Market Opportunities and Challenges for Pumped Hydro in an Evolving Power Grid

Preprint

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Introduction

This paper explores several market opportunities and challenges for pumped storage hydropower related to ongoing changes in the electric power grid. Two PSH technologies are investigated—a conventional design that has a fixed-speed pump and an advanced design that can vary the amount of water it pumps[1]—under three variable generation penetration scenarios. The results provide a way to do relative comparisons of the opportunities and challenges that pumped storage hydro faces as the variable generation in a system increases.

Note that this effort is early-phase work that is being conducted as a part the U.S. Department of Energy Hydropower Valuation Consortium pumped storage hydro technoeconomic study.

The Changing Power Generation Landscape

Most pumped storage hydropower in operation in the United States was built in the last century, at a time prior to the inclusion of variable generation in the nation's electric power grid. Much of it was built to support the operation nuclear power plants, allowing them to operate at peak efficiency. However, in recent years, the nature of the grid has changed. Large coal- and nuclear-fired generation plants have retired, and variable generation is common.[2]

Two main factors have led to these changes. The first is the low price of natural gas, and the second is the rapidly falling prices of variable generation. As the cost of natural gas has dropped, gas-fired generation has become more competitive, often displacing coal and nuclear on the dispatch stack. Contributing to the retirements are the increasing and uncertain costs associated with regulatory compliance combined with the decreasing costs of both wind and solar generation. With renewable generation price drops, their installation has accelerated, and these forms of generation can, at times, displace traditional baseload generators, lessening the revenue streams for the coal and nuclear fleet.

Test System Configuration

The test system used for this work is self-supporting (i.e., meets its own load needs), with the exception that it does occasionally rely on neighboring systems for excess energy sales and energy import during times of stress. The system load is approximately 600 MW, and its generation mix is representative of midsized utilities throughout the West and Midwest. The thermal fleet is a mix of coal with a few gas-fired combustion turbines, and it provides between 50% and 70% of the annual energy generation (the actual amount of energy provided varies with the amount of renewables in the system). The next largest energy source is hydropower, which provides approximately 20% of the annual energy. The balance of the system's energy is provided by wind and solar.

Three levels of wind and solar generation were investigated: 10%, 20%, and 30%, all on a nominal annual energy basis. These variable generation (VG) scenarios are designated 10% VG, 20% VG, and 30% VG and consist of an approximate 2:1 mix (on an annual energy basis) of

[1] Both ternary and variable-speed pump technologies fit this classification.

[2] U.S. Department of Energy, *Staff Report to the Secretary on Electricity Markets and Reliability* (Washington, D.C.: August 2017).

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wind to solar photovoltaics (PV). As new variable generation was added, it was done in a manner to minimize wheeling costs yet provide generation diversity.[3] Two types of pumped storage hydropower (PSH) were investigated: a conventional, 60-MW PSH facility with fixed-speed pumping (C-PSH) and an advanced, 60-MW PSH facility with variable pumping (A-PSH). Each facility consists of two, 30-MW plants with eight hours of storage. The round-trip efficiency for both the C-PSH and A-PSH units was set at 80%, and both were allowed to switch freely between generation and pumping. The 10% variable generation scenario with no installed PSH served as the baseline for this study.

Load values as well as prices for energy imports and exports were based on actual operating data. Operating parameters for the generation fleet (ramp rates, minimum stable levels, and start and stop costs and times) were derived from those used in the Western Wind and Solar Integration Study: Phase 2.[4] The wind and solar forecasts and generation amounts are from the National Renewable Energy Laboratory's WIND[5] and SIND[6] Toolkits and are derived from numerical weather prediction models.

Two types of market simulations were performed: day ahead and real time. The day-ahead simulations used a one-hour resolution along with the 24-hour look-ahead (the look-ahead also used one-hour resolution). All generation was optimized over a rolling two-day, 48-hour optimization window (24 hours for the day-ahead plus the 24-hour look-ahead), and the results of the day-ahead optimization were used to commit the coal-fired resources as well as set the dispatch for the hydro units. The day-ahead market simulation was also used to determine the offer base and expected pumping times and amounts for the PSH units (i.e., the amount of energy sold into and purchased from the day-ahead market).

