Hydropower Modeling Gaps in Planning and Operational Studies

November 2022

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Industry engagement report – Internal memo from results of industry engagement and literature research at the end of Q1 (Objective 1)

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Context: HydroWIRES

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

The U.S. electricity system is rapidly evolving, bringing both opportunities and challenges for the hydropower sector. While increasing deployment of variable renewables such as wind and solar have enabled low-cost, clean energy in many regions in the United States, it also creates a need for resources that can store energy or quickly change their operations to ensure a reliable and resilient grid. Hydropower (including PSH) is not only a supplier of bulk, low-cost, renewable energy, but also a source of large-scale flexibility and a force multiplier for other renewable power-generation sources. Realizing this potential requires innovation in several areas: incorporating new operations into planning and licensing decisions; predicting new operations and management patterns and costs to prevent unplanned outages; and designing new turbines and control systems for fast response and frequent ramping while maintaining high efficiency.

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

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

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

Executive Summary

More renewables are being integrated into the grid, replacing and displacing traditional resources. Retirement of traditional generation resources include coal, nuclear, and even natural gas power plants. Consequently, more reliance will be placed on hydro-based generation to provide ancillary services as well as baseload generation that would replace solar and wind when there is no sun or wind available.

Because hydropower generation is a clean energy resource, provides substantial amounts of inertia and primary frequency response, and can easily ramp up or down, the role of hydro in the future will be more important for maintaining integrity of the power system. As system inertia and governor response are decreasing due to retirement of conventional generation sources, hydro generation is becoming more stretched. In general, more flexibility in control of power systems is needed due to the volatile effects of renewable resources, notably solar and wind.

Modeling of hydro generation in power system software has not changed greatly over the decades and, as the role of hydro generation is changing, new expected modes of operation will push the boundary of existing models. In that context, it is timely to examine gaps in modeling of hydro-based generation in steady-state and dynamic simulation studies as represented in power system simulation software.

Power system models and study software are keystones of operation and planning. Steady-state (base case[1]) and dynamic models are used to perform planning and operational system studies. Planning studies are used for evaluation of capital investment in new infrastructure and to make sure the future system will meet demand and stay reliable, while operation studies are used to estimate system operation limits. To operate the power system safely and economically, operation points are kept within precalculated limits. If models of the power system and individual components are not accurate then study results will not be accurate, adversely affecting reliability and economy of power system operation.

Hydro-based generation representation in the software and models used for operation and planning studies accounts for nominal water availability only, which leads to inaccurate results depending on water conditions in watersheds. Moreover, environmental constraints such as maximum and minimum headwater elevation, minimum instantaneous and average flows, and others are not represented in power system models. The following examples illustrate consequences.

Water surplus during spring melt in the Columbia Basin sometimes requires curtailment of wind generation. During high-water-flow conditions, the usual practice is to let water pass through turbines and generate as much electricity as possible. The turbine intake is below the water surface, so the water passed through the turbines does not come into the contact with air. If the water is spilled through the spillways, the spilled water comes into the contact with air and saturates with nitrogen. Too much nitrogen in the water kills endangered fish. There are legal limits in the amount of nitrogen in the water set by the northwest states. During such extreme conditions, grid operators cannot reduce hydrogeneration to allow an increase in wind power in the system. This can result in occasional curtailment of wind generation. Such seasonal impact of the water conditions is not captured in the planning model where hydro is assumed to have average generation conditions. Coupled with light loading conditions, such

[1] A base case is a bus-branch steady-state model of the interconnection used for system operation and planning studies. The Western Interconnect (WI) base case is assembled by the Western Electricity Coordinating Council (WECC) System Review Subcommittee and staff from data submittals of planning coordinators. Eleven base cases are assembled annually representing different study timeframes (e.g., long-term planning, seasonal operational for the next year such as heavy winter and hot summer cases). Once assembled, base cases are sent back to the subcommittee for their review and approval.

water misrepresentation can lead to inaccurate short- and long-term system studies such as erroneous transmission flow estimation and inaccurate system response to contingencies, which can lead to inadequate operator decisions.

Low-water conditions present different challenges. For example, Hyatt Power Plant stopped power production this summer due to record low-water conditions in Oroville Lake, the second largest reservoir in California.[2] The six turbines were taken offline because water levels dropped below the minimum required for power generation.[3] Similarly, Colorado River hydro projects have decreased capacity due to low-water conditions. This power needs to be replaced from other sources, changing how power flows through the system, stressing the system differently, and reacting to contingency differently than planned since water availability was assumed. These examples indicates that the power system should be planned for low- and high-water conditions, not just for nominal water conditions. For this reason, we need to bring water data into the power system models (steady-state and dynamic) and plan the system properly. It becomes even more important with increased renewable integration and retirement of conventional generation since hydropower will carry most of the responsibilities for regulation, system inertia, and frequency response.

Moreover, as many hydro-based generation models were developed in the early 1970s, it is time to evaluate their suitability for use in modern power system studies. So far, hydro-based generation modeling was not a problem due to abundance and diversity of other resources that were able to provide regulation and ancillary services. This will definitely change in the future and modeling deficiencies will have more impact on the accuracy of system studies and infrastructure investments as more conventional resources are retired.

The objectives of this project were identification and evaluation of modeling gaps for existing and new hydropower replacements/installations. In the evaluation we heavily relied on interaction with industry consisting of one-on-one interviews, workshops with industry members, and direct engagement with the Western Electricity Coordinating Council (WECC) Model Validation Working Group and System Review Working Group. Our focus was on the Western Interconnection (WI) as it has the highest exposure to hydro-based generation. During this effort we have been privileged to talk to subject matter experts from regulatory agencies,[4] transmission system operators and balancing authorities,[5] Department of Energy agencies that operate hydro projects,[6] power system software vendors,[7] independent consultants, and the Northwest Power Pool. We also reached out to WECC subcommittees that encompassed overall industry within the WI Modeling Validation Subcommittee (MVS), which is responsible for development and validation of dynamic models, and the System Review Subcommittee responsible for development of base cases used by WI utilities to perform operation and planning studies. Finally, we organized workshops and webinars in collaboration with WECC and the MVS. The outcome of interaction with industry experts was to identify and prioritize hydro modeling gaps and provide recommendations on how to mitigate identified gaps.

As a takeaway, the following gaps have been identified in order of priority:

1. **Water availability not properly represented in system models**. Water availability is reflected through water head and available maximum generation output. Water head is the change in water levels

[2] https://www.wwdmag.com/one-water/california-shuts-down-major-hydroelectric-plant-due-low-water-levels-lake-oroville

[3] https://www.cnbc.com/2021/08/06/california-shuts-down-major-hydroelectric-plant-amid-severe-drought.html

[4] North American Electric Reliability Corporation and WECC

[5] California Independent System Operator, Bonneville Power Administration, Idaho Power Company, Salt River Project, BC-Hydro

[6] U.S. Bureau of Reclamation, U.S. Army Corps of Engineer

[7] Powertech, GE Consulting, PowerWorld

between the hydro intake and the hydro discharge point. Power output of each hydro generator is proportional to the value of water head. In our steady-state models, it is assumed that the generator can provide nominal output, which is not always the case. Water levels vary annually and with seasons. Consequently, hydro generators' available capacity needs to be adjusted to reflect water availability; overestimation leads to optimistic results. To resolve this gap, software needs to be able to impose desired water levels from a historical database on steady-state and dynamic models used for system studies. That way operation and planning engineers would be able to impose the desired water condition and study the effects they might have on the power system, allowing more accurate planning and operation studies.

2. **Interdependences among hydro projects and environmental constraints are not properly represented in system models.** These interdependencies include how water can be shifted from project to project and the many environmental constraints reflected in requirements to maintain maximum and minimum elevation levels and ensure tailwater and forebay rate-of-change levels are kept within specified ranges. In our base cases (steady-state model) these interdependencies and regulations are not modeled, so generation is often dispatched unrealistically. Unrealistic generation dispatch in operation and planning studies can affect calculation of system operation limits and lead to unrealistic power-flow patterns. Consequently, this can also affect congestion and contingency reserve deployment. Interdependencies and environmental constraints should be converted into mathematical rules and implemented in commercial software used for system studies as constraints so that software can impose them during the solution process.
3. **Rough zones are not represented in the power system model so generation dispatch in system studies might not be realistic.** Rough zones are consequences of turbine design and fluid dynamics. Operation of hydro turbines within rough zones can lead to violent oscillations that can be up to 5% in magnitude of generation megawatt output. In general, the generator operator tends to avoid operation in rough zones since it increases wear and tear and can lead to damage of the turbine-generator set. These oscillations can excite interarea modes of oscillations if frequency of both coincide. Rough zones are not modeled in system studies so simulation results can keep hydro generators operating in rough zones. This is especially true in cases with large renewable penetration, when a lot of regulation and generation movement is required. Our dynamic models cannot reproduce rough zone behavior and modeling of rough zones is out of scope of the typical power simulation software. New fields representing rough zones should be added in generator tables in software used for power system studies. Rough zones should be flagged in software as "forbidden zones" so that hydro units are not dispatched in these zones. Data about rough zones should be provided through a regular data submittal process.
4. **Many dynamic models of hydro generation turbines are outdated.** These models were developed in late the 1960s and early 1970s. Water head cannot be changed in some dynamic models and there is dependency among parameters of dynamic models when head changes. Model parameters are evaluated during generation testing and are accurate for specific test conditions, but when water levels change they should be adjusted. Consequently, frequency response of the system is very optimistic. Dynamic models of hydro-based generation should be reviewed, outdated models retired, and new models recommended and developed.
5. **Inaccuracy in Frequency response during simulation studies.** There are multiple reasons why frequency response in simulation studies is usually optimistic. One reason is water head as it was explained previously. Another reason is discrepancies between data in models and field settings. This is especially the case for deadbands and droops. Typical droops in dynamic models are set at 5%, but in the field it might be set differently (more than 5% so the unit is less responsive). A further reason is in secondary control that is not present in dynamic models. Secondary control will quickly return the generator to predisturbance output canceling governor response. In order to improve frequency response, generator owners should provide an update on settings when changed (droop and deadbands).

Generators having secondary control that return output to a pre-contingency state should be marked so their governors can be blocked in the simulation studies and the water head value adjusted.

6. **Data issues and incorrect parameters values in dynamic models.** In general, the quality of model parameters should be improved. For example, although turbine-governor models have provision to include power output and gate opening curve data (which can only be obtained from field testing), it is usually not provided by the generator owners during the data submittal process. Also, field tests are run and modified parameters submitted to the base case model, which is an expensive process and done every 5–10 years, so parameters are typically not changing during this time period. Dynamic models are complex, containing many parameters that are estimated based on field tests. These parameters are entered into the dynamic-mode database manually and there is always possibility of errors. This issue is not limited to hydro-based generation models. Model data issues can cause oscillations or unusual results in simulation studies. Tools that point out erroneous data can be developed.

7. **Advanced pumped storage models are not widely available.** As it is anticipated there will be more variable speed pumped storage, it would be desirable to have a dedicated dynamic model of pumped storage hydropower (PSH). Currently, PSH is modeled as a generator with a disabled governor model and pump mode is modeled as a motor load that is not adequate since this model does not contain hydrological characteristics. As there is currently no advanced PSH (variable speed) it would be difficult to validate the model as the accuracy of the models is tested against measurements obtained during system disturbances Recently, an Advanced PSH model has been developed by GE Consulting that can be used in system planning studies. However, to validate the model an Advanced PSH plant must exist since in model validation process, we compare system actual response during disturbances to simulation. Currently, in the USA, only conventional PSH projects exist so this is not an emergent issue.

Finally, the power system is not planned for various water availability such as high- and low-water conditions in combination with a large amount of renewable generation. The power system is planned to withstand heavy and light loading conditions, which are reflected in the power system interconnection model used for system studies. These models are known as base cases and typically reflect heavy summer or winter loading conditions as power-flow patterns are different in summer and winter and can vary significantly with year. Different power-flow patterns stress the system differently in pre-contingent and post-contingent states. However, base cases are developed with the assumption that water is readily available, which might not be the case. Similar to planning for different load levels, if hydro is a significant part of the overall generation fleet, the power system should be planned for different water level availabilities. Lack or surplus of water also results in different power-flow patterns through the system. It is obvious that drought conditions result in lower hydro generation production. Addressing above-mentioned modeling gaps will allow for better planning and operation of power system.

Based on discussions with industry, the urgent need for large-scale system studies is not perfection of individual models, but rather getting ambient conditions and environmental constraints into the databases so water availability can be accurately represented. Ambient conditions should be represented as a separate database at the same level as ambient conditions are currently used for composite load model development. Composite load model is generated based on climate zone, date, hour, and temperature and separate file is developed for each hour, taking into the account fact that load composition is changing in time. Similar to climate zones where date and hour are used, season and geographical conditions in different water basins should be used for water availability estimates. Data should describe parameters that do not change, such as geography, set of controls, and hydraulic time constant, then hydraulic conditions such as water head should be represented as a separate part of the database (new data tables for more descriptions of ambient operating conditions). That way, if needed, it would be possible to specify season, month, day, and hour to have reasonable estimates of what generation capacity is available and make system studies more accurate, increasing reliability of the system. In order to address these needs, the following set of recommendations have been developed:

1. Collect data for different hydro basins (Columbia, Colorado, etc.) for different seasons and different years and develop a water database. This will establish seasonal water profiles for different water basins and different water conditions (seasonal profiles for dry years, wet years, average years). That will be a starting point to address water availability and use the new database to impose water conditions on steady-state and dynamic models.
2. Develop a tool to modify the base case based on desired water profiles so that large-scale planning and operation system studies can be performed for low- and high-water conditions. A tool needs to impose a desired water profile in the base case per water basin and hydro project, and limit maximum generation output based on water availability. This would address water availability in steady-state cases (power flow).
3. Develop a tool to automatically adjust parameters of water head and corresponding dependent parameters in dynamic models per generator, plant, and water basin after power-flow water conditions are imposed. We need to establish interdependency relationships among dynamic model parameters that change with fluctuations in water head. This would address water availability in dynamic models and most of the optimistic frequency response.
4. Collect rules on how water can be shifted from project to project. Also collect environmental and other rules that are honored through water management. This will allow us to develop a tool that can implement coupling among plants and impose restrictions on generation dispatch in the system based on observed constraints. It includes the ability to flag nonoperating ranges and rough zones in base cases so engineers performing studies are aware of restrictions on dispatching generators within rough zones. This would address interdependencies, rough zones, and environmental constraints that are currently not modeled.
5. Review dynamic models used for hydro representation and provide recommendations. Many old models do not allow changing the value of water head.

To conduct accurate planning and operation studies, and ensure the grid operates reliably, it is vital to model hydro generation with more accuracy, particularly in regard to water availability. The intent is for steady-state and time-domain simulation of the system to match reality as closely as possible and avoid unrealistic expectations from hydro-based generation. Following these recommendations will result in more realistic and better-quality large-scale system planning and operational studies and, consequently, improve reliability and resiliency of the power system.

Acronyms and Abbreviations

BPA	Bonneville Power Administration
CAISO	California Independent System Operator
COI	California-Oregon Intertie
DOE	U.S. Department of Energy
FERC	Federal Energy Regulatory Commission
FFRDC	Federal Funded Research and Development Centers
IBR	inverter-based resources
LSP	light summer planning
MVS	Modeling Validation Subcommittee
NERC	North American Electric Reliability Corporation
PCM	Production Cost Model
PDCI	Pacific DC Intertie
PMU	phasor measurement unit
PNNL	Pacific Northwest National Laboratory
PSH	pumped storage hydropower
PSLF	Positive Sequence Load Flow
PSS	power system stabilizer
PSS/E	Power System Simulator for Engineering
PV	photovoltaics
RAS	Remedial Action Scheme
RoCoF	rate of change of frequency
SCADA	supervisory control and data acquisition
SRS	System Review Subcommittee
WECC	Western Electricity Coordinating Council
WI	Western Interconnection

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1 Introduction

A continuous increase in penetration of renewables and retirement of traditional coal-fired and nuclear generators imposes a larger burden on natural gas and hydro resources, which need to provide regulation and load following. As natural gas is supplied through a few major pipelines, risk of interruption is credible. Such examples include the Aliso Canyon gas leak in 2015 and the SoCalGas pipeline explosion in October 2017, both of which led to interruption in gas supply for generation of electricity. These effects were most dramatic during a summer heat wave. Southern California Edison electric utility incurred $850 million in unexpected costs, which it is now passing to its customers. A cold snap in February 2019 caused energy prices to jump once again and forced some electric power plants to shut down on a handful of days to conserve gas supplies for home heating. Gas generation is also decreasing, which places more requirements on hydro-based resources. While thermal and nuclear plants are slowly being displaced and decommissioned, hydro resources are becoming more stretched. As the power system continues to integrate variable resources, it becomes more important to accurately assess the role of hydropower and its impact on the power grid.

While hydro generation has been studied for decades, dependency of power generation and water availability, and constraints in hydro operation, are not well illustrated in planning and operation tools. There are still multiple modeling gaps that need to be addressed; if not, they can lead to unintentional load shedding or even blackouts. These modeling gaps can result in overestimation of hydro ability and water availability. A good example was the gas compressor outage at Jackson, Oregon, in winter 2019. The outage and loss of most gas projects that were supplied by this storage facility caused a significant shift from winter gas generation to hydro generation.

While the power system is planned to operate in N-1 and credible N-2 contingencies, outages of natural gas infrastructure are not considered. As water availability is not properly represented in power system models, it is difficult to predict the effect of such shifts from one resource to another. Similar situations can be expected in the future with large renewable penetration when shifts from solar and wind to hydro generation occur. Interdependences among projects are not accurately represented in the base-case[1] used for systems studies. Consequently, studies allow unrealistic generation dispatch and exaggerated capability. Generation availability is not normally derated in steady-state and dynamic models used for system studies, and models do not reflect water availability and capacity. Another issue is that most dynamic models of hydro-based generation were developed in the 1960s and 1970s and need to be updated.

In this document we illustrate some of the gaps that need to be addressed. These gaps were identified through numerous discussions with industry partners and from personal experience.

[1] Base-case consists of steady state model of interconnection representing specific loading conditions and corresponding dynamic model

2 Hydropower Modeling Challenges

Hydropower provides relatively low-marginal costs and clean electricity used across the world. As variable generation sources such as wind and solar penetration increase into the grid and older thermal plants are slowly retiring, it is critically important to reevaluate the modeling of existing resources as the operational paradigm changes to maintain system reliability. Significant work has been done in the past to represent the steady-state and dynamic behaviors of hydropower plants in the electric grid. In this section, we will explore the existing research in hydro generator model development and highlight the various gaps observed. In (Tiffany Choi, 2011) and (SCC, 2017), several risk factors of hydropower generation were identified that affect the ability of hydro facilities to produce the electricity they need at the right time. Some of the key factors include weather variability and extreme weather events, shifts in hydropower generation patterns, and effects from the evolving power industry and growing renewable resource use.

The hydro generator governor model issues identified in the literature and from industrial experience are:

1. Water availability not properly represented in system models:
   a. Over/underestimation of water availability in steady-state models that leads to over/ underestimation of available generation capacity
   b. Static water head values that are not adjusted to represent current water availability in dynamic models.
2. Interdependences among hydro projects and environmental constraints not represented in system models.
3. Rough zones are not represented so generation dispatch in system studies might not be realistic.
4. Problems with data and incorrect parameters values in dynamic models.
5. Inaccuracy in frequency response during simulation studies due to:
   a. Governor dead band not modeled properly
   b. Secondary control loops not modeled
   c. Incorrect droop characteristics
   d. Frequency trip settings.
6. Many dynamic models of hydro generation turbines are outdated:
   a. Water head cannot be adjusted
   b. Water-hammer effect and water inertia are not represented in older models that are still in use.
7. Advanced pumped storage hydropower (PSH) model not widely available.

2.1 Water Availability Impact on Maximum Power Output

Water level and availability depend on a number of factors such as season, amount of precipitation, snowpack, and temperature. Typically, lowest water availability is during winter months when reservoirs are prepared for spring runoff. Modeling hydropower constraints accurately requires accounting for the wide variety of requirements for water flow, reservoir characteristics, and other hydrological conditions and variables. (Brady Stoll, 2017) reviewed many of the constraints facing hydropower facilities and the challenges of accurately modeling these constraints and found there are several ways hydropower can be more accurately modeled. These include collecting more precise and granular data, improving the representation of constraints within production cost models and capacity expansion models, and linking with watershed models to comprehensively account for all constraints associated with power and water systems.

Hydrogeneration output directly depends on the value of water head. Head is the change in water levels between intake and hydro discharge point. The turbine mechanical power P_m is proportional to the product pressure and flow. Figure 1 illustrates the schematic of a hydro plant.

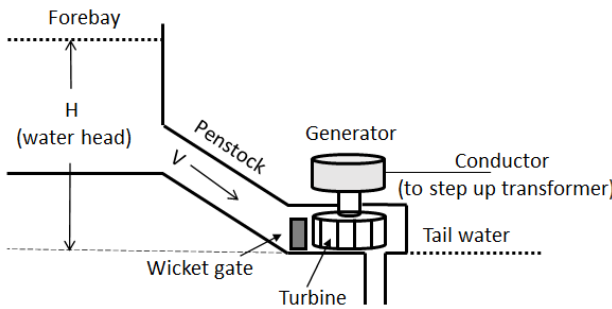


Figure 1. Water pressure depends on water head.

