Impact of Hydrological Data on Power System Operational Studies

Preprint

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Impact of Hydrological Data on Power System Operational Studies

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Abstract

Hydropower is expected to play an important role in maintaining grid reliability and flexibility as the share of variable renewable energy increases. While the current hydropower operational models have been studied and used widely, they haven't been updated for decades to meet new performance standards. For example, current steady state and dynamic models often neglect hydrological conditions, which may lead to unrealistic expectations when relying on hydropower for energy and ancillary services. To study this impact, a multi-timescale hydrological model was created by leveraging the National Renewable Energy Laboratory-developed Multi-timescale Integrated Dynamics and Scheduling (MIDAS) tool. Using MIDAS, we compare the impact of considering hydrological conditions in a day-ahead unit commitment (DAUC) schedule on the reduced 240-bus Western Interconnect (WI) test system under winter and summer case studies. We show that neglecting current hydrological conditions of hydropower plants in power system models can lead to an overestimation of hydropower capabilities, which could lead to power balancing issues. For example, power system DAUC simulation results of our reduced test system show that in the case where hydrological conditions are not considered in the model, an approximate 31% overestimation of hydropower capabilities occurs in the summer case and approximately 60% occurs in the winter case compared to what is available. Additionally, results show an underestimation of WI day-ahead power system generation costs by approximately \$54M - \$80M in the weekly summer scenario and \$116M - \$126M in the weekly winter scenario. This analysis helps to underscore the importance of considering hydrological data in power system operational studies.

1 Introduction

Hydroelectric power, a sustainable energy source with eco-friendly attributes, is a vital contributor to the Western Interconnect (WI) system's energy mix at 25% of the capacity share in 2021 [1]. However, as climate change can intensify reservoir evaporation, modify the seasonality of river runoff, alter precipitation patterns, and lead to fluctuations in reservoir levels across the WI system, it brings heightened variability and an increased risk of incorrectly estimating hydropower generation compared to historical norms [2]. Addressing these challenges necessitates accurate

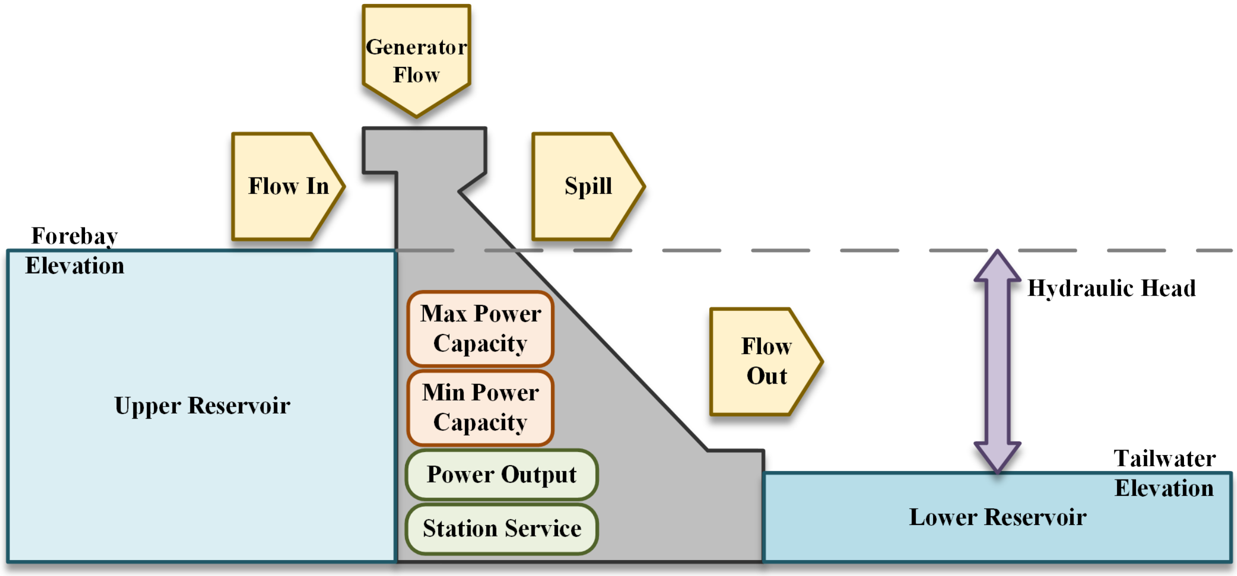


Figure 1: Graphical depiction of hydropower plant parameters. The hydraulic head is the difference between the forebay and tailwater elevations.

representation of hydrological dynamics, ensuring precise estimation of hydrological conditions, and incorporating these conditions into both steady-state and dynamic hydropower models. Further, the integration of a large-scale renewable energy portfolio, including photovoltaic (PV) and wind, into energy systems is pivotal in mitigating the effects of climate change. However, this transition poses a new challenge to system operators to balance power and maintain frequency stability [3] and compounds the need of accurate hydropower models to assist in power balancing and grid stability services. Additionally, due to complex environmental regulations and seasonal stream flow variability, hydropower may not be as flexible as it is commonly represented in power system models [4]. For example, approximately 70% of the potential generation lost in the U.S. between 2013 and 2012 is due to forced outages on hydropower plants and pumped storage hydropower (PSH) units from generator failure, transformer failure, and lack of water, while 80% of outages due to lack of water correspond to the Western Electricity Coordinating Council (WECC) fleet [5]. Moreover, the average availability (percentage of time units are not offline due to planned or forced outages) of hydropower and PSH units in WECC have decreased in recent years compared to other regions [5]. For the many aforementioned reasons, it is increasingly important that hydropower models accurately represent current conditions, especially for the WECC region.