The real-time market simulations used a five-minute resolution with a two-hour look-ahead (the look-ahead uses a one-hour resolution).[7] The wind, PV, PSH, and combustion turbines were all assumed to start and be dispatched in real time. Hydro was assumed to operate at the dispatch value that had been determined in the day-ahead market (i.e., it was assumed inflexible in real time). Coal-powered plants, previously committed in the day-ahead market, were allowed to vary their dispatch levels; however, the plants could not be stopped or started.

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[3] Wind and PV were sited such that they were realistically close to the load (i.e., limited to one grid boundary crossing/wheeling charge) yet provided some geographic diversity (e.g., PV was placed in several areas throughout the balancing authority area).
[4] D. Lew, G. Brinkman, et al., *The Western Wind and Solar Integration Study Phase 2* (NREL/TP-5500-55588) (Golden, CO: The National Renewable Energy Laboratory, September 2013).
[5] https://www.nrel.gov/grid/wind-toolkit.html
[6] https://www.nrel.gov/grid/sind-toolkit.html
[7] The two-hour look-ahead was to account for the operator's insight into how the load was expected to change over the next two hours—e.g., is the afternoon expected to get warmer than originally forecasted?

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Market Opportunities

This preliminary work has focused on two areas: increasing grid flexibility and reducing the system's annual operating costs.

The Increased Need for System Flexibility

As the amount of variable generation in the test system was increased, the average net load change between five-minute market intervals was found to increase (see Table 1 for a summary of how the net loads changed).

Table 1. Net Load Change between Five-Minute Market Intervals

Scenario	Avg. Net Load (MW)	Avg. Net Load Change between Intervals (MW)	Avg. Change between Intervals as a % of Avg. Net Load	Max. Net Load Change between Intervals
10% VG	312	1.85	0.59%	55.1
20% VG	282	2.13	0.75%	49.7
30% VG	257	2.28	0.89%	58.6

Based on a percentage of net load, the average net load change between five-minute market intervals increased by approximately 50% as the amount of variable generation in the test system was increased from 10% to 30%. This increase is significant in that it puts additional ramping-related requirements on the generating fleet.[4]

Related to net load variability is the number of thermal plant starts needed to support the system and its changing net load (see Table 2). For this particular system, the thermal unit starts decreased with increasing variable generation, although they stayed stable on a number of starts per unit of energy basis (the variable generation added to the system was well balanced, which helped manage unit starts).

Table 2. Day-Ahead Thermal Generator Starts by Scenario

Scenario	No PSH	C-PSH	A-PSH
10% VG	151	37	30
20% VG	117	48	48
30% VG	115	53	52

Both the C-PSH and A-PSH plants were found to reduce thermal starts between 54% and 80% and start costs by 50% or more (see Table 3), helping to manage both wear-and-tear and start-related fuel costs for the thermal fleet.

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Table 3. System-Wide Day-Ahead Generator Start Costs by Scenario

Scenario	No PSH	C-PSH	A-PSH
10% VG	$573,000	$267,000	$249,500
20% VG	$477,500	$215,000	$215,000
30% VG	$384,500	$129,000	$128,000

The start-cost savings account for approximately 20% to 45% of the overall PSH-related cost savings (see the next section for additional information).

PSH-Related System Operating Cost Reductions

PSH is a highly flexible, low-marginal-cost, and fast-acting generation asset, and in the market simulations, it was shown to reduce system-wide operational costs in both the day-ahead and real-time markets.

Table 4. System-Wide Day-Ahead Annual Operating Costs (millions of dollars)

Scenario	No PSH	C-PSH	A-PSH
10% VG	$57.7	$56.8	$56.8
20% VG	$51.8	$51.2	$51.1
30% VG	$47.2	$46.0	$45.9

Table 4 shows cost reductions in the day-ahead simulation between 1.2% and 2.8%, which are significant reductions for a system of this size.

Table 5. System-Wide Real-Time Annual Operating Costs (millions of dollars)

Scenario	No PSH	C-PSH	A-PSH
10% VG	$66.3	$59.7	$59.7
20% VG	$55.4	$53.0	$53.0
30% VG	$50.0	$48.1	$47.9

The cost savings in the real-time market simulations were even larger, ranging between 3.9% and 10%. These results demonstrate how storage can manage price spikes and reduce operational costs.

Directly influencing the operating costs is the reductions in curtailment that PSH can provide.

