Grid Integration and Market Analysis of Adjustable-Speed Pumped Storage Hydropower

Preprint

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Grid Integration and Market Analysis of Adjustable-Speed Pumped Storage Hydropower

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***Abstract*— Many products and services integrated into the electric grid are currently provided by conventional power plants; however, the response time from conventional power plants is slower than hydropower. Similarly, some services, such as spinning reserve, can be provided by modern renewable generation (wind or photovoltaics); however, the renewable generation must be curtailed down, and thus there is loss of opportunity to harvest clean energy while operating in spinning reserve mode. On the other hand, adjustable-speed pumped storage hydropower (AS-PSH) can readily perform these functions while pumping or generating, thus also providing the benefit of energy arbitrage, which can increase system efficiency.

This paper presents results from production cost models showing the effect of adding AS-PSH of 50-MW capacity to three regional independent system operator areas that have different ancillary service markets and different generation mixes. The paper measures the benefits to these market areas from the ancillary services that can be provided by the AS-PSH along with load-shifting. The paper also considers the cost savings and additional system flexibility in the day-ahead and real-time markets. The main metrics to provide these insights are savings in the total system production cost and in variable renewable energy curtailment, respectively. The paper analyzes the simulated operation of the additional hydropower to determine the breakdown of system cost reduction provided by the ancillary services and load-shifting.

***Index Terms*— Adjustable-speed pumped storage hydropower, curtailment, production cost modeling, energy arbitrage, Obermeyer Hydro, reserves, ancillary services.**

I. Introduction

With increasing amounts of variable generation being added to electric power systems, pumped storage hydropower (PSH), particularly adjustable-speed pumped storage hydropower (AS-PSH), shows increasing potential to maintain stability and provide value. The elimination of expensive underground power stations—enabled by the submersible Obermeyer Hydro reversible pump turbine—pointed to the need to assess the benefits to the electric grid of pumped storage facilities comprising machines with unit ratings in the 50-MW range. For this work, we used a production cost model to study the benefits of a 50-MW pump turbine in the year 2024 for three competitive regions in the United States. Guided by discussions with Obermeyer Hydro, we quantified the production cost that a 50-MW pump turbine unit could save each region, and we provide insight into the system-wide reduction in the curtailment of variable renewable generation, thus showing the value of PSH to a power system. A higher system value suggests a higher potential for markets to offer larger remuneration for the benefits that the pump turbine can provide.

The production cost model minimizes the total cost of system-wide generation for the day-ahead and real-time markets in a given region. Because each system has different reserve requirements and a different generation mix—particularly different renewable generation penetration levels—the pump turbine reveals a different value it can provide to the system it resides in.

II. The Production Cost Model

We modeled three regions—the Independent System Operator of New England (ISO-NE), Californian Independent System Operator (CAISO), and the Northwest Power Pool (NWPP)—using PLEXOS, a commercially available, security-constrained production cost software tool that can model the detailed operation of an electric power system. For each simulation run, the total generation cost of the modeled system is minimized by optimizing all generation together, enabling valuation of a storage unit by comparing runs with and without the corresponding storage unit. For each region, a day-ahead and a real-time market is simulated, taking neighboring regions' interconnection flows into account. The day-ahead markets are run with every generator and storage object in the model having perfect foresight of prices for the following day, given wind and solar day-ahead forecasts. The real-time markets model the redispatch of energy at a 5-minute resolution using actual wind and solar profiles to reflect the variability in prices caused by wind and solar forecasting errors.

A summary of the ancillary services modeled for each region follows. Figure 1 shows the generation mix by percentage of energy for the year 2024 for each region. For this modeled year, the total generation for CAISO, NWPP, and ISO-NE is 213,451 GWh, 146,994 GWh and 91,769 GWh, respectively.

