



The Role of Pumped Storage Hydro Resources in Electricity Markets and System Operation

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Abstract --- The most common form of utility-sized energy storage system is the pumped storage hydro system. Originally, these types of storage systems were economically viable simply because they displace more expensive generating units. However, over time, as those expensive units became more efficient and costs declined, pumped hydro storage units no longer have the operational edge. As a result, in the current electricity market environment, pumped storage hydro plants are struggling. To offset this phenomenon, certain market modifications should be addressed. This paper will introduce some of the challenges faced by pumped storage hydro plants in today's markets and propose some solutions to those problems.

I. Introduction

Utility-sized energy storage systems are still very much under development. Currently, the most common type is pumped storage hydro (PSH). The majority of the nation's 20 GW of PSH was established in the mid to late 1970s (ASCE 1993) in response to a significant increase in oil and gas prices as well as concerns about the security of supply (Denholm 2010). This led to the Power Plant and Industrial Fuel Use Act, which paved the way for serious consideration of PSH (Energy Information Administration 2009b). Over the years, as traditional gas-fired turbines improved (e.g., combined-cycle gas turbines), the space for PSH gradually shrunk. However, with the recent developments in PSH technology, PSH is slowly regaining its place. This resurgence of PSH will require changes in electricity market practices and modifications to its role in system operations for it to remain a significant contributor to the system.

There are two types of electricity markets: regulated and restructured. Both markets operate on the same principle. The lowest-cost generators are scheduled to reliably serve the expected load and then operated to meet the actual load based on security-constrained unit commitment and economic dispatch. However, regulated markets do not divulge their exact market rules. As a result, this paper will focus more on restructured markets because their information is more readily available. These markets treat storage systems very differently. Assume, for example, a storage facility large enough to completely flatten the system net load. This would allow generation to operate at a constant level by charging during periods of low demand and returning that energy during times of high demand. This would allow cheaper base generation to be used to supply the majority of the load at its most efficient operation levels. This would completely eliminate the need for expensive peaking plants to meet demand. If the generation savings exceed the cost of the storage system, this would be attractive in a regulated environment. However, because generators and storage are paid based on the marginal cost of energy in any hour, this type of storage system would not be practical in a restructured environment. Although the extreme cost of peaking generators would have been enough to justify the installation of the storage system, the price difference would collapse as soon as the storage system became operational. As a result, compensation for the storage system would significantly decrease until the storage system ultimately financially fails if its source of income was the energy arbitrage payments to recover initial capital costs.

II. Energy Arbitrage

Net generation and load must be continuously balanced in real time to maintain system reliability. This is accomplished through a combination of unit commitment and economic dispatch of generation and ancillary services to compensate for fluctuations that are faster than the economic dispatch schedules. Restructured markets typically operate sequential energy markets that clear day-ahead hourly, hour-ahead hourly, and every five minutes. Because

electricity is a real-time commodity in which production and consumption occur simultaneously, the production cost varies with consumption quantity. This potentially allows storage systems to engage in energy arbitrage.

Energy arbitrage and ancillary services both require the flexible control of real power that storage can provide. Energy arbitrage involves charging storage at times when energy is plentiful and inexpensive and returning that energy to the power system when it is scarce and expensive. Ancillary services typically refer to active power operating reserves, voltage support, and black-start services. Operating reserves involve resources that are standing ready to inject energy into the power system when a major disturbance occurs (contingency reserves) or constantly injecting or removing energy from the power system to compensate load variability, conventional generators, and renewable generators (regulating and following reserves). Operating reserves can also be classified by when they are used (in response to a system event, or continuously operating). Figure 1 shows different categories of operating reserves and why and when they are needed (Ela 2011).