The mechanical output of a hydro turbine is given by

$$P_m = K_p H V \tag{1}$$

Where V is velocity of the water
H is hydraulic head at the gate
K_p, K_u are constants of proportionality

The water flow is given by

$$V = K_u G H^{\frac{1}{2}} \tag{2}$$

Where GH is G-gate position.

Consequently, turbine mechanical output is proportional to the 1.5 power of hydraulic head:

$$P_m = K_p H V = K_p H K_u G H^{\frac{1}{2}} = kGH^{\frac{3}{2}} \tag{3}$$

From the above equations, the more water head available, the higher water pressure across the turbine will be, thus more power can be generated. Lower water level in reservoirs results in less available generation capacity. In our power-flow models, also known as base cases, the same head value is used for all seasons, which is not correct since head value should change with water levels in the reservoir. Power system studies (planning and operation) are performed using base cases. The maximum power P_{MAX} (that is equal to turbine mechanical output Pm minus rotational losses) in power-flow studies have historically been treated as a constant value (nominal head) in both operational and planning studies. P_{MAX} is directly proportional to water level H as shown in equation (3), however water availability is not considered, and the assumption is that hydro generation can produce maximum power which is not correct.

Head value in dynamic models should change, but instead stays as it was during generation testing and in the model for the next 5–10 years. Modifications are needed, otherwise this leads to a combination of optimistic and pessimistic results, depending on what and when is studied. Lower water levels mean lower

P_{MAX} and less governor response, while higher water levels mean higher P_{MAX} and better governor response. Figure 2 illustrates governor response and droop characteristics. In low-water conditions, generator maximum nameplate output P_{MAX} cannot be reached due to a decrease in waterhead based on equation (3). It is obvious from Figure 2 that if available power (due to water head) is smaller than maximum power $P_{available} < P_{MAX}$, governor response might be affected, where $P_{available}$ is the new maximum generation output given by equation (2) and depends on available water head.

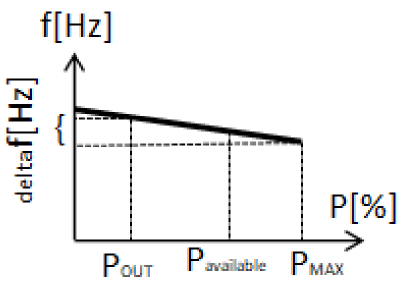


Figure 2. Droop characteristic of generator.

If the frequency changes by delta**f**, then based on the droop setting, the generator will increase intake by opening the wicket gate more to let more water in the turbine. If for the given frequency disturbance, the generator was supposed to increase output to P_{MAX}, and if there is not enough water head, then the generator output will increase only to $P_{available}$, which is lower than P_{MAX}, affecting frequency response. Some operation modes would ignore frequency response:

- Base loaded with gates wide open
- Controlling something other than frequency, e.g., water flow
- Load control mode so frequency control is overridden and returned to predisturbance MW output, then L_{dref} is used as a reference signal and unit output will be limited by reference signal.

To improve turbine-governor modeling accuracy, L_{dref} and H_{dam} or H_0 (depending on annotation in different governor models) in dynamic models should be adjusted. There are other modeling parameters that are dependent on head value. Planning studies use nominal head that could lead to overrepresentation of turbine-governor response to system frequency events. In the power-flow model, P_{max} should be derated based on what water level is available. P_{max} is used in advanced applications such as state estimator, real-time contingency analysis, real-time voltage stability, and real-time transient stability. If forecasted P_{max} data values are available, they could be added to operational studies. Seasonal P_{max} data adjustment could also be implemented in planning studies.

To show the sensitivity of accurate representation of water head in time-domain simulations, a simple two-machine infinite bus test case is used as seen in Figure 3. A gas turbine is tripped and the response of the hydro generator is observed for changing head value in the HYGOV4 governor dynamic model (Figure 4). The sensitivity results show that 5–10% variation in head value can significantly affect the dynamic response (and frequency recovery) of the resource.

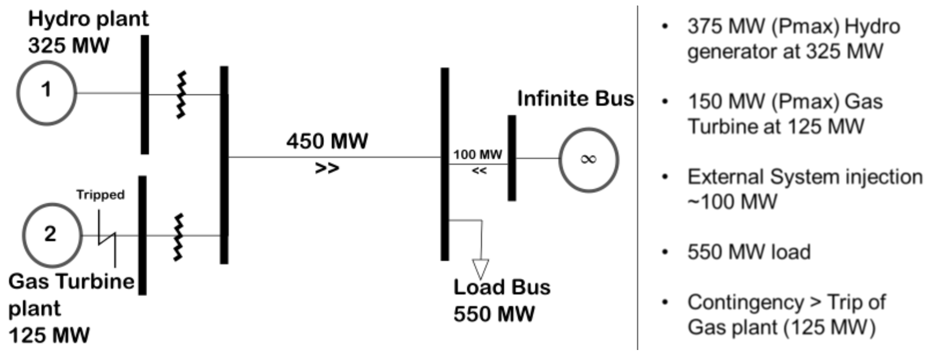


Figure 3. Test case for the hydro dynamic model.

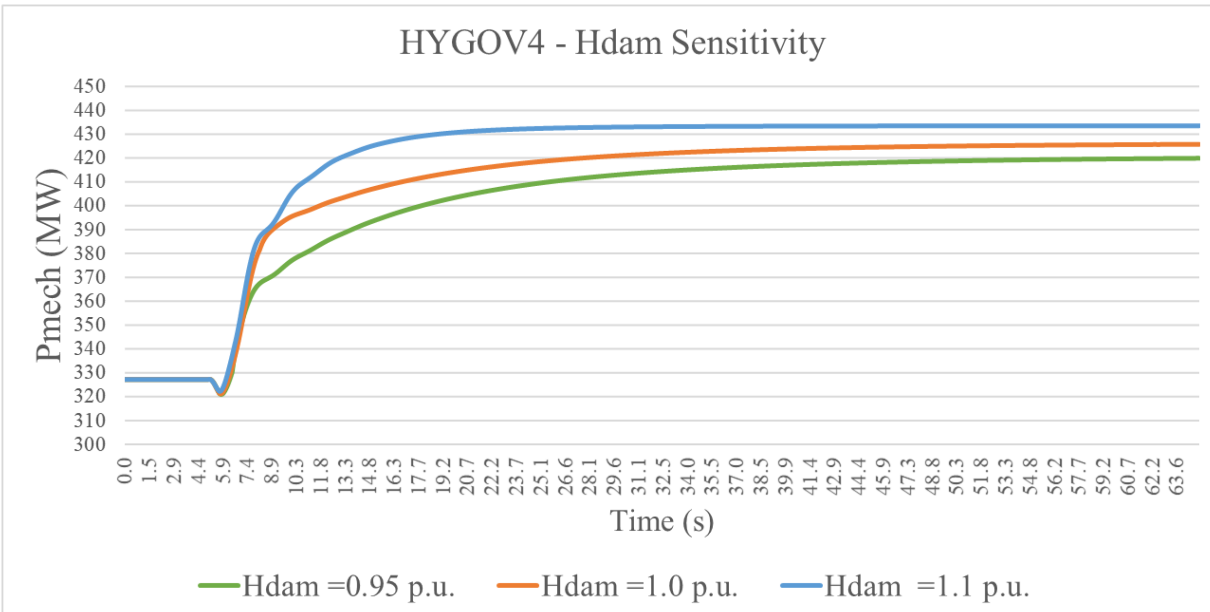


Figure 4. Mechanical power generated based on different water head levels (0.95 per unit to 1.10 per unit of nominal head level) in the HYGOV4 model for a hydropower plant in the Western Interconnection (WI).

2.2 Interdependencies

Different water basins would have different interdependences. The Columbia River watershed provides more than 40% of the total U.S. hydro generation. The Columbia River is highly regulated due to flood protection, transport needs, and regulations. Hydro projects are owned and operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation. Management of hydro projects is very complex and subject to many constraints based on the Endangered Species Act (which requires flow to support fish migration and spawning) and the Clean Water Act (which imposes minimum generation conditions).

Power production is generally of lower priority for the federal system of dams. Hydro system operators are required to maintain maximum and minimum elevation levels and to ensure that tailwater and forebay rate-of-change levels are kept within specified ranges for mid-Columbia and lower Columbia projects. Water propagation needs to be taken into account to maintain the ratio between plants; for example, three sequential plants on the Snake River—Hells Canyon, Oxbow, and Brownlee—at 450:220:750 MW so that if Brownlee was operated at half capacity, then Oxbow would be capped at 110 MW and Hells Canyon at

225 MW to maintain Brownlee ~375 MW. Note there are reservoirs at Brownlee and Oxbow that provide some additional flexibility. Figure 5 shows the ratio of output for Hells Canyon, Oxbow, and Brownlee in the 2018 Western Electricity Coordinating Council (WECC) planning cases for various seasons.

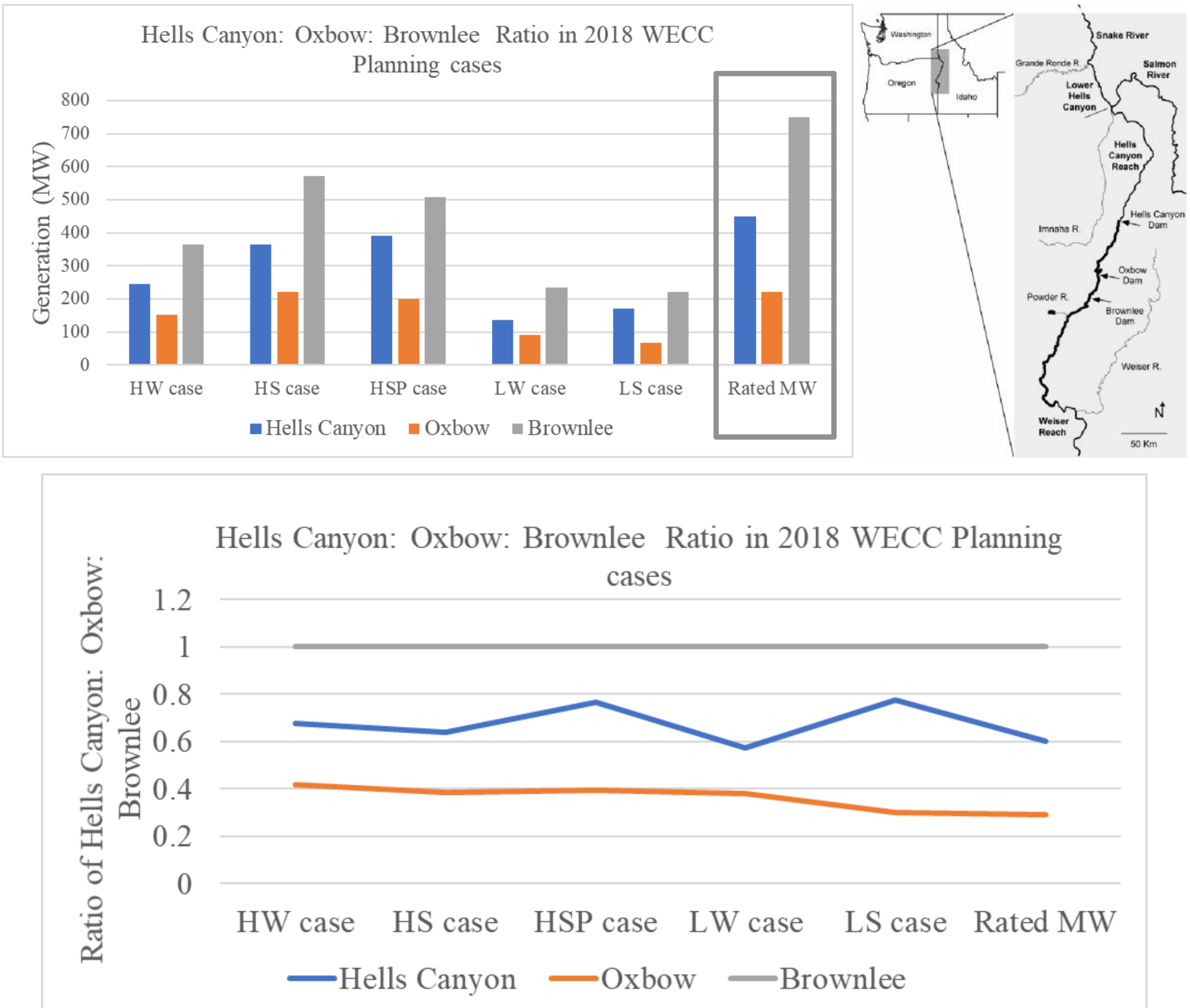


Figure 5. Hells Canyon, Oxbow, and Brownlee ratio in 2018 WECC planning cases: Heavy Winter (HW), Heavy Summer (HS), Heavy Spring (HSP), Light Winter (LW) and Light Summer (LS). Default case refers to the nominal rated generation ratio Hells Canyon: Oxbow: Brownlee: 450:220:750 MW.

For the Columbia River these constraints are even more rigid since, after the Grand Coulee Dam, all mid-Columbia and lower Columbia plants are run-of-the-river projects. The Columbia River Base System Projects in Figure 6 shows the interdependent nature of the various hydropower project systems.

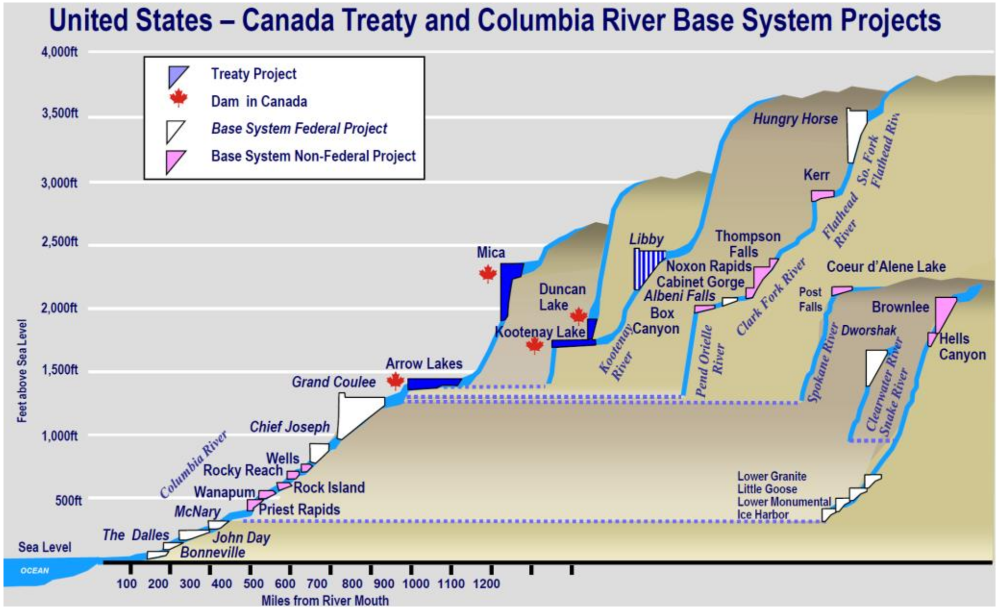


Figure 6. Columbia River Base System Projects and interdependencies.[2]

There are similar interdependences for other water basins (Colorado River and California). Most of the time power production as a byproduct of water management. For example, hydro in Northern California is often not dispatchable because of

- irrigation and other water restraints
- design of the dam (spill gate design limitations)
- water reduction
- during hydro runoff period in spring, hydro takes precedence over everything else.

All these constraints are not modeled in base cases (power flow) so hydro generation can be dispatched unrealistically. Environmental constrains that affect dispatch and water propagation need to be taken into account. Dependent generation like reregulation dams should be coupled in software but are not.

2.3 Rough Zones

Another aspect of hydro turbine modeling that affects power system simulation performance is forced oscillations. (Venkatasubramanian, 2016) discusses an event in the western American power system when a forced oscillation was observed at a frequency close to a well-known 0.38 Hz interarea electromechanical mode frequency. The oscillation was caused by a hydro plant operating in rough zone. In (H. Zhang, 2019), the authors present a framework of online oscillation monitoring systems, and forced oscillation detection and source location tools that peak reliability used. The tools discussed in the work helped to identify a hydro unit that could potentially excite the interarea mode of oscillations. These forced oscillations remain undetected in the generic power system studies since current dynamic models in simulation software cannot model such behavior. Such oscillations can result in extreme turbulence and cavitation leading to severe mechanical damages.

[2] Scott Winner, BPA, "Winter Operations: A Hydro System Perspective"

Generation operators are familiar with rough zones; however, software tools used in operation and planning do not have any information on rough zones for specific generators. A consequence of operating in rough zones can be forced oscillation as shown in Figure 7, which illustrates an instance when, in the peak reliability control room, unusual oscillation was noted. As oscillation frequency coincided with a prominent interarea mode of oscillation and damping was zero, it generated alarm. By tracing to its origin, it was found that this oscillation was the consequence of a hydro unit that decreased its output to accommodate increase in wind generation and operated in the rough zone.

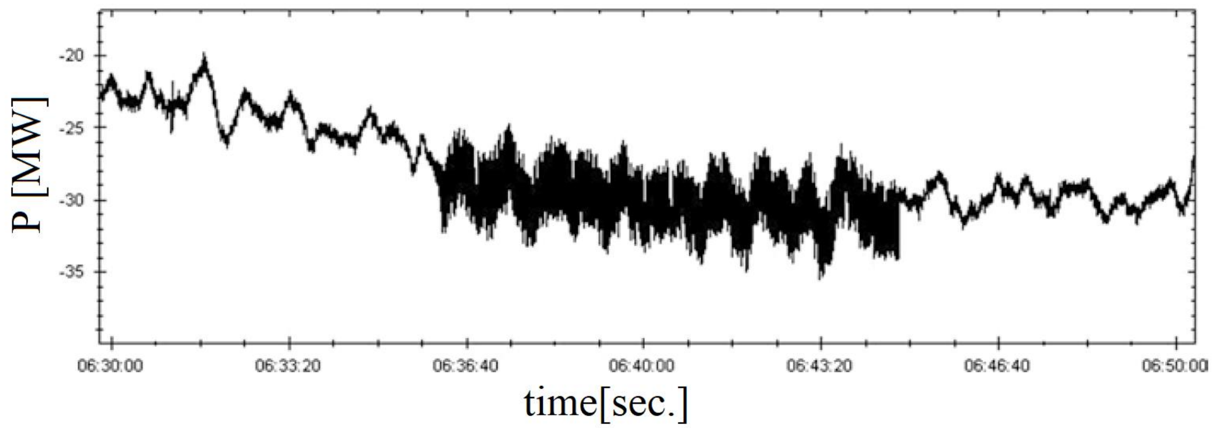


Figure 7. A 500 kV line forced oscillation caused by hydro generator operating in rough zone.[3]

In general, generator operators tend to avoid operation in rough zones, and they try to run through as fast as possible. At some plants, there are automatic controls that detect rough operation and change operating setpoints until they smooth out.

One of the more troublesome types of rough zones for both Francis and fixed-blade propeller turbines is the "vortexing" zone that can occur on some turbines (mostly Francis) when operating in the mid-gate loading region like 40–60% wicket gate opening. It is a hydraulic phenomenon that can actually cause relatively large (>5%) power swings on generator output at low frequencies (1/4 the turbine shaft speed). It is different from cavitation, which typically happens at the more extreme upper and lower loading zones on a hydro machine and can cause more structural damage to the draft tube, head cover, penstock, and other large machine structures that support the weight of the turbine and rotor. Adding lots of air to the water going into the turbine can help, but sometimes this just becomes a forbidden zone that you pass through as quickly as possible when going from one operating region to the other

The issue with rough zones is that models used in dynamic simulations cannot reproduce this effect and, if operating in a rough zone, forced oscillation can excite the interarea mode of oscillation. Another issue is that in power flow there is no knowledge of restricted zones of operation for specific hydro units so they can be dispatched inappropriately. It is expected that hydro generators will operate more frequently in rough zones due to increased need for regulation with the increase in renewable resources.

[3] Source: H. Zhang, S. Kincic and E, Sherrill, "Advanced Power Application for System Reliability Monitoring"

2.4 Data Issues and Incorrect Parameter Values in Generator Dynamic Models

In (Vladimir Koritarov, 2013), the authors present a comprehensive list of dynamic models used for existing hydro turbine-governor set including PSH. The report presents the importance of accurate modeling of hydro models as well. Optimistic models can result in unsafe operating conditions and widespread power outages, while pessimistic models and assumptions can result in overly conservative grid operation and underutilization of transmission capacity. In (Power System Dynamic Performance Committee, 2013), a review of various turbine-governor models used in power system studies were presented for various resource types and the importance of the various parameters were discussed in detail. In (Undrill, et al., 2009), the authors presented a summary of the WECC dynamic data model validation program lessons learned and recommendations following failure of simulations to reproduce events that occurred in the summer of 1996 in the WI. The paper emphasized the need of having realistic models to ensure reliable and economic power system operation.

Prior to phasor measurement units (PMUs), generator model validation was performed primarily using field tests as presented in (L. N. Hannett, 1994). However, with recent advancements in PMUs and dynamic disturbance recorders, there are more advanced methods available for model data parametrization. The Reliability Guideline (NERC, 2016) was intended to raise industry awareness and utilization of dynamic disturbance recorder/PMU and synchrophasor data for dynamic model verification of power plant models. Utilities are required to validate the model every few years using test data to make sure the representation in power system simulators is accurate. As these tests are performed at prevailing system conditions the performance of such models during different conditions may be inaccurate. Some hydro modeling gaps may arise due to improper representation of environmental and system conditions.

