Can Modular Pumped Storage Hydro (PSH) be Economically Feasible in the United States?

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Abstract

To date, the vast majority of global and domestic Pumped Storage Hydro (PSH) development has focused on the construction of large (generally greater than 300MW), site-customized plants. The viability of alternative design paradigms for PSH technologies has been actively discussed in industry and the research community, but no reliable determinations on the viability of these concepts have been made. Of particular interest is the development of smaller, distributed PSH systems incorporating elements of modular design to drive down cost and increase the ease of implementation. Small modular PSH could present a significant avenue to cost-competitiveness through direct cost reductions (requiring R&D) and by avoiding many of the major barriers facing large conventional designs such as access to capital, the long, uncertain licensing process, and the suppression of market prices (and subsequently revenues) caused by adding utility-scale storage to grid. These distributed modular units would typically serve large commercial and industrial loads in regions with adequate topography; examples include large industrial facilities, national laboratories, and data centers.

However, the cost and design dynamics of this new form of PSH development are not known, and it is ultimately unclear whether the benefits of modularization are sufficient to outweigh the economies of scale inherent in utility scale development, or prove superior to alternative distributed-storage technologies (i.e. batteries). This research fills portions of this knowledge gap by evaluating the technical feasibility and economic viability of modularizing the design of PSH. Determining feasibility involves both an evaluation of the technology strategies for modularization, and the market realities facing alternative PSH designs, including the size, geography, and power market distribution of potential locations, and the production economies of scale necessary to reach economic viability.

Equipment vendor expertise is utilized to evaluate modularized implementations of PSH components and subsystems to address technical viability. Various configurations and their cost-performance tradeoffs will be explored, including standardized reversible Francis units, as well as "off-the-shelf" applications of industrial pumps. Additional future research will attempt to address civil works cost reductions, including the application of alternative materials (e.g., carbon fiber) to the penstock and manufactured reservoirs.

To systematically explore the cost-performance tradeoffs of modularization, the initial analysis, reported in this paper, focuses on a reference case for the potential development of small modular PSH at an abandoned coal mine, with existing upper and lower reservoirs, operating as a closed loop. A subsequent analysis is planned to evaluate and revise a reconnaissance study (HDR 2011a) for the potential development of a m-PSH project to balance Oak Ridge National Laboratory's (ORNL) operational and supercomputing loads (peak of 25 MW, variability of 10+ MW). Analysis support from the Tennessee Valley Authority (TVA) and

direct access to the “owner’s” (i.e. ORNL’s) site, power needs, and finances will provide a unique opportunity for the holistic evaluation of all customer and grid operator portfolio benefits from such a facility.

1. BACKGROUND AND INTRODUCTION

As variable renewable energy sources, such as solar and wind, begin to play an expanding role in the United States’ (U.S.) electricity supply, power systems planners, operators, and policy makers have become increasingly interested in the use of energy storage to provide fast response back-up to enhance the resilience and stability of the grid (see DOE 2013 for a detailed investigation). However, the future use of energy storage will build off an existing base of approximately 21 GW of energy storage, the vast majority of which is pumped storage hydropower (PSH); thus, PSH represents the primary storage technology proven to function at utility scale over time. Similar to conventional reservoir-generated hydropower, PSH provides the means to store electrical power as potential energy. During off-peak hours, water is pumped from a low elevation to a reservoir at a higher elevation using an alternative electrical source. Figure 1 illustrates the basic configuration of a typical PSH project.

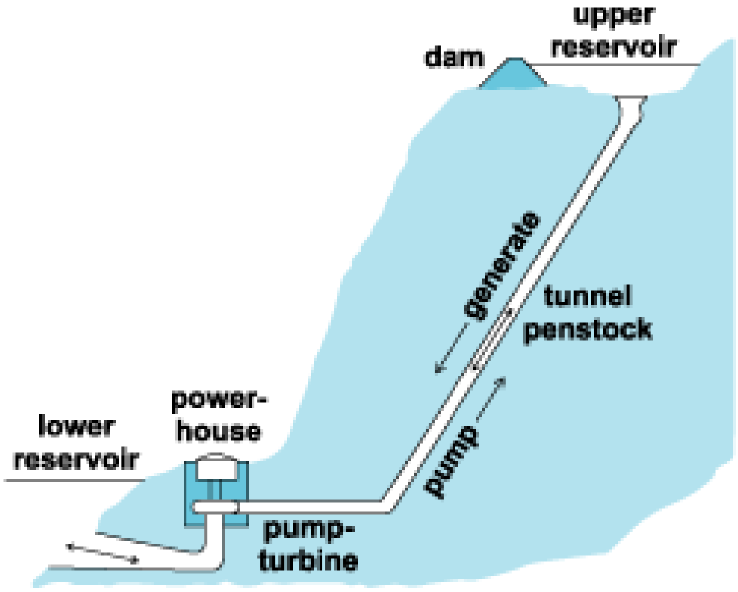


Figure 1. Pumped-hydro energy storage diagram (McGraw-Hill 2005)

Pumped storage’s proven performance stretches back more than 100 years, starting with the 1909 construction of the first PSH facility near Schaffhausen, Switzerland and arriving in the U.S. in 1929 with the Rocky River Project near Milford, Connecticut. Many additional PSH projects were constructed in the U.S. throughout the 1960s, 1970s, and 1980s in order to store excess energy generated by nuclear power stations at night, and release this energy during the day to meet peak loads. Europe, in particular, has seen recent resurgence in development activity of these large-scale PSH plants, but activity has focused on using modern technology with advanced configurations, such as variable speed or ternary units, to balance the energy variability inherent in the increasingly-common renewable energy technologies. The majority of these European projects were built at an economy of scale with custom pumped turbine equipment designs.

