How Today's Hydropower Impacts Tomorrow's Grid: Counterfactual Scenarios Showing Grid Impacts if Hydropower Goes Away

Stuart M. Cohen

National Renewable Energy Laboratory

Suggested Citation
Cohen, Stuart. 2023. *How Today's Hydropower Impacts Tomorrow's Grid: Counterfactual Scenarios Showing Grid Impacts if Hydropower Goes Away*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-86295.
https://www.nrel.gov/docs/fy24osti/86295.pdf.

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-6A40-86295
November 2023

National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 • www.nrel.gov

NOTICE

This work was authored by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Water Power Technologies Office. The views expressed herein do not necessarily represent the views of the DOE or the U.S. Government.

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

U.S. Department of Energy (DOE) reports produced after 1991 and a growing number of pre-1991 documents are available free via www.OSTI.gov.

NREL prints on paper that contains recycled content.

About HydroWIRES

In April 2019, the U.S. Department of Energy Water Power Technologies Office launched the HydroWIRES Initiative[1] 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. electric 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. electric 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, including understanding value drivers for hydropower under evolving system conditions, describing flexible capabilities and associated 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)

Acknowledgments

I would like to thank Jaquelin Cochran, Wesley Cole, Jennifer Daw, Bethany Frew, Michael Purdie, Mark Ruth, Greg Stark, and Aidan Touhy for their thorough review of this work prior to publication, and Amy Brice for editing support. All errors and omissions are the sole responsibility of the author.

Table of Contents

Abstract 1
1 Introduction 1
2 Capacity Expansion Modeling Approach 2
3 Scenarios for Hydropower Retirement 4
4 Impacts on the National Electricity Mix 5
5 Environmental and Economic Implications 9
6 Conclusions 14
References 17

Abstract

Amidst ongoing discussions about hydropower removals, retirements, and reduced availability due to drought and other environmental considerations, it is important to understand the long-term effects of reduced hydropower resources on the U.S. electric grid. This analysis uses the Regional Energy Deployment System (ReEDS™) grid planning model to compare several representative scenarios of retiring hydropower and pumped storage hydropower (PSH) capacity over time and explore the overall implications on the U.S. grid from now (2023) through 2050. In the scenarios, retired hydropower capacity and generation is replaced by a mix of both fossil and non-fossil resources, including natural gas, wind, solar, and battery technologies. The results show that additional natural gas usage across the national electric sector leads to an increase in cumulative national electric sector carbon dioxide and criteria pollutant operating emissions of less than 1% in many scenarios but up to 4%–5.3% in some cases. Total electric sector costs also increase by <1% in many scenarios but up to 3.6% in the most extreme scenarios where nearly all the hydropower and PSH fleet retires, equating to $340 billion in undiscounted costs. National results indicate that absent additional interventions, retiring hydropower and PSH capacity could increase electric sector emissions and direct capital and operating costs. However, more focused analysis is required to evaluate asset-level, local, and regional implications, and a broader scope is necessary to weigh these electric sector impacts alongside economic, ecological, water management, and other cross-sectoral effects that could be either negative or positive.

1 Introduction

Hydropower assets have long supplied low-carbon electricity to the U.S. power system while providing a wide array of power and non-power services, including firm capacity, flexible electricity generation, flood control, and water supply stability (DOE 2016). However, these benefits come with some negative environmental impacts on local and downstream ecology, prompting discussions and proposals around retiring hydropower capacity by depowering or removing dams and pumped storage hydropower (PSH) facilities (DOE 2016; McReynolds 2023; Olsen et al. 2022). In addition, some hydropower assets are at risk of becoming less available or unavailable to produce power because of changes in water availability and water management needs (Chalise, Sankarasubramanian, and Ruhi 2021; Voisin et al. 2020). It is thus important to understand the long-term implications of removing hydropower assets from the generation fleet. Without hydropower, including run-of-river generation, flexible reservoir hydropower, and PSH, stakeholders in the electric sector will have to alter their investment and operating decisions, which will impact the overall generation mix as well as economic and environmental outcomes.

This study quantifies an answer to the question, “What happens to the grid if hydropower goes away?” using a robust electric sector capacity expansion model to compare scenarios that progressively retire hydropower assets to a baseline scenario where the existing hydropower fleet persists as it does today. The scope of this work is limited to electric grid investments and operation, so it does not include or make assumptions about other current and potential uses of existing dams. Hydropower retirement scenarios also do not necessarily imply dam removal, only the retirement or decommissioning of the power generation components. Within the grid, some ancillary services such as operating reserves are considered, but an analysis of all shortterm grid services such as inertia, voltage support, and black start is outside the scope of the current work. Impacts of hydropower retirements beyond the electric grid, including those on economic, environmental, and water management systems, are also beyond the scope of this work. While this study is not a comprehensive evaluation of the possible range of hydropower retirement/removal outcomes, future electric sector scenarios, and complex interactions between multisectoral systems within which hydropower and PSH operate, it identifies key electric sector trade-offs when considering the future of U.S. hydropower assets. These grid trade-offs can then be incorporated into a more comprehensive discussion around the complex, multifaceted impacts of hydropower depowering or removal.

This work complements two other studies that explore hydropower and PSH interactions with variable generation (VG) and other grid technologies to establish their value for decarbonizing the electric grid. One of the studies, *Storage Effectiveness in Enabling Variable Generation and Avoiding Fossil Emissions* (Stark, Dhulipala, and Brinkman 2023), demonstrates that the longer storage durations provided by PSH are more effective for complementing VG and reducing fossil emissions in future electricity scenarios. The other study, *The Role of Hydropower Flexibility in Integrating Renewables in a Low-Carbon Grid* (Stark and Brinkman 2023), uses a similar approach to examine the value of flexibility among the existing hydropower fleet for providing reliable capacity and flexible energy while reducing cost. Where these works considered the impacts of adding storage and flexibility to the grid, the analysis described herein studies the corollary impacts of subtracting hydropower and PSH using similar data, tools, and metrics.

2 Capacity Expansion Modeling Approach

The Regional Energy Deployment System (ReEDS™) capacity expansion model was used to perform this analysis[1] (Ho et al. 2021). ReEDS is an open-access grid planning tool that has been under development by the National Renewable Energy Laboratory (NREL) since 2003 and used for numerous high-impact grid planning studies such as the U.S. Department of Energy's *Hydropower Vision* report (DOE 2016), a 2035 decarbonization analysis (Denholm et al. 2022), an analysis of the Inflation Reduction Act (IRA; Steinberg et al. 2023), and the annual NREL standard scenarios report (Gagnon et al. 2022). ReEDS is a linear program that minimizes the cost of power system investment and operation in the contiguous United States from the present to multiple decades in the future. In this work we simulate power system evolution through 2050. ReEDS uses demand and fuel price projections along with technology cost and performance assumptions to determine the least-cost mix of generation, transmission, and storage assets for a given electricity scenario. It ensures the system meets requirements for electricity demand, operating reserves,[2] firm capacity,[3] and any existing policies, such as the IRA. Here, electricity

[1] https://www.nrel.gov/analysis/reeds/index.html. Source code available upon request at https://github.com/NREL/ReEDS_OpenAccess.