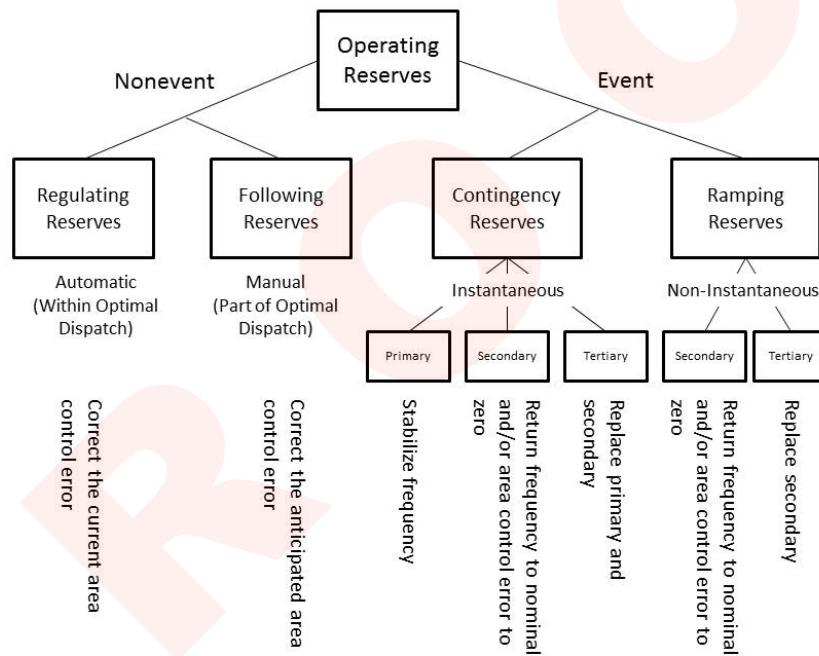


Figure 1. Operating reserves and why/when they are needed

Energy arbitrage can be done in vertically integrated, regulated markets based on the marginal cost of generation (system lambda) or in restructured markets based on energy market prices. Time frames can be as long as seasonal to as short as every five minutes, with daily arbitrage being common. For energy arbitrage to be financially practical, the ratio of the cost of charging the energy to discharging it must exceed the round-trip efficiency of the storage system. There must also be a sufficient number of viable arbitrage opportunities to cover the capital and operating costs of the system. Obviously, the shorter the time frame, the more arbitrage opportunities there are, but the market must operate in this time frame. Storage can also provide spinning (contingency) and regulation reserves. Markets typically value flexibility through energy and ancillary service prices. Ten years of average annual ancillary service prices from

five market areas (California, Electric Reliability Council of Texas, New York, Midwest Independent System Operator, and New England) show that market operators typically value regulation reserves the most, followed by spinning reserves (Kirby 2012). Recent technological advances in PSH technology have allowed them to potentially take advantage of the ancillary services market. Conventional fixed-speed pumped storage plants typically cannot provide regulation while pumping or when idle. They must be generating and operating above the minimum load and below full load so that they have room to move up and down in response to the system operator's automatic generation control signal. New, adjustable speed plants have the ability to provide both regulating and following reserves while in pumping mode. They can also provide spinning reserves when generating below full load or when idling in condensing mode with the turbine spinning air and while in pumping mode. They also have the potential to provide nonspinning reserves depending on the system ancillary service requirements. Daily ancillary service price patterns show that spinning and nonspinning reserves are typically lowest overnight, when a storage system would most likely be charging (i.e., pumping). Therefore, a flexible plant can maximize profits by not only responding to the expected daily pattern of energy and ancillary service prices, but by changing how it responds based on how energy and each of the ancillary service prices change in real time (Kirby 2012).

III. Pumped Storage Hydro Modeling and Quantitative Analysis

The scheduling and dispatch of PSH in power systems has been a topic of investigation for a long time. For example, McDaniel and Gabrielle (1966) discussed daily operation of the Smith Mountain PSH plant analyzing commitment and dispatch decisions. Aoki et al. (1987) proposed an efficient unit commitment algorithm with detailed PSH representation via Lagrangian Relaxation. More recently, research is being done on the challenges and opportunities for PSH. Deane et al (2010) performed a techno-economic review of existing and proposed PSH plants in Europe, Japan, and the United States. They show that current drivers for new PSH capacity include the large-scale expansion of variable, renewable energy; a growing demand for energy and peak power; increasing interconnections and closer coordination between regional markets giving more opportunities; security of supply; and refurbishment of existing equipment for improved efficiency. PSH plants can be remunerated through ancillary services, capacity markets, and energy. However, it is argued that for energy arbitrage to be profitable the pumping price has to be at least 25% to 30% lower than the selling price.