Given a proven track record and strong global development, it is no surprise that similar interest in large-scale PSH exists in the U.S. As an illustration, Figure 2 reveals major increases in Federal Energy Regulatory Commission (FERC) PSH preliminary permit applications over the last decade.

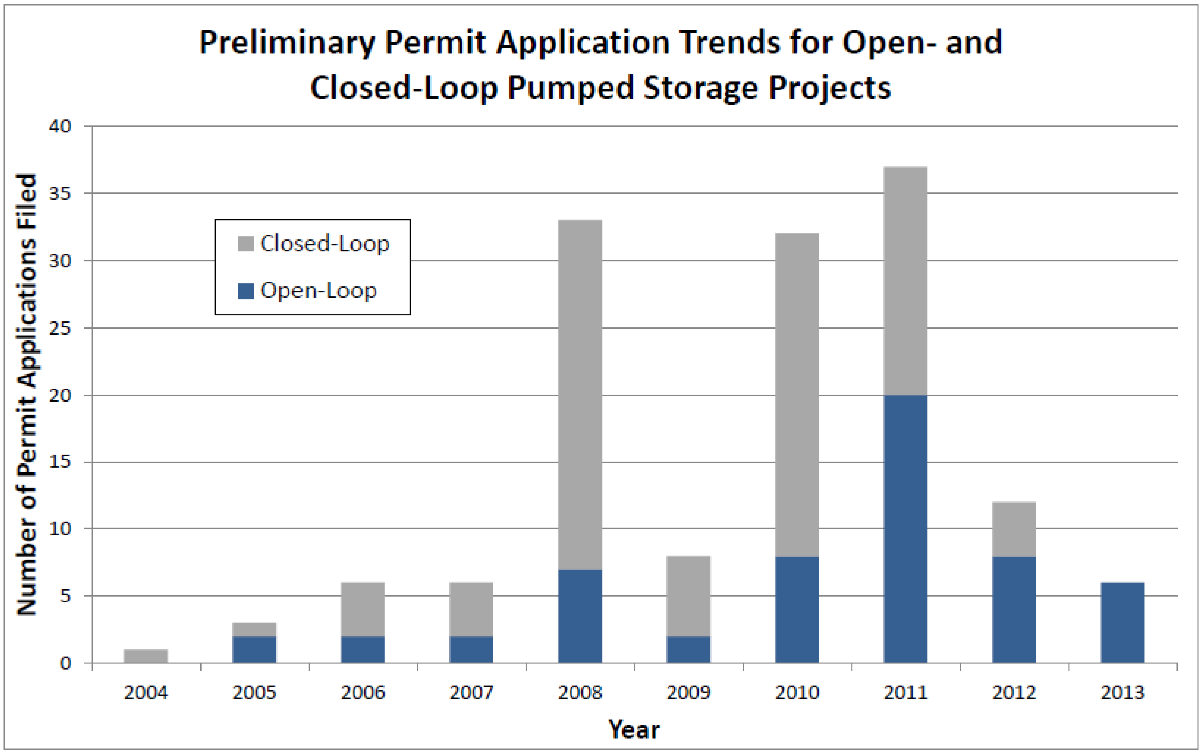


Figure 2: PSH Preliminary Permit Trends

Source: FERC Staff (FERC, 2014a)

As of May 1, 2014, FERC was tracking over 40 GW of active preliminary permits across the U.S., of which the average size was nearly 800 MW with the smallest having an installed capacity of 150 MW (FERC, 2014b).

However, in spite of intense interest in PSH development and increasing importance of energy storage for integration of variable renewables, new PSH development has been limited to a single plant (only 40 MW) in the last decade (ORNL, 2014). This lack of development has been attributed to the interaction of many complex factors, including improper valuation by markets and extensive permitting and licensing timelines (NHA, 2012). Typically, the types of PSH constructed in the U.S. and under development in Europe (and elsewhere) are large-scale energy infrastructure projects that face major market and institutional barriers to their implementation in the United States.

