HydroWIRES
U.S. DEPARTMENT OF ENERGY

Challenges and Opportunities for Electric Utility Modeling and Asset Valuation Frameworks

Case Study on Valuing New Potential Pumped Storage Hydropower

February 2026

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HydroWIRES

The U.S. electricity system is changing rapidly with the large-scale addition of variable renewables, and the flexible capabilities of hydropower (including pumped storage hydropower) make it well positioned to aid in integrating these variable resources while supporting grid reliability and resilience. Recognizing these challenges and opportunities, WPTO has launched a new initiative known as HydroWIRES: Water Innovation for a Resilient Electricity System. HydroWIRES is focused principally on understanding and supporting the changing role of hydropower in the evolving U.S. electricity system. Through the HydroWIRES Initiative, WPTO seeks to understand and drive utilization of the full potential of hydropower resources to contribute to electricity system reliability and resilience, now and into the future.

HydroWIRES is distinguished in its close engagement with the DOE's national laboratories. Five national laboratories—Argonne National Laboratory, Idaho National Laboratory, National Laboratory of the Rockies, Oak Ridge National Laboratory, and Pacific Northwest National Laboratory—work as a team to provide strategic insight and develop connections across the U.S. Department of Energy portfolio that add significant value to the HydroWIRES Initiative.

HydroWIRES operates in conjunction with the Grid Modernization Initiative, which focuses on the development of new architectural concepts, tools, and technologies that measure, analyze, predict, protect, and control the grid of the future, and on enabling the institutional conditions that allow for quicker development and widespread adoption of these tools and technologies.

Connections With the HydroWIRES Road Map

This report on electric utility modeling and asset valuation frameworks focuses primarily on addressing HydroWIRES Objectives 1.2 and 1.3: Value Drivers and Valuation Methodologies. It is informed by an extensive body of work among all participating national laboratories in hydrological and grid modeling along with hydropower valuation, and results from it will inform subsequent PSH and other valuation studies for grid technologies. Other relevant DOE efforts include modeling and analysis supported by the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy, the U.S. Department of Energy Office of Science, the U.S. Department of Energy Office of Electricity, and the U.S. Department of Energy Grid Deployment Office, as all of these offices support model development and analysis that utilizes comparable tools for a wide range of energy and water research questions including asset valuation.

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Abstract

Asset valuation by electric utilities is becoming increasingly difficult in the rapidly changing electric sector. Rapid deployment of variable generation and inverter-based storage systems along with uncertain demand growth, policies, and other factors create a challenging environment for understanding the value proposition of a new potential asset. This report describes an effort between the Tennessee Valley Authority and three U.S. Department of Energy (DOE) laboratories (Argonne National Laboratory, National Laboratory of the Rockies, and Pacific Northwest National Laboratory) to perform a detailed review of utility modeling and analysis practices for asset valuation and to identify challenges and opportunities for advancing its methods into the future. It focuses on a case study of new potential pumped storage hydropower (PSH) because of growing interest in new PSH capacity to provide energy balancing, firm capacity, and a range of ancillary services. Staff from the DOE labs conducted systematic interviews about current practices in capacity expansion modeling, production cost modeling, hydrological modeling, and transmission reliability modeling while also discussing how scenario analysis is conducted and how models and data are integrated. The effort resulted in a set of strategic actions in the areas of models, model integrations, and scenarios that could be valuable to utilities, system operators, and other stakeholders conducting integrated grid analysis. Individual model actions suggest exploring computational trade-offs with detail and resolution across spatiotemporal structure, supply- and demand-side details, transmission overlays, market interactions, and ancillary services. Automated processes to pass data between models and conduct larger scenario suites could also enhance valuation practices. Doing so could enable a more consistent study of asset value across a broader range of uncertain future grid conditions, where PSH could be particularly valuable. Utilities and other industry stakeholders can learn from and adapt applied research-grade methods developed by DOE laboratories and other research institutions to improve decision-making and accelerate progress toward a reliable, secure, and affordable energy system.

Acronyms and Abbreviations

ANL	Argonne National Laboratory
CEM	capacity expansion model/modeling
DERs	distributed energy resources
DOE	U.S. Department of Energy
FERC	Federal Energy Regulatory Commission
IBRs	inverter-based resources
NEPA	National Environmental Policy Act
NLR	National Laboratory of the Rockies
NREL	National Renewable Energy Laboratory
PCM	production cost model/modeling
PNNL	Pacific Northwest National Laboratory
PSH	pumped storage hydropower
PV	photovoltaics
TVA	Tennessee Valley Authority
VG	variable renewable generation

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1.0 Motivation and Context

Electric utility investments in generation, storage, transmission, and other assets must firmly establish the value proposition for those assets relative to the costs. Doing so is especially important for high capital cost assets (i.e., billions of dollars in cost), particularly when the project development can take up to a decade and the asset may operate continuously over 50 to 100 years. Utilities have many valuation tools at their disposal, including both internally developed and commercial tools ranging from spreadsheet cost-benefit calculators to sophisticated optimization-based or other modeling and analysis techniques (EPRI 2024). All tools, models, and techniques have limitations. Although this simple reality is unavoidable, an obvious goal is to mitigate limitations that substantially affect the question being asked—in this case, what is the value of the asset, relative to its cost?

In the rapidly changing landscape of the U.S. electric sector, valuation techniques need to adapt to emerging industry trends. These include accelerated deployment of variable renewable generation (VG); growth in shares of inverter-based resources (IBRs), including solar photovoltaics (PV) and battery storage; demand electrification; rapidly changing regulations; and uncertain future weather conditions (Gagnon et al. 2024; Craig et al. 2018). It can be difficult to quickly modify valuation tools used by industry practitioners to accommodate these trends for various reasons. Proprietary software might lack customizability, exclude specific technology representations, and have a lag in necessary updates. Internal tools are readily modifiable but could still include legacy structural or other challenges (e.g., inflexible spatial and temporal resolution, limited operational detail) to capture emerging trends. Practitioner tools are also often designed to examine an outlook no further than 20–30 years in the future, and often a shorter time frame than that, depending on the decision and asset type (Cooke 2022; Wilson and Biewald 2013). They are often grounded firmly in current technologies, infrastructure, markets, and institutions and implicitly assume these core system characteristics do not change.

On the other hand, research-grade tools are often developed specifically to examine emerging long-term trends that might be beyond typical utility decision horizons. These trends could impact near-term decisions if they accelerate faster than median expectations or demonstrate a risk of stranded assets (Chernyakhovskiy et al. 2021). Uncertainty around the ultimate impacts of new grid technologies, policies, and environmental conditions is a key concern driving grid modeling and analysis research that is fundamental to understanding future asset value (Feng et al. 2023; Scott et al. 2021; Hu et al. 2024). Research-grade tools developed by the U.S. Department of Energy (DOE) national laboratories aim to capture these effects in an applied setting that is actionable for electric sector practitioners and decision makers (NREL 2021; Ho et al. forthcoming; Koritarov et al. 2021; Stephen 2021; Brinkman et al. 2021). These tools might not capture all of the technical and institutional constraints on a given asset, system, or market, so they might not be suitable for final investment and other decisions (e.g., for integrated resource plans). However, they can complement practitioner decisions via expanded and informative scenario analysis.

Considering this alternative focus of DOE laboratory models, researchers at Argonne National Laboratory (ANL), National Laboratory of the Rockies (NLR), and Pacific Northwest National Laboratory (PNNL) engaged with the Tennessee Valley Authority (TVA) in a review exercise to characterize electric utility industry practices and offer perspective on future potential practices for asset valuation throughout the industry.

Valuation improvements might include model parameter or formulation adjustments, tighter model coupling, expanded scenario suites, or changes to financial modeling methods. Valuation of a pumped storage hydropower (PSH) plant is used as a case study based on the particular interest and support of the project. With the potential growth of VG, new nuclear, and carbon capture and storage, flexible

technologies could become increasingly valuable to complement these less-flexible assets (Gagnon et al. 2024; Larson et al. 2021; Steinberg et al. 2023). Valuing utility-scale storage such as PSH is thus an acute interest area for power system planners.

Lessons learned through this PSH valuation exercise could apply to broader storage and asset valuation and be considered among utilities in both market-based and vertically integrated structures. The overarching question this work addresses is: What challenges and opportunities exist in utility power sector asset valuation practices in light of the changing electric sector landscape?

2.0 Methods

The primary method of gathering information for this report was consultation with TVA experts. Laboratory staff worked with TVA to identify key individuals with deep knowledge and experience in the following model classes: (1) capacity expansion modeling (CEM), (2) production cost modeling (PCM), (3) river operations, and (4) transmission reliability modeling. CEM primarily analyzes investment decisions over years-to-decades timescales with limited operational detail. PCM represents detailed operations down to minute-to-hour timescales for 1 or more years to understand bulk supply and demand of energy and ancillary services. Transmission reliability modeling examines subminute behaviors to analyze grid strength along with static and dynamic stability, often including nonlinear behaviors of the power system. River operations encompass hydrological modeling, environmental modeling, river routing, and reservoir operations. Resource adequacy assessment was also discussed briefly and is discussed here in its relationship to other model classes.

Table 1 lists each model type along with the specific models used by lab participants in this effort. There are several other critical stages to the PSH project development and analysis process, including plant design, financial analysis, and transmission analysis, but these are outside the scope of this discussion.

