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Evaluation of the Feasibility and Viability of Modular Pumped Storage Hydro (m-PSH) in the United States

Adam Witt
Boualem Hadjerioua
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September 2015

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Environmental Sciences Division

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EXECUTIVE SUMMARY

The viability of modular pumped storage hydro (m-PSH) is examined in detail through the conceptual design, cost scoping, and economic analysis of three case studies. Modular PSH refers to both the compactness of the project design and the proposed nature of product fabrication and performance. A modular project is assumed to consist of pre-fabricated standardized components and equipment, tested and assembled into modules before arrival on site. This technology strategy could enable m-PSH projects to deploy with less substantial civil construction and equipment component costs. The concept of m-PSH is technically feasible using currently available conventional pumping and turbine equipment, and may offer a path to reducing the project development cycle from inception to commissioning.

When applied to a site with existing waterworks and reservoirs, m-PSH project costs are competitive with alternative energy storage options. The cost estimate for the first case study of a 5MW, 50MWh m-PSH facility in the eastern U.S. (PJM Interconnect) ranges from $8.7 million to $12 million, or $1,700/kW to $2,400/kW. The estimated maximum annual net revenue for a flexible, 75% roundtrip efficient, single-speed unit, obtained by co-optimizing the unit for energy and ancillary services, ranges from $312,000 in a typical year (2013) to $564,000 in a year with high market volatility (2014). The benefit-cost ratio exceeded 1 only in the case of high price volatility, for units with a roundtrip efficiency greater than 75%, and for the minimum construction cost scenario. The case study is sensitive to project costs and simulated revenues, with economic feasibility demonstrated solely under ideal conditions.

When all m-PSH civil works and equipment need to be procured, m-PSH is not economically viable. The cost estimate for the second case study of a 5MW, 25MWh m-PSH facility on the ORNL campus is $20 million to $22 million, or $4,000/kW to $4,400/kW. As opposed to a competitive market, the unit would operate within a vertically integrated energy system where revenue opportunities are less attractive. The potential market strategy of co-locating near a load center and operating in a peak-shaving capacity requires predictable, steady load cycles that were not present in this case. Economic indicators obtained for best and worst case scenarios did not signal project feasibility, and the necessary regulatory processes and approvals are expected to be more complicated at sites without existing water works.

Modular PSH with installed capacity of less than 1MW is not economically feasible even under ideal conditions. A third case study analyzes the physical parameters necessary to support m-PSH on a high-rise building. Low energy density, excessive water requirements, and spatial limitations are the barriers to m-PSH adoption in this case. To overcome these barriers, ORNL is conducting proof-of-concept research on a novel pumped storage device that artificially increases head at ground level.

Modular PSH is not intended to replace conventional large pumped storage facilities but might offer an alternative for wider energy storage deployment, without encumbering the regulatory, customized equipment, or project-specific transmission costs. With no m-PSH units deployed at present, it is largely unclear whether the benefits of modularization are sufficient to outweigh the economies of scale inherent to large-scale development. The first case study shows narrow economic promise in terms of overall project costs, under the assumption that the limited capacity and existing waterworks and reservoirs help expedite the necessary regulatory approvals. All cases demonstrate that m-PSH project viability is largely dependent on the presence of existing infrastructure and the pursuit of multiple revenue streams.

Two additional, future R&D pathways could prove valuable in enhancing the viability of m-PSH. First, research should address civil works and equipment cost reductions, including the application of alternative materials (e.g., carbon fiber) and design and construction methods related to hydraulic equipment, structures, penstocks, and reservoirs, where appropriate. Second, the pursuit of alternative revenue streams should be explored, including the coupling of m-PSH with wind and solar to enhance renewable integration and the use of targeted m-PSH to reduce system operating costs.

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ABBREVIATIONS

AGC	Automatic Generation Control
AS	Ancillary Services
BCR	Benefit-Cost Ratio
BFV	Butterfly Valve
CAES	Compressed Air Energy Storage
CAISO	California Independent System Operator
CS1	Case Study 1
CS2	Case Study 2
CS3	Case Study 3
DA	Day Ahead
DOE	Department of Energy
EKPC	East Kentucky Power Cooperative
ERCOT	Electric Reliability Council of Texas
EU	European Union
FCR	Fixed Charge Rate
FERC	Federal Energy Regulatory Commission
GLIDES	Ground Level Integrated Distributed Energy Storage
GV	Gate Valve
HDR	HDR Engineering, Inc.
ICC	Initial Capital Cost
LCOE	Levelized Cost of energy
LMP	Locational Marginal Price
LOC	Lost Opportunity Credit
m-PSH	Modular Pumped Storage Hydropower
NPV	Net Present Value
NYISO	New York Independent System Operator
ORNL	Oak Ridge National Lab
PD	Positive Displacement
PJM	PJM Interconnection LLC
PSH	Pumped Storage Hydropower
RPS	Renewable Portfolio Standard
RT	Real Time
RTE	Roundtrip Efficiency
RTO	Regional Transmission Organization
TVA	Tennessee Valley Authority
WACC	Weighted Average Cost of Capital

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1. BACKGROUND AND INTRODUCTION

Power systems planners, operators, and policy makers have become increasingly interested in the use of fast-response energy storage to enhance the resilience and stability of the electric grid (DOE, 2013). The largest source of stored energy worldwide and the only well-established storage technology to consistently perform at utility-scale is Pumped Storage Hydropower (PSH). Similar to conventional reservoir-storage hydropower, PSH provides the means to store electrical power as potential energy. To operate effectively, during off-peak hours or lower energy cost periods, water is pumped from a low elevation to a reservoir at a higher elevation using a low cost electricity source. When there is an increased demand for that energy, water is released from the upper reservoir, down through the power-generating turbines, and into the lower reservoir. In a closed-loop system, the upper and lower reservoirs are removed from a naturally flowing stream or lake system, thereby reducing the potential environmental impacts to the stream or lake. Figure 1 illustrates the basic configuration of a typical PSH project.

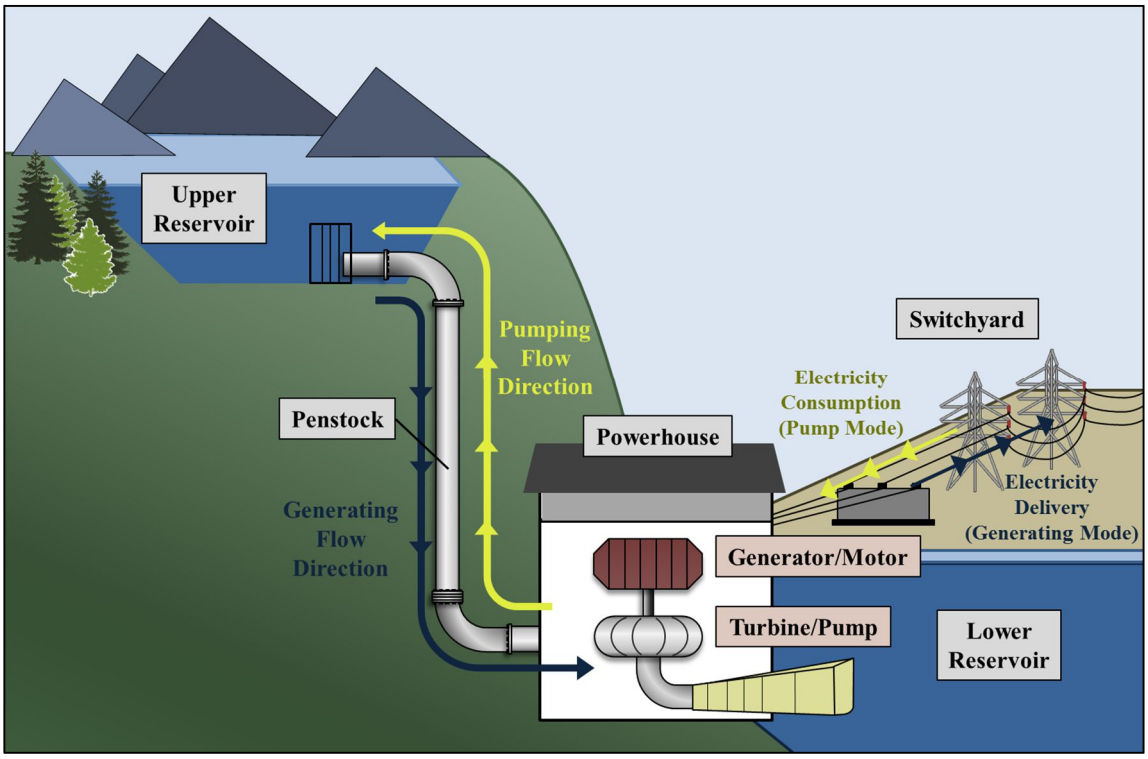

Figure 1. Pumped storage hydroelectric plant schematic (not to scale).

The proven performance of pumped storage dates back to 1909, when the first PSH facility was constructed near Schaffhausen, Switzerland. PSH arrived in the U.S. in 1929 with the completion of the Rocky River Project near Milford, Connecticut. Many additional PSH projects were constructed in the U.S. throughout the 1960s, 1970s, and 1980s as a means to store excess energy generated by increasingly prevalent nuclear power stations. Nuclear plants support baseload electricity demand throughout the day, but at night it is too expensive and challenging to operate plant capacity at less than peak efficiency. The large storage capacity of PSH reservoirs has often served as the ideal means to utilize excess energy generated at night, which could be stored as potential energy and later converted to electricity during periods of peak demand. The difference between day time energy revenue during the pumped storage generating period and night time pumped storage pumping period energy consumption cost (arbitrage),

allowed the capital cost of early pumped storage stations to be financially viable. In more recent years, energy generators have identified ancillary benefits (e.g., frequency regulation and operating reserves) that can be quantified as revenue to offset costs and improve financial viability. High round-trip efficiencies on the order of 80% and a useful life on the order of 50-100 years are additional contributing factors that led to widespread adoption of PSH as the dominant energy storage technology. As of 2011, the U.S. operated 41 PSH plants with nearly 20,500MW of installed capacity, representing approximately 20% of the total installed hydropower generating capacity (Hadjerioua et al., 2011).

To date, the vast majority of PSH development worldwide has taken place on a utility scale (generally greater than 200MW). The average capacity of dedicated PSH plants (all turbine-generator units are reversible) in the U.S. is 673MW (Uria-Martinez, Johnson, & O'Connor, 2015), while the average size of all PSH plants in Japan is 722MW, and projects in the EU range from 62.5MW to 1,800MW (Deane, Ó Gallachóir, & McKeogh, 2010). One of the main drivers for large plant size is the reduction in overall cost per kilowatt realized as installed capacity grows. Economies of scale achieved in utility-scale PSH construction help mitigate large capital costs and justify the significant regulatory and permitting expenses associated with new large capacity hydropower development. Over the past two decades, however, a blend of complex factors, including incomplete valuation in electricity (energy, capacity, and ancillary services) markets, the falling market price of natural gas, and extensive permitting and regulatory timelines have combined to significantly hamper new PSH development in the U.S. (NHA, 2012). The need for additional reliable revenue streams to supplement energy arbitrage has been consistently demonstrated (Hadjerioua et al., 2011). Since 1995, only one multipurpose PSH plant has been constructed in the U.S. (Figure 2). Some efforts are under way to address these issues, including recent legislation requiring the Federal Energy Regulatory Commission (FERC) to evaluate the feasibility of a two-year licensing process for closed-loop PSH projects that do not use an existing water body as a reservoir (FERC, 2014) 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).

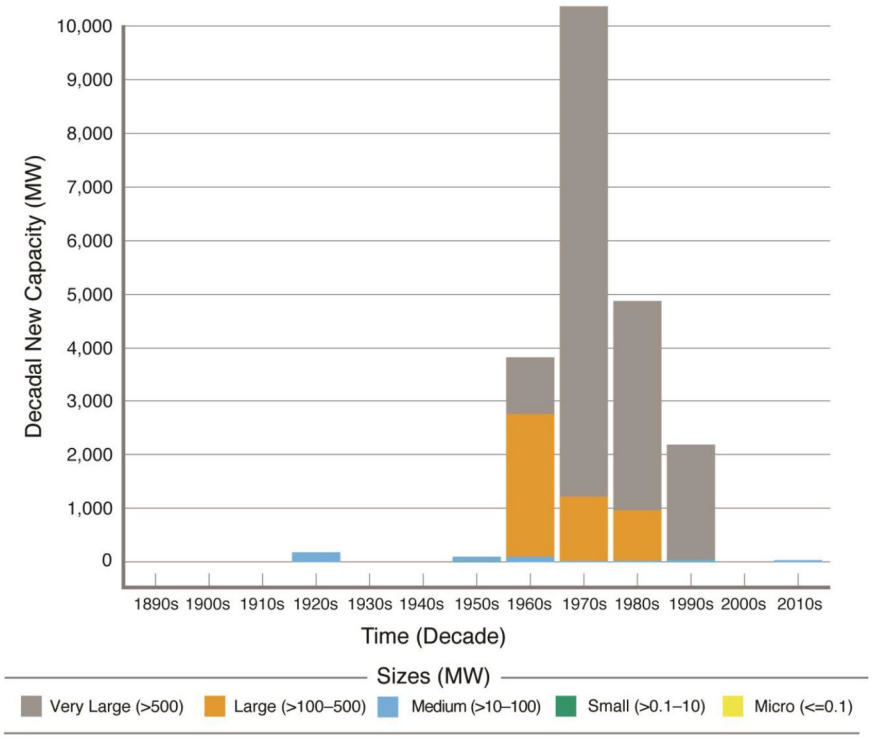

Figure 2. U.S. PSH installation timeline by plant size (Uria-Martinez et al., 2015).

Despite the challenges associated with bringing PSH capacity online, the proven operational reliability and flexibility of PSH has sustained global interest in development. Europe has seen resurgence in construction of large-scale PSH facilities that employ advanced configurations, such as variable speed or ternary units, to help balance the grid variability inherent to renewable energy economies (Deane et al., 2010). According to FERC, a total of 51 PSH projects were being actively pursued in the U.S. as of December 31, 2014, more than the total number of installed PSH projects in the U.S. (Uria-Martinez et al., 2015). In a recent national assessment, more than 2,500 sites with greater than 10MW of generating potential are suitable for new PSH development, including 31 hydroelectric plant sites, 7 non-powered dam sites, 97 greenfield sites, and 2,370 paired existing water body sites (Hall & Lee, 2014). When the screening requirement was reduced to include all sites with at least 1MW of potential, a significant number of additional sites were introduced, including 44 hydroelectric plant sites, 20 non-powered dam sites, and 1,829 paired existing water body sites.

The increasing penetration and falling costs of wind and solar installations are factors driving broad interest in not only PSH, but a vast array of energy storage technologies. Intermittent renewable generation is surging, with non-hydro renewables now routinely surpassing hydropower in terms of kilowatt-hours generated per month in the U.S.[1]. The relatively cheap but unpredictable nature of wind and solar generation requires flexible grid storage with load-following and fast-response capabilities (Budischak et al., 2013; Mai et al., 2012), something PSH has been providing for decades. At present, an assortment of battery technologies with distributed storage capabilities greater than 1MW are being deployed to meet these needs, due in part to relatively short construction and regulatory lead times, decreasing costs, production tax credits, and flexible configurations that lead to high-energy densities (Bjelovuk, 2010; Denholm et al., 2013; Dunn, Kamath, & Tarascon, 2011; Nair & Garimella, 2010).

The well-documented benefits of PSH are known at the utility scale, but an open research question is whether or not PSH projects are scalable, and if so, what competitive advantages small scale PSH may have over alternative energy storage technologies. Typical pumped storage projects are unique with custom designs due to site locations, characteristics, and configurations. 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 feasibility of these concepts have been made. Of particular interest is the development of smaller, distributed PSH systems that incorporate elements of modular design to drive down cost, increase the ease of implementation, and minimize regulatory and environmental hurdles. Recent studies have shown that smaller, efficient, pumped storage units with modular or standard configurations could enable more renewable energy penetration than larger storage systems (Anagnostopoulos & Papantonis, 2008; Weitemeyer et al., 2014). Small modular PSH could present a significant avenue to cost competitiveness through direct cost reductions and by avoiding many of the major barriers commonly associated with large conventional designs, such as access to significant capital and the potential impact to market prices (and subsequently revenues) caused by adding utility-scale storage to grid. These distributed modular units would typically focus on serving large commercial and industrial loads in regions with adequate topography and existing nearby, accessible transmission and distribution; examples include large industrial facilities, national laboratories, and data centers.

This assessment focuses on the feasibility and viability of an alternative design approach termed modular PSH, or m-PSH. Ideally, smaller capacity, distributed-scale m-PSH (< 25MW) components would utilize a common modular design enabling economies of scale during the design and fabrication stage. Much of the actual manufacturing, fabrication, assembly, and testing could be done before onsite delivery. Smaller and more deployable modular units could receive streamlined regulatory treatment and be well-suited for

1 Based on estimated from the U.S. Energy Information Administration (EIA). Retrieved June 02, 2015 from http://www.eia.gov/todayinenergy/detail.cfm?id=17351

design standardization and replication, in turn reducing the typically higher prices associated with a site-specific, customized PSH plant. The resulting implementation and construction schedules would be more predictable with less risk. The subsequent reductions in lead time, equipment procurement, and construction time would decrease the frequency of construction cost overruns and improve access to attractive financing options.

Most pump-generating turbines designed for larger projects are highly customized to the site-specific project conditions, including the elevation difference between the upper and lower reservoirs (head), the volume and flow of water through the penstock, ramping speeds, expected start/stop cycling, and the desired storage capacity. The use of smaller and simpler pumping and generating units would allow equipment manufacturers to standardize production according to particular unit capacities based on head and flow ranges at lower manufacturing costs, similar to what is occurring in many small hydropower applications. As such, the m-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);
- existing substations and transmission infrastructure;
- existing hydroelectric generation where only new turbines and/or a pump house is required.

Even if a site is physically suitable for this scope of PSH development, economic and financial viability must be considered. As described, m-PSH focused on simplifying the project development process, shortening the delivery cycle from concept to commissioning, using existing waterworks, transmission, and distribution systems could increase the reliability and predictability of project success while providing numerous financial benefits. Under the existing paradigm of custom site layouts and unit design, smaller plants are typically more expensive on a per-kilowatt basis. However, the standardization and modularization of small PSH units could enable significant cost reductions by streamlining design and manufacturing capabilities. Most large-scale pumped storage projects require significant transmission additions and upgrades, in turn leading to high added cost and licensing time. The modular approach being considered could have standard interconnection details and utilize existing transmission and distribution, with only minor upgrades needed. It is also expected that the environmental and social footprint will be proportionally smaller with fewer environmental impacts.

Development of modular pumped storage hydropower is a major focus for the U.S. 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 PSH plants and the potential for cost-reduction pathways. This report details the framework and methodology used to analyze m-PSH in Sections 2 and 3, and includes results from three case studies designed to explore m-PSH potential in Sections 4, 5, and 6. Summaries, conclusions, and the current status of m-PSH development are discussed in Section 7.

2. PROJECT ANALYSIS METHODOLOGY

To assess the feasibility of developing small m-PSH, it is important to first describe how "small" and "modular" are defined in this report in order to characterize the research and design space. Small PSH concepts are separated into three classifications based on use and size:

- Utility (25MW–100MW): The function of these units is similar to larger custom plants that provide general support to the grid, but the smaller size could 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 (1MW–25MW): 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 (< 1MW): 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.

Across all size classes of small PSH, modular refers both to the compactness of the project design and the proposed nature of product fabrication and performance. A modular project consists of pre-fabricated standardized components and equipment, tested and assembled into modules before arrival on site. This technology strategy could enable m-PSH projects to deploy with less substantial civil construction and equipment component costs. In contrast to a custom, site-specific design, a primary result of m-PSH is simplicity in design that may sacrifice optimal peak efficiency to obtain greater cost savings. This simplicity could facilitate a smoother integration of power generating infrastructure at attractive locations, which may reduce the interconnection issues related to transmission and distribution while reducing the overall development schedule and life-cycle cost. By enabling integration into the existing distribution system, m-PSH could reduce the need for new transmission lines and transmission upgrades. Compared to larger projects, the advantages of small m-PSH may be leveraged to accelerate deployment at a higher number of locations. The shorter implementation and construction time, reduction of capital and other soft costs (escalation, inflation, etc.) during the implementation period, and simpler, repeatable equipment and construction fabrication techniques would reduce project development risk.

For this assessment, it is assumed that smaller-scale PSH projects could be deployed at sites where there would be minimal environmental impacts, thereby reducing or even eliminating some of the more time-consuming regulatory hurdles associated with larger-scale hydropower and pumped storage projects.

To capture major market and cost drivers, a flexible methodology is used to analyze a variety of potential m-PSH development scenarios. An illustration of the feasibility evaluation process for various project aspects is shown in Figure 3. Major considerations that must be addressed include:

- Project size or demand need;
- Equipment (flexible vs. single-speed technology, round trip efficiencies);
- Site features (existing reservoirs, topography, geologic conditions, environmental constraints);
- Market location (ability for project to recognize revenue for project performance);
- Market strategy (energy, energy plus ancillary services, peak shaving).

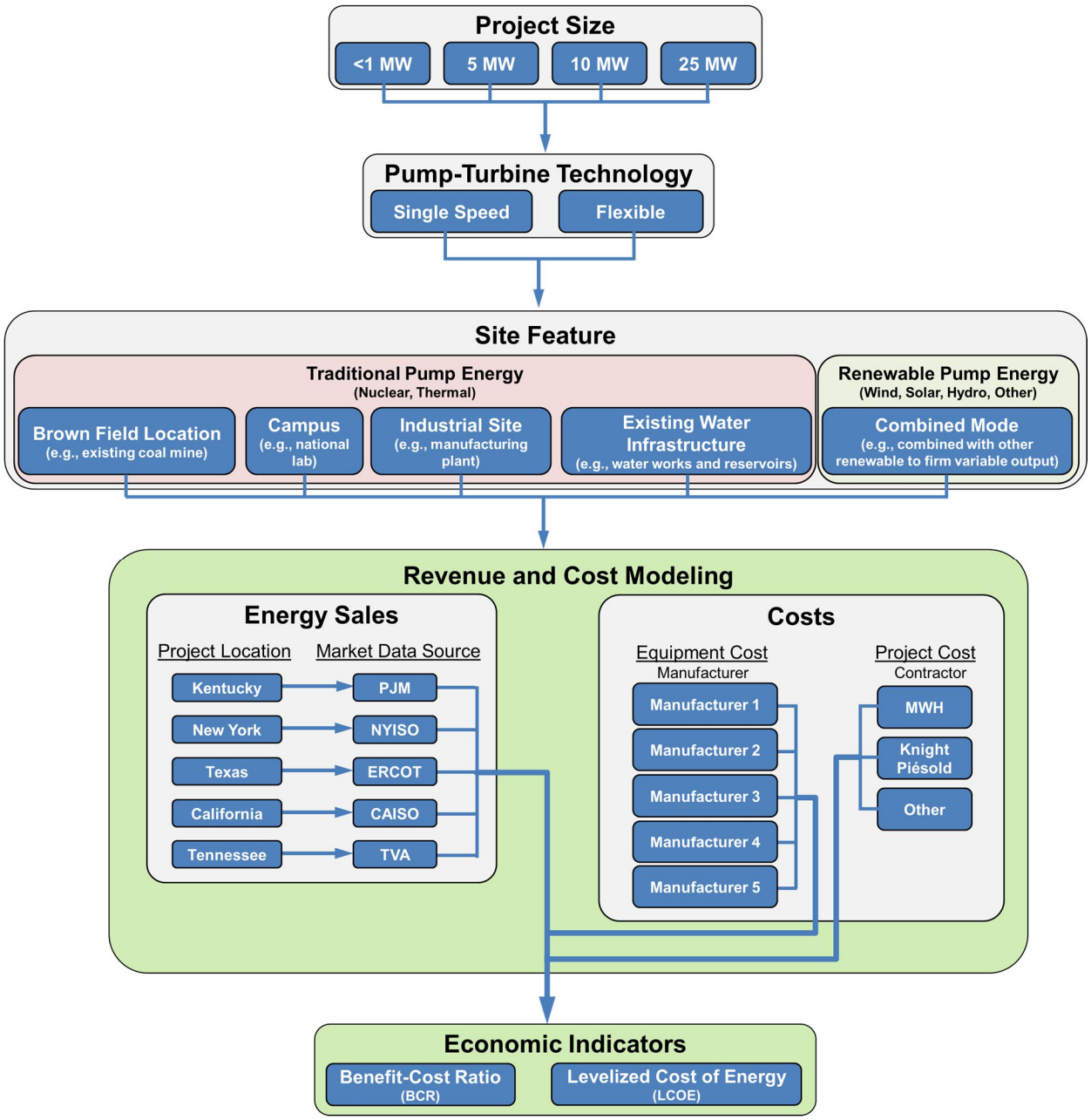

Figure 3. Flowchart representing the m-PSH viability analysis.

To systematically explore the cost-performance tradeoffs of modularization and to develop a grounded reality of the obstacles that m-PSH may have to overcome under realistic market scenarios, this analysis focuses on three site-specific reference cases of various technological configurations, sizes, and geographies:

- Case Study #1 (CS1): 5MW m-PSH at a decommissioned Kentucky coal mine;
- Case Study #2 (CS2): 5MW m-PSH at the ORNL campus; and
- Case Study #3 (CS3): m-PSH on high-rise buildings.

In each case, an initial project-specific hydraulic analysis is conducted to make a sizing determination. For CS1, equipment and civil cost estimates are then provided by manufacturers, contractors, and consultants for various modular designs. While this analysis focuses on a site-specific design, partners were requested to reflect aspects of modularity and standardization in cost estimates. When possible, construction costs are given on a unit basis so results can be extended to different development scenarios. For CS2, the modular cost estimates from CS1 are used to update an existing study of PSH feasibility on the ORNL campus (HDR Engineering Inc., 2011). While this study includes important siting, equipment, and viability analysis, the cost estimates do not reflect a modular approach to PSH development, and they are subsequently modified to conform to the m-PSH methodology. High-level cost estimates for CS3 are supplied by various manufacturers.

Economic viability is assessed by simulating revenue streams from various competitive energy and ancillary service markets based on estimated project size. CS1 is situated within the PJM Interconnection (PJM), a Regional Transmission Organization (RTO) in the eastern U.S., and revenue determinations are obtained using publicly available historical market clearing prices. To provide geographical context, hourly market clearing prices from three additional major RTOs and Independent System Operators (ISOs) are analyzed[2], including CAISO, NYISO, and ERCOT, representing the western, eastern, and southern geographical regions of the U.S. For CS2, analysis support was provided by the Tennessee Valley Authority (TVA) and ORNL via direct access to hourly campus power demand, allowing a unique opportunity for the holistic evaluation of campus m-PSH. Revenue potential for CS3 is not simulated directly for various reasons outlined in Section 6.

[2] Hourly market clearing prices are publicly available and can be found at:
PJM - https://dataminer.pjm.com/dataminerui/pages/public/lmp.jsf
CAISO - http://oasis.caiso.com/
NYISO - http://www.nyiso.com/public/markets_operations/market_data/custom_report/index.jsp
ERCOT - http://www.ercot.com/mktinfo/prices

3. ECONOMIC FEASIBILITY METHODOLOGY

An m-PSH owner would have multiple options for marketing their capacity and energy within a regional energy market. First, the owner could enter a long-term power purchase agreement with a nearby or regional utility and negotiate a fixed price for output. If combined with a fixed price contract for the necessary pumping power it needs to purchase (e.g., co-locating with an intermittent renewable resource that could sell its excess power at very low prices), the result would be a low-risk marketing strategy for the m-PSH owner. Table 1 provides an example of the annual revenue stream with a fixed contract that guarantees a differential of $10, $20, and $30/MWh between the sale price of generated power and the purchase price of pumping power. These net revenues represent a unit that would generate power 10 hours per day at full capacity (5MW) and, given roundtrip efficiency of just greater than 70%, would pump the rest of the day.

Table 1. Estimated annual net revenue for a 5MW m-PSH facility operating under a power purchase agreement.