Some initial efforts are underway to address these issues, including recent legislation requiring FERC to evaluate the feasibility of a 2 year licensing process for closed-loop PSH projects which do not use an existing water body as a reservoir (FERC, 2014c), and other regulatory processes to change how the grid benefits provided by PSH and other technologies are valued (e.g., "pay for performance" in frequency regulation). While these incremental steps are promising for the PSH industry, one could easily imagine a more direct approach involving a new type of PSH capable of bypassing many of the market and regulatory issues currently inhibiting new project deployment through prohibitive project designs, implementation schedules, and associated risks. Smaller and simpler units could enjoy streamlined regulatory treatment and be better suited for design standardization and replication, in turn reducing market prices as a larger plant would. The use of smaller and simpler pumping and generating units would allow the equipment manufacturers to focus standardization around particular head and flow ranges, similar to what is occurring in small hydro application. As such, this new PSH framework could be applicable to a wide variety of situations, including but not limited to locations with:

- existing upper and lower reservoirs,
- existing waterways, tunnels, or pipelines connecting existing reservoirs,
- suitable head differential but without existing reservoirs (closed-loop),
- and existing hydroelectric generation where only new turbines and/or a pump house is required.

In a recent report (INL, 2014), Idaho National Laboratory performed an assessment to identify locations across the U.S. that may be suitable for new PSH development. Based on a minimum capacity of 10 MW, the assessment found that over 2,500 sites are suitable for new PSH development, including 31 hydroelectric plant sites, 7 non-powered dam sites, 97 greenfield sites, and 2,370 paired waterbody sites. When the screening requirement was reduced to include all sites with at least 1 MW of potential, a significant number of additional sites were introduced, including 44 hydroelectric plant sites, 20 non-powered dam sites, and 1,829 paired waterbody sites. This assessment demonstrates the unique opportunity for PSH development, though the number of sites which may be suitable for modularized development is likely to be much lower.

Even if a site is physically suitable for this scope of PSH development, economic feasibility must be considered. As described, a more direct approach to PSH focused on simplifying the project development process, shortening the delivery cycle from concept to commissioning, and increasing the reliability and predictability of project success would provide numerous financial benefits. Under the existing paradigm of custom site layouts and unit design, smaller plants are typically more expensive on a per kW basis. However, the standardization and modularization of very small PSH units may enable significant cost reduction potential.

Development of this new PSH mode, referred to as modular PSH (m-PSH), is a currently a major focus for the Department of Energy (DOE). To investigate the feasibility of developing m-PSH units, DOE’s Wind and Water Power Technologies Office has tasked Oak Ridge National Laboratory (ORNL) with assessing the cost and performance trade-offs of modularizing small PSH plants and the potential for cost reduction pathways. This paper details the project’s framework and methodology (Section 2) and includes some preliminary results from the study to date (Sections 3 and 4). In addition, the current status and future trajectory of the analysis is summarized (Section 5).

2. METHODOLOGY

To assess the feasibility of developing small m-PSH, it is import to first define “small” to define the research and design space. Compared to larger projects, smaller and simpler PSH may be deployable at a higher number of potential locations and reduce the overall development schedule and life cycle cost. Smaller, distributed PSH reduces the need for transmission upgrades and new transmission lines because it may enable integration in the distribution system. Smaller PSH concepts can be generally separated intro three classifications based on use and size:

- Utility-Scale (20-200 MW): The function of these units is similar to larger custom plants providing general support to the grid, but the smaller size may allow for standardization and modularization of design and make alternative market arrangements (i.e. direct support of variable renewable energy installations) economically feasible.
- Municipal, Industrial, Commercial (1 – 20 MW): PSH plants of this size would generally serve dedicated loads from high-demand facilities or address their associated localized transmission issues. Candidate locales include large industrial plants, national laboratories, and data centers.
- Distributed (< 1 MW): These micro-sized PSH plants could potentially support isolated communities (such as remote villages, or mining installations) or high-congestion areas of load by balancing the local micro-grid.

However, the cost, implementation schedules, and design dynamics of these potential new forms of PSH development are not known, and it is ultimately unclear in each case whether the benefits of modularization are sufficient to outweigh the economies of scale inherent in large-scale development or to prevail against alternative storage technologies competing in similar markets (e.g. batteries, flywheels, compressed air energy storage).

To evaluate these trade-offs, different size and technology configurations of modular PSH plants will be considered. To capture major market and cost drivers, the following aspects of PSH development will be addressed:

- Project size
- Adjustable vs. Single Speed Technology
- Site features
- Market location

Typical periods of generation would occur during peaking hours and last from 6 to 10 hours, while pumping could last from 14 to 18 hours. The generating-to-pumping ratio is largely location and system dependent, though pumping time can be reduced to take advantage of cheaper off-peak energy production.

Using equipment and civil cost estimates provided by manufacturers, contractors, and consultants for various modular designs, ORNL is evaluating individual project viability by simulating revenue streams from various competitive energy and ancillary service markets across the country. An illustration of the feasibility evaluation process for various project aspects is provided in Figure 3. To illustrate this evaluation process, the following two sections detail an example cost estimate and simulated market revenue for a 5 MW single-speed modular unit in the PJM energy market.

