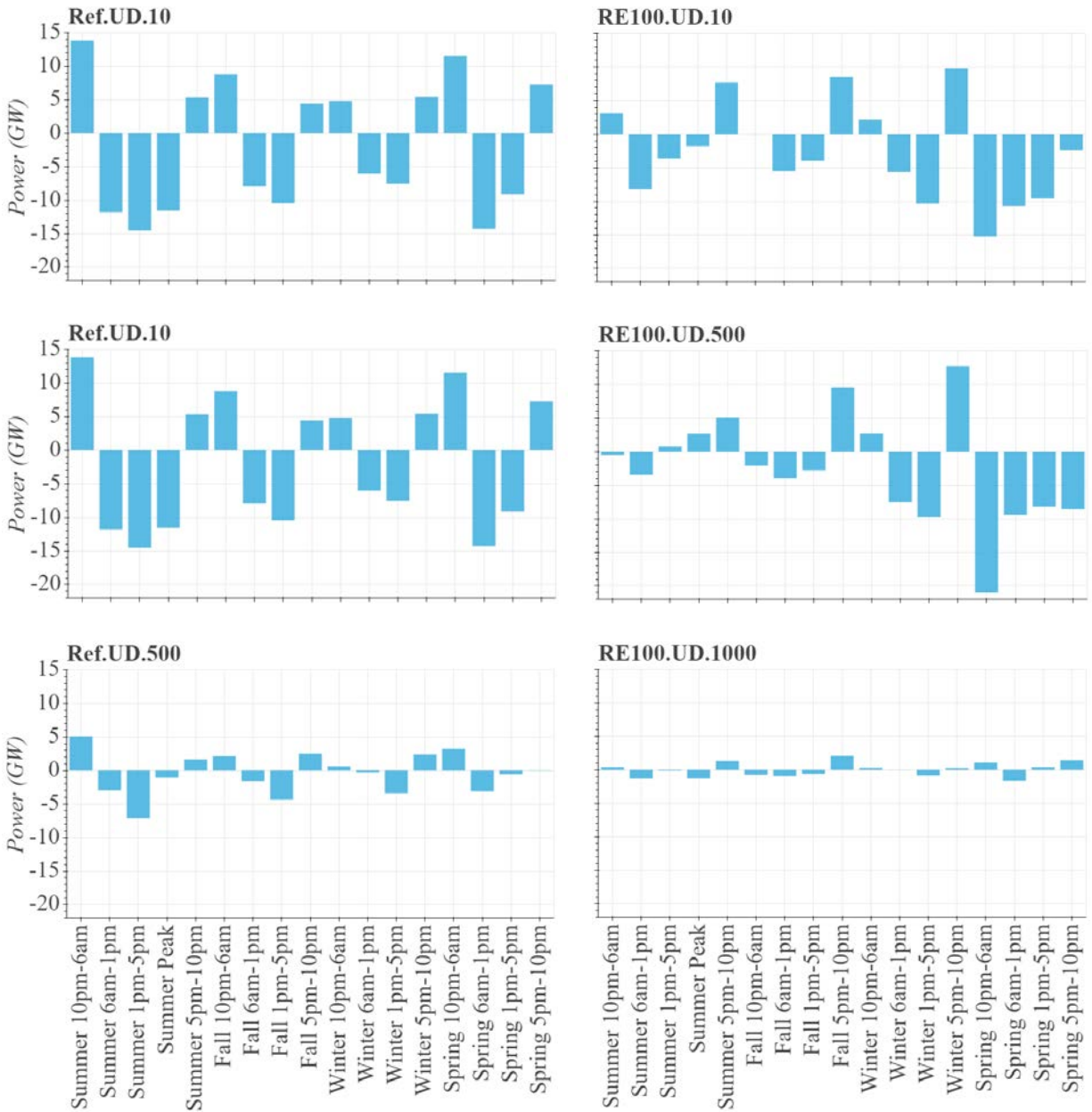


Figure 4.4. Change in national non-PSH hydropower power output in each ReEDS time-slice in 2050 relative to the corresponding Base scenario without flexibility upgrades available. When hydropower is more dispatchable, generation shifts to time periods when VG is less available.

Upgrading hydropower dispatchability has large impacts on the national capacity mix despite operating on a small fraction of the system (Figure 4.5). In Ref scenarios, additional hydropower dispatchability corresponds to additional wind and PV deployment and is sometimes accompanied by a reduction in coal and natural gas-combined cycle capacity. There is also a smaller increase in short-duration (2–4 hour) battery capacity, reduced PV-battery hybrid deployment, and some increase in natural gas combustion turbine capacity when hydropower flexibility upgrades are very high. In RE100 scenarios, wind and PV deployment is nominally much higher than in Ref scenarios. Here, there is some long-term complementary with wind deployment, but PV and battery deployment is reduced greatly because these technologies are no longer required to meet overall system capacity requirements. In the high-RE case,

the capacity value of added hydropower dispatchability reduces the need to deploy additional renewable capacity with lower capacity credit. The changes in wind and PV on a rated capacity basis are proportionately higher than hydropower capacity changes because increased dispatchability has multiple benefits: (1) more flexible energy provision from low-cost hydropower enables more efficient use of VG energy, and (2) increased hydropower capacity credit can reduce the effect of increased VG deployment reducing its marginal ability to supply firm capacity.

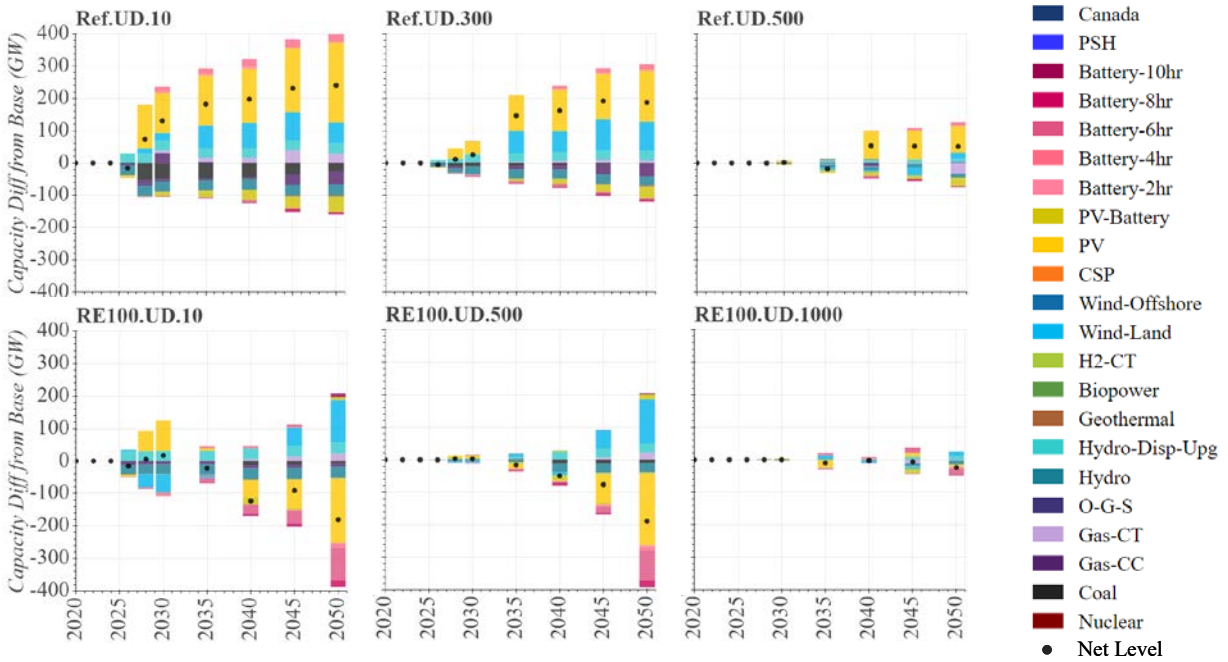


Figure 4.5. Change to the national capacity mix with flexibility upgrades (Hydro-Disp-Upg). Increased hydropower flexibility can substantially influence the deployment of RE, battery, and natural gas-based technologies, with the technology-specific impacts being scenario dependent.

Figure 4.6 plots of discounted value streams for hydropower flexibility upgrades over time. In Ref.UD scenarios, energy and reserve margin capacity value are fairly equally weighted, as indicated by dispatch results where hydropower is used more extensively for energy arbitrage. This is also the case in RE100.UD scenario through 2030 (when changes to the national capacity mix are similar to Ref.UD scenarios), but the energy arbitrage value is quickly dominated by the energy value for meeting the national renewable energy requirement, and reserve margin value is larger than in Ref.UD scenarios. The value streams for RE100.UD scenarios show the increasing value of capacity in a high-VG system and why the overall value can be high despite hydropower being used less for serving electricity demand in some parts of the year.

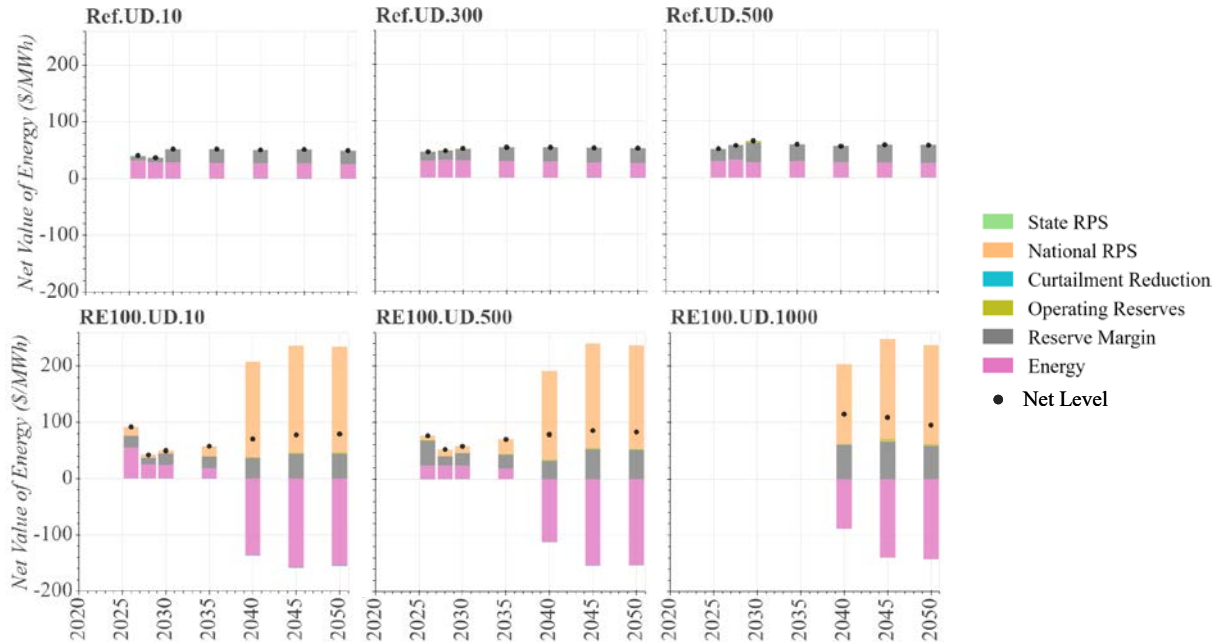


Figure 4.6. Discounted value streams for hydropower with dispatchability upgrades over time for select scenarios, normalized by energy production. Dispatchability upgrades are driven by energy, capacity (reserve margin), and policy (national renewable portfolio standard) value.

4.4.2 Adding Pumps to Hydropower Generation

This section parallels the presentation in Section 4.4.1. Figure 4.7 (page 4.56) plots the deployment of pump upgrades over time, revealing a different story than dispatchability upgrades. Pump upgrades are more modest and occur in later years than dispatchability upgrades. Ref scenarios add pumps to no more than 12.2 GW of the 43.3 GW eligible capacity even at unrealistically low costs. At a higher (\$1,000/kW 2004 USD) cost in the Ref.UP.1000 scenario, only 116 MW of capacity adds pumps. Upgrades are used much more extensively in RE100 scenarios, especially beyond 2035 when renewable energy shares approach 100%. However, even the RE100.UP.10 scenario does not upgrade all eligible capacity, though it does get very close with 43.2 GW being upgraded in 2050.