Generation –Pumping Price Differential	Annual Generation MWh	Annual Pumping MWh	Annual Net Revenue
$10/MWh	18,250	25,550	$182,500
$20/MWh	18,250	25,550	$365,000
$30/MWh	18,250	25,550	$547,500

With these fixed price differentials, the operational strategy for the m-PSH unit would be to maximize the number of hours it can generate since it receives a fixed amount of net revenue per MWh produced. Depending on the future evolution of electricity market prices, a fixed price contract might result in a lower return than what could be achieved by participating in the wholesale market. As an introductory measure of typical market energy price differentials, Figure 4 shows the average hourly day ahead clearing price for four different markets by season in 2014. In the winter months of Jan – Mar, a peak/off-peak price differential of $80/MWh was observed for much of the quarter in PJM and NYISO markets, while the differential falls to $40-$60/MWh in ERCOT and $20-$30/MWh in CAISO. These differentials are uncharacteristically high, the result of extremely cold weather and large increases in the price of natural gas to satisfy record heating demand. In the remaining months, maximum peak/off-peak differentials sit between $20-$40/MWh for 2-3 hours per day in most markets.

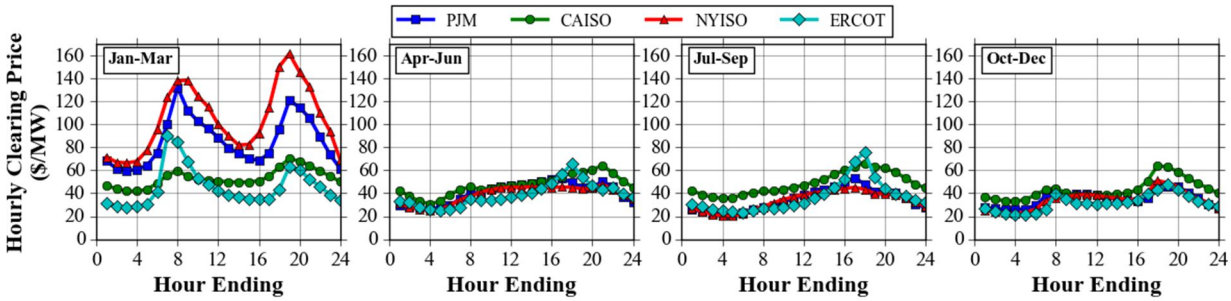

Figure 4. Average 2014 day ahead energy prices by season.

The simple revenue structure proposed above does not include the provision of ancillary services (AS) to the transmission system. The fast response and high precision capabilities of PSH and hydropower generating units are often called upon to provide frequency regulation, spinning reserves, and non-spinning reserves, ancillary services that are monetized in deregulated energy markets. PSH plants that co-optimize energy and ancillary services bids can significantly increase their revenue potential compared to the traditional model of pure energy arbitrage (Deb, 2000; Ela et al., 2013). While this practice requires plants to operate at partial load to reserve capacity for load balancing activities, the revenue potential can be economically attractive.

In a competitive energy market, power is dispatched based on power system conditions and the baseline economic operation of all generating units available in the system. In PJM, for example, a PSH plant offering energy and regulation capacity is required to submit a day in advance, for each unit for every hour (PJM, 2012, 2015a):

- A market type (regulation only or both energy and regulation);
- The maximum amount of regulation capability in MW (the regulation range must be twice the regulation assigned in MW to ensure the unit can symmetrically provide both up and down regulation from a set mid-point);
- An offer price reflecting capability and performance characteristics;
- An availability status;
- The maximum and minimum MW of energy generation capability while providing regulation;
- The minimum amount of regulation in MW physically possible;
- Any additional operational constraints.

Power system operators will co-optimize hourly energy and ancillary service offers from all generators (thermal, combustion, nuclear, PSH, etc.) to maximize profit and minimize power plant cycling costs, load-following costs, and unit commitment costs (Hadjerioua et al., 2011). While hourly co-optimization is a common practice with most RTOs, it is thought to undervalue PSH storage capability on a utility scale compared to optimal scheduling carried out over multiple days (Kirby, 2012).

A recent review of pumped storage operation models provides a comprehensive summary of a wide range of revenue generation optimization methodologies, the bulk of which co-optimize bids for energy and ancillary services (Pérez-Díaz et al., 2015). The rest of this section will describe the current methodology developed for optimizing the revenue stream for an m-PSH owner offering unit capacity using three different market strategies: pure energy bids, co-optimization of energy and ancillary services bids[3], and peak-shaving near a load center.

3.1 REVENUE MODEL FORMULATION

Given the relatively small installed capacity of the m-PSH units considered in this study, if the power were sold into a wholesale electricity market, the facility would be a price taker (i.e., it would not influence the market price or have "market power")[4], and it would not have considerable storage to create

3 As of 2013, PJM maintained a competitive market for three types of ancillary services: frequency regulation, spinning reserves and non-spinning reserves. Contracts for provision of black-start service or voltage control could generate additional sources of revenue for the m-PSH owner beyond what is currently offered in the PJM wholesale market. Revenue from such contracts and/or from participation in PJM's long-term capacity market could be added ex-post to the results of the optimization presented in the next section. By the same token, if new product offerings that allow monetizing additional project benefits arose, they could be included in the revenue calculation.

4 If feasible, alternative arrangements to sell power at retail rates (e.g., if the m-PSH was located on the customer-side of the meter and could participate in a net-metering program) could be advantageous.

regional portfolio effects. The revenue model thus relies on optimization of a single unit assuming *a posteriori* knowledge of historical energy and ancillary services prices, and assuming energy price trends would not respond to additional m-PSH capacity in the marketplace. A linear programming model[5] is used to maximize the annual net revenue of the m-PSH unit under various operating modes using hourly market clearing prices. The benefit-cost ratio and levelized cost of energy from the project are computed assuming that similar price patterns will be sustained over time.

The model is purely deterministic and assumes operators have perfect foresight into the dynamics of hourly energy and ancillary services clearing prices. Consequently, simulated revenues using the mathematical approach should be interpreted as an upper bound to potential revenues that could be achieved under ideal conditions as they do not consider system costs, they assume an annual availability factor of 100%, and they assume the power system operators will accept all capacity bids from the plant owner. Despite these caveats, energy prices mimic daily load patterns across RTOs rather consistently, and the revenue methodology is sufficiently robust to reveal system trends across space and time. Additionally, an m-PSH unit bidding against thermal units for energy and ancillary services would have a high probability of having bids accepted and of recovering system costs on an annual basis. Within PJM for example, nearly all hydropower and pumped-storage units recover their annual avoidable costs[6] through energy and ancillary service revenue (Figure 5). It is feasible that an m-PSH unit with equipment capabilities similar to existing PSH units could structure energy and ancillary service bids competitively.

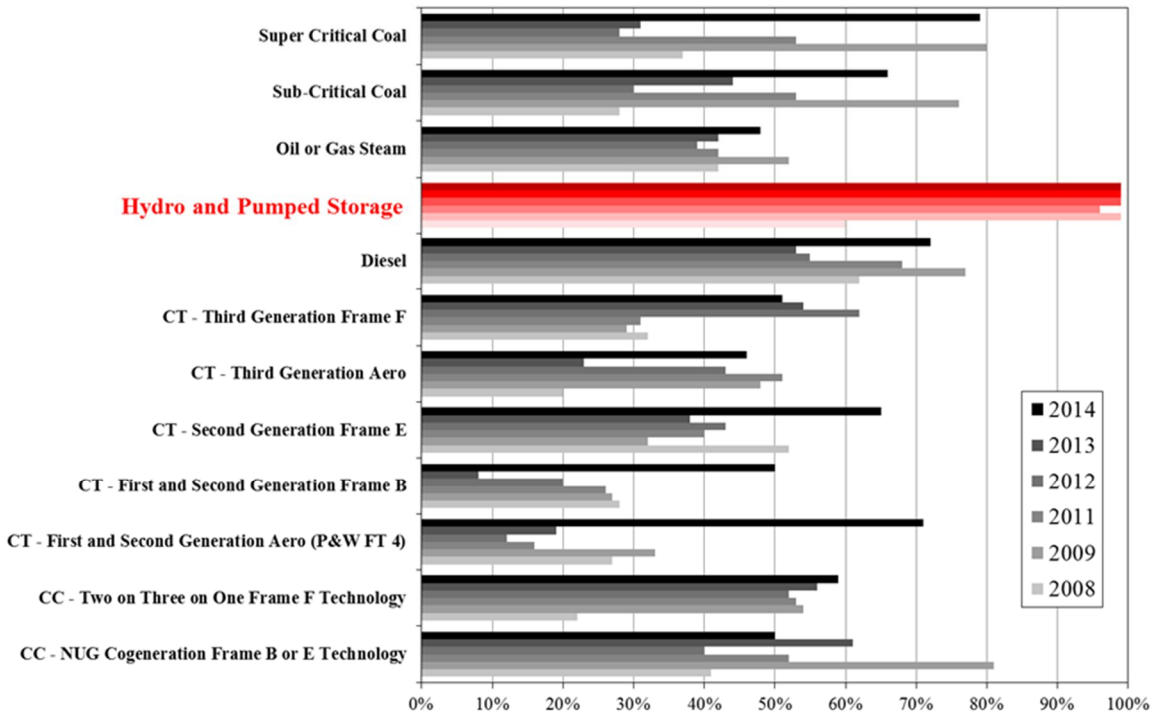

Figure 5. Proportion of generating units recovering avoidable costs through revenue generated in energy and ancillary service markets (Monitoring Analytics, 2014).

5 The optimization problem was written as a dynamic, mathematical linear programming model using the PuLP python library. Optimization problems are solved using the GLPK (GNU Linear Programming Kit) solver.
6 In this case, avoidable costs are the annual costs (not including fixed costs) required to keep a unit operational, including the incremental costs of producing energy (Monitoring Analytics, 2014).

To accommodate a range of potential turbine technologies, the revenue model is developed for a base generating unit and a flex generating unit (Figure 6). The total amount of energy and ancillary services provisioned in any given hour may vary between the upper and lower bounds (operational max and min), and is determined solely by the market clearing price. When bidding into energy markets only, both units are allowed to generate between 60% and 100% of their installed capacity. When the unit is co-optimized to bid capacity into the ancillary services market, there are two possible modes of operation. When bidding regulation capacity, the unit must operate at an economic basepoint to accommodate regulation up and down signals. When bidding spinning reserves capacity, the unit can generate at an operational minimum and allocate the remaining available capacity for spinning reserves. For a 5MW base unit co-optimizing energy and ancillary services, the regulation economic basepoint would be 4MW with 1MW available for regulation up or down, while the spinning reserves basepoint would be 3MW, with 2MW of capacity for spinning reserves. This framework is designed to give the turbine unit flexibility to operate within the boundaries where efficiency remains relatively constant, depending on turbine design. In all cases turbine efficiency is assumed constant for all operational capacities.

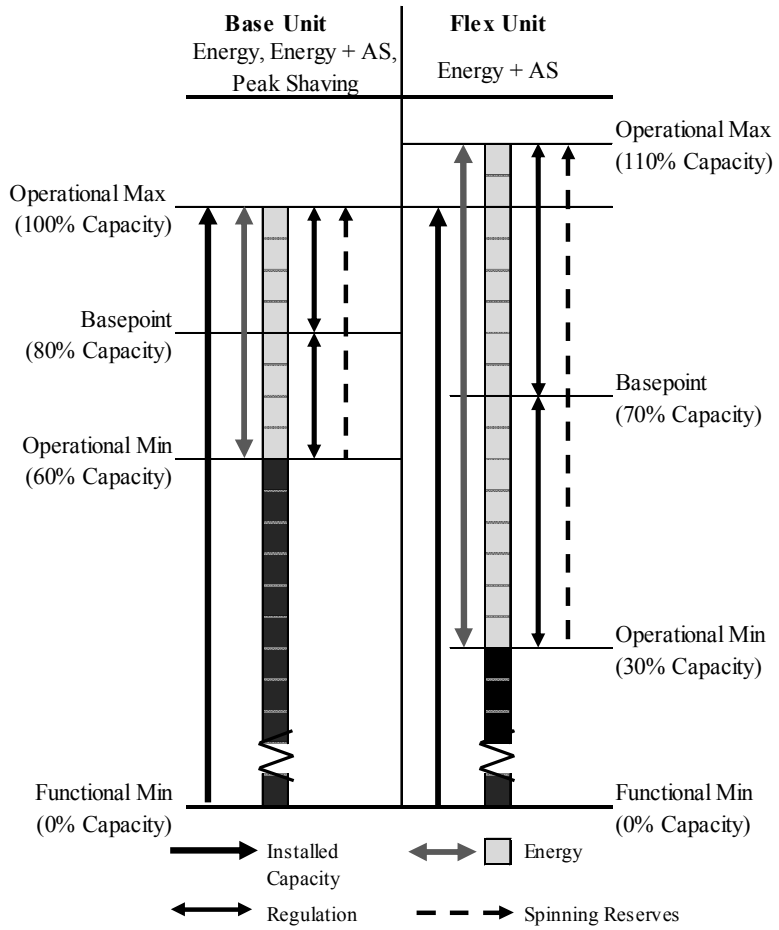

Figure 6. Schematic of two m-PSH turbine operational models and respective revenue models to which they apply. Arrows indicate range of energy, regulation, and spinning reserve generation capability.

Based on discussions with equipment manufacturers, no reversible pump/turbine unit is available in the marketplace with installed capacity on the order of m-PSH projects studied in this report. To accommodate present technological limitations, the revenue model assumes a separate single-stage, single-speed pump unit with no ancillary services capabilities. Single-stage pumps are not sufficiently

flexible to operate for frequency regulation, and spinning reserve during off-peak hours is generally not financially attractive[7] (MWH, 2009). A modular pump unit could be equipped to provide spinning reserve and vars, though it is unlikely these services would be valued for small m-PSH capacity in a larger market context. Adjustable speed pumps are capable of offering regulation and spinning reserve capacity in pumping mode, yet no variable speed units are currently installed in the U.S. By restricting the analysis to existing equipment capabilities, the analysis provides a baseline of what can be expected from readily deployable technologies.

3.1.1 Energy Revenue Model

To establish a baseline of revenue potential for CS1 and CS2, the energy model employs market arbitrage by generating power when electricity is most expensive, and pumping when the cost of electricity is at a minimum. A linear program is developed to optimize potential revenues over a set time,

$$\max \sum_{t=1}^{T} [p_t * (d_t - c_t)], \qquad \text{(Eq. 3.1)}$$

subject to the following constraints,

$$\text{storage}_t = s_t = s_{t-1} + \eta c_t - d_t \; \forall t \qquad \text{(Eq. 3.2)}$$

$$c_t, d_t \in [0, P_{\max}] \; \forall t \qquad \text{(Eq. 3.3)}$$

$$s_t \in [0, S_{\max}] \; \forall t \qquad \text{(Eq. 3.4)}$$

$$\text{if } d_t > 0, c_t = 0 \; \forall t \qquad \text{(Eq. 3.5)}$$

$$\text{if } c_t > 0, d_t = 0 \; \forall t \qquad \text{(Eq. 3.6)}$$

where T is the length of time in hours over which the optimization is carried out ($T = 24$ for a one day optimization), p_t is the hourly price of electricity ($/MW) at hour t, d_t is the power (in MW) discharged through the generator at hour t, c_t is the power required (in MW) to pump and charge the upper reservoir at hour t, η is the roundtrip efficiency, P_{max} is the installed capacity (MW) of the unit, and S_{max} is the total storage available in the upper reservoir (MWh).

The constraints can be summarized as follows. Total storage available in a given hour is equal to storage in the previous hour plus the difference between pumping (including efficiency losses) and generation (Eq. 3.2). Roundtrip efficiency is applied in bulk to the pumping mode, which allows the generation and pumping output to be quantified in terms of rated MW while still accounting for efficiency losses as they apply to water volume changes in the upper reservoir. Generation and pumping power must be positive and less than the installed capacity of the unit (Eq. 3.3), total storage must be positive and less than the total storage of the upper reservoir (Eq. 3.4), and generation and pumping cannot occur simultaneously (Eqs. 3.5 and 3.6).

3.1.2 Energy + AS Revenue Model

The same optimization technique is applied to the energy and ancillary services revenue equation for CS1,

$$\max \sum_{t=1}^{T} \left[p_t * (d_t - c_t) + p_t^{reg} d_t^{reg} + p_t^{sr} d_t^{sr} + NSR(p_t^{nsr} d_t^{nsr})\right], \qquad \text{(Eq. 3.7)}$$

7 While a single-speed pump could offer spinning reserve capacity by operating as an interruptible load, the meager market price of off-peak spinning reserves is not deemed sufficient in this case to justify the increased cost of start/stop cycling.

subject to the following constraints, in addition to constraints Eqs. 3.2-3.6,

$$d_t + d_t^{reg} + d_t^{sr} \leq P_{\max} \, \forall t \quad \text{(Eq. 3.8)}$$

$$d_t \geq k_{reg} d_t^{reg} + k_{sr} d_t^{sr} \, \forall t \quad \text{(Eq. 3.9)}$$

$$\text{if } d_t, c_t = 0 \; and \; s_t > 2P_{\max}: \; NSR = 1 \, \forall t, \qquad else \; NSR = 0 \quad \text{(Eq. 3.10)}$$

p_t^{reg} is the hourly price of regulation (\$/MW) at hour t, d_t^{reg} is the power (in MW) bid into the regulation market at hour t, p_t^{sr} is the hourly price of spinning reserves (\$/MW) at hour t, d_t^{sr} is the power (in MW) bid into the spinning reserves market at hour t, p_t^{nsr} is the hourly price of non-spinning reserves (\$/MW) at hour t, d_t^{nsr} is the power (in MW) bid into the non-spinning reserves market at hour t, NSR is a variable to ensure non-spinning reserves are only bid when neither the pump nor turbine are spinning, and k_{reg} and k_{sr} are coefficients that ensure energy and ancillary services bids are co-optimized within the framework outlined in Figure 6. For example, a 5MW base unit with $k_{reg} = 4$ and $k_{sr} = 1.5$ would be able to bid a maximum of 1MW into regulation or 2MW into spinning reserves. Optimization constraints ensure that energy and ancillary service bids do not exceed installed capacity (Eq. 3.8), that energy generation is maintained around an economic basepoint (Eq. 3.9), and that a minimum of 2 hours of non-spinning reserve capacity (the minimum acceptable bid in the PJM market) is bid when neither generation nor pumping is taking place (Eq. 3.10).

3.1.3 Peak Shaving Revenue Model

A third market strategy for m-PSH is to locate near a load center and reduce or shave local peak electricity load through generation. The reduced load would be redistributed to a later time, when pumping would simultaneously charge the reservoir and increase the load. The effect would be a smoothing of the load profile over time and a decrease in the maximum electrical load. Utility regulators are frequently encouraging utilities to impose a demand charge on large consumers of electricity, a billing mechanism designed to recover a share of transmission and distribution capacity costs. The charge is typically based on the largest single load during a 15 minute period in a given month, and can make up 30% to 70% of the monthly electric bill of a commercial customer (Arista Power, 2015). There is market potential for m-PSH to act in a peak shaving capacity if the benefits of pumping and generating are comparable in magnitude to the demand charge.

To assess the benefits of peak shaving for CS2, a load balancing equation is optimized,

$$\min \sum_{t=1}^{T} [l_t - d_t + c_t + L], \quad \text{(Eq. 3.11)}$$

Subject to the following constraints, in addition to Eqs. 3.2-3.6,

$$l_t - d_t + c_t < L \quad \text{(Eq. 3.12)}$$

where l_t is the hourly electrical load and L is the maximum load in T. Equation 3.12 optimizes the charge and discharge cycles to ensure the maximum reduction of L. The base unit operational mode is implemented in this model, and the optimization algorithm is relaxed to allow for incremental pumping and generating (greater than 0 but less than the operational minimum). Realistically, a single-speed turbine or pump would not have the flexibility to operate at less than the rated capacity, and in this case, revenues should be perceived as an upper bound to what could be achieved under ideal conditions.

3.2 ADDITIONAL REVENUE MODEL ASSUMPTIONS

3.2.1 Determining Generation and Pumping Times

A reasonable strategy must be devised to reduce operational and startup costs (start/stop cycling) while optimizing revenue generation potential. For the energy and energy + AS revenue models, hourly blocks of generation and pumping windows are assigned based on historical price averages, which vary both seasonally and annually (Table 2). These time frames are based on PJM pricing dynamics, which vary hourly and seasonally (Figure 7). Summer months (Apr – Sep) are generally characterized by energy prices that peak in the midday and decline in the evening and through the next morning. The fall and winter months have two daily peaks, one in the morning and one in the evening. Afternoon and late night (early morning) represent the best times to consume energy for an m-PSH facility, as energy prices are consistently at a daily minimum.

Table 2. CS1 generation and pumping windows for summer (Apr – Sep) and winter (Oct – Mar) months.

Summer Generation Window	Summer Pumping Window	Winter Generation Window	Winter Pumping Window
12pm – 9pm	10pm – 11am	7am – 11am, 5pm – 9pm	12pm – 4pm, 10pm – 6am

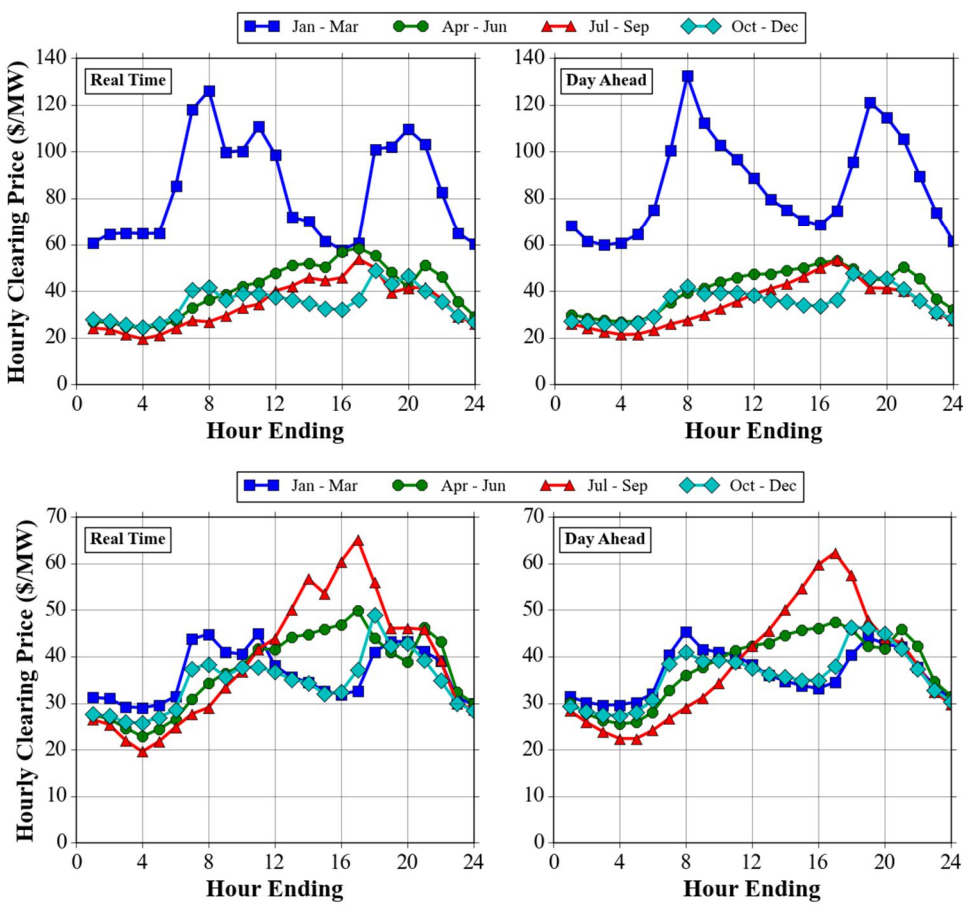

Figure 7. Real time and day ahead market clearing prices in the PJM RTO for 2014 (top) and 2013 (bottom).

3.2.2 Revenue Optimization Window

The time frame over which the optimization algorithm acts (the value of *T*) must align with a typical forecast window for a PSH operator. Many models implement daily, weekly, or bi-weekly optimization periods, with longer periods generally performing better due to improved execution of inter- and intra-day arbitrage (Kanakasabapathy & Shanti Swarup, 2010; Lu, Chow, & Desrochers, 2004). Long-term projections are not an explicit requirement to develop an operational strategy that maximizes profit, but day-ahead price projections must be fairly close to the actual clearing price (Connolly, Lund, Finn, Mathiesen, & Leahy, 2011). For CS1 and CS2, optimization is carried out on a daily (herein referred to as 24hopt) and weekly (herein referred to as 7dopt) basis. For a peak shaving application, daily optimization will reduce the peak demand on a given day at the expense of increasing the minimum load on the same day. If the load minimum on that day is much higher than the load maximum on a day later in the week, peak shaving will not serve its purpose. The peak shaving model of CS2 is carried out on a two week basis to capture larger temporal fluctuations in demand. In this case, the m-PSH operator would need relatively accurate two-week forecasts of local electricity demand.

3.2.3 Frequency Regulation Assumptions

Frequency regulation bids are only considered in CS1, which is located in the PJM interconnection. To implement FERC Order 755, PJM started producing two regulation signals in 2012: slow, or RegA (for most generation resources, where the ramping constraints are more of a limiting factor than the energy availability) and fast, or RegD (mostly geared toward energy-limited resources like batteries and demand response). These signals are telemetered by Automatic Generation Control (AGC) to generating units on a 2-4 second basis, and units must adjust their output and telemeter their capability back to PJM within seconds. Traditional generation resources will generally follow the RegA signal, with hydro responding within one minute and thermal units responding in up to three minutes (PJM, 2011). Some batteries and flywheels can respond in seconds, a capability that qualifies them to follow the RegD signal. The assumption is that an m-PSH unit using similar turbine technology as existing hydropower assets could follow the RegA signal with reasonable accuracy.

It is assumed that up and down fluctuations of the random RegA signal will net out to zero over time. This is an important consideration in the operational model, which adjusts turbine output (i.e. flow of water through the unit) based on regulation signal direction. When the unit receives a regulation up signal, it must increase electricity generation from the economic set point up to the operational maximum (See Figure 6), which leads to increased flow out of the upper reservoir through the unit. Conversely, a down signal will decrease electricity generation and flow through the unit. With each movement the unit is compensated for performance, yet up signals require additional flow out of the upper reservoir while down signals allow for water to be conserved with respect to the electricity generated. It is assumed these actions cancel each other out over time, and that discharge out of the upper reservoir is not impacted by regulation (i.e., no regulation contribution to Eq. 3.2). To confirm the assumption, a summer and winter month of sub-second RegA and RegD signals are analyzed during peak and off peak hours (See Table 2) to observe fluctuation trends (Figure 8). Over time, both signals are evenly distributed about a signal movement of 0. The RegD signal shows a wider distribution, with a greater number of large signal movements relative to the RegA signal. It is reasonable to assume that over the course of peak and off-peak hours, an m-PSH unit responding to regulation signals would maneuver equally up and down about an energy generation set point, and that flow out of the upper reservoir can be computed based entirely on that set point.

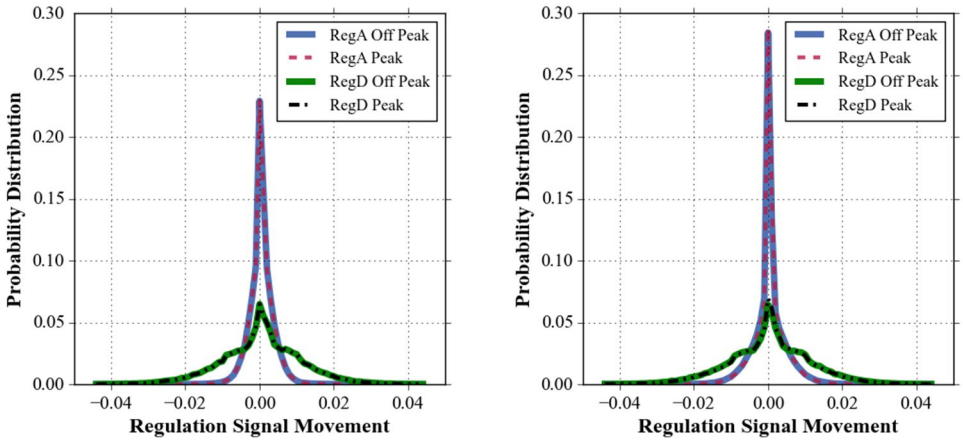

Figure 8. Probability distribution of PJM RegA and RegD signal movements in July,2013 (left) and June, 2014 (right).