[2] ReEDS enforces the supply of three operating reserve products: flexibility reserves, spinning reserves, and regulation. Requirements for each are based on load and variable renewable deployment, and eligible technologies can contribute based on their assumed generation ramp rate.

[3] Firm capacity needs are defined by reserve margin requirements used by regional transmission organizations, and capacity credit is either assumed or calculated for each technology. Variable renewable and storage technology capacity credit are calculated in each balancing area after each model solve year based on the previously built infrastructure using an hourly dispatch submodule, and dispatchable resources such as nuclear and fossil technologies are assigned a 100% capacity credit.

demand and fuel prices are taken from the U.S. Energy Information Administration (EIA) 2022 Annual Energy Outlook Reference case (EIA 2022a), and technology assumptions are taken from the NREL 2022 Annual Technology Baseline (ATB) Moderate case (NREL 2022). Other input assumptions and data, including load and renewable energy hourly profiles, are consistent with the NREL 2022 Standard Scenarios Mid-Case (Gagnon et al. 2022).

The ReEDS model version used for this analysis is based on the version used for the recent IRA policy analysis (Steinberg et al. 2023). In each solve year, its intra-annual time resolution includes 42 representative days, each with six chronological 4-hour time slices. This configuration balances resolution with computational tractability while clustering days based on similar hourly wind, solar, and load profiles to provide a descriptive set of dispatch conditions for other resources.[4] Operating constraints, including transmission and generation capacity and energy limits, are enforced in these time slices, and seasonal energy limits for hydropower are enforced by mapping representative days to seasons. Storage energy arbitrage is also possible across time slices in each representative day but not across days.[5] There are 134 supply-demand balancing areas connected by an aggregate transmission overlay, and most technologies, including hydropower, are represented at this spatial resolution with additional disaggregation by technology subcategories and resource classes to further differentiate operating parameters. For example, battery technologies are differentiated into 2/4/6/8/10-hour storage durations, there are 10 solar photovoltaic (PV) resource classes, and there are 15 land-based wind resource classes. This spatial and technology resolution allows substantive information about resource availability, quality, and cost, though it cannot explicitly consider all practical siting limitations. ReEDS also uses 7 years of hourly wind, PV, and load data to dynamically characterize renewable energy curtailment and the capacity credit of renewable energy and storage, recalculating these values for each model year based on the state of the system after the previous year. This procedure allows ReEDS to represent regional, intra-annual, and interannual differences in curtailment, capacity credit, and resource adequacy needs.

The existing non-PSH hydropower fleet is not explicitly represented at the unit or plant level in ReEDS, but each balancing area differentiates between dispatchable, or flexible, hydropower and non-dispatchable hydropower. Dispatchable capacity can follow load, provide operating reserves, and commit its full capacity toward firm capacity requirements. Non-dispatchable capacity supplies energy with a fixed, flat profile defined by its seasonal energy budget, cannot supply operating reserves, and contributes only its fixed output toward firm capacity requirements. ReEDS also allows upgrades to the existing hydropower fleet, powering of non-powered dams, and new stream-reach development using resource supply and cost data from *Hydropower Vision* (DOE 2016). Existing PSH is similarly aggregated to the balancing area resolution. PSH is characterized using data from the International Hydropower Association (IHA 2021), and new closed-loop PSH opportunities are represented using data from NREL geospatial analysis[6] (Rosenlieb, Heimiller, and Cohen 2022). PSH can provide multiple value streams in

[4] Full documentation of this procedure will be included in an upcoming update to the ReEDS model documentation. The resolution used here was chosen by comparing accuracy at different time resolutions up to full 8,760-hour-per-year resolution for subnational regions, similar to the methods described in Pfenninger (2017) and Reichenberg and Hedenus (2022).

[5] Allowing energy arbitrage across longer time scales is an area of active model development.

[6] The latest updates to PSH supply curves are described at: https://www.nrel.gov/gis/psh-supply-curves.html.

ReEDS, including energy arbitrage, operating reserves, and firm capacity. This representation enables the model to represent multiple value streams associated with hydropower and PSH, and changes to the availability of these technologies can result in gaps in services that must be filled through other investments, changes to system operation, or both.

3 Scenarios for Hydropower Retirement

Because of the long-lived nature of hydropower and PSH assets, the default ReEDS assumption is to never retire these assets. This assumption thus establishes a baseline "no retirement" scenario (Base.NoRet) for comparison to alternative scenarios with phased hydropower and PSH retirements throughout the United States. The hydropower retirement scenarios are implemented exogenously by enforcing retirement dates for specific units, with the specified retirement date being some duration of years before or after the facility's Federal Energy Regulatory Commission (FERC) license expiration date, if applicable, or based on an assumed physical lifetime for facilities that do not operate under a FERC license (i.e., federally owned and operated facilities). FERC license expiration dates are taken from the Oak Ridge National Laboratory Existing Hydropower Assets database, and plant online years are already included in the ReEDS unit database built from EIA National Energy Modeling System model inputs consistent with the 2022 EIA Annual Energy Outlook (Johnson, Kao, and Uria-Martinez 2022; EIA 2022a; 2022b). Hydropower and PSH retirements are also prohibited before a designated earliest retirement year for a scenario; this specification prevents retirements from taking place in the past.

These scenario design parameters are used to define three hydropower retirement trajectories that capture a wide range of outcomes, from modest retirements to an extreme case where effectively the entire hydropower and PSH fleets are off the grid by 2050. This first-order approach is not intended to represent plausible futures and only encompasses changes to electric grid investment and operation. It is designed to enable counterfactual comparisons to the baseline scenario and demonstrate the long-term grid implications of the existing hydropower fleet on the U.S. electricity system. Any effects upstream, downstream, or outside of grid planning and operation are not considered.

The three retirement trajectories (SlowRet, ModRet, and FastRet, corresponding respectively to slow, moderate, and fast retirement) are described in Table 1 and shown graphically in Figure 1, which also shows the remaining hydropower and PSH available over time for each scenario. Figure 1 differentiates between federally owned and nonfederal assets and separates hydropower and PSH into separate panels. Most PSH assets are nonfederal, under FERC licenses, and were built in a relatively short time period, so PSH trajectories tend to have periods of rapid retirements. Hydropower construction was more distributed over time and encompasses a larger number of facilities of varying sizes, so trajectories are relatively smooth over time. The FastRet scenario serves as a bounding case by drastically reducing capacity in the initial 2025 year and retiring nearly the entire existing hydropower and PSH fleet by 2050. The other scenarios represent intermediate outcomes between FastRet and the Base.NoRet scenario.

In addition to the three retirement scenarios, additional scenario variants independently apply these retirements on either hydropower or PSH or both. Scenario names are tagged with .PSH or

.Hyd to indicate which technology is retired. Including the baseline scenario without additional hydropower and PSH retirements, 10 scenarios are included in this study.