One solution to this challenge is to provide power system models with current hydrological condition-informed data, which determines the capability of the hydropower unit. The maximum power output capability of hydropower plants is (non-linearly) dependent on the hydrological head of the plant, which is the difference between the upper forebay (water intake) and lower reservoir (hydro discharge) elevation, as shown in Figure 1. The power output capability of a hydropower plant is proportional to the three-halves power of the head, as shown in Eq. 1, where $\overline{P_t}$ is the new maximum plant power output capability at time t, $\overline{P}$ is the nominal plant power capability, and h_t is the upper reservoir head value in per unit (p.u.) at time t. The head value can significantly reduce the power output capability of the hydropower unit if not at nominal value (1 p.u.). For example, if the head is 0.85 p.u., the power output is limited to 78% of the unit's rated capacity. Considering multiple hydropower plants across the WI are likely not at nominal head, this can cause a large error in expected hydropower capability. As most steady-state power system models consider hydropower plants at a constant 1 p.u. head value throughout the year, modeling hydropower units in this way does not capture the true capability of the plant based on the available water. This miscalculation can cause imbalances in power generation and demand. As hydropower is increasingly relied upon as a clean resource to quickly balance generation and load from fluctuations in renewable energy generation, accurate model representation is becoming more important. Furthermore, this impact trickles down into the dynamics of the system as the dynamic governors also have inaccurate information on the capability of the plant. For more accurate planning and operational studies, the changing water availability must be considered in steady-state and dynamic power system models.

$$P_{max,t} = \overline{P} \cdot h_t^{3/2} \tag{1}$$

There are very few cases where the water head can be ignored when estimating a hydropower plant's power capability with relatively small impact. These cases could include situations where the forebay elevation does not change significantly over seasons or short periods of time (large reservoir) and the head is large relative to the variation in tailwater elevations (large dam height) [6]. Additionally, the plant's hydraulic head value would need to remain close to the nominal value while keeping in mind it could take a long time for the forebay elevation to rise significantly after a long period of drought for large reservoirs. However, due to environmental changes and recreational constraints, it is rare a plant would face these conditions over a long period of time. Further, it is unlikely the water head would remain at exactly the nominal (1 p.u.) head value. Therefore, the head-dependency should be accounted for in most, if not all, hydropower plant operation models. This especially includes plants with large reservoirs below nominal capacity due to their larger power producing capabilities, and thus, larger impact on the power system operation.

For example, the Western U.S. is currently in a historical drought which is impacting hydropower capabilities [7]. Based on historical data gathered from the United States Bureau of Reclamation's Reclamation Information Sharing Environment [8] and Hydrologic Database [9] datasets, Hoover Dam hydropower plant located in the WI system, faced a range of 0.06 p.u. (32.8 ft) difference in head over 7 (2015-2021) years with a maximum head of 0.785 p.u. (419 ft), as show in Figure 2. Consequently, Hoover Dam is only at 69% (1,445 MW) capacity at its highest availability level and 62% (1,290 MW) at its lowest availability during this time period (a difference of 155 MW). However, it is possible that Hoover Dam was still modeled at 100% capability (and at nominal head) in power system models. For a 2,078.8 MW plant, this can have a significant impact on expected generation. For instance, at a head value of 0.785 p.u., the difference in expected generation when assuming the plant is at nominal head is around 634 MW. At the lowest head value recorded during this time period (0.728 p.u.), the difference is around 789 MW. This impact is often amplified in smaller hydropower plants with smaller upper reservoirs, where the hydraulic head is not as robust to changes in water levels. However, due to the smaller power capacity associated with smaller plants, the impact on the power grid may not be as significant. Further, seasonal changes in water levels over a year can be quite significant, as can be observed for Hoover Dam. With all hydropower plants in the power system model treated at nominal capacity, this compounded error in the expected generation could be significantly large compared to what is actually available from the hydropower fleet based on water levels.

The inaccurate representation of water availability in power system models, reflected by the

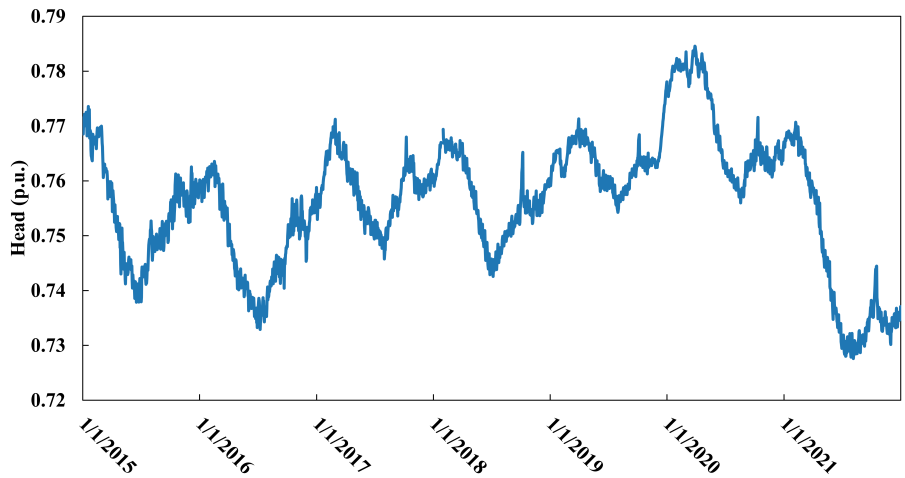


Figure 2: Daily water head variation from Hoover Dam over years 2015-2021 [8], [9]. Hoover Dam has a nominal head of 576 feet.

water head value, has been identified by industry experts and the Western Electricity Coordinating Council's (WECC's) Modeling Validation Subcommittee as the highest priority gap in hydropower modeling [10]. When current water availability conditions are not considered in power system simulations, the output capability of hydro plants will be overestimated if the head is not at its nominal value. Therefore, in this work we focus on comparing models that have knowledge of water availability to those that do not. To achieve this, we use representative historical 2019 hydropower generation data with the assumption that the water head, and other factors such as discrete operating or rough zones, turbine efficiency, and cascading plant interactions, were considered in the operation of the hydropower plants. For the case without knowledge of the water availability, we allow the system to optimize a day-ahead unit commitment (DAUC) simulation with the nominal maximum power value for all hydropower plants.

Due to the industry-focused nature of this work, very few have published studies of comparing operation and/or dynamic simulation impacts when hydrological conditions (specifically water head) are not considered. In one example, authors in [11] show that head-dependent hydropower models require a negligible computational effort beyond linear programming models that do not consider head dependence. However, the authors note that the head is frequently set to a constant value and not a time-variant value by power system operators. On the other hand, many national laboratories are investigating the need for accurate hydropower technology representation in power system models. Work improving hydropower representation in [12] was brought about by a workshop with industry professionals from 25 diverse organizations. The work promotes the need for hydropower models to have explicit representation of river operations in production costs models to encourage co-optimization of hydropower plants considering objectives from both power systems and the systems that impact water storage and flow. Additionally, guidance in [13] suggests the need for testing and validation of hydropower generation units for time frames ranging from long-term planning to dynamic responses. Therefore, the timely topics in this report are widely recognized as an emerging challenge today.