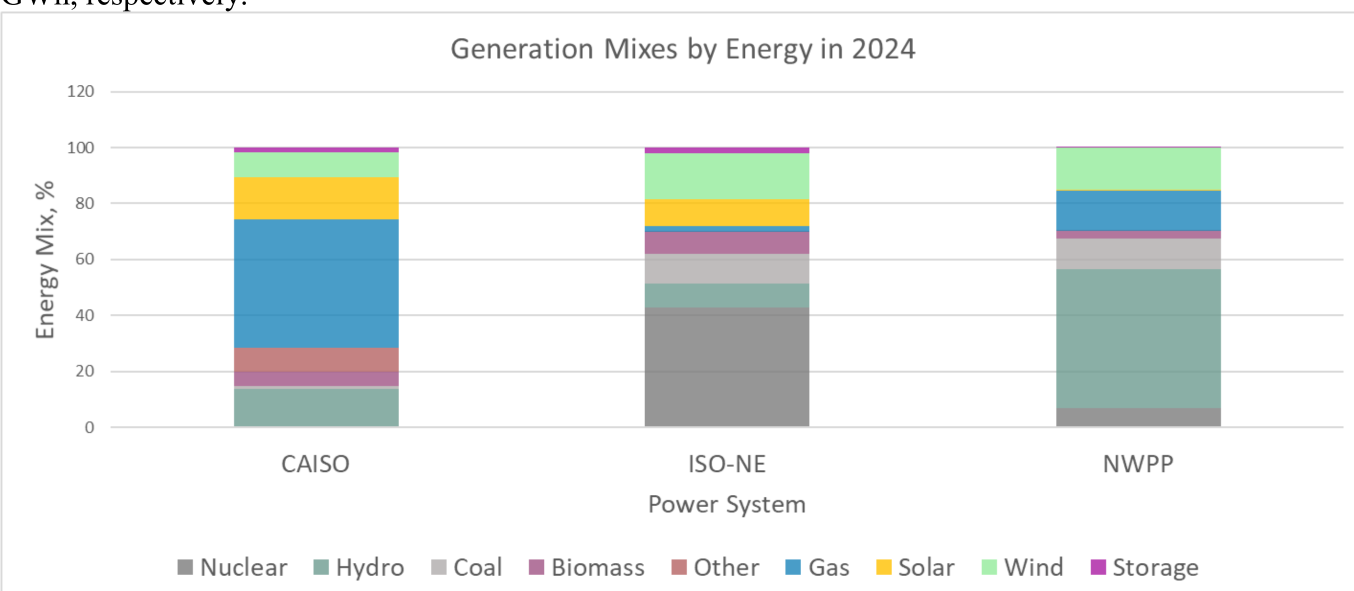

Figure 1: Generation portfolio for CAISO, ISO-NE, and NWPP

For the three regions, the National Renewable Energy Laboratory (NREL) used existing models that have been used for similar studies; individual details are explained as follows.

a. CAISO and NWPP

CAISO and NWPP were extracted from a model of the Western Electricity Coordinating Council (WECC) that was used for the *Low Carbon Grid Study* [1]; the model assumptions can be found in https://www.nrel.gov/docs/fy16osti/64884-02.pdf. The modeling assumptions were created for the year 2024, including new renewable energy and expected storage. Because of the large number of simulated objects within this model—including more than 5,000 generators and almost 20,000 nodes—the impact from adding a single PSH unit can be significantly affected from the error bands within the model. Therefore, it makes sense to extract the focus regions, CAISO and NWPP, to be modeled separately. The methodology for doing this was identical for CAISO and NWPP but will be explained and illustrated for CAISO specifically.