All other ReEDS input assumptions are consistent with the Mid Case scenario in a recently published IRA policy analysis using ReEDS (Steinberg et al. 2023). These include technology cost and performance assumptions from the 2022 ATB Moderate case and fuel price and load growth projections from the AEO2022 Reference case (EIA 2022a). Capacity expansion results for the Base.NoRet scenario are shown in Figure 2 to set the context for hydropower retirement scenarios.

Table 1. Hydropower and PSH Retirement Scenario Definitions

FERC license expiration dates and plant lifetime were used to define three stylized hydropower and PSH retirement scenarios that examine the implications of hydropower and PSH removals in the United States.

Hydropower Retirement Scenario	Retirement Relative to FERC License Expiration Year	Assumed Lifetime if Not FERC Licensed	Earliest Retirement Year
SlowRet	+20 years	100 years	2030
ModRet	On year	75 years	2025
FastRet	−20 years	50 years	2025

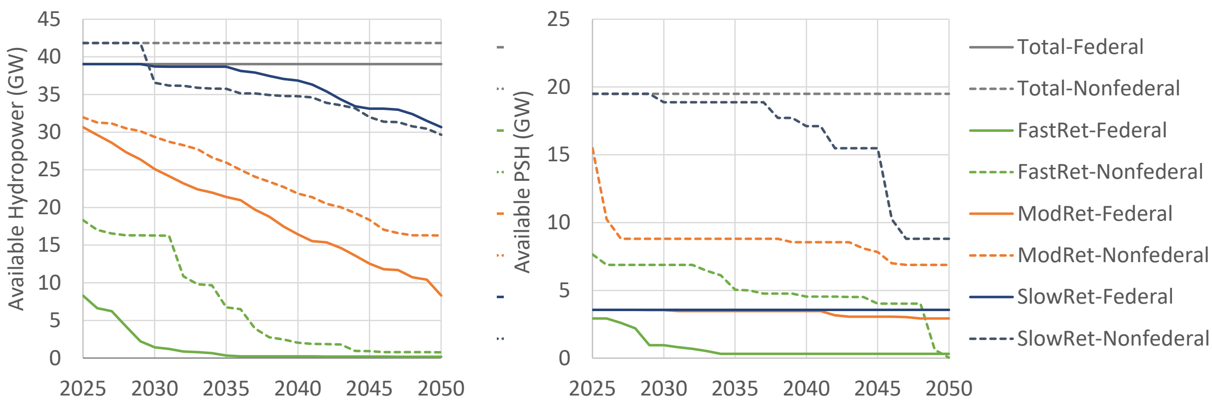

Figure 1. Retirement scenarios span a wide range of outcomes for both federal and nonfederal assets, up to the FastRet scenario that retires substantive capacity in the initial year and nearly all existing hydropower and PSH by 2050. Total hydropower and PSH of each type are shown for reference.

4 Impacts on the National Electricity Mix

The baseline scenario national capacity and generation mix are shown in Figure 2 to provide context for the changes that occur when hydropower and PSH assets are removed. While hydropower impacts could be concentrated in the Pacific Northwest region and other areas where hydropower and PSH make up a larger share of capacity and generation, national results are discussed exclusively to acknowledge the first-order approach and avoid overemphasizing specific regional results. A regional analysis should entail a more detailed consideration of the timing and magnitude of specific unit- and plant-level hydropower and PSH retirements, involving broad stakeholder engagement.

Through 2035, the system is heavily influenced by the IRA tax incentive policies. Coal and nuclear capacity experience capacity retirements, and there is substantial growth in wind and PV capacity along with battery storage to help balance those variable generation resources and meet system capacity requirements. After 2035, the IRA tax credits phase out because the decarbonization goal is reached. Absent any subsequent policy to continue decarbonization, wind, PV, and battery deployment slows, and natural gas usage rebounds. Significant deployment of simple-cycle gas turbines (Gas-CT) also occurs after 2035 when tax credits no longer clearly favor battery technologies for firm capacity and operating reserve requirements. In this baseline system, hydropower and PSH are relatively small shares of the national mix; in 2050, capacity is 3.4% hydropower and 1.1% PSH while generation is 5.2% hydropower. In addition, they provide consistent contributions of energy and capacity along with operating flexibility, which is not readily observed from the national electricity mix but is expected based on other analysis (Stark and Brinkman 2023).

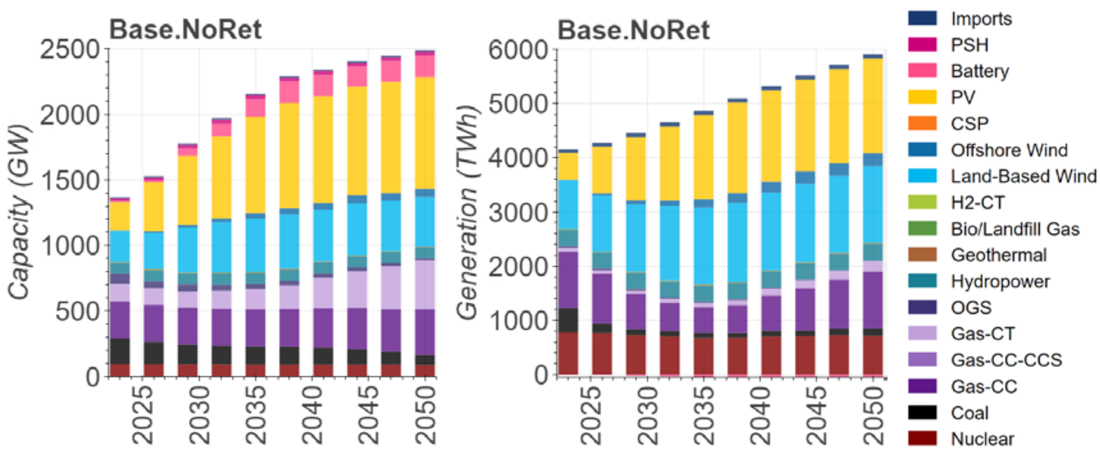

Figure 2. National capacity and generation over time in the Base.NoRet baseline scenario without hydropower and PSH retirements. The system deploys substantial wind, PV, and battery capacity until the IRA tax credits phase out and natural gas usage rebounds.

In the legend, CSP = concentrating solar power, H2-CT = hydrogen-fueled combustion turbine, Bio/Landfill Gas = dedicated biopower and landfill gas-to-power, OGS = oil/gas-based steam generators and internal combustion engines, Gas-CT = simple-cycle gas turbines, Gas-CC = combined-cycle natural gas, Gas-CC-CCS = Gas-CC with carbon capture and sequestration technology. Imports are from Canada.

Figure 3 and Figure 4 demonstrate the implications of retiring hydropower and PSH on the national capacity and generation mix relative to the baseline system. Each row shows a different retirement scenario, and the ensuing discussion progresses through the columns, which show the effects of retiring PSH, hydropower, or both.