Table 1. Model Types and Models Used by Laboratory Staff

Model Type	Laboratory Model(s)
Capacity expansion modeling	ReEDS™[1], ALEAF[2], GridPath[3], GCAM[4]
Production cost modeling	Aurora[5], ALEAF, PLEXOS[6], Sienna[7], GridView[8], GO[9]
Resource adequacy modeling*	PRAS[10]
Transmission reliability modeling	PSS/E[11], PSLF[12]
River operations modeling	MOSART-WMPY[13], RiverWare[14], ResSim[15]

[1] https://www.nlr.gov/analysis/reeds/.
[2] https://www.anl.gov/esia/a-leaf.
[3] https://www.gridpath.io/.
[4] https://gcims.pnnl.gov/modeling/gcam-global-change-analysis-model.
[5] https://www.energyexemplar.com/aurora.
[6] https://www.energyexemplar.com/plexos.
[7] https://www.nlr.gov/analysis/sienna.html.
[8] https://www.hitachienergy.com/us/en/products-and-solutions/energy-portfolio-management/enterprise/gridview.
[9] https://im3.pnnl.gov/model?model=GOWEST.
[10] https://www.nlr.gov/analysis/pras.html.
[11] https://www.siemens.com/global/en/products/energy/grid-software/planning/pss-software/pss-e.html.
[12] https://www.gevernova.com/consulting/planos/steady-state-power-flow.
[13] https://im3.pnnl.gov/model?model=MOSART-WM.
[14] https://riverware.org/.
[15] https://www.hec.usace.army.mil/software/hec-ressim/.
* While resource adequacy modeling is not discussed separately in this report, it is discussed within the context of capacity expansion modeling and model integration.

For each of the four model types discussed in this report, laboratory staff members asked TVA experts a series of questions to better understand the technical and institutional characteristics of existing practices.

These discussions helped to achieve consensus on limitations and potential areas of improvement. These questions were as follows:

1. What are key data inputs, assumptions, projections, and limitations?
2. What are limitations imposed by model structure?
3. What are limitations imposed by workflow processes?
4. What is the model logic underpinning these approaches?
5. How do evolving grid conditions and needs inform model design and logic?
6. What scenarios are implemented and why? What are the limitations and constraints on scenario choice?
7. How do the model or analysis approaches address risk/uncertainty?
8. How does the model interact with other models/tools, and what challenges/limitations are present in model integration?
9. How is this model integrated into a consolidated multimodel framework?
10. What model limitations limit the capacity for an integrated solution?

The questions were posed within the specific context of PSH valuation but also could be used for broader discussions. In addition to this series of questions, lab staff had additional deep-dive discussions with TVA staff on PCM and hydrological modeling. The PCM discussions examined software-specific challenges in greater detail. The discussions on hydrological modeling practices examined water management changes and operational considerations with a potential new PSH facility.

3.0 Model Review Discussion

Asset valuation involves executing multiple model classes, and valuation practices can be influenced by how models are run individually as well as model interdependencies (Koritarov et al. 2021). These interdependencies can range from one-way data transfer to manual iteration between models to automated model coupling with iteration and convergence criteria. Because there are unique considerations between independent and interdependent model execution, we discuss individual model attributes before addressing model integration practices. We then provide a holistic discussion of scenario exploration strategies across all model types.

3.1 Individual Model Attributes

Models are often characterized by several basic attributes—for example, spatial and temporal scope and resolution, solution method, core assumptions, and formulations of domain-specific aspects such as technology availability and operating constraints. This section examines each of the four model classes included in this study, highlighting challenges and opportunities for several key model attributes related to asset valuation.

3.1.1 Capacity Expansion Modeling

CEM tools are designed to inform investment decisions and typically operate on multidecadal timescales to align with economic lifetimes, that is, the desired time frame to recoup investment costs (Gacitua et al. 2018). These tools typically optimize a least-cost set of investment (and sometimes operating) decisions across a range of possible generation, storage, transmission, and/or other investment classes.

3.1.1.1 Temporal Scope and Resolution

Key model structural decisions must be made around temporal scope and resolution to balance accuracy with computational tractability (Mallapragada et al. 2018; Brown et al. 2024; Levin et al. 2024). For example, one might optimize the CEM over a full 20-year study period representative of an economic lifetime. This full intertemporal optimization ensures a true optimal solution under the given model setup. However, the need to incorporate 20 years of data and constraints could limit model resolution elsewhere or the restrict the ability to include additional features or constraints, such as a more detailed representation of energy storage systems that better demonstrate the value of PSH (Bistline et al. 2020).

Intra-annual time resolution is also important to represent coincidence between load, renewable energy, and operations; one area of increased resolution could be to increase the number of representative days in the model (Brown et al. 2024; Levin et al. 2024). Depending on the approach for defining representative days, it is possible the chosen set of representative days does not accurately capture the distribution of possible operating conditions that would drive the value proposition for alternative technologies, including PSH. Further, critical operating conditions may change over time as variable renewable energy deployment alters net load profiles, making it increasingly difficult to properly value PSH and other technologies across all modeled years (Kaur et al. 2016; Craig and Brancucci 2021). Intra-annual time resolution is also critical for capturing storage energy arbitrage value (Bistline et al. 2020; Sánchez-Pérez et al. 2022; Haas et al. 2017; Frazier et al. 2020). Representative days can capture diurnal arbitrage value that is likely the highest-value near-term opportunity for all storage systems, including PSH. However, energy arbitrage value across multiple days, weeks, or months is not captured, and this longer-term value is one potential advantage PSH has over other storage technologies (Denholm and Mai 2019). The value-

versus-duration relationship is particularly important when making investment decisions about storage assets. Periodic reevaluation of alternative representations of intra-annual time resolution could be important as the storage value proposition and broader power sector evolve.

A limited interannual planning model horizon can also ignore any value of assets beyond the horizon. This limitation is especially disadvantageous to PSH, which, along with other hydropower assets, tends to have the longest physical life among all electricity generation and storage assets (National Renewable Energy Laboratory [NREL] 2023). For example, comparing PSH and batteries over a 20-year life is very different from comparing PSH and batteries over 100 years in which the original PSH asset remains but batteries must be replaced multiple times. The relatively long life of PSH relative to other technologies could be considered by extending the planning model horizon or adjusting its cost of capital based on the weighted average cost of capital for the true physical life (e.g., 100 years) relative to the default 20-year economic life, as was done in the 2016 DOE *Hydropower Vision* (DOE 2016).

3.1.1.2 Load Shapes

Related to the challenges associated with time resolution is the representation of load shape, including the degree of load elasticity and flexibility in response to price or other signals. CEM studies might have difficulty capturing key drivers of PSH value if they are unable to effectively represent demand-side flexibility that competes with PSH flexibility and services. This might entail alternative scenarios and operational constraints governing building and transportation electrification technologies or other distributed resources (Murphy and Mai 2021; Marañón-Ledesma and Tomasgard 2019; Fitiwi and Bertsch 2018; Pfeifer et al. 2018). Demand-side flexibility, such as with large industrial demands or aggregated residential and commercial demand response programs, could compete with supply-side flexibility if it existed in significant quantities, creating more uncertainty in PSH value. Truly addressing this limitation could require rigorous bottom-up load modeling that includes emerging technologies and trends. This issue is discussed more in Section 3.3.2 about uncertainty characterization but is introduced here because CEM is an important starting point to consider alternative and flexible load scenarios.

3.1.1.3 Capacity and Ancillary Service Value

The CEM representation of capacity and ancillary service value, or the lack thereof, is critical to its ability to value flexible technologies such as PSH (Emmanuel et al. 2020; IRENA 2019; Stephen 2021; Frew et al. 2017; Cole et al. 2017). It is first important to consider the changing contributions, typically declining, of VG and storage to resource adequacy requirements as more of these assets are deployed. To represent resource adequacy requirements, utilities or system operators might use a summer and winter reserve margin requirement to capture PSH and other capacity value for resource adequacy. This requirement appropriately estimates changes to variable generation and storage capacity credit, but the requirement remains fixed, based on characteristics of the current system. However, although it is common practice to use a fixed reserve margin requirement for one or more seasons, doing so could either overvalue or undervalue capacity for resource adequacy by not explicitly representing periods of capacity stress within an investment planning framework that spans 20 years or more (Stephen 2021). This is particularly important for future years in which nondispatchable resources are likely to make up a much larger portion of the asset base (Cole et al. 2017). The model integration discussion in Section 3.2 addresses greater integration with resource adequacy models. In the specific context of CEM models, it is important to consider going beyond a reserve margin representation of resource adequacy requirements when considering accelerated variable renewable and storage deployments.

Ancillary services, such as those shown in Table 2, are known to be critical services that PSH is well suited to provide. However, current practices including CEM modeling can be limited in representing the

true value of these services and how this value might change over time. PSH is generally expected to be able to provide the full range of ancillary services in generation mode, and designs with variable or other advanced pumping designs can similarly provide a wide range of ancillary services in pumping mode. Regardless, capacity expansion models (CEMs) can struggle to represent the true value of these services. For example, using fixed requirements for reserve services over time and changes to grid topology ignores the potential for greater ancillary services needs because of the growing absolute magnitude of forecast error as variable generator deployment continues. Bulk power services and ramping can be represented within the spatial, temporal, and operational resolution and detail of the model, but this does not often capture full plant capabilities. Other services might not be represented at all and might have no well-defined economic value in practice despite their importance to grid reliability and resiliency. Further, CEMs are not generally set up to represent necessity and impact of deploying ancillary services in response to disruptive events that could change in frequency or intensity. Table 2 summarizes a taxonomy of services along with valuation challenges in the context of CEM modeling.