Regional differences in the attractiveness of pump upgrades are demonstrated in Figure 4.8, which shows cumulative state-level pump upgrades for in several progressive years for the RE100.UP.10 scenario with the highest observed upgrade deployment. Figure 4.9 maps these result as the fraction of eligible capacity with pumping added. Texas is again an initial candidate for the upgrade, along with neighboring states and states along the southern Atlantic Coast. Once deployment accelerates, upgrades occur throughout the United States, without any strong correlation to electricity demand centers. California, Oregon, and Washington are some of the last states to receive pump upgrades. The regional distribution of pump upgrades does not vary significantly across scenarios for a given deployment level, e.g., pump upgrades have occurred in roughly the same locations for both Ref.UP.10 and RE100.UP.500 in 2040. Most states tend to upgrade 100% of eligible capacity if such upgrades are competitive. As with dispatchability upgrades, these states already have large flexible hydropower facilities, which reduces the incentive to invest in other flexibility options such as hydropower pumping upgrades.

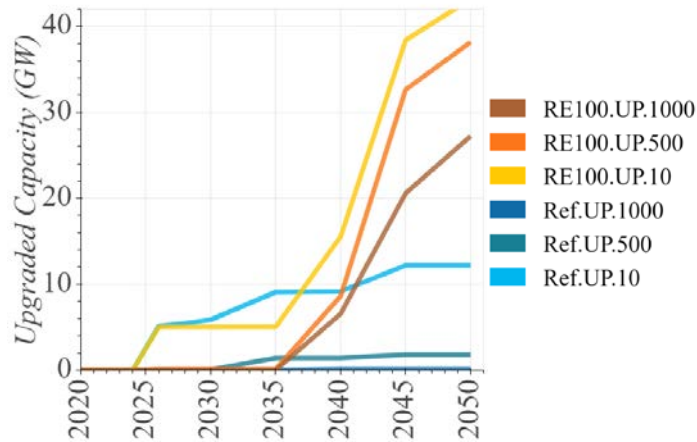


Figure 4.7. Capacity upgraded over time by adding pumps to dispatchable hydropower. With 43.3 GW eligible for this upgrade, pump upgrades are far more attractive in high-RE scenarios.

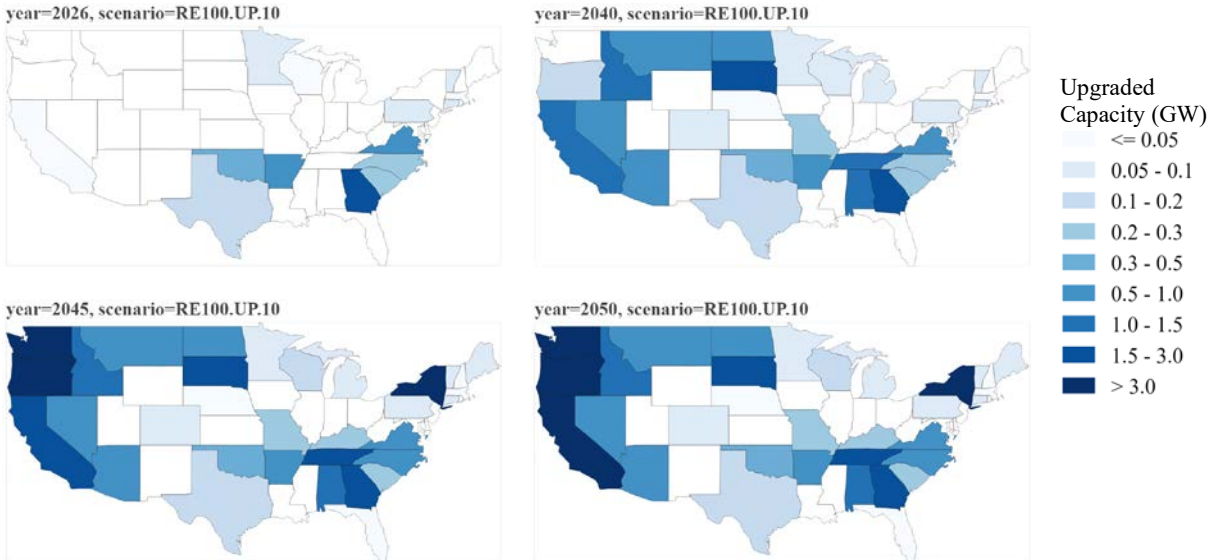


Figure 4.8. Cumulative pump upgrades by state in the RE100.UP.10 scenario in model years 2026, 2040, 2045, and 2050. These pump upgrades occur initially in Texas, neighboring states, and the southern Atlantic coast but eventually become regionally dispersed.

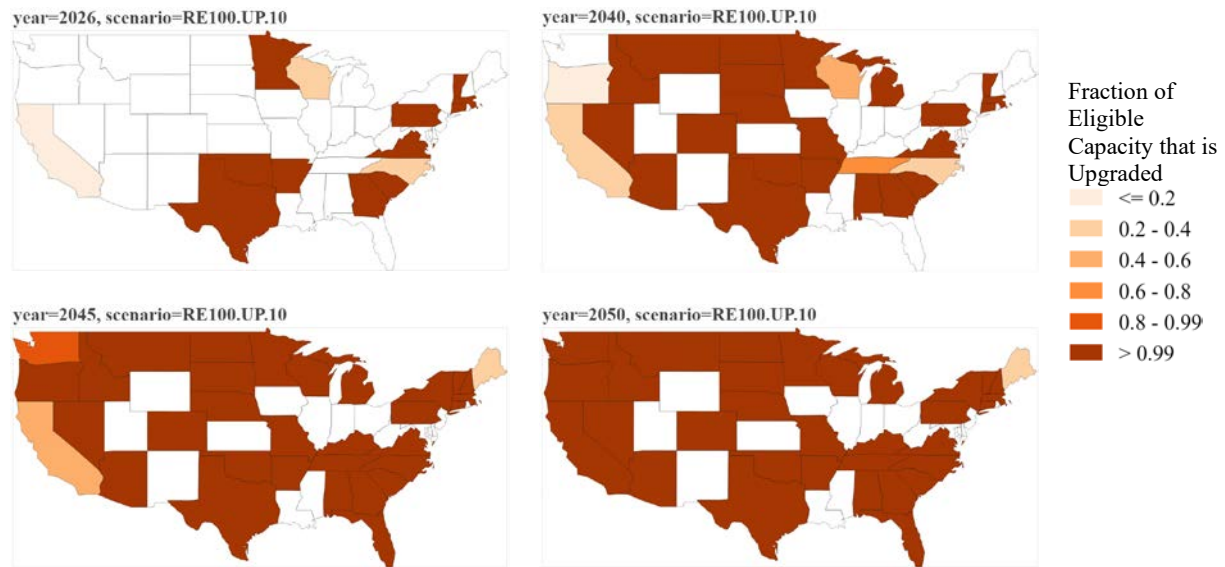


Figure 4.9. Fraction of eligible capacity that adds pumping by state in the RE100.UP.10 scenario in model years 2026, 2040, 2045, and 2050. When pump upgrades are competitive, they often deploy on 100% of the capacity in a given state.

Figure 4.10 and Figure 4.11 plot 2050 time-slice power output and operating reserve provision for hydropower that has been upgraded with pumps (Hydro-Pump-Upg) and the rest of the non-pumped hydropower fleet (Hydro) in the Base scenarios and in the UP.10 scenarios with the lowest modeled upgrade cost. This display reveals differing incentives for adding pumps to existing hydropower facilities. 2050 hydropower electricity dispatch is unchanged between Ref.Base and Ref.UP.10, but facilities with pumps are used extensively to provide operating reserves. In contrast, pumps offer substantial energy arbitrage opportunities in RE100.UP.10 that are unavailable in RE100.Base case, and the upgraded capacity does not contribute to operating reserves. Though incentives and value streams can change over time, these 2050 results demonstrate how alternative electricity futures can offer very different reasons for choosing to invest in pumps or any flexibility upgrade.



Figure 4.10. Power output from hydropower without pumping (Hydro) and hydropower with added pumps (Hydro-Pump-Upg) in each ReEDS time-slice in 2050 for Base scenarios and lowest-cost pump upgrade scenarios. Ref scenarios do not use pump upgrades for energy arbitrage, while RE100 scenarios do.

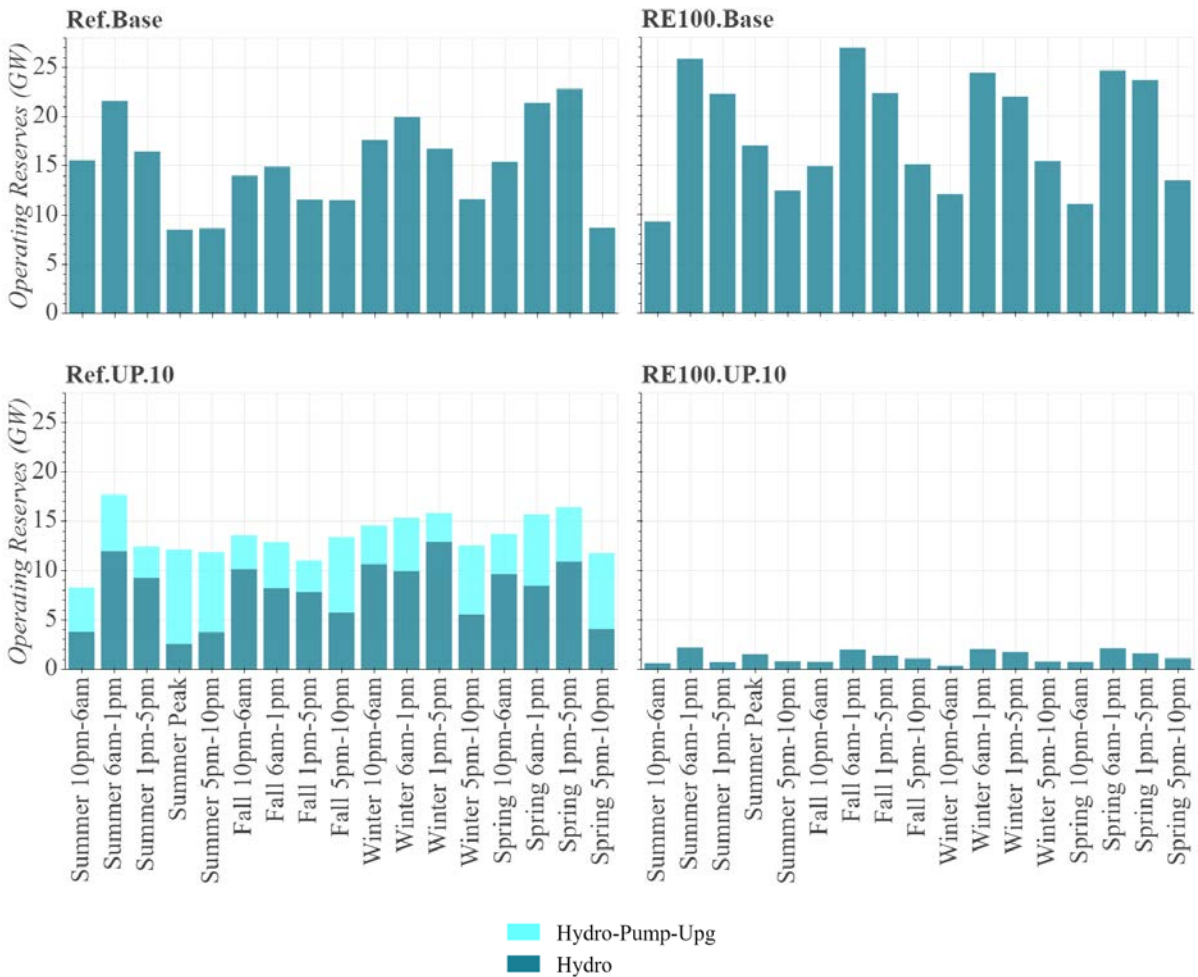


Figure 4.11. Operating reserve provision from hydropower without pumping (Hydro) and hydropower with added pumps (Hydro-Pump-Up) in each ReEDS time-slice in 2050 for Base scenarios and lowest-cost pump upgrade scenarios. Ref scenarios use pump upgrades to provide operating reserves, while RE100 scenarios do not.

Pumping upgrades can also change the balance of renewables, fossil, and storage in the capacity mix (Figure 4.12). In the only Ref scenario with substantial upgrade deployment (Ref.UP.10), added flexibility from pumps corresponds to additional wind, PV, and battery deployment, and a corresponding reduction in natural gas-based capacity. In RE100 scenarios, however, there is only an increase in wind and battery deployment and a notable reduction in PV-battery hybrid capacity. Similar to dispatchability upgrades, these results reflect the ability for additional hydropower flexibility to reduce overall capacity needs on the system, provided hydropower upgrades are less expensive than competing flexible technologies such as PV-battery hybrids.

