Preprinted- HydroVision July 2012

Co-optimizing Energy and Ancillary Services from Energy Limited Hydro and Pumped Storage Plants

Brendan Kirby, www.ConsultKirby.com, Palm City, Florida
Power System Researcher and Consultant
kirbybj@ieee.org 865.250.0753

Abstract

A recent U. S. Department of Energy-sponsored and industry-cosponsored project focused on understanding and quantifying benefits to transmission grids provided by conventional and pumped-storage hydroelectric plants. As part of that project the benefits of co-optimizing the provision of energy and ancillary services from both energy limited hydro and pumped storage was examined. This paper describes the benefits of extending the current practice where system operators co-optimize energy and ancillary services from conventional generators during each single hour to encompass a multi-hour to week long co-optimization. Co-optimization benefits both the generator that can provide energy and ancillary services and the power system. The generator benefits because the system operator schedules the optimal combination of energy and ancillary services to maximize the generator's profits. The power system benefits by both obtaining the needed reliability services and by minimizing operating costs for both energy and ancillary services. This paper shows how that same philosophy that currently works very well for fuel-burning generators would also work for hydro. It is achieved when the schedule of energy limited hydro and pumped storage is optimized over an extended period. For pumped storage co-optimizing energy arbitrage and ancillary services significantly improves the economic viability of the plant.

Introduction

Pumped storage is a versatile power system resource that can be used to increase power system reliability, reduce customer costs, and facilitate wind and solar integration. With multiple hours of energy storage capability, pumped storage can move energy from times of surplus to times of greater need, reducing energy price volatility and helping generators with surplus energy and consumers with peak energy demands. Pumped storage plants flexibility, fast ramp rates, fast startup and shutdown, low cycling costs, and accurate control make them ideal suppliers of regulation and contingency reserve ancillary services. A few plants with variable speed pumps are also able to supply regulation while pumping. The need and value of these benefits from pumped storage depend on conditions throughout the power system that change in real-time. Obtaining the maximum value out of the plants requires knowledge of current and expected future power system conditions as well as the pumped storage plant capabilities. This knowledge is typically not fully available to the pumped storage plant operator but is available to the power system operator. Consequently the power system operator can do a much more effective job of scheduling pumped storage resources than can the pumped storage plant operator.

Unfortunately power system operators, especially in areas with electricity markets, are currently prohibited from fully scheduling pumped storage plants because this might be considered to be commercial participation in the energy markets. Instead, the pumped storage operator must guess at when the plant's energy and ancillary service capabilities will be of greatest value based on much less information than is available to the power system operator. This underutilizes a valuable resource and hurts the pumped storage plant and power system customers in general.

Allowing the power system operator to schedule pumped storage is conceptually no different than allowing the power system operator to co-optimize energy and ancillary service provision from conventional generators. In both cases the generator operator tells the power system operator the generator's capabilities and costs and the power system operator determines the best use of the facility. An operator of a conventional generator provides information on production cost versus generation level, minimum and maximum output, ramp rate capability, regulation range, and often startup costs and times. The system operator determines what combination of energy and ancillary services the generator should supply each hour to both maximize the generator's profit and to minimize total power system costs. This co-optimization of energy and ancillary services is performed by the system operator at each of the ISOs and RTOs.[1] Co-optimization could be extended to include pumped storage pumping as well as generation. The only real difference from today's operation is that the system operator might have to forecast net energy needs somewhat further into the future than is required for the current day-ahead markets, depending on the energy storage capacity of the pumped storage plant. While this is a difference, the power system operator is certainly in a better position to forecast system requirements than is the pumped storage plant operator.

This paper initially discusses the differences between conventional generators and storage resources for simplified energy scheduling to illustrate the importance of forecasting and the system operator's role. It then discusses the compounding impact of ancillary services and their importance for power system reliability, wind integration, and storage viability. Most of the discussion specifically addresses pumped storage plants. The concepts apply equally to energy limited hydro with water behind the dam and flexibility to schedule generation.