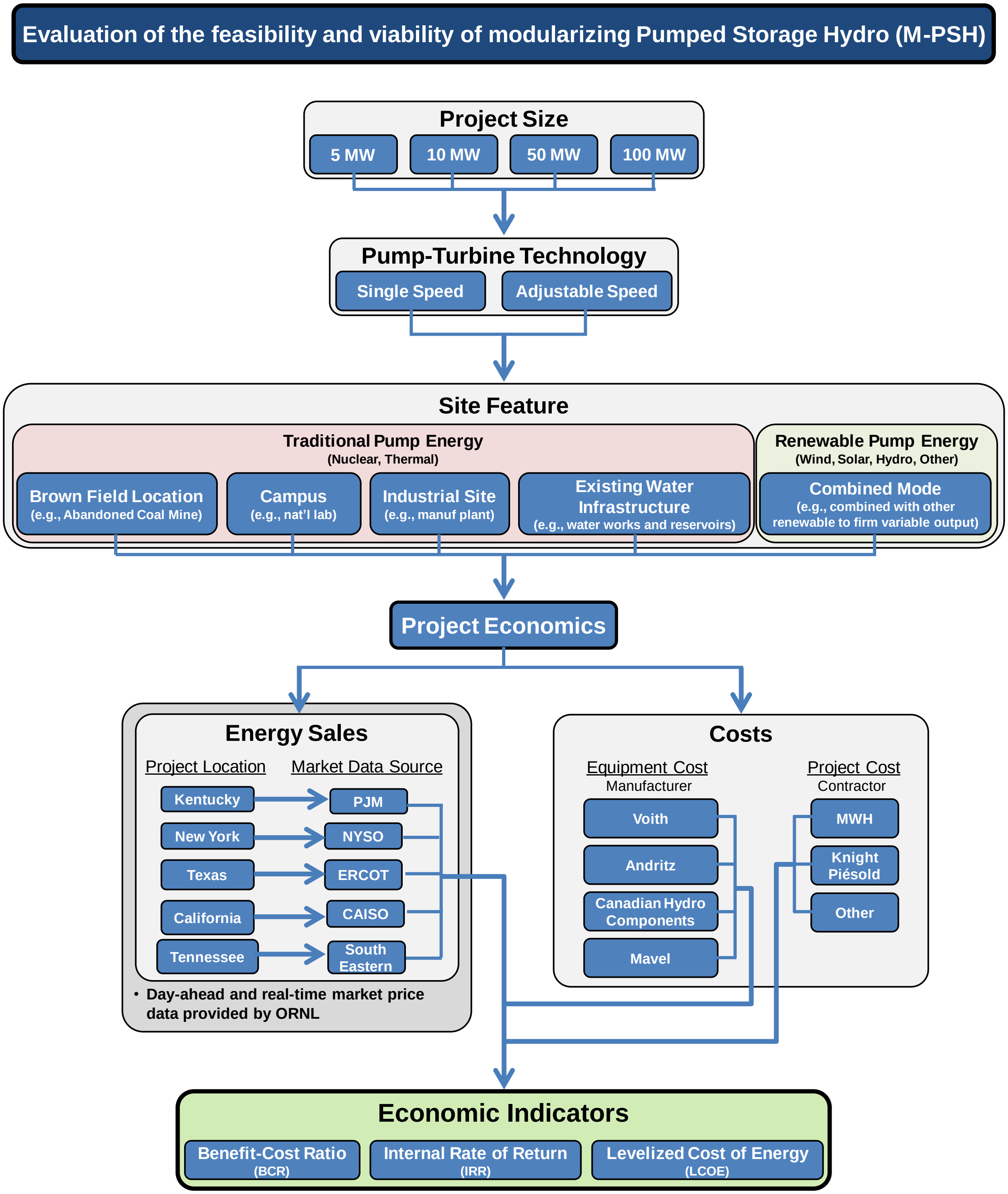


Figure 3: Overall Flowchart to Develop m-PSH viability Analysis

3. EXAMPLE COST ANALYSIS OF A 5 MW M-PSH

3.1 FIRST CASE STUDY: OLD COAL MINE

The Dam:

The first m-PSH case study involves utilization of an existing dam as an upper reservoir and an old coal mine as a lower reservoir. The Dam is located in Kentucky, owned by a coal company, and covers approximately 520 acres. The Reservoir storage is summarized in Table 1.

Table 1. Reservoir Storage

Stage	Elevation (feet)	Million-Gallon	*Volume/ac-ft.
Emergency Spillway	1214	170	560
Principal Spillway	1210	125	425
Current water level	1197	72	260

***Includes 41 ac-ft of Sediment**

Water in Mine

The total volume of water stored in the mine is approximately 770,000,000 gallons, with a net head of about 500 feet. A schematic of the proposed site is provided in Figure 4.

