FINAL

BULK STORAGE STUDY FOR THE 2017 INTEGRATED RESOURCE PLAN

B&V PROJECT NO. 192472

PREPARED FOR

PacifiCorp

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BLACK & VEATCH
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1.0 Introduction

Black & Veatch Corporation (B&V) was retained by PacifiCorp to perform a Bulk Energy Storage Study (Study) to support PacifiCorp's 2017 Integrated Resource Plan (IRP). IRPs are developed by power utilities to evaluate a portfolio of generating resources and energy storage options for their system in order to balance increasing levels of variable energy resources and, as generation from variable energy resources and their relative percentage of load grow, the need for additional system flexibility to assure grid reliability. For PacifiCorp, generating resource options include fossil fuel options, such as coal and natural gas, as well as renewable options including wind, geothermal, hydro, biomass, and solar.

Energy storage technologies have been evaluated in the past by PacifiCorp.

- HDR Engineering (HDR) was retained by PacifiCorp to perform an energy storage study titled "Energy Storage Screening Study For Integrating Variable Energy Resources within the PacifiCorp System" dated December 9, 2011, to support PacifiCorp's 2013 IRP.
- To support PacifiCorp's 2015 IRP, HDR provided an updated version of their 2011 study titled "Update to Energy Storage Screening Study for Integrating Variable Energy Resources within the PacifiCorp System" dated July 9, 2014.

As requested by PacifiCorp to support their 2017 IRP, the scope of work for this Study is only an update of the estimates of costs, schedules, and operating/performance characteristics provided in the previous HDR energy storage studies with a focus on two primary energy storage technologies with specific projects of each in various stages of planning as follows.

- Pumped Storage Hydroelectric
  - Swan Lake North
  - JD Pool - Klikitat
  - Seminoe
- Compressed Air Energy Storage
  - Magnum Energy

The results of the Study are provided in the following report sections and appendices. The information presented has been gathered from and is based on public and private documentation, studies, reports, and project data of the specific projects associated with the two primary energy storage technologies of the scope of work. Although not included in the scope of work for this Study, a thorough and applicable discussion of considerations for integrating variable energy resources into power systems is provided in HDR's 2011 and 2014 reports for information purposes and will not be restated herein.

2.0 Pumped Storage Hydroelectric

The previous HDR 2011 and 2014 energy storage studies considered potential pumped storage hydroelectric projects within the PacifiCorp operating power system region as follows:

- HDR 2011 Study
  - Swan Lake North
  - Yale-Merwin
  - JD Pool
  - Parker Knoll
- HDR 2014 Study
  - Swan Lake North
  - JD Pool
  - Black Canyon[1]

For this Study, PacifiCorp has requested that only the estimated costs, schedules, and operating/performance characteristics from the HDR 2014 study be updated for the Swan Lake North, JD Pool, and Seminoe projects.

2.1 GENERAL

A pumped storage hydroelectric facility requires a lower and upper reservoir. During times of minimal load demand or when required to absorb energy, excess energy is used to pump water from a lower reservoir to an upper reservoir. When energy is required (during a high value or a peak electrical demand period), water in the upper reservoir is released through a turbine to produce electricity. The pumping and generating is typically accomplished by a reversible pump-turbine/motor-generator. In addition to providing electricity at times of peak power demand, applications for pumped storage hydroelectric projects include:

- Providing transmission system support through ancillary services, such as load shifting and following, frequency control, grid stabilization, and reserve generation, etc.
- Energy storage for less dependable renewable resources, such as wind and solar energy.

Pumped storage projects may be categorized as either open-loop or closed-loop pumped storage projects. The Federal Energy Regulatory Commission (FERC) defines these classifications as follows:

- Open-loop pumped storage projects are continuously connected to a naturally-flowing water feature.

[1] Black Canyon Pumped Storage Project is a precursor to the Seminoe Pumped Storage Project.

- Closed-loop pumped storage projects are not continuously connected to a naturally-flowing water feature.

For open-loop pumped storage systems, acquisition of environmental approvals has become increasingly challenging due to the need to develop a lower reservoir on an active river or existing lake. To mitigate this issue, many recent pumped storage developments have proposed closed-loop systems, which often utilize existing features such as abandoned quarries or underground mines as the lower reservoir of the pumped storage system. This allows the pumped storage project to be developed and operated off-stream, reducing environmental impacts and also reducing costs associated with development of the lower reservoir.

2.2 SWAN LAKE NORTH

2.2.1 Current Project Status

In HDR's 2014 study, it is noted that various preliminary Federal Energy Regulatory Commission (FERC) permits and a draft license application were filed for the Swan Lake North Pumped Storage Project (FERC No. 13318) (Project) between 2010 and 2012. Over this period, the proposed capacity of the project went from 1,000 megawatts (MW) to 600 MW due to the developer, Swan Lake North Hydro LLC, making a number of changes to the project layout, size of reservoirs, water conveyance arrangement, and consideration of surface penstocks. The 600 MW project capacity was the basis for HDR's 2014 study.

Since 2014, a Final License Application (FLA) was filed by Swan Lake North Hydro LLC on October 27, 2015, and is currently under consideration by the FERC. In this document, the proposed project capacity was further reduced to 400 MW due to further project optimization during the course of final license application development. Although drawings from the final license application are not publically available through the FERC website, it is assumed that the general project configuration will be similar to the site layout and profile provided in the HDR 2014 study, only at a lower capacity. The 400 MW project capacity and the description of the project facilities provided in the final license application exhibits that is publically available from the FERC website are the basis for this Study.

2.2.2 Project Description

The Project is a closed-loop pumped storage system with an installed capacity of 393.3 MW in generating mode. It will be located approximately 11 miles northwest of Klamath Falls, Oregon. A general summary of the proposed Project facilities is provided in Table 1 in Appendix A.

2.2.3 Schedule

The proposed construction schedule for the Project is described and presented in Exhibit C of the FLA. The schedule assumes approximately 24 months for final design with an expected completion date in 2017. Final review and approval of the design is anticipated to take 6 to 12 months after which construction will begin. Construction will take approximately 4 years to complete. The proposed commercial operation date is November 2022, assuming a FERC Notice-to-Proceed in January 2018.

2.3 JD POOL

2.3.1 Current Status

In HDR's 2014 study, it is noted that an original preliminary FERC permit and a successive application had been filed by the Public Utility District No. 1 of Klickitat County, Washington (KPUD) for the JD Pool Pumped Storage Project (FERC No. 13333) (Project) on November 29, 2008, and April 30, 2012, respectively. The information provided in the successive application was the basis of information for HDR's 2014 study. The proposed Project capacity at that time was 1,500 MW.

After the HDR 2014 study, a Pre-Application Document (PAD) was filed by KPUD in October 2014. The information in the PAD revised the project configuration and reduced the Project proposed capacity to 1,200 MW. Due to the effective date of the successive application, KPUD filed a second successive preliminary permit application on November 3, 2015, in order to extend the effective date of the application. At the same time, Clean Power Development LLC (Clean Power) filed a competing preliminary permit application for the proposed Columbia Gorge Renewable Energy Balancing Project (FERC No. 14729) (Columbia Gorge Project) at the same location.