Slow, modest retirements of PSH (Figure 3a and d) largely result in additional battery and Gas-CT capacity, which supply firm capacity and operating reserves that PSH would otherwise provide. When the only impact is on technologies built primarily for capacity services, there is negligible change to the generation mix (Figure 4a and d). However, as more PSH is retired and sooner, other effects arise (Figure 3g and Figure 4g). In addition to greater battery and Gas-CT capacity, capacity and generation of other fossil fuel technologies are incrementally higher due to delayed retirements, and the FastRet.PSH scenario also has more combined-cycle natural gas (Gas-CC) in most years. There is often slightly more wind but less PV when the PSH fleet retires sooner. Changes to natural gas technologies, wind, and PV are further reflected in changes to the generation mix. Less PSH reduces PV deployment because PSH can complement PV by shifting its energy to different times of day. Without that combination, the system favors additional wind and/or fossil-based generation that is more readily available throughout the day.

Hydropower retirements can have very different implications because of hydropower's direct use as an energy resource. Overall, reductions in hydropower capacity and generation prompt a diverse response, with consistent increases in natural gas, wind, and storage capacity relative to the baseline (Figure 3b, e, and h). Impacts on PV capacity are modest and inconsistent except in the FastRet.Hyd scenario (Figure 3h), where the rapid, substantive loss of hydropower resources leads to a persistent increase in PV capacity that is complemented by an increase in storage technology capacity, both battery and new closed-loop PSH. Removing flexible hydropower from the system creates a demand for other flexible technologies, and these results demonstrate that economic and environmentally acceptable new PSH construction could meet some of that demand.

With slow-to-moderate hydropower retirements, a consistent response is additional natural gas use (Figure 4b and e). With rapid hydropower retirements (Figure 4h), there is greater initial usage of natural gas (and coal, at first), but this trend reverses after 2038, after which gas usage is lower than the baseline, and nuclear generation also falls slightly due to the 1.1–1.6 GW additional nuclear capacity that is retired in 2038. The reversing trend for natural gas usage in the FastRet.Hyd scenarios stems from the IRA policy and its built-in incentive phaseout when its decarbonization goal is reached. Sufficient hydropower retirements occur in the FastRet scenario for the near-term increase in natural gas usage to delay the phaseout schedule of the IRA tax credits, delaying but not eliminating the rebound in natural-gas-based generation observed in all scenarios. While the magnitude and speed of hydropower retirements in FastRet is extreme, it demonstrates the potential interplay between hydropower and decarbonization policy designs.

When both hydropower and PSH are retired together, the impacts are largely an aggregate of the technology-specific retirement scenarios, with hydropower effects being dominant because of the larger magnitude of retired capacity. Although the FastRet.Hyd.PSH scenario builds new PSH in response to existing hydropower and PSH retirements (Figure 3i), there is still a net decrease in PSH capacity of 14.9 GW in 2050. On the whole, retiring PSH tends to result in less total capacity (Figure 3a, d, and g), but there is generally a long-term increase in total system capacity investment when hydropower is retired (Figure 3b, d, and h). A net increase in total capacity with hydropower retirements reflects the relatively higher capacity factor and firm capacity credit that hydropower contributes relative to the variable renewable and battery technologies that are installed in response. The magnitude of impacts is still relatively small compared to a system that nears 2,500 GW and 6,000 TWh in 2050, but changes of tens to hundreds of gigawatts can be significant regionally, especially in areas like the Pacific Northwest where hydropower is a large share of the regional generation mix.

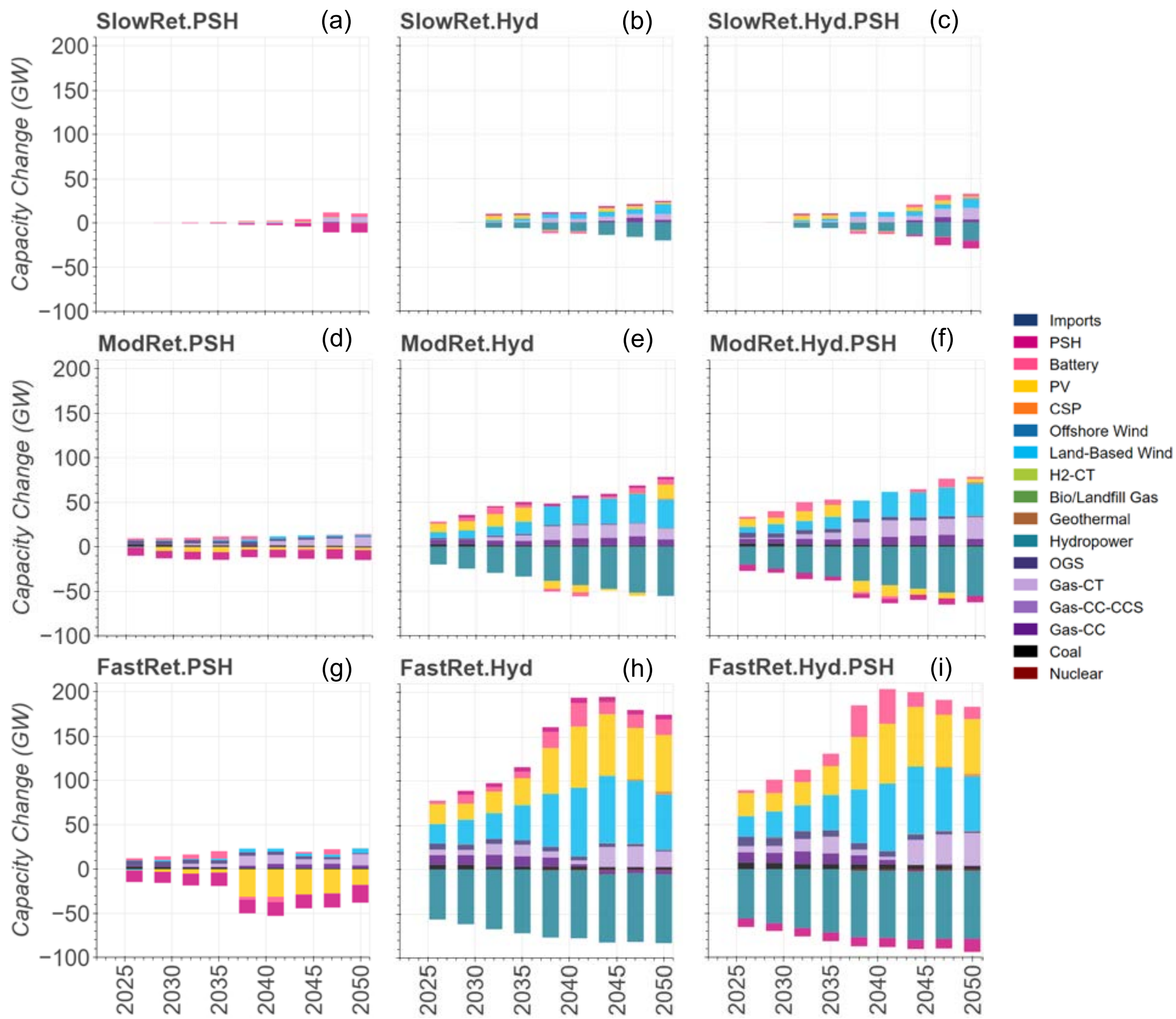

Figure 3. Change in the national capacity mix relative to the baseline for each of the hydropower and PSH retirement scenarios. Retirements are offset by a combination of technologies including wind, PV, natural gas, and battery.