In this work, we leverage the National Renewable Energy Laboratory (NREL)-developed Multi-Timescale Integrated Dynamics and Scheduling (MIDAS) simulation tool [14]. The inputs to MI-

DAS are hourly PV, wind, and load data, generator price data and constraints, and transmission network data. The output of MIDAS utilized in this work is an hourly day-ahead unit commitment of generators, including the output dispatch levels and on/off statuses, as well as the daily reserve schedule. In this model, the hydropower generators are treated similar to other generator types with steady-state parameters such as power maximum and minimum capabilities, start up and shut down (ramp) capabilities and times, initial status, hours running, and power conditions, minimum on and off times, block bids, and reserve capabilities and costs. The unit commitment scheduling problem is solved using a mixed integer linear programming formulation [15], and can even be extended to a real-time economic dispatch schedule and second-level dynamic solution within the closed-loop MIDAS tool, but is out of the scope of this work.

We study the impact of hydrological conditions on a reduced 240-bus WI model [16]. This reduced and aggregated model, along with representative 2019 input data, allows us to quickly test research concepts, but is not a fully detailed WI model. In 2018, hydropower made up just over 24% of the capacity of utility-scale resources in the WI territory [17], so this is a good area to conduct such a study. We study the seasonal impact different hydropower model types with and without knowledge of hydrological conditions have on the power system given the hydrological conditions vary throughout the year. The study finds the critical importance of hydrological condition considerations. It reveals that the absence of hydrological conditions in hydropower models will increase overestimation of hydropower units, and in turn, cause power-balancing issues.

An additional solution to challenges brought about to the power grid due to an increasing number of renewable generation, is utilizing energy storage systems to provide power-balancing and frequency ancillary services, where PSH plays an important role. PSH has its own unique characteristics with the capability to provide both energy and ancillary services, but its impact is highly dependent on current hydrological conditions. However, how to accurately incorporate hydrological conditions into PSH models is another new challenge. In this work, the MIDAS model was updated to intake historical end-of-day state of charge (SOC) values rather than return to the initial SOC values for the day or have no enforcement on the SOC. With this incorporated, PSH units are able to shift according to historical seasonal patterns. The 240-bus WI model includes 4 PSH units modeled after actual units in the WI with storage times of 4, 5, 10, and 153 hours. The ability to capture longer storage times in a DAUC problem is essential in ensuring the capabilities of PSH are fully realized in the model.

The remainder of this paper is organized as follows. We outline the methods used to test the impact of considering hydrological conditions in power system models in Section 2. Case studies of different hydropower model types, their results, and analysis of those results are provided in Section 3. We conclude the work in Section 4.

2 Method

To understand the impact of hydrological data considerations in grid planning and operation models, this paper leverages the capabilities of the MIDAS model [15], an NREL in-house tool. This tool is employed to simulate and explore the intricate interplay between economics, reliability, and stability within a grid characterized by high levels of renewable, hydropower, and pumped storage hydropower generation. The powerful capabilities of MIDAS lie in the ability to simulate the power system from economic scheduling timescales to dynamic stability analysis timescales.

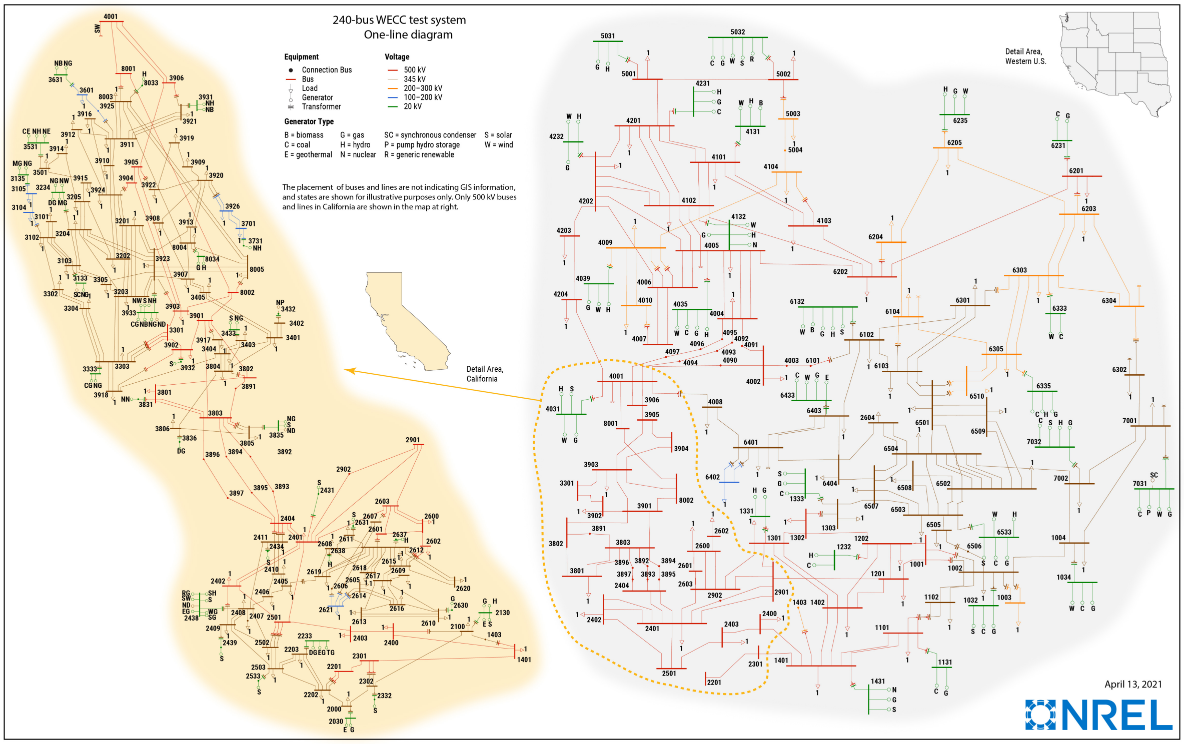


Figure 3: One-line diagram of the Western Interconnection (WI) reduced 240-bus model.

In this way, the model can evaluate the impact on economics and reliability simultaneously. Further, this tool enables renewables to provide grid services by seamlessly studying the technical and economic feasibility of operation. The first model of this kind, MIDAS bridges the power system dynamics and scheduling across different timescales. It also assesses the regulation reserve and primary frequency response (PFR) reserve requirements under different renewable generation levels. This capability helps to understand the overall performance of regulation fleets and evaluate different control strategies for providing grid services. A better understanding of the interactions of PFR, secondary frequency response, and their reserves is enabled by studying the MIDAS simulation results.

This study first introduces an approach to hydropower modeling and simulation within the context of the reduced 240-bus WI model, as shown in Figure 3, based on the MIDAS framework. Based on work in [18], the 240-bus WI model was developed by NREL and is publicly available [16]. Confirmation of the model representing WI generator parameters and verification of the dynamic model are provided in [19].