The lower reservoir site for both applications is currently undergoing a cleanup process due to decades of contamination from the former operation of the Columbia Gorge Aluminum smelter. Given the uncertainty of the timeline for the site cleanup and its suitability for development, FERC found it not prudent to issue a preliminary permit for the site and dismissed both applications.

The above information concerning the Project status and dismissal of the preliminary permit applications filed by KUPD and Clean Power is summarized from FERC's "ORDER DISMISSING PRELIMINARY PERMIT APPLICATIONS" document dated December 23, 2015. FERC also notes in this document that they may consider development applications in the future for the site, but the applications must thoroughly address all concerns related to developing the Project at a previously contaminated site. Thus, permitting this site in the future may require special considerations, and its timeline is unknown at this time.

Based on the public information available from the FERC website, the 1,200 MW project capacity and the description of the project facilities provided in the PAD are the basis for this Study.

2.3.2 Project Description

The Project is a closed-loop pumped storage system with an installed capacity of 1,200 MW in generating mode. It will be located approximately 8 miles southwest of Goldendale, Washington. A general summary of the proposed Project facilities is provided in Table 2 in Appendix A.

Based on a review of the PAD information, there is a high likelihood that the Project can be further optimized to reduce costs, such as finalizing the total storage requirement of the reservoirs and the number and/or size of the water conveyance conduits.

2.3.3 Schedule

The proposed development and construction schedule for the Project is outlined in the PAD as follows:

- Pre-filing Schedule for Filing License Application: 1 year
- Pre-construction Development Activities after FERC Issuance of License, Including Design/Construction Drawings: 3 years
- Project Construction: 5 years
- Anticipated Commissioning of Project: 5th Year of Construction

2.4 SEMINOE

2.4.1 Current Status

The HDR 2014 study included the Black Canyon Pumped Storage Project (FERC No. P-14087). A preliminary FERC permit application for the project was prepared by Gridflex Energy, LLC and filed by Black Canyon Hydro, LLC on January 25, 2011. The application showed several possible alternatives for pumped storage development that included two new upper reservoirs that could be connected to one of two existing lower reservoirs, the Seminoe and Kortes Reservoirs. Both of the existing reservoirs are owned and operated by the U.S. Department of Interior's Bureau of Reclamation. The original preliminary permit for the project, along with Gridflex's response to HDR's Request for Information (RFI), was the basis of information for HDR's 2014 study. As noted by HDR, there was conflicting information relative to generating and pumping capacities between the original preliminary permit and the RFI response.

On July 1, 2014, Gridflex prepared and Black Canyon Hydro, LLC filed a successive preliminary permit application for the Black Canyon Pumped Storage Project (FERC No. P-14087). This filing occurred about the time HDR had concluded their 2014 study. The successive application identified and included an additional alternative for consideration. However, on November 26, 2014, FERC issued an order denying the successive preliminary permit on the general basis that very little progress toward the filing of a development application had been made during the course of the original three-year permit term and did not warrant a successive permit.

Gridflex prepared and Black Canyon Hydro, LLC filed a preliminary FERC permit application for the Seminoe Pumped Storage Project (FERC No. P-14787) (Project) on June 16, 2016. This Project is similar to and utilizes the concept of the Black Canyon Pumped Storage Project. Per FERC letter dated June 21, 2016, some deficiencies and the need for additional information were identified with regard to the application. Gridflex prepared and Black Canyon Hydro, LLC filed an amended preliminary FERC permit application on June 28, 2016, which was accepted by FERC on June 30, 2016. The proposed total Project capacity is 700 MW and consists of two developments (i.e. East and West) that utilize the existing Seminoe Reservoir as their lower reservoir.

2.4.2 Project Description

The Project is an open-loop pumped storage system with a total installed capacity of 700 MW in the generating mode. It will be located approximately 30 miles northeast of Rawlins, Wyoming. The Project utilizes the water resources of the North Platte River as stored and conveyed through the existing reservoir. The Project includes two new forebay reservoirs (i.e. East and West), two underground powerhouses, two power tunnels between the forebays and powerhouses, and two tailrace tunnels between the powerhouses and the existing Seminoe Reservoir. In the generating mode, the East and West powerhouses have installed capacities of 400 and 300 MW, respectively, for a total Project installed capacity of 700 MW. A general summary of the proposed Project facilities is provided in Table 3 in Appendix A.

2.4.3 Schedule

The preliminary permit includes a three-year duration schedule for studies to design the technical aspects of the Project and confirm its economic viability. No overall schedule for Project implementation was provided; however, it would be anticipated that the FERC final license application would be completed in 2019 with final engineering, construction, and commercial operation of the Project completed during the 2020 through 2025 timeframe.

2.5 OPERATING CHARACTERISTICS AND REGULATORY OVERVIEW

A relevant discussion of typical pumped storage hydroelectric project operating characteristics relating to the beneficial services that such projects can provide, and general considerations and important aspects concerning environmental and regulatory factors with regard to siting and developing a potential pumped storage project are provided in HDR's 2014 report for information purposes and will not be restated herein.

2.6 CAPITAL, OPERATING, AND MAINTENANCE COSTS

The following sections provide an update of the cost estimates from the HDR 2014 study with regard to expected capital and operation and maintenance (O&M) costs for the three potential pumped storage projects in the PacifiCorp region selected for this Study. Costs provided are expressed in mid-2016 dollars.

2.6.1 Capital Cost

The HDR 2014 study provided a general discussion of capital costs associated with pumped storage projects. As noted in the HDR 2014, which is particularly true, the direct cost to construct a pumped storage facility may vary greatly and is dependent upon a number of physical site factors. The HDR 2014 study also notes the direct and indirect cost items generally included for capital costs, which would also generally include Owner project contingency, development, and project team costs. In addition to those cost items, capital cost assumptions for this Study include an Engineer-Procure-Construct (EPC) type of project delivery methodology and estimates reflecting a +/- 30% order of accuracy, which would approach an Association for the Advancement of Cost Engineering (AACE) Class 4 cost estimate classification.

2.6.1.1 Swan Lake North

As reported in the HDR 2014 study, EDF provided an AACE Class 4 cost estimate of $2,300/kW for the envisioned 600 MW facility at that time, which apparently compared favorably to earlier cost opinions prepared by HDR for the Project. Escalating this cost to mid-2016 dollars using a rate of 3% per year results in a total project cost of approximately $2,500/kW. The 3% per year escalation rate was used in the HDR 2014 study and is considered appropriate for escalating HDR values to mid-2016 dollars for this Study.

No recent cost information was available from Swan Lake North Hydro LLC for the current Project capacity of 400 MW and description provided in their FLA dated October 27, 2015. Based on our review of the Project described in the FLA, a cost opinion on the order of $2,600/kW would be expected, which compares favorably to the developer's escalated unit cost of $2,500/kW.

2.6.1.2 JD Pool

As reported in the HDR 2014 study, HDR performed a reconnaissance level study and AACE Class 5 cost opinion in 2005 for the 1,500 MW Project envisioned at that time. Their study resulted in an escalated cost opinion of $2,500/kW in 2014 dollars. Escalating to 2016 using a rate of 3% per year, this cost opinion would be approximately $2,700/kW.