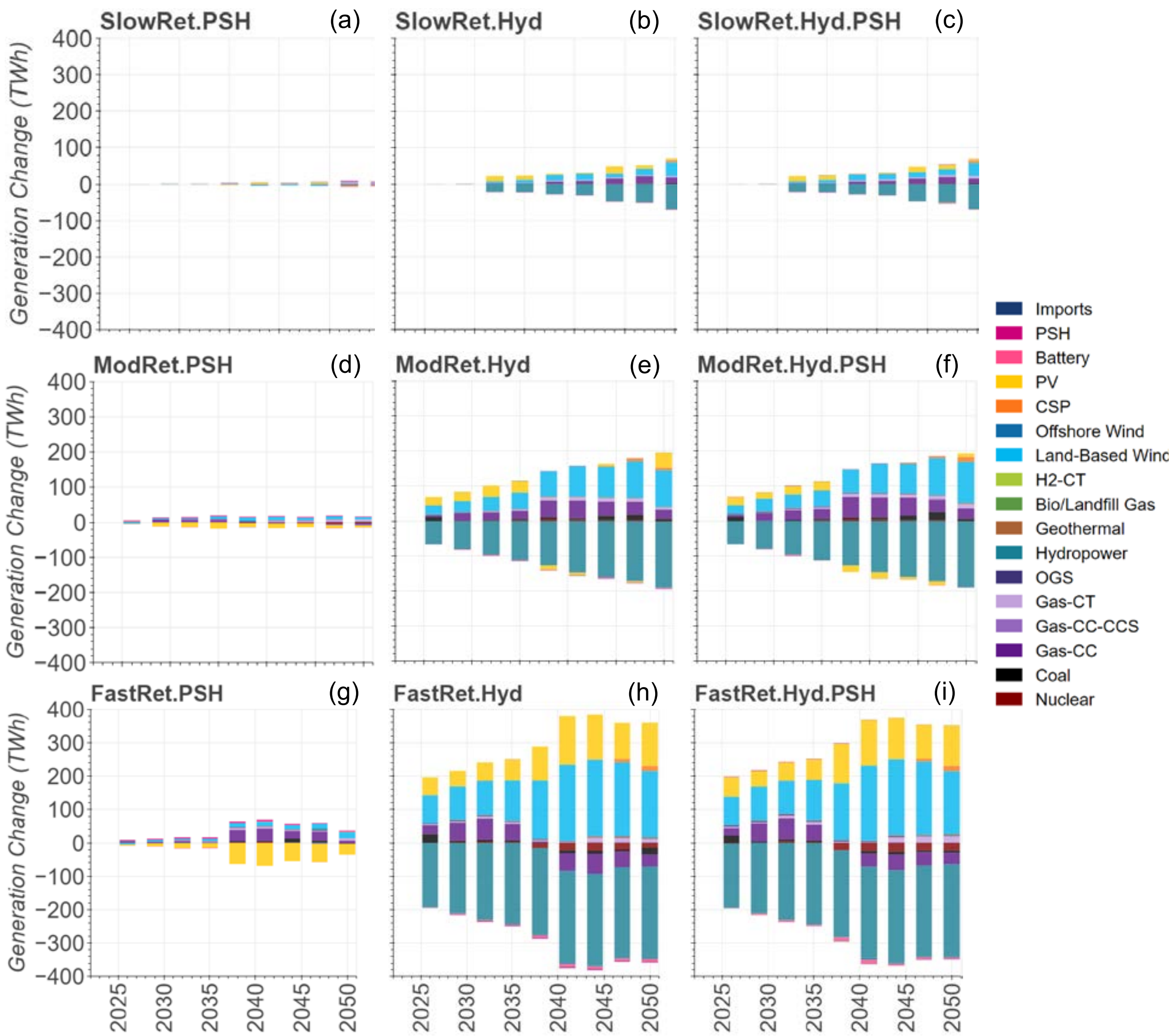

Figure 4. Change in the national generation mix relative to the baseline for each of the hydropower and PSH retirement scenarios. Lost hydropower generation is typically compensated by a combination of wind, PV, and natural gas, but some effects are scenario- and time-dependent.

5 Environmental and Economic Implications

Changes to the generation and capacity mix in turn influence both environmental and economic outcomes in the electric sector, and these impacts help explain the potential trade-offs when considering hydropower and PSH retirements. Figure 5 plots the annual national emissions of several pollutants over time for all scenarios along with differences from the baseline scenario. These emissions are at the point-of-use only (i.e., power plants), so they do not include full life cycle emissions associated with construction and decommissioning. This caveat is notable in the present discussion because PSH has shown to have generally lower life cycle greenhouse gas impacts than batteries, and some scenarios respond to retiring hydropower and PSH with additional battery deployment (Simon et al. 2023).

Generally, emissions trajectories are qualitatively similar for all scenarios, decreasing steadily until the IRA tax credits begin to phase out and natural gas usage rebounds (Figure 5a–e). Sulfur dioxide (SO_2) is an exception (Figure 5e) because natural gas generation does not emit SO_2, so its emissions stay low after the near-term decrease in coal usage for electricity.

The difference plots (Figure 5f–j) tell a clearer story of the emissions impacts of hydropower and PSH retirements, consistent with the changes to the generation mix shown in Figure 4. There is an emissions increase for almost all pollutants in all scenarios and years, corresponding to national changes in natural gas and coal electricity. Even small changes to coal generation are reflected in these results, particularly for SO_2 (Figure 5j). The FastRet.Hyd and FastRet.Hyd.PSH scenarios (dashed orange lines) are exceptions to the typical increase in emissions because fossil-based generation is relatively lower after 2038 in these scenarios due to interactions with the IRA tax credit phaseout described above. This result is another example of how policy design and complex power sector interrelationships can lead to nonintuitive outcomes.