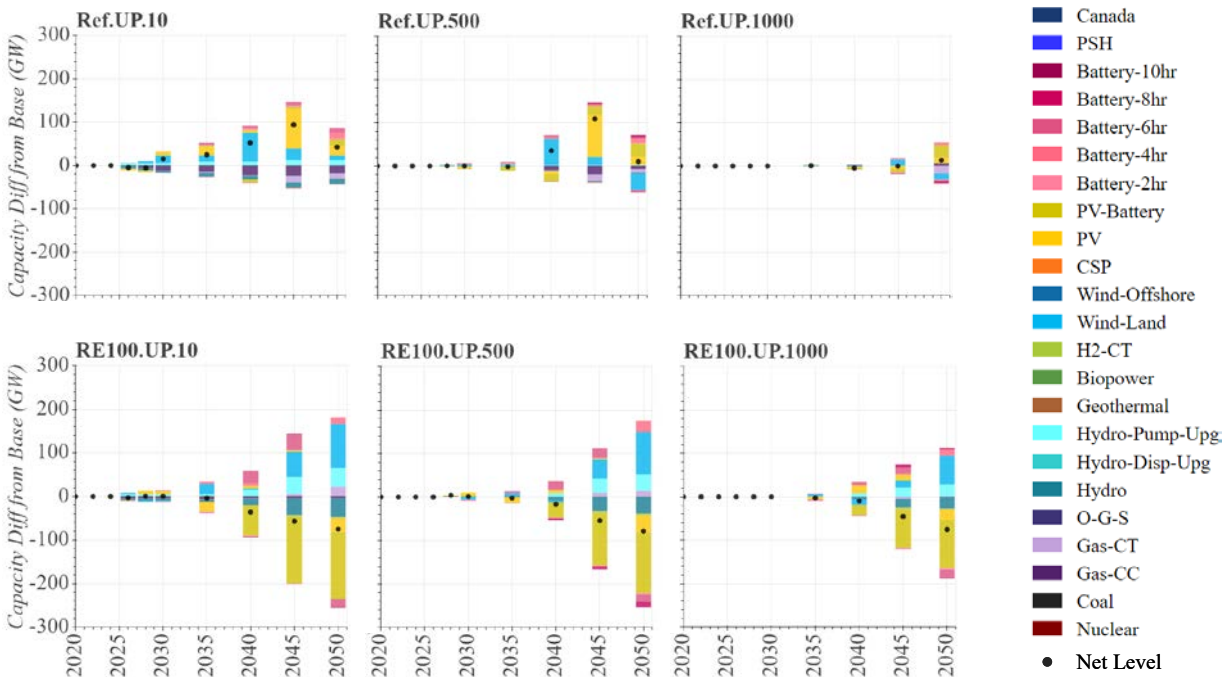


Figure 4.12. Change to the national capacity mix with pump upgrades. Pump upgrades can help facilitate RE deployment and reduce the need for alternative flexible technologies (e.g., PV-battery).

Discounted value streams for capacity with pump upgrades (Figure 4.13 and Figure 4.14) show a clear dominance in capacity value as the reason for investing in these upgrades. Two figures are needed because capacity value for meeting reserve margin constraints is much higher than other value streams. In years with substantial upgrade deployment, operating reserves are also key value streams. Energy value is typically low and sometimes negative due to the need to pump with grid electricity. Overall, it appears that the benefits of adding pumps might be lower than those of other ways to improve hydropower flexibility, but increased pumping capacity does enable hydropower to better serve capacity needs both for short-term operation and long-term resource adequacy.

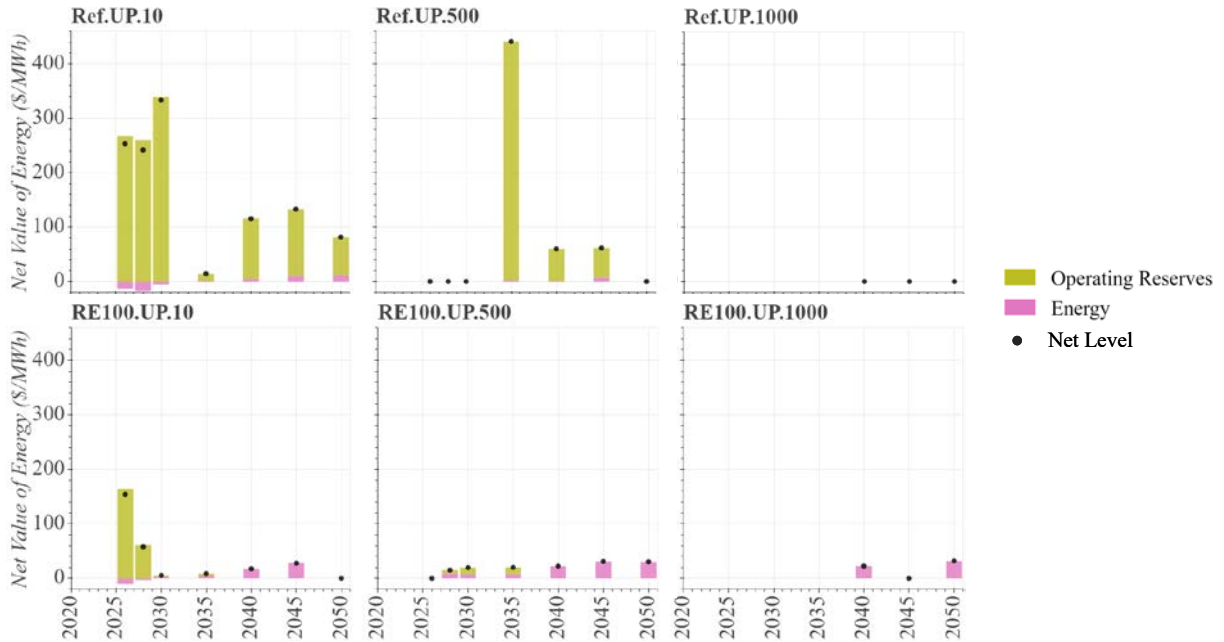


Figure 4.13. Discounted energy and operating reserves value streams for hydropower with pump upgrades over time for select scenarios, normalized by energy production. Operating reserves is a key value stream in Ref scenarios, with energy arbitrage having some value in RE100 scenarios.

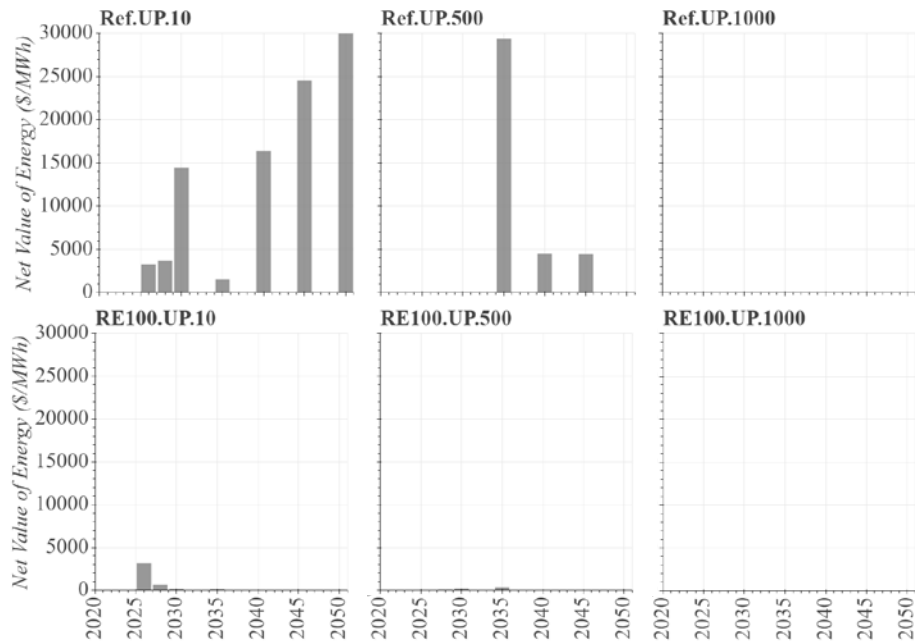


Figure 4.14. Discounted reserve margin value streams for hydropower with pump upgrades over time for select scenarios, normalized by energy production. Reserve margin value of pump upgrades is high in many years in Ref scenarios.

4.4.3 Increasing Capacity or Energy

Independent capacity and energy upgrades are analyzed not only by observing differences relative to the Base scenarios but also by studying interactions between independent capacity and energy upgrades when both are available. Figure 4.15 begins this discussion with the total (non-PSH) hydropower capacity over time for scenarios that can only upgrade capacity (UC, left panel) and those with both capacity and energy upgrades available (UCE, right panel). The figure axis does not start at zero because changes are relatively small. In the Base formulation, around 3 GW upgrades occur in the first available year (2026), and by 2050 total of 3.4 GW upgrades occur in the Ref.Base scenario and 4.9 GW in the RE100.Base scenario, reaching 79.8 GW hydropower capacity in Ref.Base and 81.3 GW in RE100.Base. The decoupled upgrade scenario results range near these values. Generally, there is no complementary increase in total hydropower capacity when energy upgrades are made available along with capacity upgrades (i.e., the left and right panels are nearly identical). Assigning 100% to capacity upgrade costs leads to much less upgrade deployment than Base scenarios in the Ref.UC.100 scenario but more deployment in the RE100.UC.100 scenario. Though capacity upgrades lag the Base formulation in RE100.UC scenarios, the rapidly rising value of capacity in later years supports this upgrade. Capacity value is less influential in Ref scenarios than in RE100 scenarios, so capacity-only upgrade costs must be lower than 50% the total supply curve costs to meet or exceed long-term upgrades in Ref.Base.

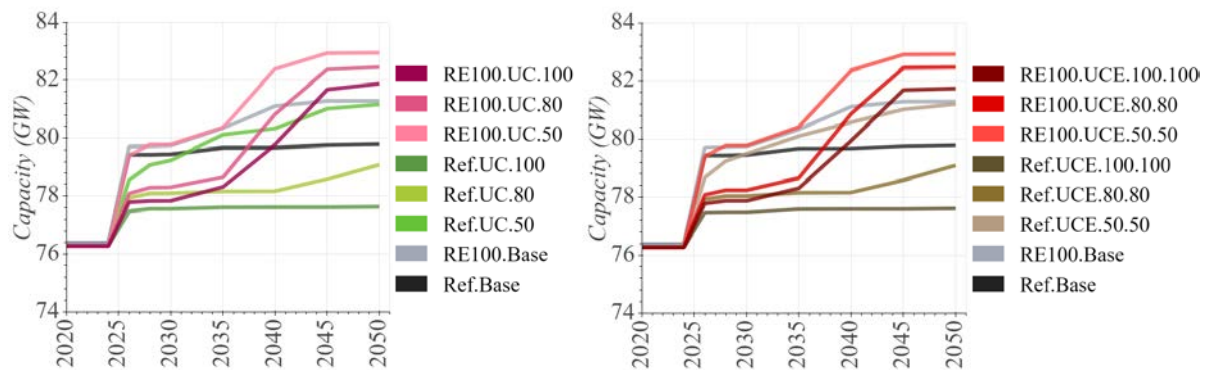


Figure 4.15. Change in total hydropower capacity over time with capacity-only upgrades (UC, left panel), independent capacity and energy upgrades (UCE, right panel), and Base configurations with the prior formulation having combined capacity-plus-energy upgrades. Capacity upgrades vary by cost and scenario but are largely a similar magnitude as the Base scenarios. Note that the figure axis does not start at zero.

The state-level distribution of capacity upgrades through 2050 in the UC scenarios is shown in Figure 4.16 along with deployment locations for the Base scenarios. The corresponding UCE scenarios are not shown because they are not appreciably different from UC results. Qualitatively, the geographical distribution of upgrades is similar between Base and UC scenarios, which indicates region-specific cost could be the primary driver of capacity upgrades. In the scenario with the least capacity upgrade deployment (Ref.UC.100), upgraded capacity is concentrated in the western United States. As upgrade costs are reduced, upgrades become more attractive in the central and eastern parts of the country. In the RE100.UC scenarios with the greatest upgrade capacity, there is a strong concentration of upgrades along the West Coast but a wide distribution throughout the eastern United States. Interestingly, capacity upgrades do not occur in Texas, where flexibility upgrades appeared particularly attractive (Sections 4.4.1 and 4.4.2).