Table 2. Ancillary Services Treatment and Fitness for Present and Future Grids

Category	Service	PSH Valuation Challenge in CEM
Bulk	Capacity	Typically limited to reserve margin constraint with separate resource adequacy modeling
	Energy	Inadequate resolution and operational representation
Frequency response	<1 s	Not typically represented
	1 s to 30 s	Not typically represented
	30 s to 5 min	Not typically represented
Reserves	Spinning	Often a fixed requirement
	Non-spinning <15 min	Often a fixed requirement
	Non-spinning >15 min	Often a fixed requirement
Ramping	Up	Inadequate resolution and operational representation
	Down	Inadequate resolution and operational representation
Voltage	Volt/VAR control	Not typically represented
System restoration	Black start	Not typically represented

min = minute; s = second.

Although the true relationship between variable renewables and ancillary services requirements is uncertain, techniques exist to approximate it within CEMs (Lew et al. 2013). New constraints could also be considered to better capture PSH value for maintaining grid strength and stability. For example, IBR deployment (including battery storage) could drive a requirement for technologies that provide inertia and ride-through capabilities. Ancillary services representation in CEM is an ongoing research topic but remains important for consideration by practitioners responsible for investment decisions involving multidecadal assets (Denholm et al. 2024).

Another aspect of capacity and ancillary services value is the relationship between transmission and other generation/storage/demand resources for service provision. This relationship and its effect on investment decisions could be best understood by representing transmission endogenously within the CEM. A transmission overlay within the CEM would enable it to capture potential value of PSH for alleviating

transmission congestion and reducing transmission investment needs (Brown and Botterud 2021; Tröndle et al. 2020; ESIG 2022). It would also incorporate costs and constraints consistent with realistic transmission expansion timelines and restrictions. Then an analyst could use CEM to explicitly investigate how new PSH can reduce transmission investment needs, especially in scenarios with spatial concentrations of variable renewables or a rise in distributed energy resources (DERs). A CEM transmission representation would enable an endogenous understanding of the trade-offs between generation, storage, and transmission technology choice and location. There is a trade-off between transmission detail and computational tractability, and this trade-off could be explored with various levels of transmission aggregation.

3.1.1.4 Strategic Actions

The following are strategic actions to consider in capacity expansion modeling:

1. Compare valuation results under alternative PSH economic lifetimes closer to the true physical life of the asset.
2. Perform sensitivity analysis considering alternative temporal scope and resolution to better understand accuracy-tractability trade-offs and how they affect solutions, including PSH value.
3. Consider alternative choices for representative days that better capture changes to net load profiles over time and enable representation of storage arbitrage value beyond diurnal scales.
4. Develop CEM capabilities to represent flexible loads that might compete with PSH for providing grid services.
5. Account for changes in ancillary services requirements with variable renewable deployment, and value all services appropriately.
6. Study the impact of incorporating transmission constraints within the CEM, starting from a coarse zonal aggregation.

3.1.2 Production Cost Modeling

Production cost models (PCMs) are designed to simulate detailed operations for a fixed set of system resources without considering potential resource additions or retirements (Stoll et al. 2016; Diakov et al. 2015). They are typically operated at time intervals of 5 minutes to 1 hour and capture the operating behavior of individual units or power plants. Typically, these models minimize the cost of system operations over a specified time horizon, often 1 year, while considering detailed plant-level constraints on energy, capacity, ramping, and other operational characteristics. In addition to modeling unit dispatch, PCMs may also optimize unit commitment decisions for individual resources, or they alternatively may rely on commitment heuristics or assumptions to limit computational burden. Transmission systems may be represented through any of three primary approaches, with increasing computational requirements: (1) an unconstrained copper-plate representation that does not consider transmission constraints, (2) a “pipe-and-bubble” representation that determines transmission flows on individual lines to balance supply and demand in each load zone, and (3) a full direct current optimal power flow representation that uses physical laws to calculate transmission flows based on zonal or nodal generation and load (U.S. Department of Energy 2024). Key model inputs include hourly demand projections, fuel prices, and unit cost and performance characteristics.

3.1.2.1 Temporal Scope and Resolution

Hourly simulation over the full model horizon is one approach, given sufficient computational resources. Although this configuration is effective at producing intertemporal least-cost solutions for a given simulation, it has similar implications on PSH valuation as with CEM models. Optimizing over the full horizon could strain computational capacity and prevent modeling teams from considering greater detail elsewhere, such as in the operational detail of PSH and other storage systems or spatial disaggregation of generation and transmission assets (Stoll et al. 2016; Akdemir et al. 2024). For example, certain technology types such as wind, solar, and hydropower might be aggregated, which limits the accounting of variability of renewable resources in evaluating the PSH operation. Depending on the model horizon, it might also preclude any consideration of longer time scopes (30 years or longer) that span a realistic physical lifetime of PSH facilities.

Depending on the length of current model runtimes, it might be useful to consider alternative temporal scope and resolution that explores trade-offs between optimizing across long time horizons and expanding scope or detail in different areas (Stoll et al. 2016; Akdemir et al. 2024). For instance, several sequential 5- or 10-year simulations could allow better technology or other representations with an acceptable deviation from a 20-year optimum. Alternatively, or in addition, a large set of individual single-year production cost runs might be considered to explore a broader range of scenarios—for example, to explore the impacts of variations in weather profiles without necessarily capturing multiyear sequential progression. Deviations could be tested with equivalent model configurations and different temporal scopes.

3.1.2.2 Transmission Representation

Another important consideration for future PSH valuation and PCM in general is the representation of power flows within the service area and between external service areas. Historically, transmission system capacity planning has often taken place downstream from generation planning, which often assumes sufficient transmission capacity to justify ignoring transmission constraints in PCM simulations. However, as the system continues to evolve, and new variable renewable generation resources are introduced further from load centers, transmission usage patterns may change substantially (Medina et al. 2022). In particular, transmission congestion may become increasingly impactful and therefore not prudent to ignore in PCM.

Including transmission in PCM could better demonstrate the value of PSH and other assets for alleviating future potential transmission congestion or better management of resources. One example of improved resource management could be reduced variable renewable curtailment, which could exhibit more value when representing realistic transmission constraints given the potential concentration of variable renewable generator deployments to specific areas with high resource quality (Jorgenson et al. 2022). In general, congestion relief can facilitate more efficient use of low-cost generation resources, and PSH could thus play a role in most cost-effective generation and transmission operation.

3.1.2.3 Imports and Exports

Power flows between a given service territory and other service territories might use an aggregated representation because of legal and/or jurisdictional boundaries. For example, the PCM might represent only one or a few external resources that can be called up to help serve demand with prices and available quantities that vary hourly. These prices are determined through an external electricity market price forecasting process, which does not include extensive sensitivity analysis. This formulation can be effective at representing present-day contracts and constraints, but it does not consider how external

markets and providers might change over time and how that would affect broader power exchanges throughout an interconnect.

One possible enhancement would be to separate the current single external market representation into multiple customers, each representing the physical or legal constraints on a different customer or region, then allowing for the possibility of expanded trade with external service providers. Another option would be to consider additional external price scenarios, either for the current single external market framework or in conjunction with expanded external representation. These enhancements could help to reveal scenarios in which PSH holds more, or less, value than when only a single external market is represented (Anwar et al. 2022).

3.1.2.4 Distributed Energy Resource Representation

A separate but related challenge is the representation of power flows and trade with owners and aggregators of DERs, which could include solar PV, batteries, or electric vehicles. A utility might not model these resources explicitly because of their historical low market share and the lack of any direct authority or control, but increased adoption could impact the bulk power system (Yip et al. 2023). The quantity, location, and flexibility of DERs can affect the value proposition of PSH from the perspective of energy balancing, reserve capacity needs, and managing grid stability (Ahmadi et al. 2021; Kang et al. 2017; Quint et al. 2019). The challenge of accounting for growing DER adoption also relates to spatial resolution and transmission representations, where additional detail could become more important as DER adoption increases.

3.1.2.5 Ancillary Service Value

PCM tools typically are better able to represent ancillary services markets and value than CEMs can. However, they still must simplify these into model formulations that do not represent the nuances of real-time grid operation and short-term stability and dynamics (Brinkman et al. 2021; Energy Exemplar 2024a). Fixed ancillary service requirements are typical. Often these constraints are nonbinding and relatively easy to satisfy with traditional thermal resources. Thus, they do not produce a shadow price or explicit market value. Therefore, there has been minimal need to consider providing them with PSH resources. However, emerging trends suggest increasing deployment of variable renewables and thermal resource retirements without equivalent replacement (e.g., coal) could increase the need for and value of ancillary services that PSH is well suited to provide. Specifically, fixed-speed PSH, currently used exclusively in the United States, cannot provide regulation reserves while operating in pumping mode. Traditionally, this has not been a limiting factor because of the abundance of other resources providing this service. As this dynamic changes and variable-speed pumping becomes a more attractive value proposition, it may be prudent to revisit these constraints through informed modeling (Viola et al. 2024; Ela et al. 2019). A key consideration for future modeling efforts is therefore capturing how system reserve requirements may change as the generation portfolio evolves (Lew et al. 2013).