In (Kosterev, 2004), the author presents an approach for hydro generator model validation based on the measurements taken at the point of interconnection. Governor tests and monitoring were performed and resulted in revisions and improvements of model parameters for the hydro plants in the Pacific Northwest.

It was observed from simulation studies that several generator outputs were going above rated megawatt capacity (MWcap) during dynamic simulations. This can lead to overestimation of hydro contributions to mitigate certain contingencies. One reason is because the MWcap is not treated as the total possible output of the governor. The MWcap of the turbine, head height of the dam, and nonlinear gain points can combine to give a higher capability than the MWcap itself. This can be avoided by detecting and finetuning certain dynamic model parameters. One example is shown in Figure 8, where the turbine gain parameter A_t was not tuned correctly resulting in overestimation of the governor response from the resource.

In Figure 8, A_t is turbine gain. Turbine gain is defined as the gate opening for no load versus the gate opening for full load for water to flow through. This characteristic is changing with water head availability. Larger head equals lower gate opening to achieve full load. In the model's turbine gain, A_t is treated as a constant.

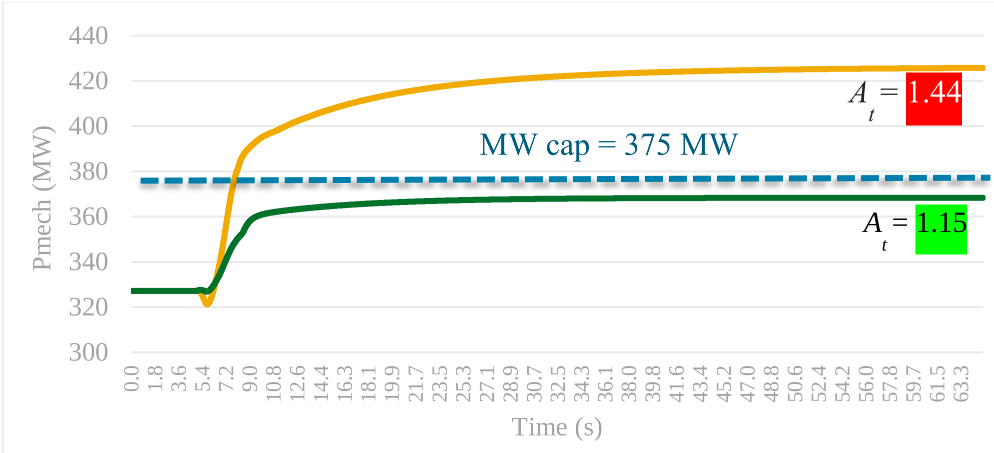


Figure 8. At sensitivity test for HYGOV4 – P_{mech}.

2.5 Inaccuracy in Frequency Response during Simulation Studies

Frequency response of an interconnected power system depends on each unit in the system that is online. Frequency response becomes more of a concern with the increase in renewable fleet and retirement of conventional generation because renewables do not provide inertia responses and are not required to carry reserve allowing for the frequency response. Frequency response includes inertia response, primary (governor), and secondary (automatic generation control) response. Some units, particularly large steam-based turbines such as used in nuclear and coal-fired plants have the governor blocked so they do not provide primary or secondary frequency response but do provide inertial response. Hydro-based generation provides a large share of sustained frequency response due to the fact it can increase generation output relatively fast as they are constant temperature devices. There are multiple factors that can affect frequency response and include time constants, deadbands, type of the generation fleet deployed at the time of disturbance, secondary control of generation units, total loading of the system during disturbance, etc. Some of the papers discuss frequency response of large systems in more detail and provide more insight. Factors affecting frequency response are analyzed in following articles.

(John Undrill, 2018) reviews factors that affect the ability of a large synchronous electric power system to control and manage its frequency. A comprehensive study of implications provides system conditions and resource mix on frequency response is presented in (Joseph H. Eto, 2018). Some of the major inference from this report include:

- *"For a given loss of generation, system inertia and the timing of primary frequency response determine how frequency is arrested."*
- *"Smaller deadbands on turbine governors increase how quickly delivery of primary frequency response will begin."*
- *"Gas turbines may not be able to sustain primary frequency response following large loss-of-generation events."*

A system performance study conducted by WECC for a Pacific DC Intertie Reliability Action Scheme Event (MVWG, 2014) showed modeling improvement was required to accurately represent frequency response behavior in system studies. Another study for California Independent System Operator (Nicholas W. Miller, 2011) for a frequency response at different system conditions including low and high hydro scenarios, concluded that California did not have any issues with frequency response. The analysis involved the existing hydro models and did not mention adjusting steady-state/dynamic model parameters based on hydrological conditions that can affect the results of such performance studies.

In (L. Pereira, 2003), the authors identified the discrepancy between gas turbine-governor response in simulations versus reality and provided a new approach for thermal governor modeling to represent actual system operations accurately. (NERC, 2019) provided a comprehensive analysis showing how turbine-governor model responses vary in simulations compared to actual measurements and analysis of some of the underlying issues of governor parameters. A key takeaway from this report was that turbine-governor deadband should be accurately represented in dynamic models. If deadband is not modeled in the dynamics for turbines, it will result in overestimation of frequency responses. In (G. Kou, 2016), a model validation procedure to study the impact of governor deadband is presented for the Eastern Interconnection.

We validate frequency response after events, usually the trip of a large generator, by simulating the event and comparing simulated frequency response to PMUs for available buses. There were multiple instances where simulated frequency response was very optimistic. Figure 9 and Figure 10 illustrate a few examples from the WI. As seen from simulation for the specific event, results were quite different compared to actual response. The frequency nadir seen in the simulation was 59.75 Hz (black trace) compared to 59.66 Hz (red trace) for the actual event. That means study results were on the optimistic side.

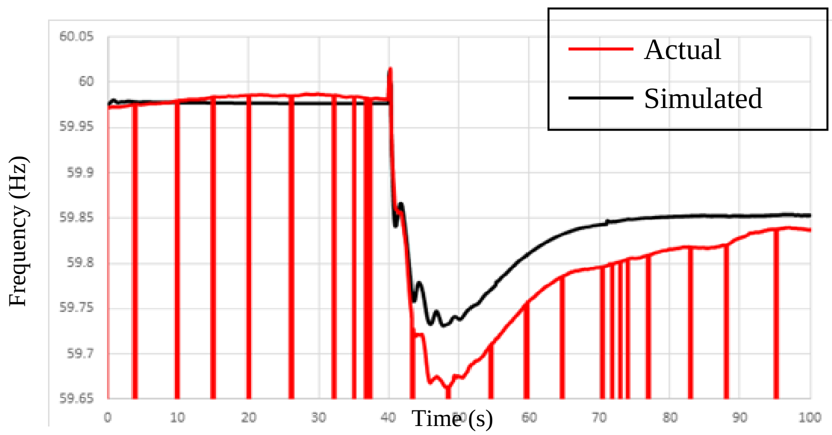


Figure 9. Example 1: Frequency response event showing overestimation of simulation results compared to actuals (the zero drops in the actual data corresponds to dropouts in PMUs).[4]

We were able to identify 168 units throughout WECC (some hydro as well) whose actual frequency response was very different from what was expected. The difference in frequency response was due to not modeling secondary control loop that would decrease generator output. More of a concern is that the governor response in models/studies may be overestimated due to plant control or area supervisory control and data acquisition (SCADA) systems that reset control to constant setpoints.

There is the possibility in any governor that deadband has been intentionally set. If so, the corresponding governor model must include this deadband as it will affect the dynamic response. If this setting is more than a small fraction of a percent, for our validation disturbances, the setting means the governor is not frequency responsive. Deadband settings can be adjusted in the plant to block unnecessary response to frequency changes to reduce the wear and tear of devices. If deadband is not correctly modeled, units respond to the frequency events in system studies but not all units respond in real operating scenario, so

[4] Source: S. Kincic, "Hydro Modeling in System Studies" (source: S. Kincic, "Hydro Modeling in System Studies" available et: https://www.wecc.org/Administrative/Kincic%20-%20Hydro%20Modeling%20in%20System%20Studies.pdf

response time in studies will be much faster than reality. But deadband data that are added correctly can be a pretty good match with reality. Similarly, if droop is not modeled, simulations will provide a better frequency response than reality resulting in overestimation.

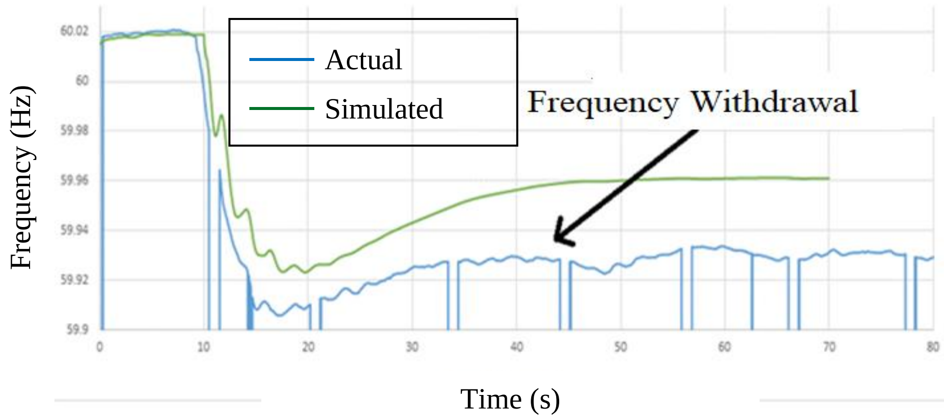


Figure 10. Example 2: Frequency response event showing overestimation of simulation compared to actuals (the zero drops in the actual data corresponds to missing measurement data). Frequency withdrawal is when secondary control loop (usually from SCADA) overrides governor response and return generator output to predisturbance output.[5]

Hydro-based generation is affected by the above-mentioned factors such as deadband settings, secondary control loops, and droop characteristics. However, hydro-based generation is not affected by temperature changes (hydro turbines are constant temperature devices) contrary to gas turbines that cannot maintain large increases over short times due to temperature stress of material. Hydro-based generation frequency response is limited by hammer effect and water–time constant and initial frequency response of hydro is opposite due to the fact that water turbine pressure initially drops when gates open more to let more water flow into the turbine. If control gains of hydro governor are set high, it can lead to sustained oscillations. As the system of the future will rely more on hydro generation for frequency response, it is important to accurately model it to make sure that available frequency response is sufficient.

2.6 Advanced Pumped Storage Hydro Models

When integrating large amounts of renewable energy into electric power systems, energy storage is one of the key solutions to maintain the instantaneous power balance. PSH is a mature energy storage technology that has attracted some attention in recent years. Especially the adjustable-speed PSH that uses a doubly fed induction machine or full-converter-based machine. This technology has become popular because the fast power response capability can provide the essential frequency support for the low-inertia and high-renewable-dominated electric power system. With that, dynamic models for PSH become important when studying their impact on large grid operation.

In the current commercial software, like Power System Simulator for Engineering (PSS/E) and Positive Sequence Load Flow (PSLF), the conventional PSH system is modeled as a hydro generator or motor to represent generating and pumping modes, respectively. For the transient dynamic study, it is reasonable to do so since the transition from generating to pumping mode can take several minutes, which is out of the scope of the transient dynamic study. Typically, a hydro generator can operate in pumping mode during

[5] Source: S. Kincic, "Hydro Modeling in System Studies" available at https://www.wecc.org/Administrative/Kincic%20-%20Hydro%20Modeling%20in%20System%20Studies.pdf

low-demand hours when it operates as a synchronous motor and draws power from the network. In this case its governor is disabled in the dynamic model. Here is a physical sequence of how a hydro generator is turned in pumping/condensing mode:

1. Generator is online at zero MW. Gate is typically 12–17% open.
2. Close the gates completely; the generator starts motoring with the turbine submerged in water. Generator is consuming a lot of MWs.
3. Blow air out of the draft tube (use air tanks with compressors), so the turbine is spinning in air. The generator will consume a few MWs associated with losses.

The unit inertia does not change. For a hydro unit, most of the inertia is in the generator rotor anyway, it has the most diameter. Generator parameters stay the same, governor model is removed, power system stabilizer (PSS) should be disabled. However, when studying the long-term dynamic impact of conventional PSH on the grid, some factors might need to be considered such as gate long-term dynamic. For example, the models in generating and pumping mode are different, and the elastic water effect in the penstock and throttling effect of wicket gate need to be modeled for pump starting and shutting down (Liang and Harley 2010). These factors have not been properly modeled in the current PSH models and are not included in the commercial software. Currently in pumping mode, we just disable the governor and PSS model assuming the gate opening is constant.

In addition, advanced PSH technologies (including adjustable and ternary pumped) become more attractive in a grid with high-renewable penetrations. Adjustable-speed PSH has fast response capability that outpaces conventional PSH and leads to fast growth in the market and installation. (Kuwabara et al. 1996), (Lautier et al. 2007), and (Muljadi et al. 2015) did studies in Japan, Europe, and North America, respectively; however, there is no mature dynamic model to represent adjustable-speed PSH in the commercial software. In the WECC planning case, type 4 generic renewable model is used to represent adjustable-speed PSH and unfortunately the generic renewable model could not capture the hydraulic dynamics of the simulation. Meanwhile, the adjustable-speed PSH machines will be much larger than those used in wind units, and thus the higher currents and voltages may require different power electronic devices.

Note that Argonne National Laboratory has developed user-defined models of adjustable and ternary PSH in PSS/E (Feltes et al. 2013). ("Modeling Ternary Pumped Storage Units," Argonne National Laboratory - Google Search, n.d.) and the National Renewable Energy Laboratory have develop related adjustable and ternary PSH user-defined models in PSLF (Dong et al. 2019). However, these models have not been fully validated and commercialized by the software company, so most users have no way to accurately model the advanced PSH for their studies.

3 Industry Outreach and Workshop Outcomes

This section presents the overview of industry outreach and workshop feedback summary. The goal of this exercise was to get feedback from industry experts on the various aspects of the hydropower modeling gaps and rate the importance of the modeling gaps for specific industry sectors. We observed some variance in the importance of the modeling gaps pertaining to a particular industry type. The industry outreach also allowed us to understand the reasoning behind some of the modeling gaps not being addressed and gaps that may become important and need addressing with the changing dynamics of the grid.

The workshop also presented a platform for various industry experts to review and discuss issues pertaining to hydro modeling gaps. At the end of the workshop, a survey was sent out to participants to rate the hydro modeling gaps and provide input on gaps that were not discussed as a part of the workshop. After careful review of the industry outreach and workshop survey results it can be concluded that water availability modeling in power systems is considered by most of the industry experts as an important gap that needs to be addressed sooner than other gaps. This section presents a detailed summary of the results of the industry outreach efforts.

3.1 Industry Outreach Overview

As a part of outreach, experts from the following industries were interviewed individually on the various aspects of the hydro modeling gaps. Table 1 provides a list of the affiliations of the experts who participated in the outreach with Pacific Northwest National Laboratory (PNNL).

Table 1. Stakeholders interviewed.

Stakeholder Name	Stakeholder Type
WECC	Regulator authority
North American Electric Reliability Corporation	Regulator authority
California Independent System Operator	Balance authority/transmission operator
Bonneville Power Administration	Balance authority/transmission operator
U.S. Bureau of Reclamation	DOE agency, hydro projects operator
U.S. Army Corps of Engineers	DOE agency, hydro projects operator
Idaho Power Company	Balance authority/transmission operator/generator and transmission owner, hydro projects operator
BC-Hydro	Balance authority/transmission operator, hydro projects operator and owner
PowerTech Lab	Software vendor
GE Consulting	Software vendor
Modeling Validation Subcommittee (MVS)[6]	WECC Technical Committee
System Review Subcommittee[7]	WECC Technical Committee

The summary of comments from industry experts are tabulated in Figure 11. It shows the perspective of the utility/planners, model developers, and vendors with respect to each of the modeling gaps. The diagram is generated by allocating a value of 1.0 based on the positive response of the interviewees for a particular

[6] The MVS reviews, recommends, develops, and validates system models used to support reliability assessments and other modeling tools that advance the mission of WECC.
[7] The SRS develops, implements, and monitors guidelines and policies for the development of interconnection-wide power flow and dynamics stability cases that support RAC's reliability assessments and WECC members' ability to meet requirements of NERC Standards.

modeling gap. From the figure, it can be concluded that from the utility/planner perspective, the water availability modeling gap seems to be more important, followed by the deadband and model data issues. From a model developer perspective, water availability, model data issues, and rough zones seem to be more important compared to deadband issues, while other modeling gaps have no particular interest. From a vendor perspective, all modeling gaps (advanced pumped storage, water availability, interdependencies, and model data issues) have equally high importance except for deadband and rough zones, which are not considered as a priority modeling gap. The primary takeaway from this exercise is that water availability is considered by all industry types as an important modeling gap that requires attention, model data issues is the next modeling gap that may need intervention, followed by deadband issues, rough zones, interdependencies, and advanced pumped storage modeling.

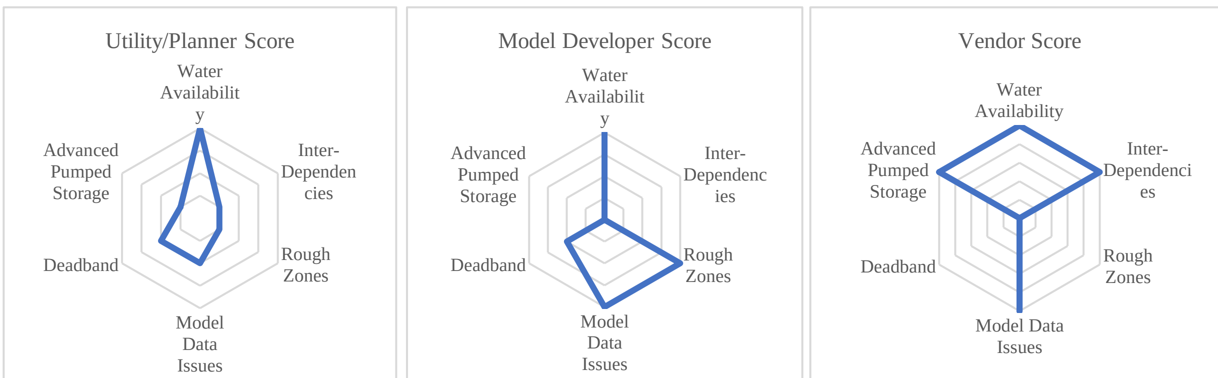


Figure 11. Industry outreach summary of hydro modeling issues based on affiliations (higher score suggest modeling gap is considered important by a majority of experts).

3.2 Workshop

3.2.1 Overview

A workshop was conducted on 9 April 2021 in collaboration with WECC MVS to present modeling gaps from various industry experts. The workshop provided a platform to share and discuss hydro modeling gaps and challenges among a larger group of industry experts that included utility planners, software vendors, independent consultants, and other agencies responsible for developing and managing hydro data and models. Some of the major lessons from the workshop will be discussed in this section along with summary of the feedback sent to the participants at the end of the workshop. The workshop consisted of the following thrust areas:

1. Introduction to modeling gaps in hydropower in the context of the evolving power grid (PNNL)
2. Tutorial on the hydro plant dynamic behavior (John Undrill)
3. Impact of seasonality in water levels in hydro dams and its effect on hydro modeling (U.S. Army Corps of Engineers)
4. New hydro turbine and pump capabilities (GE Renewable Energy)
5. Simulation examples of hydro modeling gaps (Idaho National Laboratory, National Renewable Energy Laboratory)
6. Updating hydro plant models in simulation programs (John Undrill)
7. Additional topics in hydro modeling (U.S. Bureau of Reclamation).

3.2.2 Workshop Survey/Feedback

Figure 12 shows that participants rated the importance and relevance of the workshop to their field in a range of 1–10, where 1 was lowest and 10 the highest score. The demographics of the participants who responded to the workshop feedback form is show in Figure 13. The majority of the workshop survey feedback is provided by utility/planners.

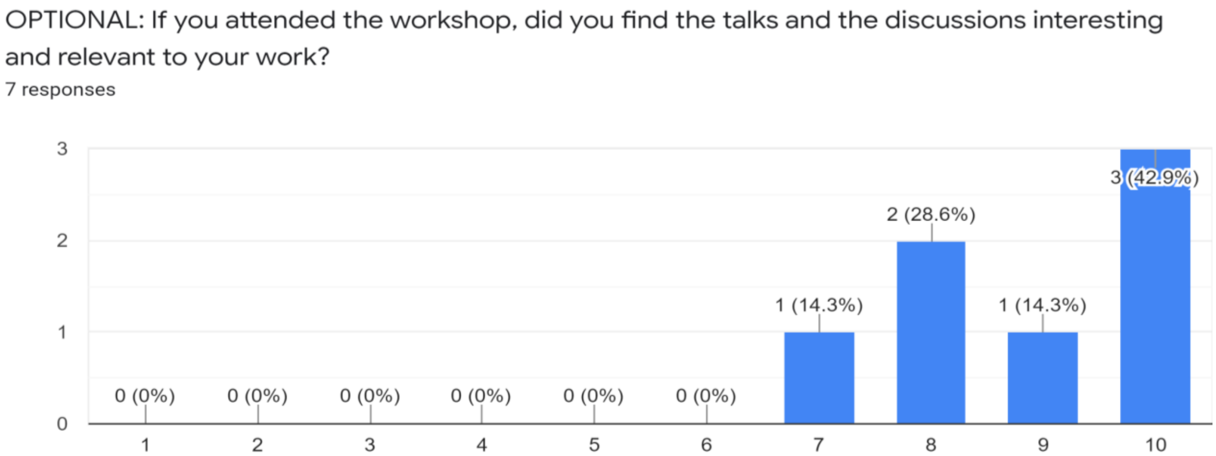


Figure 12. Workshop feedback showing relevance and importance score for participants.