Scheduling Energy Production

Electric power systems schedule generation to minimize total production costs by selecting the lowest cost generation first and adding increasingly more expensive generation until the load is met. This is done through marginal-cost-based economic dispatch in vertically integrated utilities and through cost-based-bids in market regions. The scheduling results are essentially the same. Scheduling intervals are typically one hour for day-ahead and hour-ahead schedules and five minutes for real-time scheduling. Generator operators simply present the generators'

[1] SPP does not currently operate an ancillary service market but is expected to do so by 2014.

production costs ($/MWH) and capabilities (MW and MW/minute) to the system operator and the system operator schedules the generation. The left side of Figure 1 shows the scheduling of a fuel-burning resource with a $35/MWH production cost in red. The unit is operated whenever the system marginal cost or market clearing price exceeds $35/MWH: from 8:00 to 21:00 on the first day of this example.[2] While startup times, minimum run times, minimum off times, and ramp rates must be respected, each scheduling interval can be treated essentially independently when determining if a specific generator is selected to operate. More importantly for our discussion, the generator operator can submit the same bid information each interval without having to forecast what the power system requirements or resulting prices will be. The only factors influencing the generator operator's bid concern changes in the generator's capabilities (equipment outage, for example) or costs (changed fuel price, for example).

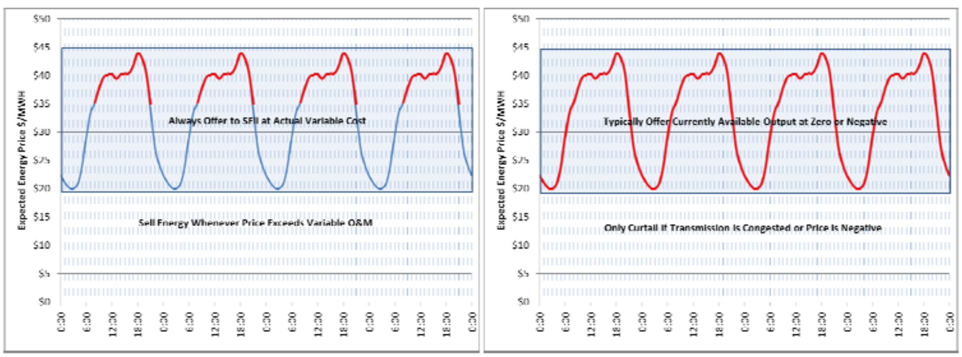

Figure 1 System operators schedule conventional (left) and renewable (right) generators based on cost-based bids and system energy prices.

Operators of wind and solar plants similarly only consider factors associated with their own plants in structuring their energy market offers, as shown by the right hand side of Figure 1. A wind or solar plant may be required to provide production forecast information, and the plant capability will typically vary from scheduling interval to scheduling interval as the wind and sunlight vary, but the plant will typically offer its full available output at zero or negative cost every interval.[3] Again the plant operator does not need to forecast power system needs or prices when structuring their energy offer. The renewable generator's full available output will be scheduled every interval, because of the low price, unless there is transmission congestion or another reliability-based constraint.

A hydro facility with a reservoir and more generating capacity than stream inflow is in a very different energy market position if the power system operator can't optimize the generation schedule. Consider a 100 MW hydro generator with six hours of reservoir storage and a river that continuously delivers enough water to support 25 MW of generation.[4] The plant could generate 25 MW around the clock but it would be better for both the power system and the

[2] Unit minimum run times, minimum off times etc. are respected in both actual markets and vertically integrated utilities but are ignored here for simplicity.
[3] Offers will be negative if the plant receives either a production tax credit or renewable energy credits.
[4] This simple example ignores changing hydro plant capacity as the reservoir level changes.

hydro generator if the plant generated 100 MW for the six hours of greatest power system demand and highest energy prices. The power system operator has load forecasts and generation schedules to forecast which six of the next twenty four hours will have the greatest need and highest price but the hydro plant operator does not.