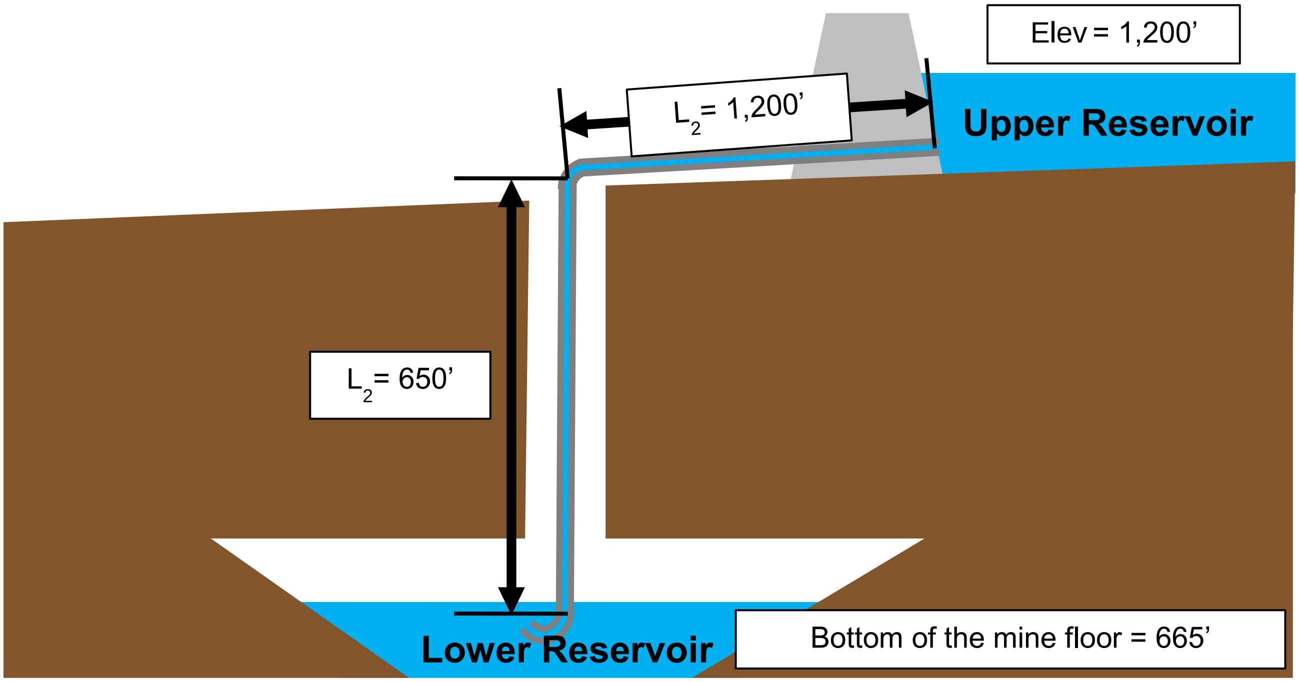


Figure 4. Schematic layout for a potential m-PSH at old coal mine project

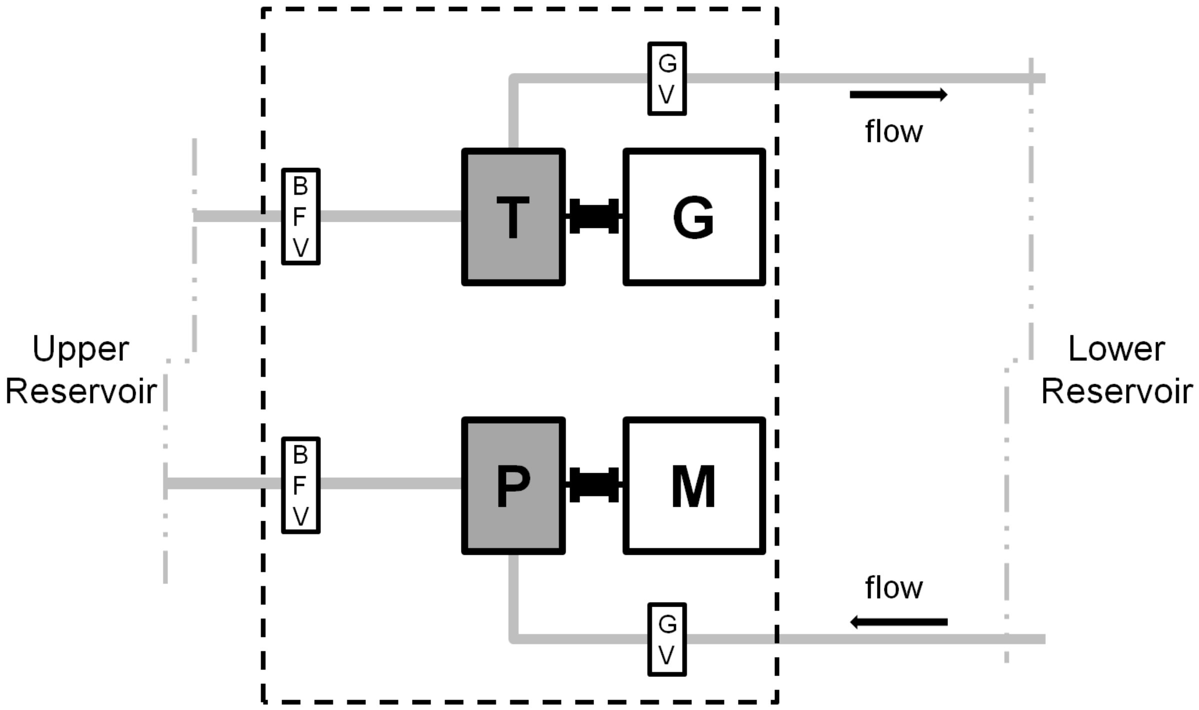
3.2 POWER HOUSE DESIGN CONCEPT, (Courtesy of Voith, 2014)

To illustrate the evaluation process in the context of a 5 MW m-PSH plant, Voith (2014) has developed a cost estimate for the specific configuration shown in Figure 4. The cost estimate is based on a powerhouse layout as illustrated in Figure 5.