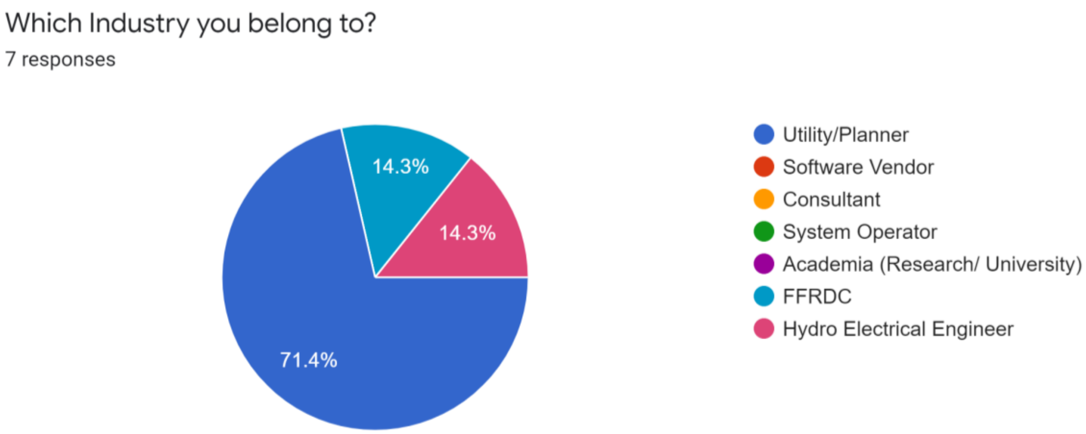


Figure 13. Workshop feedback showing demographics of participants.

The summary of the workshop survey in Figure 14. shows that the model data issue gap impact received the highest overall score (51/70) and advanced PSH received the lowest score (31/70). The modeling gap impact score is calculated by adding the score of each survey question regarding the importance of a specific modeling gap. The maximum impact score for a specific modeling gap is calculated as model importance score (0-10) times the number of surveys received (seven). It should be noted that the scores in the workshop feedback summary are only from a subset of attendees since not all ~60 participants submitted their feedback. Additionally, the scores are anonymous in most instances and it may be difficult to explain the primary reason behind a low or a high score. However, the feedback collected during the interview with selected industry experts may shed additional light on the modeling gaps that are more important to a specific demographic of the industry. In the next part of the report, the major outcomes from the industry outreach and workshop summary will be discussed.

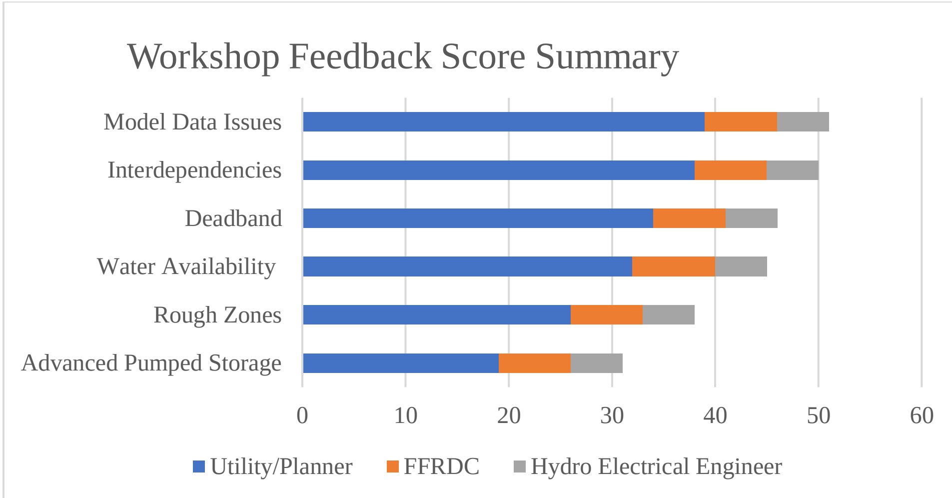


Figure 14. Workshop feedback summary of the modeling gap impact score from workshop participants (max possible score 70).

The scores show the perceived impact of addressing a hydro modeling gap in system operations and planning. This is dependent on the amount and type of hydro resources a particular utility owns. For example, not all utilities own PSH and a low value of the gap impact score suggests that the pool of feedback providers may not have too many PSH resources to model.

3.3 Water Availability

Water availability was marked as an important hydro modeling gap from the perspective of the industry outreach interviews and received a good modeling gap impact score in the workshop feedback summary as shown in Figure 14. Although it ranked as the fourth most important out of the six modeling gaps in the workshop summary, we do not agree with the assessment and we consider this the most important modeling gap that needs to be addressed. This argument is backed up by the results of the industry outreach interviews, where water availability was considered important by most utility planners. The importance of this modeling gap from the workshop presentations is discussed below.

There were three presentations from industry experts that discussed the challenges and practices behind modeling water availability in simulation studies. Some of the system planners that work for entities without hydro projects seem to look on their footprint only. When performing system studies with the objective to maximally stress their interface with their neighbors, they did not take into the account if this was realistic. Their objective was mainly to establish limits on the interface to determine how much they could safely import or export. However, they are missing the larger picture of impact of water on overall interconnection as their utilities might not operate any hydro resources.

Water availability modeling in power system simulations was identified by most industry experts as an important gap; however, there are several challenges and reasons why the same has not been used in the modeling tools. Most of the utilities in North America do not consider water levels and heads in planning and operation studies. During field testing, the recorded data are nominalized to head value that is most likely to occur than the actual head on the testing day. Additionally, parameters like water–time constants also depend on water head during field testing. Dry seasons impact water head, so there are significant effects on plant capability and response—full gate opening will not produce rated output if the head values are lower than nominal. Industry experts pointed out that for some high head dams, 10 years of data show that head may vary by almost 50%. Inability to properly represent water levels in the power system simulation software is a significant gap and should be addressed immediately. Recorded water head level data can be part of the simulation software, and base case models should be adjusted based on water conditions to accurately reflect the contribution of hydropower in simulation studies.

Several presentations from the workshop addressed modeling gaps related to water availability and head in power system simulations. It was also shown that the gate positions of hydro turbines are varied to accommodate water head levels to maintain power output of the plants. The data also showed variation of hydro plant head in the order of 100–250 feet across seasons and its effect on power output characteristics of various plants in the Pacific Northwest. One recommendation was to use different hydro head parameters in the models for various seasons based on historical or forecasted water availability to estimate power output of plants accurately, especially for high head dams. It was also noted that hydropower plants are designed to operate efficiently at 80–90% load and at nominal head. Hydro governor model parameters like water–time constants and controller gains remain independent of the head parameter and hence the hydro turbine dynamic models should be able to alter head parameters without any effect on the other model parameters.

The majority of hydro models were developed at a time when several approximations had to be made due to limitations on the computation capability. However, some of the newer hydro models, like h6e, hyst1, and hypid in PSLF, are more generic and can reflect the various aspects of modern hydro turbine and speed governing settings. The present testing requirements lead to the addition of parameters into hydro models that are difficult to estimate/measure, resulting in a good match during testing. However, the industry needs to focus on more important items that ensure maximum power output. Time constants for servo mechanisms and ambient conditions (water head value) are represented correctly, which should improve the operational accuracy of these hydro models in power system studies.

The summary of feedback received from participants regarding the water availability modeling gap is presented in Figure 15. It shows the majority of workshop attendees rated the water availability modeling gap to be important in simulation studies for the industry, but we see one of the participants (utility/planner) voted 0. We do not have enough data to comment on the specific reason behind the feedback. One possible reason could be that the utility does not own any hydropower facilities and modeling water availability may not be their priority.

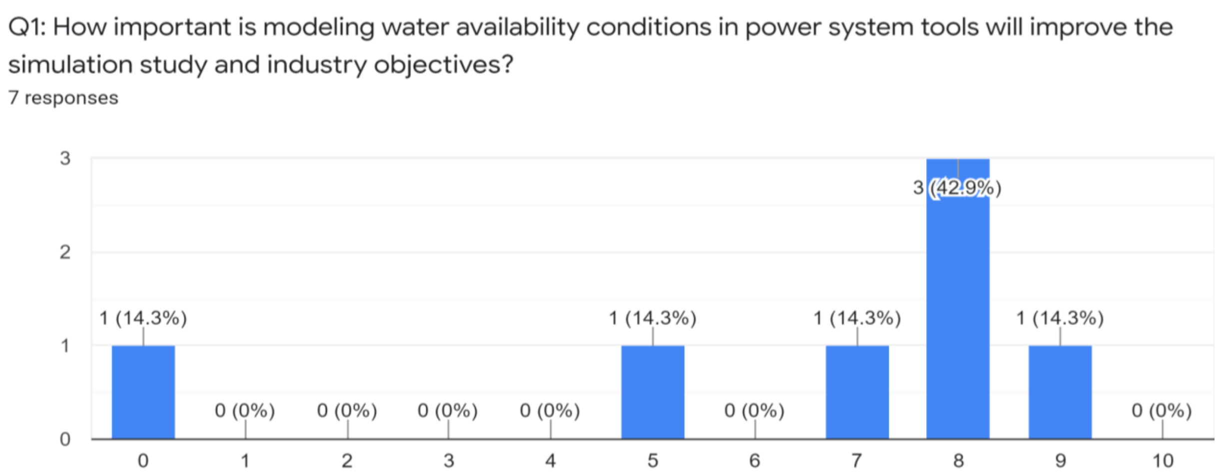


Figure 15. Workshop feedback showing importance of water availability as a modeling gap (lowest 0, highest 10).

3.4 Interdependencies

Interdependencies was marked as one of the important hydro modeling gaps from the perspective of the industry outreach interviews. It received a moderate score in the workshop feedback summary as shown in Figure 16 and was ranked as the second most important out of the six modeling gaps. However, workshop presentations did not provide any additional insights regarding interdependencies. As discussed earlier, interdependency and water flow restrictions between hydro generators on the same river system can results in restricted dispatch of generation across plants. Even though a plant may have a higher rated capacity, its generation level is determined by the hydro plant in the upper stream of the river. Industry experts accepted this modeling gap to be important; however, many of the experts rated this gap to be lower on the priority list as it is more important for long-term simulations like production cost modeling and not for operational planning. It was emphasized by the experts that the study engineers need to be educated on river flow operations and the model data exchange between production cost modeling and planning cases.

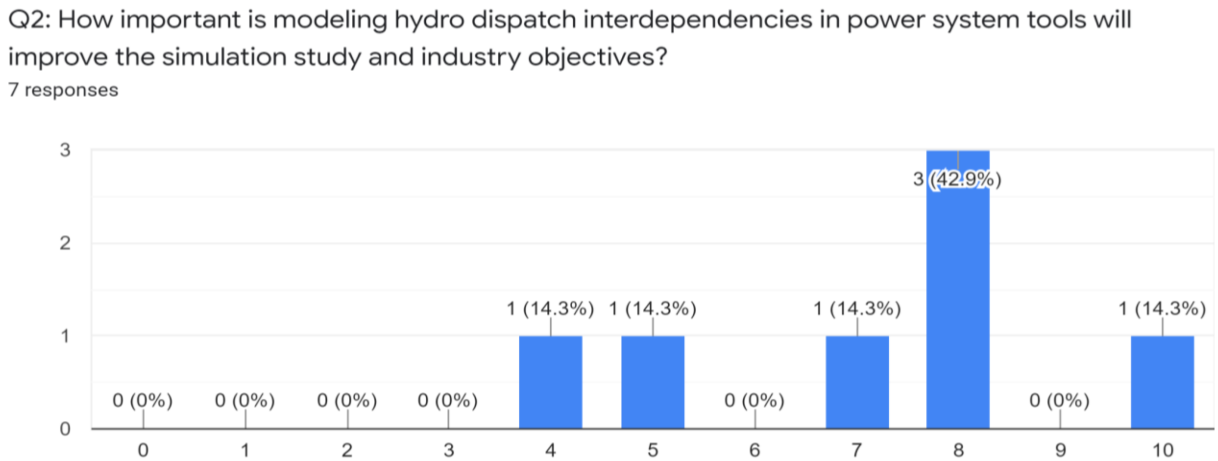


Figure 16. Workshop feedback showing importance of interdependencies as a modeling gap (lowest: 0, highest 10).

3.5 Rough Zones

Rough zone modeling was marked as one of the less important modeling gaps from the perspective of the industry outreach interviews and received a lower score in the workshop feedback summary as shown in Figure 17. It was ranked as the fifth most important out of six modeling gaps. The reason for the lower score may be because of modeling complexities and that most plant controllers are designed to avoid rough zones automatically. The workshop presentations did not provide any additional insights regarding this gap.

Rough zones are associated with the tangential velocity of water leaving a turbine, which can result in an axial unstable vortex in the draft tube and produce very large power swings (e.g., 200 MW swings in upland Brazil). Based on industry comments, accounting for actual rough zones is a difficult task as it is unique to the plant and highly dependent on other environmental conditions like head. There is a lot of optimization and some plant control systems are well automated to avoid rough zones, unless there is some override, and units will not operate in rough zones.

If not modeled in system studies, simulation results can keep resources in these rough zones, especially in studies with high variation of renewable generation. Rough zones pose an issue that may be mitigated by educating planners and having rules embedded in production cost models to avoid rough zones so that system planners can avoid dispatching resources in rough zones in simulation studies. Per one of the leading software vendors, there is no requirement from clients on rough zone modeling, but it can pose challenges when managing renewables. If it becomes impactful, the industry may push to develop an advanced model based on turbine design and hydraulic properties. Utilities in the past have installed pressure sensors in penstock for a plant to monitor and control mechanical oscillations due to rough zones.

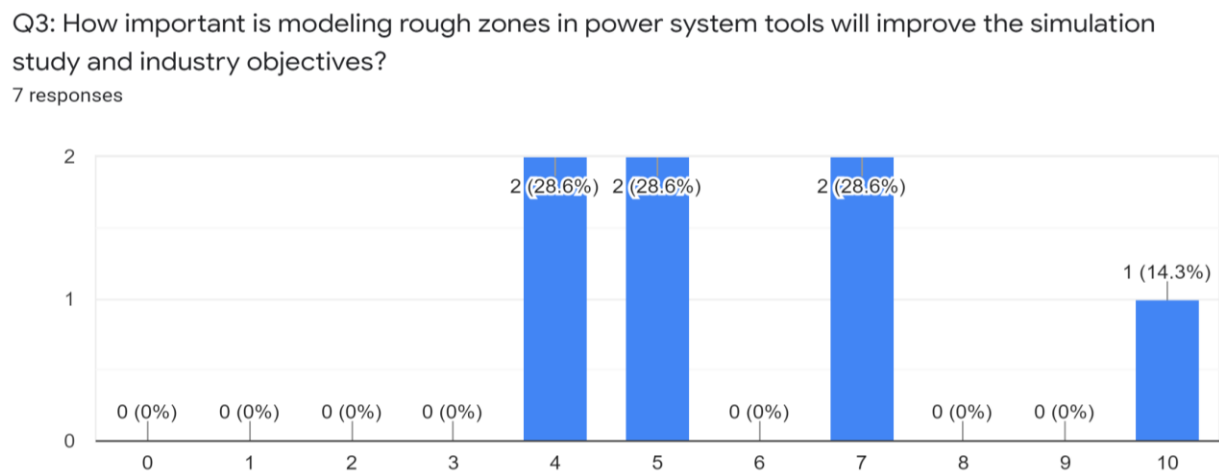


Figure 17. Workshop feedback showing importance of rough zones as a modeling gap (lowest 0, highest 10).

3.6 Data Issues and Incorrect Parameters Value in Dynamic Models

Model data issues was marked as the most important hydro modeling gap from both the industry outreach interviews and workshop feedback. The reason it has the highest score may be that industry always encounters erroneous model data in the simulation studies affecting the accuracy of the response. Model data issues are difficult to address and can be hard to identify, and model data are only updated every 5–10 years during field testing. The workshop presentations covered some of the instances where model data errors can lead to inaccurate response from turbine-governor models in simulation studies.

Model validation is used for steady-state and dynamic models. The steady-state model validation is straight forward but dynamic model parameter validation requires field testing. Manufacturers provide theoretical explanations on the concept of the model for specific equipment and need benchmarking with field test data to show model accuracy and performance. Models used in planning studies are accurate, but the model parameters are not always tuned and added correctly. Dynamic model validation studies are done every 5–10 years, so if there are faulty parameters, they remain in the model for a long time.

There are several inaccuracies with respect to both model data and design. Although turbine-governor models have provision to include the power output and gate opening curve data (which can be only obtained from field testing), they are usually not provided by the generator owners when submitting data to WECC. Additionally, for Kaplan turbines, gate opening and blade angle can affect plant output but may not have enough data to represent such behaviors in the existing models. Hence, model data inaccuracies can lead to inaccurate simulation studies. When asked about the requirement for a data checker, we found that a data checker is available but limited to steady-state parameters, and erroneous dynamic model and control gain parameters are difficult to identify, hence require field testing to compare simulation results actual plant behavior.

It was pointed out that many engineering approximations were used to develop models over last few decades and there has been no incentive to update or improve them as long as they work. One example is observed in the analysis of the modeling data issue where the turbine gain model parameter error results in output of the plant above its rated capacity; however, this behavior was observed only when the system disturbance was large, and the system operated in highly stressed operating condition. For nominal disturbance and operating conditions, issues like this may never surface. However, as operating scenarios change due to increased renewables, those temporary model fixes can result in significant inaccuracies in simulation studies. Model data issues are more generic and not limited to hydro generation only.

It was shown that if certain nonlinear characteristics of hydro turbines that affect efficiency, like gate positions and blade angle curves, are not explicitly added in hydro models, it may lead to inaccurate response during frequency event simulations. Another important model parameter includes controller gains that can often mean inaccurate outcomes. The summary of the workshop feedback received from participants regarding the model data issues gap is presented in Figure 18.

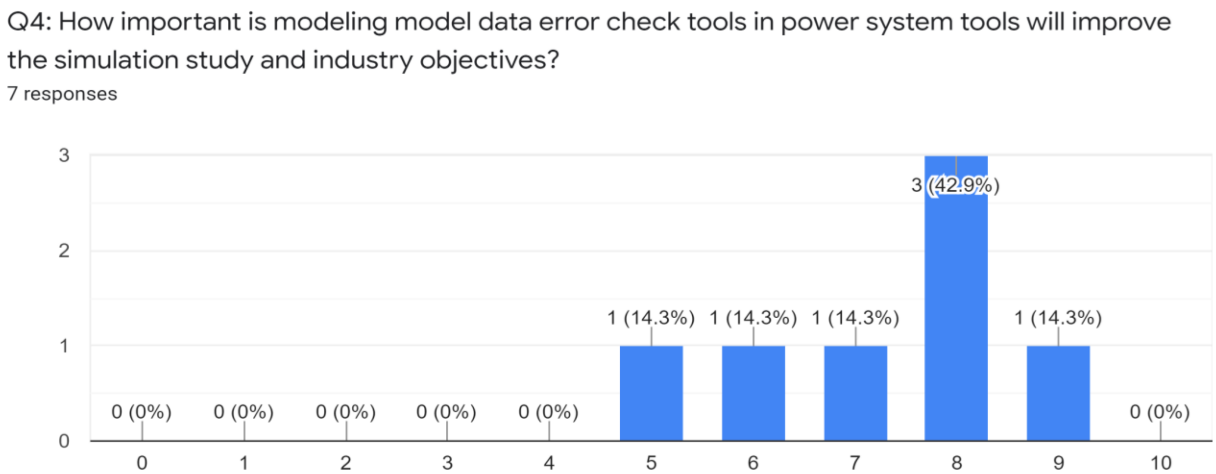


Figure 18. Workshop feedback showing importance of model data issues as a modeling gap (lowest 0, highest 10).

3.7 Frequency Response/Deadband

The deadband issue was marked as an important hydro modeling gap from both the industry outreach interviews and the workshop feedback summary. It was ranked as the third most important out of six modeling gaps. Frequency response studies are very important for industry to estimate trajectory of the system frequency during a major grid event. Overestimation of frequency response in simulation studies is possible if deadband logic in the models does not match actual response time of the governors. The summary of workshop feedback regarding the deadband modeling gap is presented in Figure 19. The workshop provided some simulation sensitivity studies on deadband modeling errors and their effect on the grid frequency response with increased penetration of renewables. The details of the same are presented in Section 2.5.

Power electronic control parameters are usually set by commission engineers and not modified after initial validation during commissioning; hence, these parameter settings affect the plant response and do not match with simulation models, which can result in inaccurate response. Some of the utilities mentioned there might be errors in the models and need tuning and further investigation. More of a concern is that the governor response in models/studies may be overestimated due to plant control or area SCADA systems (secondary control) that reset control to constant setpoints. It becomes more common to automatically suspend the setpoint controls and allow a governor to fully respond if the frequency dropped by a certain margin so that their allocation would not fall short.