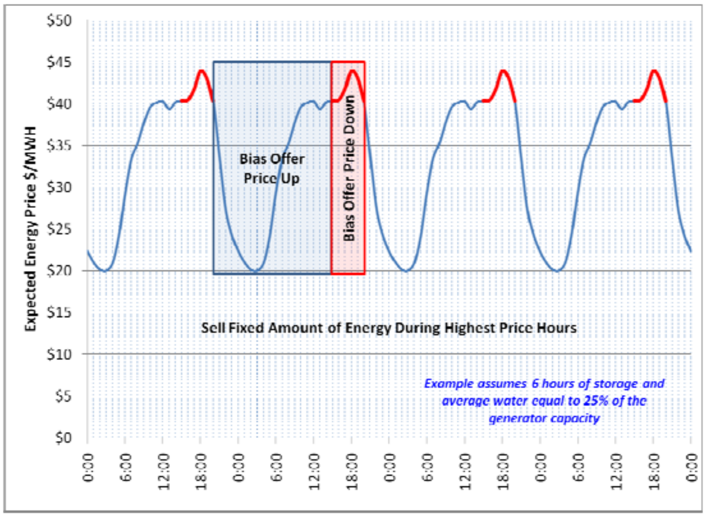

Figure 2 Energy limited hydro must bias its offer up or down from its guess of expected system energy prices to try to maximizes value.

If the hydro plant operator offers the plant capability (100 MW) at the plant marginal cost ($0/MWH), like a conventional generator or a renewable generator, the plant will be scheduled at full output until the energy runs out (0:00 to 6:00). This is not desirable. Instead, the hydro plant operator must forecast the expected power system demand and the expected hourly energy prices and offer to generate at a price that will result in exactly six hours of operation: $40/MWH for the example shown in Figure 2. Offering at a lower price ($35/MWH, for example) would result in the hydro plant running earlier in the day (8:00 to 14:00) and missing the most valuable hours (16:00 to 22:00). Offering at a higher price ($42/MWH, for example) would result in the plant operating for two hours instead of six. Because the hydro plant operator will not be able to predict the prices perfectly she will likely predict the hours of preferred operation instead, which are typically easier to forecast. She could then bias the price offer up ahead of the expected 16:00 best start time and down from 16:00 through 22:00 to assure that the plant utilizes all of the available water. This bidding strategy is better than offering the plant at its marginal cost starting at midnight and better than trying to forecast the exact price that would result in exactly six hours of operation but it is still far from ideal. Specifically, it does not allow the plant to be optimally rescheduled to be best used if power system conditions change and the limited energy would be most valuable at another time.

Pumped storage plants have an even more complex scheduling problem than energy-limited hydro as shown in Figure 3. Low prices, or at least the times of lowest prices, as well as high must be forecast so that both pumping and generating can be optimized. In this example the pumped storage operator might schedule pumping (purchasing power) from 01:00 to 0:400, the hours when energy is expected to be lowest cost. As with energy limited hydro, the pumped storage operator must structure the generation offer to try to generate during the times of greatest system need and highest energy price. An additional constraint is that the marginal production cost is not zero, as it is for the hydro plant. Instead it is the cost of purchased energy divided by the roundtrip plant efficiency. Still, that is a minimum price and the pumped storage plant operator must bias up the generation offer price to try and force the plant to generate during the most valuable hours, not just the first hours the price exceeds the minimum.

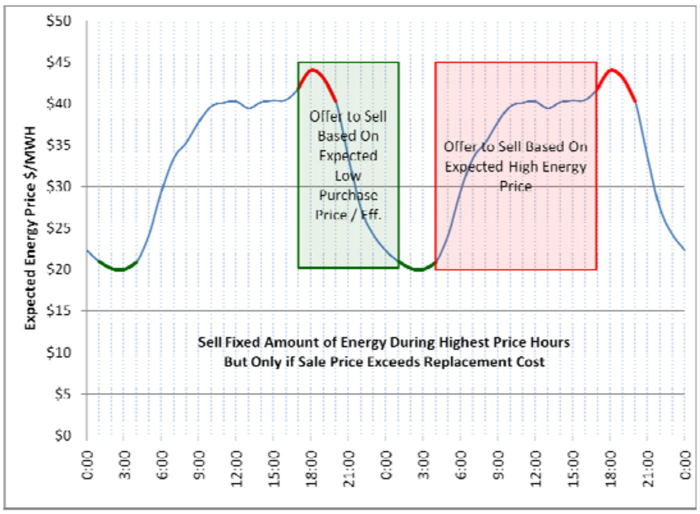

Figure 3 A pumped storage plant must guess at both the high and low energy prices.