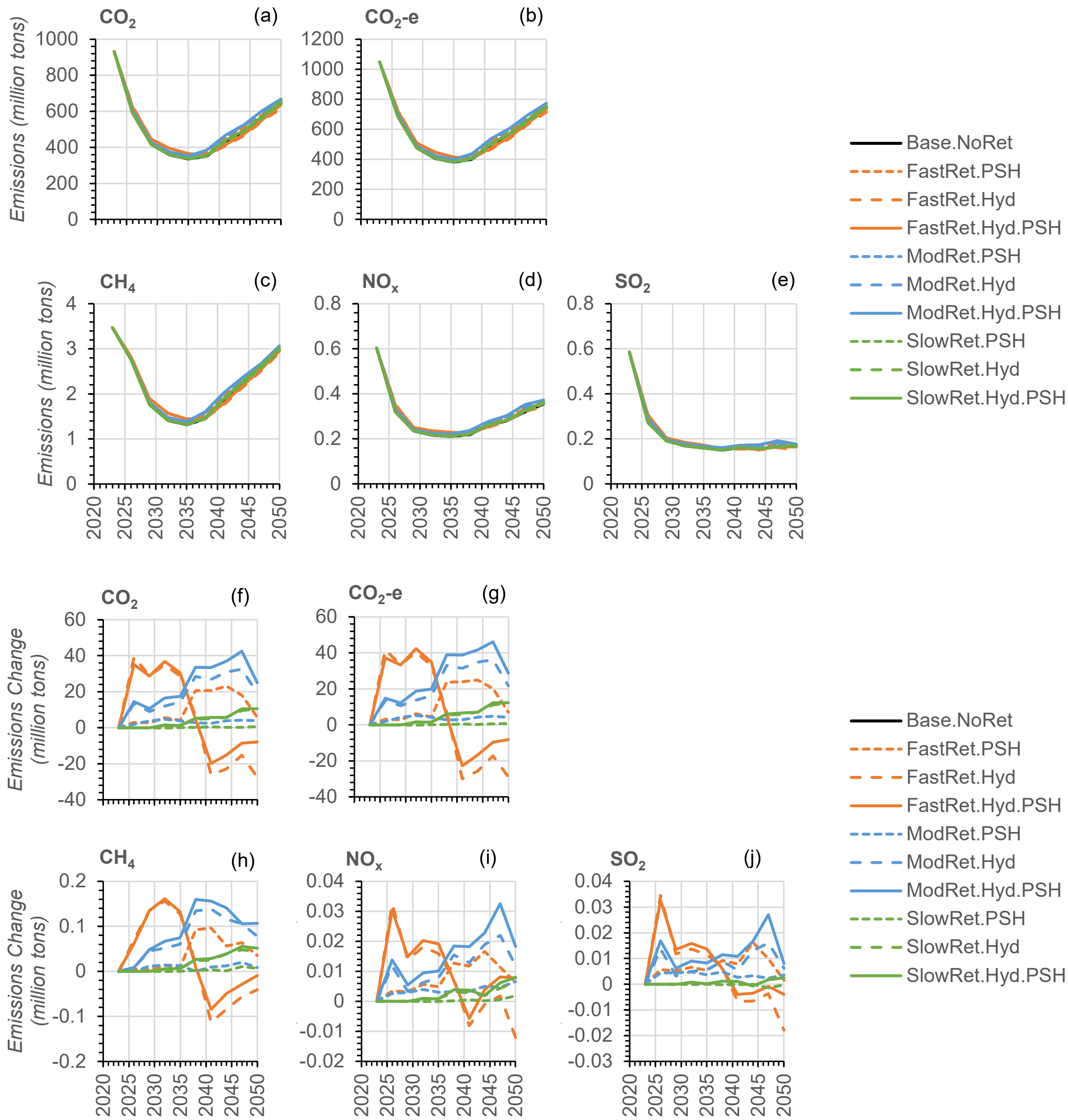

Figure 5. Modeled national emissions trajectories for criteria pollutants (NO_x = nitrous oxides, SO_2 = sulfur dioxide, CH_4 = methane), carbon dioxide (CO_2), and CO_2-equivalent (CO_2-e) for all scenarios (panels a–e) and the differences in emissions relative to the baseline scenario (panels f–j). Hydropower and PSH retirements typically lead to higher emissions except for FastRet.Hyd scenarios.

For some pollutants, particularly greenhouse gases, the long-term accumulation of emissions is also important to consider. Figure 6 shows how hydropower and PSH removals affect cumulative emissions over 2023–2050 by plotting the change in emissions totals relative to the baseline scenario. For the SlowRet scenarios and the ModRet.PSH scenario, emissions increase by less than 1% except for SO_2 (Figure 6e) in the ModRet.PSH scenario. Because FastRet scenarios have less fossil fuel usage than the baseline after 2038, emissions increase the most for the ModRet scenarios with hydropower retirements, where increases range from 4% to 5.3%. These changes correspond to 450,000 short tons NO_x (Figure 6d), 340,000 short tons SO_2 (Figure 6e), 2,600,000 short tons CH_4 (Figure 6c), and 690 million metric tons of CO_2 (780 million metric tons CO_2-equivalent combining CO_2 and CH_4) (Figure 6a and b). While these changes could be considered small in relative terms, they demonstrate that hydropower removals could create local air quality concerns with potential equity implications, and additional fossil fuel usage works against the overall global carbon budget for meeting decarbonization goals. Local impacts could be greater in regions that are more dependent on hydropower for electricity or regions where additional fossil-based generation is required to make up for reduced hydropower output nearby.

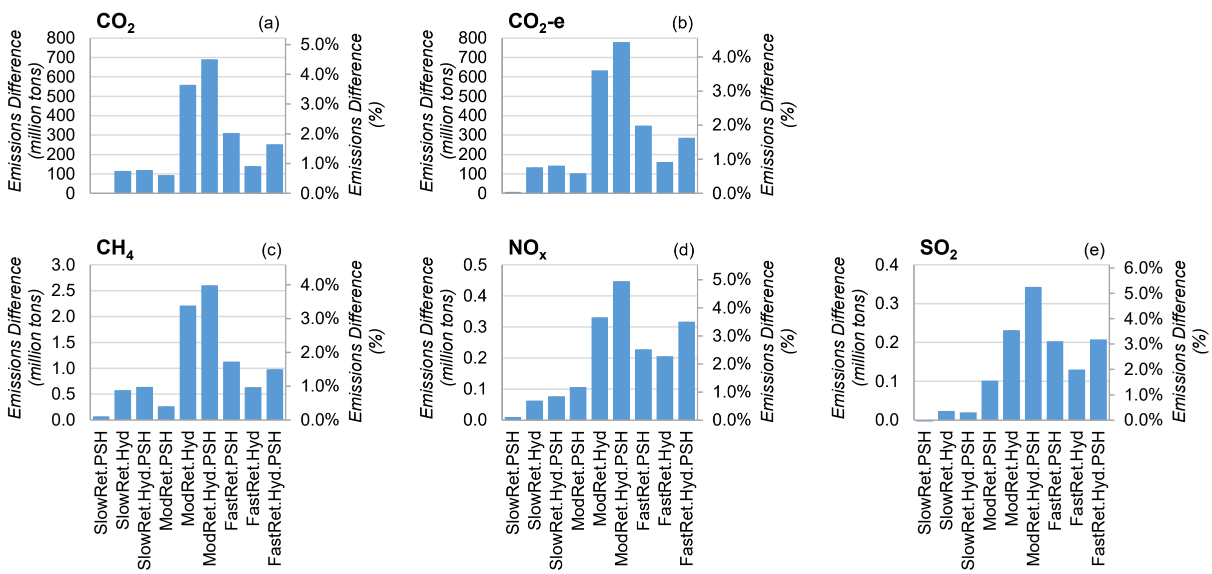

Figure 6. Absolute and percent difference in cumulative emissions from the baseline scenario in the years 2023 to 2050. Cumulative emissions are typically 1%–5% higher depending on the scenario. CO_2 and CO_2-e are shown in metric tons, and other pollutants are shown in short tons.