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Table 6. Real-Time Annual Curtailment Estimates

Scenario	No PSH	C-PSH	A-PSH
10% VG	1.5%	0.2%	0.3%
20% VG	2.3%	1.6%	1.6%
30% VG	12.1%	8.6%	8.7%

Challenges

Three types of market challenges were investigated: quantifying the compensation received for providing non-energy-related services to the system, investigating how flat price duration curves impact price arbitrage opportunities, and valuing flexibility in day-ahead energy markets.

The Value Offered Is Not Always the Compensation That Is Received

In all market simulations, the addition of PSH significantly reduced the annual operating costs for the test system. Cost savings ranged from 1.2% to 2.8% in the day-ahead market simulations and between 3.9% to 10% in the real-time simulations. Examples of the annual system-wide savings along with the net revenues received for providing these savings in shown in Table 7.

Table 7. System-Wide Day-Ahead Annual Operating Cost Savings (thousands of dollars)

Scenario	C-PSH-Related Savings	A-PSH-Related Savings	C-PSH Net Revenue	A-PSH Net Revenue
10% VG	$867	$961	$0	$20
20% VG	$599	$618	$30	$47
30% VG	$1,257	$1,324	$273	$441

Of note is how the compensation received for providing similar system-wide value can vary markedly form one scenario to the next. For instance, the annual costs savings for the 10% VG scenario are 50% more than those in the 20% VG scenario; however, the compensation received by the PSH plants is higher in the 20% VG scenario. Note that these findings are not unique to PSH and can make it difficult for storage stakeholders to estimate revenue streams and value overall projects.

Flat Price Duration Curve

The price duration curve for the system is quite flat for the 10% and 20% VG scenarios (see Figure 1), and this limits the opportunity for energy arbitrage, as shown in the PSH generation numbers (Table 8).

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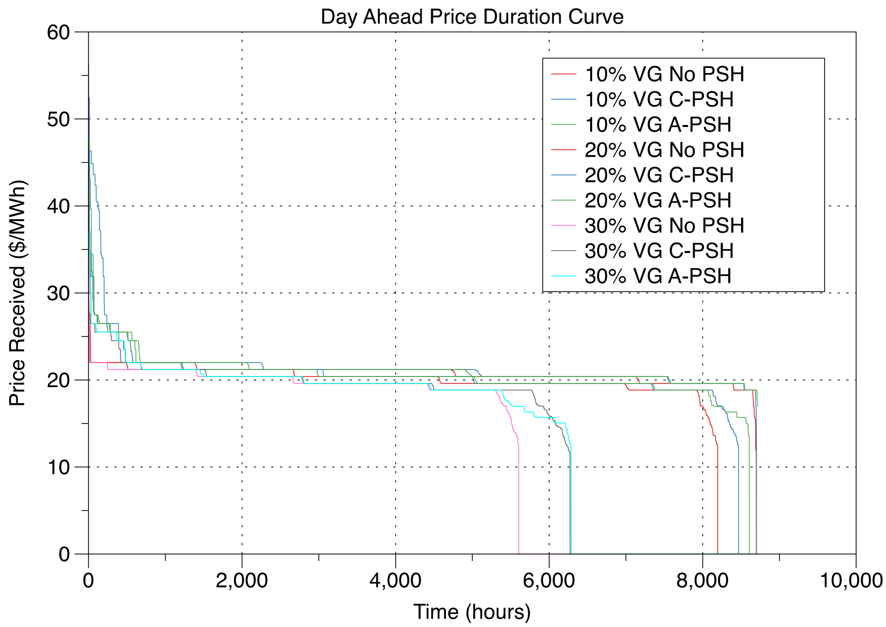

Figure 1. Annual price duration curve

Contributing to the challenge is that the gas prices are such that there is little difference between coal- and gas-fired energy prices (the only arbitrage opportunity is between when the system is curtailing variable generation and when it is not).

Table 8. Annual PSH Generation (Day-Ahead Markets)

Scenario	C-PSH Generation (MWh)	A-PSH Generation (MWh)	C-PSH Utilization	C-PSH Utilization
10% VG	15,720	12,901	3.0%	2.4%
20% VG	19,344	18,924	3.7%	3.6%
30% VG	58,008	50,893	11.0%	9.7%

The maximum possible use for each PSH plant is 44.4% (the balance of the time is used for storage recharging). As shown, the PSH units in the scenarios are used for only a fraction of their full potential.