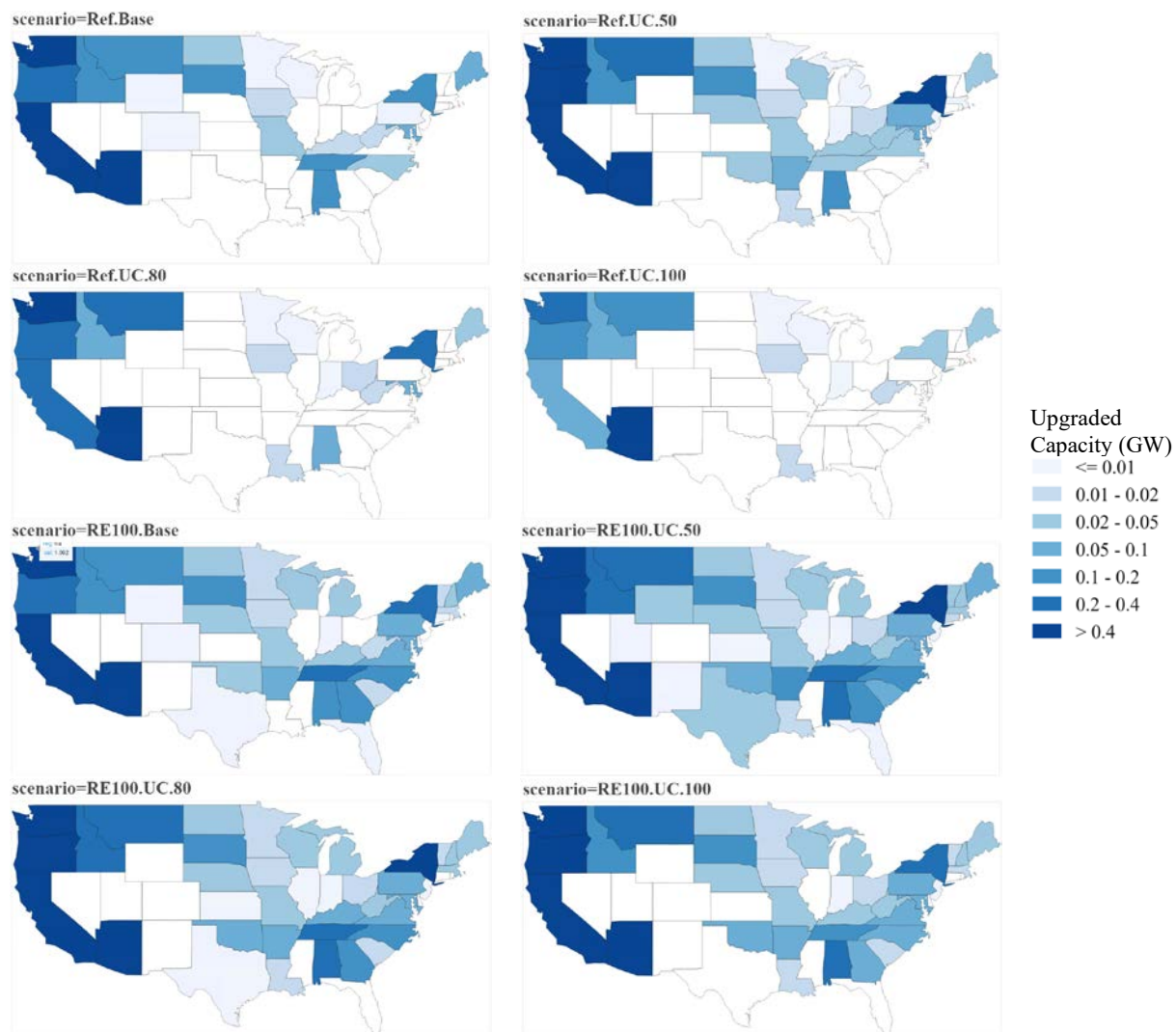


Figure 4.16. Cumulative capacity upgraded through 2050 by state for scenarios with capacity-only upgrades available (UC) and the Base scenarios with combined capacity-plus-energy upgrades. Capacity upgrades are initially attractive in the western United States but occur throughout the United States in scenarios with more capacity upgrades.

National hydropower generation is compared for the Base, UE, and UCE scenarios in Figure 4.17. Energy-only upgrade scenarios follow a similar pattern as Base scenarios; some initial upgrades occur in 2026 and are followed by modest increases, but total generation is consistently lower than in Base scenarios. Upgrades in Base scenarios provide additional energy and capacity, which is a stronger overall upgrade incentive than energy-only upgrades in the UE scenarios. In RE100 scenarios, hydropower generation is lower in 2045 and 2050 because some available hydropower energy is unused, which occurs because marginal operating costs are assumed to be slightly higher for hydropower than wind and PV technologies in ReEDS. When both capacity and energy upgrades are available, hydropower generation is instead consistently greater than in Base scenarios, even when 100% of the supply curve cost is assigned to each upgrade type. Where capacity results are nearly identical between UC and UCE scenarios, the addition of capacity upgrades is complementary to energy upgrades for increasing total hydropower generation. However, it is worth noting that the interannual variability in hydropower generation was 217–356 TWh between 1990 and 2020, so the differences observed in these scenarios are within the bounds of historical interannual variability (EIA 2021b).

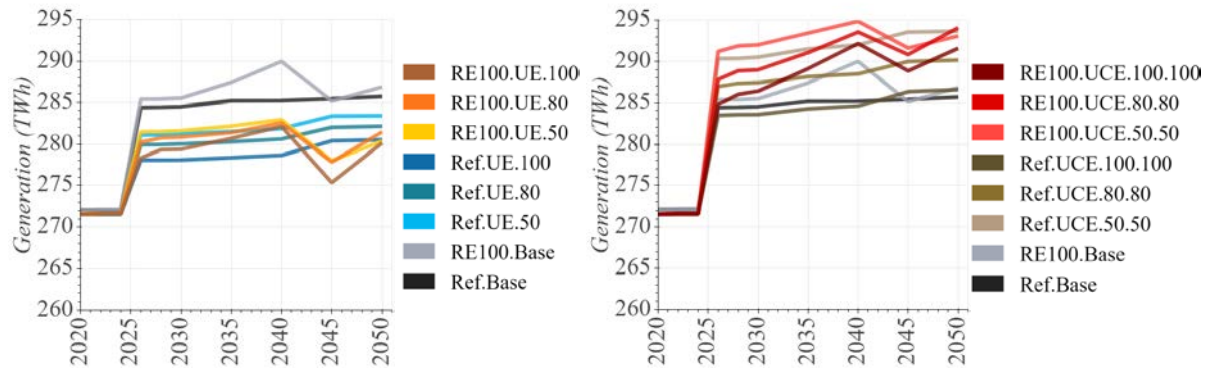


Figure 4.17. Change in total hydropower generation over time with energy-only upgrades (UE), independent capacity and energy upgrades (UCE), and Base configurations with the prior formulation having combined capacity-plus-energy upgrades. Independent capacity and energy upgrades lead to the greatest overall hydropower generation, but results are similar to Base scenarios. Note that the figure axis does not start at zero.

Figure 4.18 and Figure 4.19 show the 2050 incremental increase in hydropower generation from upgrades relative to a system where no hydropower upgrades take place. Figure 4.18 includes Ref scenarios, and Figure 4.19 includes RE100 scenarios, with the Base scenario of each showing in the top row. Locations with additional generation follow a similar pattern as capacity upgrades in Figure 4.16, with the most attractive locations being along the West Coast. However, New York also stands out as a potential region where hydropower energy is valuable, albeit more so in the Ref scenarios than in the RE100 scenarios. As hydropower energy additions increase, these upgrades spread throughout the eastern U.S., other Western states, and the Northern Plains. The spatial distribution of energy-only upgrades remains similar to the corresponding Base scenarios.

This investigation of independent capacity and energy upgrades suggests that capacity could be a more important driver of hydropower upgrades than energy, particularly in a future with high VG shares. Thus, there could be reason to focus more on capacity upgrade potential than on energy when exploring hydropower upgrades at the site or system level. However, from a national system modeling perspective, the upper limit on hydropower upgrades is low enough such that this nuanced approach to capacity versus energy upgrades has little bearing on model outcomes. Given the increased complexity, computational burden, and difficulty characterizing costs, the coupled capacity-plus-energy upgrade representation remains used by default to understand national hydropower upgrade deployment potential.

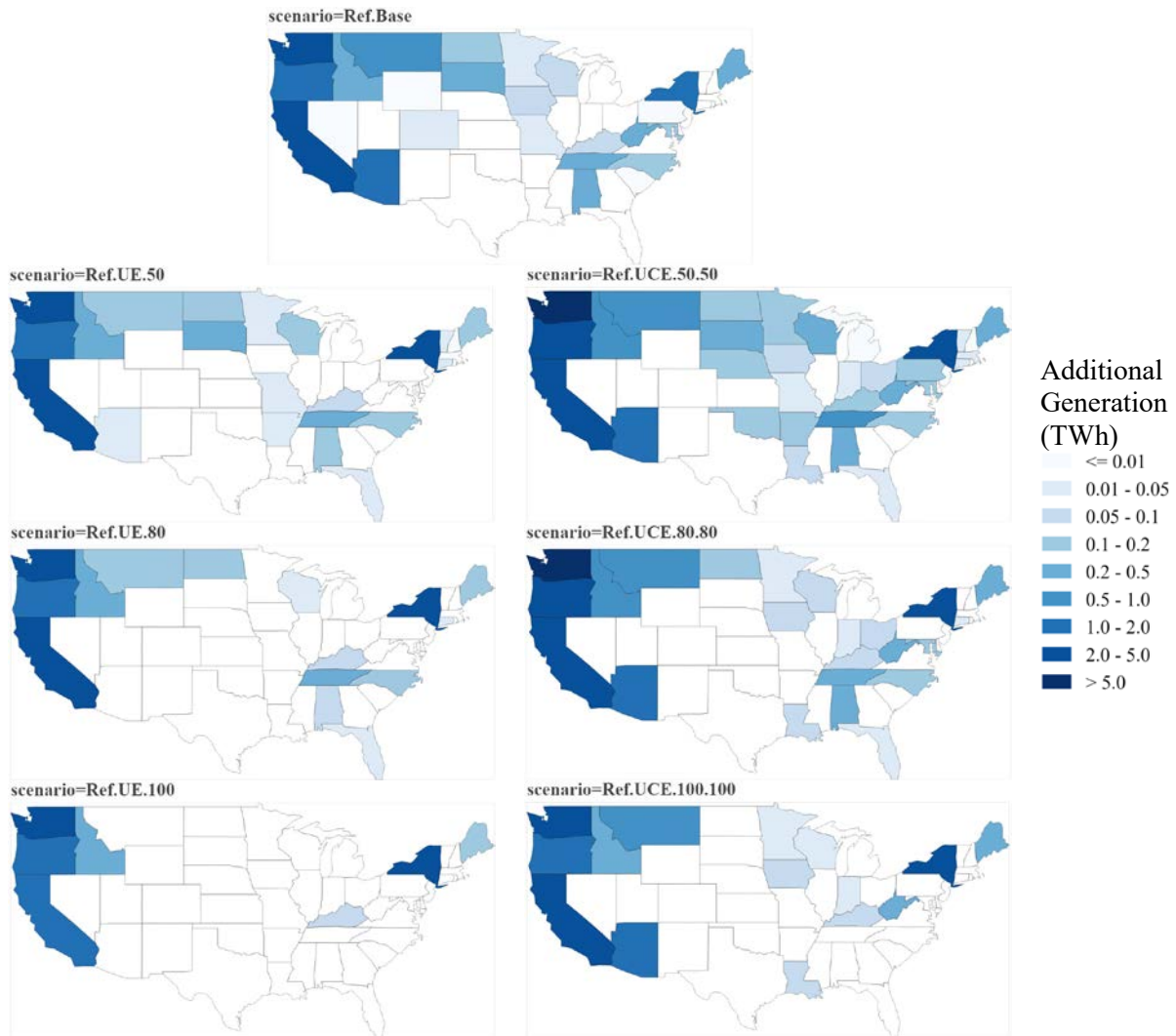


Figure 4.18. Additional 2050 generation from hydropower relative to a “no upgrade” case in Ref scenarios with energy-only upgrades available (UC), independent capacity and energy upgrades (UCE), and the Base scenarios with combined capacity-plus-energy upgrades. Upgrading hydropower energy availability is most attractive in the western United States but becomes more geographically dispersed as more capacity upgrades.