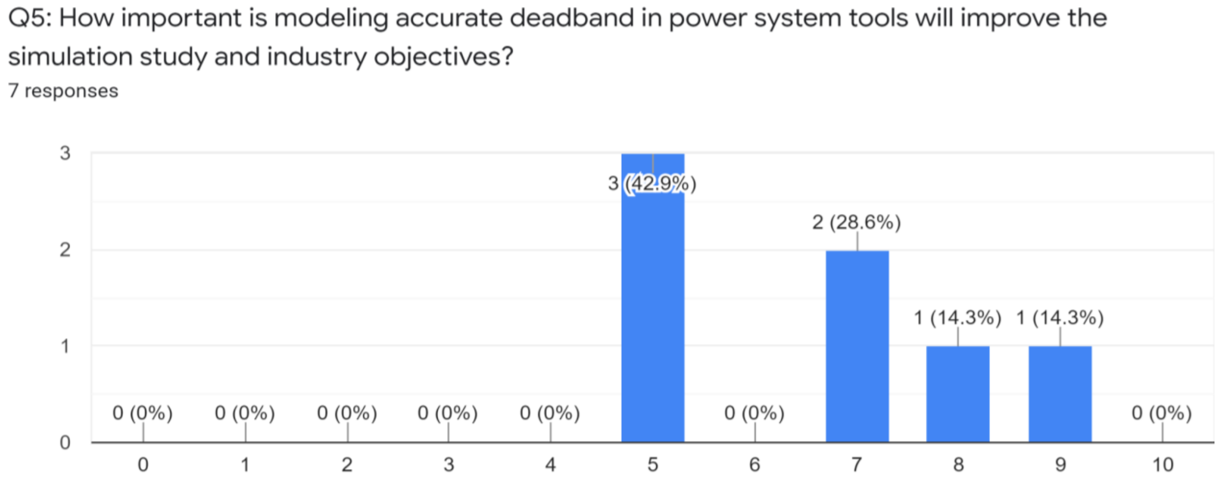


Figure 19. Workshop feedback showing importance of frequency/deadband issue as a modeling gap (lowest 0, highest 10).

3.8 Advanced Pumped Storage Hydropower Models

Advanced PSH modeling was marked as the least important gap both from the industry outreach interviews and workshop feedback summary. The primary reason was there are other critical challenges that need to be addressed immediately. The summary of the workshop feedback is presented in Figure 20. The workshop provided insights about new pump hydro turbine capabilities that are coming to the electricity grid in the future.

The feedback from industry experts suggests that little effort has been made to develop models that represent PSH explicitly and industry has been using existing motor and generator data in dynamic models. For planning studies, PSH modeling may not be a very high priority at this time and current modeling approaches are sufficient for planning studies. From the industry outreach interviews, system planners said the current approximate models for PSH are sufficient for planning studies unless reliability issues are involved. The workshop feedback summary varied widely. Additionally, not all utilities own PSH and addressing modeling gaps may not be a priority for them.

New technology such as variable speed PSH can provide frequency support in both direction (pumping and generating) as well as faster response. The workshop provided detailed insights on new pump turbine capabilities that are in active research and development:

- New runner hydraulic/mechanical design for low load operation
- New power electronics, frequency converters to enhance the pumped hydro operations and controls:
  - Increased flexibility with variable speed and low load
  - Increased reactivity with fast mode changes.

All the new technologies discussed may require industry to start building these models for dynamic studies as these devices use complex power electronic capabilities to provide flexibility to the grid.

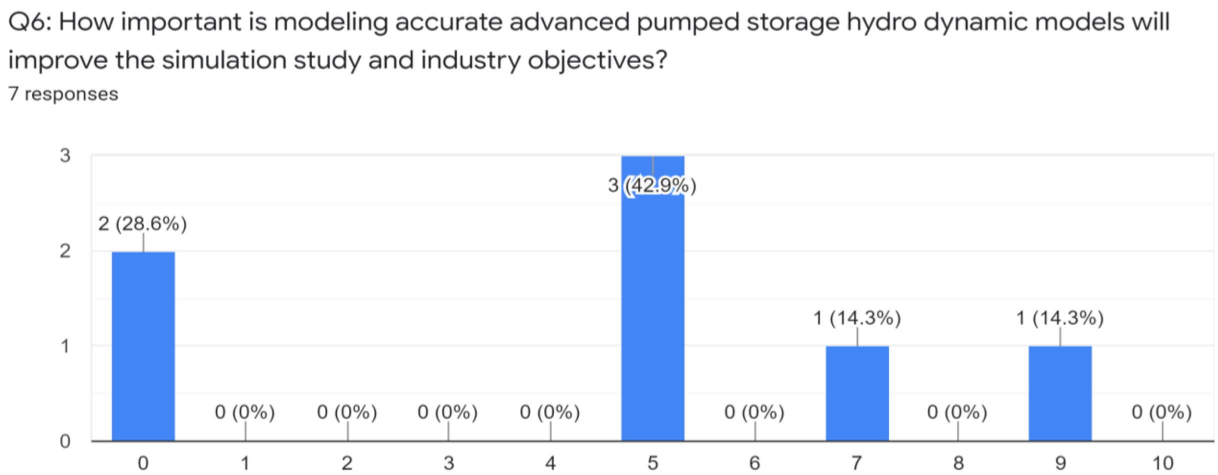


Figure 20. Workshop feedback showing importance of advanced PSH as a modeling gap (lowest 0, highest 10).

3.9 Additional Gaps and Future of Hydro Modeling Challenges

During the industry outreach interview process and workshop feedback summary, participants were asked about any additional modeling gaps that might be relevant for this project. The following section provides a list of other modeling gaps that were identified. These will be explored and analyzed in a future work and are out of the scope of this report.

The following were identified by industry experts:

- Recognize the generator capability curves correctly (real and reactive power capability). Owners like to have maximum capability reported to avoid curtailment. Some generators are rated at 1.0 power factor, but in WECC reactive power support is required so real power is curtailed to provide +/-0.95 or +/- 0.9 power factor. However, generator capability curves are never derated based on system head. This gap is directly linked to the water availability modeling gap and addressing that modeling gap will address the issue with respect to derating the capability curves.
- Traveling wave (hydraulic dynamics) may be a potential gap to be studied to check for impact in transient stability studies.
- PSS tuning issues can cause undamped or growing oscillations so adaptive PSS tuning for different system conditions should be investigated.

The following new modeling gaps were identified by workshop participants:

- The need to provide accurate hydroelectric generator relay protection models in the dynamic models of the WECC base cases.
- Supplemental controls such as headwater, flow/discharge that can cause frequency withdrawal.

4 Simulation Studies to Address Modeling Challenges

In this section, some of the simulation studies performed to demonstrate the modeling challenges associated with hydro governor models are presented. The objective of the studies was to bring awareness to limitations associated with the hydro governor models currently used in the WECC planning scenario. The results of these simulation studies were presented in the workshop to get feedback from industry members as well as to bring up issues that might occur during system planning if the modeling gaps are not addressed. These results are preliminary analysis and further studies need to be conducted to draw rigid conclusions in terms of impact of the hydro modeling gaps on system planning.

4.1 Impact of Water Availability and Model Parameters

Out of the various modeling gaps identified for hydropower resources in previous sections, this section primarily focuses on demonstrating the impact of the modeling gaps related with water availability and model data issues. As can be seen in the responses from industry outreach (Figure 15 and Figure 18), these issues are important to the power system community related to hydropower plant planning, operation, and modeling.

4.1.1 Simulation Methodology

To demonstrate the challenges of these issues we use the methodology shown in Figure 21, which is a comprehensive simulation-based technique.

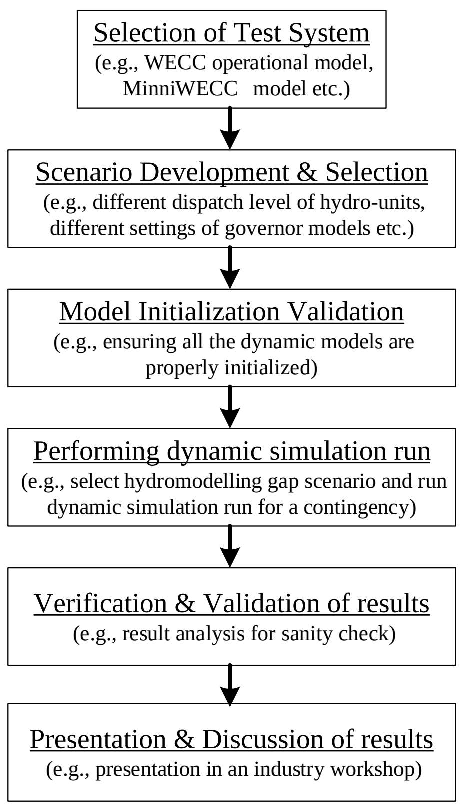


Figure 21. Methodology used in simulation studies, discussions, and dissemination of results.

For demonstration of challenges/gaps in the hydropower model, the following candidate test systems were considered:

- WECC 2020HS operational case: One of the base cases that WECC publishes in its database, this model includes both steady-state and dynamic data required to mimic the power system conditions for a specific point in time and the 2020HS case refers to heavy summer for the year 2020.[8]
- MinniWECC system: A reduced-order dynamic model of the larger WECC system, shown in Figure 22, represents the larger WECC system with use of aggregated loads and generators models. MinniWECC is able to model the complexity of the entire WECC system for accurate evaluation and testing of various impacts on the system.[9] The generator units highlighted in green are represented as hydro generators with hydro turbine-governors model, the other generating units had their governor systems disabled in the MinniWECC system considered.

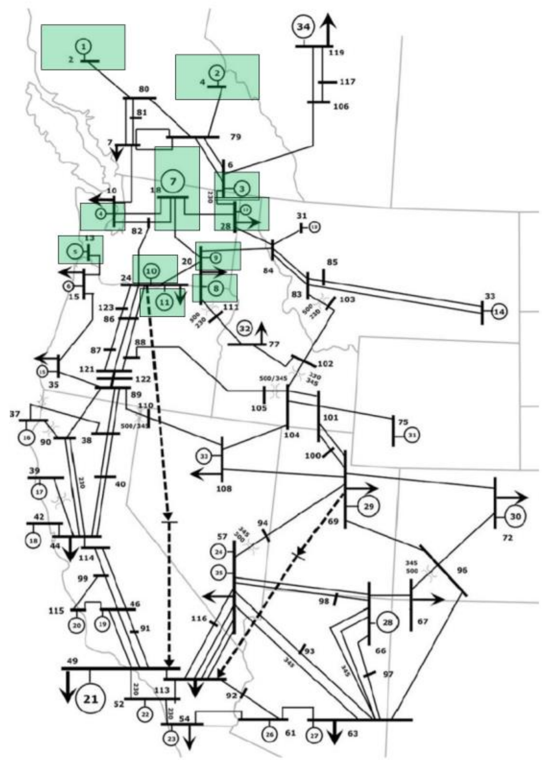


Figure 22. Simplified hydro MinniWECC system. Green boxes represent hydro generation in Pacific Northwest.

Upon analysis of the Siemens PSS/E[10] model of the WECC operational case, the hydro governor models observed represent a small fraction of the turbine-governor models in the WECC system. The majority is gas turbine-governor systems modeled using “GGOV1.” Also, among the models used in the WECC planning case, a significant number do not have flexibility to vary the head parameter, both in terms of numbers and overall capacity, which enables us to study the impact of water availability on system stability and frequency response. The representation of various governor types in the WECC operational case is

8 https://www.wecc.org/SystemStabilityPlanning/Pages/BaseCases.aspx

9 Fan, R., Wang, S., Huang, R., Lian, J., & Huang, Z. (2020). Wide-area measurement-based modal decoupling for power system oscillation damping. *Electric Power Systems Research*, *178*, 106022.

10 https://new.siemens.com/global/en/products/energy/energy-automation-and-smart-grid/pss-software/pss-e.html

shown in Figure 23. Figure 24 shows the number of various types of hydro governor models currently being used in the WECC 2020HS operational planning cases.

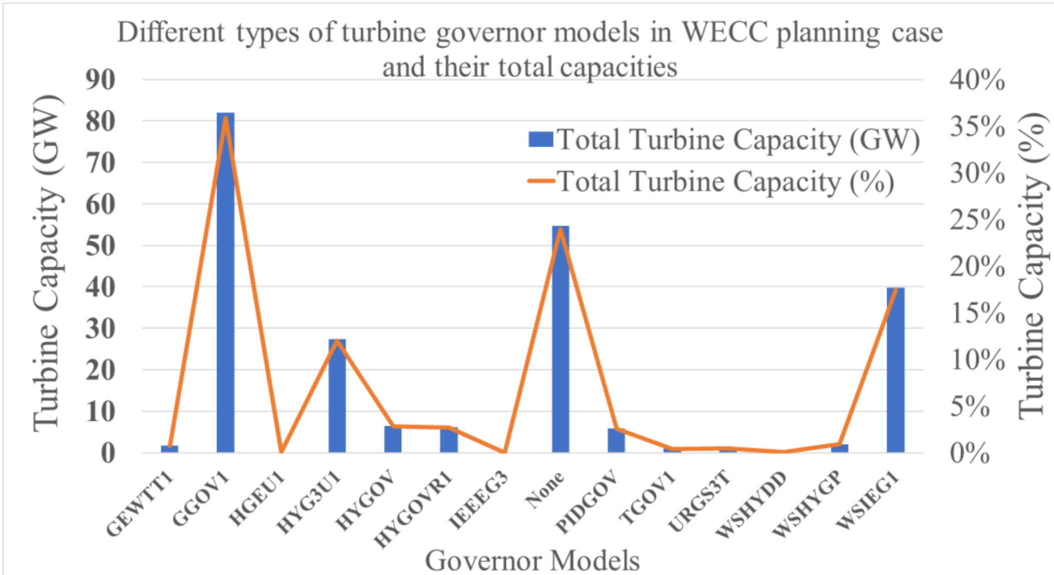


Figure 23. Total capacity of different turbine types in WECC operational case and total turbine capacity in the system.

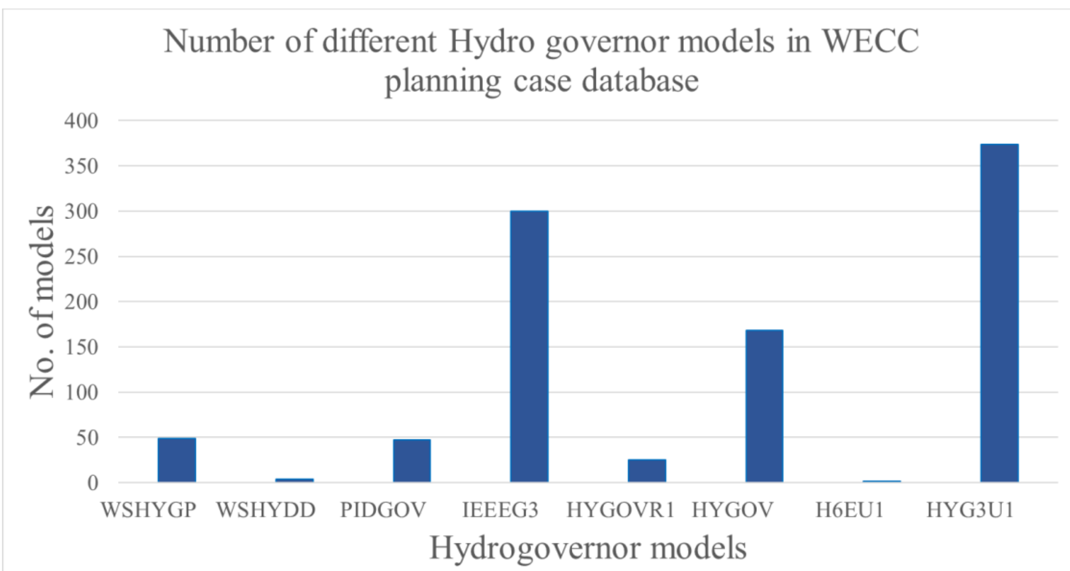
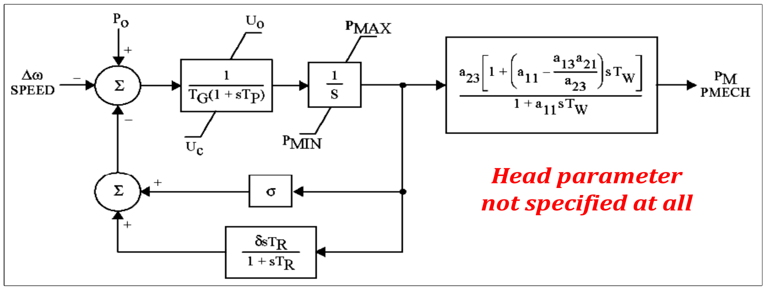


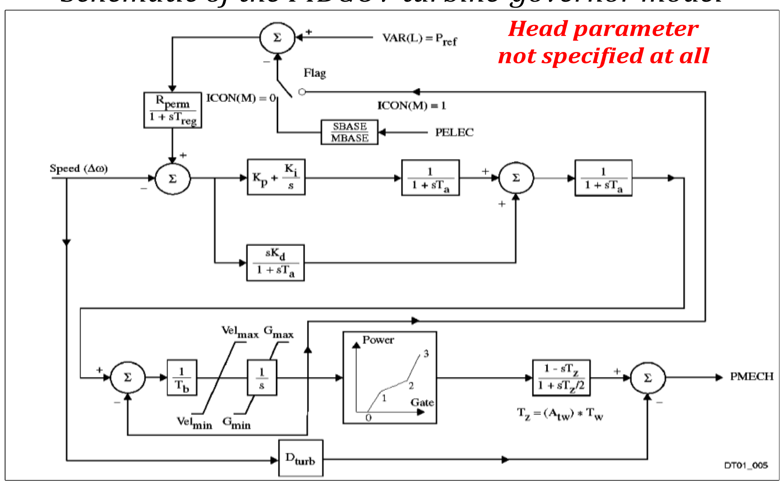
Figure 24. Hydro governor models in WECC operational case.

Among the various models currently used in the PSS/E version of WECC planning case, only the HYG3U1 and H6EU1 have the flexibility of varying the nominal head parameter. Other modes, like IEEEG3, PIDGOV, HYGOV, etc. either do not consider head parameter at all or consider the nominal head always fixed at 1 p.u. In the schematic diagram of the hydro turbine-governor model that is frequently used in the WECC operational case (Figure 25), only the HYG3U1 turbine-governor model has the flexibility to change the nominal head parameter to represent various operating conditions.

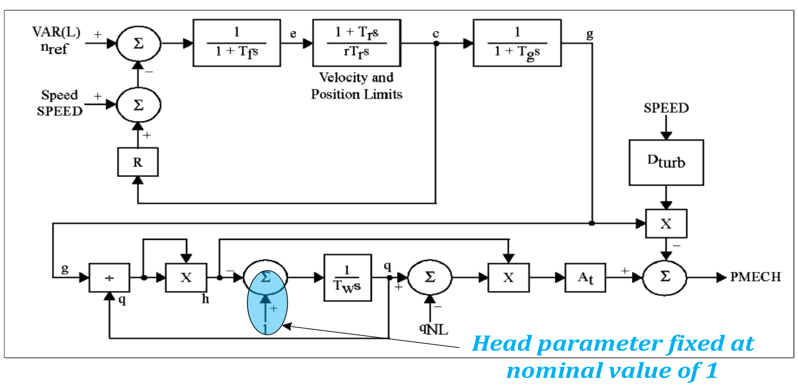
Schematic of the IEEEG3 turbine-governor model



Schematic of the PIDGOV turbine-governor model



Schematic of the HYGOV turbine-governor model



Schematic of the HYG3U1 turbine-governor model

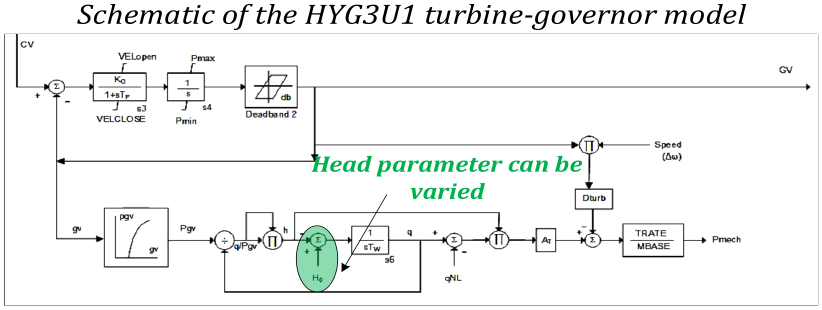


Figure 25. Hydro turbine-governor models used in the PSS/E version of the WECC operational case (source: Siemens PSS/E User Manual).

In the 2020HS operational case,[11] even for the HYG3U1 model that allows the change in nominal head parameter, most of the turbine-governor models had their head set at 1 p.u., irrespective of the operational point of the hydro generator system. Figure 26**Error! Reference source not found.** shows the mechanical power output (Pmech) versus head plot from data in the operational case.