No recent cost information was available from KPUD for the current Project described in their PAD dated October 2014, having a capacity of 1,200 MW. However, as reported in the HDR 2014 report, KPUD did provide a cost opinion of $2 billion to $2.5 billion for a 1,000 to 1,200 MW project in their Preliminary Permit Application, which equated to unit costs of $1,700 to $2,500/kW. Escalating to 2016 using a rate of 3% per year, these cost opinions would be approximately $1,800 to $2,700/kW. Based on our review of the Project described in the PAD, a cost opinion on the order of $2,700/kW would be expected, which compares favorably to the developer's escalated unit cost for a 1,200 MW Project.

2.6.1.3 Seminoe

As reported in the HDR 2014 study, HDR noted that the Developer's estimated cost of $1,500/kW in 2014 dollars appeared too low to satisfactorily cover the direct and indirect costs (i.e. capital costs) of the original Black Canyon Pumped Storage Project, which has a different installed capacity than the Seminoe Pumped Storage Project. HDR's cost opinion for Black Canyon was on the order of $2,000 to $2,300/kW in 2014 dollars. Escalating to 2016 using a rate of 3% per year, these costs would be approximately $1,600/kW and $2,100 to $2,400/kW, respectively. Based on our review of the 700 MW Seminoe Project described in the preliminary permit, an average cost opinion for the combined East and West facilities on the order of $2,600/kW would be expected, which compares favorably to the upper range of HDR's escalated cost opinion for the Black Canyon Project.

2.6.1.4 Summary

A comparison of the cost opinions is provided in Table 4 in Appendix A. It would appear that the capital cost of a pumped storage hydroelectric project would be in the range of $1,800 to $2,700/kW.

2.6.2 Annual Operation and Maintenance (O&M) Costs

The "Pumped Storage Planning and Evaluation Guide" dated January 1990 by the Electric Power Research Institute (EPRI) is an appropriate resource for estimating annual costs for pumped storage hydroelectric projects and was used by HDR in their 2014 study. Based on this document, estimating the annual costs to operate and maintain a pumped storage hydroelectric project would include the following.

- Operation and Maintenance (O&M). O&M costs can be estimated by the following equation:

$$\text{O\&M Costs (1987\$/yr)} = 34{,}730 \times C^{0.32} \times E^{0.33}$$

where:

C = Plant Capacity, MW

E – Annual Energy, GWh

- General expenses. A 35% surcharge of the site specific O&M cost is suggested to cover administration expenditures.
- Insurance. To cover payments for insurance, a surcharge of 0.1% of the plant investment cost is suggested.

As noted in the HDR 2014 study, using the EPRI information, a 2.06 escalation factor had to be used to obtain the annual costs in 2014 dollars. Escalating to 2016, using 3% per year, this factor becomes 2.19. Table 5 in Appendix A summarizes the annual costs for the three Projects considered for this Study.

2.6.3 Bi-Annual Outage Costs

As noted in the HDR 2014 study, it is recommended within the hydro industry that bi-annual outages be conducted for inspections and possible repairs following the inspections. The frequency of inspections and possible repairs can vary greatly from project to project depending upon the usage (hours/year) and cycling of the units that may occur, along with site specific conditions that may impact the condition of the units over time. The assumption of taking two units out of service during a 3-week outage every two years for a 4 unit, 1,000 MW powerhouse at an estimated cost of $262,000 in 2014 dollars is reasonable. Escalating this cost using 3% per year would be approximately $280,000 in 2016 dollars and appropriate for budgeting purposes. Our review of the bi-annual outage cost compares favorably with the escalated value; assuming only nominal repairs are required.

2.6.4 Major Maintenance Costs

As noted in the HDR 2014 study, it is also recommended within the hydro industry that a pump-turbine overhaul (i.e. major unit rehabilitation) and generator rewind be scheduled at year 20, and the typical outage duration for this work is approximately 6 to 8 months. Because of the nature of this type of facility, pumped storage projects typically operate more hours per year than conventional generating units. This results in increased cycling of the units, which impacts service life requiring major maintenance. These are reasonable assumptions and suggested for this Study.

Because the scope of this type of rehabilitation work can vary greatly, HDR in their 2014 study suggested an estimated cost of $6.28 million for reversible Francis units at year 20. Escalating this value using 3% per year would be approximately $6.7 million in 2016 dollars. This value appears to be slightly low. In using the "Hydropower Modernization Guide" date July 1989 by the EPRI, a range of major rehabilitation average costs for the size of units being considered at Swan Lake North, JD Pool, and Seminoe (i.e. 100 MW to 300 MW) would be approximately $3.7 to $8.0 million. We suggest using this range of costs for major maintenance costs during the plant life.

2.7 SUMMARY

A matrix of operating parameters and costs for the pumped storage bulk energy storage option is provided in Table 6 in Appendix A. An estimated EPC expenditure timeline for a pumped storage facility based on a 5-year EPC schedule is also provided in Table 7 and Figure 1 in Appendix A.

3.0 Compressed Air Energy Storage

3.1 CAES TECHNOLOGY DESCRIPTION

3.1.1 Current Project Status

The DOE maintains a Global Energy Storage Database.[2] Black & Veatch filtered and sorted the data as shown in Table 8 in Appendix A. The characteristics of the identified projects included in the DOE database for the Technology Categories of Compressed Air Energy Storage (CAES) and Liquid Air Energy Storage (LAES) as of June 14, 2016 are shown. Descriptions for these projects as given in the DOE database are provided in Table 8, Table 9 and Table 10 in Appendix A. While the information in the DOE database is informative, not all the data is current.

As noted in the HDR 2014 study, only two CAES plants are currently in operation; the Power South (formerly AEC) McIntosh plant rated at 110 MW in McIntosh, Alabama which began operation in June 1991 and the 290 MW Huntorf facility which began operation in December 1978 in Hannover, Germany. Both of these plants use a solution mined salt cavity and are diabatic type CAES plants.

Other large CAES plants have been proposed but, as of yet, have not moved forward beyond conceptual design or have been cancelled.

With respect to the larger CAES projects, several were identified in the HDR 2014 study and include the following;

- Western Energy Hub Project
- Norton Energy Storage (NES) Project
- PG&E Kern County CAES Plant
- ADELE CAES Plant in Stassfut, Germany

Updates for CAES plants are as follows:

3.1.1.1 Western Energy Hub Project

The Western Energy Hub is situated directly above a salt dome at a nominal depth of 3,000 feet. Three-dimensional seismic mapping of the formation indicates the salt dome measures at least one mile thick and is approximately three miles wide. The Western Energy Hub project is planned to include multiple phases and services to support the expansion and utilization of renewable energy technologies. The Western Energy Hub will feature solution-mined salt caverns capable of storing natural gas, compressed air, and liquid energy products (including refined products of aviation fuel, diesel, and motor gasoline) underground.