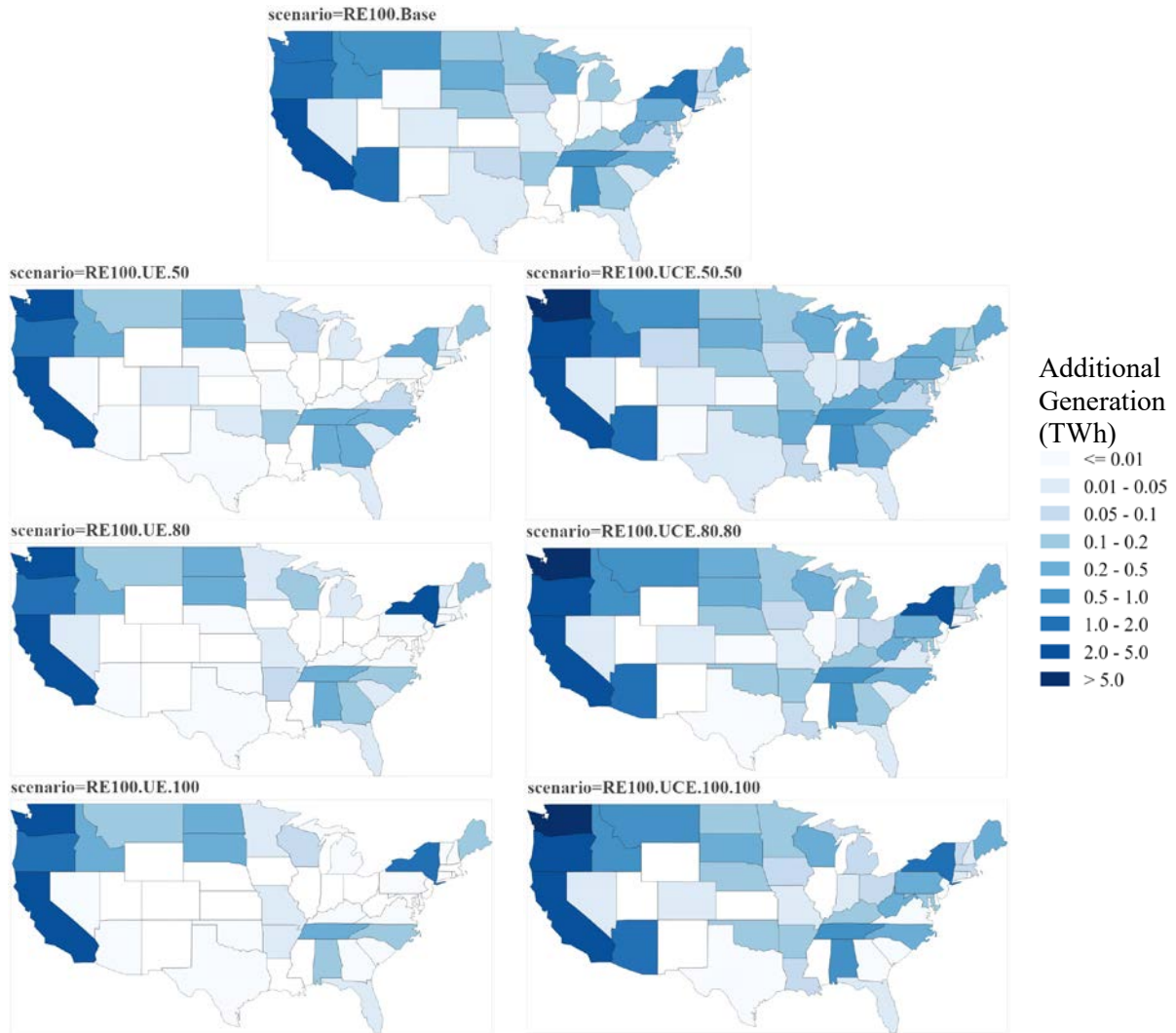


Figure 4.19. Additional 2050 generation from hydropower relative to a “no upgrade” case in RE100 scenarios with energy-only upgrades available (UC), independent capacity and energy upgrades (UCE), and the Base scenarios with combined capacity-plus-energy upgrades. Additional hydropower energy is very geographically dispersed in RE100 scenarios.

5.0 Broader Modeling Implications

In previous sections, we explored each hydropower and PSH modeling and data improvement independently to isolate its effects. Here we discuss this work's broader implications with a scenario analysis that includes new suggested default hydropower and PSH assumptions for ReEDS as well as two scenarios that enable all new features with different degrees of favorability toward hydropower and PSH cost and operability. This more holistic approach leads to the discussion of how this work could be incorporated into other modeling and analysis approaches, and what additional improvements are recommended in the future.

5.1 Scenario Comparison with All Changes

Table 5.1 summarizes the specifications for feature-combination scenarios. The Default scenario represents reference case inputs for ReEDS that will be used as defaults in all future scenario analysis unless otherwise specified. The changes relative to the Base case are conservative, including only the new cost-calibrated PSH supply curves with a 10-hr storage duration and the plant-level duration and pump capacity data for existing PSH. Other features are unavailable by default due to high uncertainty about how they should be parameterized. Additional site-level data on operability and upgradeability, along with improved upgrade cost estimation, could allow other features to be active by default.

The All scenario activates all new features with relatively conservative assumptions for cost and flexibility. Independent capacity and energy upgrades are each assigned 80% of the original supply curve cost, dispatchability upgrades are \$500/kW (2004\$), and pump upgrades are \$1000/kW (2004\$). Seasonal energy shifting and arbitrage is enabled but with 90% of the energy required to remain in-season. The 10-hr PSH supply curve before cost calibration is used to demonstrate PSH deployment opportunities.

The AllFlex scenario represents a low-cost, high-flexibility case where independent capacity and energy upgrades are each 50% of the supply curve cost, dispatchability upgrades are \$300/kW (2004\$), and pump upgrades are \$500/kW (2004\$). Seasonal shifting and arbitrage offer additional flexibility by only requiring 50% energy to remain in-season. This scenario also uses the 10-hr PSH supply curve before cost calibration.

Table 5.1. Scenario Specifications for Scenarios that Combine New Model Features

Scenario Parameter	SCENARIO			
	Base	Default	All	AllFlex
PSH supply curve	ORNL supply curve from Hydropower Vision	New cost-calibrated 10-hr duration supply curve	New 10-hr duration supply curve before cost calibration	New 10-hr duration supply curve before cost calibration
Capacity/energy upgrades to existing fleet	Coupled capacity+energy upgrade supply curve by ORNL for Hydropower Vision	Coupled capacity+energy upgrade supply curve by ORNL for Hydropower Vision	Decoupled capacity and energy upgrades, with each costing 80% of the combined cost from the ORNL supply curve	Decoupled capacity and energy upgrades, with each costing 50% of the combined cost from the ORNL supply curve
Upgrades from nondispatchable to dispatchable hydropower	Not available	Not available	Available at \$500/kW (2004\$)	Available at \$300/kW (2004\$)
Upgrades from dispatchable hydropower to add pumps	Not available	Not available	Available at \$1,000/kW (2004\$)	Available at \$500/kW (2004\$)
Plant-level PSH data	Uses generic 12-hr assumed storage duration and assumes pump input capacity = generator output capacity for existing fleet	Uses plant-level duration and pump capacity data for the existing PSH fleet	Uses plant-level duration and pump capacity data for the existing PSH fleet	Uses plant-level duration and pump capacity data for the existing PSH fleet
Seasonal energy shifting for hydropower at no incremental cost	Unavailable, so 100% energy must be used within nominal season	Unavailable, so 100% energy must be used within nominal season	90% energy must be used within nominal season	50% energy must be used within nominal season
Seasonal energy arbitrage for PSH at no incremental cost	Unavailable, so 100% of energy pumped must be used to generate in that season	Unavailable, so 100% of energy pumped must be used to generate in that season	90% of energy pumped must be used to generate in that season	50% of energy pumped must be used to generate in that season

Figure 5.1 and Figure 5.2 display total capacity over time for PSH, hydropower, upgraded hydropower with added dispatchability and pumping, and the sum of all hydropower types except PSH (Hydro + Upgrades). Ref scenario results are in Figure 5.1, and RE100 result are in Figure 5.2. As in Section 2.4.1, PSH deployment under Defaults is negligible. In the All scenarios with moderate improvements to hydropower upgradeability and flexibility, PSH deployment reaches 37.3 GW in Ref.All and 39.2 GW in RE100.All, but PSH growth is largely negated in the AllFlex scenarios. In these scenarios, highly flexible hydropower competes with PSH directly. In Figure 5.1 and Figure 5.2, hydropower upgrades (Hydro-Disp-Upg and Hydro-Pump-Upg) will result in a 1:1 reduction in base hydropower capacity (Hydro). Ref.All/AllFlex scenarios do not deploy many pump upgrades even at lower cost, but dispatchability upgrades are used to a large extent. In RE100 scenarios, nearly all hydropower either adds dispatchability or pumping by 2050, with RE100.AllFlex having accelerated dispatchability upgrades relative to RE100.All scenarios. The added flexibility becomes increasingly valuable in RE100 scenarios after 2035, when upgrades take place even under more-conservative cost assumptions. The combined Hydro+Upgrades panels also show that hydropower capacity upgrades occur in all scenarios on the order of 3–7 GW.

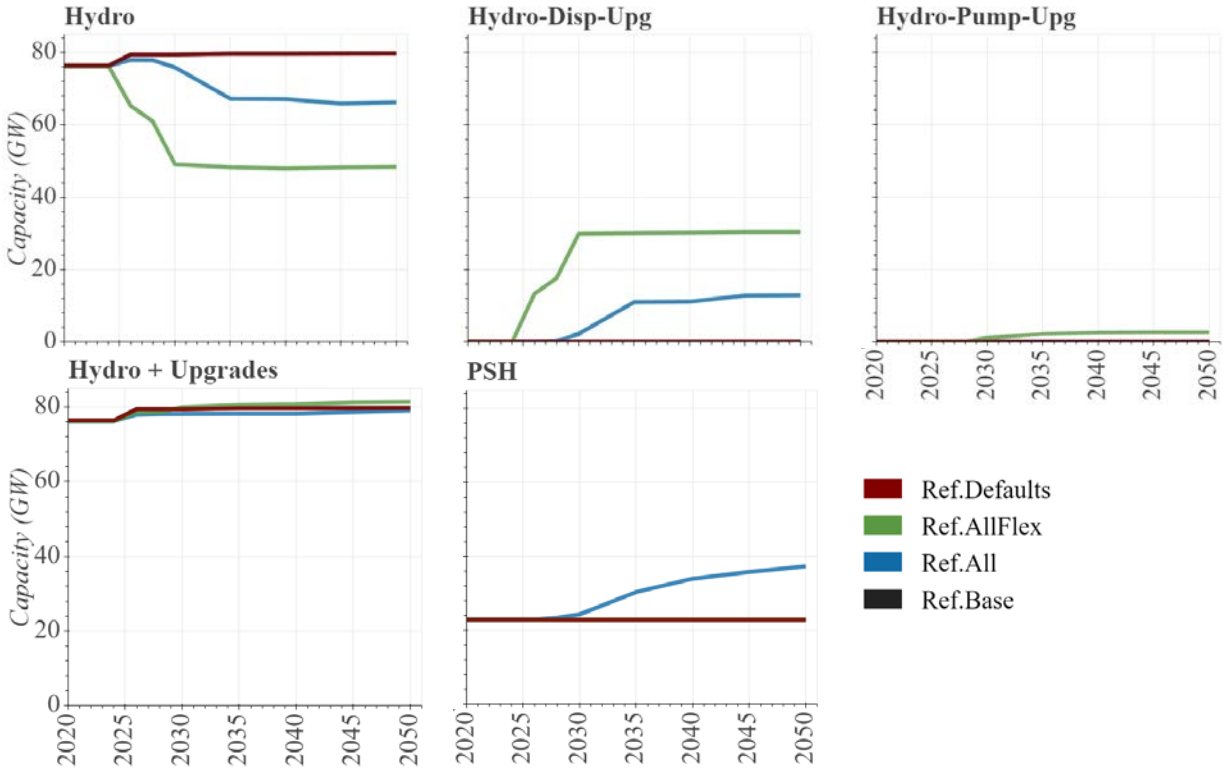


Figure 5.1. Capacity of each hydropower and PSH technology type over time for Ref scenarios, showing PSH deployment and upgrades from hydropower to add flexibility (Hydro-Disp-Upg) or pumping (Hydro-Pump-Upg) as well as the sum of hydropower plus all upgrade types (bottom-left panel). Dispatchability upgrades are more prevalent than pumping upgrades, and low-cost PSH is deployed.