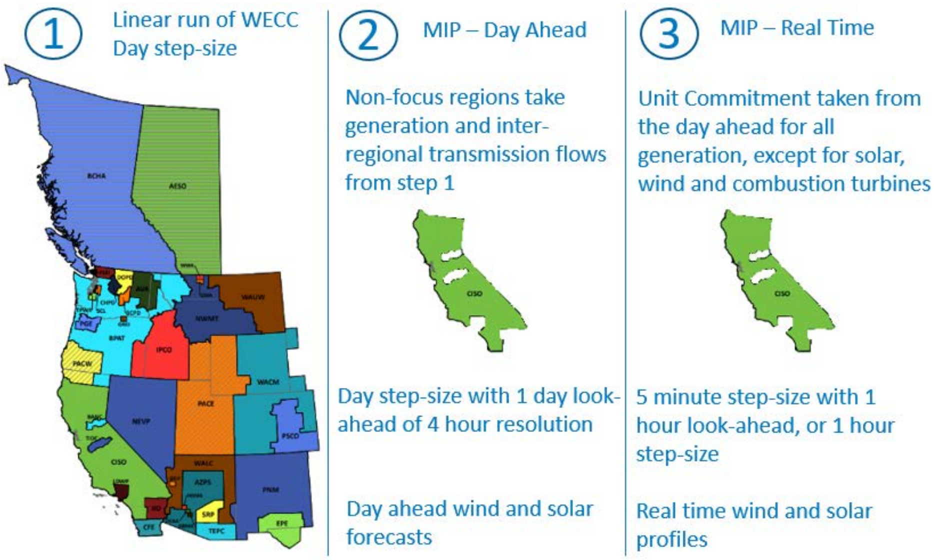

Figure 2: Production cost modeling methodology for CAISO and NWPP

The first step is to run a linear model of WECC to quantify generation in the regions outside of CAISO. The linear run means that no integer constraints—such as minimum up/down times—are considered and is a necessary approximation to reduce the computational time of simulating such a large detailed model. The generation in each region outside of CAISO can be passed to the second step, where a full mixed-integer problem is solved only for CAISO, with imports and exports to neighboring regions determined by following the previous linear run in Step 1. Step 2 simulates the day-ahead market and passes the unit commitment— for units that cannot recommit in the real-time market—to Step 3. Here, the time resolution is at its maximum (5 minutes) to distinguish the value of a fast-ramping PSH unit, and the wind and solar profiles are now based on actual output from a historical year instead of the forecasted profiles in Step 2. This accounts for variability in prices resulting from renewable energy forecast errors.

Reserve objects modeled for both regions are a flexibility reserve and a spinning reserve. The flexibility reserve provision is calculated from a combination of forecast errors of wind power, solar power, and load forecasts. The corresponding response time is 20 minutes. The spinning reserve provision is calculated as 3% of regional load. It has a response time frame of 10 minutes. The modeled pump turbine unit is able to contribute to both of these services.

Because of computational constraints, transmission is not represented for the CAISO and NWPP models.

b. ISO-NE

The ISO-NE model is based on a model used for the report on the *Impact of Utility-Scale Distributed Wind on Transmission-Level System Operations* [2] (Chapter 2 describes the PLEXOS model). The model was then modified with solar and wind power penetration quantities reflecting the year 2024, per the modeling assumptions of TEPPC 2024. This was done by scaling existing solar generation in the model and adding selected wind sites based on Chapter 3 [2].

Transmission is represented only for ISO-NE with 3,327 nodes. Reserve objects modeled include a contingency spinning reserve, regulation-up reserve, and regulation-down reserve. The contingency reserve has a response time frame of 10 minutes and is defined as half of 125% of the largest contingency, which is a nuclear power plant with a capacity of 1,318 MW. Therefore, the contingency reserve provision throughout the year is 824 MW. The regulation-up and regulation-down reserves have a wind forecast error and a load component.

III. Methodology

In every case, the day-ahead and real-time markets are run without modification to the generation or storage objects within the model and then run again with the addition of the pump turbine unit, and outputs are compared. The modeled pump turbine's properties are shown in Table 1.

Table 1: Modeled Pump Turbine Properties

Property	Value
Generation capacity	50 MW
Pumping capacity	50 MW
Storage quantity	12 hours
Round-trip efficiency	80 %
Ramp rate	Infinite
Variable operational and maintenance cost	0, $
Minimum generation level	0 MW
Minimum pumping level	0 MW

The production cost model optimizes each time step as a mixed-integer linear program (MILP). Each integer solution is declared optimal when the current integer solution is within a user-defined gap from the best known bounding linear relaxation. With CAISO, the high-fidelity detail of the model rendered the effect from the 50-MW pump turbine to be within the tolerance of this gap, and therefore results did not hold integrity. We investigated adding eight 50-MW pump turbines to CAISO, which was sufficient additional capacity to potentially exceed the MILP gap. Results presented here are based on outputs divided by eight to represent an individual 50-MW pump turbine.