The authors of a 2012 white paper by the National Hydropower Association's Pumped Storage Development Council indicated that development of new PSH, particularly in areas with increased wind and solar capacity, would significantly improve system reliability while reducing the need to construct new fossil-fueled generation. They suggested new regulatory policies, including presenting bulk energy storage as a new asset class, forming a streamlined licensing process for low-impact PSH, and allowing regional transmission organizations and independent system operators to enter into long-term, fixed-price contracts with energy storage owners. The National Hydropower Association's summary of a 2010 PSH technology summit addressed issues and barriers along with proposed actions, including establishing a pumped storage design, siting, and demonstration project; creating working groups to evaluate mechanisms to ensure revenue streams such as rate base financing and grid stabilization payments; financing projects under federal loan guarantee programs; and exploring ways to reduce time required to develop

PSH plants and reduce upfront developer risk. Miller and Winters (2010) suggested the Federal Energy Regulatory Commission allow pumped storage to qualify as transmission facilities for purposes of determining eligibility for future incentives and possible creation of storage credits.

There has been extensive research in the area of proper PSH bidding strategies in restructured, competitive electricity markets. Deb (2000) discussed the need for PSH to participate in energy markets as well as ancillary service markets. The revenue of PSH is no longer dictated by the avoided costs of other power plants. Using the California market as an example, he showed that PSH can obtain a large increase in profits by participating in ancillary services markets (spinning and nonspinning), as opposed to only seeking arbitrage opportunities in energy markets. Kanakasabapathy and Swarup (2004) proposed a more realistic description of the PSH operating constraints in determining the optimal bidding strategy. They assumed that the PSH can participate in energy, spinning reserve while pumping, and nonspinning reserve while offline. Using the Lewiston-Niagara PSH plant in New York, they demonstrated that a weekly operating strategy gives higher profits than a daily strategy as a result of more flexibility in scheduling decisions because the storage constraint is imposed at the end of the planning horizon (week versus day). Connolly et al. (2011) investigated the profitability of a potential PSH plant in more than 10 different electricity markets assuming all revenue comes from energy arbitrage. They found that accurate price predictions are important for PSH plants to recoup potential energy arbitrage profits. There was also large variability in the profitability of PSH plants in different markets as a result of differences in the magnitude of price variations. In most markets, there was also a large variance in year-to-year profits. They concluded that PSH is a risky investment without a more predictable profit or additional revenue, which may come from ancillary services. Schill and Kemfert (2011) attempted to model strategic interactions between PSH and electricity markets with a focus on potential strategic utilization of PSH in the German electricity market. They found that ownership influences the usage of PSH. Strategic storage owners generally underutilize their storage capacity, particularly if a large share of PSH is owned by an oligopolistic generator. The strategic behavior is much less prominent when the storage capacity is distributed between multiple market participants. PSH leads to arbitrage profits for the owner, but its price-smoothing effect decreases generation-related producer surplus for all generating firms; whereas demand surplus and total welfare increases. Therefore, investments in new PSH capacity may not be attractive for market participants that also hold other generation capacity. Their analysis did not consider revenue from ancillary services. Tsai et al. (2009) showed that a PSH unit has the ability to make profits in a competitive energy market because of its outstanding response time, ramp rate, and start-up and shutdown times.

Pumped storage specialists concur on how growing wind power penetration in the United States energy supply system supports hand-in-hand the development of pumped storage. Miller and Winters (2010) suggested how pumped storage is proving to be an establishing technology for wind power because it can absorb excess generation and release it during peak demand times. They cite the 2006 Wind Integration Study performed by the Public Service Company of Colorado that states that doubling pumped storage capacity in the Public Service Company of Colorado system could reduce the cost of wind integration by as much as \$1.30/MWh in a 20% wind penetration case analysis. Suul et al (2008) found that for isolated power systems with renewable generators, pumped storage is important for its provision of primary frequency control during times of low demand and high output from fluctuating renewable sources. Castronuovo