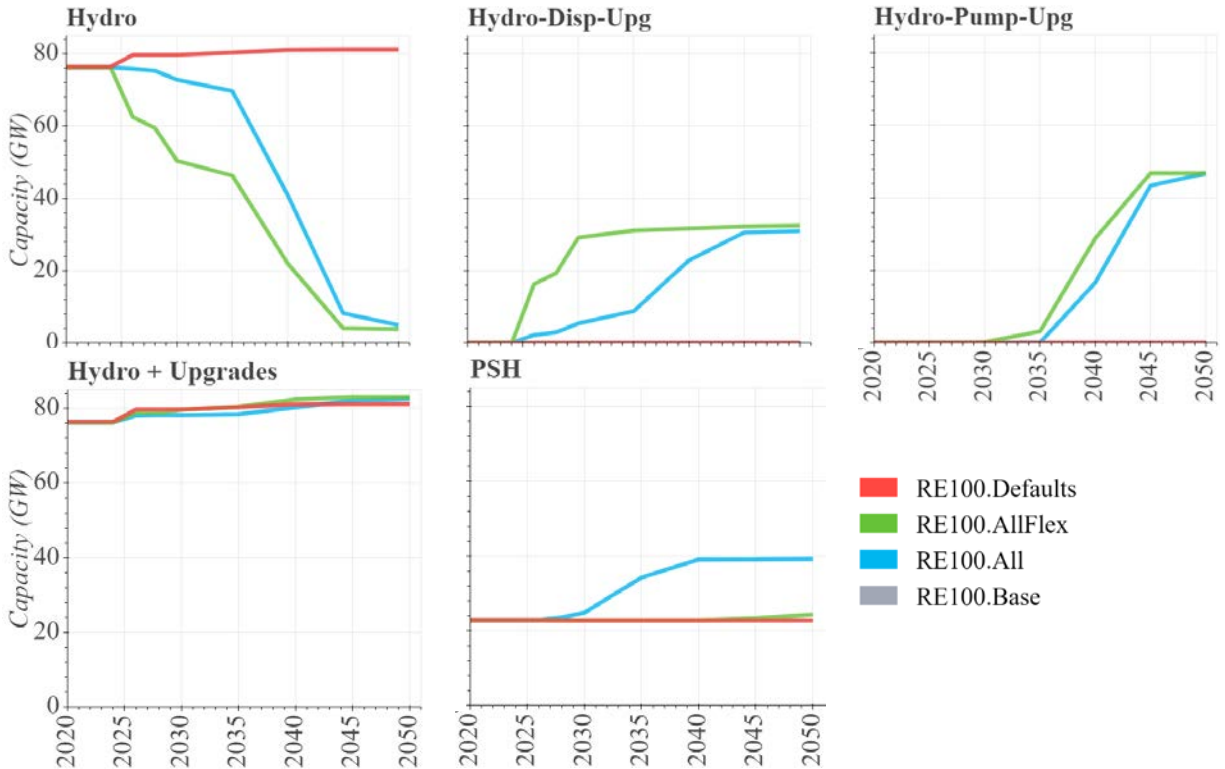


Figure 5.2. Capacity of each hydropower and PSH technology type over time for RE100 scenarios, showing PSH deployment and upgrades from hydropower to add flexibility (Hydro-Disp-Upg) or pumping (Hydro-Pump-Upg) as well as the sum of hydropower plus all upgrade types (bottom-left panel). Some RE100 scenarios increase flexibility of nearly all hydropower, and high-flexibility hydropower can compete with new PSH deployment.

Figure 5.3 shows the corresponding net generation for each hydropower and PSH category, and the bottom left panel is the total net generation summed across all these technologies. Larger-magnitude negative net generation for PSH corresponds to increased usage or energy arbitrage due to round-trip efficiency losses. Dispatchability upgrades do not generally affect net generation (a reduction in hydropower corresponds to an equal increase in Hydro-Disp-Upg), but pumping upgrades result in a net generation reduction because pumps may be oversized and use additional energy from the grid. Because of these effects and some displacement by other low-cost technologies, the RE100.All/AllFlex scenarios experience a substantial reduction in total net energy produced by all hydropower and PSH types after 2035. This result demonstrates the value of hydropower capacity over energy in the later years of these scenarios; however, it could be strongly contingent on the assumed marginal costs of hydropower being higher than wind and solar technologies.

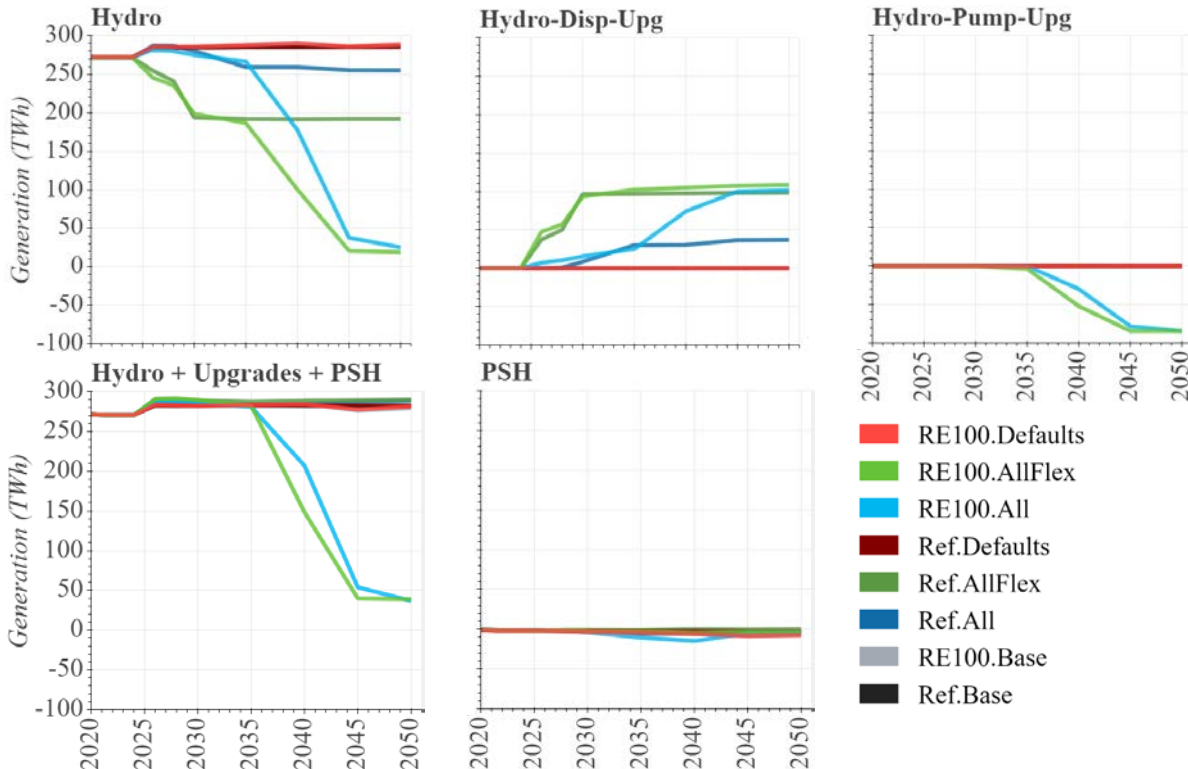


Figure 5.3. Generation of each hydropower and PSH technology type over time, showing PSH deployment and upgrades from hydropower to add flexibility (Hydro-Disp-Upg) or pumping (Hydro-Pump-Upg) as well as total net generation of hydropower, upgrades, and PSH (bottom-left). Pump efficiency losses and displacement by other low-cost technologies sometimes results in reduced generation.

Figure 5.5 (page 5.72) and Figure 5.6 (page 5.73) report the change in national capacity and generation mix relative to Base scenarios. The Defaults scenarios have relatively small changes. In the Ref.Defaults scenario, minor changes to PSH data result in additional PV capacity and generation, with minor effects on other generation technologies. The RE100.Defaults scenario has some additional PV and battery deployment in later years, with some PV displacing wind in those years.

The All and AllFlex scenarios have much larger effects on the national electricity mix. Capacity outcomes largely mirror those observed in dispatchability upgrade scenarios (UD) in Section 4.4.1, suggesting that this upgrade opportunity has the greatest overall influence on national outcomes. The addition of pump upgrades and new PSH capacity appears to amplify the trends observed in UD scenario results for RE100 scenarios, as the magnitude of capacity changes are slightly higher in Figure 5.5 than in Figure 5.4. This is also true for Ref.All relative to Ref.UD.500, but Ref.AllFlex has slightly smaller magnitude changes than Ref.UD.10.

Changes to wind and PV generation in the All and AllFlex scenarios correspond to their capacity outcomes, with Ref.All having higher PV generation, Ref.AllFlex having higher PV and wind generation, and RE100.All/AllFlex having higher wind generation but lower PV and PV-battery generation. The net reduction in total hydropower energy production for RE100.All/AllFlex can also be observed in Figure 5.6, with the reduction in the original hydropower category being larger than the positive values for Hydro-Disp-Upg. Additional PV in the Ref.All scenario displaces a combination of coal, natural gas-combined cycle, and PV-battery generation depending on the year, but the magnitude of fossil energy displacement is much greater in the Ref.AllFlex scenario. Despite modest changes to hydropower

capacity, additional PV and wind in these scenarios displace substantial quantities of fossil fuel-based generation.

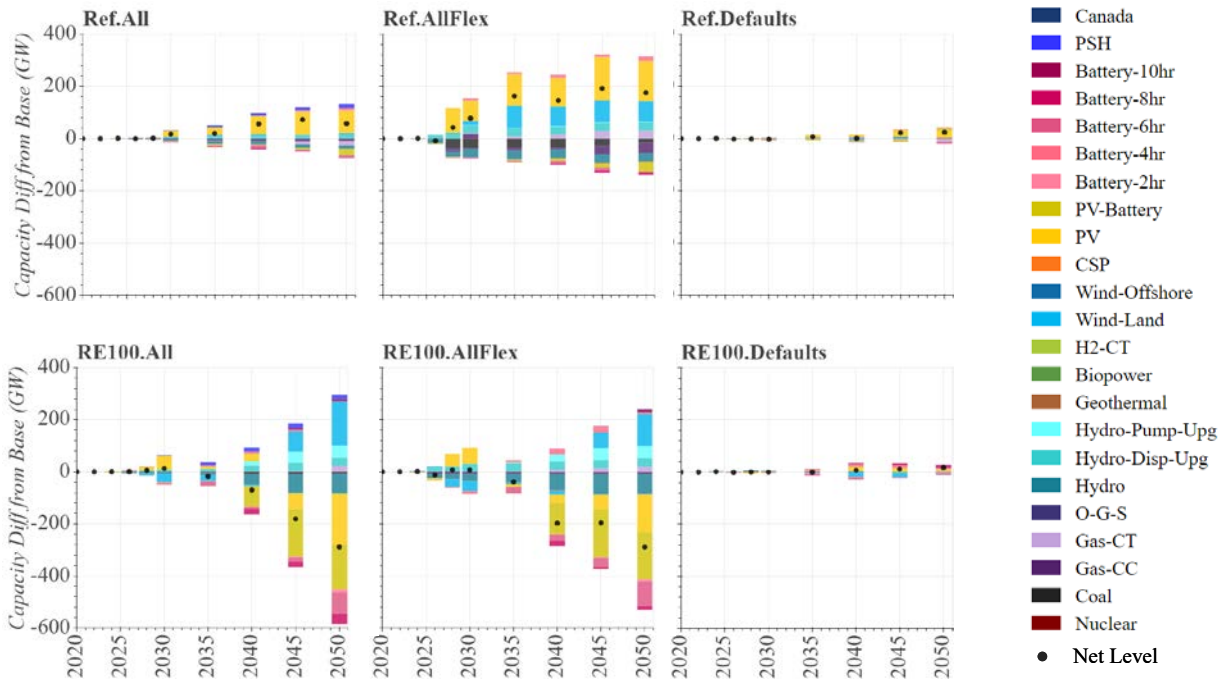


Figure 5.5. Change to the national capacity mix relative to Base in scenarios with combined new features and data. Increased hydropower and PSH flexibility and upgradability supports greater wind and PV capacity in Ref scenarios and reduces system capacity needs in RE100 scenarios.