To address these emerging challenges, utilities might consider developing a new tool to determine ancillary services requirements as a function of variable renewable energy deployments. For example, the ReEDS CEM uses literature-derived relationships between variable renewable deployments and ancillary services requirements, and these relationships are passed along to PCM models downstream (Lew et al. 2013). Similarly, the PCM used for the North American Renewable Integration Study calculates ancillary services requirements considering wind and solar resources uncertainty with regional heterogeneity (Brinkman et al. 2021).

Utilities might also consider representing additional reserve or ancillary services products within the PCM or in a complementary analysis. Competitive electricity markets in the United States include a wide range of services for response times ranging from 30 seconds to 30 minutes, and some, like the California Independent System Operator and Southwest Power Pool, also have ramping products. Although vertically integrated utilities would not operate markets for these services, it might consider how their inclusion in its operating procedures and modeling might affect economic and reliable operations. This could be explored in PCM by testing new constraints, which could show the potential value of including such constraints in operations and of the flexible technologies like PSH that can effectively satisfy them (Ela et al. 2019; Viola et al. 2024). Utilities could also conduct analyses to assess how changing the operating constraints that limit PSH ancillary service provision could impact system costs in different future generation portfolios (Cohen and Mowers 2022; Stark et al. 2023; Koritarov et al. 2014). A simpler approach could be to supplement PCM-derived value with a presumed value of additional services using prices or compensation charges from other systems (Viola et al. 2024; Gilmore et al. 2024; Almetwally et al. 2024). This approach could be more appropriate for services such as voltage support or black start capability.

3.1.2.6 Platform Challenges

All modeling platforms have limitations associated with core model structures. One challenge with commercial software is these structures might not be obvious, observable, and modifiable. For example, software might automatically relax physical constraints such as ramp limits or minimum run times using penalized slack variables. This practice can improve solution feasibility in the model but also produces unrealistic operating conditions. Specifically, if the model allows greater operational flexibility in other resources than is physically possible, it could underestimate the value of PSH for providing grid flexibility.

One option would be to work with the software developers to increase certain slack variable cost penalties to prioritize enforcement of certain operational constraints. This practice could introduce scaling issues and increase run times, but the computation cost may be worth the improved accuracy (Chen et al. 2010; Stark et al. 2023). Incorporating postprocessing procedures that enforce physical feasibility and adjust the model dispatch outputs accordingly might also be considered, but these can be hard to implement, and it could be difficult to anticipate what manual feasibility checks are necessary before errors occur (Stark et al. 2023).

PCMs might also be unable to distinguish between fixed- and variable-speed pumping PSH plants. This capability is important for capturing PSH value; however, specifying constraints that require fixed-speed pumps to pump at maximum capacity or allow variable-speed pumps to supply regulation reserves while pumping has been shown to create computational difficulties while still failing to represent realistic PSH operations (Cohen and Mowers 2022; Koritarov et al. 2014; Stark et al. 2023). This challenge alone reflects strong structural uncertainty around the model's estimation of PSH value, particularly if ancillary services market value grows with variable renewable deployment. Improving the distinction between fixed-speed PSH, variable-speed PSH, and other flexible storage and generator technologies will be important for accurately estimating the value of new PSH resources.

3.1.2.7 Strategic Actions

The following are strategic actions to consider in production cost modeling:

1. Perform internal analysis to study the implications of alternative temporal scopes, then study computational trade-offs between temporal scopes and other model configuration choices.
2. Test the impacts of explicitly representing a transmission system at zonal or nodal resolution along with additional options for capturing interactions with neighboring entities.
3. Consider disaggregating traded electricity to consider multiple specific customers, including DERs.
4. Work with PCM commercial vendors to develop methods to prioritize individual operating constraints if they are not inherently strictly enforced by the tool.
5. Improve ancillary services representations to consider growing reserve requirements with variable renewable deployments and additional or alternative service requirements.
6. Study methods to better differentiate fixed-speed versus variable-speed PSH operations in PCM models.

3.1.3 Hydrological Systems Impacts Modeling

New PSH can have several types of site configurations, with one distinction being open-loop versus closed-loop. Open- and closed-loop PSH have different impacts on hydrological systems that require differences in the focus of their impact assessment. Open-loop PSH is continuously connected to a flowing body of water, and impact assessments primarily address water quality, water quantity, and aquatic resource impacts on surface water systems. Hydrological system impact assessments from add-on PSH, that is, PSH created through adding an upper reservoir to an existing lower reservoir, are also focused primarily on surface water quantity, water quality, and aquatic biodiversity, although water quality impacts of constructing the new reservoir are also important. Unless otherwise noted, open-loop PSH is hereafter inclusive of add-on PSH.

Closed-loop PSH, which relies on reservoirs that are disconnected from flowing rivers, has assessments with greater focus on groundwater than open-loop PSH. However, closed-loop PSH that uses an existing river or stream for initial reservoir fill and evaporation make-up water will also require assessment of surface water impacts (Saulsbury 2020; Pracheil et al. 2025).

Although surface and groundwater quantity and quality and aquatic resource impacts are important to assess for construction and operation of all types of PSH, additional impact categories will eventually be assessed as part of National Environmental Policy Act (NEPA) requirements that must be met as part of the Federal Energy Regulatory Commission (FERC) licensing or federal hydropower development process. Additional categories assessed as part of NEPA include cultural resources, geology and soils, terrestrial resources, recreation and land use, threatened and endangered species, socioeconomics, and air quality and noise (Saulsbury 2020; Pracheil et al. 2025). State and federal impact assessments beyond those required by NEPA may also be required as part of water quality, historic property, and other regulations.

Because of their integration with flowing rivers, open-loop PSH operations may have water-level fluctuation impacts in downstream reaches and reservoirs from timescales ranging from minutes to multiple days. Those interactions can propagate into impacts on hydropower production and scheduling, water temperature and dissolved gas concentration, recreation, and infrastructure such as municipal drinking water and cooling water intakes (Saulsbury 2020). From an aquatic ecology perspective, fish and other aquatic biodiversity can have diurnal to seasonal changes in movements, habitat use, and life stage

distribution that may be disrupted by short-term fluctuations in downstream reservoir elevation as well as local changes in stream temperature and dissolved gas from PSH water releases. For example, fish that move over the course of the day from deeper to shallower water or from cove habitats to the main body of the reservoir may become stranded as the downstream reservoir elevation changes during pumping (Bozeman et al. 2025) or entrained into the upper reservoir (Mathur et al. 2018). Changes in reservoir/river elevation where the pumping and releases occur may also mean that recreational anglers and boaters will navigate a changing water level throughout the course of a day as some underwater hazards may become visible, safe to pass over, or submerged and a navigation hazard.

Published reports provide a comprehensive overview for investors exploring whether a closed-loop (Pracheil et al. 2025) or open-loop (Saulsbury 2020) project might be more cost- and time-effective for getting the state and federal permits (e.g., FERC preliminary permit), certifications (e.g., § 401 Clean Water Act certification), and licenses (FERC license) required for PSH construction and operation (Levine et al. 2021). However, integrated power system, hydrological system, and natural resource impact assessments that consider a range of water availability and power demand scenarios are not currently part of these requirements yet are essential for understanding the viability of developing a PSH site. Moreover, because there is no single tool available that can address all the needs of an integrated hydrological system impact assessment, a team of experts will likely be required for its completion. Below, we provide strategic actions for performing such an integrated PSH-hydrological system operation impact assessment. These actions are designed with open-loop PSH in mind because they have the greatest interaction with the rest of the hydrological system, although they are largely applicable to closed-loop PSH as well.

Assessing impacts of a PSH system can be performed in three stages. In Stage 1, the impact on the surface water system can be evaluated with the PSH intended operations (typically price following or peak load shaving), without any change to existing hydrological system operations. This assessment provides a benchmark for the cost of PSH operations on aquatic resources and river services, including hydropower operations. It also provides information needed for designing appropriate mitigations, particularly flow requirements such as reservoir elevation requirements or PSH pumping or generation restrictions.

The second and third stages of the assessment are performed as needed, depending on the outcome of Stage 1. Stage 2 considers assessing hydrological system impacts of the proposed PSH operations on the aquatic resources and river services under one or more potential flow mitigation scenarios. In this way, Stage 2 of the assessment provides a benchmark for evaluating the minimum cost of the intended PSH operations.

If costs of PSH operations determined in Stage 2 are not acceptable, Stage 3 includes a reoperation of both PSH and the hydrological system, which can be performed as a co-optimization or iterative process. Proceeding from Stage 1 directly to Stage 3 might appear reasonable, with the caveat the computational cost of co-optimization and iterations typically does not support a thorough evaluation of all aquatic resources and river services in the process. The Stage 2 benchmark is essential to assess the influence of the mitigation revenue and power system outcomes performed by the optimal co-optimized reoperation of the hydrological system.

For the Stage 1 evaluation, an operational river routing and reservoir operation model from the institution operating the river can be leveraged. Typically, the models do not represent all aquatic resources and river services such as water quality, recreation, and biodiversity, and additional analysis is necessary. For Stage 2 evaluation, a reoperation of the hydrological system under mitigation scenarios can be an intensive process depending on the capabilities of the initial model. Stage 3 is the most computationally intensive

and interdisciplinary effort, prone to results that depend on the representation of hydropower operations and scheduling (Stark et al. 2023).