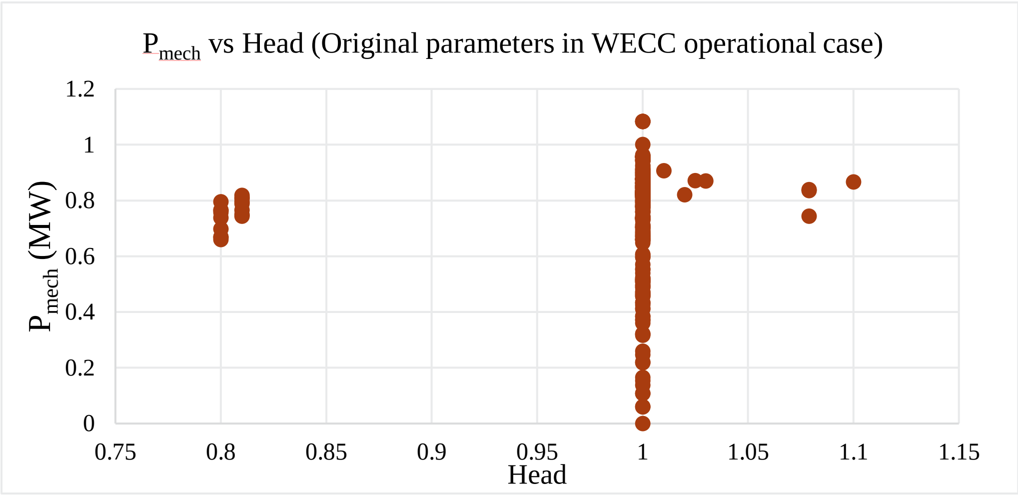


Figure 26. Variation of head value used in the WECC operational cases for various generators at different operating conditions.

With the hydro turbine-governor systems being a minority of the turbine-governor models used in the system, the impact of changes in the nominal head parameters on the WECC operational case was minimal due to the dominant response of the other turbine-governor models in the system. An example result of the frequency response of the larger WECC system following loss of a unit of "paloverde nuclear powerplant" is shown in Figure 27.

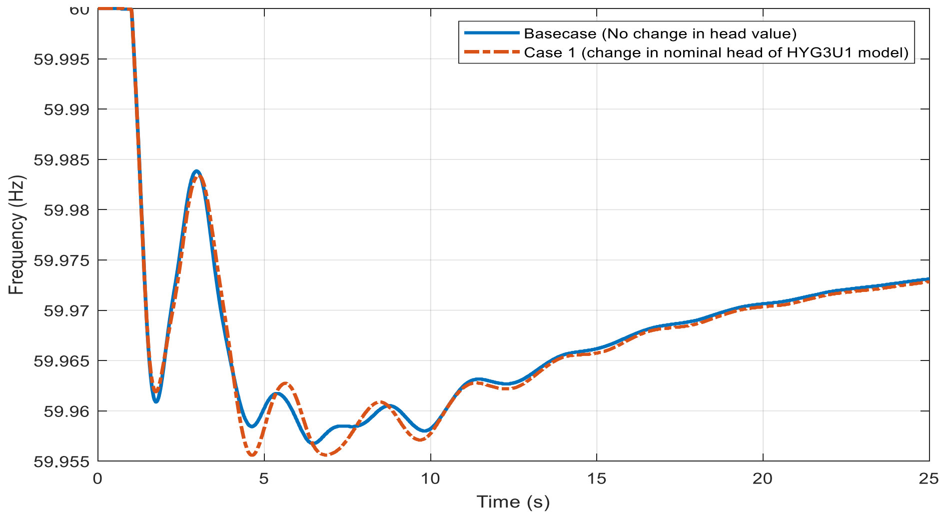


Figure 27. WI center of inertia frequency comparison with 10% decrease of nominal head parameter of represented by the HYG3U1 model.

[11] 2020HS is WECC base case developed in 2019 representing heavy summer loading conditions for 2020. This case was used for operation studies during 2020 as a most accurate case.

It can be observed that, because of the dominant response of the other turbine-governor units, the frequency response of the WI does not show significant variation even when the head of the majority of the hydro turbine model represented by HYG3U1 is reduced by 10%.

As such, the MinniWECC system was used for the majority of the studies to demonstrate the impact of water head variation as well as the model data issues. For the simplified MinniWECC system, to isolate the impact of the variation of nominal head on the frequency response of the system, most of the governor turbine models used in the system were disabled. However, some of the generator units within the MinniWECC model were represented as hydro generators with hydro turbine governors modeled using the HYG3U1 model, which allows the variation of the nominal head parameter H_0.

4.1.2 Impact of Head Variation/Water Availability

To study the impact of head variation/water availability on the frequency response of the system, a sensitivity study was performed by decreasing the head parameter of all the hydro generators in the MinniWECC system by 0.05 p.u., starting from a nominal value of 1 p.u. Also, as the nominal head was lowered, the hydro generators were redispatched according to the limit imposed by the head value. This is done as the power output of the hydro generators is dependent on the (3/2) power of the head value.

$$P = \rho g k V H^{(1.5)}$$

Where P is the mechanical power output from the turbine, 'g' is the acceleration due to gravity, V is the water velocity, and 'H' is the head.

When the hydro units are dispatched according to the head values, the other generators are redispatched accordingly to ensure the load and generation balance in the system, except for a particular unit that is fixed and which was used as a contingency event during the sensitivity studies. Also, for the dynamic simulation studies, the loads in the system were modeled as constant power loads. The mix of various generation and load for different scenarios is shown in Table 2.

Table 2. Generation and load mix

Scenario	Total Generation (including Hydro)	Total Hydrogeneration	Total system load
Base Case: Head (H) = 1.0	107.509 GW	19.85 GW	105.985 GW
Case 1: Head (H) = 0.95	107.510 GW	19.85 GW	105.985 GW
Case 2: Head (H) = 0.90	107.503 GW	19.639 GW	105.985 GW
Case 3: Head (H) = 0.85	107.504 GW	19.640 GW	105.985 GW
Case 4: Head (H) = 0.80	107.40 GW	18.580 GW	105.985 GW
Case 5: Head (H) = 0.75	107.348 GW	17.38 GW	105.985 GW

With variation of the nominal head parameter, the ability of the hydro turbine-generator system to respond to a particular frequency event changes. Figure 28 shows the total combined response of all hydro generator units following a loss of 4 GW of generation in the MinniWECC system. With the lower head, the overall response of the hydro generators for a same-frequency event is lower. The inability of the hydro generators to push a higher amount of electrical power in the system is tied to the limit imposed on the system by the head available. This reduction in power response from the hydro generators leads to worsened frequency response in the system as shown in Figure 29.

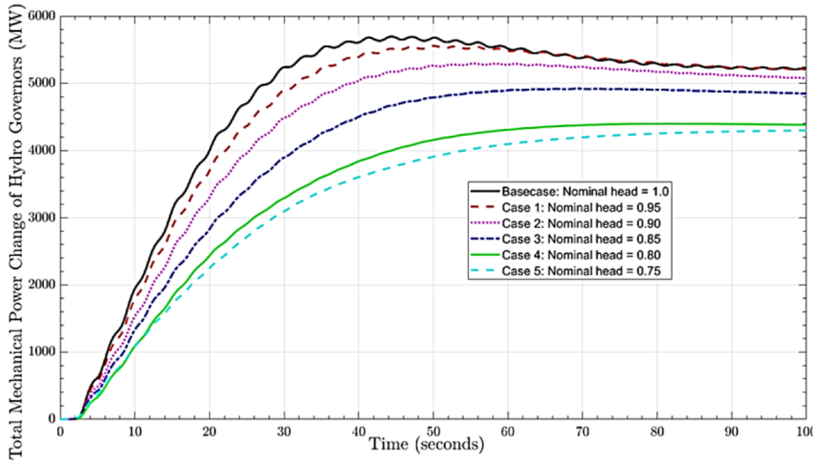


Figure 28. Combined electrical power output response of all the hydro generator units in the MinniWECC system following loss of 4 GW generation.

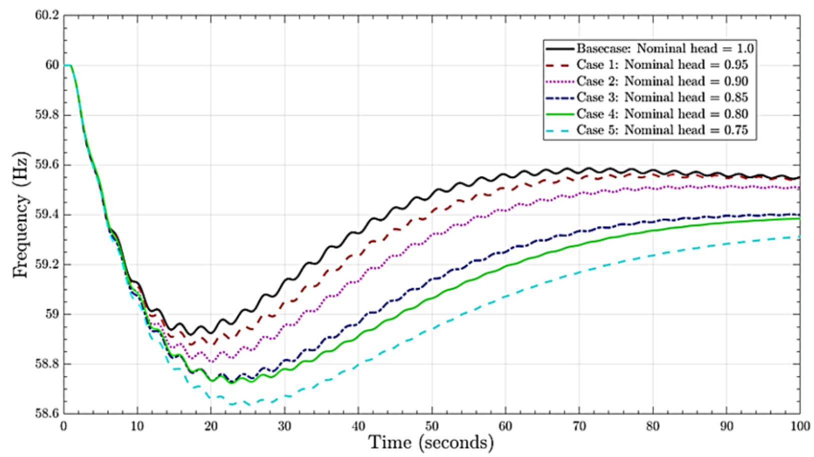


Figure 29. Frequency of MinniWECC system for various nominal head conditions following loss of 4 GW generation.

The results show that incorrect use of head value in the hydro turbine governor models can lead to optimistic frequency response of the system if the actual water availability and head level is lower than what is used in the model. This might be crucial in the future when the majority of energy resources are renewable with limited ability to regulate frequency. If the hydro generators in the future are expected to provide frequency regulation, proper estimation of their head values is crucial to ensure a better frequency response of the system following a contingency.

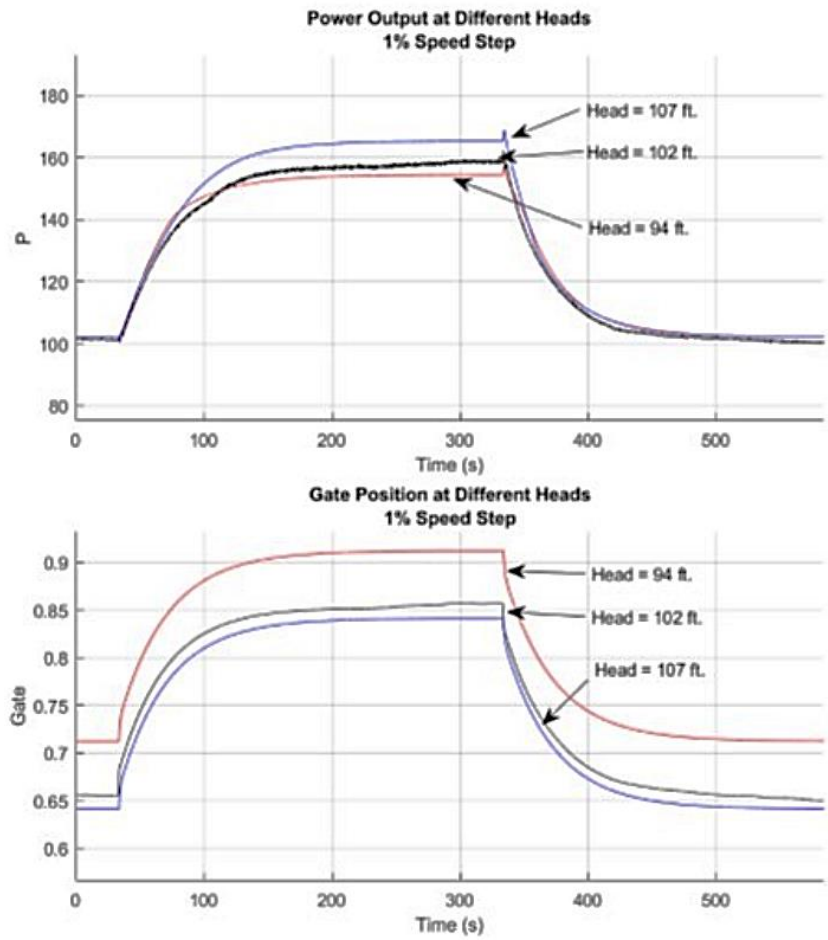
4.1.3 Impact of Turbine Gain Parameter Variation

Turbine gain parameter, A_t, in hydro turbine-governor model is defined as,

$$A_t = \frac{1}{(g_{FL} - g_{NL})}$$

Where g_{FL} is the full-load gate opening (in p.u.) ($0 \leq g_{FL} \leq 1$) and g_{NL} is the no-load gate opening (in p.u.) ($0 \leq g_{NL} \leq 1$).

It should be noted that with the variation of water availability and head, the gate opening of the hydro governor-turbine system can vary during full-load and no-load operation. For example, for the same power output, lower head requires a larger gate opening. Figure 30 shows a power output and gate characteristics of a hydro turbine-governor system at various head levels. It shows that the gate opening to generate the same amount of power differs when the head levels are different, which impacts the gain parameter in the model for a given head.



Courtesy of *Impact of seasonal/annual variation in water levels on hydro modeling*, Sean Brosig and Maggie Watkins, USACE Hydroelectric Design Center, presented on WECC MVS-DOE workshop on gaps on modeling hydro-based generation

Figure 30. Variation of the power output and gate position of a hydro generator unit at different head levels.

The initial studies conducted by the team determined that mechanical power output of the hydro turbine-governor models can exceed their rated capacity. Such response has been tied to incorrect parametrization of the turbine gain parameter in the model for the head conditions considered. As such, the impact of variation on mechanical power output response and system frequency response has been studied. Figure 31 shows the mechanical power response of hydro generator in bus 17 with changes in the turbine gain parameter. Note that, with the increase in turbine gain, the overall mechanical power output response of the model is faster and with a larger peak, compared to the base case and the case with a decrease in turbine gain. Such faster and larger responses of all the hydro units in the system can lead to better frequency response as shown in Figure 32. The results shows that incorrect parametrization of the turbine gain parameter can significantly impact the frequency response of the system in simulation studies, which can lead to incorrect decision-making by the transmission planners and system operators.

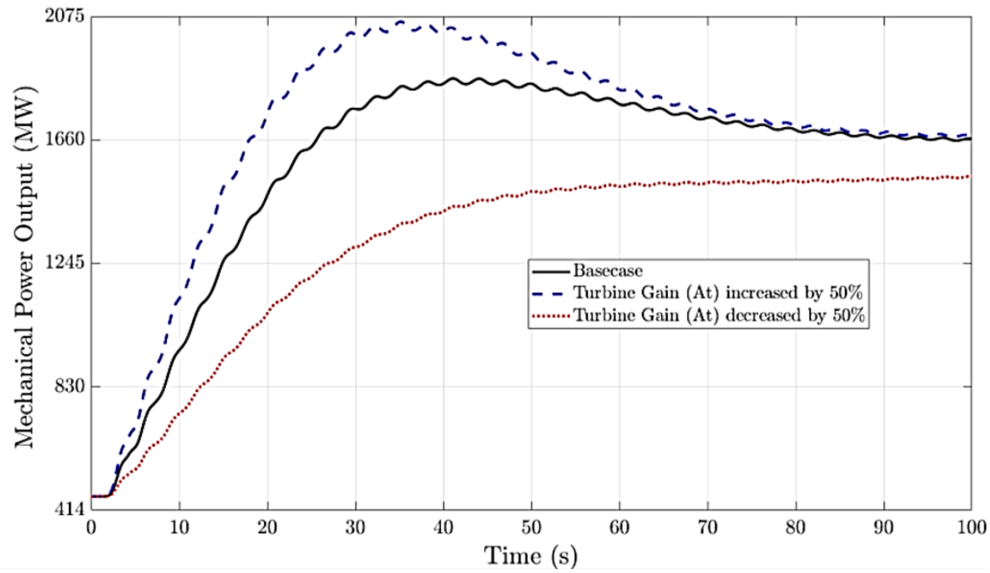


Figure 31. Mechanical power output response of hydro turbine-governor model in generator bus 17 of MinniWECC system.

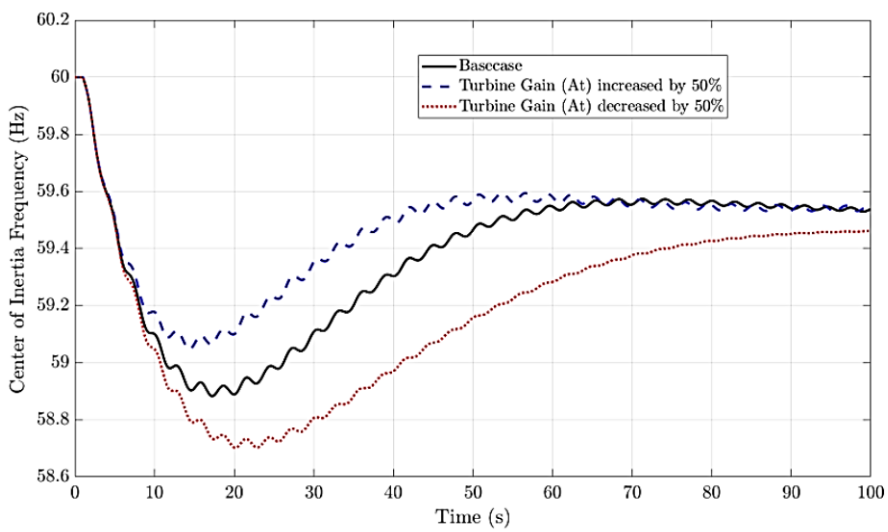


Figure 32. System frequency of MinniWECC system following changes in turbine gain parameter.

Based on the discussion with industry expert and workshop participant, if the base turbine rating is less than the generator rating, turbine output can exceed the maximum generation of the generator or the turbine base as well. In such scenarios, it seems like the current practice is to adjust the turbine gain parameter to ensure the model properly initializes. However, as discussed, the correct practice should be adjustment of head parameter "H0" instead of the turbine gain parameter.

4.1.4 Summary

Variation of head parameters of the hydro generators can have noticeable impact on overall system-wide frequency response, if the majority of generating units have limited capability of frequency regulation. A mechanism to update nominal head parameter as well other model parameters at various operating conditions of hydro turbine generators can help better decision-making for transmission planners.

4.2 Impact of Hydro Governor Deadband

In general, turbine-governor models include a deadband for the primary frequency control. The function of this deadband is to prevent the prime mover responding to small frequency variations that could cause wear for mechanical parts. The deadband can be divided into an inherent deadband and an intentional deadband. The inherent deadband is from the mechanical linkage between speed sensing and valve/gate movement. It is unpredictable and can be varied with operating conditions; however, the value is usually very small (<5mHz).[12] The intentional deadband is based on control design of governor manufactures. Based on Order No. 842 issued by Federal Energy Regulatory Commission, it requires that the maximum deadband parameter is no greater than ±36 mHz.[13]

In this section, we are trying to understand the impact if the hydro governor's deadband is not accurately presented in the model for frequency response analysis of the large-scale interconnection.

4.2.1 Method

In this study, we are not only interested in the impact of hydro governor on the current interconnection grid, but also on the future grid with large-scale renewable integration. The basic study method is presented in Figure 33. First, we selected the WI as our test system because the abundant water resource and large number of the hydropower plants are located in the western United States. Second, we leveraged the high-renewable penetrated WECC cases that have been developed and validated through a previous project. Third, we compared the impact of hydro governor deadband under different scenarios (different deadband, different renewable penetration levels, different disturbances).

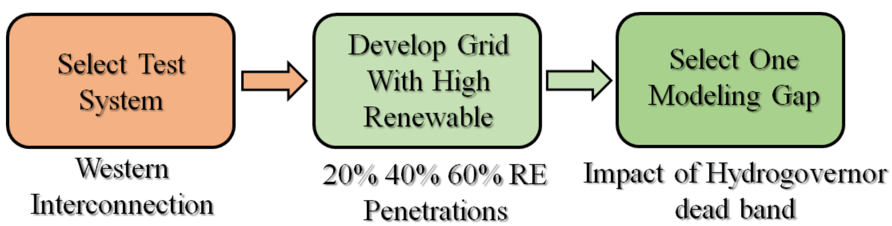


Figure 33. Methodology of conducting the deadband study. RE = renewable energy.

[12] WECC Control Work Group, WECC Tutorial on Speed Governors, https://www.wecc.biz/Reliability/Governor%20Tutorial.pdf

[13] FERC, "Essential Reliability Services and the Evolving Bulk-Power System–Primary Frequency Response," Docket No. RM16-6-000, Order No. 842, Feb 15, 2018: https://www.ferc.gov/sites/default/files/2020-06/Order-842.pdf

4.2.2 Introduction of WECC High-Renewable Case

4.2.2.1 WECC Base Case

A 2022 light spring planning (LSP) case of the WI was chosen as an ideal benchmark for the frequency response study because the relatively low level of online synchronous power generation in a light-load condition might represent a challenge for frequency response. The model of the 2022 LSP case is implemented in GE's PSLF analysis simulation software. The original instantaneous output and penetration level of the total generation, load, wind generation, and photovoltaics (PV) generation are summarized in Table 3. The total generation in the 2022 LSP case is 117 GW, wind is the largest renewable resource at approximately 13.9% instantaneous penetration, and PV is a small portion of the renewables at only 1.1% instantaneous penetration.

Table 3. Summary of generation and load in WECC 2022 LSP case

	Capacity (MVA)	Rate (%)	P_{gen} (MW)	Rate (%)
System Total Generation	312,438		117,238	
Load	N/A		112,990	
Wind Generation	26,323	8.4	16,464	13.9
PV Generation	1,838	0.6	1,347	1.1

The 2022 LSP case is modeled at a very detailed level with more than 4,000 generators and 19,000 buses. Each power plant has detailed dynamic models, including generator, exciter, and turbine-governor models that can vary widely as a result of the diversity in power plant configurations. Control devices, such as high-voltage direct current controls, and protective systems, such as underfrequency load shedding and line protection, are included in the WI dynamic database as well.