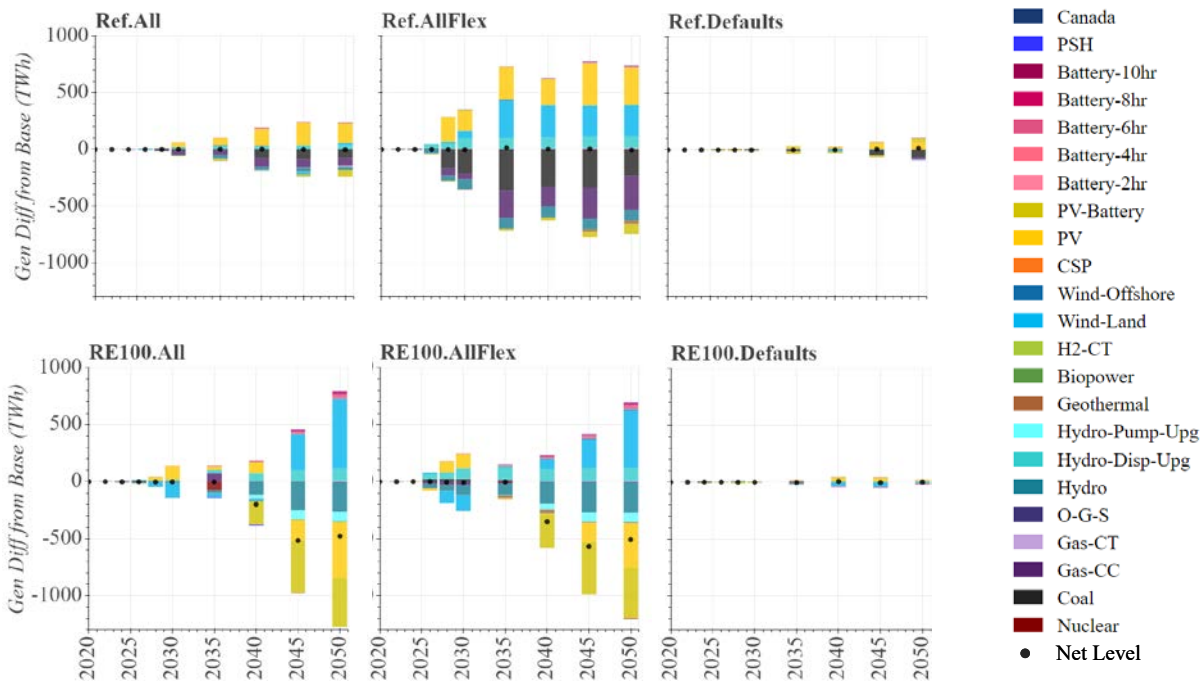


Figure 5.6. Change to the national generation mix relative to Base in scenarios with combined new features and data. Increased hydropower and PSH flexibility and upgradability reduces fossil fuel use in Ref scenarios and decreases net electricity demands from PV-battery storage losses in RE100 scenarios.

The emissions implications of fossil fuel displacement are shown in Figure 5.7. Because CO₂ emissions in RE100 scenarios are driven primarily by the renewable energy requirement, hydropower and PSH outcomes have negligible influence on emissions. However, any fossil fuel use reductions in the Ref scenarios correspond to CO₂ emissions reductions. Changes are modest for Ref.Defaults and Ref.All, but the highly flexible Ref.AllFlex scenario results in a 2050 emissions reduction of 35% relative to Ref.Base.

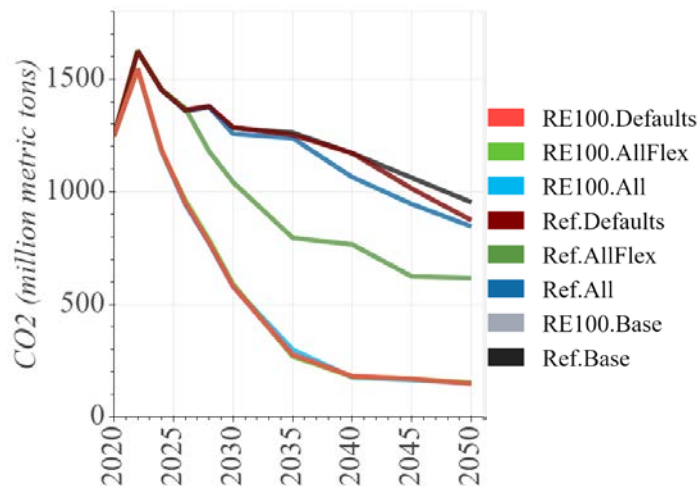


Figure 5.7. CO₂ emissions over time in scenarios with combined new features and data. Increased hydropower and PSH flexibility and upgradability can facilitate lower CO₂ emissions.

Though hydropower and PSH outcomes do not affect emissions results in RE100 scenarios, they can affect economic outcomes. Figure 5.8 plots a total marginal electricity cost metric over time for the feature-combination scenarios; the metric includes all energy, capacity, and policy cost components using shadow prices from each corresponding model constraint. After 2035, RE100.All/AllFlex scenarios have lower total marginal electricity costs than RE100.Base/Defaults, demonstrating the ability of flexible hydropower and PSH to reduce system operational costs under a given set of emissions outcomes. The Ref.All/AllFlex scenarios also have lower costs than Ref.Base, but differences are smaller, on the order of \$2/MWh.

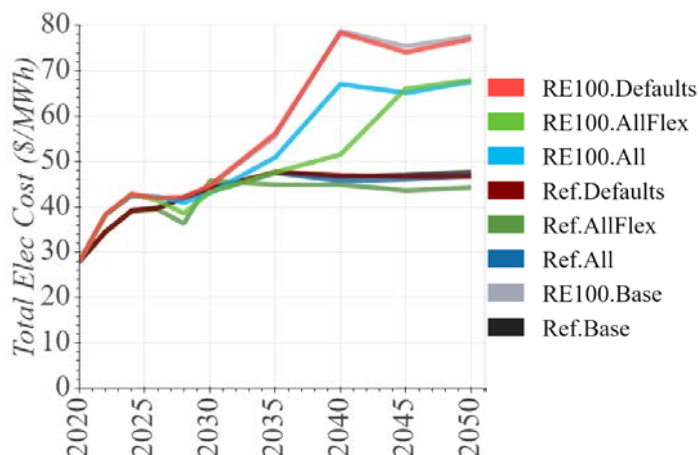


Figure 5.8. Total marginal cost of electricity over time in scenarios with combined new features and data. This metric includes all marginal cost components, including those from energy, capacity, and policy requirements. (2020 USD). Increased hydropower and PSH flexibility and upgradability can reduce electricity costs, particularly in low-carbon scenarios.

Another cost metric is the present value of total system costs throughout 2020–2050, which is calculated using a 5% discount rate and reported in Table 5.2. This calculation includes all investment and operating costs annualized before discounting to the present day. Given this calculation method, Ref.All and AllFlex scenarios have slightly higher total costs than Ref.Base, although differences are less than 1%. The discount rate can play a role in this economic comparison; for example, undiscounted costs in later years are lower in Ref.AllFlex than Ref.Base, but these differences are discounted heavily for the results in Table 5.2. In addition, costs beyond 2050 for investments made through 2050 are not taken into account. Costs are progressively lower in RE100 scenarios with additional hydropower and PSH flexibility and upgradeability. Changes are less than 1% with RE100.Defaults and RE100.All, but the RE100.AllFlex scenario has as more substantive 4.2% total cost reduction. Overall costs impacts are relatively small, but these results suggest that advancing hydropower and PSH flexibility could help achieve a deeply decarbonized grid at lower cost.

Table 5.2. Present Value of Total System Cost from 2020 to 2050 for Base Scenarios and Each Scenario with Combined Features and Data, Showing Absolute and Relative Differences from Base Scenarios Values using a 5% discount rate. Discounted costs are slightly higher in Ref scenarios with new hydropower and PSH capabilities, but maximizing hydropower and PSH contributions in RE100.AllFlex results in a notable cost reduction.

Scenario	2020–2050 Discounted Cost (billion 2020 USD)	Difference from Base (billion 2020 USD)	Change from Base (%)
Ref.Base	2,414.2		
Ref.Defaults	2,415.9	1.7	0.1%
Ref.All	2,427.0	12.8	0.5%
Ref.AllFlex	2,429.8	15.5	0.6%
RE100.Base	2,778.4		
RE100.Defaults	2,776.0	-2.4	-0.1%
RE100.All	2,759.6	-18.9	-0.7%
RE100.AllFlex	2,661.3	-117.1	-4.2%

5.2 Adapting Methods to Other Capacity Expansion Models

The ReEDS model developments and results described throughout this report offer insight into what additional data and model constructs could be useful to implement into other CEMs and electricity planning tools. Although ReEDS has specific structures and components that influence its hydropower and PSH technology representations, we offer recommendations based on how other tools might differ from ReEDS in spatial, temporal, process resolution or other model structures.

The influence of dispatchability upgrades presented in Sections 4.4.1 and 5.1 shows that adding or improving the ability of a model to invest in greater hydropower flexibility is perhaps the most useful model advancement for understanding the future role of hydropower technologies. It is thus important for models to differentiate degrees of hydropower flexibility and allow the option to increase hydropower flexibility at some cost. Increasing flexibility by adding pumps seemed less attractive overall in the U.S. context than increasing dispatchability by other means, but pump upgrades could be worthwhile to represent in other systems, particularly those with fewer low-cost flexibility options. Although limited data make it difficult to parameterize site-level hydropower flexibility and upgrade opportunities, creating a model formulation that offers this option could provide an important sensitivity case, particularly when considering future electricity systems with high shares of VG.

Implementations of interseasonal energy transfers and arbitrage are not necessarily realistic from a practical system planning perspective, but they highlight the importance of considering longer-duration planning horizons when making investment decisions for electricity systems with large hydropower and PSH facilities. The energy storage capacity of hydropower, whether or not pumping exists, can play a role in balancing seasonal variations in VG, so it follows that hydropower and PSH could help balance these technologies between the diurnal and seasonal timescales. The approach described in Sections 3.1 and 3.2 could be adapted for other timescales and resolutions in models that can accommodate multiday, weekly, or monthly operating resolution, offering additional insight into how hydropower and PSH can compete with or complement VG and other technologies. Data challenges again make site-level accuracy a challenge, but exploratory scenarios may still yield important insights.

The new closed-loop PSH supply curve data implemented as reported here represents an important new data set that is readily adaptable for other CEMs or planning tools. With the publication of site-level data, PSH resource availability and cost information can be aggregated as needed for any U.S. region of interest (Rosenlieb and Heimiller 2022). ReEDS results show these data can help identify new PSH deployment opportunities, laying the groundwork for future more-detailed sensitivity analysis of PSH resource availability and cost in ReEDS and other tools.

Several new model constructs we examined had less overall impact on aggregate national outcomes in the U.S. context, but these new features and data should not necessarily be ignored for detailed regional or national analysis where hydropower and PSH are larger shares of the capacity mix. Distinguishing pump types in a practical manner was not possible for ReEDS and is unlikely useful for modeling investment decisions in the near term, but pump type distinctions could be useful for planning analyses under future market regimes where operating reserves and other ancillary services have higher value. Plant-specific pump capacity and storage duration did not have major impacts on national ReEDS solutions, but this parameterization is likely more important when studying individual sites or smaller geographical regions, particularly where facilities with unequal pump and generator capacities or storage durations deviate from nominal values.

The detailed study of independently upgrading hydropower capacity or energy also did not yield conclusive improvements in solution quality for the scenarios we studied. However, this modeling exercise produced new methods for considering upgrade opportunities in CEMs, and these techniques could be applicable beyond hydropower. For example, nuclear capacity uprates could use the capacity-only upgrade framework, with an even simpler approach because nuclear is not typically under energy-limiting constraints.

Altogether, this rigorous presentation of new model data and formulations along with feature-specific results shows the importance of continuing to improve planning model capabilities of hydropower and PSH so that tools do not miss important opportunities to optimize grid configurations and reduce decarbonization costs.

5.3 Application to Other Model Types

Beyond CEMs and planning tools, this hydropower and PSH modeling work can inform both higher-resolution models such as electricity production cost models (PCMs) and tools that cover the entire energy sector or multiple economic sectors (e.g., integrated assessment models or general equilibrium models).

Because PCMs often have higher temporal resolution and operational detail, they could implement some of the hydropower and PSH flexibility constructs herein in greater detail than CEMs. Similar to CEMs, a PCM must first be able to distinguish between different degrees of hydropower or PSH flexibility and effectively parameterize capacity and energy limitations on diurnal and longer timescales. The exploration of interseasonal constraints in ReEDS and the intermediate-duration storage analysis in Section 3.5.4 indicate that PCM analysis seeking to understand future hydropower and PSH operation would benefit from optimizing operation over timescales on the order of days, weeks, or more either by simply expanding the time horizon or using a multistage optimization at varying time horizons and resolutions. This practice would be further improved by implementing plant-specific data when available, such as the PSH pump capacity and duration data from the IHA database (IHA 2021). Given that PCMs typically represent individual plants and hourly or subhourly operation, plant-level details are likely more important to PCM model outcomes than in CEMs.