3.1.3.1 Strategic Actions

The following are strategic actions to consider in hydrological systems impacts modeling:

1. Focus PSH impact assessments on the integration among hydrological systems, aquatic resources, and river services, by first identifying permitting requirements in terms of metrics and analytical resources needed for their evaluation.
2. Use a three-stage process that provides best practices in assessing, designing, and reporting on the impacts of PSH operations under multiple water availability and power system scenarios.

3.1.4 Transmission Reliability Modeling

Several factors are driving increased concerns over weakening grid stability and strength in certain regions. These factors include large and potentially concentrated IBR deployments, retirements of large fossil fuel plants such as coal, and large loads including PSH in pumping mode. Given broad connectivity across the Eastern Interconnection, frequency stability is not an urgent problem in the eastern United States (NERC 2023). However, in the eastern load center, fossil fuel plants are planned to retire soon, whereas renewable energy development will be located mainly in the western region. This uneven geographic distribution between the load and new generation limits the ability of reactive power generated in the west to support the eastern grid, with voltage sag and stability being the primary issue (TVA 2023). Meanwhile, in existing dynamic model libraries, there is no robust variable-speed PSH model, hindering the understanding of this advanced technology's role in supporting voltage stability. These issues could be exacerbated in other interconnects with smaller systems or more geographically sparse generation assets and loads.

PSH operations in general might undergo significant changes. Traditionally, PSH systems have been used for load leveling—pumping water during off-peak hours and generating electricity during peak demand to help stabilize the grid. However, with the continued expansion of renewable energy, particularly solar, PSH operations will need to adapt to new net load patterns. For example, PSH may need to shift to pumping mode during peak solar generation to absorb excess low-cost energy midday, partially because of power purchase agreement terms that can reduce the financial incentive to curtail excess solar generation or otherwise limit operational flexibility (Denholm et al. 2010; Ela et al. 2013; Koritarov et al. 2014). Because of this shift in PSH operations, stability scenario design will become more complex, requiring the implementation of not just peak load scenarios but also high IBR scenarios, such as solar, wind, and batteries (MISO 2021). During high IBR scenarios, net load decreases, and more traditional generators that provide voltage support may be offline. This highlights the need to explore and value how variable-speed PSH can be used to provide voltage support under these conditions.

As the grid's stability margin declines with the transition to renewable energy, a more integrated approach is becoming increasingly necessary. Conducting stability scenario design and analysis only during the dynamic simulation stage is insufficient because the available resources for stability support are limited by the type and location of online generators. Incorporating new transmission reliability constraints into the planning and operation stage can help improve system strength and stability (Chu and Teng 2023; Gao et al. 2023; Wogrin et al. 2020; Ullmark et al. 2024). Variable-speed PSH with the advanced PSH technology can play a crucial role in meeting these reliability requirements effectively, making it increasingly important to represent the operational differences between fixed- and variable-speed PSH in all model classes. This would include transient stability analysis of contingency events to understand

system needs and study active and reactive control strategies for variable-speed PSH. Examples include doubly fed induction generator technologies that provide fast power control using a power converter while the turbine governor controls rotational speed with the gate position. Following contingency events such as a generation loss, this fast power control capability can offer superior transient performance compared to a conventional synchronous machine unit.

3.1.4.1 Strategic Actions

The following are strategic actions to consider in transmission reliability modeling:

1. Analyze grid stability in scenarios that include peak load, high IBR deployment, and alternative PSH operation modes.
2. Compare the contribution of fixed-speed versus variable-speed PSH to grid frequency and voltage response under a range of contingency scenarios.
3. Conduct transient stability analysis across contingency scenarios to identify frequency and voltage support needs that can be used to validate device-specific dynamic stability performance and develop effective control strategies.
4. Incorporate transmission reliability considerations endogenously into CEM planning and PCM operation model stages—for example, by adding requirements for frequency or voltage services, or developing heuristics that require reliability-oriented operational constraints (e.g., must-run) at certain load or other grid conditions.

3.2 Model Integration Practices

Grid modeling tools of varying scales and scopes are often used together to provide a more comprehensive integrated picture of current and future grid planning and operations (Brinkman et al. 2021; DOE 2024; Cochran 2021). This practice allows for the study of a greater set of analysis questions so that decisions are better informed and there is greater confidence in the accuracy and robustness of results. Figure 1 is a model process flow diagram showing several possible ways model components discussed in this report could be linked. A major challenge with model integration, however, is achieving consistency across different models of varying scope, resolution, and structure (Iyer et al. 2019). Different models use different data in different formats and represent physical systems in different ways, depending on their structure, features, and computational tractability. Achieving consistency across models thus entails manual or automated data transfer processes that can proceed in one direction or establish feedback loops (Iyer et al. 2019; Vorosmarty et al. 2017; Mongird and Rice 2024).

The next several subsections discuss various ways in which CEM, PCM, river operations, and transmission reliability models are integrated into cohesive workflows and how these workflows might evolve to support PSH valuation and any other integrated grid analysis. We begin with discussing water-energy connections in grid modeling because of the unique characteristics of hydropower and water-energy interactions. Then we more generally discuss one-way workflows and model feedback, in which the latter could involve one or more iterations.

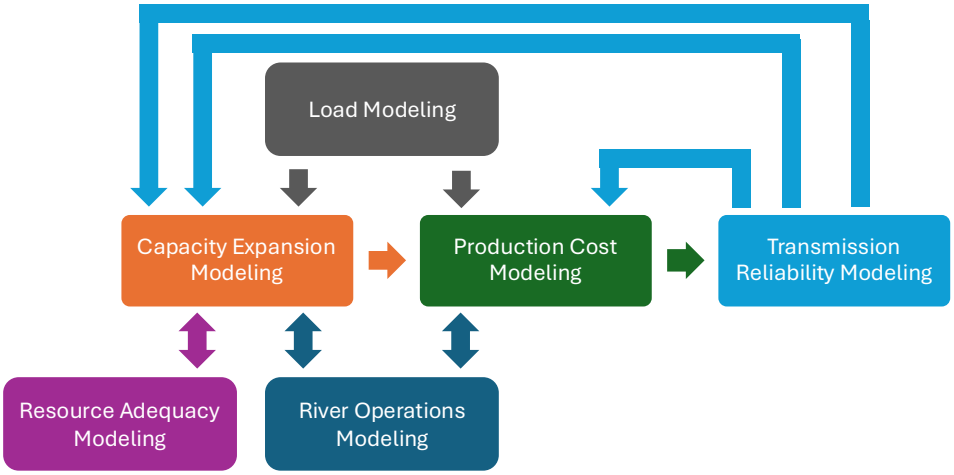

Figure 1. Diagram showing several possible one-way model workflows and feedback

3.2.1 One-Way Workflows

One-way workflows in integrated grid planning typically involve CEM simulations that inform future infrastructures to simulate in PCM (Cowiestoll and Frazier 2022). Transmission reliability modeling could also be conducted downstream from CEM and PCM modeling using future infrastructure information from the CEM (DOE 2024). Other tools such as load forecasting, resource adequacy, or resource potential models can also exist upstream or downstream from CEM-PCM workflows, depending on whether they are being used to inform CEM or PCM data or constraints or evaluate CEM or PCM outcomes (Stenclik 2024; Maclaurin et al. 2021; Mai et al. 2018).

3.2.1.1 Capacity Expansion Modeling to Production Cost Modeling

Typically, infrastructure results from a CEM can be used to create PCM model inputs, but this is often a largely manual process. In practice, this process can be time-consuming to maintain fully consistent datasets and assumptions for both models and transfer data from CEM to PCM with any necessary data expansions. Although effective at creating consistency in the generation fleet between CEM and PCM models, the required time prevents resources from being used in other areas, such as expanded scenario analysis or improving base model formulations. It also inherently limits the degree to which integrated modeling studies can iterate as study needs evolve.

Increased automation and model choice are two strategies to reduce CEM-to-PCM conversion time. Although automation is initially a high-effort (and thus costly) endeavor, it could lead to substantial improvements in workflow efficiency that enable orders of magnitude of more scenarios to be explored (Cowiestoll and Frazier 2022). Although considering more scenarios means more data to process, it can lead to more robust decision-making under uncertainty, particularly in a dynamic system like the electricity and broader energy system. A downside to automation is the need to maintain any automation tools so that they stay compatible with both upstream and downstream models. However, automated translation could be developed incrementally (e.g., start only with generating unit data). Effectively developing and maintaining CEM-to-PCM translation tools could allow utilities to perform internal analysis with scopes on par with the NREL Standard Scenarios and Cambium datasets (Gagnon et al. 2024), which in 2023 included 70 CEM scenarios and 8 PCM scenarios in 5-year intervals between 2025

and 2050. Expanded scenarios could be important to better identify the relationship between key system drivers and PSH value.
Simply choosing models that combine CEM-PCM capabilities or have built-in CEM-to-PCM conversions could also greatly expedite workflows but at significant upfront cost (Bonaldo et al. 2024; Energy Exemplar 2024b). Many commercial tools and open-source research-grade tools have sufficient flexibility to define a solution space that spans both planning and operational horizons (Energy Exemplar 2020; Bonaldo et al. 2024; Energy Exemplar 2024a; NREL 2024). This level of flexibility and integration can become increasingly important as emerging technologies such as variable renewables, distributed resources, electrified transportation, and storage create greater uncertainty in the future of the grid. Changing tools and processes creates substantial challenges from a staff training and capability perspective, but these challenges can be weighed against the benefits.