Within the reduced WI model, the power system configuration based on 2019 data is comprised of 4 pumped storage hydro units (with a capacity of 3,023 MW), 25 hydropower generation units (with a capacity of 60,480 MW), 5 biomass facilities, 47 gas-fired power plants, 2 geothermal installations, 3 nuclear power plants, 19 steam turbines, 74 utility-scale or distributed photovoltaic (PV) systems, and 18 wind farms, collectively contributing to a total installed capacity of 289,970 MW. Generator capacity is depicted in Figure 4. The WI input data is realistic but is not comprised of real historical data in all cases. Specifically, the aggregated hydropower output follows daily and seasonal historical hydropower dispatch patterns from 2019 but does not exactly match.

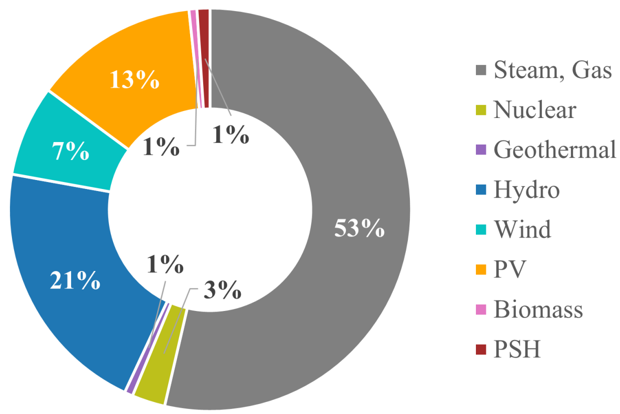


Figure 4: Generation capacity mix of reduced 240-bus WI model.

As most U.S. dams prioritize water management over power generation, we use aggregated historical data to mimic a previous year's actions with the assumption considerations for flood control, water supply, recreation, navigation, environmental flows, water quality, wildlife needs, among other constraints have been included. These, among other factors, have been identified as restrictions on hydropower flexibility [20]. We compare results where power system operators are informed on water availability of hydropower plants to a case where the power system is optimized based only on maximum and minimum capabilities of the plants without knowledge of water availability.

MIDAS is a closed-loop simulation framework capable of simulating from economic scheduling timescales to dynamic stability analysis timescales. It runs from day-ahead unit commitment to real-time economic dispatch simulations, accounting for both power flow and frequency timescales. However, this work focuses on a day-ahead unit commitment problem and frequency-level timescales will be studied in future work. MIDAS was modified from the previous version to allow for pumped storage hydropower end-of-day state of charge (SOC) time series data to be read into the model and applied to the power output schedule of the generators. Historical data from 2019 of the PSH unit's upper reservoirs storage volume, or SOC, were therefore incorporated into the model. This allowed for the PSH units to have seasonal changes and operate on longer-duration storage timescales in a software that only solves for one day with limited look-ahead.

This research presents an innovative approach involving the development of three distinct hydrological models to represent varying dispatch settings and hydrological conditions. The study considers three different hydropower models, as outlined in Table 1. Hydro-1 model type is non-dispatchable based on time series data. This type can be thought of as hydro plant operators optimizing their schedule outside of the power system optimization problem while considering only their plant's operating constraints. The power system operators cannot change the dispatch of these generators. Hydro-2 model type is dispatchable based on maximum and minimum power capabilities. This model considers the power system operators optimizing the power system based on nameplate capabilities of plants without considering current hydrological conditions. This could be considered as a worst-case scenario for how hydropower plants are modeled in power system operations today. However, most operators typically have daily, weekly, or monthly energy targets for hydropower generation which cannot be exceeded while assuming nominal maximum output capabilities or time series data bounds. Finally, Hydro-3 model type is dispatchable based on time series data. This model allows hydropower plant operators to optimize their schedule considering hydrological conditions, but the power system has the capability to 'curtail' or downward dispatch the hydropower units. The determined schedule is read into the power system model in MIDAS as a time series dataset. The power system is optimized to minimize generator costs (fuel costs, start-up/shut-down costs), ancillary service (primary frequency response and automatic generation control) costs, load shedding costs, constraint violation penalty costs, and unsatisfied ancillary service penalties subject to generator, energy storage system, and system network and power flow constraints. A piece-wise linear bidding mechanism is used for generator cost functions.

Table 1: Hydropower Modeling Types in MIDAS

Hydro-1	Non-dispatchable based time series data
Hydro-2	Dispatchable based on maximum and minimum power ratings
Hydro-3	Dispatchable based on time series data

The study encompasses three scenarios, each aligned with one of these hydropower models, and conducts two comprehensive week-long analyses, one for a representative summer week and another for a representative winter week. The representative seasonal load profiles depicted in Figure 5 are used as input for the summer and winter simulations. This analysis includes assessments of day-ahead unit commitment (DAUC) economics and capability analyses.

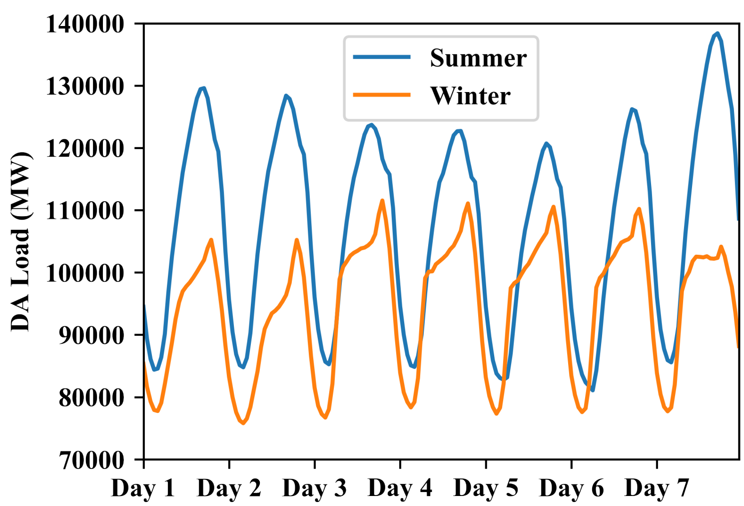


Figure 5: Summer and winter weekly day-ahead load schedule.

In power system operating models, ancillary services, such as operating reserves, are planned for in advance to prepare for instances of imbalances in power and demand, frequency stabilization, and unexpected generator trips. This preparation allows the system to quickly respond during a disturbance by turning on or ramping up resources previously allocated to assist in preserving the system. In MIDAS, reserves are held according to available generator headroom and specific generator governor capabilities for PFR and automatic generation control. Along with a user-defined reserve requirement, such generator specifications are inputs to the MIDAS model and match typical response speeds and capabilities of certain generation types. Unmet reserve is financially penalized in the objective function.