[2] http://www.energystorageexchange.org/projects

Magnum is currently developing the Magnum Refined Products phase and it is expected to be the first underground salt cavern storage facility for refined products in the Rocky Mountain Region. The Magnum Gas Storage Project would also include the first High-Deliverability Multi-Cycle (HDMC) storage facility in the Rocky Mountain Region. The facility will contain four solution mined storage caverns capable of storing 54 billion cubic feet of natural gas. It will be interconnected with the interstate natural gas pipeline system by a new 61-mile-long header pipeline.

In addition to these services, the Western Energy Hub project will include a CAES plant in conjunction with a combined-cycle power generation project. The CAES plant will include additional solution-mined caverns to store compressed air. Off-peak renewable generation will be used to compress air into the caverns. The compressed air will be released to produce power during periods of peak power demand. Magnum anticipates an in-service date for the CAES plant of around 2021. Additional information on the CAES plant as provided to PacifiCorp by Magnum is included in Table 11 in Appendix A.

3.1.1.2 Norton Energy Storage (NES)

As noted in the HDR 2014 study; "In December 2012, First Energy suspended construction on the project due to unfavorable economic conditions including low cost of power prices and insufficient demand. As of September 2013, the Ohio Power Siting Board invalidated the certificate at this site." No further activity has been noted.

3.1.1.3 PG&E Kern County CAES

PG&E continues to evaluate the potential development of a Compressed Air Energy Storage (CAES) project and issued a Request for Offers (RFO) on October 9, 2016. Offers were received on June 1, 2016 with potential negotiations with shortlisted bidders to commence in August 2016. PG&E anticipates the project would be between 100 and 350 MW and would be required to have a minimum storage duration of 4 hours.

The RFO is intended to potentially procure products and services related to the CAES project, and to determine the technical and economic feasibility of energy storage using compressed air in a depleted natural gas reservoir in a porous rock formation, approximately one half to one mile underground.

The depleted natural gas field in San Joaquin County, California was selected for the project site and was subjected to air injection/withdrawal testing. PG&E notes that specific findings on geology, preliminary engineering, environmental analysis, and other information was gathered through testing and analyses for the site.

3.1.1.4 ADELE CAES

No new information could be found for the adiabatic ADELE CAES plant. It does not appear that there has been any recent development activity.

3.1.1.5 APEX Bethel Energy Center

This 317 MW CAES plant with 96 hours of storage was announced in 2013. In 2014 the project was placed on hold. It does not appear that there has been any recent development activity.

3.1.2 Performance Characteristics

3.1.2.1 Site Elevation

Site elevation will impact the compression work required to charge the storage for any CAES technology. Given the compressor section is not directly connected to the expansion turbine for conventional CAES operation, the volume flow of compressed air made available to the expansion turbine is not affected by site atmospheric pressure, but is instead driven by storage pressure. There is only a minor impact for conventional CAES plant output due to variation in exhaust pressure due to site elevation. Other configurations which may include a combustion turbine would see a greater impact due to site elevation.

3.1.2.2 Reliability/Availability

In addition to the historic availability data given in the HDR 2014 study, the Huntorf CAES plant has reportedly operated with 99 percent starting reliability.

3.1.2.3 Start Times

In addition to the start times given in the HDR 2014 study, newer CAES plants can achieve start times and fast ramp rates as noted in Table 11 in Appendix A. This data was provided to PacifiCorp by APEX Magnum.

3.1.2.4 Emission Profiles/Rates

No updates.

3.1.2.5 Air Quality Control System Design

In addition to Dry-Low NO_x combustion technology, water injection may also be used to control NO_x. A selective catalytic reduction (SCR) system can be included in the recuperator design to further reduce NO_x emissions. CO catalysts can also be incorporated into the recuperator design to control CO emissions if required by the CAES plant design and air permit requirements.

3.1.3 Geological Considerations

In addition to the geological formations generally considered for storing compressed air: salt domes, aquifers, and rock caverns; depleted methane reservoirs, which are being considered for the PG&E Kern River CAES plant, can be used.

For the Huntorf and McIntosh plants, there were large vertical salt domes that were accessible for solution mining of single caverns for compressed air storage. In some parts of the country, the salt is deposited between rock layers, creating shorter, squatter caverns with susceptibility to overhead shale spalling. These cavern costs can be higher.

In addition, underwater storage reservoirs, as offered by Hydrostor, are possible. Above ground storage can be considered for smaller plants or when geological conditions are not favorable for a site.

3.1.4 Capital, Operating, and Maintenance Cost Data

Regarding the HDR 2014 study's discussion of project schedule, it is noted the project durations can be driven by the storage system development. Based on a Front End Engineering Design (FEED) study prepared for the NYSEG Seneca CAES Project for a 136 MW to 210 MW utility-owned facility, it is noted that the development time required to complete the three cavern system required for the site was estimated at approximately six years. The CAES plant would have initially gone into service with only one third of the required storage capacity and would not achieve full capability until after approximately five years of commercial operation. The above emphasizes the point that the time required to develop storage can be very site dependent.

3.1.4.1 Capital Costs

The HDR 2014 study assumes project capital costs to include project direct costs associated with equipment procurement, installation labor, and commodity procurement as well as construction management, project management, engineering, and other project and owner indirect costs. The HDR estimate does not include storage cavern cost. Values were presented in 2014 dollars.

Table 11 in Appendix A shows a capital cost, including site development costs, of $1,740/kW as provided by APEX Magnum. No further cost breakdown or clarification for this cost was provided. Black & Veatch interprets this cost to be the installed cost including the solution-mined caverns. This cost is assumed to not include any Owners costs.

Site-specific factors can strongly influence the design of the CAES plant, the cavern and associated costs and ultimately the project economics.

3.1.4.2 Operating Costs

In addition to the operating costs given in the 2014 report, expected O&M costs for the Magnum CAES facility are given in Table 11 in Appendix A.

Appendix A. Data Tables

Table 1 Swan Lake North Pumped Storage Project Facilities Summary[3]

ITEM	DESCRIPTION
Project Type:	Closed-Loop Pumped Storage
Upper Reservoir:	
Storage:	
Total:	3,229 acre-feet (ac-ft)
Live:	2,562 ac-ft
Surface Area:	
Maximum Fill:	64.21 acres (ac)
Minimum Fill:	45.87 ac
Operating Levels:	
Maximum:	6,128 mean sea level (msl)
Minimum:	6,084 msl
Elevation Change During Operation:	44 feet
Overflow Spillway Capacity:	3,230 cubic feet/sec (cfs)
Reservoir Lining:	Asphaltic concrete with geomembrane liner and underdrain system
Lower Reservoir:	
Storage:	
Total:	3,206 ac-ft
Live:	2,581 ac-ft
Surface Area:	
Maximum Fill:	60.41 ac
Minimum Fill:	39.89 ac
Operating Levels:	
Maximum:	4,457 msl
Minimum:	4,408 msl
Elevation Change During Operation:	49 ft
Overflow Spillway Capacity:	3,230 cfs
Reservoir Lining:	Asphaltic concrete with geomembrane liner and underdrain system
Source of Initial Fill and Long-term Refill:	Local Groundwater Agriculture Pumping System (Three existing wells)
Water Conveyance:	
Headrace Penstock:	
Diameter:	13.8 ft (4.2 meter)(1 pipe)
Length:	9,655 ft