Flexibility Is Not Directly Valued in Most Day-Ahead Energy Markets

One of the challenges for flexible assets, including new variable-speed pumped storage plants, is that the value of their flexibility is not visible in the current day-ahead markets. An asset that can ramp to full energy output in two minutes looks no different from one than can ramp to full output in an hour when seen from the day-ahead market perspective (both can ramp over their full range within the one-hour resolution of the market simulation). The differences become apparent in the simulation results where it can be seen that the variable-speed plants can offer results similar to the fixed-speed plants while consuming 2% to 18% less energy (see Table 8).

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Table 9. Day-Ahead Market Pumping Energy and Cost

Scenario	C-PSH Pump Load (MWh)	A-PSH Pump Load (MWh)	C-PSH Pumping Cost ($)	A-PSH Pumping Cost ($)
10% VG	19,650	16,126	439,640	332,823
20% VG	24,180	23,655	442,998	424,842
30% VG	72,510	63,617	679,332	492,801

The performance differences between the two storage technologies were captured in the current work because the storage volumes were included as part of the day-ahead optimizations; however, most of today's market structures would not be able to differentiate between the two PSH technologies (both are zero-marginal-cost offerings). Although the costs for either PSH technology have been shown to produce similar operational cost outcomes, the energy usage estimates to produce these results is markedly less in the A-PSH scenarios (between 2% and 18% less). Additional work is needed in this area to better understand the optimization choices with respect to fixed-speed and variable-speed pumping.

Conclusions

Two market opportunities were investigated: (1) the ability of PSH to increase system flexibility and thereby better accommodate increased penetrations of variable generation and (2) the ability of PSH to reduce annual operating costs. The day-ahead market simulations demonstrated that PSH could help a system accommodate increased amounts of variable generation, reducing curtailment by approximately 30%, generator starts by 19%, and system-wide operating costs approximately 3% in the high-variable-generation scenario day-ahead market simulations. System-wide operating costs were reduced between 3.9% and 10% in the real-time simulations.

Although the current market conditions were found to provide several opportunities, challenges were also identified. The most notable challenge is related to estimating how much revenue will be received for providing non-energy services to a grid. Nine scenarios were investigated, and it was difficult to determine any sort of pattern relating system cost savings provided to PSH net revenue received. The most remarkable comparison was in the case where the installation of a VSH PSH plant reduced operating costs by $961,000 in the 10% VG scenario and $1,324,000 in the 30% VG scenario. Net revenues for the PSH plant were $0 in the 10% VG scenario (i.e., they had no incentive for providing the service); whereas they were $441,000 in the 30% VG scenario. These results highlight the challenges that PSH developers (and storage developers generally) face when trying to estimate net revenue streams going forward. Additional challenges were found with respect to the day-ahead energy markets not explicitly valuing unit flexibility and the effects of flat price duration curves on storage unit use.

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Future Work

This initial work was limited to investigating “ideal” (zero mode switching time) PSH units in energy-only markets. Future work will investigate the value differences between fast-mode switching PSH units and those that take several market cycles (e.g., 15 minutes) to switch from one mode (e.g., generation) to another (e.g., pumping).

In addition, the value that PSH can provide to traditional ancillary service markets as well as new flexibility markets will be investigated. As part of this work, real-time simulations with perfect foresight will be performed to help bound the upper limit of value for variable-speed pumping.

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List of Scenarios

10% VG No PSH	10% wind and solar with no pumped storage hydro
10% VG C-PSH	10% wind and solar with two 30-MW fixed-speed pumped storage hydro units
10% VG C-PSH	10% wind and solar with two 30-MW variable-speed pumped storage hydro units
20% VG No PSH	20% wind and solar with no pumped storage hydro
20% VG C-PSH	20% wind and solar with two 30-MW fixed-speed pumped storage hydro units
20% VG C-PSH	20% wind and solar with two 30-MW variable-speed pumped storage hydro units
30% VG No PSH	30% wind and solar with no pumped storage hydro
30% VG C-PSH	30% wind and solar with two 30-MW fixed-speed pumped storage hydro units
30% VG C-PSH	30% wind and solar with two 30-MW variable-speed pumped storage hydro units

List of Acronyms

A-PSH	Advanced pumped storage hydro
C-PSH	Conventional pumped storage hydro
MWh	Megawatt-hour
PSH	Pumped storage hydro
VG	Variable generation

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