The production cost model analyzes both the day-ahead and real-time markets. The day-ahead model is set up so that every generator and storage unit has perfect foresight for at least 24 hours ahead. This enables storage units to make decisions at any time step with an understanding of potential energy arbitrage opportunities in the following 24 hours. In the real-time model, to ensure that the generation reacts to the differences between the wind power and solar power day-ahead forecast compared to their real-time outputs, this perfect foresight is removed. The purpose of the production cost model is to minimize production cost, but without foresight it cannot see opportunities for energy arbitrage, so it is only ever worth it to charge a storage unit when free generation is being curtailed, or to avoid system instability such as transmission constraints, because charging creates a higher production cost unless it is using free curtailed generation. In the real-time market, however, storage units are able to provide reserves by holding back generation or pumping capacity. Future work in this area could include creating heuristics for each storage unit to make decisions about whether it should generate or charge for the purpose of energy arbitrage. Otherwise, price outputs from the production cost models could be input into a price-taker model to forecast potential energy arbitrage revenue opportunities for the modeled pump turbine.

IV. Results

In this section, we present production cost savings and wind power and solar power curtailment reduction for all three modeled regions; see Table 2. We examine this on a nodal level for the ISO-NE model, including the contribution from the modeled pump turbine to reserves.

Table 2: Production Cost Modeling Results Overview for 2024

	Production Cost Savings ($)		**Curtailment Savings (%) Compared to Base Case Run**	
Region	**Day-Ahead**	**Real-Time**	**Day-Ahead**	**Real-Time**
CAISO (modeled with no transmission constraints)	Negligible	Negligible	Negligible	Saves 1.3% compared to base
ISO-NE (modeled with transmission constraints)	Negligible	2,850,000–5,293,000	None	Negligible
NWPP (modeled with no transmission constraints)	Negligible	Negligible	None	Negligible

Production cost savings from the pump turbine, within a given system, give insight into the value of the pump turbine to that system through better optimization of the total generation. Storage is a net user of energy, and its value to reducing production cost is within the flexibility that it provides to a power system, predominantly by providing reserves and shifting load from costly hours to less costly hours. In Table 2, "negligible" refers to results within the MILP gap and therefore within the error band of the model, so they cannot be regarded as significant.

Also shown in Table 2, CAISO and NWPP production cost savings in the day-ahead and real-time markets are within the MILP gap of the model and therefore insignificant. Note that these systems are run without transmission constraints, and the effect of this assumption is that the results do not show the value of storage that arises from alleviating transmission constraints.

ISO-NE is run as a nodal model with full representation of the transmission system. The day-ahead market is sufficiently flexible to result in a value of storage that does not exceed the MILP gap. In the real-time model, however, the instability of the system driven by renewable energy forecast errors results in significant production cost savings with the modeled pump turbine. Because of transmission constraints, this savings depends on what node the pump turbine is added to because of transmission constraints. The sensitivity of this is investigated by performing multiple runs with the pump turbine added to a different node; see Table 3. Here, the table shows the total production cost within the base run (ISO-NE without the pump turbine added), the total production cost within the pump turbine run (ISO-NE with the pump turbine added), and the resulting savings. This is separated for the ISO-NE region (upper), the neighboring regions (middle), and the sums of these two values (lower).

Table 3: Real-Time Market Production Cost Savings for ISO-NE in 2024

	Production Cost for ISO-NE from Real-Time ($000)		
Node	Base	Pump Turbine	Savings
Highest load	6,350,680	6,347,627	3,053
Day-ahead highest peak price	6,350,680	6,345,106	5,574
Large wind power plant	6,350,680	6,346,019	4,661
Day-ahead highest energy generated	6,350,680	6,346,678	4,002
Real-time highest peak price	6,350,680	6,347,891	2,789

	Production Cost for Neighboring Regions from Real-Time ($000)		
Node	Base	Pump Turbine	Savings
Highest load	3,558	3,500	59
Day-ahead highest peak price	3,558	3,840	-281
Large wind power plant	3,558	3,693	-135
Day-ahead highest energy generated	3,558	3,573	-14
Real-time highest peak price	3,558	3,497	61