and Lopes (2004) showed that a combined wind generator and pumped storage plant can increase its operational profits anywhere from 12% to 22%, depending on the deviation penalty level by co-optimizing the wind generator and the pumped storage operation together as opposed to optimizing only a wind generator. Ding et al. (2012) performed a similar analysis but considered the number of daily starts/stops along with the start/stop costs of the PSH and also included the subhourly variations in wind power fluctuations. They compared the results of a deterministic, chance-constrained, and stochastic optimization formulation. They found small differences between all the results, but the underlying trend was that the combined operations of a wind generator and PSH plant can increase profits by as much as 25% compared to stand-alone operations of a wind farm. Black and Black (2007) analyzed the impact of wind power forecasting uncertainty on the value of PSH in the United Kingdom power system assuming wind power supplies more than 20% of the energy. They focused on the potential contribution of PSH toward nonspinning reserves and their impact on other reserve providers such as gas turbines. They found that using the PSH to meet the reserve requirement can increase system efficiency, enhance wind power absorption, and reduce CO₂ emissions. The benefits of storage are most significant in systems with low generation flexibility and large wind penetration. Donalek et al. (2009) showed that properly designed pumped storage facilities could assist in integrating intermittent wind energy resources into the regional dispatch. They concluded that pumped storage units with the newest technology, such as adjustable speed and ternary units, can supply load following and become the fastest response stations in the power system. They can also be used to mitigate the frequency of industrial load shedding caused by system disturbances.

IV. Treatment of PSH in Electricity Markets

In the United States, nearly 66% of electricity consumed is within restructured electricity markets. These markets have evolved into the standard market design (Hogan 1998). This design reflects a pool-based market where there exists a two- or three-settlement system for forward and real-time markets, with co-optimized energy and ancillary services, locational marginal pricing for energy, and financial transmission rights markets in place for hedging. Energy is sold in forward (e.g., day-ahead hourly markets) and balanced in hour-ahead and five-minute real-time markets with locational marginal prices. Financial transmission rights are a hedging instrument put in place to collect the locational differences in energy price. In some of the U.S. markets, capacity markets are also put in place to incentivize investment in installed capacity and to ensure peaking units can recover fixed costs. Current ancillary service markets typically include regulation, spinning, nonspinning, and sometimes supplemental reserve. Following and frequency response services are being considered as explicit ancillary services that may be appropriate for market procurement by several regional transmission organizations (Ela 2012a). Although following reserve has been getting attention as a new payment source (Navid 2012), primary frequency response is not incentivized in any of the market regions (Ela 2012b). Voltage support and black start are ancillary services that are required for system reliability but have not proved to be amenable to hourly market procurement. Instead, these services are obtained through interconnection requirements (voltage support and reactive power) and through longer-term contracts (black start).

The concept of pricing in the United States is for uniform marginal pricing. Marginal pricing reflects the cost of serving the next increment of demand, whether it is for energy or for

ancillary services. The prices differ depending on the location in the system. For energy, the prices differ at every generating bus-bar. For ancillary services, there are less location requirements, and prices are either the same throughout the market region or there are zonal differences when large interfaces are constrained. In a lossless system without transmission congestion, the price at every bus in the system will be the same. When transmission congestion is apparent, it causes more expensive resources to be needed on one side of the constraint, because the cheaper units are constrained by the transmission limits. This causes the price to be higher where the expensive unit is needed and lower at the location of the cheaper unit. This is typically determined via direct current power flow equations. Prices will also be higher at locations that are closer to the load, even without transmission congestion. The ancillary service clearing price is the total increase in system cost if an incremental amount of operating reserve is required. Ancillary service markets will also have a pricing hierarchy (Oren 2001). This is in place because some ancillary services are more important than others. This way there are incentives always in place so that market participants will always want to provide the most valuable ancillary service. Most ancillary service clearing prices are paid to market participants for the provision of capacity to provide that ancillary service rather than how they perform in providing that service. There has been recent motivation to allow for payment based on performance for regulating reserve, such as Federal Energy Regulatory Commission Order 755. This will allow faster responding units to be paid more. Independent System Operators also have rules that ensure that no participant receives a negative profit that may arise from nonconvex cost curves, commitment constraints, or out-of-market reliability rules. The participant will receive a make-whole payment to ensure that it does not lose money. Because PSH is not fully optimized, nor does it have official “costs,” the make-whole payment rules may not fully apply. However, if PSH is fully optimized by the market and ends up losing money by paying more during pumping periods than it makes during generation periods, make-whole payments may be necessary.