Power House Concept

Individual Pump with Motor

Individual Turbine with Generator (Horizontal or Vertical configuration possible)



T: Turbine, G: Generator, M: Motor, P: Pump, BFV: Butterfly Valve, GV: Gate Valve
Note: Any piping/penstock between equipment is outside of Voith scope limit

Figure 5. Configuration of the equipment layout, Voith April 2014

For this specific configuration the assumed design parameters are:

- Rated Power = 5 MW
- Rated Net Operating Head = 150m (492.2ft)
- Nominal turbine runner size = 1.0m with a nominal flow of 4 m3/s (141.3 cfs)
- Nominal single stage Pump size = 1.4 m (4.6 ft) with a nominal flow of 2.8 m^3/s (98.9 cfs)

The equipment price estimate of this plant is as shown in Table 2. Economy of scale from a volume order is assumed, and some non-hardware costs, such as engineering, project management, transportation, etc. are included.

Table 2. Equipment cost estimate for 5 MW m-PSH project

	Voith	**Supplier 2**	**Supplier 3**	**Supplier 4**
Component	**Cost**	**Cost**	**Cost**	**Cost**
Turbine-Generator	$1,282,500	In Progress	In Progress	In Progress
Valves	$405,000			
Pump and Motor	$2,196,000			
Unit Auxiliaries	$445,950			
Total =	**$4,329,450**			
$/KW =	**$866**			

To provide a complete cost estimate for supply of the entire power plant hardware, additional components such as the unit governor, controls, protection system, switchgear, interconnecting wiring, and interconnecting piping, cooling water systems, and bearing oil systems would also be required. Voith could provide cost estimates for these components, but they have not been included in Table 2. We have allowed an additional $600,000 to $800,000 for these equipment and systems and addition of a set-up medium voltage transformer at an existing substation. The Civil works pre-concept estimate includes some modifications to the existing switchyard.

In addition to these hardware costs, other costs are omitted from the calculation that would be required, such as the powerhouse structure, penstock, and tailrace costs, as well as labor costs for the installation of civil works components. Other soft costs such as permitting, environmental studies and other consulting engineering services would be required.

There are many other necessary configurations and parameters that could be optimized later through more detailed analysis. Below are a few design options to be considered:

1. The required submergence for the pump and turbine for the centerline of the turbine or pump wheel.
2. Machinery speed for both the pump and the turbine.
3. Vertically or horizontally arranged equipment layout. The preferred initial approach for this analysis is a simple, low-cost arrangement.
4. Two conduits to the lower and upper reservoir, with a bifurcation after the BFV and GV. Alternatively, the lower reservoir may only require a suction chamber and draft tube, as well as a gate (draft tube gate or stop logs). This arrangement is typical in pump wells and at draft tube ends.
5. Direct drives between the motors and pumps, and turbines and generators.
6. Single stage pumps compared to other designs.

4. PRELIMINARY PROJECT LAYOUT AND ESTIMATED PROJECT COST

What is desired in the preliminary project layout is simplicity and modularization. Early concept work has demonstrated that both are achievable, but more engineering work is needed to complete the preliminary project layouts based on manufacturer information. These preliminary layouts will be presented at Hydrovision 2014 after added work and peer review..

Preliminary design requires a 4 ft. diameters penstock varying in thickness from 3/8 to ½ inch. A bifurcation is needed with shut, off butterfly valve (BFV) and operator in the pump stem and turbine stem downstream of the bifurcation before entering the pump or turbine. The Turbine-Generator assembly is proposed in one module and the Pump-Motor assembly is proposed in a second module. The modular approach allows for assembly and testing of a completed module prior to arriving on site. From upper surface to the lower reservoir there will be a winch hoist and steel stairs for access. A construction crane would be used to place the modules at the lower reservoir level. To extent practical, electrical and control equipment will be located at ground surface in a prefabricated metal building. A new reinforced concrete intake would be constructed at the upper reservoir. The intake structure would be furnished with a trash rack and a vertical lift steel gate with hoist. The penstock would be fully vented downstream of the intake structure.

Pre-concept civil works estimates are in the range of $5.0 Million to $7.0 Million.