3.2.1.2 Informing Transmission Models

Transmission models designed to evaluate grid deliverability, reliability, strength, and stability must use nodal generation and transmission information, and upstream CEM-PCM models might not have such resolution. Downscaling a future generation and transmission infrastructure for use in a nodal transmission reliability model is a challenging process that involves substantive engineering judgment around asset siting while also identifying critical reliability periods (DOE 2024; Kuna et al. 2024). Without nodal resolution in CEM and PCM models, any detailed transmission system expansions must be considered downstream from CEM and PCM work and thus cannot influence least-cost planning and operations solutions. This practice increases uncertainty around the cost-optimal way to site new transmission assets and limits the understanding of how transmission constraints and costs can influence the value proposition for new PSH and other assets. It also prevents insights into how transmission constraints and reliability needs might influence siting of PSH and other facilities (Wiedemann and Adjiashvili 2022; Jayadev et al. 2020; Zheng et al. 2024). As grid stability becomes a greater concern with retiring thermal generation and increased deployment of variable renewables and inverter-based battery storage, it becomes increasingly difficult to confidently plan and study new transmission needs after decisions are made upstream on generation investments.

If CEM and PCM tools include transmission constraints, even at an aggregate level, these can help inform scenarios for future nodal transmission systems to study in grid stability and other high-resolution transmission models (DOE 2024; Jayadev et al. 2020; Zheng et al. 2024). In the context of PSH, this could substantially help establish PSH value for providing grid reliability services, or it could identify siting trade-offs by showing where the PSH might improve or degrade grid stability under alternative scenarios (Koritarov et al. 2021; Prasasti et al. 2024; Zhao et al. 2022). Even if engineering judgment and heuristics remain necessary to convert from an aggregate to a nodal transmission representation, the improved one-way workflow from CEM/PCM to transmission models can facilitate more robust analysis.

3.2.1.3 Other Model Connections

Grid models are often informed by a wide range of other specialized models and data tools to populate the breadth of required input data. Here we focus on two: long-term load forecasting and resource adequacy assessment.

Load forecasting is necessary to project the quantity and profiles of future electricity demand. The shape of the load curve over various timescales (diurnal, interday, interweek) is critical to estimating the value of energy storage assets, especially large-scale assets such as PSH (Sánchez-Pérez et al. 2022; Sepulveda et al. 2021; Denholm et al. 2021). Load forecasting is also becoming increasingly difficult because of uncertainties in data center load growth, transportation and building electrification, and DERs. Each of

these technologies changes the load shapes observed at the substation level by the utility (Sigrin et al. 2016; Mai et al. 2018; Hale et al. 2018; Willems et al. 2022). In addition, some electrified loads provide opportunities for aggregation and centralized demand response management (Obi et al. 2020; Riaz and Mancarella 2022; Eid et al. 2016). It is unclear how flexible loads will interact with PSH and other flexible assets, but there is potential to influence the PSH value proposition. Expanded scenarios for future load growth and load profiles could lead to new insights into PSH value and other planning decisions.

Resource adequacy modeling is used to test the ability of a grid infrastructure to serve load under a large sample of outage conditions and other uncertain grid conditions (Stephen 2021; Alberta Electric System Operator 2017). These models can be used downstream from CEM tools using a projected future infrastructure. Alternatively, they could be used upstream with a given infrastructure to help determine the capacity reserve margin a CEM should use to ensure it plans a system that meets resource adequacy requirements (Kuna et al. 2024; Stephen and Kirschen 2024). Utilities might use resource adequacy models to inform the reserve margin requirement in their CEM. Although this one-way process may have been effective to date, the growing deployment of variable renewables and storage complicates resource adequacy estimation that must now consider forecast uncertainty of renewables and storage energy limits on top of load uncertainty and asset availability. There is thus a risk the reserve margin used in CEM misrepresents true stress periods for meeting load. This is important for PSH valuation because capacity value for resource adequacy can be a major driver of storage value (Sodano et al. 2021; Frew et al. 2018). It is thus important to consider the uncertainty around an appropriate reserve margin requirement or if the current approach to specify a reserve margin in CEM is appropriate for the expected future grid composition. The next section on model feedback elaborates further on how CEM and resource adequacy models could interact.

3.2.1.4 Strategic Actions

The following are strategic actions to consider when exploring one-way workflows:

1. Conduct cost-benefit analysis to decide if resources should be committed to automating data translation processes between models or using models that are more integrated or flexible.
2. Consider methods for representing endogenous transmission expansion within CEM and PCM tools to create more robust grid topologies to study PSH value for providing transmission reliability services.
3. Identify key data workflows upstream from grid models (e.g., load, resource adequacy) and use them to develop scenarios for alternative data and assumptions to use across models.
4. Expand resource adequacy modeling to consider a broader range of possible grid configurations and events that might occur over the operating lifetime of the PSH facility.

3.2.2 Model Feedback Loops

Feedback over one or more iterations enables increased consistency across models while allowing the broader modeling suite to better optimize its objective, given the full breadth of features available across all models. However, this often comes at substantial computational expense and upfront cost to design data transfer and other procedures for iterating through one or more model linkages (EIA 2023; Caron et al. 2018; Mongird and Rice 2024; Reed et al. 2022). In practice, feedback often occurs informally through lessons learned from one model that helps inform future use of another. Here we discuss ways feedback might be considered solely from a technical perspective; this report does not discuss the potential for organizational strategies to facilitate cross-model feedback.

3.2.2.1 Transmission Reliability To Inform Resource Planning

A key challenge to the field of integrated grid modeling is incorporating transmission reliability and grid stability considerations into long-term planning and operations modeling. Doing so is becoming increasingly important as the grid evolves toward variable renewables and storage while retiring thermal generation and dealing with challenging constraints on transmission asset expansion (DOE 2024; Lew et al. 2021; Lin et al. 2022). In practice, transmission management has a substantial effect on grid dispatch and operations, particularly PSH that provides many reliability services, such as voltage support and frequency regulation, which are not explicitly represented in CEM or PCM tools (Koritarov et al. 2021). If they were, it would enable a more complete picture of the range of services that PSH provides and enable a more balanced examination of optimal asset investment strategies.

Although it could be extremely difficult to tightly couple transmission reliability models with CEM or PCM, it could be beneficial to incorporate transmission reliability analysis earlier in the grid modeling workflow and consider how infrastructure plans may be modified to account for stability results. For example, cost-optimal CEM might favor large-scale battery deployment, but this outcome might create stability concerns with unexplained battery trips during disturbance events (Grid-India 2023; Xie and Shair 2024). The CEM does not represent these events or grid behaviors, but it could consider a cost or performance penalty (or benefit) by technology to reflect their impact on grid stability (Ullmark et al. 2024; Wogrin et al. 2020; Chu and Teng 2023; Gao et al. 2023). Including a transmission overlay in CEM or PCM could enable other options for using transmission reliability models to inform transmission constraints, particularly if any transmission expansions are then included in transmission reliability models to assess the combined impact of transmission and other assets such as PSH. In a high-variable renewable, high IBR future, transmission reliability analysis has a key role to play in investment decisions.

3.2.2.2 Capacity Expansion Modeling–Production Cost Modeling Coupling

If efficient one-way workflows are established from CEM to PCM modeling, PCM outcomes could be used to better parameterize the CEM (Mongird and Rice 2024; Mansouri et al. 2022; Iyer et al. 2019). CEMs typically have a coarser representation of operational parameters and constraints than PCMs, meaning there could be discrepancies between intra-annual dispatch results that are critical for establishing energy, capacity, and reserve value for PSH and other resources. If operational outcomes diverge enough between PCM and CEM, particularly at the new PSH facility being evaluated, it could be important to consider how the CEM configuration might be adjusted to better match the more detailed PCM operating results. Iteration between the two could then achieve an acceptable level of convergence to foster confidence that the investment decisions in the CEM are fully consistent with the detailed operating decisions in the PCM (Mansouri et al. 2022).

3.2.2.3 Dynamic Resource Adequacy Requirements

The previous section on one-way feedback discussed how stochastic resource adequacy models can be used to inform CEM capacity reserve margin requirements. Resource adequacy models, however, use an exogenously defined infrastructure configuration that could be updated with results from a CEM. There is thus an opportunity for feedback between the two model types, where the resource adequacy model could inform any resource adequacy (e.g., reserve margin) constraints in the CEM with an initialized infrastructure, then performance of the resulting CEM infrastructure could be checked in the resource adequacy model (Kuna et al. 2024; Stephen and Kirschen 2024). If unserved energy or other metrics violate standards, the resource adequacy model could then be used to update CEM parameters or

constraints to facilitate improved performance. This process could repeat until the CEM infrastructure meets resource adequacy standards.

This iterative process could proceed in multiple ways. The resource adequacy model could simply update the reserve margin requirement in the CEM. Alternatively, the resource adequacy model could be used to identify which time periods across a multiyear stochastic dataset should be considered "stress periods," in which resource adequacy is difficult to maintain (Kuna et al. 2024). These stress periods could then be included explicitly in the CEM along with any necessary reserve margin to ensure resource adequacy in those periods. Stress periods can vary over time and location with the deployment of variable renewables, storage, and other grid assets, so any coupling framework must allow for this flexibility. Enabling dynamic resource adequacy requirements in a CEM would require substantial time and cost to develop efficient data transfers between the two models. However, it would ultimately allow a better understanding of the value of PSH in satisfying resource adequacy requirements and result in a more reliable system.