Since 2012, PJM uses a new mechanism to determine the credit that each participating resource obtains from bidding capacity in the frequency regulation market. Historically, all resources obtained a credit based on the frequency regulation clearing price. Now, the credit that each resource receives is adjusted by a performance score that varies between 0 and 1, reflecting the accuracy, delay, and precision with which the unit follows the AGC signal sent by the market operator. The credit received for each MW is the sum of two components (PJM, 2015a):

Regulation Capability Clearing Price Credit =
(Hourly Regulation MWs Provided *
Historic Performance Score *
Hourly Regulation Market Capability Clearing Price) +
Lost Opportunity Credit

Regulation Performance Clearing Price Credit =
(Hourly Regulation MWs Provided *
Historic Performance Score *
Mileage Ratio *
Hourly Regulation Market Performance Clearing Price)

Assuming that the m-PSH unit is following the traditional (slow) regulation signal, a conservative performance score for hydro units is 0.85. The lost opportunity credit (LOC) is the foregone revenue or increased costs incurred by a generating unit that services the regulation market in lieu of the energy market. For self-scheduled units, the LOC is $0, which is the assumption in this case. The mileage ratio is a scalar that reflects that cumulative signal movement over the course of an hour per MW of capacity, or ΔMW/MW. The RegA mileage ratio is publicly available on an hourly basis, and generally falls between 2 and 5. These three variables are used, along with the formulas for regulation price credit, to simulate the revenue that m-PSH can obtain from providing frequency regulation.

3.3 ECONOMIC INDICATORS

An economic analysis is performed to assess the feasibility of CS1 and CS2 over the span of 50 years. Cost and revenue estimates are combined to develop three economic indicators: Benefit-Cost Ratio (BCR), Levelized Cost of Energy (LCOE), and Net Present Value (NPV). The following assumptions are applied to all cases unless otherwise indicated:

- Annual Operation and Maintenance (O&M) costs are fixed at 2.5% of project capital costs;
- Due to the small project size, the owner would not be responsible for O&M related to transmission or distribution lines;
- Inflation is assumed steady at 2%;
- The discount rate (weighted average cost of capital, WACC) is estimated at 5.2% and the fixed charge rate (FCR) at 6.1% based on power industry averages.

3.3.1 Benefit-Cost Ratio

The benefit-cost ratio (BCR) is a standard metric useful in determining the overall value of a project. If the BCR is greater than 1, the return on project costs is positive and the investment is considered economically attractive. The BCR is calculated as the ratio of the net present value of lifecycle benefits to the net present value of lifecycle costs, meaning both the quantity and timing of revenues versus expenditures determines project feasibility, computed as,

$$BCR = \sum_{i=1}^{n} \frac{Net\ Revenues_i}{(1+r)^i} \Big/ \left[\sum_{i=1}^{n} \frac{O\&M\&R_i}{(1+r)^i} + ICC\right] \qquad \text{(Eq. 3.13)}$$

where *Net Revenues* are the present value of future annual revenues (energy revenue + A/S revenue) adjusted for inflation, minus the present value of future annual pumping costs adjusted for inflation, O&M and replacement costs (O&M&R) are the present value of future annual costs adjusted for inflation, r is the discount rate, *ICC* is initial capital cost, and n is the life of the project (assumed to be 50 years).

3.3.2 Levelized Cost of Energy

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 the resources and assets used in the operation of an energy project, calculated according to the equation

$$LCOE = \sum_{i=1}^{n} \left[ICC * FCR + \frac{O\&M\&R_i + F_i}{(1+r)^i}\right] \Big/ \sum_{i=1}^{n} E_i \qquad \text{(Eq. 3.14)}$$

where F is the present value of future annual fuel (pumping) costs adjusted for inflation and E is the annual generation (energy only) in MWh.

3.3.3 Net Present Value

The net present value (NPV) compares the amount of capital invested to the present value of future cash inflows. It is calculated as the difference between the present value of all future gross revenues adjusted for inflation and the present value of future cash outflows adjusted for inflation, or

$$NPV = \sum_{i=1}^{n} \frac{Net\ Revenues_i - O\&M\&R_i}{(1+r)^i} - ICC \qquad \text{(Eq. 3.15)}$$

4. CASE STUDY #1: COAL MINE

4.1 INTRODUCTION AND BACKGROUND

The use of existing mines is an extremely attractive m-PSH development opportunity as most sites have paired reservoirs with a substantial elevation differential, transmission lines in place, and have exceeded their useful life with no immediately identifiable repurpose use. Standard dimensions are used for mine shafts, meaning a modular approach to water conveyance system design and construction could be employed. If the site can be classified as closed-loop, environmental and regulatory requirements may be significantly less burdensome, shortcutting the critical path to project viability. As of 2011, a quarter of FERC issued preliminary permits for large-scale PSH were for projects that included an underground cavern as a lower reservoir (Yang & Jackson, 2011). The novelty of this particular m-PSH opportunity is in the cost reduction, implementation time predictability, and risk reduction achieved through modularization of components designed for a standard installation.

4.2 EXISTING FACILITIES AND CONCEPT PROJECT LAYOUT

The first case study is located in Kentucky at a site[8] originally developed for underground coal mining operations in the 1980s (Figure 9). An existing upper reservoir will be paired with an existing coal mine (lower reservoir) to create a closed-loop m-PSH facility. The lower reservoir will be converted from an existing underground cavern which contains an estimated 750 million to 1 billion gallons of water. Water will be pumped from the lower cavern to an existing upper reservoir that covers approximately 520 acres. During generation, the water will be gravity-fed back through the shaft to the lower cavern at a net head of approximately 500 ft. A vertical shaft approximately 20 ft in diameter and 640 ft in depth will house water and electrical conveyances. An estimated 1,700 ft of penstock is required to connect the upper reservoir intake to the lower reservoir generating equipment. A conceptual schematic of the proposed facility is shown in Figure 10.

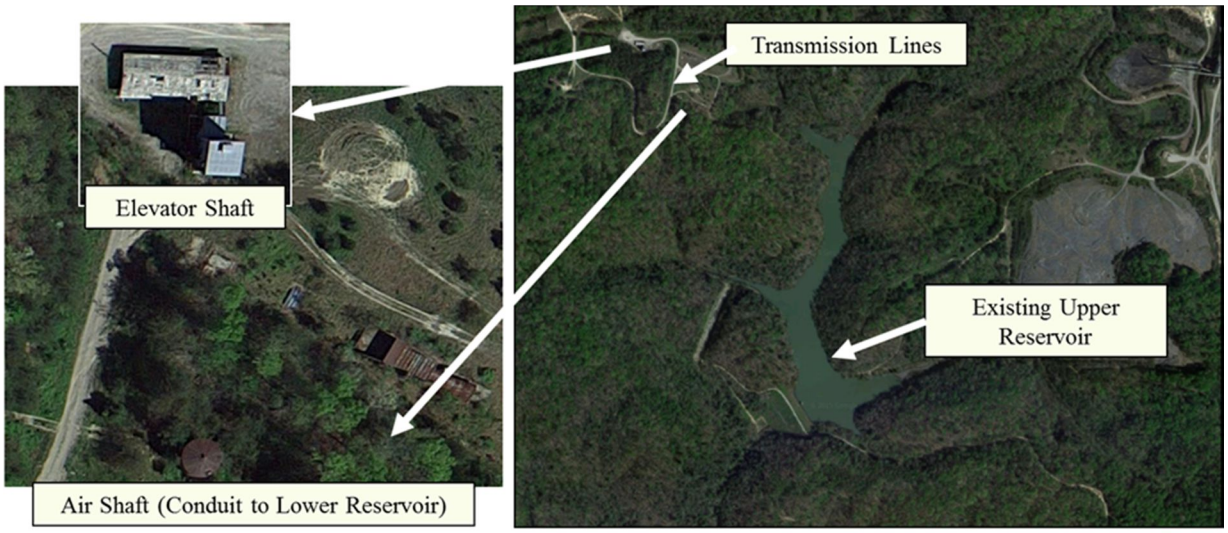

Figure 9. Aerial view of the proposed coal mine m-PSH facility (Map data ©2015 Google).

8 Approximate water volumes and site characteristics, including elevations and distances were provided by the project owners during a site visit conducted by the authors.

Table 3. CS1 upper reservoir storage.

Stage	Elevation (ft)	Gallons (millions)	Volume[a] (acre-ft)
Emergency spillway	1214	170	522
Principal spillway	1210	125	384
Current water level	1197	72	221

[a]Does not include an estimated 41 acre-ft (13 million gallons) of dead pool.

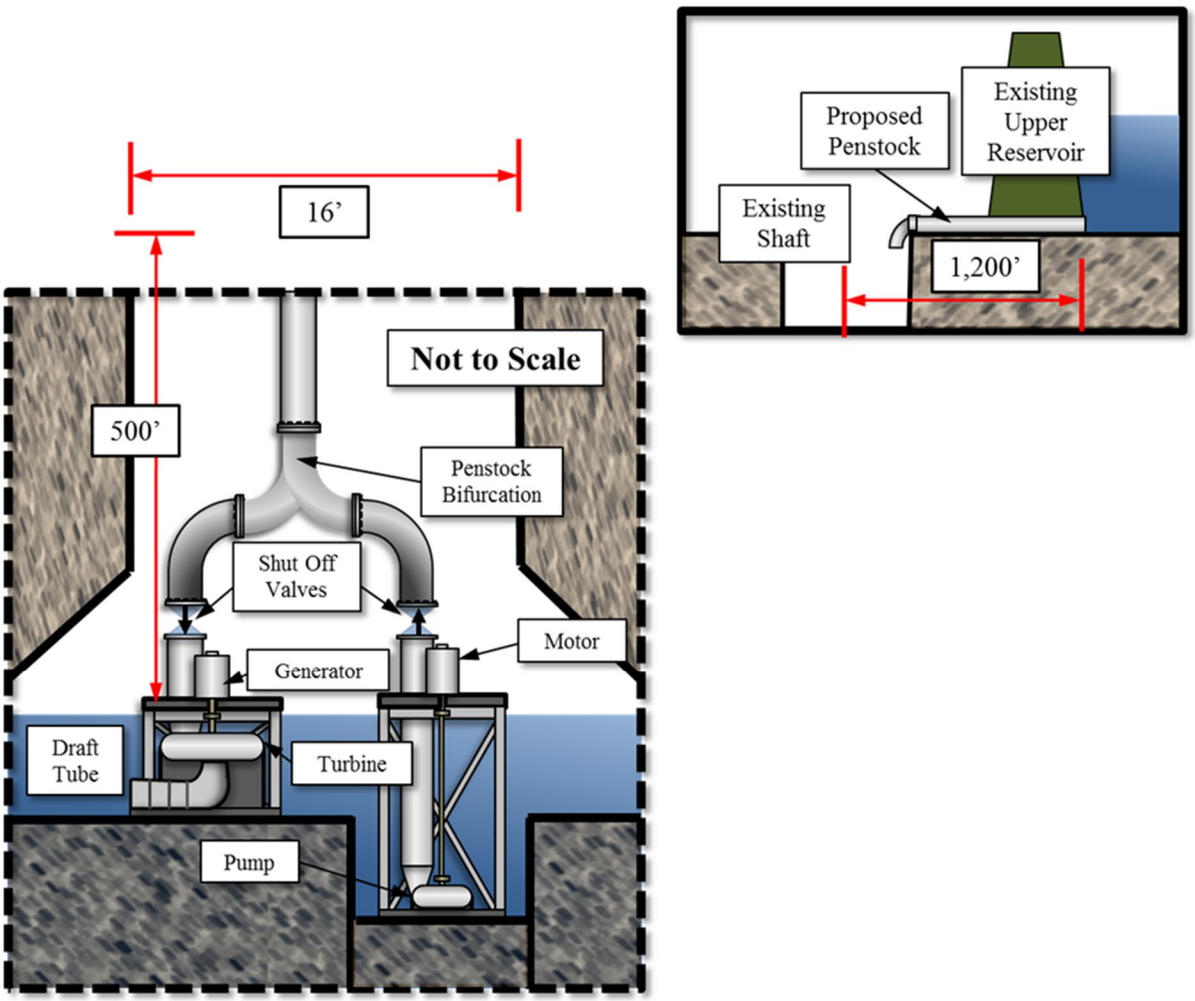

Figure 10. Schematic conceptual layout of the CS1 m-PSH facility.

Preliminary site characteristics are used to generate a baseline equipment and civil works hydraulic specification. The 53 million gallons of available storage in the upper reservoir (principal spillway – current water level) could support approximately ten hours of discharge at 197cfs. If the entire upper reservoir storage capacity were assumed available for m-PSH operation (principal spillway – dead pool), a discharge of 416cfs could be maintained. Discharge through the turbine, Q, will be limited by the penstock, which must exhibit a balance of size and cost appropriate to the site. By assuming a penstock design that accommodates a maximum flow velocity of $V = 11$ ft/s, the maximum pipe diameter can be approximated using

$$d_p = 2\sqrt{Q/\pi V} \quad \text{(Eq. 4.1)}$$

to give 4.8ft and 6.9ft for discharge of 197cfs and 416cfs, respectively.

It must be noted that the diameter of the mine shaft that will house the proposed penstock, turbine, and pump units is a constant 19.5ft, and in order to achieve maximum cost efficiency excavation costs must be minimized. In this sense, it is assumed that all equipment must be lowered through the existing mine shaft, and sufficient space must be available for the turbine and pump casing while leaving adequate room for maintenance access. Geometric constraints become the primary limiting factor much more so than the available storage in the upper reservoir or the feasible penstock diameter. Furthermore, the bathymetry of the mine floor is not well defined, and a complete characterization is outside the scope of this study. The conceptual schematic was designed to accommodate these assumptions by including separate platforms for the turbine and pump units, which provide flexibility to position the generating and pumping units between the mine floor and the bottom of the shaft. A penstock bifurcation must take place somewhere between the end of the mine shaft and the platforms, and is necessary to support separate pumping and generating units. As discussed in the next section, no equipment manufacturer was able to provide a single reversible pump/turbine unit of the size desired in this study, thus guiding the conceptual design as depicted in Figure 10. To ensure the bifurcation and equipment are supported within the current mine geometry, a conservative penstock diameter of 4ft is used. This estimate also supports the modular nature of the project, as a 4ft diameter penstock is a standard, readily available conveyance.

By assuming d_p = 4ft, Eq. 4.1 is rearranged to arrive at an approximate discharge of Q = 138cfs. The estimated head of H = 500ft is input into the power equation,

$$P\ (in\ MW) = \frac{QH\eta_t}{k}, \quad \text{(Eq. 4.2)}$$

where k is a conversion factor equal to 11,814 ft^4/s-MW, to give a rough estimate of ideal turbine output, P = 5.8MW (if turbine efficiency, η_t, were 100%). Assuming turbine efficiency could be consistently maintained between 85% and 90%, the expected power output from the unit should be very near 5MW.

4.3 POWERHOUSE DESIGN CONCEPT AND COST

In contrast to a custom, site-specific design, a primary result of m-PSH is simplicity in the form of a modular design that may sacrifice optimal peak efficiency to obtain greater cost savings. Early concept work and discussion with industry experts has demonstrated that this is achievable, though more engineering analysis is needed to complete a detailed conceptual project layout. The proposed project layout and general hydraulic scoping from Section 4.2 were communicated to five equipment manufacturers who in turn provided technical specifications and price estimates for the necessary equipment. One manufacturer assisted in developing an equipment schematic used for cost estimating, shown in Figure 11. All manufacturers recommended either a horizontal or vertical Francis type turbine with a synchronous generator, and a separate centrifugal pump/motor unit. The turbine configurations were designed to give a compact, standardized arrangement, to maximize performance over a wide range of flow and head, and to allow for a unit setting above the tailwater. Efficiency curves were provided and used to determine an appropriate range of round-trip efficiency for m-PSH operational simulations. Economies of scale from a volume order are assumed, and estimates reflect some non-hardware costs, such as engineering design, project management, transportation and start-up/testing. Cost estimates from all manufacturers are presented in Table 4.

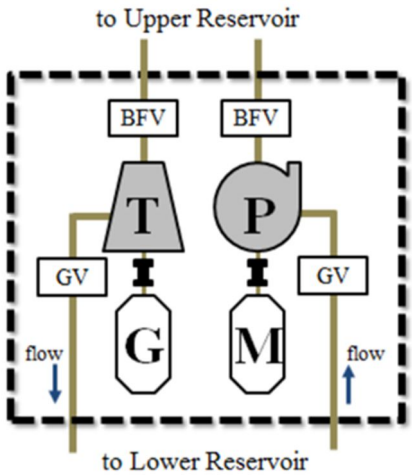

Figure 11. Configuration of the equipment schematic. T:Turbine, G: Generator, M: Motor, P: Pump, BFV: Butterfly Valve, GV: Gate Valve.

Table 4. Equipment cost estimates.

Component \ Manuf.	Manuf. 1	Manuf. 2	Manuf. 3	Manuf. 4	Manuf. 5	Average
Turbine-generator						-
Type	Francis (H or V)	Francis (H)	Francis (V)	Francis (H)	Francis (V)	
Power Rating (MW)	5.00	5.30	5.17	5.45	5.21	
Runner Diameter (ft)	3.28	2.40	2.54	2.89	3.67	
Cost ($)	1,282,500	2,500,000	Included	1,200,000	Included	
Valves ($)	405,000	Included	Included	Not Included	Included	-
Draft Tube ($)	Not Included	Included	Included	Not Included	Included	-
Pump-motor						-
Power Rating (MW)	5.0	6.0	-	5.50	5.50	
Pump Diameter (ft)	4.60	3.61	-	6.3	4.59	
Cost ($)	2,196,000	1,400,000	Not Included	1,750,000	Included	
Unit auxiliaries	445,950	Included	Included	Not Included	Included	-
Plant Balance*	700,000	700,000	700,000	700,000	700,000	-
Total† =	**5,029,450**	**4,600,000**	3,500,000	**3,650,000**	**4,700,000**	**4,494,862**
$/kW(gen capacity)† =	**1,006**	**868**	**-**	**670**	**902**	**862**

*Consultant estimate
†Estimates from Manuf. 3 are not included in averages as they do not include an estimate for the cost of a pump unit.

An additional allowance of $600,000 to $800,000 is estimated for the balance of plant equipment, which may include new switchgear and step-up transformers for the existing substation, a unit governor, controls, interconnecting wiring, and bearing oil systems. Total equipment costs vary between $3.5 and $5 million, or $700 to $1,000/kW of generating capacity.

There are many other necessary configurations and parameters that could be optimized later through more detailed analysis. The following 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. Vertical or horizontal arrangement equipment layout. The preferred first approach for this analysis is of a simple, basic, non-customized low cost arrangement;
4. A penstock with a bifurcation after the butterfly valve (BFV) and gate valve (GV). It is also possible that pipe will not be required at the lower reservoir except for a suction chamber and draft tube. These draft tubes could have a gate (draft tube gate or stop logs). This is typical in pump wells and at ends of draft tubes;
5. Direct drives between the motors and pumps and between the turbines and generators;
6. Single-stage pumps compared with others.

4.4 CIVIL WORKS DESIGN CONCEPT AND COST

A pre-concept civil works design and cost estimate was developed by an experienced registered Professional Engineer after a detailed site visit. The concept schematic design has a 4 ft diameter spiral-welded steel penstock varying in thickness from ⅜ to ½ in, depending on the various stresses the piping will encounter. A bifurcation is needed with shutoff 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 before arrival 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 the 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. The short penstock length and configuration are expected to reduce the hydrodynamic considerations in pumping and generating modes.

Based on the civil works conceptual design, low and high cost estimates were developed (Table 5). All estimates include the cost of delivery, installation, and engineering project management. An additional 12% contingency is added to further account for engineering project management costs and additional components not included due to the lack of detailed civil arrangement concept drawings. Turbine-generator and pump-motor assemblies are proposed as a single module, enabling assembly and testing of a full module before arrival. Modifications to the switchyard and foundations for the new switchgear and transformers have been included in the civil works estimate based on a schematic sketch of the pump module and turbine module. Total civil works estimates are in the range of $5 million to $7 million.

Table 5. Pre-concept civil works cost estimate.

Item	Units	Low estimate			High estimate			Description
		No. of units	Unit price ($)	Subtotal ($)	No. of units	Unit price ($)	Subtotal ($)	
Intake and upper dam modifications	Modular	1	450,000	450,000	1	750,000	750,000	Intake installation, head gate, hoist, trash racks; dam repairs and excavation
Penstock	ton	200	6,000	1,200,000	300	6,000	1,800,000	Includes bifurcation, installation, and supports
Pump module	Modular	1	750,000	750,000	1	950,000	950,000	19.5 × 19.5 module, includes installation
Turbine module	Modular	1	650,000	650,000	1	850,000	850,000	19.5 × 19.5 module, includes installation
Access (lower to upper)	Modular	1	550,000	550,000	1	650,000	650,000	Includes surface 20 ton pad winch and stairs, installation
Electrical (lower to upper)	Modular	1	300,000	300,000	1	400,000	400,000	Includes structural conduits and power leads (lower to upper)
Surface electrical/ control building	Modular	1	350,000	350,000	1	500,000	500,000	Includes prefabricated building and foundations
Switchyard modifications	Allowance	1	250,000	250,000	1	350,000	350,000	Modify existing substation, new foundations for new switchgear and transformers
Subtotal =				4,500,000			6,250,000	
Contingency (12%)				540,000			750,000	
Total =				**5,040,000**			**7,000,000**	
Total $/kW (5MW gen capacity) =				**1,008**			**1,400**	

4.5 PROJECT COSTS

A rough order of magnitude estimate of total project costs ranges from $8.7 million and $12 million, or $1,700/kW to $2,400/kW (Table 6). As a reference, 14 large scale PSH projects (300MW to 2,100MW) constructed between 1965 and 1991 reported capital costs that varied between $700/kW and $1,900/kW (MWH, 2009, adjusted to 2015 dollars). Total CS1 project costs are at the high end of this range, revealing the benefit of economies of scale for larger projects. The percentage breakdown of CS1 costs is similar to PSH projects in the planning and engineering phase (O'Connor et al., 2015), indicating the cost distribution is on par with PSH in the regulatory pipeline (CS1 equipment costs include indirect costs). These comparisons are provided only as a point of reference, and are used with caution. The wide variability in project costs reflects the unique characteristics of individual sites, and an apples-to-apples comparison of construction costs is generally not achievable. A large range of uncertainty is present in all project cost estimates, and in most cases it is not clear if the total estimate includes "soft costs" such as engineering or environmental impact assessments. For CS1, additional costs may stem from an analysis of ventilation requirements, geotechnical stability, and structural adequacy of the underground cavern.

Table 6. CS1 high and low estimate project costs.

	Low Estimate	(%)	$/kW	High Estimate	(%)	$/kW	O'Connor et al., 2015
Equipment	3,650,000	42.0	730	5,029,450	41.8	1006	35.0
Civil Works*	4,500,000	51.8	900	6,250,000	52.0	1250	53.4
Indirect	540,000	6.2	108	750,000	6.2	150	11.7
Total Cost	**8,690,000**		**1,768**	**12,029,450**		**2,406**	

*Includes electrical infrastructure

A comparison of PSH total project costs to m-PSH cost estimates is shown in Figure 12. While m-PSH project costs are generally higher than installed, large-scale PSH projects, they are significantly under cost projections of recent siting and preliminary level assessment cost studies for approximately 60 greenfield PSH plants (MWH, 2009), and in line with estimated of installed and proposed projects around the globe (Akhil et al., 2013) . The challenge in comparing m-PSH to installed PSH projects is that generating capacity of m-PSH is significantly less than any installed project, two installed PSH projects with the same generating capacity may have significantly different construction costs and site characteristics, and only two PSH projects have been installed in the U.S. in the last 20 years. Challenges aside, the analysis presented herein suggests m-PSH costs are not prohibitive when compared with existing and proposed large-scale projects.

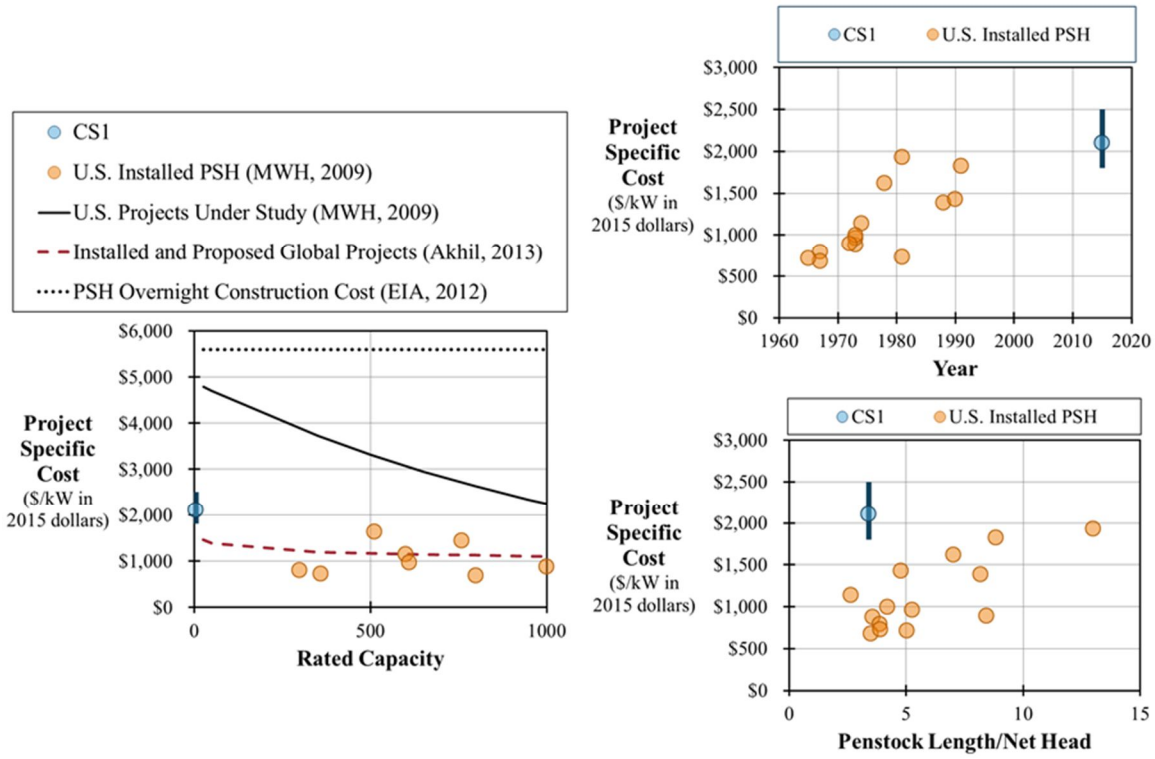

Figure 12. CS1 project cost comparison with large scale PSH (MWH, 2009). The vertical line on CS1 spans the range of low to high project cost estimates.

For technology screening purposes, a comparison of CS1 project costs with several alternative storage technologies (i.e., batteries) with 1-40MW of power and a variety of storage capabilities is shown in Figure 13. The first four entries represent installed and operational projects[9,10,11,12], and the remaining performance and cost metrics were obtained from original equipment manufacturers, and include estimated component, installation, and interconnection costs (Akhil et al., 2013). Significant variability in costs and estimates makes the comparison somewhat trivial, but it is instructive to note that CS1 has maneuvering room to remain cost competitive with alternative storage technologies, while maintaining

9 http://news.nationalgeographic.com/news/2010/03/100325-presidio-texas-battery/
10 http://www.nytimes.com/2010/07/28/business/energy-environment/28storage.html?_r=0
11 http://www.duke-energy.com/news/releases/2013012301.asp
12 Wald, 2011

significant advantages in terms of expected plant life, storage potential, proven reliability, and system power potential.

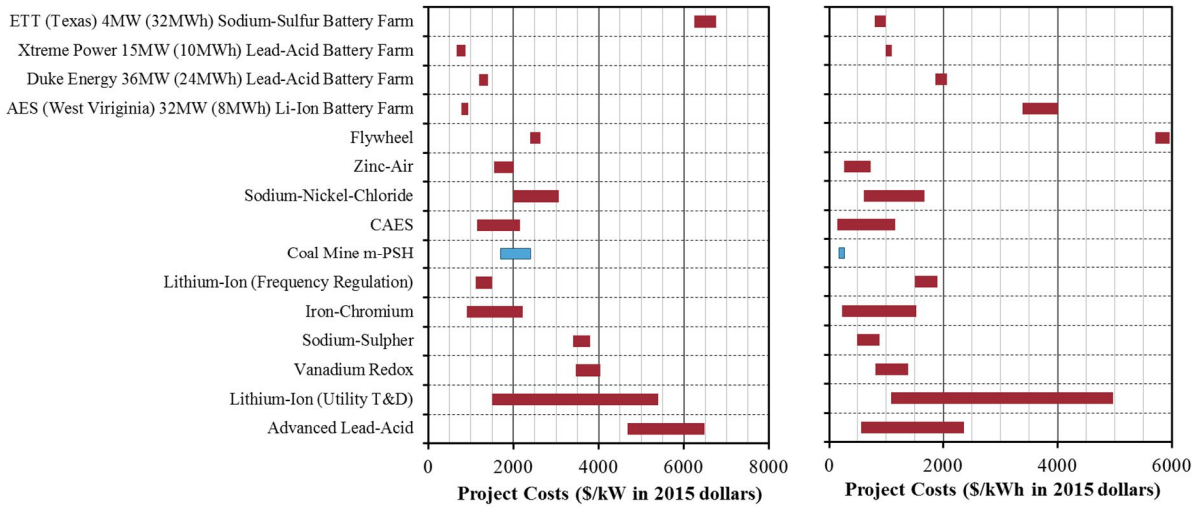

Figure 13. CS1 (blue) project cost comparison with alternative energy storage technologies (red) on a $/kW (left) and $/kWh (right) basis.