3 Results

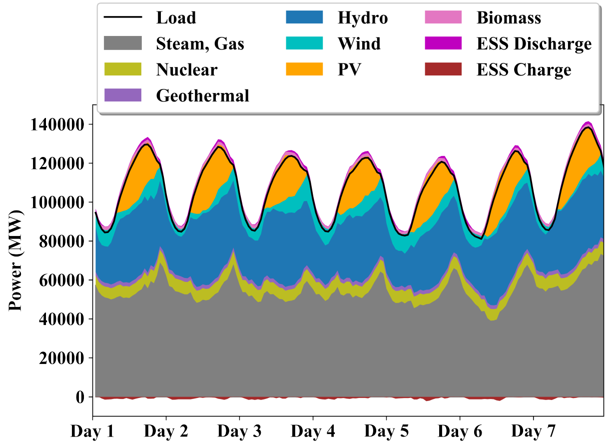
To test the impact of a power system operator with and without knowledge of water availability for hydropower plants, we consider a day-ahead unit commitment simulation of the WI 240-bus model using MIDAS. To compare seasonal impact, we study two representative weeks. We study the final week in June as our summer case and the final week in October as our winter week. Typically, summer has higher water availability, so hydropower plants may see a larger range of operation. Conversely, winter months typically see lower water availability to prepare for spring runoff. Note, a 1% PFR reserve requirement is enforced in these cases.

In the WI system scheduling model, steam/gas, nuclear, geothermal, hydropower, wind, PV, biomass, and electrical energy storage (EES) (in the form of PSH) generating units are scheduled to meet system demands. The summer day-ahead unit commitment (DAUC) weekly MIDAS simulation results are depicted in Figure 6. In the Hydro-2 model case (Figure 6b), where hydrological conditions are not considered by the power system operator in the optimization problem, an intriguing observation emerges. We see that hydropower capabilities are overestimated in this case and therefore over dispatched in the day-ahead schedule. In contrast, in the Hydro-1 (Figure 6a) and Hydro-3 (Figure 6c) cases, where historical hydropower generation data is used and, therefore, hydraulic head conditions are inherently considered, the hydropower fleet is dispatched to a lesser extent according to current capabilities. Steam and gas generators replace the over-dispatch observed in the Hydro-2 case in the water availability-informed cases, Hydro-1 and Hydro-3. Quantitative results of this shift are provided in the following analysis.

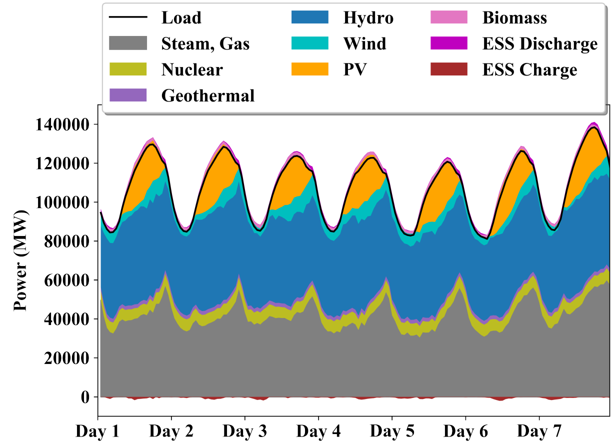
In addition, due to the Hydro-3 model allowing downward dispatching of hydropower plants, Hydro-3 sees a slightly smaller output than the Hydro-1 case in order to better serve the power system. A slightly larger wind resource can be observed in the Hydro-3 case. Given the option, the power system has opted to utilize more wind for power generation and hold the additional hydropower capacity in reserves in replace of the wind capacity. More information on this interplay is provided in the following analysis regarding PFR results.

As expected, this impact is greater in the winter case when water availability is lower. For example, in the winter case, depicted in Figure 7, we see a significantly higher over-estimation of hydropower capabilities in the case where hydrological conditions are not considered (Hydro-2 type), Figure 7b, compared to cases with knowledge of current hydrological conditions, Figures 7a and 7c. Again, steam and gas turbines replace the expected hydropower generation in the cases where hydrological conditions are considered.

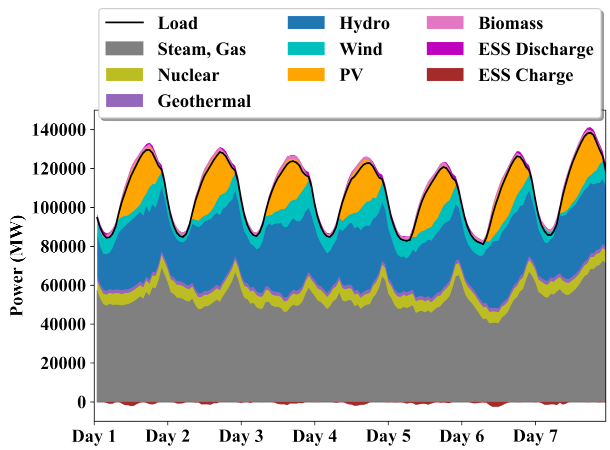
In these seasonal scenarios, significant modification in power system operation can be observed. For example, only 69% of the hydropower dispatch in the Hydro-2 summer case is actually available based on Hydro-1 model results. In other words, hydropower is over-dispatched by 31% in the summer case where hydrological conditions are not considered. In the winter case, this outcome is worsened. Only 40% of the dispatched power in the Hydro-2 case is available, so the hydropower



(a) Hydro-1



(b) Hydro-2



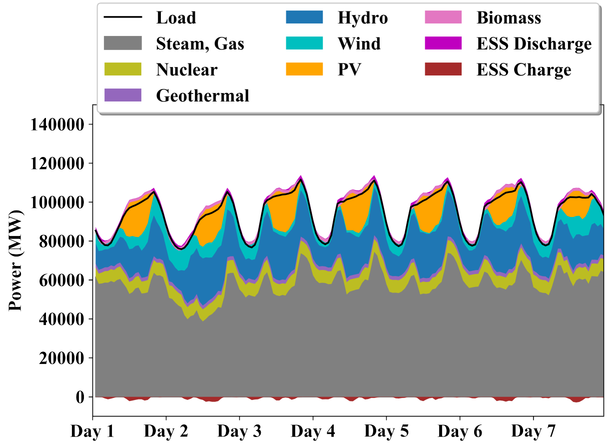
(c) Hydro-3

Figure 6: Summer weekly day-ahead dispatch schedule with (a) Hydro-1, (b) Hydro-2, and (c) Hydro-3 types. In the case where the power system operator is not informed on hydrological conditions (Hydro-2), the hydropower fleet is over-dispatched and is replaced by steam and gas generators in the water availability-informed cases (Hydro-1 and Hydro-3).