3.2.2.4 Strategic Actions

The following are strategic actions to consider when exploring model feedback loops:

1. Identify ways to incentivize or disincentivize technology investments and operation in CEM and PCM to reflect their impacts on grid strength stability. This may involve model coupling or modified workflows that include transmission reliability analysis at an earlier stage.
2. Compare model operational outcomes between PCM and CEM tools to determine if they are sufficiently consistent across temporal and spatial scales, or if feedback should be considered to facilitate greater agreement.
3. Consider ways to dynamically update resource adequacy requirements in the CEM by coupling or otherwise iterating with a probabilistic resource adequacy model.

3.3 Scenario Exploration Strategies

Given the number of key drivers of electric sector outcomes and the uncertainty around those outcomes, it is not practical to simulate all possible outcomes or even a statistically representative sample that represents the distributions of all key drivers. Therefore, it is common practice to define a set of representative scenarios that identify key drivers of sectoral outcomes and examine the sensitivity of outcomes to variations in those drivers. These scenarios can be chosen based on known trends, or there can be a quantitative sampling procedure that defines some scenario inputs. Determining a suitable scenario suite is a complex process constrained by computational and staff resources, and it is made more complex when considering consistency across multiple model types that offer different scenario options because of structure and data requirements (Li et al. 2022; Witt et al. 2020; Fodstad et al. 2022). This section discusses some of those challenges in detail and how future scenario modeling might achieve greater cross-model consistency while covering a broader range of electric sector uncertainty.

3.3.1 Consistency Across Models

Some aspects of cross-model consistency, such as unit characteristics or load projections, are readily maintained by one-way model workflows and data development processes. With other more nuanced and model-specific assumptions, such as capacity credit for variable renewables and storage, it is more difficult to achieve consistency. If spatial and intra-annual temporal resolution is not the same across a CEM, PCM, and transmission reliability analysis workflow, the expected production from variable

renewables might imply different abilities to serve load, even if aggregated availability is consistent. Resource adequacy modeling is also able to consider variable renewable capacity availability under a broader set of conditions that more explicitly represent periods in which capacity credit is more valuable; this value is not as well represented in the PCM and CEM tools with more direct economic outcomes (Stephen and Kirschen 2024; Frew et al. 2017). Difficulty consistently capturing capacity value is particularly important for PSH valuation, given its known strength in this area. Increased integration of resource adequacy and CEM models, as discussed earlier, is one way to improve this consistency.

Resource adequacy modeling also highlights the inability to represent certain scenario classes effectively across all models, which further complicates a value assessment for PSH and other technologies. For example, extreme weather and other hazard or contingency events can technically be represented in CEM or PCM, but doing so overstates their expected frequency because they are not represented across a stochastic or probability-weighted sample space (Bennett et al. 2021; Moreno et al. 2020; Perera et al. 2020; Brockway and Dunn 2020). PSH has known anecdotal value for responding to hazards and grid events, but this value is not well represented in common least-cost modeling frameworks. Creating or expanding upon existing stochastic sampling methods for PCM and CEM model inputs could resolve this inconsistency but at significant cost and time requirements. Recognizing this limitation in overall value assessment is a first step, followed by continual reevaluation of available methods for incorporating extreme events into long-term integrated grid planning decisions (Bennett et al. 2021; Moreno et al. 2020; Perera et al. 2020; Brockway and Dunn 2020).

Model scenario inconsistencies can also be created simply by updating data or assumptions in downstream models without restarting the full workflow. This can be exacerbated if model teams are not closely coordinated and can be improved by increasing automation of data transfers between models and teams. It is reasonable to expect data and assumptions to change over the course of a study, so it is important to develop tools that facilitate rapidly achieving consistency and determine how to most efficiently use these tools given study needs (Cowiestoll and Frazier 2022; Iyer et al. 2019; Mongird and Rice 2024; Hardy et al. 2024). Doing so can improve both the quality and possible scope of a valuation study.

3.3.1.1 Strategic Actions

The following are strategic actions to consider when exploring consistency across models:

1. Consider advanced methods in scientific literature for incorporating extreme events into integrated grid modeling scenario suites to consider the value of PSH for responding to such events.
2. Create tools and processes that achieve greater and more automatic consistency across models and
2. iterations of analytical workflows.

3.3.2 Characterizing Uncertainty

The key components of characterizing uncertainty are first deciding on the critical uncertain elements driving outcomes, then determining how to represent the uncertainty in those elements (Li et al. 2022; Roald et al. 2023; Singh et al. 2022). The first step is discussed here as the choice of scenario types, or scenario levers. The second is discussed as scenario sampling, or scenario settings. Together, these define a scenario suite for one or more models. Valuing a specific asset such as PSH can also be facilitated by simulating any scenario with and without the new asset so that its impacts can be isolated. Valuation of new potential assets could be much improved simply by expanding the scenarios used in valuation procedures in ways such as those discussed in the next section.

3.3.2.1 Scenario Types

Scenario types are typically chosen based on which data or assumptions are thought to have the biggest or most uncertain impact on model outcomes, but they are also driven by modeling capabilities and other interests. Here we discuss elements both inside and outside utility control as part of a broad scenario definition because controlled elements such as generation technology investment choices are still often driven by uncontrolled elements such as technology costs and supply chain constraints. Common scenario types include: load growth, fuel prices, policy/regulations, and technology choice (Child and Farrell 2024). Technology choice reflects how investments are directed to emphasize certain grid characteristics such as resiliency, distributed generation, renewable energy, or environmental outcomes. These are typically implemented first in the CEM, then infrastructures are passed to the PCM to maintain as much consistency as possible.

It is important to continually reevaluate scenario types to remain responsive to evolving electric sector trends and cover a meaningful range of plausible outcomes. For example, fuel price scenarios could become less important as fossil generation, particularly coal, largely retires. On the other hand, there is growing uncertainty around transportation and building electrification and how these and other demand-side generation and storage systems will interact with the bulk power system (Murphy and Mai 2021). Data center growth is another key demand driver (Shehabi et al. 2024). Although demand-side resources are not in the direct control of a vertically integrated utility, their increasing impact on net load and grid management needs cannot be ignored, and including alternative demand-side and distributed resource scenarios could inform utility policy and practices (Prasanna et al. 2021; McCabe et al. 2022; Fitiwi and Bertsch 2018; Marañón-Ledesma and Tomasgard 2019). These might vary the effect on demand quantity, load shape, and load flexibility, all of which will interact strongly with a proposed PSH facility.

Generation, storage, and transmission technology uncertainty is also an important consideration, particularly in a multidecadal planning period. Technology costs and performance for storage technologies competing with PSH are changing rapidly (National Renewable Energy Laboratory 2023). Future solutions such as hydrogen-based systems, carbon dioxide capture, and advanced nuclear could also play a role that either competes with or complements flexible assets like PSH (Gagnon et al. 2024; Larson et al. 2021; Iyer et al. 2017). Although some technologies might be perceived as low-probability investments in the near future, they could be more important to consider for a 100-year asset such as PSH. Scenarios involving transmission technologies and investment options, including line upgrades, new corridors, or reliability assets such as synchronous condensing, could also affect the value proposition of PSH or other assets (DOE 2024). A transmission representation in CEM and PCM models would enable exploration of this sensitivity.

Another dynamic area worth considering under a scenario suite is the interactions with other service territories. Broadening the spatial scope of the models to include other service territories might not be practical, but it could be useful to consider how developments in other nearby service territories such as new investments, load growth, or new policies, could alter assumptions around imports, exports, and multi-market participation. External markets could enhance or reduce opportunities for PSH depending on how they change over time, making such sensitivities a useful exercise. These types of cross-market interactions have been studied at an interconnect scale in NREL's Interconnections Seams study (Bloom et al. 2020).

Extreme weather and other hazards also constitute a large array of possibilities that impact the grid over many spatial and temporal scales (Perera et al. 2020; Brockway and Dunn 2020; Craig et al. 2018). Common practices use static profiles that reflect normalized weather conditions. However, long-term trends in temperature-driven load and technology performance as well as precipitation-driven hydropower and cooling water availability create uncertain future grid conditions (Auffhammer et al. 2017; Craig et

al. 2018; Miara et al. 2019). All of these effects can influence long-term planning decisions. Short-term weather events could change in frequency and intensity and could offer another scenario consideration relevant to flexible technologies like PSH (Perera et al. 2020; Bennett et al. 2021). These can be considered in PCM or transmission reliability modeling. Such extreme operating conditions may be significant drivers of PSH value and are therefore important to capture and assess.

Transmission reliability analysis typically has its own set of scenarios focused on identifying worst-case situations for grid strength and stability, such as peak gross load with solar PV oversupply that prompts PSH to operate in pump mode. An expanded scenario approach could also consider changes to transmission infrastructure or changes to infrastructure in other service territories. Other scenarios could represent extreme events that go beyond single or double contingency events (Guo et al. 2021; Mujjuni et al. 2023; Jufri et al. 2019). These can be informed by CEM and PCM scenarios even if they are not fully consistent. Expanding transmission reliability scenarios in creative directions is important to understand the reliability contributions of flexible assets such as PSH.