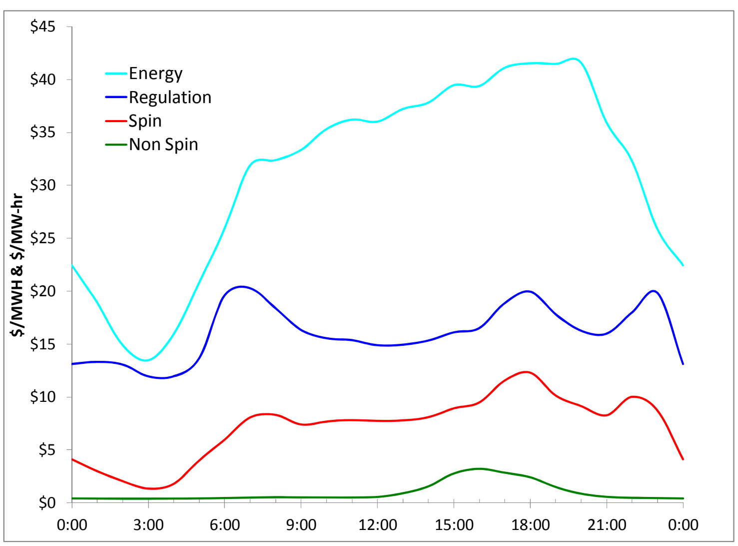

Figure 4 CAISO 2011 average energy and ancillary service prices vs time of day.

Note that in both the energy limited hydro case and the pumped storage case the plant operators want to be price takers during the highest price ours of the day. They are manipulating their offer bids simply to try to optimize the scheduling. The hydro and pumped storage generator operators are in a particularly poor position to perform this price forecasting function since they do not have the load, wind, or solar forecasts. They also do not know the conditions of the other generators. They especially cannot change their bids in response to rapidly changing conditions where the physical flexibility of their resources would be especially useful. This hurts the hydro and pumped storage plants as well as all other power system users.

Ancillary Services from Pumped Storage

The fast and accurate control capability available from most pumped storage plants and many hydro plants make them ideal providers of ancillary services. Ancillary services are also an important revenue source for plants that have an increasingly difficult time remaining profitable through energy arbitrage alone. The relative difference between daytime and nighttime marginal energy cost was greater during the 1970s and 1980s when many of the existing pumped storage plants were designed and built than it is today. (Denholm et al 2010) Low cost coal and nuclear power were typically on the margin at night while high cost gas and oil were on the margin during the day. Gas is often on the margin both day and night now and the relative cost of gas fired generation is closer to coal due to shifts in fuel prices, increased combustion turbine efficiency, and increased emissions controls on coal plants. The net result is that pumped storage plants increasingly depend on ancillary service revenues.

We developed a basic Fortran-based optimization model to explore various operating modes and determine which, energy or ancillary services, were the most profitable to supply. The model uses a year of hourly day-ahead energy and ancillary service prices. In the examples shown here we used energy and ancillary service prices from CAISO for 2011, shown in Table 1. CAISO ancillary service prices increased in 2011 compared with 2009 and 2010 though they are still below 2008 and earlier levels. Average prices for 2011 by time of day are shown in Figure 4. Spinning and non-spinning reserve prices are typically low at night and rise during the day. Regulation prices are high around the clock with additional increases during the morning load ramp up and evening load ramp down. Energy prices show the expected daily load pattern.[5]

Table 1 CAISO ancillary services prices rose in 2011 compared with 2009 and 2010.

	2002	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
	CAISO Annual **Average** and Maximum Ancillary Service Prices ($/MW-hr)									
Regulation	**26.9**	**35.5**	**28.7**	**35.2**	**38.5**	**26.1**	**33.4**	**12.6**	**10.6**	**16.1**
(up+down)	111	164	166	188	399	421	618	500	124	120
Spin	**4.3**	**6.4**	**7.9**	**9.9**	**8.4**	**4.5**	**6.0**	**3.9**	**4.1**	**7.2**
	250	92	125	110	225	400	400	416	66	48
Non-Spin	**1.8**	**3.6**	**4.7**	**3.2**	**2.5**	**2.8**	**1.3**	**1.4**	**0.6**	**1.0**
	92	92	129	125	110	400	399	416	66	35
Replacement	**0.90**	**2.9**	**2.5**	**1.9**	**1.5**	**2.0**	**1.4**			
	80	55	90	36	70	175	244			

[5] Energy prices are for the "reference bus" since the location of the hypothetical plant is not known.