Power systems require significant flexibility to operate reliably. The increased variability and uncertainty of wind and solar generation are increasing the need for flexibility. Capacity is required to meet the maximum net load. Ramping capability is required to follow the daily net load fluctuations and is supplied through subhourly scheduling (5-minute scheduling) when there is an abundance of ramp capability. A dedicated ramp or following service with separate payments for ramp services may be required if the economic energy supply generation does not inherently have sufficient ramping capability. Midwest Independent System Operator and California Independent System Operator are considering implementing dedicated following services. Regulation is required to match the short-term variability. Contingency reserves are required to respond to sudden failures of large generators and transmission lines. All of this flexibility is absolutely required. Specific resources and specific technologies are not required, however. Markets have proven very effective at obtaining the required flexibility from a host of available resources and technologies. Storage has technical capabilities that closely match the power system’s need for flexibility, but storage must deliver that flexibility at a cost that is lower than the alternatives to be economically successful.

Storage systems have a unique difficulty in today’s market environment in that they are unable to capture the benefit they provide to other power system users. Because storage can collapse its own market (reduce the marginal cost of electricity), it will receive a lesser payment than it would have if it did not participate. This would ultimately lead to the financial demise of

the storage system. Therefore, distinction must be made about the system value versus the market value. The total system benefits will always increase with increased storage, but the benefits per unit of storage size will decrease. This means there is a point where increasing the storage system's size beyond this point would be counterproductive in today's market. This is similar to the problem faced by new transmission line construction where the new transmission lines alleviate the congestion differential that might be used to finance them.

V. Market Design Topics for PSH

Based on the recent report by the Electric Power Research Institute (2013), the following suggestions are made regarding the market treatment of PSH:

1. PSH should be fully optimized in the day-ahead markets. This will allow the day-ahead market to schedule the mode of PSH based on minimizing costs over the full horizon. The length of the horizon may be important as well. Currently, only PJM does this.
2. PSH should be fully optimized in real-time markets. This will allow the real-time market to schedule the mode of PSH based on minimizing costs and information that has been updated since the day-ahead market. Currently, no market performs this in the real-time commitment models.
3. PSH should be compensated for lost opportunity costs based on multiple hours for ancillary service clearing prices. Because the PSH depends on its optimal operation over long time periods of at least a day, the lost opportunity costs of the resources are highly complex. If by providing ancillary services in one hour it loses an opportunity to provide energy in another, those pricing mechanisms should be accounted for.
4. PSH should receive make-whole payments. When the PSH is fully optimized in the market, they should receive guarantees that if they follow the schedules given to them by the independent system operator, they will be made whole.
5. PSH should be compensated based on subhourly settlements. If settlements are made on a subhourly level, the PSH plant will have opportunities to utilize fast response to meet real-time pricing swings that can greatly benefit the system. With hourly settlements, the PSH has little incentive to follow prices within the hour, only to follow the average hourly price.
6. PSH should be paid for its performance as well. PSH can benefit from providing superior regulating reserves, when the response is needed. By paying for the performance of regulating reserves, they can earn additional revenues compared to if they are paid the same as slow-moving regulating resources. All of the independent system operators and regional transmission organizations have modified rules for Federal Energy Regulatory Commission Order 755 and are beginning to implement the market design modifications.
7. PSH should be compensated for primary frequency response. Primary frequency response is not necessarily incentivized in current markets. It could be an additional revenue stream for PSH because conventional and especially advanced PSH can provide this service.
8. PSH should be compensated for following reserves. Following service is being proposed in Midwest Independent System Operator and California Independent System Operator, and discussed more broadly throughout the industry. It can bring additional revenues to

PSH plants and especially adjustable-speed PSH that can provide it during both generation and pumping modes.

9. PSH should be compensated for voltage control. There are currently no markets for voltage control in the United States, only cost-recovery mechanisms. A pricing mechanism for voltage control could bring additional revenues for PSH and advanced PSH.

VI. Conclusion

Much of the nation's PSH plants were initiated during the mid- to late 1970s, at a time where they could be justified by offsetting more expensive peaking plants. However, with the continual improvement in natural gas-turbine technology, it is becoming more and more difficult for PSH to compete in the current market environment. PSH can provide many services to the power system that are not captured in today's market structure, such as increased flexibility, primary frequency response, following reserves, and fast-acting regulation reserves. Part of the problem is that PSH is not adequately represented during the optimization of the commitment and dispatch formulations. Bidding strategies for PSH plants were presented. The way the market structure currently stands and the way PSH fits into that market structure was shown. Finally, potential market changes that can help PSH in today's restructured markets were presented and discussed in this paper.

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