[3] The information in this table has been obtained from Exhibits A and B of the FLA filed by Swan Lake North Hydro LLC on October 27, 2015

ITEM	DESCRIPTION
Tailrace Penstock:	
Diameter:	9.8 ft (3.0 meter)(3 pipes)
Length:	1,430 ft
Anchor Blocks (number):	5
Powerhouse:	
Footprint:	
Substructure:	220 ft x 62.5 ft (Bottom 65 ft below ground level @ EL 4248.3 msl)
Superstructure:	305 ft x 176 ft
Crane Capacity:	190 ton
Pump-Turbine/Motor Generator:	
Type:	Variable Speed
Number of Units:	3
Generating Mode:	
Total Maximum Capacity:	393.3 MW
Total Maximum Flow:	3,072 cfs
Gross Turbine Head Range:	Between 1,627 and 1,720 ft
Time per Day:	9.5 hours
Pumping Mode:	
Total Maximum Capacity:	415.8 MW
Total Maximum Flow:	2,427 cfs
Time per Day:	11.5 hours
Annual Energy Production (Based on Operational Modeling for 8.3 hours per Day):	1,187 Gigawatt-hours (GWh)
Transmission Line:	
Voltage:	230 Kilovolts (kV)
Length:	32.8 miles (mi)
Structures:	
Height:	80 to 120 ft
Type:	Steel Monopole
Right-of-Way:	
Length:	32.8 mi
Width:	300 ft
Intertie:	BPA Malin Substation (existing) near Malin, Oregon
Project Boundary Area:	
Reservoirs and Associated Features:	857 ac
Transmission Right-of-Way:	1,637 ac
Total Project:	2,494 ac

Table 2 JD Pool Pumped Storage Project Facilities Summary[4]

ITEM	DESCRIPTION
Project Type:	Closed-Loop Pumped Storage
Upper Reservoirs:	
Configuration:	Two Reservoirs Connected By Tunnel
Total Active Storage:	11,800 ac-ft
Reservoir 1:	
Storage:	
Total:	5,000 ac-ft
Active:	4,700 ac-ft
Surface Area at Maximum Operating Level:	46 ac
Operating Levels:	
Maximum:	2,935 msl
Minimum:	2,785 msl
Elevation Change During Operation:	150 feet
Reservoir 2:	
Storage:	
Total:	7,700 ac-ft
Active:	7,100 ac-ft
Surface Area at Maximum Operating Level:	67 ac
Operating Levels:	
Maximum:	2,935 msl
Minimum:	2,785 msl
Elevation Change During Operation:	150 feet
Dams:	
Type:	Rockfill Embankment
Reservoir 1:	
Height:	165 ft
Length:	5,200 ft
Reservoir 2:	
Height:	165 ft
Length:	6,300 ft
Overflow Spillway:	None
Reservoir Linings:	Concrete
Lower Reservoir:	
Storage:	
Total:	12,100 ac-ft
Active:	11,800 ac-ft
Surface Area at Maximum Operating Level:	100 ac

[4] The information in this table has been obtained from the PAD filed by KPUD in October 2014

ITEM	DESCRIPTION
Operating Levels:	
Maximum:	580 msl
Minimum:	430 msl
Elevation Change During Operation Storage:	150 ft
Dam:	
Type:	Rockfill Embankment
Height:	165 ft
Length:	7,800 ft
Overflow Spillway:	None
Reservoir Linings:	Concrete
Initial Fill and Long-term Refill:	
Source:	Columbia River
Upgraded Existing Pump Station Capacity:	34.6 cfs
Pipeline Length to Lower Reservoir:	11,800 ft
Estimated Annual Net Water Loss Due to Evaporation:	746 ac-ft
Water Conveyance:	
Main Waterway Diameter:	21 ft
Waterway Segments Number/Length:	
Upper Reservoir Connection Tunnel:	1/2,010 ft
Low Pressure Tunnel:	2/1,140 and 1,290 ft, respectively
Vertical Power Shaft:	2/2,100 ft each
High Pressure Tunnel:	2/3,420 and 4,050 ft, respectively
Manifold:	2/270 ft each splitting into 4 penstocks
Penstocks:	4/190, 410, 610, and 820, respectively
Draft Tube Tunnel:	4/250, 350, 320, 420 ft, respectively
Tailrace Tunnel:	2/800 and 1,110 ft, respectively
Powerhouse:	
Type:	Pit Style
Footprint:	
Substructure Each Unit:	86 ft Diameter x 235 ft Deep
Superstructure:	710 ft Long x 96 ft Wide x 88 ft High
Pump-Turbine/Motor-Generator:	
Type:	Variable Speed
Number of Units:	4
Generating Mode:	
Total Capacity:	1,200 MW
Total Rated Flow:	7,000 cfs
Capacity per Unit:	300 MW
Rated Flow Per Unit	1,750 cfs
Rated Net Head:	2,200 ft (approximate)
Time per Day:	10.0 hours

ITEM	DESCRIPTION
Annual Energy Production (Based on Operating 10 Hours a Day, 50 Weeks of the Year):	4,200 GWh
Transmission Line:	
Voltage:	230 kV
Length:	3,000 ft
Intertie:	BPA Harvalum Substation (existing)
Project Area:	2,255 ac

Table 3 Seminoe Pumped Storage Project Facilities Summary[5]

ITEM	DESCRIPTION
Project Type:	Open-Loop Pumped Storage
Configuration:	Two new forebay reservoirs (i.e. East and West), two underground powerhouses, two power tunnels between the forebays and powerhouses, and two tailrace tunnels between the powerhouses and the existing Seminoe Reservoir
Upper Reservoirs:	
East Forebay:	
Storage:	4,800 ac-ft
Surface Area:	85 ac
Operating Level:	7,370 msl
Dam Embankment A:	
Type:	Concrete-Faced Rockfill (CFRD)
Height:	85 ft
Crest Length:	1,320 ft
Dam Embankment B:	
Type:	CFRD
Height:	Varies (5 ft at grade to 55 ft)
Crest Length:	5,890 ft
West Forebay:	
Storage:	3,740 ac-ft
Surface Area:	63 ac
Operating Level:	7,400 msl
Dam Embankment:	
Type:	CFRD
Height:	Varies (5 ft at grade to 60 ft)

5 The information in this table has been obtained from the Preliminary FERC Permit filed by Black Canyon Hydro, LLC in June 2016.