5. PRELIMINARY ESTIMATED REVENUE STREAM

Given the small size of the PSH units considered in this study, if the power was sold into a wholesale electricity market, the facility would be a price taker (i.e., it would not influence the market price). The following mathematical programming model maximizes the annual net revenue from energy and ancillary services that a 5-MW PSH unit could have obtained in 2011 if participating in the PJM market[1]:

5.1 PSH REVENUE OPTIMIZATION MODEL: FORMULATION AND RESULTS

$$\max_{Qg,t,Qp,t,K_t^{REG},K_t^{SR},K_t^{NR}} \sum_{t=1}^{T} e^{-rt}\left(\left[P_t * \left(Q_{g,t} - Q_{p,t}\right)\right] + \right.$$

$$\left. P_t^{REG} * K_t^{REG} + P_t^{SR} * K_t^{SR} + P_t^{NR} * K_t^{NR}\right)$$

$subject\ to$

$$0 \leq Q_{g,t} \leq \overline{K}_g$$

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[1] The optimization problem was written as a dynamic, mathematical programming model in the General Algebraic Modeling System (GAMS) and solved using the CONOPT algorithm.

$$0 \leq Q_{p,t} \leq \overline{K}_p$$

$$K_t^{GEN} + K_t^{REG} + K_t^{SR} \leq \overline{K}_g$$

$$K_t^{GEN} - K_t^{REG} - K_t^{SR} \geq 0$$

$$S_t = S_{t-1} + \rho * Q_{p,t} - Q_{g,t}$$

$$Q_{g,t} = K_t^{GEN}$$

$$S_t \geq 0$$

$$0 < \rho < 1$$

where:

P_t is the day-ahead price of electricity in hour t ($/megawatt hour [MWh])

P_t^{REG} is the day-ahead price of regulation capacity in hour t ($/MWh)

P_t^{SR} is the day-ahead price of spinning reserve capacity in hour t ($/MWh)

P_t^{NR} is the day-ahead price of non-spinning reserve capacity in hour t ($/MWh)

$Q_{g,t}$ is quantity of electricity generated in hour t (MWh)

$Q_{p,t}$ is quantity of electricity pumped in hour t (MWh)

$\overline{K}_g$ is the maximum generation capacity (MWh)

$\overline{K}_p$ is the maximum pumping capacity (MWh)

K_t^{GEN} is capacity scheduled in the day-ahead energy market for hour t (MW)

K_t^{REG} is capacity scheduled in the day-ahead regulation market for hour t (MW)

K_t^{SR} is capacity scheduled in the day-ahead spinning reserves market for hour t (MW)

K_t^{NR} is capacity scheduled in the day-ahead non-spinning reserves market for hour t (MW)

ρ is the round-trip efficiency

S_t is the amount of energy stored in upper reservoir at the end of hour t (MWh)

r is the discount rate

Model Assumptions:

- Generation *can* only take place during peak hours (7 a.m. to 10 p.m.).
- Pumping *can* only take place during off-peak hours (11 p.m. to 6 a.m.).
- The rated capacity of the pump is the same as the rated capacity of the turbine-generator.
- Spinning reserves can be provided when the unit is either in generation mode or in pumping mode.
- With a single-speed turbine, regulation can only be provided when the facility is in generation mode (single speed turbine) and operating at partial load (because PJM does not have separate regulation up and regulation down products).

- With an adjustable-speed turbine, regulation can be provided when the unit is either in generation mode or in pumping mode.
- Ability to switch from pumping at full volume to generating at full volume within 1 hour.
- No startup costs after idle periods

The first two assumptions should be relaxed in markets where negative prices happen frequently. In PJM, in 2011, the day-ahead prices were positive for the 8760 hours in the year. As for the real-time market, it cleared at a negative price only 1 hour in the whole year.

Simulated revenues using this approach should be interpreted as an upper bound to potential revenues due to two reasons. First, the model assumes that the plant owner has perfect foresight of the price levels for the entire year and that the system operator would accept the bids from the plant owner 100% of the time. Secondly, the assumed annual unit availability factor is 100%.

Initial results for the PJM market (in which Kentucky is located):

- 5 MW PSH
- 75% turnaround efficiency
- 10 hours of storage
- Single-speed turbine
- 2011 day-ahead energy and ancillary service prices

Based on initial results for the PJM market, total estimated annual revenues from participation in energy and ancillary service markets are presented in Table 3 and Figure 6.

Table 3. Estimated annual net revenue stream for a 5 MW m-PSH in PJM Market

Price series:	**Day-Ahead**	**Day-Ahead**	**Real-Time**	**Real-Time**
Turbine type:	**Single-Speed**	**Adjustable-Speed**	**Single-Speed**	**Adjustable-Speed**
Net revenue in energy market	$140,424	$137,060	$238,792	$226,561
Regulation revenue	$144,986	$432,468	$110,028	$397,738
Spinning reserves revenue	$4,672	$4,635	$13,094	$13,005
Total net revenue ($)	**$290,082**	**$574,163**	**$361,914**	**$637,305**