The model assumes the pumped storage plant operators are able to predict the times of high and low prices and thus avoids the forecasting problems discussed earlier in this paper. Clearly forecasting is not perfect so the analysis overstates potential income. Daily load patterns are sufficiently consistent, however, that the analysis results should still be conceptually indicative. The model also assumes that the plant is small enough that it does not itself influence market prices for either energy or the ancillary services. Large pumped storage plants are often located in remote areas with congested transmission so this assumption also may result in overestimating potential plant revenues.

Pumped storage can respond to hourly energy prices, buying energy and pumping when prices are low and generating power and selling energy when prices are high. Potential energy arbitrage income can be calculated based on knowledge of the plant pumping and generating capacities, efficiency, and storage volume. Sufficiently flexible pumped storage plants can also sell ancillary services to the power system. For example, if the plant can start generating and ramp to full load within ten minutes it can sell non-spinning reserve even when it is not currently operating. If the plant is generating below rated capacity it can sell the excess capacity as spinning reserve (max capacity – current generation level). If the plant is sufficiently maneuverable and generating at less than full output but above minimum generation it can sell regulation, the most valuable ancillary service. Increasing the plant flexibility increases the plant's ability to sell ancillary services and increases the potential income. Most pumped storage plants can start quickly so selling non-spinning reserve is possible. Most pumped storage plants can also be controlled rapidly and accurately so selling regulation is also possible when generating.

Optimizing the provision of energy and ancillary services is not something any generator operator has to do herself. In Regions with organized ancillary service and energy markets the independent system operator co-optimizes energy and ancillary service provision during each market interval (hour) to simultaneously minimize total power system costs and maximize individual generator profits. The generator simply states the plant capabilities, limitations, and costs. Our model does the same optimization. The pumped storage plant operator still has to determine which hours the plant is available for pumping and generating. Our model assumes that can be done optimally (perfect foreknowledge) to calculate the optimal energy and ancillary services split each hour and to calculate an upper bound on the profits obtained from each.

To examine the benefits of providing ancillary services from a pumped storage plant we modeled a plant with 16 hours of storage, 51% minimum generation, and 75% roundtrip energy efficiency. This lets a 100 MW plant[6] operate in one of several modes each hour, and switch between modes as ancillary service and energy prices change. The plant can sell 100 MW energy while generating, sell 51 MW of energy and 49 MW of spinning reserve, sell 76 MW of energy and 12 MW of + and – regulation, or a combination of the above. Non spinning reserve can be

[6] The actual plant size is not relevant to the model since the plant is a price taker and prices are inelastic.

sold when the plant is not generating or pumping. Sale of ancillary services during pumping was not modeled since most current pumped storage plants have limited flexibility to control the pumping load. A plant with pumping flexibility such as new plant with an adjustable speed pump drive would have additional opportunities for ancillary service income by selling regulation at night. The model optimized plant energy purchases and sales to maximize profits. It selects the best combination of energy and ancillary service provision for each hour. Figure 5 shows one week of operations. The lowest dark blue curve shows how the plant would operate if it only provided energy. The upper four curves show the plant's operation while providing ancillary services as well as energy with pumping and generating energy in lighter blue, regulation in red, spinning reserve in green and non-spinning reserve in purple. At times it makes sense to loose money on an energy transaction in order to allow the sale of regulation or spinning reserve. Though regulation typically has a higher price than spinning reserve it is more profitable to sell spinning reserve than regulation at times because of the lower energy generation requirement (51 MW while providing spinning reserve vs 76 MW while providing regulation) and the larger amount of spinning reserve (49 MW) that can be provided as compared with the up and down regulation that can be provided (±12 MW).