ITEM	DESCRIPTION
Crest Length:	5,890 ft
Lower Reservoir:	Seminoe Reservoir (existing)
Storage:	1,016,717 ac-ft
Surface Area:	20,291 ac
Operating Level:	6,359 msl
Dam (Existing):	
Type:	Concrete Arch
Height:	295 ft
Crest Length:	530 ft
Source of Reservoir Filling:	North Platte River (existing Seminoe Reservoir)
Water Conveyance:	
East Headrace Tunnel:	
Diameter:	18.8 ft (Tunnel/Shaft)
Length:	3,000 ft (Tunnel) 1,250 ft (Shaft)
East Tailrace Tunnel:	
Diameter:	22.6 ft
Length:	1,300 ft
West Headrace Tunnel:	
Diameter:	16.1 ft (Tunnel/Shaft)
Length:	1,300 ft (Tunnel) 1,800 ft (Shaft)
West Tailrace Tunnel:	
Diameter:	19.3 ft
Length:	2,800 ft
East Powerhouse:	
Footprint:	250 ft long x 65 ft wide x 120 ft high
Pump-Turbine/Motor Generator:	
Type:	Variable Speed
Number of Units:	3
Generating Capacity:	400 MW
Maximum Static Head:	1,079 ft
West Powerhouse:	
Footprint:	220 ft long x 55 ft wide x 120 ft high
Pump-Turbine/Motor Generator:	
Type:	Variable Speed
Number of Units:	3
Generating Capacity:	300 MW
Maximum Static Head:	1,098 ft
Annual Energy Production (combined East and West powerhouses):	1,840 GWh
Transmission Line:	

ITEM	DESCRIPTION
Voltage:	230 kV
Length:	35 mi (approximate)
Intertie:	Either Aeolous Substation (PacifiCorp)(planned) near Medicine Bow, WY or TransWest Express Terminal Substation (planned) near Sinclair, WY

Table 4 Cost Opinion Comparison

ITEM (COSTS ARE EXPRESSED IN 2016$)	SWAN LAKE NORTH	JD POOL	SEMINOE (EAST AND WEST)
B&V Cost Opinion ($/kW)	$2,600	$2,700	$2,600
Developer Estimated Capital Cost ($/kW)	$2,500	$1,800 - $2,700	$2,100 - $2,400[6]

Table 5 Annual Cost Comparison

ITEM (COSTS ARE EXPRESSED IN 2016$)	SWAN LAKE NORTH	JD POOL	SEMINOE (EAST AND WEST)
Plant Capacity (MW)	400	1,200	700
Annual Energy (GWh)	1,187	4,200	1,840
O&M Cost ($/yr)	5,400,000	11,500,000	7,400,000
General Expense ($/yr)	1,900,000	4,000,000	2,600,000
Plant Investment Unit Cost ($/kW)	2,600	2,700	2,600
Insurance ($/yr)	1,000,000	3,200,000	1,800,000
Total Annual Cost Opinion ($/yr)	8,300,000	18,700,000	11,800,000

[6] As noted in HDR's 2014 study, developer's estimated capital cost was deemed too low. HDR's cost opinion is shown.

Table 6 Pumped Storage Technology Summary Matrix

ITEM	SWAN LAKE NORTH	JD POOL	SEMINOE (EAST AND WEST)
General Criteria			
Location	OR	WA	WY
FERC Licensing Status	Final License Application Filed	Preliminary Permits Dismissed	Preliminary Permit Filed
Project Type (Closed/Open Loop)	Closed Loop	Closed Loop	Open Loop
Upper Reservoir Maximum Operating Elevation (msl)	6,128	2,935	7,370 (East) 7,400 (West)
Lower Reservoir Maximum Operating Elevation (msl)	4,457	580	6,359
Static Head (maximum/minimum) (ft)	1,720/1,627	2,505/2,205	1,079 (East)(max.) 1,098 (West)(max.)
Upper Reservoir Usable Volume (ac-ft)	2,562	11,800	4,800 (East) 3,740 (West)
Lower Reservoir Usable Volume (ac-ft)	2,581	11,800	> 8,540
Distance to Electrical Transmission Interconnection (mi)	32.8	< 1	35 (approximate)
Interconnection Size (kV)	230	230	230
Performance Characteristics[7]			
Energy Storage/Day (MWh)	3,800	12,000	7,000
Assumed Hours of Storage/Day (hrs)	9.5	10.0	10.0
Installed Capacity (MW)	400	1,200	700
Estimated Annual Generation (GWh)	1,187	4,200	1,840
Annual Forced Outage Rate (% of time)	0 – 3%[8]		
Type of Pump-Turbine/Motor-Generator	Variable Speed		
Round Trip Efficiency (%)	77		
Expected Life of Generating Equipment (yrs)	20+		
Expected Life of Project (yrs)	50+		
Basis of Cost Opinions (Costs are expressed in 2016 dollars.)			
Range of Capital Costs ($/kW)	$1,800 - $2,700		
Range of O&M Costs ($/kW-yr)	$4.45 - $6.99		
Bi-annual Outage Costs ($)	$280,000		
Range of Major Maintenance Costs/Unit ($)	$3,700,000 - $8,000,000		
Replacement Frequency (yrs)	20		

[7] Other performance characteristics, such as ramp rate, minimum loads, and time to switch from pumping to generating modes and vice versa for variable speed units, are presented in Table 3 of HDR's 2014 study and are reasonable and appropriate for this Study.

[8] Range of annual forced outage rate aligns with values presented in HDR's 2014 study.

Table 7 Estimated 5-year EPC expenditure pattern for a pumped storage facility

YEAR	QUARTER	CUMULATIVE QUARTER	QUARTERLY EXPENDITURE (%)	CUMULATIVE EXPENDITURE (%)
		0	0%	0%
1	1	1	2%	2%
1	2	2	2%	4%
1	3	3	3%	7%
1	4	4	3%	10%
2	1	5	4%	14%
2	2	6	4%	18%
2	3	7	5%	23%
2	4	8	5%	28%
3	1	9	6%	34%
3	2	10	6%	40%
3	3	11	8%	48%
3	4	12	8%	56%
4	1	13	8%	64%
4	2	14	8%	72%
4	3	15	7%	79%
4	4	16	7%	86%
5	1	17	7%	93%
5	2	18	3%	96%
5	3	19	3%	99%
5	4	20	1%	100%

Figure 1 Estimated 5-year EPC expenditure pattern for a pumped storage facility

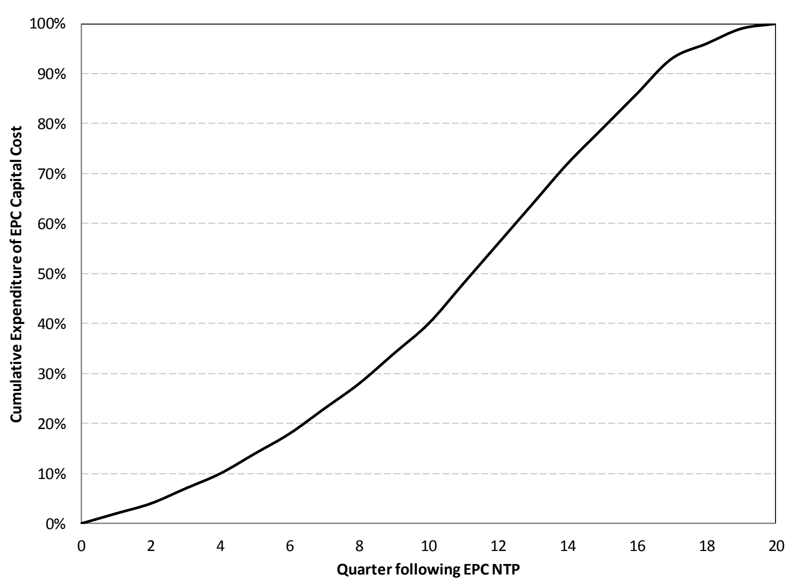

Table 8 Technology Categories of Compressed Air Energy Storage (CAES) and Liquid Air Energy Storage (LAES) as of June 14, 2016