It is worthwhile to note that one of the largest grid-scale battery energy storage facility operating in the U.S. is a 32MW, lithium-ion battery farm in West Virginia with 0.25 hours of storage (8MWh) (Wald, 2011). The facility is used to support a 98MW wind farm, and total costs (in 2015 dollars) are estimated in the range of $27 to $32 million dollars ($1,000/kW). This example highlights the delicate nature of installed cost comparisons on a kW basis. On its face, the lithium-ion facility is cost competitive with all existing energy storage technologies. However, the small discharge time at the rated power and the requirement of millions of small, linked batteries for operation limits the application of this technology, and complicates an apples-to-apples comparison of the cost of stored energy delivered through different mediums. When compared with this new technology, m-PSH does offer several competitive advantages: more flexibility in dispatching energy, the ability to sustain generation for much longer periods of time, increased longevity of power plant life (PSH frequently achieves a 50 year plant life while most batteries are rated at 15 years), and the ability to offer a spectrum of grid services at various time scales.

The lack of real world cost and performance data on PSH projects of this size is both an opportunity and a challenge. More research is needed to further drive cost reductions in modular civil works and equipment. In this particular application, the turbine-generator, pump-motor, and penstock represent the largest project costs (outside of contingencies and indirect costs), and still retain a large degree of uncertainty. An obvious avenue to cost reductions is the development of a single, reversible machine that can maintain high efficiency in pumping and generating mode. This configuration could significantly reduce equipment and civil works costs while maintaining similar operational flexibility. The compact nature of such a machine could open pathways to alternative configurations that satisfy the geometric limitations of the mine shaft. Other cost reductions may result from the use of alternative materials (e.g., carbon fiber) and design and construction methods for the hydraulic equipment and penstock. Even with existing technologies, m-PSH has the potential to avoid many of the major financial barriers commonly associated with large conventional custom designs, project schedule uncertainty, and implementation risk, including access to significant capital and a long uncertain licensing process.

4.6 SIMULATED REVENUE STREAMS

The primary market strategy analyzed in this case is to offer 5MW (50MWh) of m-PSH capacity and energy in the PJM wholesale energy and ancillary services market. Historical hourly market clearing prices from 2013 and 2014 are used to investigate revenue potential and generate a first order assessment of economic feasibility. Specific details and assumptions of the revenue model can be found in Section 3.

Daily and weekly operational patterns representative of a flexible m-PSH unit offering energy and ancillary services capacity in summer and winter seasons are highlighted in Figure 14 (left and right, respectively). The pumping and generating schedules are fixed by the times of maximum demand, roughly twelve hours throughout midday in the summer (left) and two six hour blocks in winter mornings and evenings (right). The most profitable strategy in each week, driven purely by market price signals, is to co-optimize bids of energy and regulation capacity. The unit was generating at full capacity, or 5MW, for only one hour in the April week (left) and eight hours in the November week (right). In most hours 4MW of energy is offered along with 1MW of regulation capability. No capacity is bid into the spinning reserve market, as the spinning reserve clearing price is nearly always lower than the total regulation price credit. Capacity is bid for non-spinning reserves only when prices are positive and constraints have been met. Pumping occurs nearly every day, though some days show pumping to be favorable for only two hours (April 18, 2014, left). The unit will forego a full reservoir recharge if the cost of pumping is only nominally lower than the value to be gained through generation.

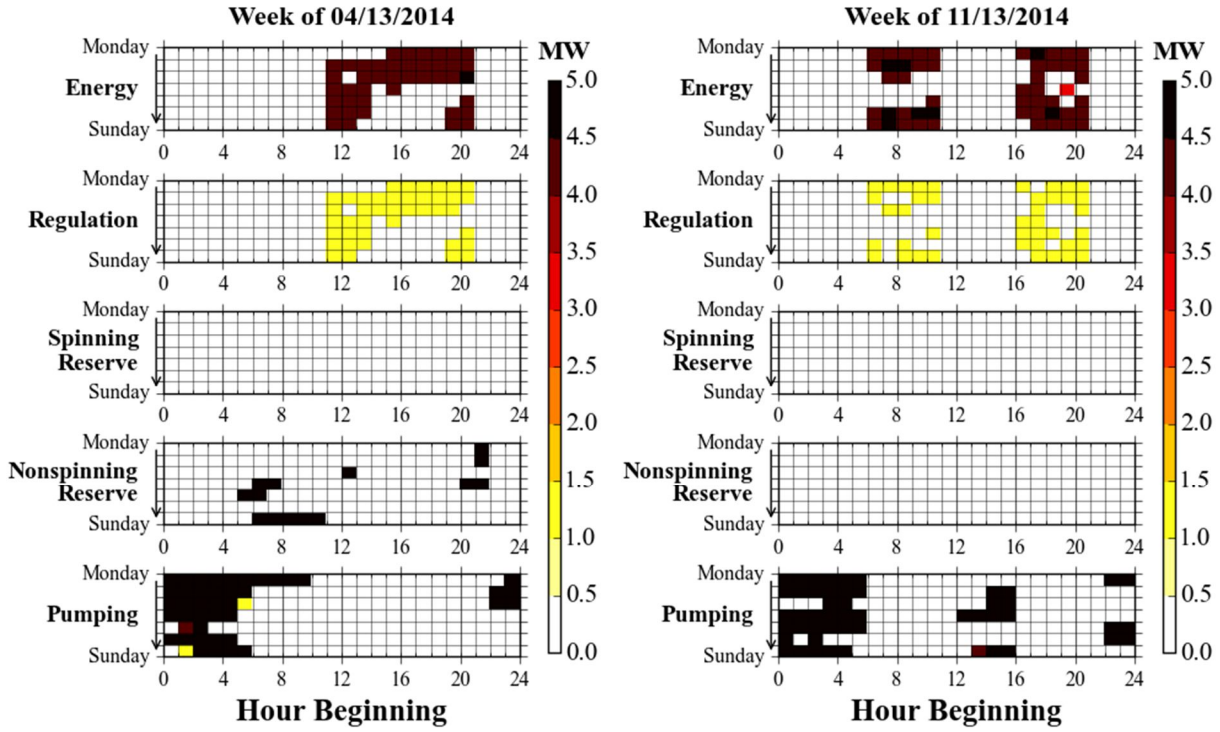

Figure 14. One full week of 2014 DA simulation results for spring/summer (left) and fall/winter (right) with weekly (7 day) optimization assuming a flexible unit with 75% round trip efficiency. The top four grids on each side represent the allocated capacity of the unit towards each market product, while the bottom grid shows pumping capacity. The top row of each block represents Monday, and each successive row is the following day. Columns represent hours of the day, while colors show unit capacity dedicated to each operation.

To examine the tradeoff between efficiency and annual net revenue potential, a variety of cases and strategies were simulated including day ahead and real time optimization, daily and weekly optimization, and energy-only versus energy and ancillary services for both the base and flex units operating in calendar year 2014 and 2013 (Figure 15, Figure 16, and Table 7; Figure 17, Figure 18, and Table 8). In each case, optimization was carried out either daily or weekly for each day or week of the year. Annual revenues (the sum of all daily or weekly revenues for the year) are benchmarked against the minimum and maximum construction cost estimates, represented as dashed lines that correspond to the revenue required to offset project costs and achieve a BCR of 1 (See Eq. 3.13).

Increased capacity bid into ancillary services markets is the primary driver of increased simulated revenue. Base and flex units show revenue increases of 40% to 100% over the energy-only (arbitrage) case. Attractive regulation prices drive the optimization routine towards a balance of energy and regulation, with respective bid quantities dictated by the flexibility of the operating scheme. The flex unit typically bids 3.5MW into the energy market and 2MW into the regulation market, while base unit bids sit at 4MW and 1MW, respectively. By doubling capacity into the regulation market and slightly dropping capacity in the energy market, the flex unit sees an annual revenue increase of 30%-50% over the base unit. Spinning reserve prices were generally not as attractive as regulation prices, and while non-spinning capacity is steadily bid, price points are too low to provide anything but nominal revenues.

The revenue simulations immediately reveal the effect of relatively high and volatile energy and ancillary service prices in 2014. Annual revenue for 2014 is nearly double that of 2013, owing to high market clearing prices in the first quarter when record cold temperatures increased electricity demand and drove up natural gas prices (see Figure 4). In both years the flex unit bidding capacity into the real time market based on a weekly optimization generates the highest revenue. Most generators in the PJM market schedule their bids in the DA, which would presumably be the case for an m-PSH unit, and therefore revenue trends should be expected to follow the DA curves. In this case, a flex unit with 75% roundtrip efficiency (RTE) could expect to earn 2014 annual net revenues of $564,364 ($113/kW). The best case construction cost scenario requires a net revenue baseline of $565,000 ($114/kWh) to produce a BCR greater than 1. If initial project costs totaled $12,000,000, a minimum of $785,000 ($157/kW) in average annual net revenue would be necessary for annual benefits to exceed costs. In no worst case scenario simulations, nor in any 2013 simulation or case, was the net revenue adequate to produce a BCR of 1.

Ancillary service revenue constitutes up to 36% and 61% of total revenue for the base and flex units, respectively. Increased revenue for A/S offerings is generated from the frequency regulation market at the expense of decreased capacity in the energy market (Table 7 and Table 8). The flex unit is able to bear more MWhs of pumping due to the increased range of operation, which opens the door to additional attractive revenue opportunities (Figure 16 and Figure 18). While pumping costs eat away slightly at energy revenues, the difference is more than made up for through the regulation market. Furthermore, regulation has a net zero effect on storage levels in the upper reservoir due to the combined result of following up and down signals over time, and the flex unit is able to bid slightly more than double the annual MWh of the base unit despite only bidding twice the capacity.

Revenue results clearly indicate m-PSH must operate at high efficiency in energy and ancillary service markets at near 100% capacity factor with limited forced outages while anticipating market dynamics with precision. In years with high market prices and high market volatility, an efficient low-cost unit could be fairly profitable. Unfortunately this scenario appears to be the exception, not the norm, and in most simulations the unit is not able to operate profitably. Market prices and simulation results from 2014 are an aberration, and should be viewed with caution. Market prices from 2010 – 2012 mimic those of 2013 and should be expected to persist into the near future. Additional revenue streams are necessary and further cost reductions must be achieved for CS1 to achieve sustained economic viability.

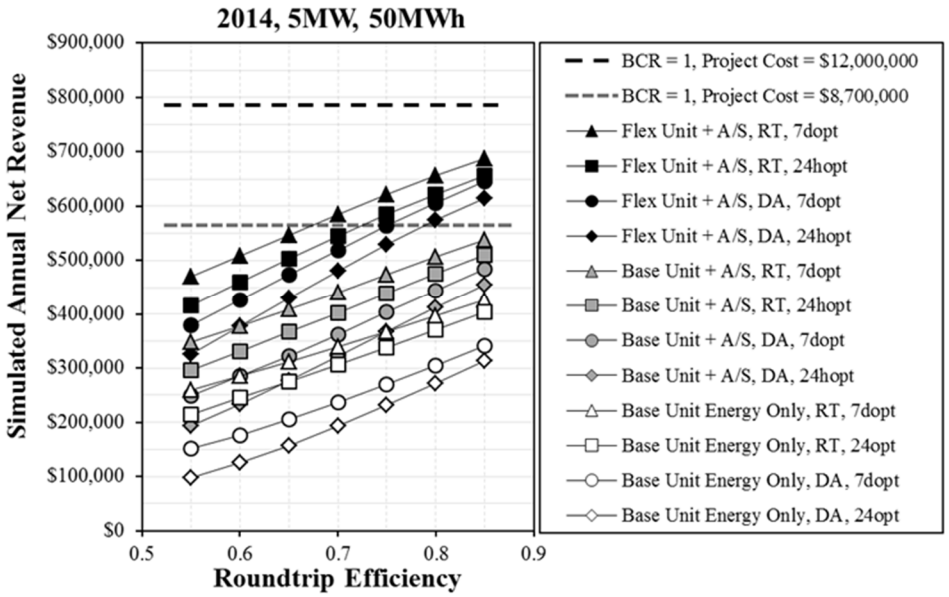

Figure 15. Simulated annual net revenues in PJM for 2014. RT = real time, DA = day ahead, 7dopt = weekly optimization, 24hopt = daily optimization, A/S = ancillary services.

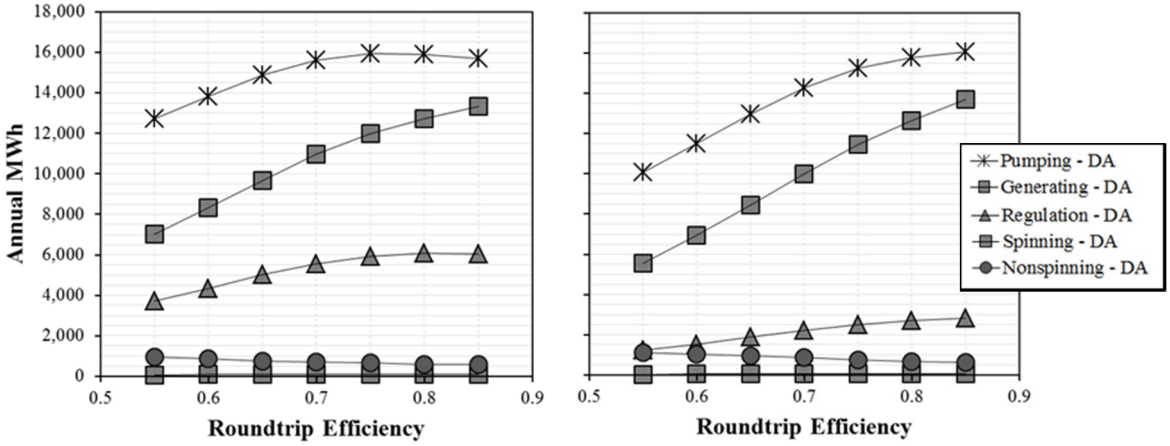

Figure 16. 2014 annual DA generation (MWh) for the flex (left) and base (right) 7dopt units.

Table 7. Simulated revenue for a 7dopt, 75% RTE unit in the 2014 PJM DA market.

	DA Energy	Base Unit DA Energy + A/S	Flex Unit DA Energy + A/S
Gross Energy Revenue	$706,252	$750,566	$764,191
Pumping Cost	$436,712	$514,590	$545,493
Net Energy Revenue	$269,540	$235,976	$218,698
Frequency Regulation Revenue	-	$146,586	$327,459
Spinning Reserves Revenue	-	$809	$1,649
Non-Spinning Reserves Revenue	-	$20,272	$16,558
A/S Revenue	-	$167,667	$345,666
Total Annual Net Revenue	$269,540	$403,643	$564,364
Total Annual Net Revenue $/kW ($/kWh)	$54 ($5.40)	$81 ($8.10)	$113 ($11.3)

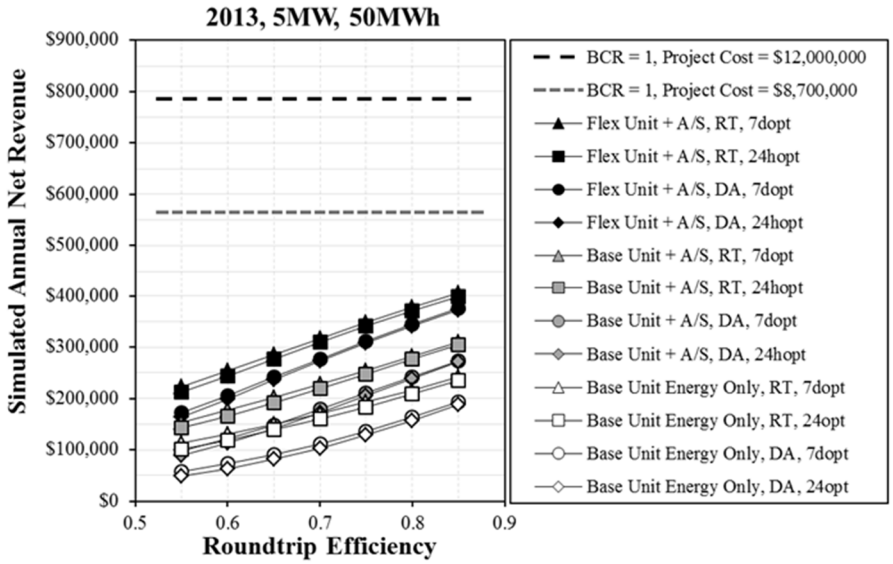

Figure 17. Simulated annual net revenues in the PJM RTO for 2013. RT = real time, DA = day ahead, 7dopt = weekly optimization, 24hopt = daily optimization.

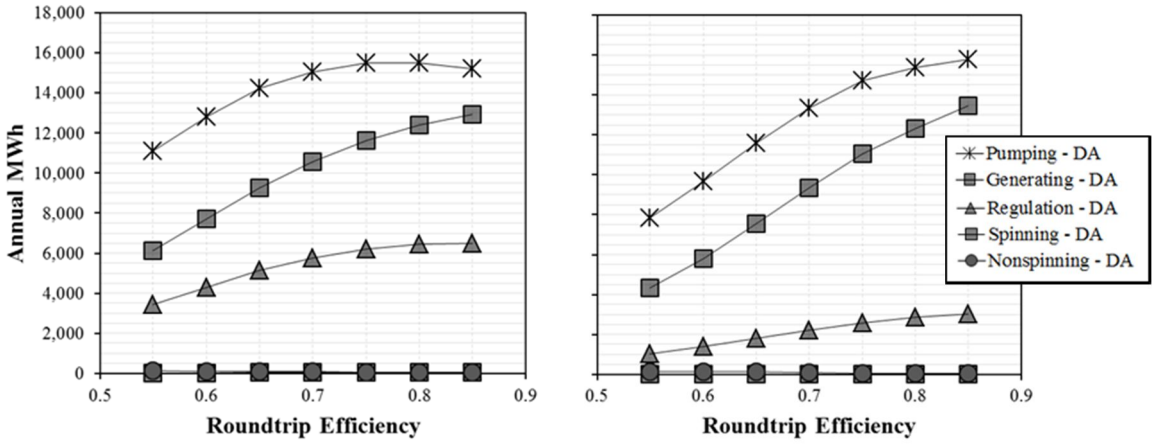

Figure 18. 2013 annual DA generation (MWh) for the flex (left) and base (right) unit.

Table 8. Simulated revenue for a 7dopt, 75% RTE unit in the 2013 PJM DA market.

	DA Energy	Base Unit DA Energy + A/S	Flex Unit DA Energy + A/S
Gross Energy Revenue	$472,808	$529,062	$540,398
Pumping Cost	$336,675	$413,816	$438,408
Net Energy Revenue	$136,133	$115,246	$101,990
Frequency Regulation Revenue	-	$94,866	$209,442
Spinning Reserves Revenue	-	$287	$665
Non-Spinning Reserves Revenue	-	$180	$88
A/S Revenue	-	$95,333	$210,195
Total Annual Net Revenue	$136,133	$210,579	$312,185
Total Annual Net Revenue $/kW ($/kWh)	$27 ($2.77)	$42 ($4.20)	$62 ($6.20)

4.6.1 Economic Indicators

Using the assumptions stated in Section 3.3 and the revenue estimates presented in the previous section, economic analyses were conducted for each combination of price series and turbine type. A cross section of these results is presented in Table 9. The best case assumes the minimum construction cost ($8,700,000) with 10 year replacements costs of 50% of the balance of plant equipment. The worst case assumes the maximum construction cost ($12,000,000) with 10 year replacements costs of 50% of the balance of plant equipment, 25 year replacement costs of 50% of the turbine-generator, and 35 year replacement costs of 50% of the switchyard costs. Results are shown only for 2014, as no scenario in 2013 produced a BCR ratio above 1.

Table 9. Economic indicators for 2014 DA 7dopt simulations.

2014		Annual Net Revenue ($1,000)	BCR		LCOE ($/MWh)		NPV ($1,000)	
			Best Case	Worst Case	Best Case	Worst Case	Best Case	Worst Case
Energy Only	$\eta = 0.70$	236	0.42	0.30	94.02	121.54	Negative	Negative
	$\eta = 0.75$	270	0.47	0.34	81.07	104.06	Negative	Negative
	$\eta = 0.80$	305	0.54	0.39	71.40	91.09	Negative	Negative
Base + A/S	$\eta = 0.70$	363	0.64	0.46	83.07	106.03	Negative	Negative
	$\eta = 0.75$	404	0.71	0.51	74.19	94.24	Negative	Negative
	$\eta = 0.80$	444	0.78	0.57	68.02	86.17	Negative	Negative
Flex + A/S	$\eta = 0.70$	519	0.91	0.66	78.44	99.41	Negative	Negative
	$\eta = 0.75$	564	0.99	0.72	72.24	91.41	Negative	Negative
	$\eta = 0.80$	606	1.07	0.77	67.79	85.83	950	Negative

If similar price patterns to those experienced in 2014 in the PJM market were to prevail over the life of the best case m-PSH unit, its associated BCR would be above 1 only for co-optimized, highly efficient, flexible units. The worst case BCR for this same unit ranged from 0.66 to 0.77, indicating profitability is not pliable with respect to the best case scenario - construction cost overruns or underestimates and significant replacement costs will quickly erode revenue potential. In most cases LCOE is well above $65/MWh which, outside of 2014, is about 50% higher than the average DA clearing price. As a reference, the wholesale cost of providing energy for PJM in 2014 averaged $70.40/MWh across all regions, approximately $54/MWh of which can be attributed to energy and ancillary services payments (PJM, 2015b). Energy and ancillary service bids from within PJM should be expected to meet the average cost requirement or risk being surpassed for lower cost generators. Simulation results indicate that, on average, an m-PSH unit would not be dispatched by a system operator if the m-PSH bid is based on best case cost estimates.

In all arbitrage cases the NPV is negative, reinforcing the conclusion that energy arbitrage alone is not a viable market strategy. Even a co-optimized base unit is not able to achieve a positive NPV in 2014 DA simulations. Only a flexible, co-optimized unit with RTE greater than 75% shows a positive NPV, indicating ancillary services revenue is a necessity for m-PSH viability.

When an m-PSH unit operates solely based on market signals, there are very low prospects for profitability, even in years where energy prices are volatile and higher than average. Additional revenue sources, incentives, discounts, or agreements need to be in place to ensure a steady and sufficient revenue stream.

4.6.2 Locational Marginal Pricing Characteristics

The market prices used in the revenue simulation are load weighted-average PJM market prices, used to provide a high level estimate of how an m-PSH unit could behave in the PJM interconnect. A more appropriate analysis should include the locational marginal price (LMP), a pricing mechanism that reflects local transmission congestion. Electrically upstream of a transmission constraint, generation exceeds load (positive congestion) and negative congestion costs lower LMPs as marginally expensive generators curtail production. The opposite occurs downstream of a constraint, where additional, marginally expensive generation is required to meet load and the congestion cost component is positive. An m-PSH facility may aid in alleviating congestion if it is electrically situated where constraints frequently occur and congestion costs are positive. From a system perspective, m-PSH could store energy when transmission costs are low, and generate when transmission costs are high. Bids from PSH generators are generally more attractive than bids from thermal generators, so m-PSH would reduce system-wide congestion costs if strategically utilized to be used in place of marginally expensive units. If energy is transmitted to the m-PSH during off-peak hours, improved transmission and distribution system utilization would be an additional added benefit.

An LMP analysis for CS1 requires some system specifications. The unit would be located within the East Kentucky Power Cooperative (EKPC), a utility co-op with approximately 3,100MW of generating capacity. EKPC operates three coal-fired stations (1,882MW of installed capacity), one combustion turbine plant (1,032MW of installed capacity), and five landfill gas plants (14.5MW of installed capacity). The balance of capacity comes from hydropower purchased through U.S. Army Corps of Engineers dams[13]. There is currently no wind or solar installed capacity, and no storage capacity within EKPC.

To assist in visualizing the LMP analysis, a geospatial representation of EKPC system boundaries, generators, and a fixed number of bus nodes is shown alongside the average difference between the local LMP and the PJM DA load-weighted average price (Figure 19, left). The LMP is calculated at each node or generator and the proposed m-PSH site is superimposed on the map (Figure 19, right). Nowhere within EKPC is the LMP greater than the PJM clearing price – at all locations, the LMP contains a negative congestion and/or transmission loss component. The largest LMP negative difference is seen near regions of high installed capacity, or near load centers (i.e., cities). In these regions the average LMP is 85%-87.5% of the average PJM DA. Very near the proposed m-PSH site the LMP is 90% of the PJM DA, indicating energy prices are on average less than those used in the revenue simulations.

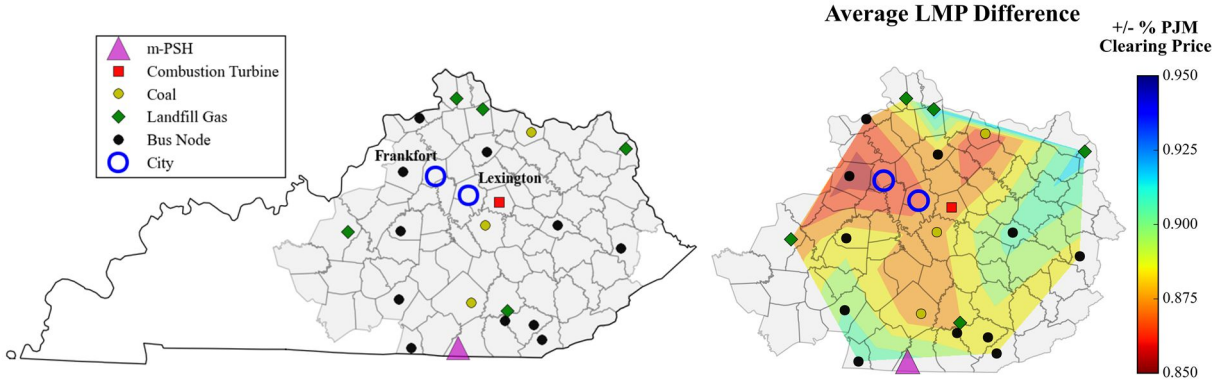

Figure 19. EKPC service region (left) and annual average LMP deviation from the 2014 PJM DA.

13 http://www.ekpc.coop/generation.html. Retrieved on June 19, 2015.

Energy revenues may improve if the off peak LMP is lower than the PJM average, and if the on peak LMP is greater. Energy arbitrage would be more efficient in this case, with gross energy revenue increasing and gross pumping costs decreasing. For summer 2014, the daily average peak LMP was 90%-95% of the PJM clearing price, and the daily average off peak LMP was 100%-105% of the PJM clearing price near the m-PSH location (Figure 20). The LMP trends indicate m-PSH arbitrage opportunities are diminished within EKPC compared to the PJM DA average. The gap between peak and off peak energy prices has been closed due to congestion and transmission loss components.

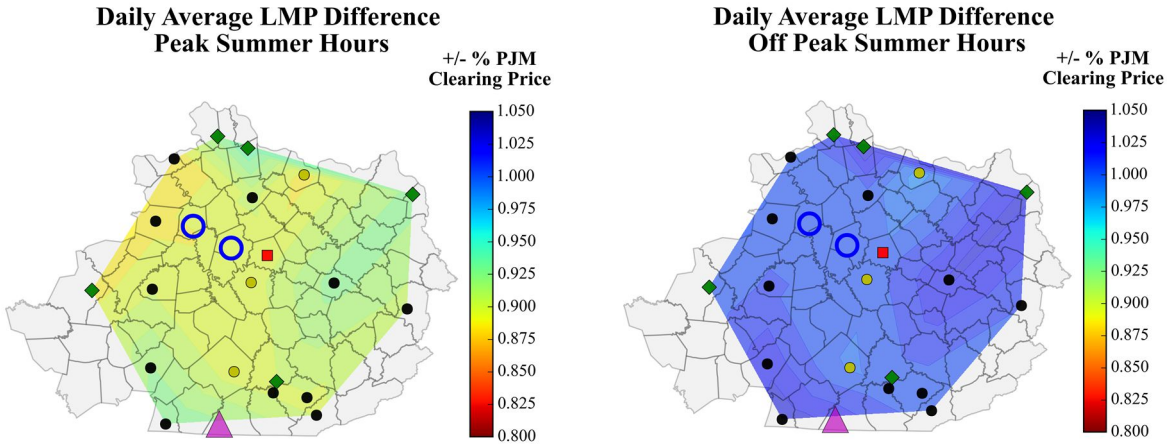

Figure 20. Comparison of Summer 2014 DA peak and off-peak LMP deviation from the 2014 PJM DA. Symbols see Figure 19.