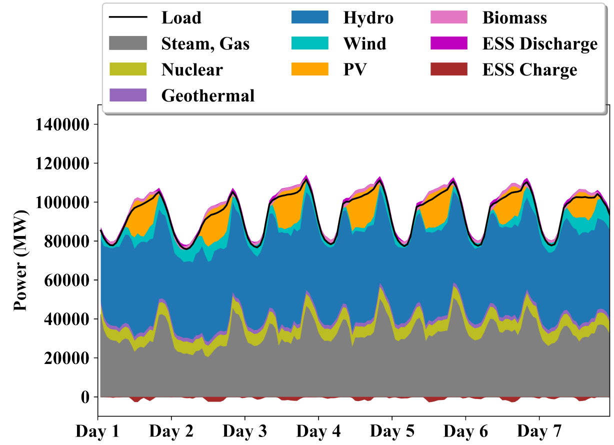
fleet is over-dispatched by 60%. This is a significant amount of energy that cannot be met by hydropower units and must be made up for by other generator types in the WI territory.

To this point, steam and gas energy production increases by approximately 29-31% in the summer case and around 76% in the winter case under the scenarios where hydrological conditions are known to the power system operator (Hydro-1 and Hydro-3). Therefore, the overestimation of hydropower capabilities can lead to a miscalculation in the estimate of non-fossil fuel generation in the system, which can lead to a shortfall in utility clean energy goals.

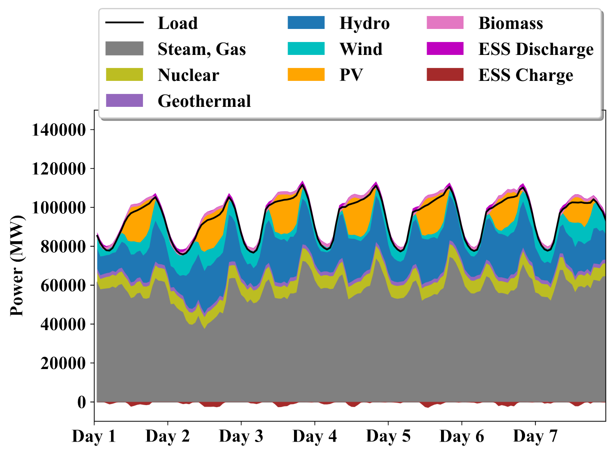
To compare the total weekly energy by generation type among different hydro models, a bar chart is depicted in Figure 8. The hatched area shows the amount of hydropower that is not available according to the time series data used in the Hydro-1 and Hydro-3 cases. However, this hydropower generation is relied upon in the day-ahead unit commitment of the Hydro-2 case, which can cause



(a) Hydro-1



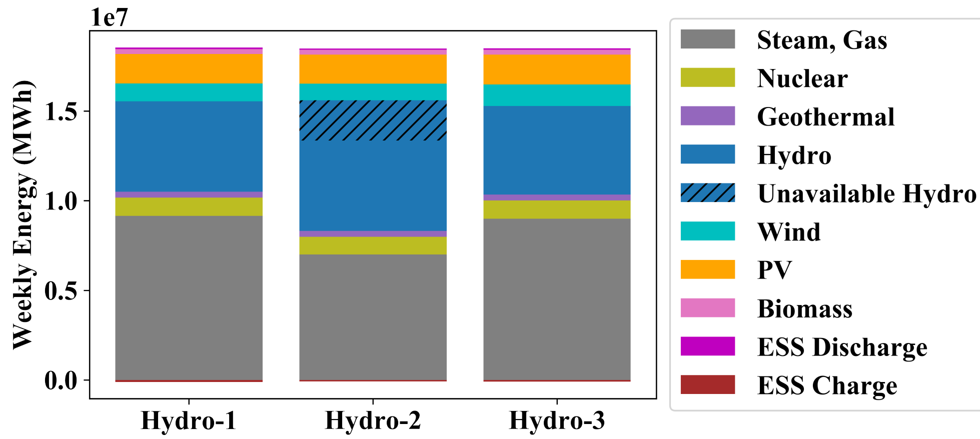
(b) Hydro-2



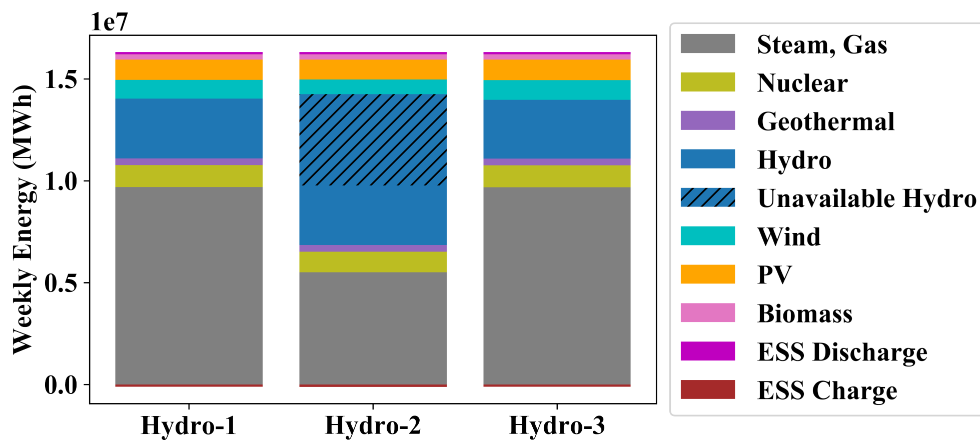
(c) Hydro-3

Figure 7: Winter weekly day-ahead dispatch schedule with (a) Hydro-1, (b) Hydro-2, and (c) Hydro-3 types. The hydropower fleet is even more over-dispatched than the summer case due to lack of knowledge of low water availability in the winter (Hydro-2). Steam and gas generators make up for this over-dispatch in the water availability-informed cases (Hydro-1 and Hydro-3).

significant issues when the water is not available in real time. The over-dispatch of hydropower in the winter case (Figure 8b) is significantly worse than in the summer case (Figure 8a). Again, it can be observed that the majority of the over-dispatched hydropower in the Hydro-2 case is replaced by steam and gas generators in the Hydro-1 and Hydro-3 cases. The biomass and geothermal dispatch is equal across all three cases. However, the dispatch of the other generation types changes minimally compared to the steam and gas commitment. Interestingly, wind power is curtailed a decent amount throughout the week (more in the winter case) in the Hydro-2 case to allow for more hydropower. Note, both wind and hydropower (along with PV) are modeled as zero-marginal cost units in this work, and this curtailment could just be a result of the optimization problem trading off between many of these units with similar cost outcomes in the objective function.