Project Name	McIntosh CAES Plant	PG&E Advanced Underground Compressed Air Energy Storage (CAES)	Next Gen CAES using Steel Piping - NYPA	SustainX Inc Isothermal Compressed Air Energy Storage	Highview Pilot Plant	NYSEG Seneca/Watkins Glen CAES Project	Texas Dispatchable Wind	Apex Bethel Energy Center
Technology Type	In-ground Natural Gas Combustion Compressed Air	In-ground Compressed Air Storage	Modular Compressed Air Storage	Modular Iso-thermal Compressed Air	Modular Compressed Air Storage	In-ground Compressed Air Storage	In-ground Iso-thermal Compressed Air	In-ground Compressed Air Storage
Record Created	6/28/2012	6/29/2012	6/29/2012	7/18/2012	10/31/2012	5/2/2013	5/21/2013	10/11/2013
Last Updated	5/23/2016	6/14/2016	5/24/2016	5/24/2016	5/26/2016	9/5/2014	5/18/2016	1/28/2015
Rated Power in kW	110,000	300,000	9,000	1,500	350	0	2,000	317,000
Duration at Rated Power HH:MM	26:0.00	10:0.00	4:30.00	1:0.00	7:0.00	0:0.00	250:0.00	96:0.00
Status	Operational	Announced	Announced	Operational	Operational	Announced	Operational	Announced
City	McIntosh	San Joaquin	Queens	Seabrook	Slough	Reading	Seminole	Tennessee
State/Province	Alabama	California	New York	New Hampshire	Berkshire	New York	Texas	Texas
Country	United States	United States	United States	United States	United Kingdom	United States	United States	United States
Announcement Date		01.01.2010	01.06.2012		01.03.2010	30.11.2010		01.07.2013
Construction Date					01.02.2011		01.01.2011	
Commissioning Date	01.01.1991	01.01.2020		11.09.2013	31.07.2011		19.12.2012	
ISO/RTO	N/A	CAISO	NYISO	ISO-NE	N/A	NYISO	SPP	ERCOT
Utility	PowerSouth	Pacific Gas and Electric Company	New York Power Authority (NYPA)		SSE (Scottish and Southern Energy)	New York State Electric & Gas (NYSEG)		
Energy Storage Technology Provider	Dresser-Rand			SustainX	Highview Power Storage		General Compression, Inc.	Dresser-Rand
Expected Use Cases:								
Black Start			X			X		X
Electric Supply Reserve Capacity - Non-Spinning								
Electric Supply Reserve Capacity - Spinning	X	X	X		X	X	X	
Load Following (Tertiary Balancing)							X	
Ramping				X				X
Voltage Support								
Electric Energy Time Shift	X	X	X		X	X		
Electric Supply Capacity							X	
Transmission Congestion Relief				X		X		
Transmission Support								
Renewables Capacity Firming		X	X	X	X			
Distribution upgrade due to solar								
Distribution upgrade due to wind								
Transmission upgrades due to solar								
Transmission upgrades due to wind								
Electric Bill Management					X			
Grid-Connected Commercial (Reliability & Quality)								
Grid-Connected Residential (Reliability)								
Frequency Regulation	X	X	X			X		X
Transportable Transmission/Distribution Upgrade Deferral								
Stationary Transmission/Distribution Upgrade Deferral								
Onsite Renewable Generation Shifting							X	
Electric Bill Management with Renewables								
Renewables Energy Time Shift				X	X		X	X
On-Site Power								
Transportation Services								
Microgrid Capability								
Resiliency								
Demand Response								

Project Name	Hydrostor UCAES Demonstration Facility	Hydrostor UCAES Aruba Project	Kraftwerk Huntorf	Pollegio-Loderio Tunnel ALACAES Demonstration Plant	Pre-Commercial Liquid Air Energy Storage Technology Demonstrator	ATK Launch Systems Microgrid CAES [1]	Hybrid Compressed Air Energy Storage and Thermal Energy Storage - UCLA - Southern California Edison [1]	Adele CAES Project [1]
Technology Type	Modular Compressed Air Storage	Modular Compressed Air Storage	In-ground Natural Gas Combustion Compressed Air	Adiabatic Compressed Air Storage	Liquid Air Energy Storage	Modular Compressed Air Storage	Compressed Air Storage	In-ground Iso-thermal Compressed Air
Record Created	10/25/2013	10/25/2013	1/30/2014	6/25/2014	5/25/2016	5/6/2013	9/10/2015	11/4/2013
Last Updated	5/10/2016	7/23/2014	4/18/2016	5/19/2016	5/26/2016	7/11/2014	9/28/2015	10/27/2014
Rated Power in kW	1,000	1,000	321,000	500	5,000	80	0	200,000
Duration at Rated Power HH:MM	4:0.00	8:0.00	2:0.00	4:0.00	3:0.00	0:45.00	0:0.00	5:0.00
Status	Under	Contracted	Operational	Under	Under	Under	Announced	Under
City	Toronto	San Nicolas	Große Hellmer 1E	Loderio	Bury	Promontory	Pomona	Staßfurt
State/Province	Ontario	Aruba	Elsfleth	Ticino	Lancashire	Utah	California	Sachsen-Anhalt
Country	Canada	Netherlands	Germany	Switzerland	United Kingdom	United States	United States	Germany
Announcement Date		01.10.2013		01.01.2013	13.02.2014	06.05.2013	20.08.2015	
Construction Date	01.01.2013	01.02.2015		13.06.2014	26.02.2015			01.01.2013
Commissioning Date	01.09.2014		12.01.1978	01.06.2016				
ISO/RTO	IESO	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Utility		WEB Aruba N.V.	E.ON		Electricity North West	Rocky Mountain Power	Southern California Edison	
Energy Storage Technology Provider	Hydrostor	Hydrostor	BBC, Alstom	ALACAES	Highview Power Storage			
Expected Use Cases:								
Black Start			X					
Electric Supply Reserve Capacity - Non-Spinning				X	X			
Electric Supply Reserve Capacity - Spinning			X					
Load Following (Tertiary Balancing)								
Ramping								
Voltage Support					X			
Electric Energy Time Shift			X				X	X
Electric Supply Capacity								X
Transmission Congestion Relief					X			
Transmission Support					X			
Renewables Capacity Firming	X	X						
Distribution upgrade due to solar								
Distribution upgrade due to wind								
Transmission upgrades due to solar								
Transmission upgrades due to wind								
Electric Bill Management				X		X		
Grid-Connected Commercial (Reliability & Quality)								
Grid-Connected Residential (Reliability)								
Frequency Regulation			X		X			
Transportable Transmission/Distribution Upgrade Deferral								
Stationary Transmission/Distribution Upgrade Deferral								
Onsite Renewable Generation Shifting								
Electric Bill Management with Renewables								
Renewables Energy Time Shift	X	X		X				
On-Site Power						X		
Transportation Services								
Microgrid Capability								
Resiliency								
Demand Response								