Models covering the entire energy sector or multiple energy and non-energy sectors might not have sufficient technology detail to represent many of the hydropower and PSH characteristics described in this report. However, the electricity system implications of hydropower flexibility upgrades and PSH data reflect the importance of continued innovation into proxy or reduced-form methods for representing short-term operation in these models. An initial recommendation, particularly for U.S.-focused modeling, is to incorporate the new data on closed-loop PSH resource availability and cost at whatever spatial resolution is available. Doing so would better improve any tool's ability to represent competition and complementarity between PSH and other storage and generation technologies. Beyond the United States, PSH resource and cost data can be derived directly from Australia National University research that provided the basis of the U.S. PSH resource assessment (Blakers et al. 2019; Andrew Blakers et al. n.d.). Where possible, it would also be useful for energy and multisectoral models to consider improving ways to value flexible operation of hydropower and PSH for providing capacity reserves and other flexibility products. Integrating upgrade opportunities directly is one way to do this, but the approach to valuing flexibility will be model-specific. Our main point is that hydropower and PSH flexibility, and its ability to improve over time, is an opportunity worth considering alongside other options.

5.4 Future Research and Applications

The work reported here constitutes a significant advancement into methods for modeling hydropower and PSH investment and operation opportunities, but continued model and data improvements could allow a clearer picture of the future role of hydropower and PSH in U.S. and other electricity systems.

Increasing operational detail through time, technology, or process resolution can better characterize unique hydropower and PSH characteristics. Perhaps the largest relevant modeling gap is an ability to balance resolution and computational limitations for representing energy storage opportunities beyond diurnal timescales. Whether models add explicit operating detail or develop reduced-form or proxy methods, it is becoming increasingly important to understand energy storage investment and operation at longer timescales, and hydropower and PSH are parts of that discussion as the only long-duration storage systems that exist today. To offer an accurate picture of long-duration storage capabilities, these developments would also need to be accompanied by site-specific energy storage data related to reservoir characteristics and constraints.

Site-specific data on upgrade opportunities and costs are also important for representing more practical hydropower upgrade opportunities, particularly those involving increased flexibility. A forward-thinking perspective and assessment of what upgrades could occur, at what time, and at what cost could allow focused regional study of these opportunities in a long-term grid planning analysis. Such studies could better incorporate regional water management challenges such as cascading systems and environmental constraints to better understand feasibility and cost for upgrading flexibility or other plant characteristics.

The initial data set on closed-loop PSH resource potential and cost explored here also has many opportunities for improvement and expansion. Variations on this data set could consider alternative technical specifications (e.g., dam height and storage duration) or geographical resource exclusions (e.g., distance from water bodies and overlap with additional land types). The generic cost model used in this data set could also be improved with more bottom-up detail and the ability to account for additional site considerations such as rock type and penstock type (e.g., underground tunnel or above-ground penstock). The influence of water availability for filling new PSH reservoirs on the feasibility and cost of reservoirs could also improve data accuracy.

In addition to improving closed-loop PSH resource supply curves, future work could assess other PSH deployment opportunities. These include alternate topographical formations (e.g., “turkey nest” or dry

gully), PSH opportunities with one or more existing on- or off-river reservoirs, or niche opportunities such as deep abandoned mines as the lower reservoir.

With or without additional model and data improvements, this work lays the groundwork for an applied exploration of hydropower and PSH flexibility by identifying impactful hydropower and PSH model improvements needed for such an analysis. Beyond the context of ReEDS and the United States, we broadly identify new ways to study the role and importance of hydropower and PSH in future electricity systems. Future analysis could explore a much broader range of electricity futures with a targeted set of sensitivity scenarios that vary hydropower and PSH flexibility along with other electricity system assumptions such as technology cost, demand flexibility, and decarbonization policy. Such a sensitivity analysis could also inform hydropower and PSH cost and performance targets by demonstrating the level of deployment and operational flexibility required for any desired system outcomes.

6.0 Summary and Recommendations

This report presents new methods of data integration and model construction to better characterize the future role of hydropower and pumped storage hydropower (PSH) in electricity systems. The improvements, which largely focus on operating flexibility and upgradeability, demonstrate the potential for the existing fleet and new closed-loop PSH deployment to complement variable generation and sometimes other storage technologies.

The initial and limited demonstrative scenario analysis of individual and combined new features generated several initial insights that could be borne out by further analysis. Improving the flexibility of existing hydropower assets has the potential to reduce CO₂ emissions and improve electricity system economics, especially if flexibility improvements can be achieved at lower cost and without major changes to electromechanical equipment (e.g., the addition of pumps). In Reference scenarios, hydropower flexibility upgrades help facilitate greater deployment of solar photovoltaics, or PV, (up to 155 GW in 2050), which supports up to 35% lower CO₂ emissions in 2050 and 7% lower electricity costs. In the 100% RE scenario, hydropower flexibility reduces the need for new construction of other flexible technologies (up to a 289 GW reduction in total 2050 capacity), allowing decarbonization at lower electricity costs (up to 12% in 2050).

An initial exploration of interseasonal energy transfers and arbitrage might extend beyond realistic planning horizons, but it demonstrates the future value of balancing seasonal differences in electricity demand and supply, particularly that of PV energy availability. New closed-loop PSH resource and cost data also indicate there might be enough attractive sites in the United States to substantially increase the total capacity and thus the overall benefit of the PSH fleet. While new PSH deployment will be sensitive to site-specific PSH costs and the economics of competing flexible technologies, Reference scenarios deployed up to 8.6 GW of new PSH, and 100% RE scenarios deployed up to 15.8 GW new PSH.

Tests that enable the independent decision to upgrade hydropower capacity or energy at existing facilities suggest capacity could be a more important driver of hydropower upgrades than energy, particularly in a future with high shares of variable generation. These results reported here highlight the importance of valuing firm capacity when making decisions regarding hydropower upgrade investments, beyond the value of any additional energy production.

We recommend models and analysis exploring the future role of hydropower and PSH in electricity systems consider model improvements or sensitivity analysis to reflect the potential for increased hydropower flexibility from the existing fleet and new closed-loop PSH. Limited site-level data on

technical specifications and operating constraints make it difficult to paint an accurate picture of the potential for increased hydropower flexibility through equipment upgrades or modified operating plans, but the potential system impact makes the possibility important to consider.

Continued implementations of improved hydropower and PSH data and representations, coupled with a broad scenario analysis, could demonstrate the range of roles hydropower and PSH can play in the grid of the future.

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Appendix A: Scenario Results for Fixed-Speed versus Adjustable-Speed Pumps

Figure A.1 compares the total 2050 time-slice power output of the U.S. PSH fleet between the Base and Pfix scenarios. The less restrictive Base scenarios demonstrate that arbitrage opportunities are greater in the RE100 scenario than in the Ref scenario, and pumping power is nearly equal to the maximum available capacity in some time-slices. Notably, PSH is a net generator in the summer peak for Ref scenarios but is storing electricity in the summer peak for the RE100 scenario. In the RE100 scenario, PV generation is sufficient to meet gross peak demand in the summer and energy arbitrage is used to shift energy to time-slices with low PV generation.

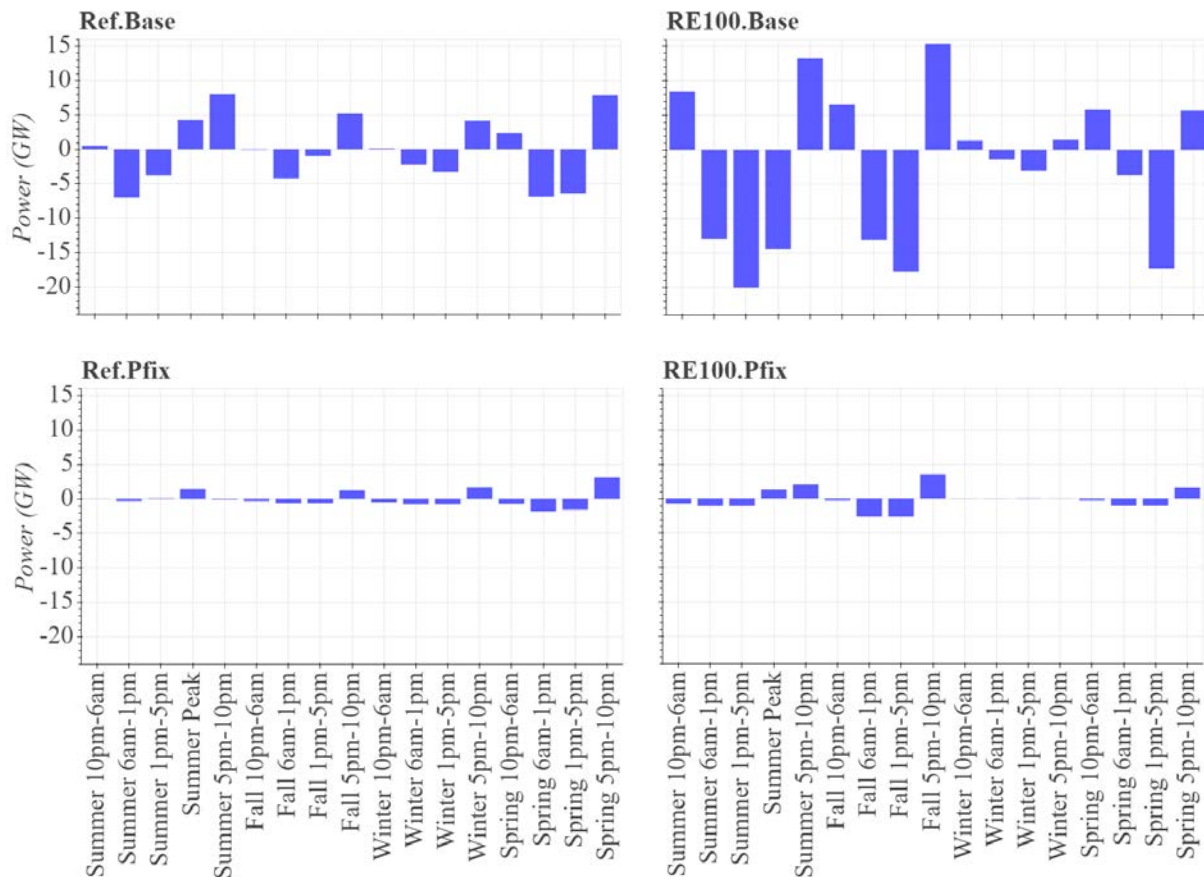


Figure A.1. National power output from the U.S. PSH fleet by time-slice in 2050 when all capacity is represented as fixed-speed versus adjustable-speed pumps. The model representation of fixed-speed pumps nearly negates energy arbitrage opportunities and is thus overly restrictive.

The additional constraint imposed for Pfix scenarios greatly reduces arbitrage opportunities for PSH. In practice, it requires the pump power to be fixed in all time-slices for each season, even those when the PSH capacity is generating electricity. The net effect is very little net output or input to the grid in any time-slice. The inability to include integer variables to represent the on/off status of pumping versus generating modes makes this formulation overly restrictive. ReEDS already has difficulty incentivizing PSH to perform energy arbitrage on par with historically observed levels because of its coarse time resolution and its inability to represent detailed electricity market drivers; this limitation is one of the major motivations for building a separate ReEDS module called Augur that includes a more accurate

assessment of hourly storage arbitrage value. Thus, we determined that this method of distinguishing fixed-speed and adjustable-speed pumps is not appropriate to include in the default ReEDS configuration. Because fixed-speed PSH can generally still switch modes fast enough to exploit energy arbitrage opportunities, the model representation should not be made more restrictive. The key differences between pump capabilities lie in ancillary service provision while pumping. Though these services are important for grid stability, they are less important for planning decisions because of the lower values of these products under current market structures (which is also demonstrated in Figure 2.6).

This report is being prepared for the U.S. Department of Energy (DOE). As such, this document was prepared in compliance with Section 515 of the Treasury and General Government Appropriations Act for fiscal year 2001 (public law 106-554) and information quality guidelines issued by DOE. Though this report does not constitute “influential” information, as that term is defined in DOE’s information quality guidelines or the Office of Management and Budget’s Information Quality Bulletin for Peer Review, the study was reviewed both internally and externally prior to publication.

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