(a) Summer



(b) Winter

Figure 8: Comparison of weekly energy dispatch for each hydropower model for (a) summer, and (b) winter seasons. The hatched area shows the amount the hydropower generators are over-dispatched in the Hydro-2 case where hydrological conditions are not considered.

To observe the differences between hydropower dispatch across the three model types, Table 2 provides quantitative results on the weekly DAUC simulation for the summer and winter cases. In the summer case, the difference in energy between the water-informed models and the uninformed model is on the order of 2,000 GWh, and beyond 4,000 GWh for the winter case. This is a significant amount of energy over the entire week that must be covered by other generation units. As previously mentioned, this leaves a 31% to 60% change (overestimation) from the model that does not have information on hydrological conditions of hydropower plants.

Further, on an instantaneous power level, during these simulated weeks, the Hydro-1 and Hydro-3 system-wide scheduled hydropower generation deviate from the Hydro-2 schedule at a minimum of 3,761 MW and 4,553 MW, respectively, in the summer scenario. At a maximum, there is a deviation of 20,838 MW between the Hydro-2 case and the water-informed cases. The winter case sees a maximum deviation of 33,236 MW from the Hydro-2 schedule, and a minimum deviation of

Table 2: Hydropower Scheduling Differences between Hydro Model Types

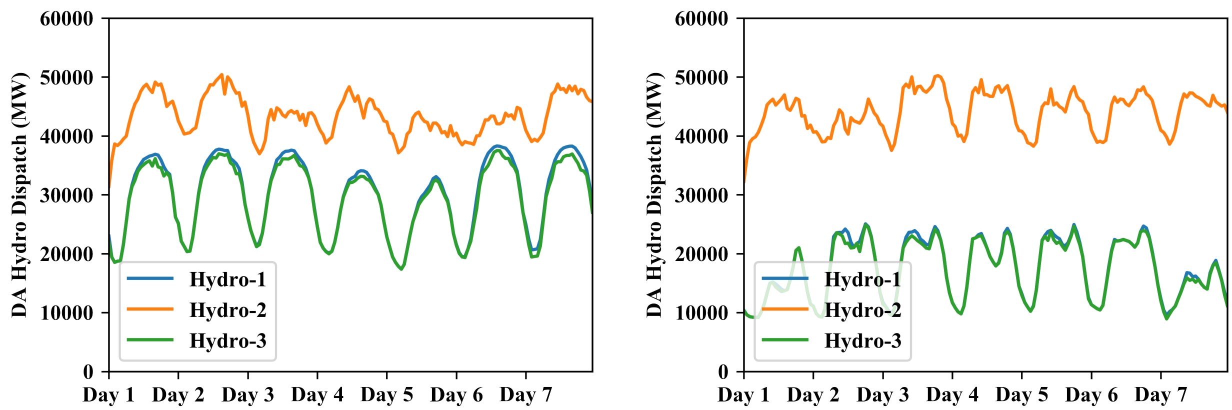
Season	Hydro Model Type	Weekly Hydropower Energy (MWh)	Difference with Hydro-2 Energy Dispatch (MWh)	Percent Decrease from Hydro-2 Energy Dispatch
Summer	Hydro-1	5,041,730	-2,244,714	31%
	Hydro-2	7,286,444	—	—
	Hydro-3	4,938,093	-2,348,351	32%
Winter	Hydro-1	2,933,613	-4,474,114	60%
	Hydro-2	7,407,727	—	—
	Hydro-3	2,890,510	-4,517,217	61%

16,730 MW for Hydro-1 and 18,500 for Hydro-3. In the best case among these scenarios, making up even the more than 3 GW of power expected in the day-ahead schedule could be quite challenging. However, in the worst case, turning on more than 33 GW of power throughout the WI territory could be detrimental to the system and may require significant load shedding.

To take a closer look at the hydropower fleet operation, only the day-ahead hydropower dispatch for each hydro type is depicted in Figure 9a for summer and Figure 9b for winter. Here, we can clearly see a significant difference between Hydro-2 type and water-informed Hydro-1 and Hydro-3 types. For the Hydro-2 model type, the scheduled generation reaches around 80% system peak hydropower capacity at peak load times and follows the load and solar fleet profiles for both seasons. The impact is exacerbated during the winter season, when water availability is low. It is also observed in Figure 9 that a difference in day-ahead scheduling between the Hydro-1 and Hydro-3 models only occurs when the power system would best benefit from downward dispatch of the hydropower fleet due to consideration of financial, ramping, or other constraints. In the summer scenario, the deviation between Hydro-1 and Hydro-3 most frequently occurs at peak solar capacity. Therefore, it can be assumed the system is opting to utilize solar power to meet the load rather than available hydropower.

The impact of overestimating hydropower output capabilities could be quite large. Unintended consequences of this overestimation could include challenges in balancing load and generation in real-time due to ramping constraints, startup costs, and other limiting factors from the generation units needed to replace expected hydropower generation. In real-time economic dispatch, the true hydrological conditions necessitate the activation of additional steam and gas generators or an increase in their output to meet load demands. This, however, introduces concerns due to the longer startup time and limited ramp-up constraints typically associated with these generators. Further, these issues could cause frequency stability issues at smaller timescales, which will be a focus of future work.

In addition to an overestimation of hydropower fleet capabilities, we see an underestimation of DAUC operation costs, as shown in Figure 10. In the summer scenario, we observe an approximately \$54 to \$80 million underestimation of total weekly system generation costs compared to water availability-informed models. When hydrological constraints are considered in the winter case, the weekly system generation costs are expected to be higher by \$116-\$126 million com-



(a) Summer

(b) Winter

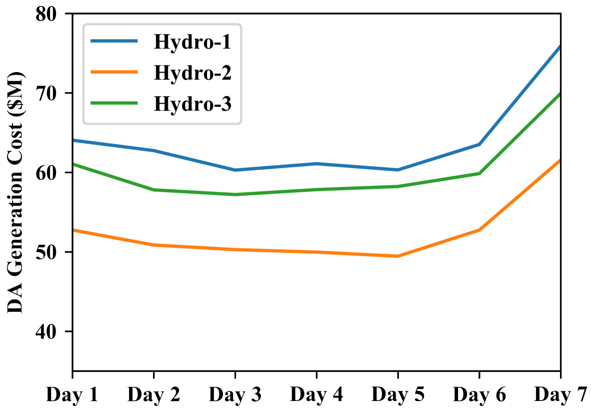
Figure 9: Weekly hydropower day-ahead dispatch schedules for (a) summer, and (b) winter seasons. Hydropower generation is over-dispatched in the Hydro-2 case where hydrological conditions are not considered in the model.

pared to the uninformed case with the Hydro-2 model. In this model, hydropower generation is a cheaper resource than the steam and gas generators that replace it, therefore we see higher costs in the Hydro-1 and Hydro-3 cases that rely on more expensive generators. Therefore, expected generation costs in uninformed models can deviate significantly from costs based on true hydropower capabilities. This impact can be worsened in a case where more energy is needed to fill the gap hydropower was expected to fill but less expensive generation types are constrained (e.g. ramping limitations) and the system must therefore rely on more expensive generators to balance the load.