	Production Cost for All Regions from Real-Time ($000)		
Node	Base	Pump Turbine	Savings
Highest load	6,354,238	6,351,126	3,112
Day-ahead highest peak price	6,354,238	6,348,945	5,293
Large wind power plant	6,354,238	6,349,712	4,526
Day-ahead highest energy generated	6,354,238	6,350,251	3,988
Real-time highest peak price	6,354,238	6,351,388	2,850

The definitions of the nodes selected are as follows:

1. Highest load — Node with the highest annual total load
2. Day-ahead highest peak price — Node that has the highest peak price in the day-ahead market
3. Large wind power plant — Node with a large wind power plant (large variable generation source)
4. Day-ahead highest energy generated — Node with the largest amount of total annual generation in the day-ahead market
5. Real-time highest peak price — Node that has the highest peak price in the real-time market

The entire system, including ISO-NE and the neighboring regions, is optimized as a whole. With transmission constraints and an import and export wheeling charge of $3/MWh, the benefit of the pump turbine occurs in the region it is placed, ISO-NE. The production cost savings from the pump turbine vary largely on the node within ISO-NE on which the pump turbine is placed.

These real-time market production cost savings result entirely from reserve contributions because the model cannot perform load-shifting in real time. Table 4 shows the pump turbine's contribution to the reserve requirements in ISO-NE.

Table 4: Annual Reserve Provision Met by the 50-MW Pump Turbine for All Three Reserves for ISO-NE Real-Time Market in 2024

Node	Up-Regulation Reserve (GWh)	Down-Regulation Reserve (GWh)	Contingency Spinning Reserve (GWh)	Total (GWh)
Day-ahead highest load	3.6	0.5	33.5	37.6
Day-ahead highest peak price	6.3	0.5	31.7	38.6
Large wind power plant	7.3	0.4	30.2	37.9
Day-ahead highest energy generated	3.8	0.5	33.4	37.7
Real-time highest peak price	4.6	0.4	32.3	37.3

Note that ordering the nodes by the total magnitude of reserves provides results in the same order of nodes as if they were ordered by the production cost savings shown in Table 3. When the pump turbine provides reserve provision, other nearby generators, which are subject to transmission constraints, are free to provide more energy and less reserve provision. The location of the pump turbine affects which generators' reserve provision is being displaced, and this has an effect on the production cost.

Curtailment of wind power and solar power is an undesirable option for the model because of the fuel savings from these generation types; however, it is sometimes necessary to avoid dump energy, and therefore curtailment can be seen as an indicator of a system's lack of flexibility. In all three regions modeled, there was negligible curtailment in the day-ahead market in the base case. In the real-time market, the wind and solar power underforecast errors revealed a requirement for curtailment. Only in CAISO was the pump turbine able to save a significant curtailment quantity. NWPP and ISO-NE had low renewable energy penetration levels compared to CAISO, which had a large portion of its generation portfolio from solar power, particularly in 2024. Underforecasting solar power during the day when solar power output is high and thermal generation is already running low results in less potential to reduce thermal generation output, and therefore the system relies more heavily on curtailment. The pump turbine takes advantage of these low-price hours by pumping, avoiding curtailment, and reserving the generation for a higher price hour. Note that with the eight pump turbines added, the difference in curtailment compared to the base case run was 10.4%, which was divided by eight to represent the value of an individual pump turbine. This method is subject to saturation effects from adding the larger quantity of storage, and therefore the 1.3% can be seen as a lower bound.

V. Conclusion

ISO-NE saw large savings in production costs as a result of adding a 50-MW AS-PSH pump turbine. Further, because these savings were based on reserve contributions, it is expected that in reality, with the additional value of load-shifting, this production cost saving would be potentially even higher. The flexibility of NWPP in 2024 is expected to be sufficient to maintain load being met by generation in an economic manner, without considering transmission constraints. In CAISO, the pump turbine provides system value, which is expected to increase as variable renewable energy penetration increases.

In reality, the pump turbine can contribute to system stability in ways that cannot be modeled in PLEXOS—such as voltage stability and inertia, for which there could be potential markets in the modeled regions in the future. Further, capacity markets provide revenue potential to storage, particularly in CAISO and ISO-NE [3], which was not modeled within this work.

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