The magnitude of the congestion and transmission loss components shows that congestion is the greater driver of LMP differences (Figure 21). The average congestion component is negative throughout all of EKPC, meaning generation frequently exceeds demand and a negative congestion pricing mechanism is implemented to correct the mix of generation. Near the proposed m-PSH facility, the average congestion loss of $4.30/MWh would put the generating unit upstream of the congestion constraint. While the unit would most likely not get asked to curtail production (bids are assumed more competitive than landfill gas and coal bids), it would suffer from reduced energy credits and in turn reduced revenue potential. The transmission loss component is very near $0/MWh, which means existing generation is not electrically distant from existing load centers. While the overall LMP loss components do not show the need for large-scale energy storage, there may be local or regional factors outside the scope of this study that would drive interest in m-PSH, including isolated load centers and generators with high curtailment costs.

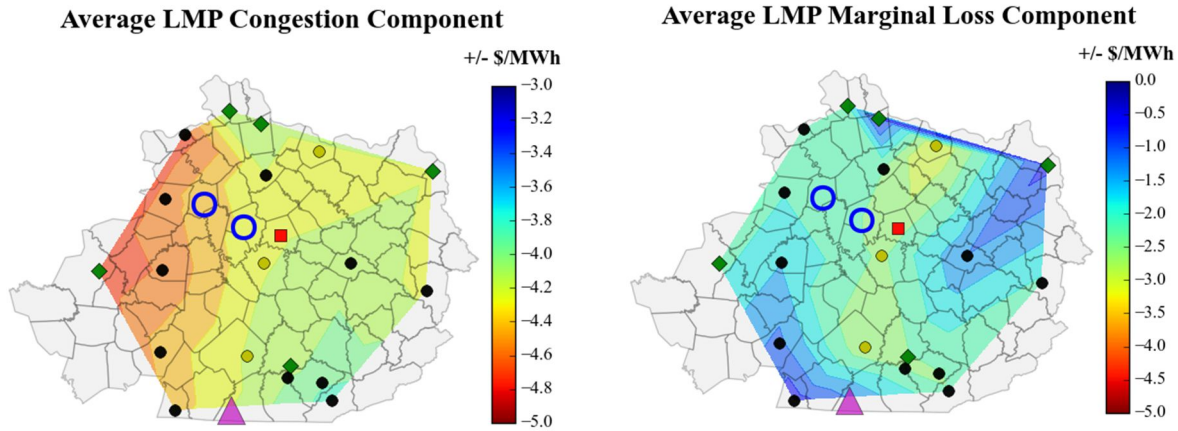

Figure 21. 2014 LMP congestion (left) and transmission loss (right) components. Symbols see Figure 19.

4.6.3 Comparison to Other ISOs

Various ISOs throughout the U.S. maintain competitive markets for energy and ancillary services (Table 10). Assuming the same constraints and limitations apply, the baseline revenue potential of an m-PSH unit operating within a different RTO can be speculated based on hourly market clearing prices.

Table 10. Competitive market products by ISO. Bold/shaded entries are plotted in Figure 22 and Figure 23.

	PJM	NYISO	CAISO	ERCOT
Energy				
Day ahead (DA)	**X**	**X**	**X**	**X**
Real time (RT)	X	X	X	X
Regulation				
Up			**X**	**X**
Down			**X**	**X**
Combined (Up and Down)	**X**	**X**		
Spinning Reserves				
Loaded within 30 minutes		X		
Loaded within 10 minutes	**X**	**X**	**X**	**X**
Non Spinning Reserves				
Loaded within 30 minutes	**X**	X		**X**
Loaded within 10 minutes		**X**	**X**	

*For comparative purposes, regulation prices in markets with separate up and down products were combined (excluding mileage and performance scores) to give a single clearing price.

For a high level comparison with PJM, market clearing prices for DA energy in the NYISO (New York), CAISO (California), and ERCOT (Texas) RTOs were plotted for the 2014 calendar year (Figure 22). Energy prices in PJM and NYISO were consistently higher than in ERCOT and CAISO in Jan-Mar, largely due to record cold temperatures and energy demand. Later in the year, DA prices in CAISO were generally highest, while the other three ISOs tracked closely throughout the day except for the early evening, when ERCOT prices peaked above PJM and NYISO. On pure energy sales alone, operation under the NYISO should produce higher gross energy revenue, especially when extreme temperatures stress the grid. Pumping costs would also be elevated, and m-PSH arbitrage potential would rely on the difference between the highest and lowest average daily clearing prices.

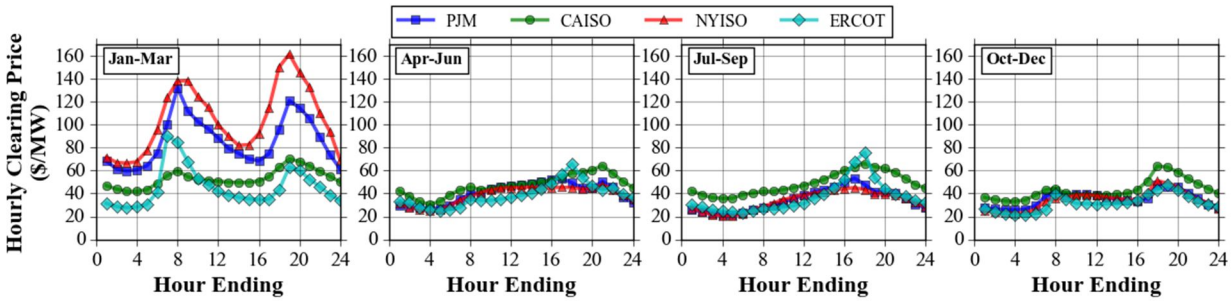

Figure 22. 2014 DA average hourly market clearing price for four ISO regions.

To quantify the expected arbitrage potential, the six minimum average daily DA clearing prices are subtracted from the six maximum average daily DA clearing prices (Table 11), giving an upper limit to revenue that could be achieved under ideal conditions with no restrictions on unit cycling (starts/stops). In severe winter cold, NYISO provides the greatest arbitrage potential, followed by PJM then ERCOT. This difference is not sustained throughout the year, as all three show diminished arbitrage potential from April through December. The expected differential in those months ranges from $10/MWh to $30/MWh. As shown in Table 1, a difference of $20/MWh maintained for 10 hours a day would provide $365,000 in annual energy revenue, and as highlighted in Figure 15, annual revenue of $530,000 is required for CS1 to consistently maintain a BCR of 1. The maximum differentials in ERCOT are consistently high throughout the year, though they quickly diminish, and the average of all differentials does not show significant promise compared to PJM, NYISO. Differentials in CAISO are relatively consistent throughout the year, though not large enough to warrant m-PSH viability. Unless the market trends of Jan-Mar persist throughout the year across the country, m-PSH will not be viable if energy arbitrage is the sole revenue strategy, and additional revenue streams are necessary.

Table 11. Average 2014 DA price differentials ($/MWh).

Season	PJM	NYISO	CAISO	ERCOT
Jan-Mar	72.69	95.19	28.22	65.96
	60.34	83.23	26.18	56.95
	53.32	78.04	21.00	38.08
	50.73	69.24	19.08	32.91
	41.24	66.39	12.92	31.37
	34.48	55.45	10.34	19.82
Apr-Jun	26.18	22.80	33.57	40.61
	25.03	19.95	27.53	30.67
	23.09	19.63	25.44	27.79
	21.51	17.16	20.28	21.19
	20.03	15.90	18.80	18.97
	18.90	13.77	11.81	12.86
Jul-Sep	31.92	24.83	30.43	52.10
	28.33	23.83	27.48	44.13
	25.33	21.75	26.91	29.10
	22.89	20.53	22.79	27.79
	18.79	17.55	20.97	19.28
	15.53	14.49	17.94	17.57
Oct-Dec	21.83	28.54	30.96	26.49
	19.72	26.30	29.38	22.16
	19.27	22.68	24.41	21.04
	15.33	16.71	18.37	17.66
	13.58	14.36	14.14	15.04
	11.32	13.05	10.03	12.21

Ancillary services clearing prices (regulation, spinning, and non-spinning reserves) across ISOs give insight into how co-optimization may take place in different geographies (Figure 23). Regulation prices are consistently highest in PJM, where a co-optimized CS1 unit obtained 30%-60% of revenues from regulation. The unit should not be expected to perform better in other regions, as regulation revenue is dependent solely on regulation pricing magnitude. In all cases and hours, spinning and non-spinning reserve clearing prices are lower than regulation clearing prices, and exhibit comparable daily patterns with the exception of ERCOT. The reliance on intermittent renewables in Texas leads to fluctuations in spinning and non-spinning reserve pricing. Sunshine and wind are frequently intermittent or unavailable in early morning and evening when electrical load increases, driving reserve market prices higher.

Despite these spikes, regulation and DA prices are generally much higher than reserve prices, and an m-PSH unit would be better off bidding capacity into regulation and energy markets. The lack of significant improvements in regulation prices across ISOs indicates a co-optimized m-PSH unit would need additional revenue streams to achieve sustained economic viability.

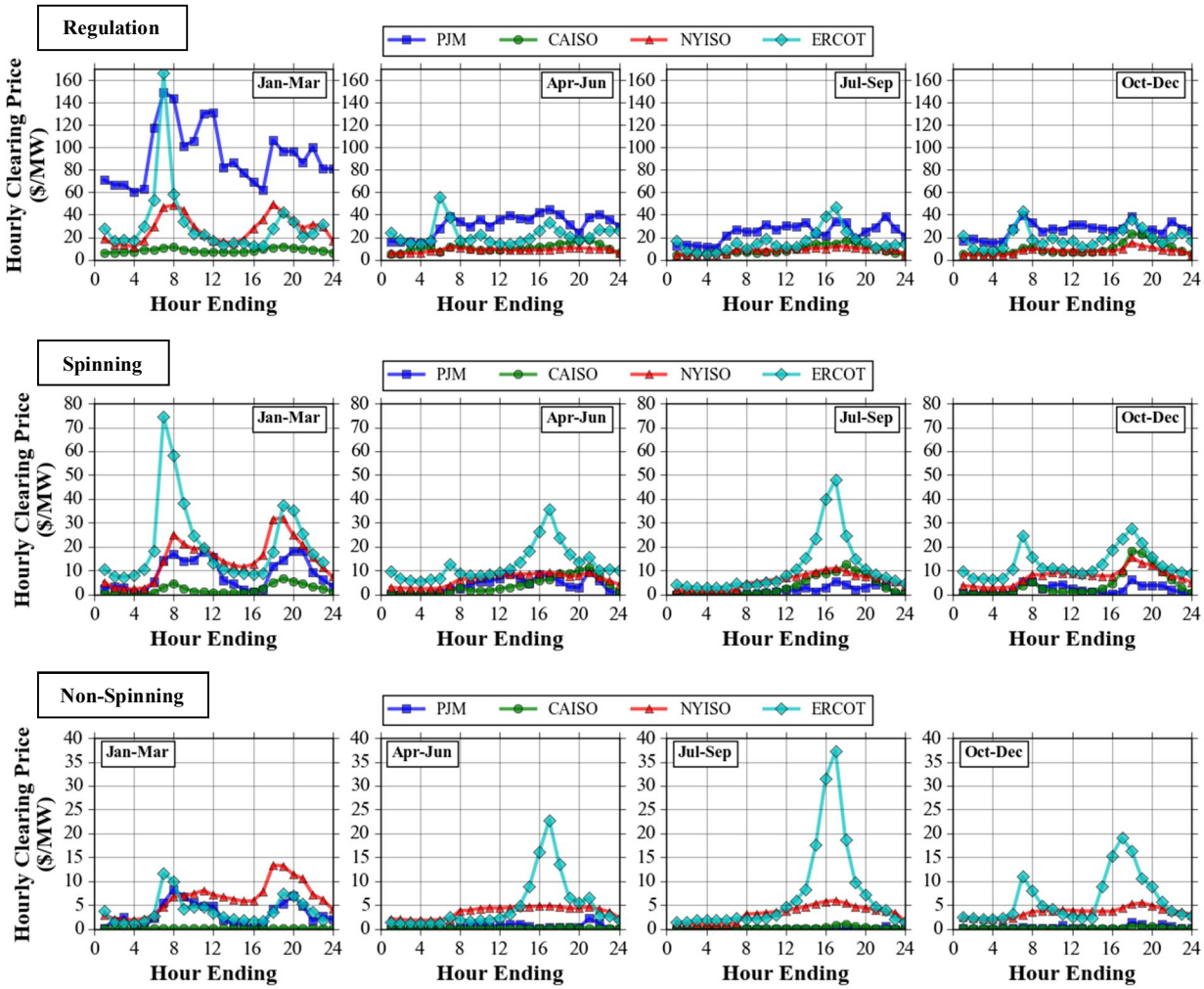

Figure 23. 2014 frequency regulation, spinning reserve, and non-spinning reserve average hourly market clearing price for four ISO regions.

4.6.4 Additional Revenue Streams

Traditionally, large PSH projects may have additional revenue streams from multipurpose use of the reservoir. There is also debate over whether PSH may be undervalued in the role it plays providing national energy security (NHA, 2012), and in providing other functions such as improving optimization of thermal plants and quick ramp rate capabilities (IWPDC, 2013). For m-PSH, reservoirs are not expected to be large enough to warrant substantial multipurpose use, revenue potential from additional water use and energy security may be limited, and "portfolio effects" achieved by integration with thermal units may not be significant based on anticipated m-PSH installed capacity.

Though the capabilities and estimated costs of m-PSH are comparable with many utility-scale battery installations (Figure 13), the latter are seeing rapid uptake throughout the country and world. The U.S.

market for battery storage is being driven largely by utilities in states with aggressive Renewable Portfolio Standards (RPS), including California, New York, and Texas, who together committed to develop more than 6GW of energy storage by 2020. A growing number of battery systems with installed capacity of approximately 5MW-10MW are being constructed to support large wind farms (Akhil et al., 2013), enabling better integration of wind capacity and increased eligibility for production tax credits (PTCs). A wind farm owner may see a two-fold or more increase in revenues over a pure energy arbitrage case when battery storage is integrated to improve dispatchability and avoid curtailment (Tewari & Mohan, 2013). Considering PSH technology is at present consistently utilized for fast-response grid stability applications, the ability of m-PSH to integrate with wind and provide a similar service is appealing. The significant disadvantage of m-PSH is that favorable topography is necessary, while battery installations, with significantly more compact footprints and higher energy densities, can be sited in nearly any location. In the case of CS1, there is no wind capacity in the area, and thus no potential for wind integration. Kentucky is one of a handful of states with no RPS, and according to PJM there is no wind or solar installed capacity in the state (Monitoring Analytics, 2014). Further analysis and scoping is necessary to determine if and where m-PSH may compliment the integration of wind capacity.

Many RTOs are aware that energy and ancillary service markets alone do not provide sufficient compensation to incentivize investments in generation resources (PJM, 2009). A new capacity performance product was introduced by PJM in late 2014 that attempts to fulfill generators cost requirements and "make them whole" when they reliably supply generation as expected. Generators must commit capacity three years in advance through a base residual auction, a mechanism designed to satisfy future capacity obligations. The most recent capacity auction[14] for 2018 set a preliminary zonal capacity price for EKPC at $162.44/MW-day. A 5MW m-PSH unit bidding full capability into the capacity market could receive $296,453 in the capacity auction, roughly 50% of best case annual energy revenues, to be distributed throughout 2018. During the delivery year, an additional capacity settlement will take place based on actual unit performance during emergency conditions, as determined by PJM. Generators that cannot meet their proposed electricity obligations will be assessed a penalty that, for 2018, is set at $2,420/MWh. High performing units will be compensated with the penalty payments from under-performing resources, and based on market data from 2014 (Paulos, 2014), some generators would have received capacity performance payments of over $4,000/MWh (nearly 100 times the average PJM market clearing price). Storage resources that wish to offer their generation as a capacity performance product must be available for continuous operation for more than 10 hours during peak load for multiple consecutive days, and they will be required to follow dispatch orders from the PJM operator (PJM, 2014). A detailed, site specific analysis would be necessary for an m-PSH owner to determine if capacity performance is a viable market strategy, and if so, how much capacity would be appropriate to allocate towards the product. The operational strategy would also need to be adjusted to ensure adequate storage is always available to meet capacity obligations during emergency conditions and forego penalties. For CS1, the capacity market appears to provide the highest potential for additional revenue. However, the revenue simulation results from 2013 demonstrate that in years with low energy price volatility, the addition of best case capacity payments would not be sufficient to achieve economic feasibility under the best case project cost scenario.

In addition to frequency regulation and spinning reserves an m-PSH unit could provide voltage control by regulating the supply and demand of reactive power through production or absorption of Volt-Ampere-Reactives (vars). In this case, the unit would need automatic voltage regulator equipment, and would need to pass a performance test to be considered eligible to provide voltage control (Hadjerioua et al., 2011). According to the PJM Interconnection Agreement, generators capable of providing reactive power

14 http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2018-2019-base-residual-auction-results-xls.ashx

must do so, and compensation is provided on a cost basis as approved by FERC (PJM, 2009). To assess the cost of voltage regulation, a detailed analysis would be necessary to quantify how voltage control may impact unit availability for energy generation and how revenue streams could offset the efficiency losses incurred when operating at a power factor less than unity. Some generators providing reactive power in PJM state that voltage control operations are generally carried out less than 100 hours per year (Bloom, 2014), making the provision of this service an attractive revenue stream compared to unit commitment. Within PJM, voltage control revenue requirements[15] can range from $600/MW-yr to $4500/MW-yr based on installed capacity and apparent power rating (Hadjerioua et al., 2011; Bloom, 2014). Based on these estimates, a 5MW m-PSH unit could earn an upper limit of $25,000/yr for this service (roughly 5% of best case annual net revenues), an amount that does not significantly impact the economic indicators. Within all of PJM, voltage control net revenues make up one to five percent of net revenues for most generators (PJM, 2009). When an m-PSH unit is located geographically close to a load center, voltage regulation may provide additional, significant value that could be quantified in a site specific analysis.

Traditional PSH also provides black-start service, a capability offered by units able to restore power after blackouts without the need of external electricity. Generally a unit must demonstrate the ability to self-start within a given time frame when automatically disconnected from the grid, and they must make a multi-year commitment to be eligible for black start service compensation. Many RTOs reimburse black-start service on a cost-basis, only covering annual capital and O&M costs related to providing the service (Hadjerioua et al., 2011). It is assumed that black-start capability is called on less frequently than voltage regulations, and that revenue potential would also be diminished. In PJM in 2015, for example, system-wide annual voltage regulation revenue requirements[16] total $274 million while black start revenue requirements[17] are $45 million. The mix of m-PSH black-start and voltage regulation revenues may be highly location and equipment specific, though in a competitive market, compensation for these services does not appear sufficient to improve economic feasibility.

Additional revenue could be achieved by exploiting the versatility of advanced turbomachinery, such as adjustable speed turbines and pumps. In this case, the unit could offer curtailable load for demand response and frequency regulation in both pumping and generation mode. There are currently variable frequency drives in service on smaller pumps, and their implementation within an m-PSH configuration could serve as the base for future adaptations. The incremental costs of adding adjustable speed technology range from 50% to 125% of single-speed equipment (MWH, 2009), and the equipment generally requires more volume and excavation costs. There are currently no adjustable speed PSH units in the U.S., and dedicated R&D on m-PSH-scale units would be required before this technology would be readily available. For these reasons revenue streams from adjustable speed units were not considered in this study.

Energy storage used to defer new transmission and distribution infrastructure projects may provide sufficient benefits to justify costs. Several battery installations in the U.S. have been strategically developed to defer costs and provide capacity relief while new generation is under construction (Doughty et al., 2010). The potential long lead times for m-PSH may be a hindrance to this revenue stream, and siting near locations with favorable elevation would be necessary. For CS1, a high level analysis of EKPC transmission congestion shows that transmission capacity is sufficient to cover existing load (Figure 21), though a more detailed analysis may reveal site-specific needs for additional storage capacity to defer infrastructure investments.

15 Annual reactive revenue requirements for all PJM generators can be found at: http://www.pjm.com/markets-and-operations/billing-settlements-and-credit.aspx
16 http://www.pjm.com/~/media/markets-ops/settlements/reactive-revenue-requirements-table-august-2015.ashx
17 http://www.rtoinsider.com/black-start-generators-1402/

Recently, a project in the Czech Republic was able to overcome m-PSH development barriers and convert an old coal mine into a small PSH facility with approximately 1MW of installed capacity (Ministry of Industry and Trade, 2015). The project uses a remote controlled Pelton turbine and control system situated approximately 500m underground. Of the $3.3 million in reported project costs, nearly 66% consisted of a government subsidy, an indication of how energy storage is currently valued internationally. In fact, a recent review of large energy storage plants in several European countries concluded that none of the existing energy storage plants are economically sustainable without government subsidies (Locatelli, Palerma, & Mancini, 2015). Nevertheless, the recent coal mine installation was able to overcome technological, environmental, and regulatory obstacles, demonstrating a pathway to m-PSH project viability.

4.7 CS1 CONCLUSIONS

This case study presents a detailed analysis of a potential m-PSH installation at a coal mine in Kentucky. Based on cost estimates and simulated revenue streams, an initial determination on economic viability can be summarized as follows: a low cost m-PSH unit with round trip efficiency greater than 75%, co-optimized for energy and ancillary services operation, will be profitable in years with high volatility and relatively high energy prices. Sensitivity to cost underestimates and construction overruns is significant, as the high cost estimate project did not exhibit economic feasibility under any market condition.

The lessons learned from CS1 can be distilled into the following guidance for future research activities:

- Existing transmission, storage, and conveyance infrastructure must be in place for m-PSH initial capital costs to be competitive with alternative energy storage technologies;
- Under these conditions, m-PSH shows cost competitiveness with utility-scale battery installations. Additional cost data on geotechnical engineering, regulatory, and environmental analyses are necessary for a full value comparison;
- Economic feasibility, at a minimum, requires co-optimization of energy and ancillary services. Energy arbitrage alone does not provide a sufficient revenue stream for sustainable operation;
- Participation in a market with distinct ancillary service products must be part of any revenue generation strategy;
- Frequency regulation offers the highest potential for ancillary services revenue. In this case, the m-PSH unit must be able to operate efficiently at partial load. The provision of black start and voltage control services would not generate sufficient revenue to produce favorable economic indicators;
- Participation in a market with capacity performance payments has the potential to improve project viability, though additional detailed analyses are necessary to determine the appropriate operational strategies to accommodate capacity product requirements;
- Environmental factors (such as very cold or hot periods, climate change, etc.) and political events (such as wars or other political strife) stress the power markets and result in higher energy and benefit pricing. Even though these events are not predictable, m-PSH could play a valuable role in smoothing market volatility if the frequency of these events increases;
- Non-traditional revenue streams should be explored. Economic feasibility is generally not achievable for a merchant unit relying solely on market price movements.
- No equipment manufacturer currently produces reversible pump-turbine units on a 5MW scale. New technology developments in this area may reduce equipment costs.
- Regulatory acceptance of m-PSH is untested, with no clear pathway for pumped-storage to receive a FERC license exemption. Early adapters to m-PSH may experience additional and unforeseen regulatory hurdles.

5. CASE STUDY #2: OAK RIDGE NATIONAL LAB CAMPUS

5.1 INTRODUCTION

Oak Ridge National Lab (ORNL) is the largest science and energy laboratory under the auspices of the U.S. Department of Energy. As a leader in energy research, ORNL operates a number of high-demand experimental and computational systems that require a reliable, flexible, and substantial source of electricity. The continuous operation of high-energy systems contributes to a fluctuating monthly electrical load, subject to seasonal variability in electricity costs.

ORNL is situated adjacent to Melton Hill Lake, a 5,470 acre lake impounded by the Melton Hill Dam, a hydroelectric dam and lock operated by the Tennessee Valley Authority (TVA). The proximity to this substantial volume of water and the rolling topographical characteristics of the ORNL campus have been identified as two favorable conditions for a potential pumped storage facility. A pumped storage facility providing electricity to ORNL could offset some of the variability in electrical load by releasing water to generate electricity during on-peak hours when demand and costs are high and pumping water during off-peak hours when demand and cost are low. By shaving peak demand, monthly electricity costs may be reduced and the variability in electrical load smoothed. A pumped storage facility could also provide valuable research opportunities as a test bed for efficiency improvements, electro-mechanical equipment optimization, and environmental impact mitigation studies.

In 2010, HDR Engineering, Inc. (HDR) completed a reconnaissance study on the viability of constructing small (5MW – 10MW) pumped storage facilities at several locations on the ORNL campus (HDR Engineering Inc., 2011). The open-loop pumped storage facility would utilize a large tank as an upper storage reservoir, and Melton Hill Lake as a lower reservoir. Their assessment included a rough cost estimate, which identified attractive pumped storage schemes based on the geological and physical characteristics of an upper reservoir and probable water conveyance schemes. A total of 14 sites were evaluated, two sites with upper reservoirs impounded by earthen dams and twelve with storage tanks for an upper reservoir. The bulk of project construction costs were estimated based on 1988 component prices from EPRI Document No. GS-6669 (1990), indexed to 2010 dollars using a combination of engineering cost indices and professional judgement. While this method provides best-guess estimates for component costs, it does not reflect the cost savings inherent to a modular design. The method also relies heavily on the choice of an indexing factor, which is subject to a wide range of uncertainty.

The goal of Case Study 2 (CS2) is to revise the ORNL campus m-PSH feasibility analysis based on modular component and civil works cost estimates from CS1. This approach will give an improved outlook on m-PSH feasibility on the ORNL campus, as manufacturer and consultant expertise regarding m-PSH components and structures will be utilized in place of dated cost estimating tools. The updated costs will be contrasted against historical electrical load data obtained from ORNL facility personnel and real-time TVA energy prices to evaluate two m-PSH applications: energy sales via arbitrage and peak shaving. A discussion of ancillary services and utility contracts will provide direction for future efforts.

5.2 UPDATING THE ORNL M-PSH CAPITAL COST ASSESSMENT

While the construction, civil, regulatory, and environmental costs inherent to a large water infrastructure project are generally site-specific, electro-mechanical equipment is designed to operate under a given set of hydraulic conditions, and it is feasible to apply equipment cost estimates across similar project schemes. The focus of this section will be on the penstock, turbine/generator, pump/motor, and balance of plant equipment costs. The remaining component costs will be left as originally estimated.

A detrimental lack of data on small-scale (<5MW) pumped storage and hydro projects plagues many feasibility assessments (O'Connor et al., 2015; Zhang et al., 2012). This fact is evident in the cost estimating technique used by HDR (2011) to evaluate the feasibility of PSH on the ORNL campus. To improve upon this approach, equipment costs from the report are updated using estimates from CS1.

To establish a baseline of project comparison, relevant hydraulic and project parameters are outlined in Table 12, and the general project schematic is shown in Figure 24. The cost update focuses on four proposed ORNL sites: T1, T6, T7, and T12 (Figure 25), referred to as 'tank sites'. These sites are chosen to represent a combination of head and penstock characteristics similar to CS1. While the construction, civil, regulatory, and environmental costs inherent to a large water infrastructure project are usually site-specific, electro-mechanical equipment is designed to operate under a given set of hydraulic conditions, and it is feasible to apply equipment cost estimates across similar project schemes. Both CS1 and the tank sites use a rough order of magnitude cost estimate subject to similar assumptions, and that order of magnitude should reflect the current best estimates for project components.

Table 12. Comparison of m-PSH project specifications.