3.3.2.2 Scenario Sampling

Once scenario types are chosen, the range and distribution of inputs and assumptions for each scenario type define the full scenario set. Ideally, one would identify a probability distribution for each key input then randomly sample across all key inputs. However, there are computational and staff resource limits on the number of distributions that can be created and samples that can be run, preventing modelers from creating a complete output distribution. Thus, care must be taken to understand any potential biases based on the characteristics of the chosen samples and to appropriately frame the likelihood of each outcome.

Stochastic CEM can be very computationally intensive, so practitioners must identify a coherent set of scenario settings for its CEM modeling (Diaz et al. 2020; Valencia Zuluaga et al. 2024; Mansouri et al. 2020; da Costa et al. 2021). Given the large and compounding uncertainty over long-term planning timescales, scenario settings must be carefully chosen to capture the range and distribution of possible outcomes of interest. Doing so could require iteration and scenario discovery when unforeseen outcomes and interactions occur (Hadjimichael et al. 2024; Bojórquez-Tapia et al. 2022). An overly restrictive set of scenario types and settings can unintentionally overstate the likelihood of the outcomes in those scenarios and have negative impacts on decision support. One way to expand the scenario range for a given study could be an initial screening step that uses a simplified model setup to quickly explore a wider range of scenarios and identify key drivers and interactions for a final scenario set. The value of a specific asset such as PSH could be very sensitive to many scenario settings; it is important to establish and explore which ones.

Extreme event scenarios are inherently difficult to characterize because of the sheer number of possible hazards and outcomes. Although there is insufficient scope in this document to fully characterize these options, it deserves mention in the context of PSH valuation because PSH holds value for responding to extreme events of many types (Koritarov et al. 2021; Ela et al. 2013). Identifying a few critical hazards and how they could manifest on the system could be an important way to evaluate new asset plans in PCM and transmission reliability models. Although these events might be unlikely, the high value of mitigating them should not be ignored in the overall value proposition of PSH or other assets.

Transmission reliability modeling offers a range of assumptions not necessarily available to other model types because of the highly detailed transmission system representation. Static power flow models typically have more detail than is included in PCM and CEM, and dynamic stability models go even further. For a given asset plan, it could be worth considering multiple assumptions around the locations and characteristics of future renewable energy, batteries, or loads connecting to the grid. Changes to interactions with external service territories could occur at varying locations and consist of many

alternative asset changes. Sampling larger contingency events that align with extreme event scenarios could include varying degrees of grouped versus distributed outages of different asset types. When so many options are considered, it is often helpful to focus first on bounding conditions but do so across a full range of possibilities. Expanded transmission reliability analysis could produce new insights into PSH value while also identifying future transmission needs and challenges.

3.3.2.3 Strategic Actions

The following are strategic actions to consider in characterizing uncertainty:

1. Identify extreme events scenarios of interest to PSH valuation and broader grid analysis and design implementations in the relevant model types.
2. Consider broader ranges of scenario samples for key scenario drivers that better identify grid conditions where PSH is most valuable.
3. Expand scenarios around cross-market interactions to acknowledge the rapidly evolving nature of surrounding service territories and beyond.
4. Use automated workflows to more readily expand scenario suites, iterate between models, and conduct custom or rapid-response studies as needs arise.

4.0 Summary of Strategic Actions

The full set of strategic actions included throughout this report are listed in Table 3, according to the corresponding category by model type, model integration method, or scenario exploration strategy.

Many of the individual model actions suggest renewed exploration of the trade-offs between computational difficulty and various aspects of model resolution and detail. These exercises are common among research enterprises pushing the boundaries of what is possible in grid and river operations modeling. Furthermore, the rapid changes occurring in the power sector suggest they could become a key part of utility practices. Particularly while assessing the value of flexible assets like PSH, there could be core model characteristics such as temporal scope and resolution, flexible demand- and supply-side technology representations, hydrological and ecological interactions, and transmission representations that are more critical to value assessment than in the past. There might also be new ways to incorporate and value ancillary services, examine changes to external market interactions, and account for long PSH lifetimes when valuing new potential PSH assets. Expanding and improving studies of transmission reliability can also better inform the value proposition for PSH and how its contributions to reliability can be considered in upstream PSH and CEM modeling.

Automated model integration requires significant effort at the outset but could vastly improve cross-model consistency and enable expanded scenario exploration of uncertainties. Doing so in a one-way fashion could reveal important areas where feedback or further integration is warranted between CEM, PCM, transmission reliability, resource adequacy, and other tools. Expanded automated processes can enable a more comprehensive and robust study of PSH value that considers extreme events, alternative technology assumptions, new trade and market considerations, demand-side developments, and distributed technologies. Evolving power sector trends are creating new forms of uncertainty and expanding the ranges and probabilities of possible grid conditions. It is important to consider these in valuation studies because PSH could be a leading technology to address many of these uncertainties and to maintain a reliable and resilient system.

Although this set of actions were derived in partnership and collaboration with TVA, they offer a range of considerations that could be applicable to all vertically integrated utilities, investor-owned utilities, system operators, or other entities conducting integrated grid modeling and analysis. As the grid of the future comes into focus, industry stakeholders can learn from and adapt applied research-grade methods developed by DOE laboratories and other research institutions. Doing so could improve decision-making and accelerate progress toward a more reliable, secure, and affordable energy system.

Table 3. Complete List of Strategic Actions From This Report, By Category

Capacity Expansion Modeling
• Compare valuation results under alternative PSH economic lifetimes closer to the true physical life of the asset.
• Perform sensitivity analysis considering alternative temporal scope and resolution to better understand accuracy-tractability trade-offs and how they affect solutions, including PSH value.
• Consider alternative choices for representative days that better capture changes to net load profiles over time and enable representation of storage arbitrage value beyond diurnal scales.

- Develop CEM capabilities to represent flexible loads that might compete with PSH for providing grid services.
- Account for changes in ancillary services requirements with variable renewable deployment, and value all services appropriately.
- Study the impact of incorporating transmission constraints within the CEM, starting from a coarse zonal aggregation.

Production Cost Modeling

- Perform internal analysis to study the implications of alternative temporal scopes, then study computational trade-offs between temporal scopes and other model configuration choices.
- Test the impacts of explicitly representing a transmission system at zonal or nodal resolution along with additional options for capturing interactions with neighboring entities.
- Consider disaggregating traded electricity to consider multiple specific customers including DERs.
- Work with PCM commercial vendors to develop methods to prioritize individual operating constraints if they are not inherently strictly enforced by the tool.
- Improve ancillary services representations to consider growing reserve requirements with variable renewable deployments and additional or alternative service requirements.
- Study methods to better differentiate fixed-speed versus variable-speed PSH operations in PCM models.

Hydrological Systems Impacts Modeling

- Focus PSH impact assessments on the integration among hydrological systems, aquatic resources, and river services, by first identifying permitting requirements in terms of metrics and analytical resources needed for their evaluation.
- Use a three-stage process that provides best practices in assessing, designing, and reporting on the impacts of PSH operations under multiple water availability and power system scenarios.

Transmission Reliability Modeling

- Analyze grid stability in scenarios that include peak load, high IBR deployment, and alternative PSH operation modes.
- Compare the contribution of fixed-speed versus variable-speed PSH to grid frequency and voltage response under a range of contingency scenarios.
- Conduct transient stability analysis across contingency scenarios to identify frequency and voltage support needs that can be used to validate device-specific dynamic stability performance and develop effective control strategies.
- Incorporate transmission reliability considerations endogenously into CEM planning and PCM operation model stages—for example, by adding requirements for frequency or voltage services, or

developing heuristics that require reliability-oriented operational constraints (e.g., must-run) at certain load or other grid conditions.

One-Way Workflows

- Conduct cost-benefit analysis to decide if resources should be committed to automating data translation processes between models or using models that are more integrated or flexible.
- Consider methods for representing endogenous transmission expansion within CEM and PCM tools to create more robust grid topologies to study PSH value for providing transmission reliability services.
- Identify key data workflows upstream from grid models (e.g., load, resource adequacy) and use them to develop scenarios for alternative data and assumptions to use across models.
- Expand resource adequacy modeling to consider a broader range of possible grid configurations and events that might occur over the operating lifetime of the PSH facility.

Model Feedback Loops

- Identify ways to incentivize or disincentivize technology investments and operation in CEM and PCM to reflect their impacts on grid strength stability. This may involve model coupling or modified workflows that include transmission reliability analysis at an earlier stage.
- Compare model operational outcomes between PCM and CEM tools to determine if they are sufficiently consistent across temporal and spatial scales, or if feedback should be considered to facilitate greater agreement.
- Consider ways to dynamically update resource adequacy requirements in the CEM by coupling or otherwise iterating with a probabilistic resource adequacy model.

Consistency Across Models

- Consider advanced methods in scientific literature for incorporating extreme events into integrated grid modeling scenario suites to consider the value of PSH for responding to such events.
- Create tools and processes that achieve greater and more automatic consistency across models and iterations of analytical workflows.

Characterizing Uncertainty

- Identify extreme events scenarios of interest to PSH valuation and broader grid analysis and design implementations in the relevant model types.
- Consider broader ranges of scenario samples for key scenario drivers that better identify grid conditions where PSH is most valuable.
- Expand scenarios around cross-market interactions to acknowledge the rapidly evolving nature of surrounding service territories and beyond.
- Use automated workflows to more readily expand scenario suites, iterate between models, and conduct custom or rapid-response studies as needs arise.

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