4.2.2.2 WECC Case with High-Renewable Penetrations

Replacing synchronous generators with PV generation reduces the number of online synchronous generators as well as the system inertia. In the developed cases, the system equivalent inertia will linearly reduce along with the penetration levels, as shown in Figure 34.

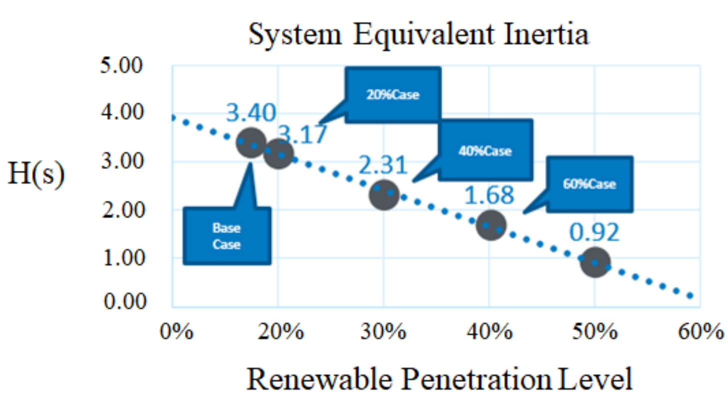


Figure 34. System equivalent inertia at different renewable penetration levels.

4.2.3 Impact Study of Governor Deadband

4.2.3.1 Base Case Study

A governor deadband is designed to prevent excessive governor actions caused by small load variations, but also delays the response of governors to contingencies. We started with a 20% renewable penetration case, the deadband of hydro governor has been changed from 0 mHz to 18 mHz to 36 mHz, and then we applied a typical N-1 contingency, which is the loss of a 804 MW unit in the WECC.

Figure 35 shows that a narrow governor deadband can improve the WECC frequency nadir and settling frequency because it makes the governor kick in earlier than one with a wide deadband. The improvement has been quantified by frequency metrics in terms of rate of change of frequency (RoCoF) and frequency nadir as shown in Table 4. It shows that hydro governor deadband has few impacts on RoCoF; this implies that comparing to the hydro governor's response time delay, the delay caused by this deadband is negligible, while hydro governor deadband impacts frequency nadirs. If we choose 0 mHz deadband case as a base case, the differences in the frequency nadirs are 6 mHz and 12 mHz, and 7% and 14% in percentage.

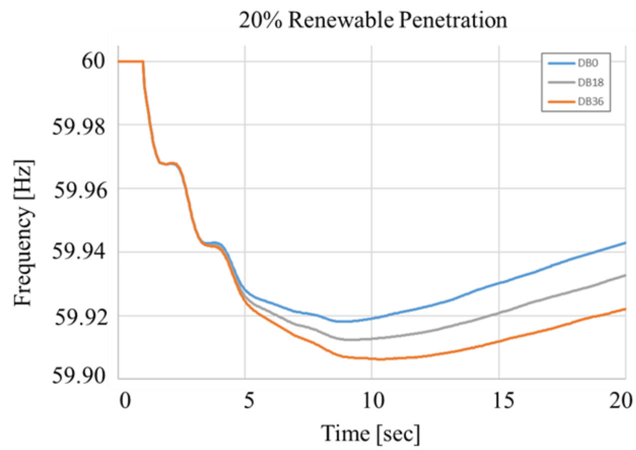


Figure 35. Frequency response of WECC with 20% renewable penetrations under different hydro deadbands.

Table 4. Frequency response metrics of WECC with 20% renewable penetrations under different hydro deadbands.

Frequency Metrics	Deadband (mHz)		
	0	18	36
ROCOF(Hz/s)	0.0582	0.0582	0.0582
Min fre (Hz)	59.9181	59.9123	59.9063
fre difference (Hz)	0	0.006	0.012
fre difference (%)	--	7%	14%

4.2.3.2 Impact of Hydro Deadbands Under Different Renewable Penetrations

To study the impact of hydro deadbands under different renewable penetrations, a series of sensitivity studies have been conducted for 40% and 60% renewable penetration. By comparing Figure 35, Figure 36, and Figure 37, the following is evident: 1) as the penetration level of the renewable energy increases, the frequency nadir and settling frequency decrease under the same gen trip event; 2) the RoCoF becomes worse (bigger) as the system inertia decreases in the high-renewable penetration case; and 3) based on observations of different deadband, the trends are similar to those found in the 20% renewable case.

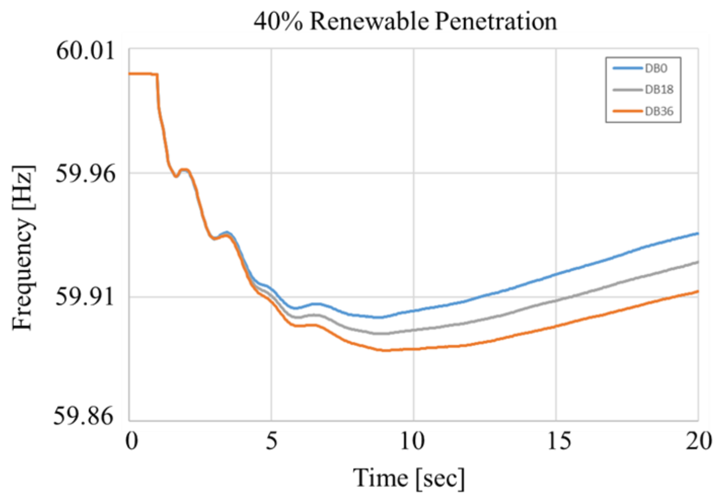


Figure 36. Frequency response of WECC with 40% renewable penetrations under different hydro deadbands.

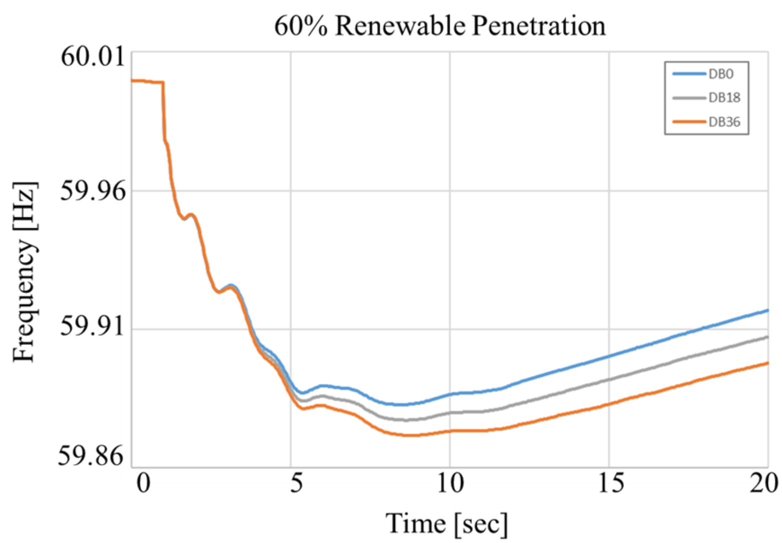


Figure 37. Frequency response of WECC with 60% renewable penetrations under different hydro deadbands.

To further quantify the impact, the frequency metrics are summarized for comparison and visualized. Figure 38 shows the RoCoFs under different renewable penetrations levels with different deadbands. Flat lines indicate that when the deadband increases, RoCoFs are still the same. This observation holds true whether in a low or high-renewable penetration case. In another words, under each penetration level, different governor deadbands do not impact the RoCoF.

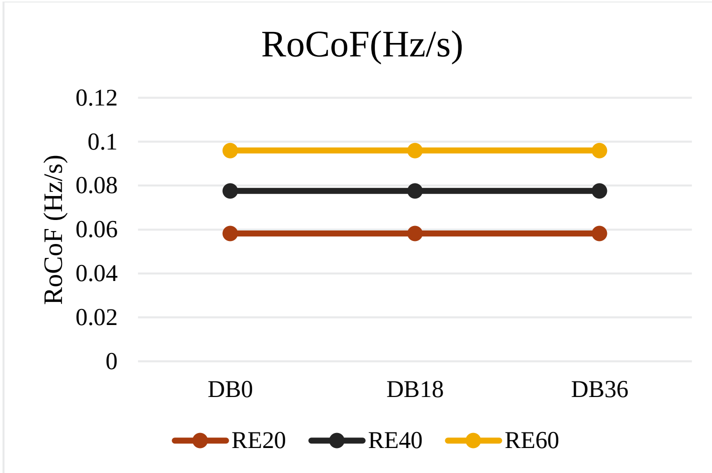


Figure 38. Compare RoCoF of WECC under different renewable penetrations and different deadbands.

Figure 39 shows the frequency nadir under different penetration levels with different deadbands. The frequency nadir linearly decreases when deadband increases for each penetration level. The decreasing rates are similar (reduce 0.006 Hz per deadband case). This means that under different renewable penetration levels, the impact of deadband on frequency nadir are the same in terms of absolute value. Deadband does not have a larger impact in the future low-inertia grid. However, if the frequency nadir could be close to the threshold of the first stage of the underfrequency load shedding during the largest N-1 contingency, then even a small frequency difference from the deadband modeling might cause a very different analysis result.

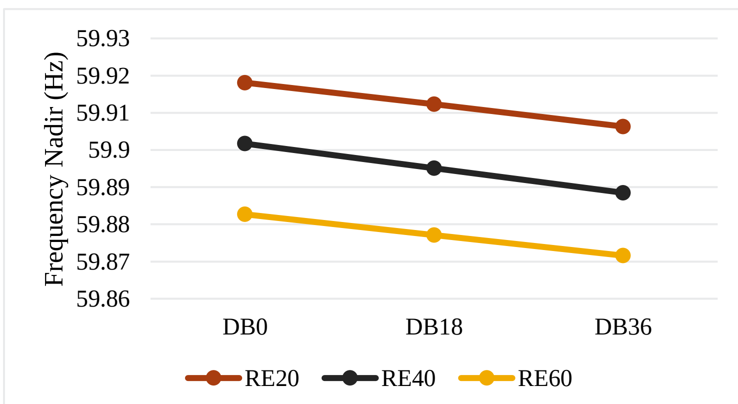


Figure 39. Comparison of frequency nadir of WECC under different renewable penetrations and different deadbands.

4.2.3.3 Impact of Hydro Deadbands Under Different Generation Trips

To study the impact of hydro deadbands under different amounts of generator tripping, two typical contingencies have been conducted in the 60% renewable penetration case. According to the target resource contingency protection criteria of the WI,[14] the loss of the two largest generating units, which are in the Palo Verde nuclear power plant and total 2,625 MW in the 2022 LSP case, was chosen as the largest N-2

[14] North American Electric Reliability Corporation, "Interconnection Criteria for Frequency Response Requirements", Atlanta GA, 2011

contingency. The loss of one unit in the Comanche generating station (804 MW) was chosen as a typical N-1 contingency.

In comparing Figure 40 to Figure 41, when the amount of generation drop is larger, the frequency nadir is lower. Figure 41 shows that a narrow deadband can improve the frequency nadir; however, this improvement was negligible compared to the large frequency deviation caused by the generation loss contingency. In terms of absolute value, the impact of deadband on frequency nadir are very similar under two cases. While in terms of percentage, the impact is larger under a small disturbance than under a large disturbance. Therefore, decreasing the governor deadband cannot meaningfully improve the WECC frequency response after large contingencies.

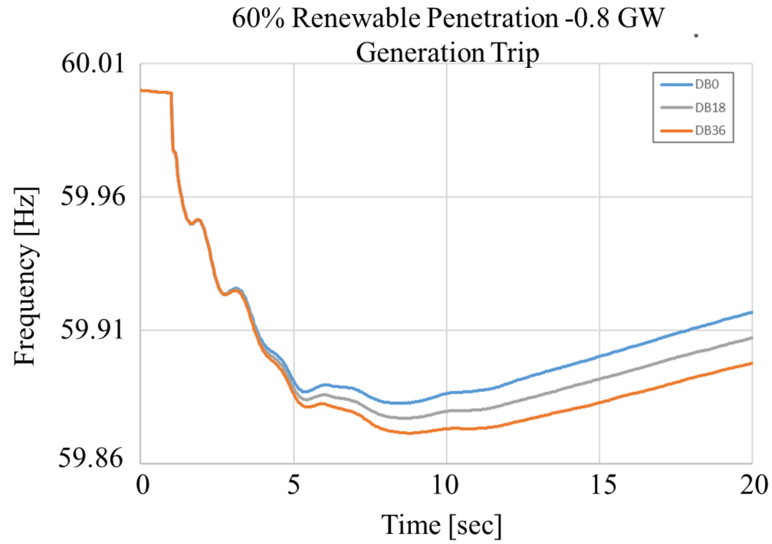


Figure 40. Frequency response of WECC with 60% renewable penetrations under 0.8 GW generation trip.

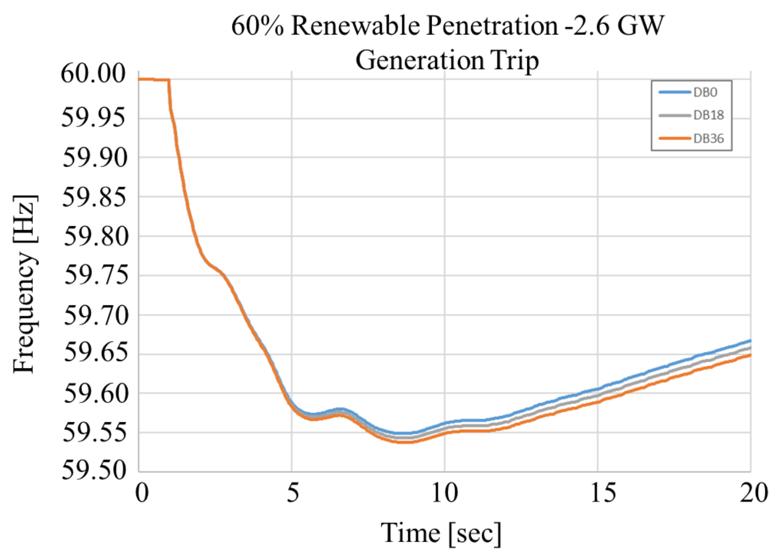


Figure 41. Frequency response of WECC with 60% renewable penetrations under 2.6 GW generation trip.

4.2.4 Summary

The deadband has impact on frequency nadir and settling frequency, but not on the RoCoF. When deadband increases, the response from the governor is slower and the frequency nadir can go lower as well as the settling frequency.

For WECC, as the penetration level of renewable energy increases, the frequency nadir and settling frequency become lower. In particular, the frequency nadir could approach the threshold of the underfrequency load shedding (i.e., 59.5 Hz in WECC). This means that even small frequency deviation errors caused by deadband modeling might affect the results of transient dynamic analysis. For example, the case without deadband modeling might give an overoptimistic results, while in fact the case may trigger the underfrequency load shedding. The deadband for each unit should be represented and modeled as accurately as possible, in particular in a high-renewable penetrated grid.

4.3 Impact of Data Issues in Hydro Modeling

4.3.1 Initial Identification and Analysis of Erroneous Parameters

Performing initial analyses using the WECC dynamic model (see Appendix A for a description of the model), we identified some discrepancies with the results from the HYGOV4 model (see Figure 42.). The yellow curve is the result of using the values defined within the model. However, the simulation results are much greater than the actual physical MWcap limit of the turbine generator as well as the P_{max}.

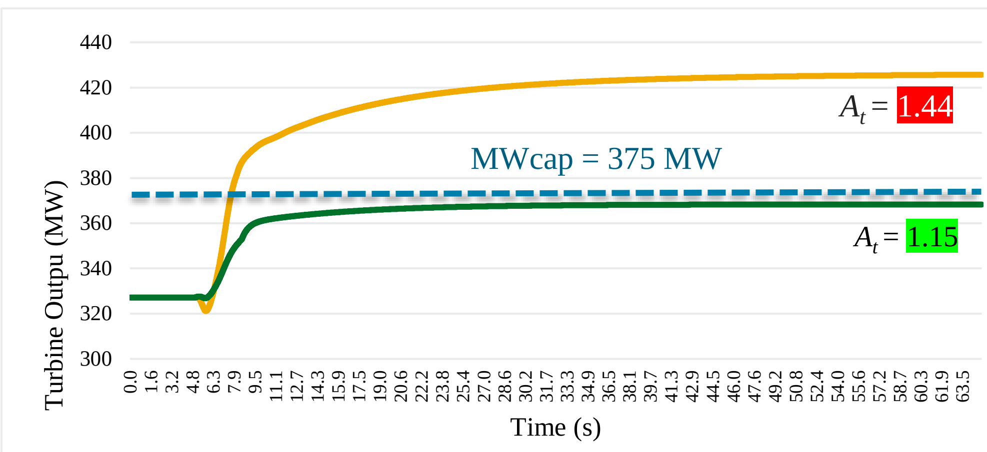


Figure 42. Simulation results with original (yellow) and corrected (green) governor parameters.

An investigation of the HYGOV4 model (WECC 2018) identified some possible anomalous parameter values within the model. This is illustrated in Figure 43 with the highlighted row. The data are sorted on the turbine gain (A_t). The turbine gain for the default HYGOV4 model is documented at $A_t = 1.44$. Within the model, the turbine gain is calculated by $A_t = 1/(q_{fl} - q_{nl})$. As you can see, A_t is much larger than the default for at least one site. The simulation was then repeated with a more realistic turbine gain value of 1.14, which resulted in the frequency response of the plant within the nominal MWcap value. These results are shown by the green curve in Figure 42.

--bus--	--name--	ID	Mbase	MWcap	at	dturb	hdam	qnl	calc_At	Dev_At
		1	9	8.5	3.5	0.5	1	0.14	1.234568	184%
		1	22	17.5	2	0.5	1	0.05	1.111111	80%
		1	55	49.3	1.5	0.5	1	0.03	1.086957	38%
		4	31	31.2	1.4	0.5	1	0.03	1.086957	29%
		1	222	207	1.44	0.5	1	0.08	1.149425	25%
		2	18	17.5	1.3	0.5	1	0.05	1.111111	17%
		1	19	19	1	1	1	0.1	1.176471	15%
		1	19	19	1	1	1	0.1	1.176471	15%
		5	18	16.9	1.24	0.5	1	0.03	1.086957	14%
		2	55	49.2	1.24	0.5	1	0.04	1.098901	13%
		1	145	160	1.11	0.5	1	0.15	1.25	11%
		3	18	20	1	0.5	1	0.06	1.123596	11%
		1	145	160	1.13	0.5	1	0.16	1.265823	11%
		3	24	24	1	0.5	1	0.05	1.111111	10%
		1	34	34.5	1	0.5	1	0.05	1.111111	10%
		3	34	34.5	1	0.5	1	0.05	1.111111	10%
		1	3	1.1	1.2	0.5	1	0.2	1.333333	10%
		1	13	12.5	1.2	0.5	1	0.2	1.333333	10%
		2	41	33.9	1.15	0.5	1	0	1.052632	9%

Figure 43. HYGOV4 WECC 2018 model values and deviation of turbine gain $\boldsymbol{A_t}$. Statistical tool allows capture of erroneous parameters.

Table 5 lists the statistics of hydropower resources violating the P_{max} constraint. This may be caused by extreme events in time-domain simulations for extended periods resulting in the exceedance. The quality of the simulation results beyond 30 s of simulation time may be inaccurate. The governor mode has the MWcap parameter that defines the max limit on the output provided by the prime mover or P_{mech}. Electrical output of the generator is dependent on the P_{mech} signal generated from the turbine-governor models. As observed in GE PSLF simulations of the simple test case, the P_{mech} for certain governor models is not respecting the MWcap parameter resulting in the generator output > P_{max}.

Table 5. 2018 WECC planning case units above P_{max} when subjected to large number of contingencies.

Row Labels	Max (%) violation > P_{max}	Number of violations > P_{max}	Max MW of largest unit with violation
GGOV1	154%	2	26
GPWSCC	2%	8	86
HYG3	10%	55	404
HYGOV	26%	53	116
HYGOV4	28%	11	207
IEEEG3_GE	22%	29	155
PIDGOV	10%	9	456
Total	-	167	-

4.3.2 Need for Automated Processes

Upon discovery of the generator output level anomaly and a suspected error in the governor parameter, the project team had to contact industry to verify there was an error and determine the correct value of the questionable parameter. The time and effort needed for this, and the probability that there were additional (undiscovered) errors given the size and complexity of the WECC planning model, illustrated the need for automated statistical processes to help identify possible problems before using the North American Energy Resilience Model to inform actual planning (e.g., resource allocation) or operation.

For this, we have identified the following needed processes:

- Anomaly detection: statistically analyze model parameter distributions to help identify possible anomalies
- Sensitivity analysis: estimate effects if there are anomalies within the model parameters
- Uncertainty quantification: estimate confidence for the model results.

4.3.3 Anomaly Detection

A user interface was created to help identify possible anomalies. This initial interface was developed in R as a prototype to help understand need and identify useful capabilities. Using R, statistical procedures to plot and analyze possible outliers were quickly implemented and tested. An example analysis is shown in Figure 44. and it is easy to see the outliers within the HYGOV4 model for turbine gain.