Project Specifications	Installed Capacity (MW)	Estimated Energy Storage (MWh)	Approximate Static Head (ft)	Discharge (cfs)	Penstock Diameter (ft)	Penstock Length (ft)
T1	5	25	475	144	3	1,600
T6	5	25	280	245	4	1,480
T7	5	25	290	237	4	2,390
T12	5	25	380	181	4	1,164
CS1	5	25	492	141	4	1,700

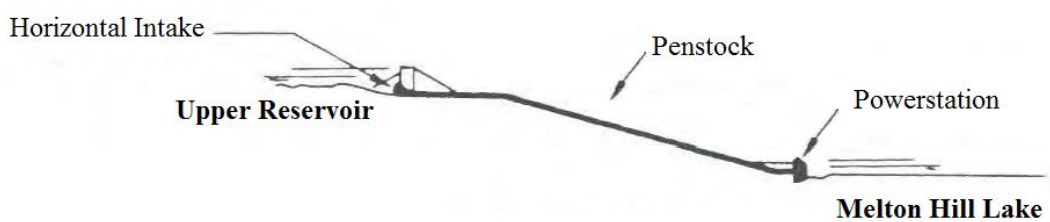

Figure 24. Project schematic for T1, T6, T7, and T12.

5.2.1 Penstock Costs

The water conveyance system for all tank sites includes a steel penstock, sized using a maximum flow velocity of 18 ft/s and a design discharge chosen to maximize power based on head at each location. All penstocks were assumed to remain above ground. Costs were estimated using a 1988 unit cost of $900/ft, escalated to 2010 dollars using a multiplier of 2.5. The design for CS1 includes a spiral-welded steel penstock varying in thickness from 3/8 to 1/2 inch. A pre-concept civil cost estimate obtained from an engineering consultant priced this penstock at $6,000/ton, with an estimated 200-300 tons required to construct 1,700 ft of penstock. This estimate includes penstock bifurcation, installation, and supports, while the tank sites costs reflect only the component costs.

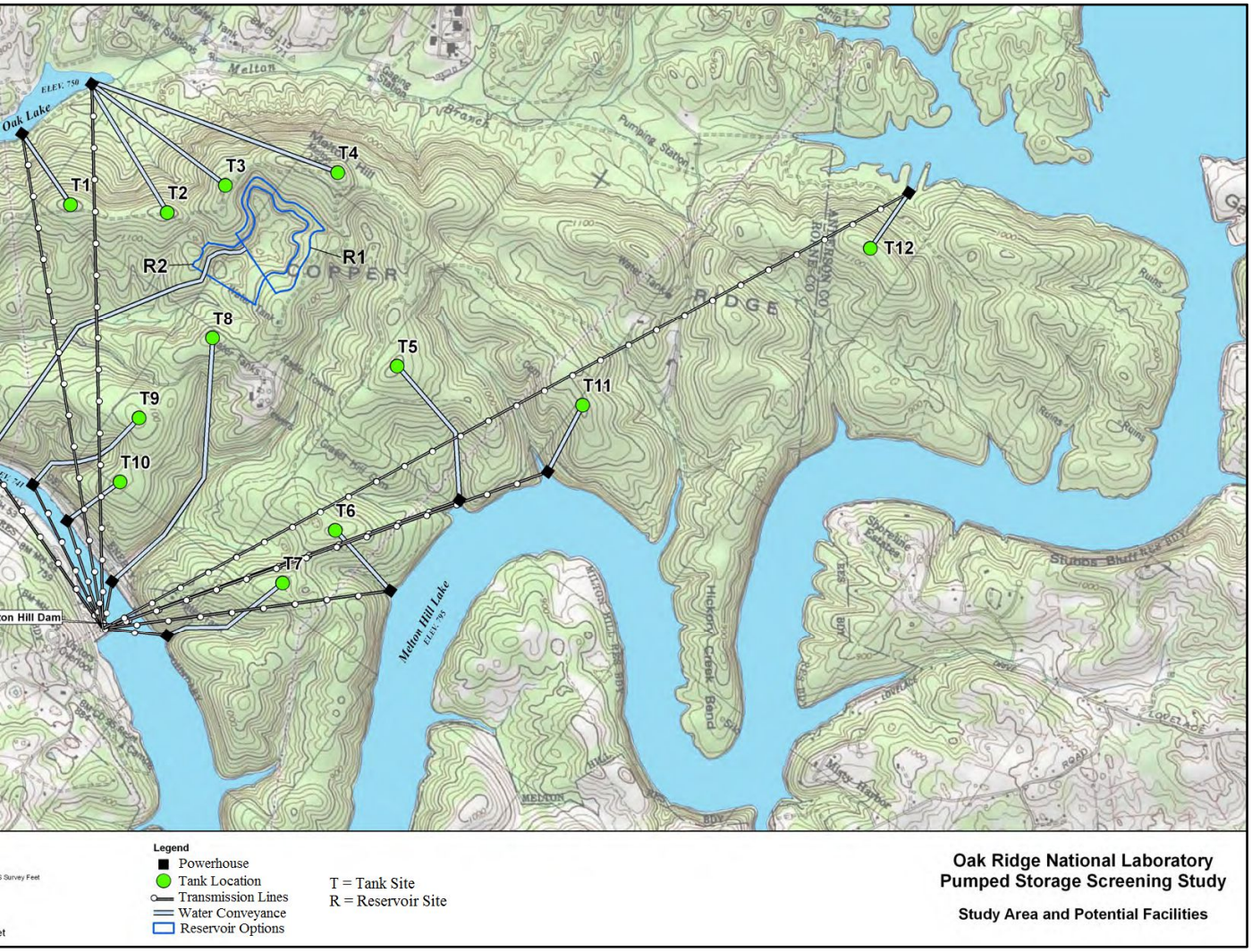

Figure 25. Study area and potential m-PSH sites on ORNL campus (HDR Engineering Inc., 2011)

To reconcile the difference between component costs, the estimation method from CS1 is applied to the tank sites (Table 13). A modern, 4 ft diameter steel penstock (including installation and supports) is sized at 250 tons / 1,700 ft = 0.15 tons/ft and priced at $6,000 per ton. This estimate reduces the penstock costs for all tank sites by approximately 60%, a sizable decrease.

Table 13. Cost of penstock calculated using m-PSH estimated from CS1.

Project	Original Penstock Cost ($)	Penstock Length (ft)	Weight of Steel Required (0.15 tons/ft) (tons)	Cost per ton ($/ton)	Updated Penstock Cost ($)
T1	3,596,000	1,600	240	6,000	1,440,000
T6	3,338,000	1,480	222	6,000	1,332,000
T7	5,366,000	2,390	356	6,000	2,136,000
T12	2,819,000	1,164	175	6,000	1,050,000
CS1	1,500,000	1,700	250	6,000	-

5.2.2 Electro-mechanical Equipment Costs

Both CS1 and the tank sites assumed the power station contained a single-speed, conventional 5MW Francis turbine and generator unit, and a separate pump/motor unit. Runners were sized based on head and anticipated discharge. All powerstation equipment costs for tank sites were estimated using a 1988 cost multiplied by an index factor of 3.0. For CS1, the schematic in Figure 11 was submitted to equipment manufacturers, and they provided powerstation equipment costs, including engineering, project management, transportation, and start-up/testing costs. The costs in this section are taken as the average of Manufacturer 1, 2, and 5 estimates (see Table 4), as they include the greatest overlap with CS2 equipment specifications.

Because rough order of magnitude estimates were obtained for each project, and the configurations are physically similar (including a draft tube for both projects), a direct comparison and update of component costs is carried out (Table 14). It is assumed that the civil costs and engineering approach applied in CS1 are on par with those of CS2. The biggest cost difference is seen in turbine, plant balance, and installation categories. The CS1 turbine cost reflects a modular design, and gives the biggest cost savings. Equipment installation for CS1 includes manufacturer delivery and installation as well as two modules designed to support the turbine and pump units, respectively. In total, major equipment costs for CS1 are approximately 70% less than those of all tank sites.

Table 14. Cost of electro-mechanical equipment.

Project	Turbine-Generator and Controls ($)	Pump-Motor ($)	Electro-Mechanical Balance of Plant Equipment ($)	Equipment Installation ($)	Total Equipment Cost ($)	Updated Equipment Cost ($)
T1	5,156,228	2,550,000	1,760,000	2,839,868	12,300,000	6,414,725
T6	7,007,708	2,160,000	1,760,000	3,278,312	14,200,000	6,414,725
T7	6,924,147	2,180,000	1,760,000	3,259,244	14,100,000	6,414,725
T12	5,798,896	2,360,000	1,760,000	2,975,669	12,900,000	6,414,725
CS1	2,093,750†	2,020,975‡	700,000*	1,600,000**	6,414,725	-

† Includes average of turbine-generator unit and valves
‡ Includes average of pump-motor unit and auxiliaries
* See Table 15
** Includes modules to support the turbine and pump units

The CS1 proposal accounts for different electro-mechanical plant balance components than the tank sites, as shown in Table 15. When the precise schematic of the turbine design is unknown, a best guess estimate of the necessary components is put forth, and several components may be left unidentified. It is assumed the plant balance for CS1 covers all necessary components for a 5MW turbine at all tank sites. For simplicity, this cost, $700,000, is added to the total equipment cost for CS1 to arrive at an updated equipment cost for all tank sites of $6,414,725. Additional substation costs may be required, and these are accounted for as contingencies and indirect csots.

Table 15. Components identified in the balance of plant equipment.

CS1	Tank sites
Valves	Main transformers
Unit auxiliaries	Control and communications equipment
Unit governor	Starting equipment
Controls	Main leads
Protection system	Breakers
Switchgear	Switches
Interconnecting wiring	Current limiting reactors
Interconnecting piping	HVAC
Cooling water systems	Cooling water
Bearing oil systems	Drainage
Step-up transformers	Compressed air system
	Other small miscellaneous items

An additional driver in the CS1 cost estimate is the assumed engineering cost savings from providing sole source “water-to-wire” installation of modular or standardized units. It is difficult to assess the extent to which this a drives prices down. The goal of modular design is to reduce costs associated with custom engineered equipment, a fact reflected in the equipment manufacturers pricing, which maintains an adequate amount of headroom for basic engineering design and equipment testing. These savings are assumed available for the ORNL m-PSH project, and reflected in the cost update.

5.2.3 Switchyard

The tank sites assumed a conventional outdoor switchyard with connections appropriate for a 138 kV transmission line. The 1988 cost of $1,000,000 was given an index factor of 2.7 for a total switchyard cost of $2,700,000. The CS1 project assumes that, based on electrical loads, a pole mounted transformer with a disconnect switch on the feeder could be installed within an existing powerhouse substation such that civil works costs would only include new foundations for the new switchgear and transformers. The switchyard civil costs for the tank sites are updated using the CS1 estimate provided by engineering consultants, $300,000, as the tank sites are similar in capacity to CS1, and it is assumed that modular powerhouse and substation infrastructure could be installed at CS2 in a similar fashion. Additional substation equipment costs are considered in contingencies and indirect costs estimates.

5.2.4 Powerhouse

A shoreline powerhouse is assumed for all tank sites, with civil works costs estimated assuming a 3 ft runner diameter, a 1988 unit cost of $400,000, and an index factor of 4.0, giving a total cost of $1,600,000. The powerhouse for CS1 assumes the building and foundations could be prefabricated offsite, resulting in substantial cost savings. The powerhouse for all tank site options is updated to the CS1 estimate of $425,000.

5.2.5 Other Costs

Two additional cost components are updated:

1. A surge chamber is used to dissipate transient pressures in the water conveyance system when sudden gate movement or unforeseen load rejections result in excess pressures. To determine the size and necessity of a surge chamber, the transient high and low are evaluated along the hydraulic grade lines for generation and pumping. Without a detailed transient analysis, it is unclear if a surge facility is needed. HDR (2011) assumed a surge chamber is necessary and estimated surge chamber costs at approximately 30% of water conveyance costs. This methodology is preserved, and the reduction in penstock costs results in a congruent reduction in surge chamber cost.
2. Contingency costs are reduced from 25% to 12.5% to reflect the improved nature of cost determination. Indirect costs are left at 25% of project costs, and remain a significant cost item. Indirect costs may include engineering, regulatory, and environmental reports and analysis, cost escalation, and for CS2, unaccounted for equipment, civil works, and substation costs.

5.2.6 Total Updated Project Costs

The unit costs for modular components are used to update project construction costs across all tank sites (Table 16). In all cases, total construction cost is reduced from the reconnaissance study by approximately 50% to the $20 million range ($4,000/kW). The biggest savings, after updating component costs and accounting for modularization, are seen in the penstock, equipment, and switchyard costs. A comparison of project costs from the ORNL PSH and m-PSH designs is shown in Figure 26. The upper reservoir for the ORNL m-PSH unit is a substantial percentage of overall project costs, reflecting the additional funding necessary when existing civil works infrastructure is not in place. The overall updated cost distribution is 24% civil works, 16% reservoir, 29% equipment and installation, 1% switchyard, 3% transmission lines, and 27% indirect costs and contingencies. This mix is more dependent on reservoir and indirect costs and contingencies compared to CS1 (See Table 6). The reduction in overall updated project costs has the added benefit that the magnitude of contingencies and indirect costs also decline.

Table 16. Cost comparison of previous ORNL campus design (left) and m-PSH design updates (right, updated line items in bold).

Project Costs - Previous				
Item	**T1**	**T6**	**T7**	**T12**
Upper Reservoir				
Storage Tank	2,540,000	4,310,000	4,160,000	3,176,000
Civil Works				
Powerhouse	1,600,000	1,600,000	1,600,000	1,600,000
Upper Reservoir Intake	200,000	200,000	200,000	200,000
Penstock	3,596,000	3,338,000	5,366,000	2,819,000
Surge Chamber	1,078,800	1,001,400	1,609,800	845,700
Site Roads	1,620,000	1,620,000	1,620,000	1,620,000
Misc. Civil Works	1,000,000	1,000,000	1,000,000	1,000,000
Civil Works Total	9,094,800	8,759,400	11,395,800	8,084,700
Power Plant Equipment				
5MW Turbine-Generator	5,156,228	7,007,708	6,924,147	5,798,896
5.8MVA Pump-Motor	2,550,000	2,160,000	2,180,000	2,360,000
Balance of Plant	1,760,000	1,760,000	1,760,000	1,760,000
Equipment Installation	2,839,868	3,278,312	3,259,244	2,975,669
Equipment Total	12,306,096	14,206,020	14,123,391	12,894,565
Switchyard	2,700,000	2,700,000	2,700,000	2,700,000
Transmission Lines	597,000	343,000	100,000	1,085,000
Subtotal Direct Costs	27,237,896	30,318,420	32,479,191	27,940,265
Contingency (25%)	6,809,474	7,579,605	8,119,798	6,985,066
Indirect Costs (25%)	6,809,474	7,579,605	8,119,798	6,985,066
Total Construction Costs	40,856,844	45,477,630	48,718,787	41,910,398

Project Costs - Updated				
Item	**T1**	**T6**	**T7**	**T12**
Upper Reservoir				
Storage Tank	2,540,000	4,310,000	4,160,000	3,176,000
Civil Works				
Powerhouse	**425,000**	**425,000**	**425,000**	**425,000**
Upper Reservoir Intake	200,000	200,000	200,000	200,000
Penstock	**1,440,000**	**1,332,000**	**2,136,000**	**1,050,000**
Surge Chamber	**432,000**	**399,600**	**640,800**	**315,000**
Site Roads	1,620,000	1,620,000	1,620,000	1,620,000
Misc. Civil Works	1,000,000	1,000,000	1,000,000	1,000,000
Civil Works Total	**5,117,000**	**4,976,600**	**6,021,800**	**4,610,000**
Power Plant Equipment				
5MW Turbine-Generator	2,093,750	2,093,750	2,093,750	2,093,750
5.8MVA Pump-Motor	2,020,975	2,020,975	2,020,975	2,020,975
Balance of Plant	700,000	700,000	700,000	700,000
Equipment Installation	1,600,000	1,600,000	1,600,000	1,600,000
Equipment Total	**6,414,725**	**6,414,725**	**6,414,725**	**6,414,725**
Switchyard	**300,000**	**300,000**	**300,000**	**300,000**
Transmission Lines	597,000	343,000	100,000	1,085,000
Subtotal Direct Costs	**14,968,725**	**16,344,325**	**16,996,525**	**15,585,725**
Contingency (12.5%)	**1,871,091**	**2,043,041**	**2,124,566**	**1,948,216**
Indirect Costs (25%)	**3,742,181**	**4,086,081**	**4,249,131**	**3,896,431**
Total Construction Costs	**20,581,997**	**22,473,447**	**23,370,222**	**21,430,372**

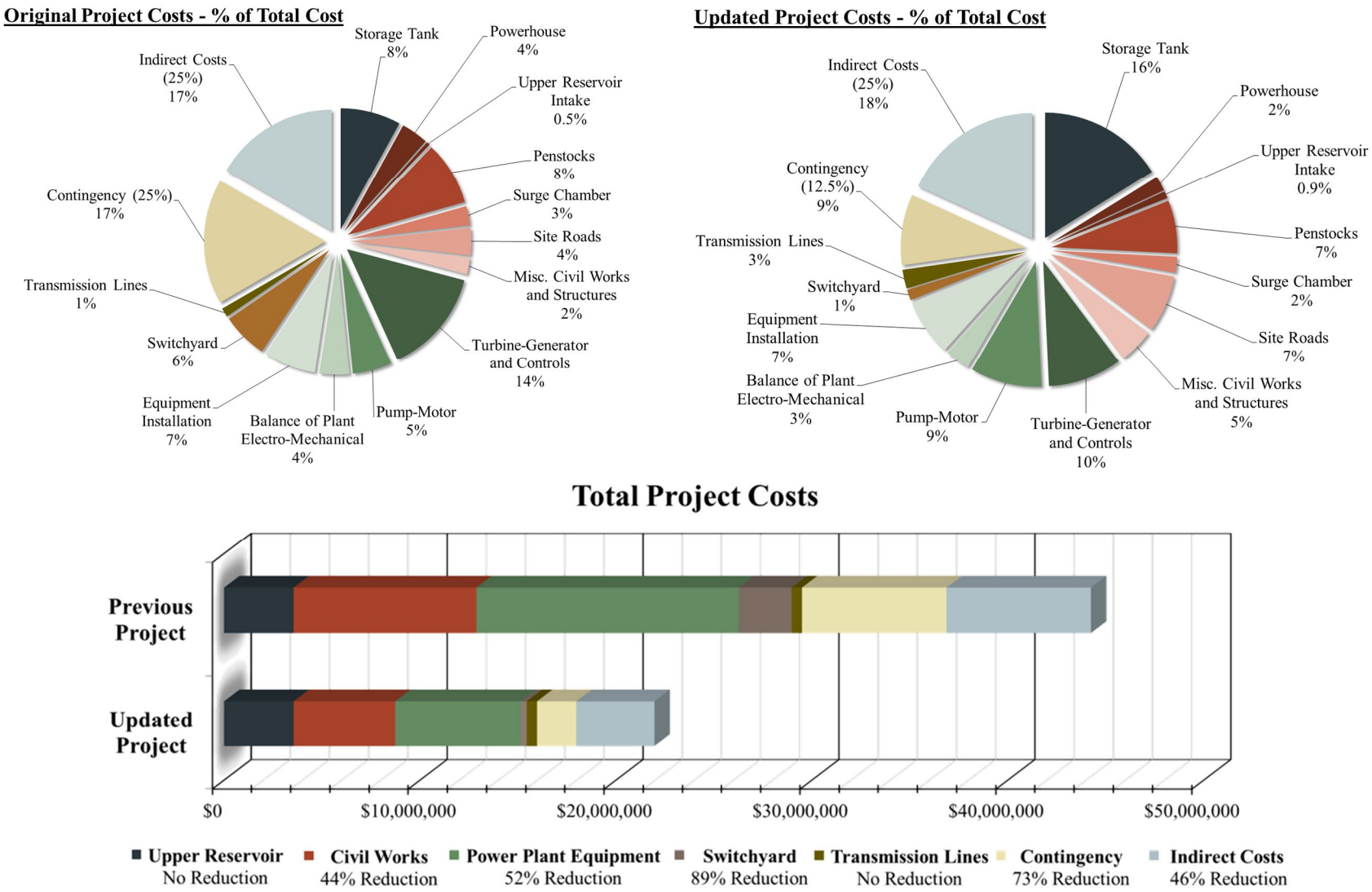

Figure 26. Breakdown of average cost percentages for ORNL PSH (left) and ORNL m-PSH (right

Project costs for CS2 are in the $20 - $22 million range, or approximately $4,000/kW, nearly double the average CS1 cost, significantly greater than existing U.S. PSH projects, but in line with PSH projects that have been studies but not commissioned (MWH, 2009). Project costs do not reflect the need for environmental studies, which would be complex and expensive due to the open-loop design. The effects of m-PSH operation on ecological indicators such as dissolved oxygen and invertebrate populations, on thermal regimes, recreation opportunities, and on the existing operational constraints of the Melton Hill Hydropower plant would require detailed impact studies that would likely increase the time for licensing and regulatory compliance, which in turn would increase the costs of financing and construction. Additional insurance, mobilization and demobilization, overhead, permitting, design, and regulatory costs could realistically amount to 25% or more of the projected costs (Knight Piésold Consulting, 2010). In short, cost savings from equipment modularization does not put ORNL m-PSH on a comparable basis with CS1, and project viability can only be achieved if all unknown cost contingencies are accounted for, generation revenue is substantial, and pumping costs are reduced or eliminated.

5.3 MARKET OPPORTUNITIES

Despite the poor economics of project construction, it is worthwhile to analyze the potential market opportunities of CS2. Future innovations in design could improve the prospects for m-PSH viability on the ORNL campus. Because no m-PSH projects are currently operational, the quantification of potential revenues, pumping costs, and additional economic benefits, guided by the experience and operational lessons of larger PSH projects, can be instructive. In addition, data is available to simulate two market approaches for revenue generation and pumping costs in an integrated electricity market. In the first case, energy arbitrage is carried out to allow the unit to generate when prices are high and pump when prices are low. The second approach allows the m-PSH unit to operate in a peak-shaving capacity. The unit will reduce a local electrical peak load by generating electricity with m-PSH, typically when electricity rates are also at a peak. The unit will pump and increase the local electrical load when it is at a minimum. The goal is to shave the peak load when electricity rates are high, and redistribute the load to a later time when rates are lower.

5.3.1 Energy Arbitrage

The first case assumes an m-PSH facility will participate as a price-taker where power can be bought and sold at TVA wholesale rates. Daily revenue is optimized over a 336 hour (two week) time frame to maximize both intra- and inter-day arbitrage. The use of a two week optimization (compared to daily and weekly optimization in CS1) assumes m-PSH operators will coordinate with TVA operators to maximize system benefits.

A typical week of m-PSH operation is shown in Figure 27, with the corresponding storage profile shown in Figure 28. A few interesting results are worthy of discussion. First, when prices are at a weekly minimum (Sunday), the m-PSH unit recharges to full storage capacity. Storage is depleted on Monday when electricity prices peak in late afternoon. Second, on Thursday, intermittent generation and pumping occur throughout the day to accommodate the variability in electricity prices. On most other week days the simulations suggest pumping in the early morning and afternoon generation. In reality, an m-PSH operator would have limited foresight into the daily peaks and troughs of electricity prices, and a set of operating guidelines would need to be followed. These rules would likely limit generation to the daytime hours and pumping to the nighttime hours. Under these constraints, revenue optimization may not always be achieved (e.g., the afternoon pumping on Thursday and evening generation on Saturday would not take place). These constraints are only highlighted to qualify the revenue estimates as an upper bound to what is realistically achievable.

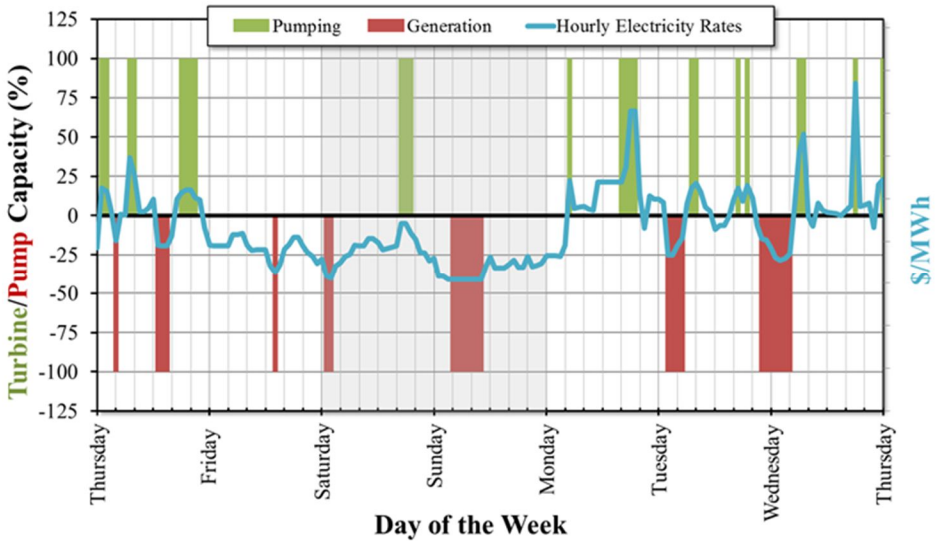

Figure 27. Electricity prices (right axis) compared with the operational mode of the m-PSH (bars, green = turbine mode, red = pump mode). When inter- and intra-day arbitrage are allowed, the system can go more than 24 hours without generating (Sunday) or pumping (Saturday morning to Sunday morning).

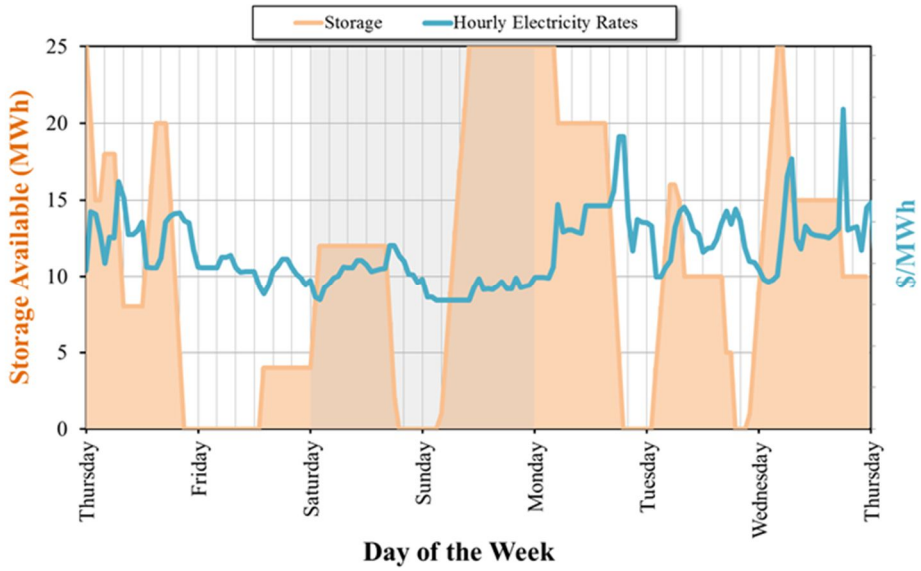

Figure 28. Equivalent m-PSH storage corresponding with Figure 27.

Annual energy arbitrage revenues for 2010 – 2013 are approximately $90,000 per year (Figure 29). In most years, the summer months provide the best opportunity for price arbitrage, as there is significant variability in energy prices. The maximum annual revenue of $114,000, or approximately 0.5% of total project costs, is achievable based on 2010 electricity prices. A conservative estimate for just annual operation and maintenance is 1% of project costs (MWH, 2009). Annual revenue estimates are not sufficient to cover annual O&M, let alone repayment of the initial construction cost and associated financing fees and investment returns. In the absence of a long-term power purchase contract, energy arbitrage alone is not a viable market strategy for a 5MW m-PSH facility on the ORNL campus.