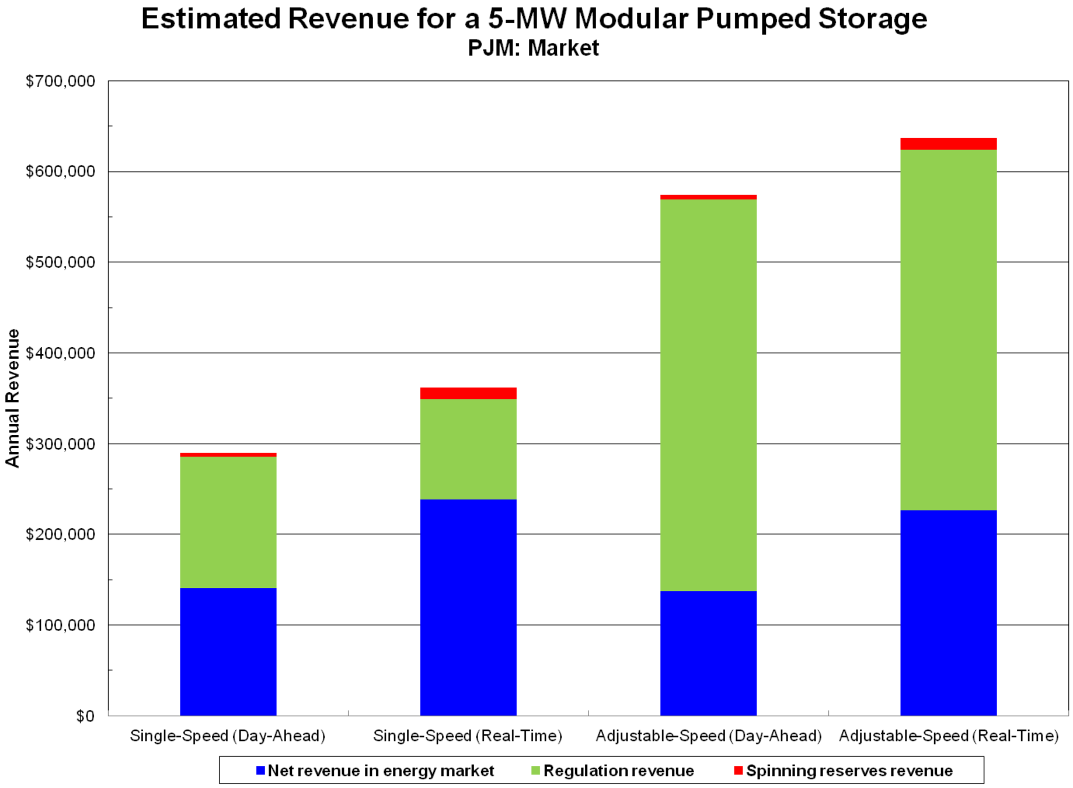

Figure 6. Estimated annual net revenue stream for a 5 MW m-PSH

Economic Indicators

The benefit-cost ratio (BCR) and internal rate of return (IRR) are two standard metrics useful in evaluating the economic feasibility of a project. The benefit-cost ratio is calculated as the ratio of the net present value of lifecycle benefits to the net present value of lifecycle costs. This means that not only the level but also the timing of revenues versus expenditures matters for determining the feasibility of a project. The IRR is the annual rate of return for which the net present value of lifecycle net benefits (i.e., benefits minus costs in each period) equals zero. The below equations show how these two metrics are computed:

$$BCR = \frac{\sum_{i=1}^{n} \frac{Benefits}{(1+r)^i}}{\sum_{i=1}^{n} \frac{Costs}{(1+r)^i}}$$

where: r is the discount rate

$$0 = \sum_{i=0}^{n} \frac{P_i}{(1+IRR)^i}$$

where: Pi is the net cash flow in period i

The levelized cost of energy (LCOE) can be interpreted as the minimum price at which a project owner must sell the electricity generated by a project to make the project economically-feasible. It is a measure of the long term cost for all resources and assets used in the operation of an energy project and is computed according to the below equation.

$$LCOE = \frac{(FCR \times Initial\ Project\ Cost) + Levelized\ O\&M\&R\ Costs}{Annual\ average\ production}$$

Where: *FCR* is the fixed charge rate

6. CONCLUSIONS AND FUTURE DIRECTIONS

The concept of modular PSH is technically feasible using conventional pumping and turbine equipment presently available, and may offer a path to reducing the project development cycle from inception to commissioning. When applied to an existing site where there are existing waterworks and reservoirs, the actual installation cost may be competitive with other energy storage options. The tariff availability, project capital cost, and development and licensing uncertainty have been an industry challenge for privately-funded, large-scale PSH. Smaller size, modular PSH may offer an opportunity to overcome some of these challenges and may avoid the large transmission costs associated with large scale pumped storage. Modular PSH is not intended to replace conventional large economy of scale pumped storage, but may offer a possible alternative for wider energy storage deployment. The preliminary analysis of the first case study indicates promise in terms of the overall costs and through use of modular approach, much of the actual manufacturing, fabrication, assembly and testing can be done prior to on site delivery. Leaving foundations, substation modifications, mechanical hook-up of penstocks and electrical/control wiring.

The preliminary cost estimate for the case study of a 5 MW m-PSH is about $10 Million to $12 Million or $2000 to $2400 KW, with a preliminary estimated annual revenue of $290,000 to $360,000 for single speed or $574,000 to 637,000 for variable speed.

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