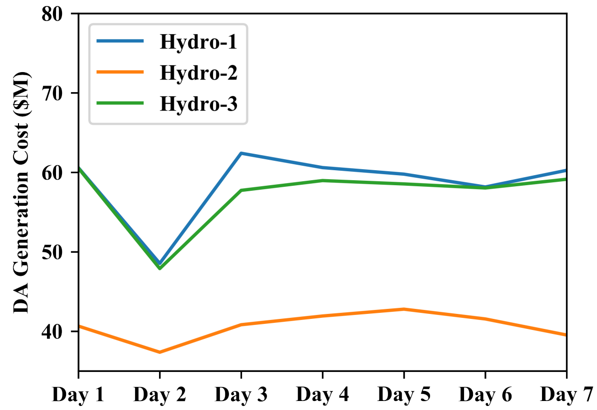
Additionally, a comparison between Hydro-1 and Hydro-3 model types reveal a difference of $9.5-$26 million across the seasonal studies. While both models consider hydrological conditions, Hydro-1 operates with non-dispatchable hydropower generation and incurs higher system generation costs compared to Hydro-3, which is dispatchable and is scheduled instead to provide ancillary services such as primary frequency response. This is due to the Hydro-1 model not being able to curtail to better meet system needs. Therefore, the ability to reduce hydropower generation (perhaps to meet ancillary services) in the power system model can be financially beneficial.

The way in which day-ahead PFR reserves are held are also impacted by hydrological conditions. For example, the weekly PFR schedule deviates slightly based on the hydropower model type used. The weekly summer PFR reserve is almost entirely met by steam and gas turbines or by ESS (PSH) units (87%-94% across all cases), but nuclear, hydropower, solar, and wind units can also provide reserves in this model. However, in each of the hydropower model cases, there is a slight difference in how hydropower is used for reserves capabilities. In the uninformed Hydro-2 case, more hydropower is held in reserves with a contribution of 6.6% of the PFR requirement. However, in the hydrological condition-informed Hydro-1 case, no hydropower generation is held for PFR since this model forces hydropower units to be non-dispatchable. In the dispatchable Hydro-3 case, hydropower generation is downward dispatched to be held in reserve for PFR (5.3% of the requirement), but not as much as the Hydro-2 case. This downward dispatch of hydropower generation allows for more wind to be used in the day-ahead operation.

Similar to the summer PFR schedule, the way in which hydropower generation is held in reserve



(a) Summer



(b) Winter

Figure 10: Weekly total day-ahead operational generation costs for (a) summer, and (b) winter seasons. Generation costs are underestimated in the Hydro-2 case where hydrological conditions are not considered in the model.

for PFR is slightly impacted by the hydropower model type used for the winter case. However, the changes in the reserve schedule compared to the summer case are more minimal due to the reduction in water availability in the winter and thus, hydropower generation. Again, steam/gas and PSH generators make up the majority of PFR reserves (77%-86% across all cases) and Hydro-1 provides no PFR reserves due to its non-dispatchable nature. Similar results to the summer case occur for the Hydro-2 case with a 6.6% share of the reserve requirement. However, as expected, a smaller contribution (2.4%) from hydropower occurs in the Hydro-3 case in comparison to the summer case.

While the Hydro-2 model case utilizes more hydropower capacity for providing PFR, it carries the potential to mislead system operators in terms of available units to provide PFR in times of need. In contrast, the Hydro-1 and Hydro-3 models accurately incorporate hydrological conditions into the DAUC scheduling model, enabling the reliable prediction of hydropower's capability to provide energy and ancillary services in real-time.

4 Conclusion

Current power system models often neglect hydrological conditions, which might lead to unrealistic expectations when relying on hydropower for energy and ancillary services. We conducted a comparative examination of a reduced 240-bus Western Interconnect model within the MIDAS framework. Numerical results show that power system operations without knowledge of hydrological information led to significantly different unit commitment results compared to models with hydrological information. In addition, day-ahead generation costs are underestimated in cases without hydrological data considered. Further, real-time prices could presumably be much higher as the expected hydropower would most likely be made up by the most expensive generators. Finally, primary frequency response reserves are slightly impacted by the overestimation of hydropower capabilities in the case without hydrological information. Therefore, it is exceedingly important to include hydrological condition information in power system models, especially as hydropower is increasingly relied upon as a clean resource to balance generation and demand as more variable renewable resources are added to the grid.

We note that many power system operators use the PSS/E power simulation software [21] and full WI system models to schedule day-ahead and real-time unit commitment and economic dispatch. However, leveraging the MIDAS tool and the reduced 240-bus reduced WI model serves as a good indicator of the steady-state and dynamic power flow results. Therefore, this work serves as a proof-of-concept of power system impacts when hydrological data are included in operational studies. In future work, PSS/E, along with modifications to its existing hydropower models, will be used to study the impact of hydropower generators with knowledge of current hydraulic head conditions at a greater level of detail. In addition, as most operators are aware of drought conditions in the West, the case with no additional hydropower constraints beyond nominal capabilities is slightly unrealistic as power system operators likely use daily, weekly, or monthly hydropower energy targets to account for external hydropower limitations. Modeling these energy target constraints can improve future work, however this study shows a worst-case scenario where hydrological conditions are not considered.

An additional next phase of our study will investigate the dynamic frequency response of hydropower models with and without knowledge of hydrological conditions. An advantage of MIDAS is that it has a one-to-one matching of the scheduling and dynamic models and can be run in a closed-loop simulation. This ongoing research seeks to enhance our understanding of hydropower dynamics and its pivotal role in optimizing grid performance while accommodating a growing renewable energy portfolio. Another interesting avenue of research is studying the impact of considering hydrological input conditions for hydroelectric plants on grids with high levels (up to 100%) of renewable-based generation.

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