It is also important to understand the economic implications of any change in the electric sector, including hydropower removals. One key cost metric is the present value of the total electricity system cost, which includes all capital and operating costs across all future model years, producing a single aggregate cost value that can then be compared across scenarios. This value can be calculated using any discount rate, and Table 2 shows results for 0% (undiscounted) and a 5% social discount rate, including the absolute changes in 2022 U.S. dollars by category as well as the percent change. Policy costs include the change in tax credit payments, so a negative number means there is more effective income from the tax credits. It is important to emphasize that these values are strictly electric sector investment and operation costs and do not necessarily include grid costs associated with replacing ancillary services such as inertia or voltage support. They also do not include any economic or societal costs or benefits in the water or other sectors resulting from hydropower capacity retirements, nor do they include externality costs from CO_2 emissions or other impacts.

When applying the 5% discount rate (bottom half of Table 2), all PSH scenarios and the SlowRet.Hyd scenario exhibit a cost increase of less than 1%, ModRet.Hyd scenarios have a

1.6%–1.9% increase, and FastRet.Hyd scenarios have a 2.9%–3.5% increase. Without discounting, relative changes are slightly greater (1.9%–2.3% in ModRet.Hyd scenarios and 2.9%–3.6% in FastRet.Hyd scenarios), indicating that there are potentially long-term impacts, the importance of which depends on the reader's relative value of current versus future costs. The absolute magnitude of cost impacts depends strongly on the assumed discount rate. The ModRet.Hyd scenarios increase costs by \$59–\$71 billion at a 5% discount rate but \$185–\$221 billion undiscounted, and FastRet.Hyd scenarios increase costs by \$105–\$128 billion at 5% and \$273–\$340 billion undiscounted. Other scenarios are \$23 billion or less at 5% and \$76 billion or less undiscounted. Capital costs are the largest contributor to these totals, but policy costs are significant in the FastRet.Hyd scenarios because of the effects described above where the IRA tax credit phaseout is delayed. In these scenarios, wind and PV generation receive the tax credit for longer, resulting in larger-magnitude negative policy costs in Table 2.

While the emissions impacts are greater in the ModRet.Hyd scenarios, cost impacts are greater in FastRet.Hyd scenarios, demonstrating that trade-offs from hydropower retirements can depend strongly on other path-dependent influences on electricity sector evolution. The dominance of capital costs suggests that hydropower retirements could add strain to capital markets and supply chains that support new electric sector investment.

Table 2. Change in the Present Value of Total Electric Sector Costs From 2023 Until the End of Capital Depreciation, Shown for Discount Rates of 0% (Undiscounted) and 5%

Total costs are often <1% higher but are up to 3.6% higher in the FastRet.Hyd.PSH case. Capital costs make up the largest change, and cost implications are greater at lower discount rates.

Change in the Present Value of Electric Sector Costs From the Baseline Scenario					
	Undiscounted				
	Absolute Change (billion $)				**Percent Change (%)**
Scenario	**CapEx***	**O&M***	**Policy**	**Total**	
SlowRet.PSH	20	4	-2	**22**	0.2%
SlowRet.Hyd	49	18	-12	**55**	0.6%
SlowRet.Hyd.PSH	68	21	-13	**76**	0.8%
ModRet.PSH	28	15	-5	**38**	0.4%
ModRet.Hyd	155	72	-42	**185**	1.9%
ModRet.Hyd.PSH	176	91	-46	**221**	2.3%
FastRet.PSH	36	31	8	**76**	0.8%
FastRet.Hyd	335	94	-156	**273**	2.9%
FastRet.Hyd.PSH	386	118	-163	**340**	3.6%
	5% Discount Rate				
	Absolute Change (billion $)				**Percent Change (%)**
Scenario	**CapEx**	**O&M**	**Policy**	**Total**	
SlowRet.PSH	4	1	0	**5**	0.1%
SlowRet.Hyd	13	4	-4	**13**	0.3%
SlowRet.Hyd.PSH	17	5	-4	**17**	0.5%
ModRet.PSH	9	6	-2	**13**	0.4%
ModRet.Hyd	53	22	-17	**59**	1.6%
ModRet.Hyd.PSH	61	28	-18	**71**	1.9%
FastRet.PSH	10	11	3	**23**	0.6%
FastRet.Hyd	129	38	-62	**105**	2.9%
FastRet.Hyd.PSH	150	45	-66	**128**	3.5%

*CapEx = capital expenditures; O&M = operations and maintenance

6 Conclusions

Amid ongoing discussions about the future role of hydropower and PSH in the U.S. electricity system, including the potential for hydropower decommissioning and dam removal, it is important to understand the long-term implications of such actions. This work uses a well-established capacity expansion model to provide a high-level, multidecadal national perspective of what could happen in the electric sector if hydropower and PSH generating capacity were retired to varying extents. It focuses strictly on electric sector investment and operations, and it does not consider ancillary grid services beyond core operating reserve products. Moreover, it does not analyze the effects of hydropower and PSH retirements beyond the electric sector, such as changes to water management and impacts on the local ecology and economy.

A set of modeled scenarios was used to explore hypothetical bounds of hydropower and PSH retirements approaching a near-full retirement of the fleet. In these scenarios, the grid responds to hydropower and PSH retirements with a diverse approach, increasing deployment and usage of a mix of fossil and low-carbon generation and storage technologies. Because hydropower and PSH provide a range of energy and capacity services to the grid, this diverse response reflects these technologies' flexibility for contributing to electricity system needs. It also demonstrates that any discussion of hydropower removals should acknowledge the complexity of addressing lost hydropower and PSH capacity and avoid assuming an equivalent replacement by any one technology—fossil-based, nuclear, or renewable.

With the assumptions used for this analysis, the near-term response to hydropower and PSH removals includes greater use of fossil fuel, typically natural gas. The cumulative impact leads to a 1%–5% increase over 2023–2050 in criteria pollutant and greenhouse gas emissions from grid operation, meaning these quantities do not include any construction, decommissioning, or non-grid emissions. Counterintuitively, the largest emissions increases do not occur in scenarios with the greatest hydropower and PSH requirements because increased CO_2 emissions in earlier years make it take longer to reach the IRA CO_2 emissions reduction target. This means that tax credits for wind and PV (and their deployment rate) remain higher for longer before the tax credits phase out due to the emissions target being reached. Policy design has nuanced impacts on relative technology competitiveness, and this analysis provides an example where policy interactions create a nonintuitive relationship between the magnitude of hydropower retirements and the magnitude of the resulting grid emissions impacts. If the IRA had not been passed, the baseline scenario would likely have been more carbon-intensive, meaning that hydropower retirements would likely increase emissions more than is observed in the present analysis. Further, the relatively small emissions changes at a national scale could mask more substantive regional impacts, particularly if there are large local increases in criteria pollutants in more hydropower-reliant communities.