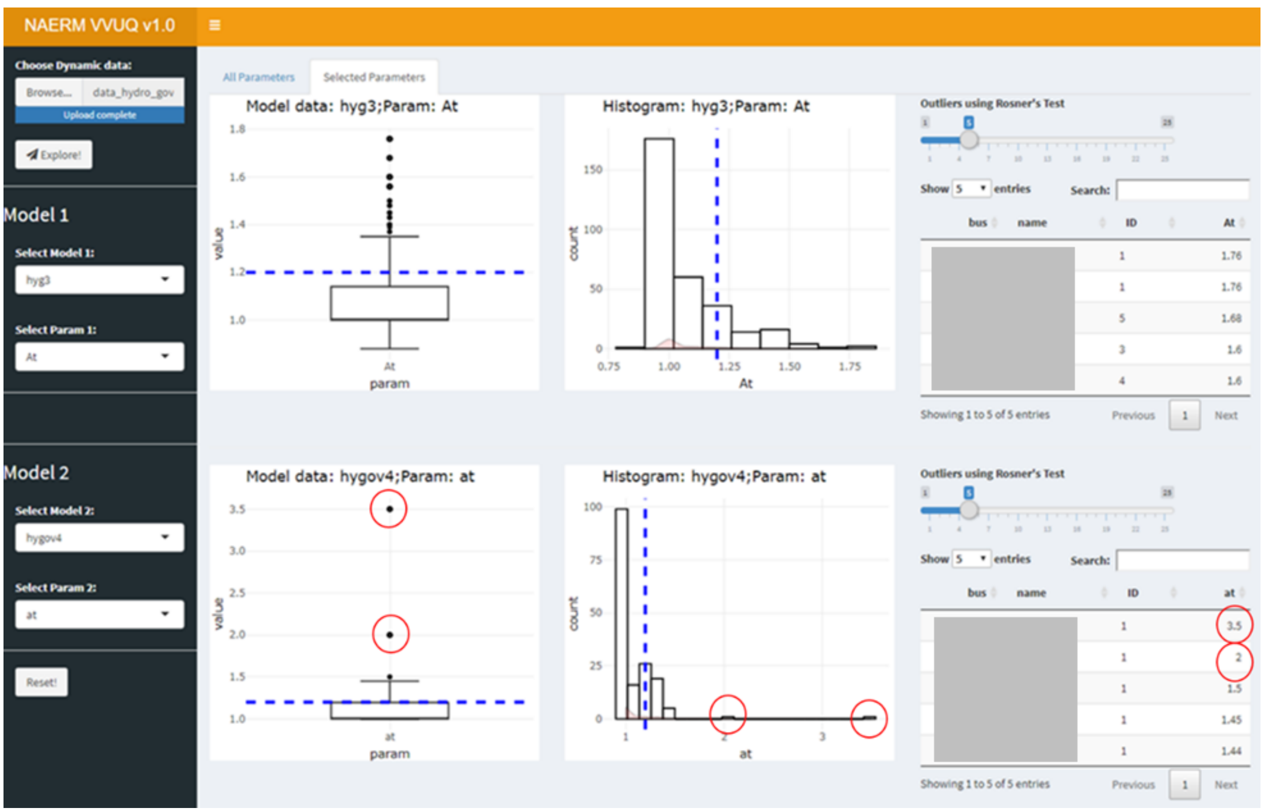


Figure 44. Statistical user interface to help find possible anomalous values (actual errors are circled).

4.3.4 Sensitivity Analysis

An initial sensitivity analysis was performed using the models and data discussed earlier. The results of this analysis are shown in Figure 45 for the A_t parameter and the HYGOV4 model. As can be seen by these results, the plant MW output/response following an event are significantly correlated to the accuracy of the dynamic model parameters. During the sensitivity analysis, it was discovered that the no-load gate opening (*qnl*) and A_t were driving the plant output increase beyond the rated capacity (P_{max}).

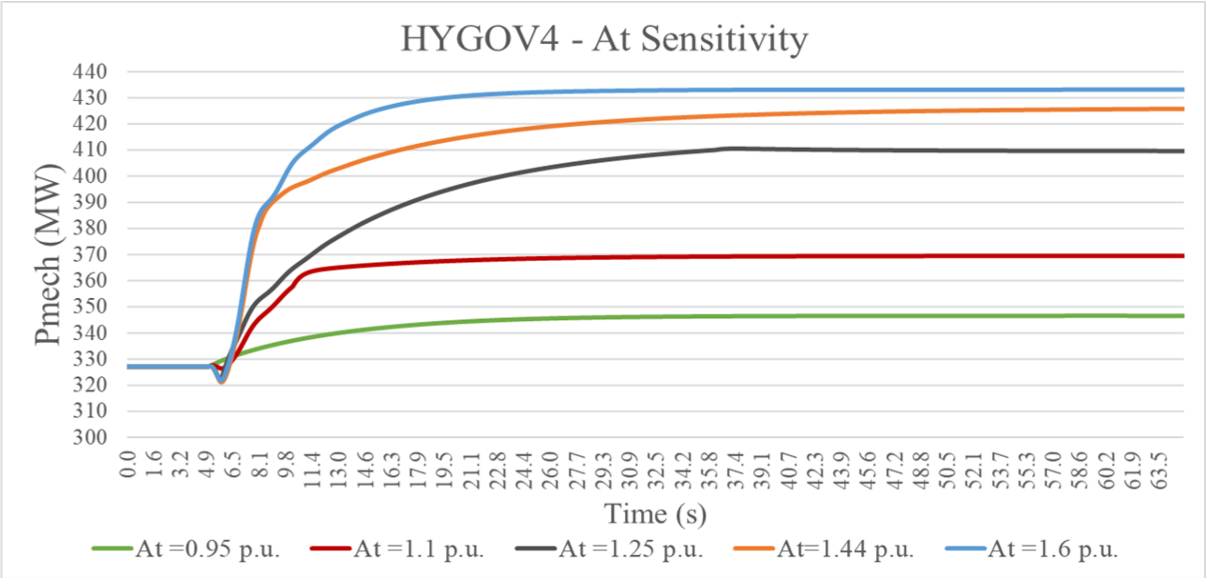


Figure 45. Sensitivity analysis of the $\boldsymbol{A_t}$ value for the HYGOV4 model.

As a next step, the sensitivity of the model parameters was compared with PMU data for specific plants.

4.3.5 Uncertainty Quantification of Hydro Dynamic Model Data Errors

A distribution for each parameter can also be extracted from the user interface shown in Figure 46. The distribution for the turbine gain (A_t) and the turbine nominal head ($H0$) for the HYG3 model are shown in Figure 47. Using these distributions, an uncertainty analysis can be performed.

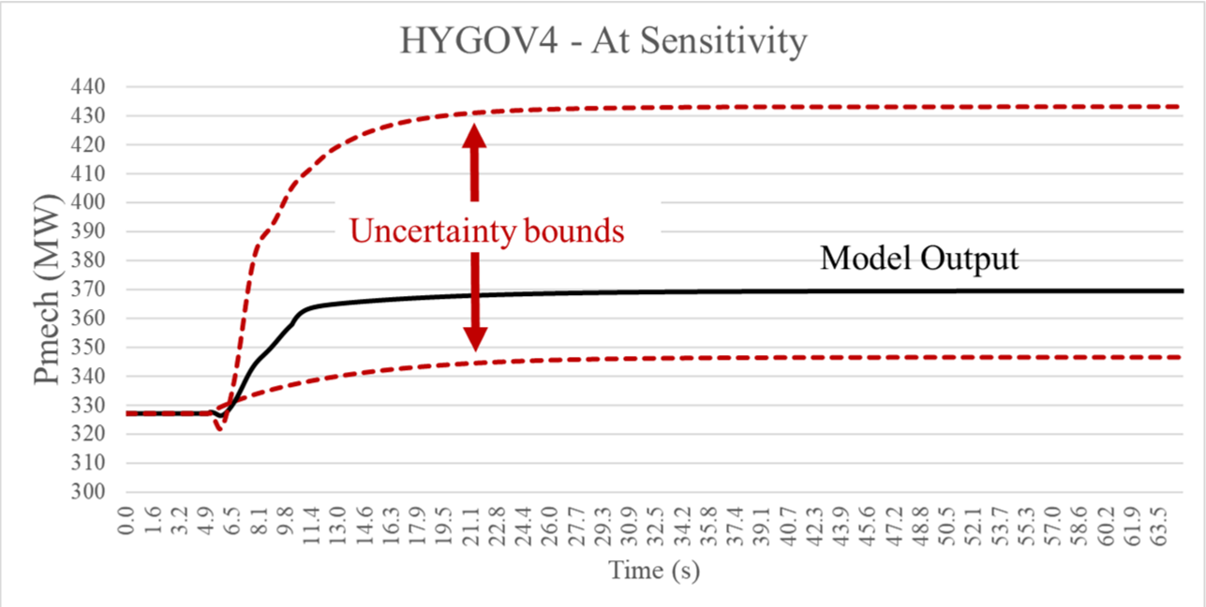


Figure 46. Preliminary uncertainty quantification results for the A_t parameter and the HYG3 model.

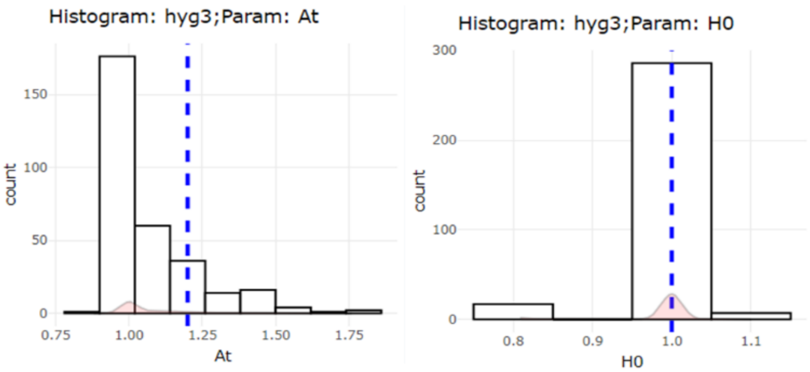


Figure 47. Parameter distributions for the HYG3 model (blue lines show default parameter value per software vendor, red curves show the continuous distribution of the model parameter values).

4.3.6 Summary

Model/parameter data issues in steady-state and dynamic models can have significant effects on the simulation results if not detected and corrected. WECC planning model data show there are outliers in model parameter values. A statistical tool to perform uncertainty quantification of parameter data issues can be useful in identifying critical parameters that may need data validation to make sure simulation results reflect realistic response following grid events in planning and operational studies.

5 Recommendations

Traditionally, the power system was planned for conventional resources, taking into account heavy winter and summer loading conditions. Adding clean, variable resources while retiring traditional generation changes patterns of power flow and how the power system reacts on contingencies making the system more stretched and susceptible to environmental conditions. Models used in operational and planning studies are decoupled from hydrological data and do not account for environmental conditions and constraints. Consequently, the power system might be under planned and has difficulties withstanding extreme conditions such as prolonged drought, leading to low-water levels in reservoirs coupled with extreme temperatures.

Industry develops base cases for heavy winter and summer loading conditions as well as shoulder cases representing light loading conditions. However, these cases consider nominal hydro conditions only, meaning the power system is not planned for low hydro conditions. In the environment of large renewable penetration of variable resources (solar and wind) and carbon-free goals, hydro becomes a more critical resource. It is more important to have proper representation of hydro availability in base cases. Similarly, as we develop cases having high and light-load conditions for planning and operation studies, we need to develop cases that account for low and high-water conditions and to accurately represent hydro generation capabilities.

Based on discussion with industry, for the large-scale system studies, the urgent need is not perfection of individual models, but rather getting ambient conditions and environmental constraints into the databases and software used for power system operation and planning studies. Ambient conditions should be represented as a separate database at the same level as currently used for composite load model development. For example, a composite load model standalone tool developed by PNNL for WECC is a database containing 12 climates zones and large industrial centers. Each zone has a combination of typical load types that change with hour, day, and season.

Consequently, based on a date, hour, and temperature, a climate zone file containing the dynamic load model was created. Every software vendor implemented the composite load model, which is now used in all system operation and planning studies. Similarly, databases containing different hydro conditions should be implemented. The developed database should be interfaced with base cases and used to populate accurate data for specific hydro conditions and water constraints, allowing their realistic representation in system studies. That way, if needed, it would be possible to specify season, month, day, and hour to have a reasonable estimate of what generation capacity is available and make system studies more accurate, increasing reliability of the system. As climate changes, a move away from traditional dispatchable resources and increase in renewable integration will make this gap more apparent.

To preserve integrity of the future system and allow further increase in renewable resource integration, the following gaps should be immediately addressed:

1. Water availability per water basin and individual plants in steady-state and dynamic models to account for available capacity and accurate frequency response
2. Interdependencies among different hydro projects so generation can be realistically dispatched in system studies
3. Proper representation of rough zones for individual generators so they are not dispatched to operate in rough zones in system studies.

The recommended way to address these gaps is outlined as follow:

- Collect data for different hydro basins (Columbia, Colorado, etc.) for different seasons and years and develop a water database. That will allow establishing seasonal water profiles for different water basins and conditions (dry years, wet years, average years). This would address water availability and use the database to impose water conditions on steady-state and dynamic models.
- Develop a tool to modify the base case based on desired water profile so that large-scale planning and operation system studies can be performed for low and high-water conditions. The tool needs to be able to impose desired water profile in base case per water basin and hydro project, and limit maximum generation output based on water availability. This would address water availability in steady-state cases (power flow).
- Develop a tool to automatically adjustment parameters of water head and corresponding dependent parameters in dynamic models per generator, plant, and water basin after power-flow water conditions are imposed. Establish interdependency relationships among dynamic model parameters that change with changes in water head. This would address water availability in dynamic models and most of the optimistic frequency response.
- Collect rules on how water can be shifted from project to project and environmental and other rules that are honored through water management. This tool could implement coupling among plants and impose restrictions on generation dispatch in systems based on observed constraints. It would include flagging nonoperating ranges and rough zones in base cases so that engineers performing studies are aware of restrictions on dispatching generators within rough zones. This would address interdependencies, rough zones, and environmental constraints that are currently not modeled.
- Review dynamic models used for hydro representation and provide recommendations. Many old models do not allow changes to the value of water head.

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Appendix A – Model Data

The test case for the hydro dynamic model illustrated in the report is shown in Figure A-1. The test system is a simple two-machine system consisting of a hydro generator plant, gas turbine generator, and infinite bus connected by a transmission line. The infinite bus does not provide any governor response and the response of the hydro plant is monitored for 60 s following the trip of the gas turbine plant at 5 s. The hydro plant is modeled with generator model (gentpj), governor models (HYG3, HYGOV4, etc.), and exciter (esdc1a) models in GE PSLF. The governor model parameters are altered to run the simulations and observe the sensitivity of the model parameters on the simulation performance.

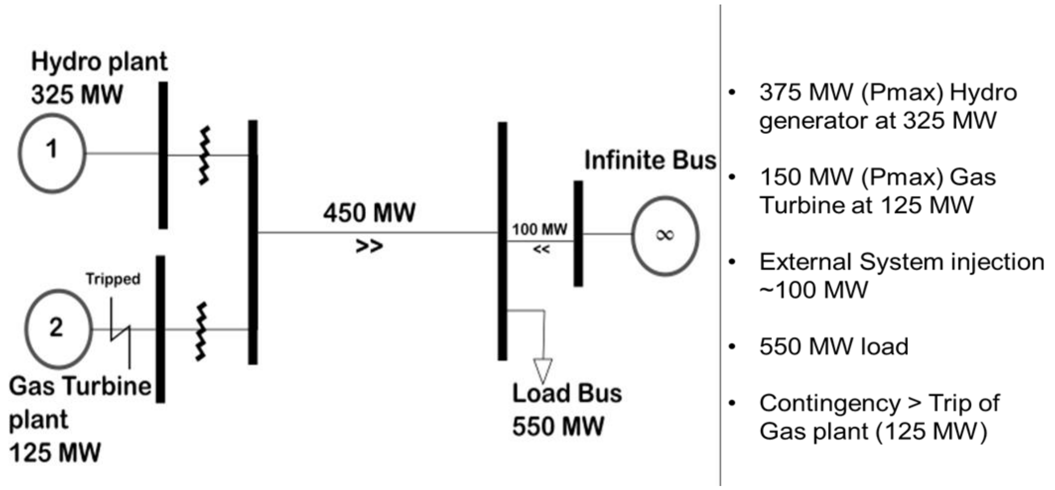

Figure A-1. Test case for the hydro dynamic model.

The governor models HYGOV4 and HYG3 are illustrated in Figure A-2 and Figure A-3. These figures show the state space diagrams of the hydro governor model and the interplay of the various parameters.

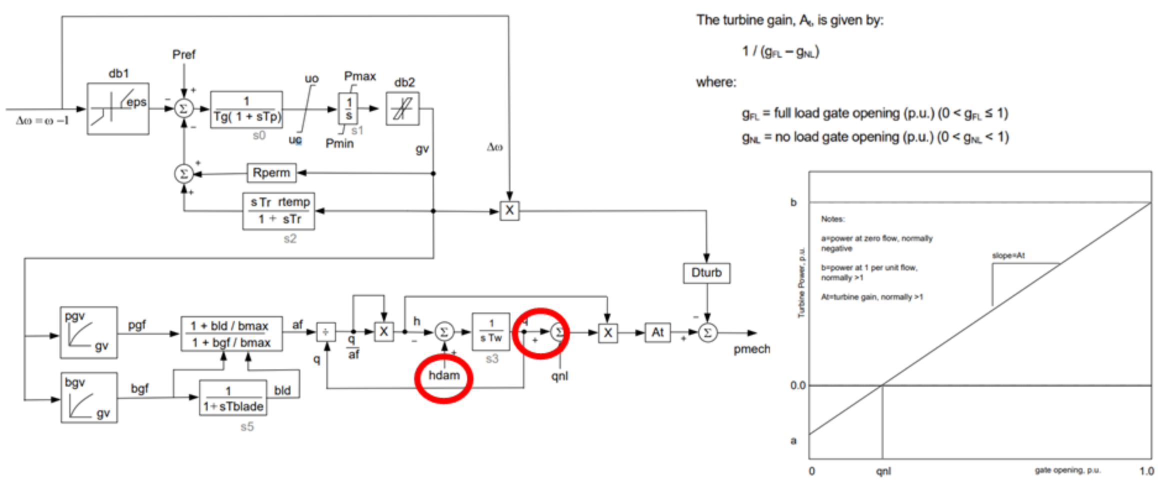

Figure A-2. HYGOV4 –hydro turbine-governor model showing the parameters that were verified using a sensitivity test.

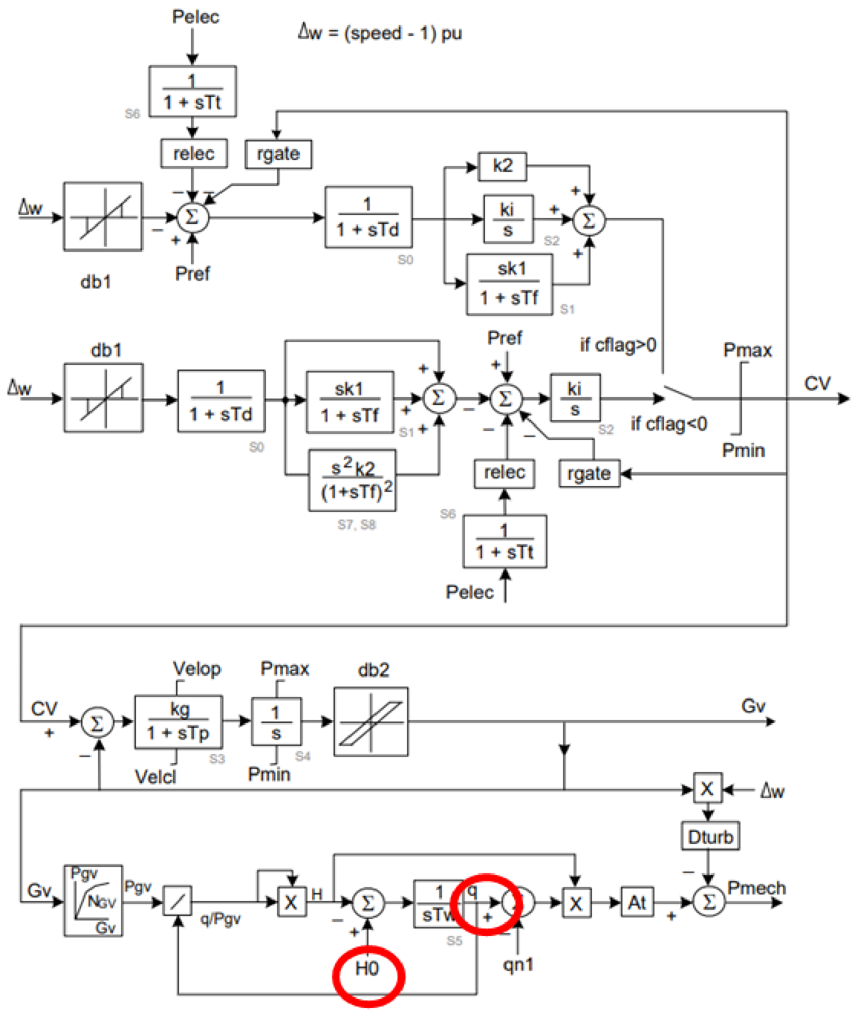

Figure A-3. HYG3 hydro turbine governor model showing parameters that were verified using sensitivity analysis.

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