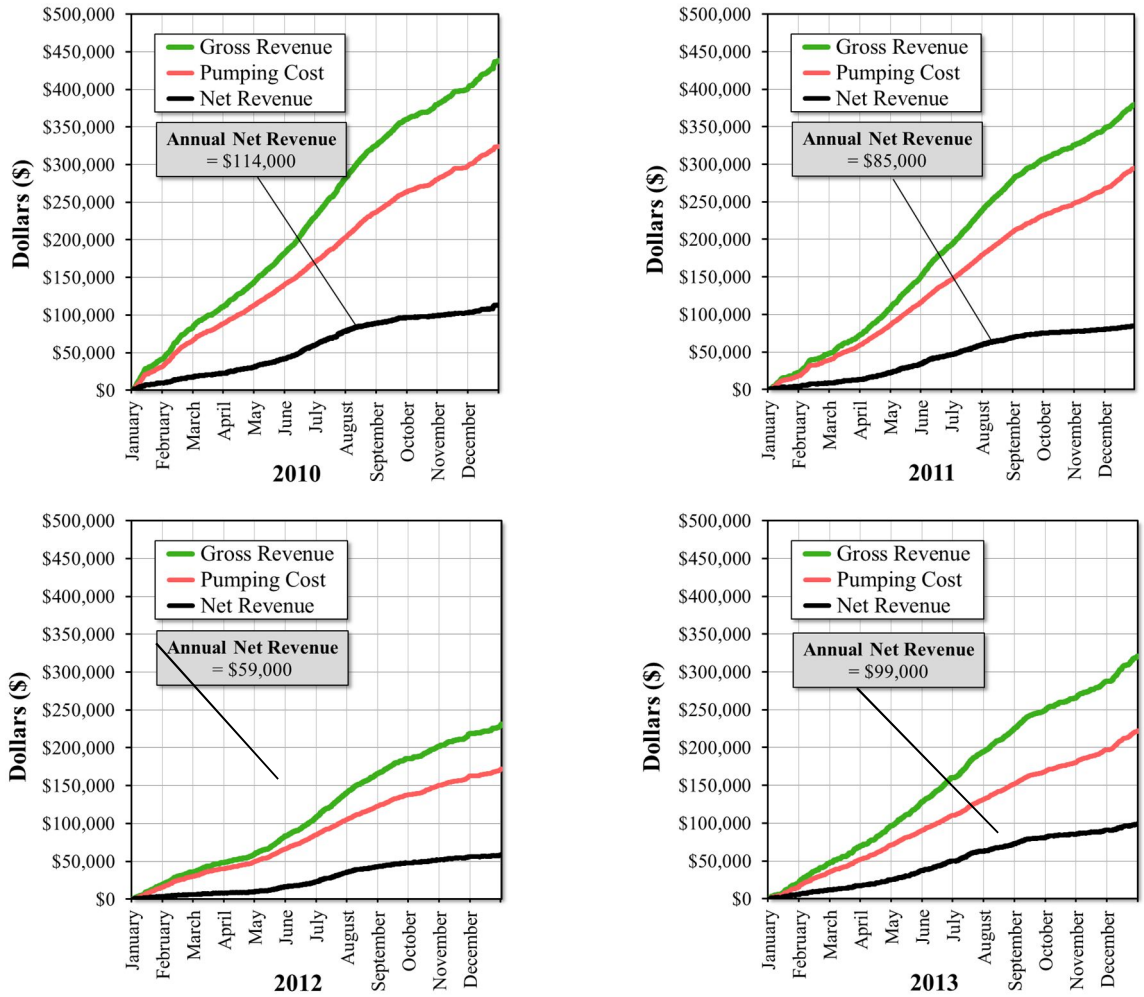

Figure 29. m-PSH energy arbitrage revenue estimates.

5.3.2 Peak Shaving

To assess the benefits of peak shaving, the monthly load profile for the ORNL campus was obtained for the period of February 2014 to January 2015. The load profile was input into the linear optimization model detailed in Section 3.1.3, and optimization was carried out over a two week temporal window. To ease model implementation, the optimization algorithm was relaxed to allow for incremental pumping and generating (greater than 0 but less than 5MW). Realistically, a single-speed turbine or pump would not have the flexibility to operate at conditions less than the rated capacity, and in this case, revenues are to be considered an upper bound on what is achievable with the previously described m-PSH technology.

A typical week of operation is shown in Figure 30. The peak load is flattened and redistributed to times when the load is at a local minimum. The system can go several days without generating or pumping if the load is relatively stable. Generation may need to occur at variable increments throughout the day as the load ramps up, and pumping usually occurs in short periods of time. The figure is illustrative of the difficulties to be expected in forecasting a fluctuating load. A complex decision framework would need to be established, with a system of triggers for generation and pumping. If a decision is made to deplete storage the day before a peak load, there may not be sufficient storage to generate the following day. If

the peak load the following day is the peak load for the entire month, m-PSH would provide no benefit as a peak shaving application.

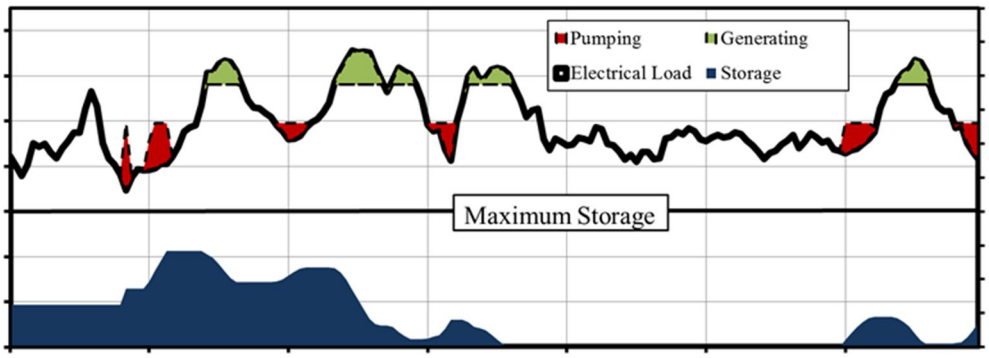

Figure 30. Arbitrary week with pumping and generation optimized to reduce the peak load. The altered load profile is shown as a dotted line.

The total annual savings in electricity charges from peak shaving is estimated at approximately $290,000, or three times as high as the average annual revenues from the energy arbitrage application, indicating peak shaving is a more favorable mode of operation for m-PSH on the ORNL campus. Greater savings are achieved in summer months, when the load is more variable and electricity consumption is near the annual peak.

Monthly m-PSH energy consumption and production is fairly small, about 79MWh of pumping and 66MWh of generation on average (Figure 31). The energy arbitrage application from Section 5.3.1 generated between 400 – 600MWh of energy and consumed approximately 600 – 800MWh of energy per month. Peak shaving appears to be less energy intensive, which may have some additional benefits in terms of local grid stability. The low energy consumption also indicates a system with a smaller installed capacity and a greater storage volume would be a favorable configuration, and m-PSH may be underutilized if operated solely in a peak shaving capacity.

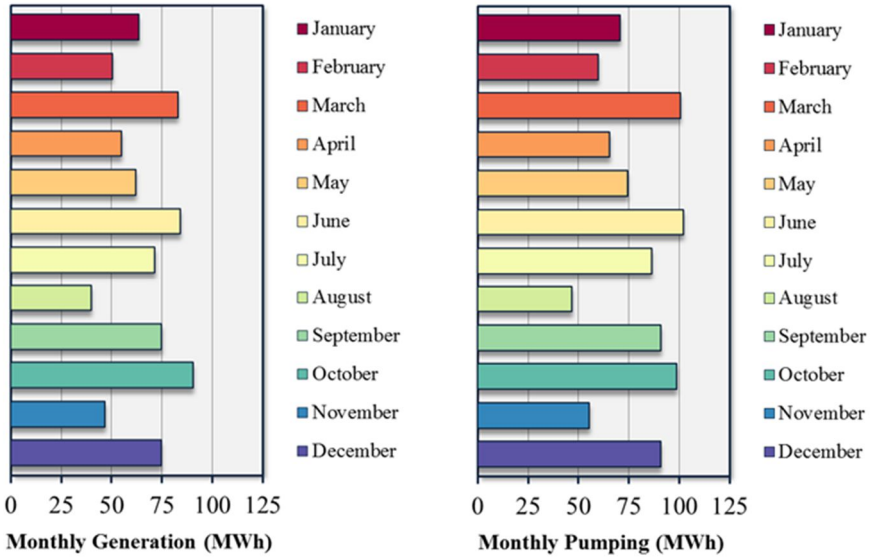

Figure 31. Monthly energy use (generation and pumping) for a 5MW m-PSH peak shaving application.

5.3.3 Economic Indicators

Despite the increased benefit from peak shaving, construction costs are too significant to warrant project feasibility. Assuming annual net revenue of $290,000 were to persist into the future, a very conservative anticipated annual O&M of $200,000 (1% of initial capital costs) would leave $90,000 to cover financing payments, replacement costs, and desired investor returns. The BCR for both the peak shaving and arbitrage applications are well below 1.0. Even in the best case scenario for the peak shaving application, every $1 invested into the project will return $0.26 in benefits (Table 17). The best case arbitrage application shows an LCOE nearly five times higher than average wholesale electricity rates. The economic indicators for m-PSH on the ORNL campus do not demonstrate project viability.

Table 17. Economic indicators for arbitrage and peak shaving applications.

Application	Case	BCR	LCOE ($/MWh)	NPV
Arbitrage	Best Case	0.11	258	Negative
Arbitrage	Worst Case	0.07	286	Negative
Peak Shaving	Best Case	0.26	-	Negative
Peak Shaving	Worst Case	-0.01	-	Negative

5.3.4 Ancillary Services

A third and potentially lucrative strategy could involve the provision of ancillary services. As shown in CS1, and noted by many others (Deb, 2000; Ela et al., 2013; Kirby, 2012), PSH participation in the ancillary services market could prove significantly more profitable than pure energy arbitrage. In addition to frequency regulation and spinning reserves, as modeled in CS1, an m-PSH unit could offer black start capabilities or local voltage control. The proximity of m-PSH to a dynamic load center, the ORNL campus, may create significant added value for voltage regulation services that could be quantified through a more detailed analysis of proprietary data. Based on data from competitive markets, that added value is unlikely to produce favorable economic indicators even under the best case cost scenario. ORNL is situated within the domain of TVA, an integrated system with no open market for ancillary services. A case study into alternative revenue generation streams is not possible at this time, and would require additional considerations beyond the scope of this study. The results of CS1 may be used to speculate that within an optimized, integrated energy-water system such as the Tennessee Valley, remuneration for the provision of ancillary services will be less than what could be obtained in other regions of the country.

5.4 CS2 CONCLUSIONS

The pursuit of energy arbitrage and peak shaving market strategies for an m-PSH facility on the ORNL campus does not appear promising. Simulated optimal revenue streams generated from the exploitation of price and electrical load volatility do not adequately compensate project owners for their initial capital investment, and in some cases, they are not sufficient to cover annual operating costs. The lessons learned from CS2 can be distilled into the following guidance for future research activities:

- When no existing transmission, storage, or conveyance infrastructure is in place, initial capital costs are too large for m-PSH to exhibit sustained economic viability.
- Though CS2 construction costs are competitive with existing utility-scale battery storage technologies, the lack of any m-PSH installed capacity is illustrative of the difficulties and uncertainty to be faced in the m-PSH development process.
- The construction of one or two reservoirs may add 25% or more to total project costs. The use of existing sites with reservoirs is favorable.

- Highly flexible integrated pump/turbine machinery would improve economic feasibility if cost competitive with separate pump and generating units.
- Participation in a market with distinct ancillary service products must be part of any revenue generation strategy.
- Co-location near a variable load with predictable peak and off-peak timing would improve m-PSH revenue potential. The ORNL campus load did not exhibit sufficient variability or a consistent peak to off-peak load differential to warrant peak shaving.
- Open-loop m-PSH is sure to encounter increased scrutiny with respect to environmental impact relative to closed-loop development.
- Regulatory acceptance of m-PSH is untested, with no clear pathway for pumped-storage to receive a FERC license exemption. Early adapters to m-PSH may experience additional and unforeseen regulatory hurdles.

6. CASE STUDY #3: BUILDINGS

To assess the economic viability of m-PSH with less than 1MW capacity, a baseline for operational viability is established. Regardless of location, a set of universal design parameters must be adhered to that incorporate the physics of the fluid system, the realities of the electricity market, and the engineering specifications of buildings. Once these parameters are established, a best case scenario is analyzed assuming infrastructure is currently in place, conditions are highly favorable for pumped storage design, and no barriers to entry exist. In addition, the minimum design specifications necessary to meet baseline performance metrics are described.

6.1 GLOBAL DESIGN CONSIDERATIONS

The study proposition that distributed-scale (<1MW) m-PSH systems could be incorporated to exploit the existing head differential on buildings is evaluated. The existing head available in buildings and the immediate proximity to the building and its adjacent building electrical loads promotes merit for further consideration. Water released from an upper reservoir tank on a rooftop can drive a hydroelectric pump-turbine below street level. The power available from any such high-rise m-PSH unit is found using the power equation (Eq. 4.2). Turbine efficiency is fairly well established, and can range from 75% to 90% for turbines on a distributed scale. An optimistic value of 90% is used for all calculations in this section. Various building heights are shown in Figure 32, plotted against the instantaneous discharge (x-axis) required to meet the desired instantaneous power output (y-axis). Any desired instantaneous power output can be met by a distinct combination of height and discharge. For example, 1MW may be generated from 1,000ft of head with a discharge of 13.1cfs. Since the height of a building is fixed, the limiting variable becomes discharge, and more importantly, how long the discharge can be maintained before the rooftop storage tank is emptied.

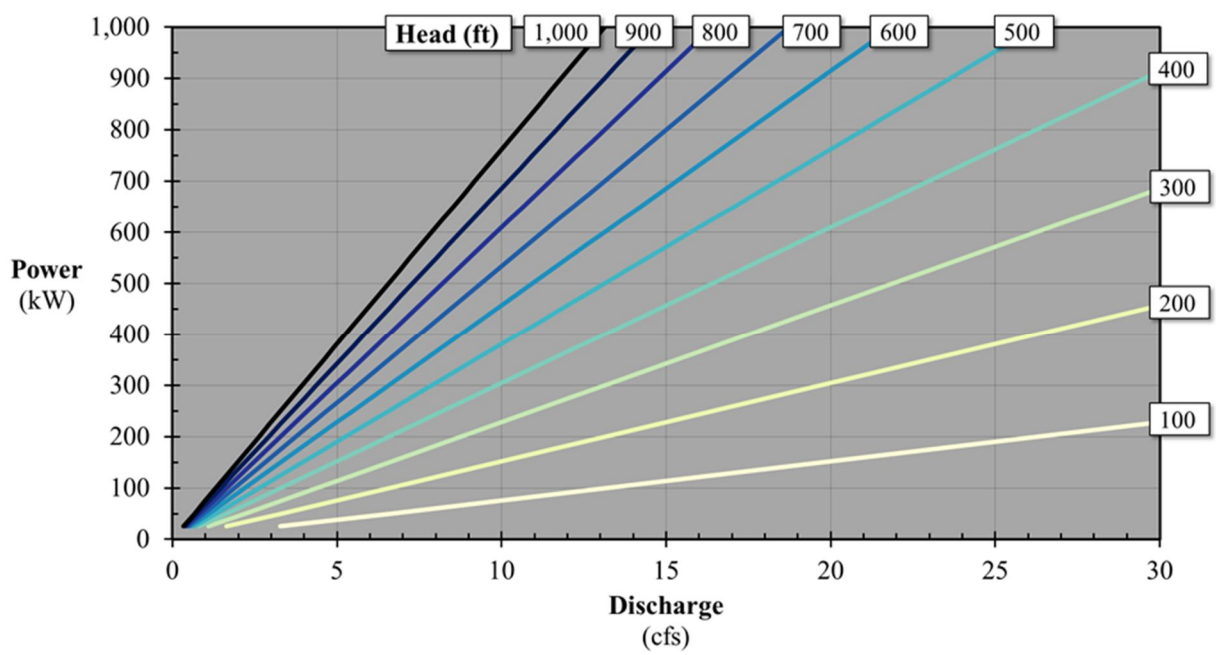

Figure 32. Instantaneous power available for a given combination of discharge (Q) and head, or building height (H) at an efficiency of 90%.

It is immediately clear from Figure 32 that significant gains in discharge at lower head differentials provide only nominal gains in power. A building with 100ft of head requires 13.1cfs to generate 100kW, and 26.2cfs to generate 200kW. Taking 26.2cfs, for example, a minimum penstock diameter of 1.4ft-1.7ft would be necessary to support that flow rate at a velocity of 11ft/s-18ft/s. One hour of 26.2cfs discharges 94,320ft^3 (705,560 gallons) of water, the approximate volume of an Olympic size swimming pool. In theory, a 100ft building would need an upper (and lower) reservoir the size of an Olympic swimming pool to support 200kWh of energy storage. Because the pipe diameter and storage volume required to meet a given discharge over a given period of time are independent of building height, the marginal costs associated with m-PSH units on shorter buildings will be much higher than taller counterparts, and building height must exceed a certain threshold to indicate economic viability. To determine that threshold, building load and storage volume must be analyzed in tandem.

For consideration as a practical power generation and energy storage application, an m-PSH system must generate a sizeable percentage of the host building energy load. If not, the notion of selling excess energy back to the grid is unrealistic, the idea that on-site storage may be used as a load reduction technique is not practical, and the m-PSH model is not viable. In New York City, for example, Con Edison will provide monetary incentives if on-site energy storage represents at least 15% of the building's peak electrical load[18]. For buildings with floor space greater than 500,000ft^2, as is typical of most high-rise buildings taller than 400 – 500ft, average hourly load is nearly 2MW, while buildings with floorspace between 200,000ft^2 and 500,000ft^2 have an average hourly load of around 500kW (EIA, 2009). These averages may vary based on age of construction, geography, and occupancy of the building, and peak load may be significantly higher than average load. The average load, heights, and respective square footage of eight high-rise buildings in New York City are shown in Figure 33 (EIA, 2009). The average load of a 400ft to 600ft tall building can vary from 2MW – 5MW, while taller buildings on the order of 800ft can sustain electricity loads of up to 18MW. As a baseline for a high-rise building in this study, the minimum feasible storage capacity is assumed to be 15% of a 2MW load or, 300kWh.

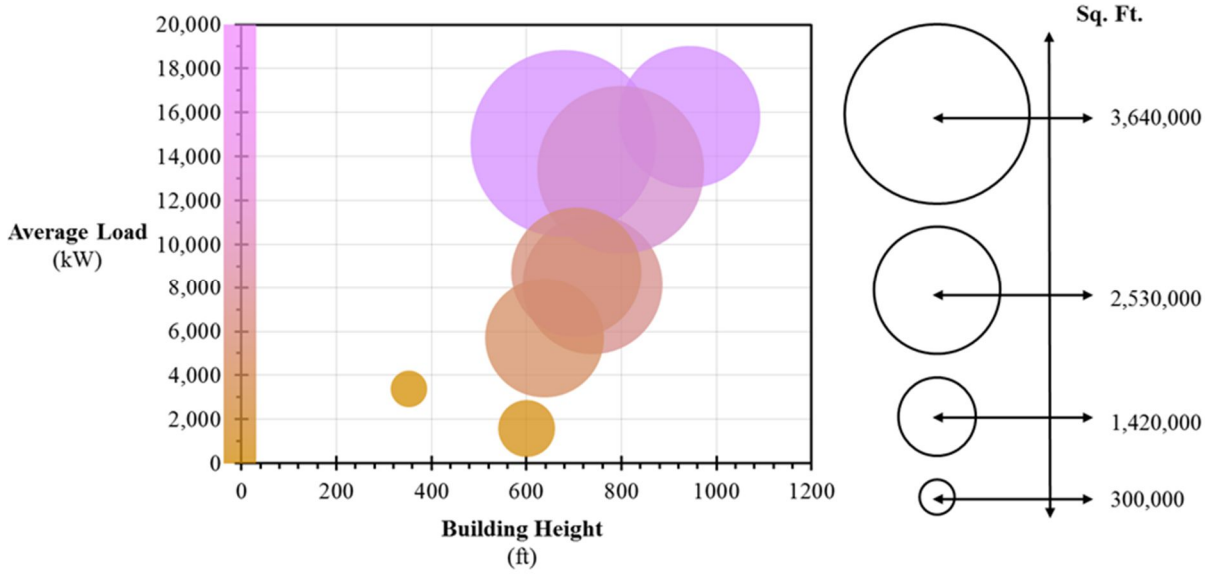

Figure 33. Comparison of building height and average load in New York City. Bubble size represents the total square footage of the building.

18 http://www.renewableenergyworld.com/rea/blog/post/print/2014/07/energy-storage-saves-money-helps-con-ed-at-manhattans-barclay-tower

The volume of water required to meet 15% of the high-rise building load is substantial. As a guide, Figure 34 shows the amount of storage available from a tank of an arbitrary volume, assuming 90% turbine efficiency. To meet the 300kWh minimum threshold on a 500ft building, a minimum of 212,000 gallons of both upper and lower storage is required, assuming every gallon of water is used efficiently for generation. To maximize head, tanks must be put on the rooftop or a top floor, where space restrictions limit tank volume. Inside a building the average ceiling would cap tank height at 10ft -12ft, putting 49ft as the absolute minimum length and width of the tank. The cost of a commercially available tank capable of storing and supporting hundreds of thousands of gallons while meeting safety and weight load requirements would be prohibitively expensive, considering energy storage potential is only 300kWh, or enough to power two floors of a high-rise building[19] for one hour. If the tanks are outside, the length, width, and weight load of the roof are limiting factors, and additional infrastructure to prevent freezing would need to be in place.

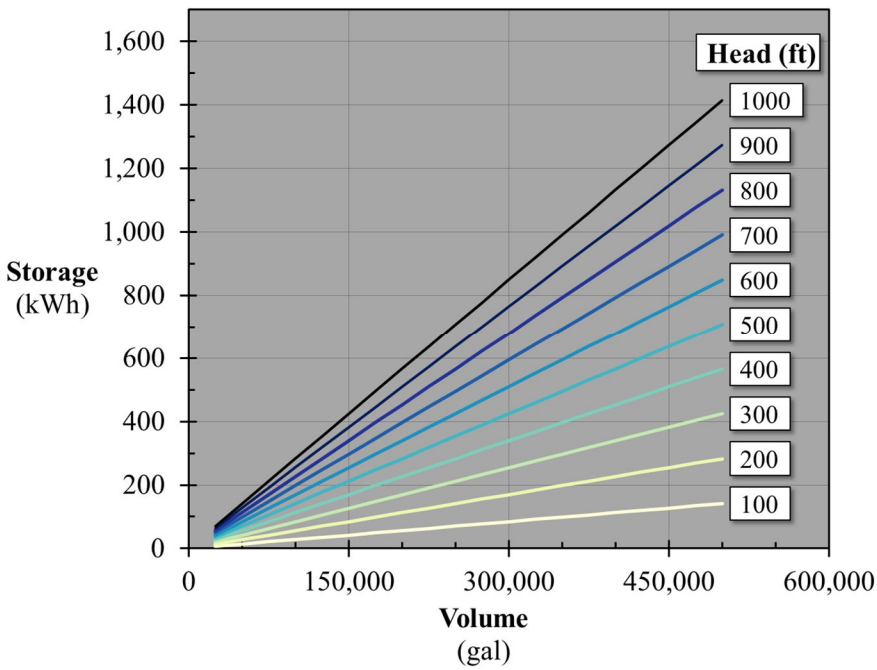

Figure 34. Total storage (kWh) available from a tank of arbitrary volume.

There are several additional engineering considerations that are outside the scope of this analysis. For example, large tanks of water have been used in high-rise buildings across the globe to reduce the shear-induced swinging of buildings. Known as tuned-liquid mass dampers, these tanks can contain on the order of 50,000 to 300,000 gallons of water[20], a quantity sufficient to dampen the structural motion of the entire building. In most cases, the structural integrity of the building is not affected by the damper, rather, the system is in place to reduce uneasy motions for occupants. Perpetual filling and emptying of an m-PSH upper reservoir with a similar volumetric capacity may affect the building dynamics in high wind shear, and further study would need to consider this affect, and whether building occupants would accept this level of motion. Additional factors like seismic zone restrictions, rooftop tank height limitations,

19 An average high-rise building power requirement is taken as 70kW – 140kW per floor (6 – 14 W/sq. ft.) (Siemens, 2012)
20 Nolte, 2007

lower reservoir excavation, the effects of intake vortices in the upper reservoir, and system noise are not considered in this analysis.

6.2 BEST CASE SCENARIO DESIGN

To examine the feasibility of using existing infrastructure on a high-rise building, we again look at New York City. Not only is a wealth of energy consumption data publicly available, the city measures an average skyline height of 1,045ft making it the third tallest city in the world[21]. If an m-PSH system is not feasible for the largest buildings in the country, further consideration is not warranted.

6.2.1 Existing Infrastructure

An assumption is made that all water infrastructure (i.e., fire suppression or potable water distribution systems) could be readily and freely converted into an m-PSH system. A typical high-rise will have multiple storage tanks distributed vertically throughout the building for the purpose of consumption, sewage removal, and fire suppression. Pumping all water from the ground floor to the roof in one shot is much more expensive than pumping smaller amounts to intermediate levels, and thus existing storage tanks are sized to distribute their contents among a small percentage of floors[22]. This applies to rooftop tanks as well, which are utilized in this example to give a maximum head for generation.

As a best case scenario, we will assume the largest installed water storage capacity is 50,000 gallons. This is a high end estimate obtained from tank manufacturers based on recent tank installations, and would likely consist of two 25,000 gallon tanks connected with a hydraulic manifold. Existing potable water and fire suppression systems consist of 4 or 6 inch diameter pipes, topping out at 8 inches. Assuming a uniform pipe diameter of 8in and a maximum water velocity of 11ft/s, the maximum discharge through the existing system is fixed at $Q = 3.8\text{ft}^3/\text{s}$. Taking for H the average height of the 25 largest skyscrapers in New York City, 1,045 ft, and assuming a turbine efficiency of 0.9, Eq. 1 gives a power estimate of 306kW. If the entire volume of the tank is used for generation, the maximum power available from the system can be generated for 29 minutes before the tank is emptied, giving the m-PSH system total storage of 148kWh. A 1,045ft building would likely have an average load on the order of 10MW or greater, meaning total generation from this system could represent about 1.5% of the average building demand for 0.5 hours.

If pipe diameter and discharge are not taken into consideration as a design restriction, Figure 35 gives the power duration curve for a 50,000 gallon tank. Again, only a miniscule percentage of the total building load would be met if generation is desired for several hours. If the goal is to power two floors, the m-PSH unit could meet that target for less than 1 hour before pumping is required. The short duration of power generation is not ideal for m-PSH; economic feasibility relies on enough storage to provide flexibility to the grid. If the high-rise m-PSH system is only generating for a few minutes before the tank is empty, it must wait until off-peak hours to pump, or begin pumping again during peak hours. Daily revenue generating potential is minimized in the former, and the latter defeats the purpose of price arbitrage. Implementation of m-PSH using existing infrastructure is therefore not economically viable.

21 http://www.ultrapolisproject.com/Tallest_25_Skylines_Cities.htm
22 http://www.grundfos.com/content/dam/CBS/global/whitepapers/Whitepaper%20-%20Boosting.pdf

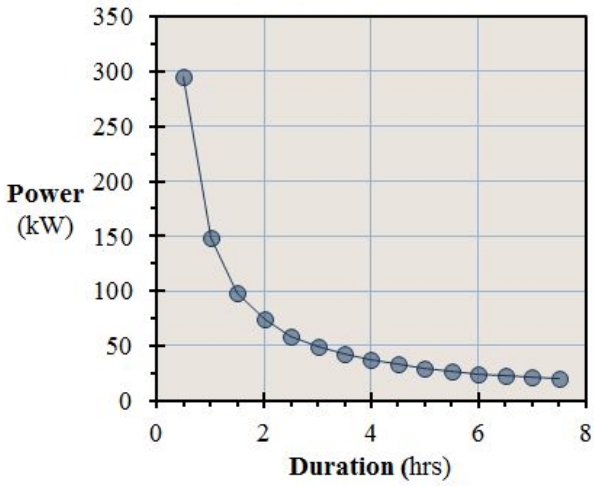

Figure 35. Duration of power available from a 50,000 gallon rooftop tank at a height of 1,045 feet.

6.2.2 Designing for Feasibility

With existing infrastructure on a high-rise building, the biggest hindrance to generation from an m-PSH system is storage capacity. We now seek to quantify how total storage could meet 15% of the average load. From Figure 33, a conservative estimate for the average load of a 1,045ft building would be 5MW, meaning total storage should exceed 750kWh. To convert that into gallons, the power equation can be rearranged to give

$$\frac{\text{storage (kWh) x 11.81 x 3600 s}}{\text{head (ft) x efficiency (\%)}} = \text{volume (ft}^3\text{)}. \qquad \text{(Eq. 6.1)}$$

A minimum volume of 250,000 gallons is required for energy storage to meet 15% of the average load. Double or triple that volume would be necessary to meet the average load of many existing buildings.