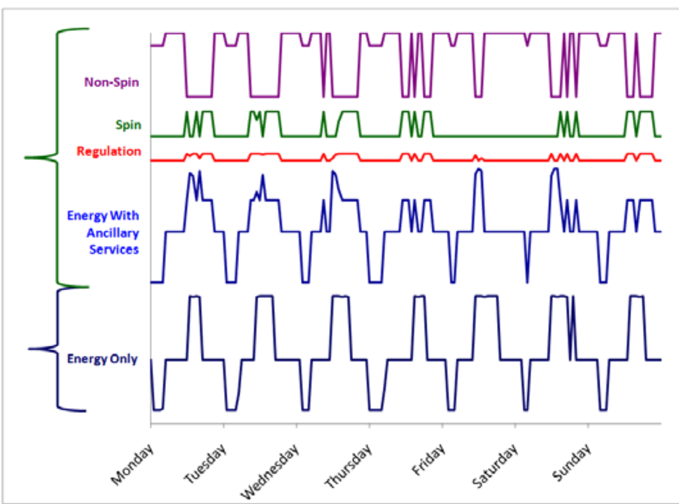

Figure 5 Pumped storage operational pattern changes when supplying ancillary services.

Table 2 shows that plant profits increased by 33% from $4.6 million per year to $6.2 million per year when ancillary services are provided. Profits from energy arbitrage drop from $4.6 million to $3.7 million per year but ancillary services add $2.8 million in profits. Ancillary services account for 40% of the plant profits. Spinning reserve accounts for over half the ancillary service profits with regulation contributing one third. Non-spinning reserve contributed over 10% to ancillary service profits.

Table 2 Pumped storage plant profits increase significantly when the plant provides ancillary services

	Profits $M												Gen MW		Ancillary Services		
	Total		Energy		Total A.S.		Reg		Spin		Non		Max	Min	Reg	Spin	Non
Optimized Energy Schedule																	
Energy Only	$4.6		$4.6		$0.0								100	51	0	0	0
Energy & Ancillary Services	$6.2	133%	$3.7	60%	$2.5	40%	$0.9	14%	$1.3	22%	$0.3	4%	100	51	+/-12	49	100
Very Flexible	$7.5	162%	$2.3	30%	$5.2	70%	$2.4	32%	$2.8	37%	$0.1	2%	100	2	+/-49	98	100
Fixed Schedule																	
Energy Only	$2.6	*56%*	$2.6		$0.0								100	51	0	0	0
Energy & Ancillary Services	$3.8	148%	$2.1	55%	$1.7	45%	$0.4	10%	$1.1	29%	$0.2	6%	100	51	+/-12	49	100

Dramatically increasing the pumped storage plant's flexibility and ability to provide ancillary services would further increase profits. A plant with an unrealistic 2% minimum load and the flexibility to provide regulation and spinning reserve over the full operating range would increase total profits to $7.5 million per year (shown as the "Very Flexible" plant in Table 2. Ancillary services would account for 70% of the profits with spinning reserve and regulation accounting for nearly equal shares (37% and 32% respectively).

Maximizing pumped storage profits as well as the usefulness to the power system depends on optimizing the split between ancillary services and energy each hour (which the independent system operator does) and optimizing the pumping and generation schedule over multiple hours (which the independent system operator will not do).

With no better knowledge than the typical daily energy price shape a pumped storage plant operator might schedule the plant to pump and generate as shown in Figure 6. Energy would be purchased during the hours of expected low prices (23:00 to 6:00) and sold during hours of expected high prices (14:00 to 20:00). Energy sales would only be made if the sale price exceeded the previous night's purchase price divided by the plant efficiency. The plant can do a little better than following an absolutely fixed schedule. Additional energy could be purchased the following night if sales were particularly good the previous day. Still, profits from energy sales would have been $2.6 million or 56% of the $4.6 million that might be obtained with a fully optimized energy-only schedule which the system operator might facilitate through additional knowledge and a much better forecast (Table 2).

Even with a relatively fixed pumping and generating schedule the example pumped storage plant significantly increases profits by supplying ancillary services. Total profits increase by 48% from $2.6 million to $3.8 million. Energy arbitrage accounts for 55% of the profits and ancillary services account for 45%.Spinning reserve is again the most important ancillary service in this example, followed by regulation.

The split between energy and ancillary service profits could change based upon the actual plant location and the resulting difference in locational marginal prices. Changes in the generation mix and the addition of more non-dispatchable generation such as wind may also change the economics. Energy profits could also decline if the plant were large enough to influence the energy price as it bought and sold energy.