Greater hydropower and PSH requirements do, however, lead to greater increases in electric sector costs due to the need for replacement capacity and generation assets. Given the size of the hydropower and PSH fleet relative to the total U.S. grid, these increases of up to 3.6% are small in relative terms but still constitute tens to hundreds of billion dollars of cumulative cost, depending on the scenario and the degree of cost discounting. These costs could be more economically damaging if concentrated in specific regions and communities that are more reliant on hydropower. However, these quantities do not include costs to replace many ancillary grid services not considered in this analysis, and they ignore any externalities or non-electric sector costs and benefits incurred as a result of retiring or removing hydropower assets. Additional research is necessary to holistically understand the cost and other impacts of hydropower and PSH retirements, considering water management impacts such as flood control and ecological changes as well as local economic effects like jobs and recreation.

This work does not explore regional implications further because the stylized nature of the scenario design prevents a nuanced and realistic exploration of local issues and expectations about specific hydropower assets. Another important limitation is the use of a single underlying electric sector scenario, where a more complete scenario analysis might consider a range of alternative assumptions for electricity demand, technology costs, etc. For example, cost impacts could be greater in scenarios requiring deeper and continued grid decarbonization because any retired hydropower must be replaced with new capacity rather than compensated by increasing utilization of existing capacity. However, some preliminary follow-on analysis suggests that impacts are on a similar order of magnitude even in scenarios with 100% decarbonization by 2035. The accuracy of operational impacts is also limited by the model temporal resolution and ability to represent several ancillary grid services and detailed operating constraints on hydropower, PSH, and other technologies. This work is helpful for providing order-of-magnitude outcomes and cross-scenario comparisons, but additional analysis using tools such as hourly production cost models and sub-minute power flow models (e.g., Stark and Brinkman 2023) could produce a more complete assessment of cost, value, and impacts of hydropower and PSH retirements.

Retiring hydropower and PSH can increase both costs and emissions in the electric sector without additional interventions. This report quantifies those impacts for select scenarios, enabling stakeholders to weigh them against other environmental, economic, and social goals and make better decisions about potential hydropower and PSH retirements and removals.

References

Chalise, Dol Raj, A. Sankarasubramanian, and Albert Ruhi. 2021. "Dams and Climate Interact to Alter River Flow Regimes Across the United States." *Earth's Future* 9(4): e2020EF001816. https://doi.org/10.1029/2020EF001816.

Denholm, Paul, Patrick Brown, Wesley Cole, Trieu Mai, Brian Sergi, Maxwell Brown, Paige Jadun, et al. 2022. *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-81644. https://doi.org/10.2172/1885591.

[DOE] U.S. Department of Energy. 2016. *Hydropower Vision*. Washington, DC: U.S. Department of Energy. DOE/GO-102016-4869. https://www.energy.gov/eere/water/articles/hydropower-vision-report-full-report.

[EIA] U.S. Energy Information Administration. 2022a. "Annual Energy Outlook 2022." Washington, D.C.: U.S. Department of Energy, Energy Information Administration.

EIA. 2022b. "Documentation of the National Energy Modeling System (NEMS) Modules." Washington, D.C.: U.S. Energy Information Administration. https://www.eia.gov/outlooks/aeo/nems/documentation/index.php.

Gagnon, Pieter, Maxwell Brown, Dan Steinberg, Patrick Brown, Sarah Awara, Vincent Carag, Stuart Cohen, et al. 2022. *2022 Standard Scenarios Report: A U.S. Electricity Sector Outlook*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-84327. https://www.nrel.gov/docs/fy23osti/84327.pdf.

Ho, Jonathan, Jonathon Becker, Maxwell Brown, Patrick Brown, Ilya Chernyakhovskiy, Stuart Cohen, Wesley Cole, et al. 2021. *Regional Energy Deployment System (ReEDS) Model Documentation: Version 2020*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-78195. https://doi.org/10.2172/1788425.

IHA. 2021. "Pumped Storage Tracking Tool." Accessed September 28, 2021. https://www.hydropower.org/hydropower-pumped-storage-tool.

Johnson, Megan, Shih-Chieh Kao, and Rocio Uria-Martinez. 2022. Existing Hydropower Assets (EHA) Plant Database, 2022. Oak Ridge National Laboratory (ORNL), Oak Ridge, TN. https://doi.org/10.21951/EHA_FY2022/1865282.

McReynolds, Ethan. 2023. "Klamath Dam Removal Plan Breaks Ground." KOBI5.com (blog). March 28, 2023. https://kobi5.com/news/klamath-dam-removal-plan-breaks-ground-205906/.

[NREL] National Renewable Energy Laboratory. 2022. "2022 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/.

Olsen, Arne, Aaron Burdick, Angineh Zohrabian, Sierra Spencer, Sara Kramer, and Jack Moore. 2022. *BPA Lower Snake River Dams Power Replacement Study*. San Francisco, CA: Energy and Environmental Economics, Inc. https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/e3-bpa-lower-snake-river-dams-power-replacement-study.pdf.

Pfenninger, Stefan. 2017. "Dealing with Multiple Decades of Hourly Wind and PV Time Series in Energy Models: A Comparison of Methods to Reduce Time Resolution and the Planning Implications of Inter-Annual Variability." *Applied Energy* 197(July): 1–13. https://doi.org/10.1016/j.apenergy.2017.03.051.

Reichenberg, Lina, and Fredrik Hedenus. 2022. "The Error Induced by Using Representative Periods in Capacity Expansion Models: System Cost, Total Capacity Mix and Regional Capacity Mix." *Energy Systems*, September. https://doi.org/10.1007/s12667-022-00533-4.

Rosenlieb, Evan, Donna Heimiller, and Stuart Cohen. 2022. *Closed-Loop Pumped Storage Hydropower Resource Assessment for the United States*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-81277. https://doi.org/10.2172/1870821.

Simon, Timothy R., Daniel Inman, Rebecca Hanes, Gregory Avery, Dylan Hettinger, and Garvin Heath. 2023. "Life Cycle Assessment of Closed-Loop Pumped Storage Hydropower in the United States." *Environmental Science & Technology* 57(33): 12251–12258. https://doi.org/10.1021/acs.est.2c09189.

Stark, Greg, and Greg Brinkman. 2023. *The Role of Hydropower Flexibility in Integrating Renewables in a Low-Carbon Grid*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5700-86752. https://doi.org/10.2172/2000741.

Stark, Greg, Surya Chandan Dhulipala, and Greg Brinkman. 2023. *Storage Effectiveness in Enabling Variable Generation and Avoiding Fossil Emissions.* Golden, CO: National Renewable Energy Laboratory. NREL/TP-5700-86751. https://www.nrel.gov/docs/fy23osti/86751.pdf.

Steinberg, Daniel C., Maxwell Brown, Ryan Wiser, Paul Donohoo-Vallett, Pieter Gagnon, Anne Hamilton, Matthew Mowers, Caitlin Murphy, and Ashreeta Prasanna. 2023. *Evaluating Impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Power System*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-85242. https://doi.org/10.2172/1962552.

Voisin, Nathalie, Ana Dyreson, Tao Fu, Matt O'Connell, Sean W. D. Turner, Tian Zhou, and Jordan Macknick. 2020. "Impact of Climate Change on Water Availability and Its Propagation through the Western U.S. Power Grid." *Applied Energy* 276(October): 115467. https://doi.org/10.1016/j.apenergy.2020.115467.