Spatial and monetary restrictions necessitate the use of several tanks to hold the desired volume of water. The most efficient configuration of rooftop tanks would be an array of cylindrical tanks – construction costs are significantly less for cylindrical tanks given their favorable volume to surface area ratio. The average size cylindrical tanks in use today[23] are 12ft in diameter and 16ft tall. At least twelve of these would be required to store 250,000 gallons.

The logistics and engineering design required to put twelve large tanks on a 1,000ft building are prohibitive. The tanks would need to be constructed on site, significant roof enforcements would be required to handle the massive load, and comprehensive safety studies would need to be carried out. This volume of water has the potential to affect the lateral motion of the building in strong wind, as mentioned above, and the constant filling and emptying of the tank would introduce complex building responses that would require extensive engineering analysis. There is also the question of underground storage – a lower reservoir with 250,000 gallons of capacity would need to be constructed underground, and an entire pipe system would need to be rerouted to the tank. Most large buildings are not designed with a functional roof, and many do not have a significant amount of free space available for large tanks (e.g.

23 Based on conversation with five tank manufacturers.

Figure 36). When taken into consideration with the generation potential - less than 1MW for less than four hours a day – the m-PSH design is not viable even under the most ideal terms.

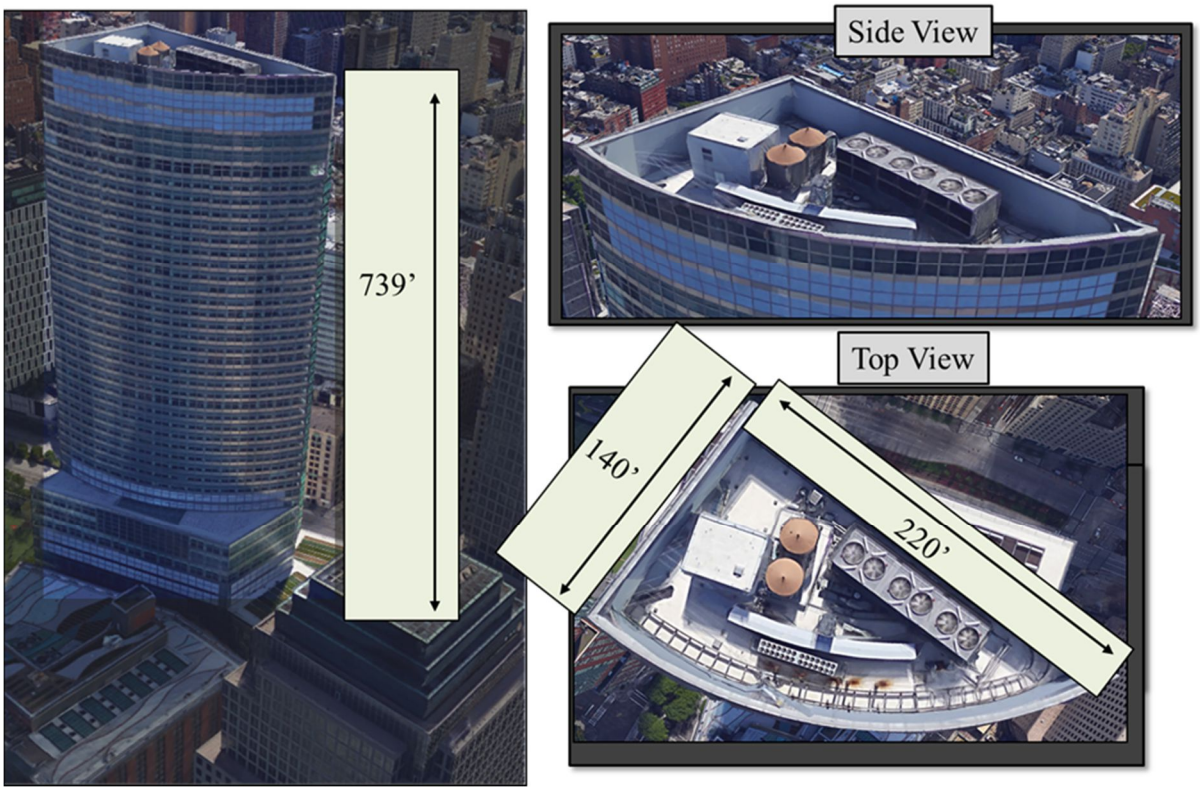

Figure 36. Dimensions and views of a 739ft tall high-rise building (Map data ©2015 Google). The two existing tanks have a capacity of approximately 40,000 gallons.

As a final exercise, the storage requirements for eight large high-rise buildings in New York City are calculated based on average load (Table 18). On the high end of the spectrum, a 677ft building with a 14.6MW average load would need fifty-one 22,500 gallon tanks for energy storage to meet 15% of the average load (Building 4). The most efficient building is 601ft tall with an average load of 1.6MW, and would require 6 tanks (Building 6). However, only 240kWh of storage would be available, much less than existing, proven technologies, and significantly less than the current 2GWh battery system installed in the building (Demand Energy Networks, 2013). The equivalent water volume of 2GWh of storage on this building would be 1,179,035 gallons, which would require fifty-two 22,500 gallon tanks. At this volume, the energy density (kW/sq. ft) is much smaller than batteries of equivalent installed capacity (Figure 37). The combination of high head and low energy density do not offer a competitive value proposition for m-PSH of less than 1MW.

Table 18. Specifications for eight high-rise buildings in New York City.

	Building 1	Building 2	Building 3	Building 4	Building 5	Building 6	Building 7	Building 8
Height (ft)	943	739	638	677	798	601	353	705
Total Sq. Ft.	2,200,000	2,138,000	1,592,000	3,637,000	2,993,000	521,000	329,999	1,877,000
Approx. Floorspace Dimensions	160ft x 90 ft	140ft x 220 ft	290ft x 85ft	320ft x 155ft	100ft x 300ft	60ft x 150ft	110ft x 90ft	295ft x 100ft
Annual Energy Use (kWh)	138,009,000	71,413,500	49,910,800	127,770,000	117,160,000	13,952,500	29,596,700	76,279,600
Average Load (kW)	15,800	8,150	5,700	14,600	13,400	1,590	3,380	8,710
Storage (kWh) [15% of average load]	2,370	1,223	855	2,190	2,010	239	507	1,307
Max Tank Volume (gal)	890,446	586,105	474,806	1,146,111	892,410	140,600	508,867	656,586
# of 22,500 gallon tanks	40	26	21	51	40	6	23	29
Total Water Weight (lbs.)	56,070,000	36,445,500	29,436,750	71,489,250	56,070,000	8,410,500	32,240,250	40,650,750

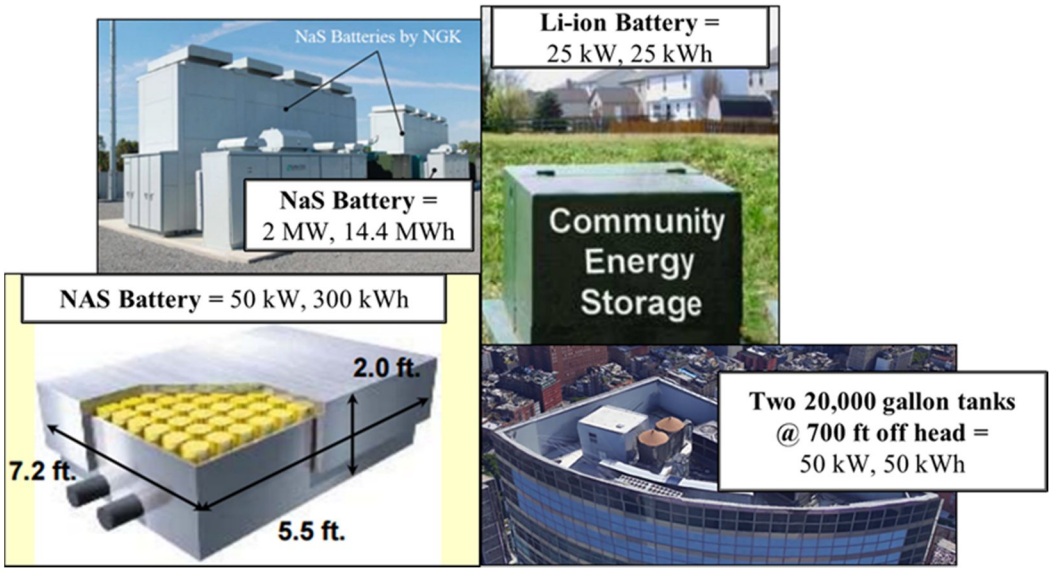

Figure 37. Visualization of the energy densities of energy storage technologies (Bjelovuk, 2010; NGK Insulators, 2013).

6.3 REVENUE POTENTIAL

Revenue simulations are carried out for a theoretical 250kW, 1MWh system in PJM and NYISO to provide an indication of revenue potential from energy sales in the two RTOs with the highest average day ahead market clearing price (Table 19). In this case, the generation could be sold to the grid, or it could be used locally and the market clearing price during the hour of generation would be considered an avoided cost. Annual revenues of between $5,000 and $10,000 could be expected for the average unit, or less than $200 per week. From Section 6.2.1, 50,000 gallons of water stored at 1,045ft could produce 305kW for 29 minutes. To sustain this generation for four hours, an additional 350,000 gallons of water would be necessary. At best, this system would need to cover operational costs, financing payments, investment returns, labor, and repairs for around $200 per week. It is clear that one if not several additional revenue streams are necessary to justify the construction and development of m-PSH less than 1MW.

Table 19. Revenue potential for a 250kW, 1MWh m-PSH system optimized with 7dopt for 2014 day ahead energy in PJM (left) and NYISO (right).

PJM				NYISO			
Efficiency	**Generation Revenue**	**Pumping Cost**	**Net Revenue**	**Efficiency**	**Generation Revenue**	**Pumping Cost**	**Net Revenue**
0.85	31,234	18,802	**12,432**	0.85	32,520	21,729	**10,791**
0.80	29,222	17,996	**11,225**	0.80	29,345	19,913	**9,432**
0.75	26,885	16,897	**9,988**	0.75	26,115	18,046	**8,069**
0.70	24,223	15,444	**8,779**	0.70	23,101	16,356	**6,746**
0.65	21,598	14,021	**7,577**	0.65	19,556	14,063	**5,493**
0.60	18,186	11,750	**6,436**	0.60	15,307	10,932	**4,376**
0.55	15,172	9,773	**5,398**	0.55	11,867	8,421	**3,446**

6.4 CONCLUSIONS

At a minimum, alternative energy storage prototypes should be cost competitive with existing technologies, they should add value by providing multiple benefits, and they should integrate easily into existing systems. Modular pumped storage with capacity of less than 1MW has been explored in depth to determine the extent of development limitations. The volume of water required to generate even a small percentage of the average building load is substantial, and the implementation, engineering feasibility, and economic viability of such systems could be very challenging and most likely unrealistic.

Utilities may see great value in distributed energy storage and electricity generation located near load centers. However, at a minimum, distributed energy storage prototypes should be cost competitive with existing technologies, they should add value by providing multiple benefits, and they should integrate easily into existing systems. The use of m-PSH on high-rise buildings does not meet any of these requirements, and a broader analysis of <1MW m-PSH shows that multiple revenue streams would be necessary to justify development.

7. UPDATE ON INNOVATIVE HYBRID M-PSH TECHNOLOGY

7.1 INTRODUCTION

ORNL is in the development stage of an innovative new technology deemed Ground Level Integrated Distributed Energy Storage, or GLIDES. The goal of GLIDES is to develop a unique, low-cost, high round trip efficiency (RTE) storage technology for building applications (beyond batteries, conventional pumped hydro storage, and compressed air energy storage). GLIDES stores energy by compressing air (compressible fluid) in high pressure vessels. Instead of compressors, GLIDES runs a high efficiency hydraulic pump to drive water into the pre-pressurized vessels and further raise the air pressure. Energy is extracted via a high efficiency, high-head, low-flow Pelton turbine.

GLIDES operates in two different modes (Figure 38). During charging mode, water is pumped from the water storage tank into high-pressure vessels. In the first prototype, vessels are initially pressurized with air up to 70 bar (~700m water head). As water starts to fill the vessels, air inside the vessels becomes compressed and its pressure will increase until it reaches 130 bar (~1300m water head), at which point the water pump is stopped. When discharging, the high-pressure air is allowed to expand, pushing the water out of the vessels at a high velocity through a unique Pelton turbine which spins a generator and dispatches electricity. The water is then recovered back into the water storage tank for another cycle. Total installed capacity of the unit will range from 1.5kW to 2.5kW, with approximately 2kWh of storage potential.

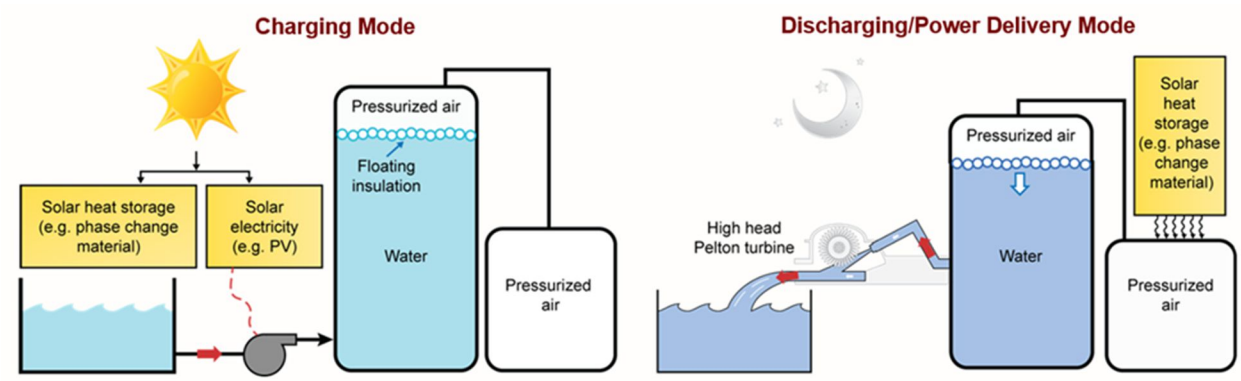

Figure 38. Schematic representation of a low cost, high round trip efficient m-PSH GLIDES technology[*,†].

*ORNL Provisional patent filed: Ayyoub. M. Momen, O. Abdelaziz, K. R. Gluesenkamp, and E. A. Vineyard, "High-Efficiency Ground-Level Pumped-Hydro Electricity Storage," Provisional patent filed, DOE S-124,766, Serial number 62/221,322.

† ORNL Invention Disclosure: Qin Fen Zhang, Brennan Smith , Ayyoub Mehdizadeh Momen, Kyle R. Gluesenkamp, "A Novel Underground Hybrid Pumped Storage Hydropower Technology", 201403311, DOE S-124,926.

7.2 PROTOTYPE ASSEMBLY

A prototype GLIDES system has been assembled at ORNL, and is currently carrying out test runs. To show the dispatchability of the electrical power generated by the GLIDES system, the prototype configuration will deliver off-grid electricity used to power electrical appliances in a specially designed load bank, which includes a microwave, a coffee-maker, lights, and space heaters. A Pressure System Hazard Analysis and Hazard Mitigation Strategy Report has been created and documented. The main potential hazards are discussed and mitigation strategies/controls have been implemented.

The GLIDES prototype consists of the following procured and constructed equipment and instrumentation (Figure 39 and Figure 40):

- Water storage tank;
- 16 MPa rated high pressure vessels;
- High efficiency positive displacement (PD) pump and motor;
- High efficiency unique Pelton Turbine;
- High efficiency electric generator;
- High accuracy pressure transducers and pressure gauges to measure and control air pressure inside the pressure vessels;
- Water level transducer to measure water level inside the storage tank;
- High accuracy thermocouples to measure air and water temperatures during GLIDES operational modes;
- Watt transducers to measure the GLIDES input and output power during charging and power delivery modes;
- A tachometer to measure Pelton turbine rotation speed.

Figure 39. GLIDES components and controls/safety instrumentation set schematic.

Figure 40. GLIDES system prototype.

The Pelton turbine was procured by leveraging the additive manufacturing capabilities at ORNL. The high-head and small jet diameter required a unique design approach to create the self-proclaimed "world's smallest" Pelton turbine buckets (Figure 41). Despite the geometrically complex and property-sensitive nature of the buckets, they were manufactured cost-effectively with a quick turnaround using state-of-the-art 3D printing capabilities at ORNL.

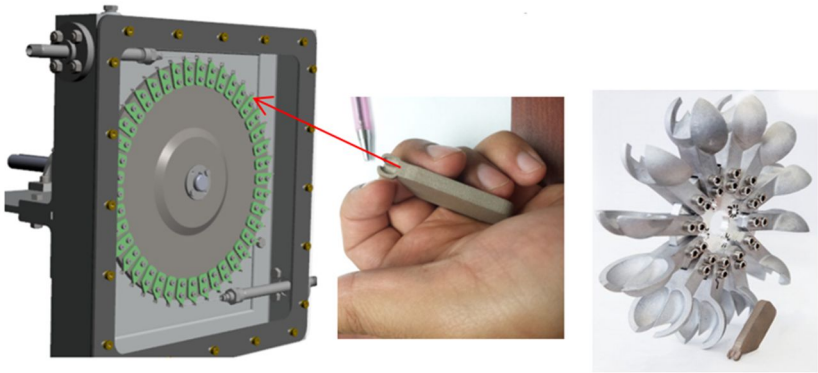

Figure 41. The "world's smallest" 3D printed Pelton turbine bucket.

7.3 TRANSIENT SYSTEM CONTROL AND MODELING

A sophisticated GLIDES LabVIEW control system has been created to perform control and safety operations while the system is running. The GLIDES computer is connected to an NI cDAQ, and it starts/ends the operation modes, matches generation to loads, and tracks the operational parameters such as air/water temperatures and pressures, turbine rotational speed, and generated output (Figure 42). The GLIDES control module includes built-in protections from over-temperature, over-pressure, turbine over-speed, and electrical over loading/surging.

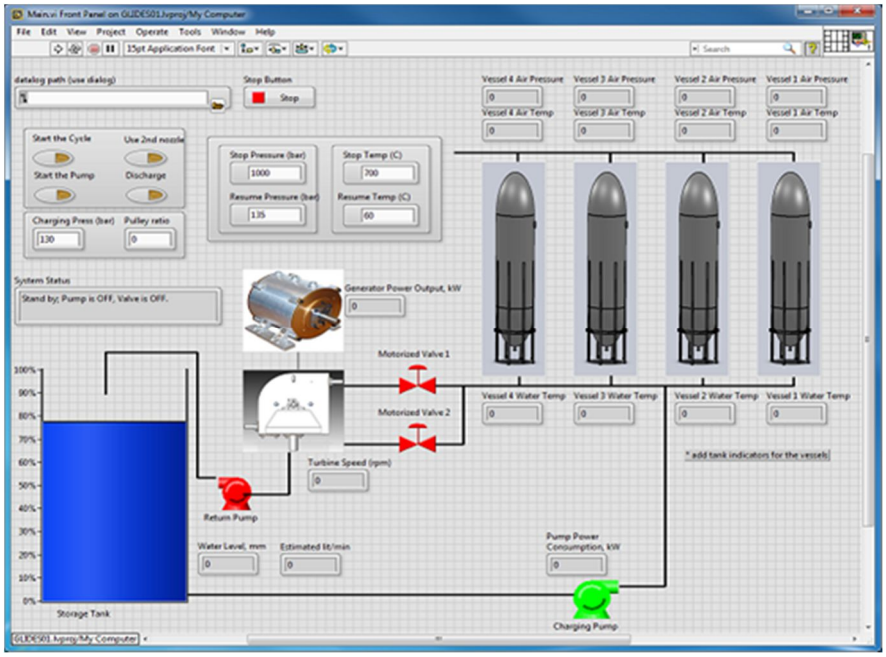

Figure 42. User control and data-log interface.

Rigorous GLIDES performance evaluation simulations indicate high roundtrip efficiency and performance, surpassing the performance of lead-acid batteries and compressed air energy storage (CAES) without the need for the favorable geography required of conventional PSH. When available waste heat is leveraged, GLIDES Round Trip Efficiency is boosted to RTE = 74% by overcoming all of the expansion/compression losses and cutting into some of the auxiliary component losses (Figure 43).

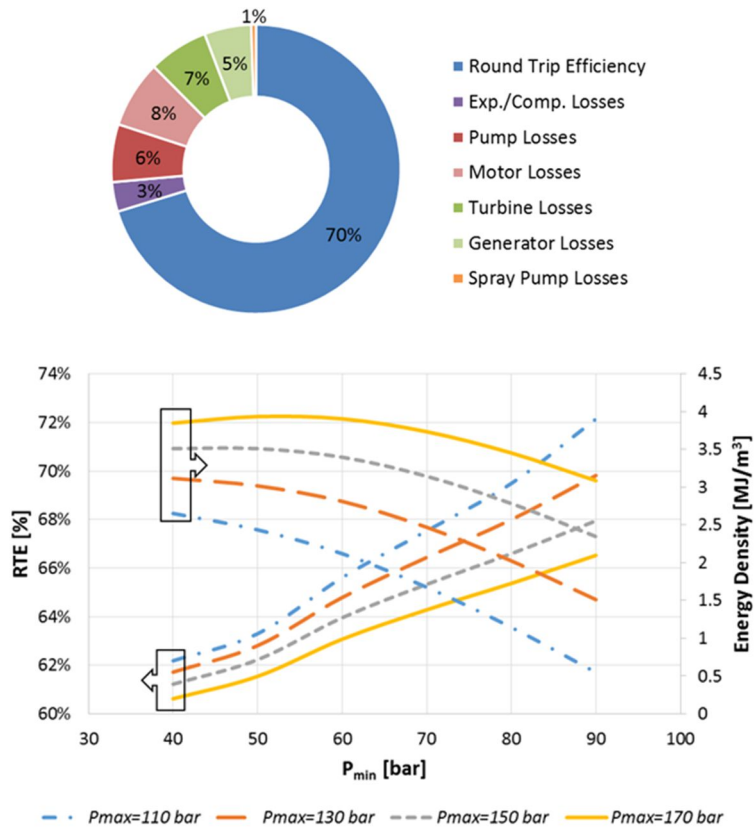

Figure 43. GLIDES roundtrip efficiency components (top) and the effect of operating pressure on roundtrip efficiency and energy density (bottom).

7.4 CONCLUSIONS

The GLIDES m-PSH system is simple, modular, and scalable, showing promise for low-cost implementation. It is flexible, accepting both heat and electricity as inputs, and demonstrates a high modeled round trip efficiency of 70-82% with quick or slow charge/discharge. These key advantages suggest that GLIDES can provide compact, economical storage of electricity for residential and commercial buildings. Ongoing testing at ORNL will continue through the rest of FY 2015.

8. MODULAR PUMPED STORAGE HYDRO CONCLUSIONS AND RECOMMENDATIONS

The viability of modular pumped storage hydro (m-PSH) is not a simple determination. Proper site selection will play a dominant role in project feasibility, while variable market economics in different regions of the country will likely mean a standard project design may be viable in one region and not another. To capture these dynamics, some basic guidelines were used as a framework for this analysis. At a minimum, m-PSH systems should produce substantial power during on-peak hours, capital costs must be recoverable in a reasonable amount of time, and revenues from generation must offset the cost of pumping, operations, and maintenance while providing a reasonable rate of return on the overall investment. These guidelines were applied to three case studies as a first look into how and where m-PSH development may take place.

The first case study examined the viability of converting an existing, decommissioned coal mine into a closed loop 5MW m-PSH facility within the PJM RTO. Equipment and civil cost estimates compare favorably with existing storage technologies. As a starting point, other potential m-PSH sites must have existing transmission, water conveyance, and/or water storage infrastructure in place for project economics to be considered favorable. Economic viability was achieved for highly efficiency (>75% RTE) m-PSH units co-optimizing energy and ancillary service bids in a volatile market year (2014). In this case, frequency regulation provided between 20%-30% of gross revenues, the BCR surpassed 1, and the LCOE was near the average market clearing price for day ahead energy. Units with RTE less than 75% did not demonstrate favorable economic indicators. In a typical market year (2013), the revenue potential from energy and ancillary services co-optimization resulted in unfavorable economic indicators for all units regardless of efficiency. A BCR of less than 1 and LCOE of greater than 50% of average electricity prices were consistent for all simulations. In no year was the market strategy of pure energy arbitrage viable.

The mix of energy and ancillary service revenue will vary based on plant geography. Frequency regulation market prices generally clear higher than spinning and non-spinning reserves, and the PJM frequency regulation market price clears higher than other RTOs analyzed in this study. Assuming the same construction costs could be achieved at similar sites throughout the country, revenues obtained from an m-PSH co-optimized for frequency regulation and energy in the PJM interconnect should be seen as an upper limit to what could be achieved in the U.S. The provision of voltage regulation and black start services do not show enough revenue potential to produce favorable economic indicators. Participation in the PJM capacity market may provide additional revenue potential, but under the best case cost scenario and assuming ideal unit performance, economic viability is still not achieved in 2013.

In the second case study, project costs for an open loop m-PSH facility on the ORNL campus were estimated and revenues were simulated assuming the unit would either sell wholesale energy to TVA or act in a local peak shaving capacity. Because no m-PSH infrastructure is in place, construction costs are nearly double those of the coal mine project. Market potential is also diminished, as TVA operates all generators in an integrated capacity and there is no competitive market for ancillary services. Barring a special power purchase agreement with TVA, energy sales alone do not constitute a viable market strategy. The peak shaving application demonstrated increased revenue potential over energy sales. However, economic indicators are still very poor, and a BCR of 0.26 is achieved only under the most ideal conditions when all load peaks are known in advance. Additional barriers including environmental feasibility, geotechnical analysis, and regulatory uncertainties do not favor m-PSH development at this site.

A third case study examined the physical limitations of a less than 1MW m-PSH unit located on a high-rise building. While these sites represent great energy potential due to the existing high head, energy generation is in most cases not sufficient to support the electricity needs of a few floors of the building for

more than an hour. At best, the system would require unprecedented volumes of water that would require cumbersome upper and lower storage capabilities, in addition to engineering feasibility studies to affirm the structural integrity of the building. An ideal 250kW, 1MWh system showed that revenue potential from energy sales under perfect conditions would be around $200 per week, and economic feasibility is far from attainable. The most significant limitations to development are high project costs in the face of low revenue streams, the need for excessive volumes of water, and low energy densities.

A novel approach to m-PSH energy storage, where topographic head differentials are not required, is currently being pursued at ORNL. This system uses pumps to compress air in storage tanks, artificially increasing the head to several hundreds of meters. Generation takes place by passing water from the tanks through the "world's smallest" Pelton turbine, a unit manufactured using advanced 3D printing at ORNL. Cost and system simulations indicate this technology has the potential to offer competitive, low-cost energy for building and commercial applications. Experimental validation of the full system assembly is currently under way.

All case studies reveal the need for better visibility into additional revenue streams and reduced pumping cost streams. At present, simulations of project economics are carried out using publicly available energy and ancillary services market prices. These operations represent the most likely source of revenue for an m-PSH owner, and market data represents the most transparent mechanism to value future revenue potential. Internationally, small scale pumped storage is being constructed with the help of substantial government subsidies. Domestically, the lack of operational m-PSH projects is indicative not only of the challenges faced in achieving economic feasibility, but of the difficulty in demonstrating and capturing alternative revenue generation mechanisms, including government or tax incentives. Current installations of alternative energy storage devices are capitalizing on additional revenue streams, including better integration of renewables, government subsidies, utility incentives, and reduced and deferred system costs. These technologies also exhibit shorter construction lead times and reduced regulatory resistance, which accelerates their integration, adoption, and most likely their nimbleness in accommodating novel and innovative revenue schemes. To be considered a realistic contender in the small scale energy storage market, m-PSH projects must identify and pursue multiple revenue streams.

Further research is also necessary to target how and where equipment and civil cost reductions can improve project feasibility. All equipment manufacturers recommended separate pump and turbine units for the 5MW m-PSH study. This recommendation should be probed further, as the pump industry has already adopted variable frequency drive technology to provide high efficiency at varying pumping heads and flows. Small scale pumped turbines could be developed from this base technology and expertise. Though most large-scale PSH facilities operate using custom made reversible pump/turbine units, the lack of a competitive market on an m-PSH scale was given as a reason why small reversible units were not manufactured. The demonstration of sustained economic viability at multiple m-PSH sites similar to the coal mine may incentivize equipment manufacturers to invest in cost competitive, compact technologies. The application of advanced materials and modular construction techniques towards small hydro development is gaining traction (Bishop and Linke, 2015), and crossover of these techniques towards m-PSH should be considered.

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