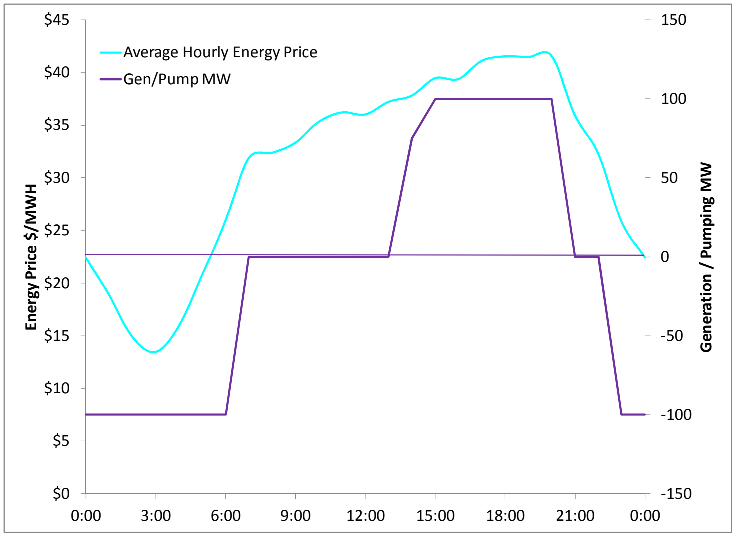

Figure 6 Without an ability to accurately forecast energy prices a pumped storage plant operator might schedule energy based on annual average hourly prices.

Conclusions: ISO/RTO Scheduling of Pumped Storage

The ancillary services available from pumped storage will likely increase in importance in the future. New plants with advanced technology will likely have increased flexibility and an increased ability to provide ancillary services. For example, variable speed pumps could supply regulation, significantly increasing a plant's ancillary service income. Lower minimum generation levels will allow increased provision of regulation and spinning reserve even during hours when energy arbitrage is not attractive. Increased penetration of variable renewables will increase the need for ancillary services and also likely result in increased ancillary service prices. Increased penetration of variable renewables may result in the need for a new following ancillary service, providing another opportunity for pumped storage. It is also possible that ancillary service prices will continue to trend towards pre 2009 prices as the national economy recovers. All of this points to both an increase in absolute income from ancillary services and an increase in the percentage of income from ancillary services relative to income from energy arbitrage.

Independent system operators do not currently schedule pumping or generating energy for pumped storage plants or for any generators. While this has little impact on conventional generators it has a significant impact on pumped storage plants. Our simplified model shows that optimal scheduling of pumped storage plants can significantly increase plant profitability and usefulness to the power system. Allowing the system operator to schedule pumped storage plants over multiple days would not be conceptually different from the current practice of co-optimizing energy and ancillary services from generators. Current practice is to co-optimize energy and ancillary services during each scheduling interval (hour). Rather than asking each generator to determine how much of each service they should provide each hour the generator tells the system operator what the generators capabilities, limitations, and costs are. The system operator then utilizes her superior knowledge of the capabilities of all of the generators and of conditions throughout the power system to determine what each generator should do to both maximize generator profits and minimize system costs.

The principles that currently work so well for co-optimization of energy and ancillary services could be extended by giving a specific level of pumped storage plant control to the system operator. Knowing the capabilities, limitations, and costs for the pumped storage plant enable the electric system operator to use superior knowledge and forecasting capabilities to schedule the pumping, generation, and ancillary service in the most beneficial way. While the system operator's forecast will not be perfect it will likely be far better than any individual pumped storage plant's forecast. Most pumped storage plant operators will likely gratefully opt into letting the system operator perform the scheduling and accept the risk that the schedule will occasionally be less than perfect.

References

P. Denholm, E. Ela, B. Kirby, and M. Milligan, 2010, *The Role of Energy Storage with Renewable Electricity Generation*, NREL/TP-6A2-47187, January

Bio

Brendan Kirby is a private consultant with numerous clients including NREL, AWEA, EPRI, Hawaii PUC and others. Served on the NERC Standards Committee, retired from the Oak Ridge National Laboratory, 37 years of electric utility experience, over 150 publications on ancillary services, wind integration, restructuring, responsive load as a bulk system reliability resource, and power system reliability. He is a licensed Professional Engineer with a M.S and B.S. degrees in Electrical Engineering. Publications available at www.consultkirby.com, e-mail kirbybj@ieee.org