Note 1: DOE still verifying record entry.
Source: DOE Global Energy Storage Database (http://www.energystorageexchange.org/projects)

Table 9 CAES and LAES project descriptions

Project Name	Rated Power in kW	Duration at Rated Power HH:MM	Description
McIntosh CAES Plant	110,000	26:0.00	The 2nd commercial CAES plant, in operation since 1991. Like the Huntorf plant, the McIntosh Unit 1 facility stores compressed air in a solution-mined salt cavern. The cavern is 220 ft in diameter and 1,000 ft tall, for a total volume of 10 million cubic feet. At full charge, the cavern is pressurized to 1,100 psi, and it is discharged down to 650 psi. During discharge, 340 pounds of air flow out of the cavern each second. The cavern can discharge for 26 hours. The plant also utilizes nuclear-sourced night-time power for compression and then produces peak power during the day by releasing the compressed air into a 110-MW gas-fired combustion turbine built by Dresser Rand. The turbine unit also makes use of an air-to-air heat exchanger to preheat air from the cavern with waste heat from the turbine. The waste heat recovery system reduces fuel usage by roughly 25%. Compared to conventional combustion turbines, the CAES-fed system can start up in 15 minutes rather than 30 minutes, uses only 30% to 40% of the natural gas, and operates efficiently down to low loads (about 25% of full load). The key function of the facility is for peak shaving.
PG&E Advanced Underground Compressed Air Energy Storage (CAES)	300,000	10:0.00	A 300 MW A-CAES demo plant will use an underground storage container (depleted gas reservoir), and next-generation turbomachinery. The project has 3 phases: Phase 1 - preliminary engineering, geologic reservoir engineering, econmoic analyses, and regulatory permitting; Phase 2 - Construction and plant commissioning; Phase 3: Plant operation and plant performance monitoring. Ph 2 of the project will go ahead if the Ph1 results show PG&E and California regulatory management that the project is cost effective.
Next Gen CAES using Steel Piping - NYPA	9,000	4:30.00	9-MW plant will use steel piping to hold pressurized air instead of geologic based air store. Preliminary plant design complete; NYSERDA funding expected in July 2012; Vendors, utility sponsor, and site location determined. Groundbreaking slated for 2013 to 2014 time frame.
SustainX Inc Isothermal Compressed Air Energy Storage	1,500	1:0.00	SustainX is constructing a 1.5MW pilot system in Seabrook, New Hampshire to demonstrate their modular isothermal compressed air energy storage system (ICAES). This second generation ICAES system is scheduled for completion in 2013, with the third generation field-deployed ICAES system ready for operation by 2014. The current schedule would have SustainX's isothermal system ready for commercial production in 2015. SustainX's ICAES system captures the heat from compression in water and stores the captured heat until it is needed again for expansion. Storing the captured heat eliminates the need for a gas combustion turbine and improves efficiency. SustainX achieves isothermal cycling by combining patented innovations with a design control on mature industrial components and principles. The system is designed for a 20-year lifetime. It achieves full power output from start-up in less than one minute, and it does not use toxic chemicals.
Highview Pilot Plant	350	7:0.00	Highview's technology uses off-peak or 'wrong-time' power to liquefy air (710 litres of air becomes one litre of liquid air), which is then held in a tank until electricity is required. The liquid air is then returned to gaseous form, expanding 710 times, to drive a turbine. Extreme cold is recovered and stored to assist with subsequent liquefaction, thus greatly improving the overall efficiency of the system. If waste heat is available (e.g. from a neighbouring power plant or industrial process) then this can be introduced at the expansion phase, enhancing system efficiency.
NYSEG Seneca/Watkins Glen CAES Project	0	0:0.00	***09/2012: NYSEG has concluded that the economics of the project are not favorable for development in the current and forecast wholesale electric market in New York State, and further project development work is not warranted.*** Read the final project report here: http://goo.gl/HbiWQ9 New York State Electric & Gas (NYSEG) intended to build an advanced compressed air energy storage (CAES) plant with a rated capacity of 150 MW (2.4 GWh) using an existing 4.5 million cubic foot underground salt cavern in Reading, New York. The plant was to be sited between the bulk of U.S. wind resources and the heavy population centers of the East Coast. The plant will have the capacity to operate 16 hours a day and will provide energy arbitrage for approximately 2,300-2,500 hours each year. It will use off-peak electricity to compress air into the cavern. When electricity is needed the air will be withdrawn, heated, and passed through a turbine to drive an electric generator, burning one-third the amount of fuel compared to conventional combustion turbines. NYSEG's CAES plant will provide flexible generation capability to accommodate fluctuations in load. The plant will be tied to NYSEG's cross-state 230 kV/345 kV transmission system that feeds major metropolitan centers in Central New York. The 230 kV line is the recipient of a large proportion of wind power and is tied to the New York City load areas. It will provide redundancy in capacity, ensure against congestion and power fluctuations, and can provide improved power quality to the grid. Iberdrola USA, the parent of NYSEG, plans to conduct a feasibility study in the future to determine the ability to increase the plant's capacity to 360 MW or greater.
Texas Dispatchable Wind	2,000	250:0.00	The Gaines, Texas Dispatchable Wind Project is a 2.0MW wind generation project located in West Texas. It is owned and operated by Texas Dispatachable Wind 1, LLC, a subsidiary of General Compression. The project consists of a wind turbine, a General Compression Advanced Energy Storage (GCAES™) system, a storage cavern, and other electrical & ancillary facilities. The project has the capability to, during periods of low demand, store portions of the energy generated by the wind turbine and later, during periods of increased demand, release the stored energy. Construction of the project began in 2011 and the project was commissioned in late 2012.
Apex Bethel Energy Center	317,000	96:0.00	Development of the 317 MW compressed air energy storage facility with 96 hours of storage has been put on hold as of 10/2014. New information on development is anticipated in summer 2015.

Table 10 CAES and LAES project descriptions (continued)

Project Name	Rated Power in kW	Duration at Rated Power HH:MM	Description
Hydrostor UCAES Demonstration Facility	1,000	4:0.00	Construction is underway on a 1 MW/4 MWh demonstration facility to showcase Hydrostor's first-of-a-kind system.□ Located Approx. 5km from the shore of Toronto, the system will be situated in Lake Ontario at a depth of 80m.
Hydrostor UCAES Aruba Project	1,000	8:0.00	Hydrostor's proprietary technology is based on a simple idea: Anchor a low-cost air cavity to the bottom of a lake or ocean floor, and store energy in it by filling it with compressed air created using surplus renewable energy. The energy is discharged from the system by releasing the air stored underwater to drive a turbine recreating electricity when it is most needed - either to meet daily demand peaks or to cover periods of calm winds or cloud cover that prevent power from being harnessed.
Kraftwerk Huntorf	321,000	2:0.00	1st commercial CAES plant, operational since 1978. The 321-MW plant utilizes nuclear-sourced night-time power for compression and produces peak power during the day via a natural gas turbine. The facility stores the compressed air in two ""solution-mined"" salt caverns which comprise a total of 310,000 cubic meters. (Water was pumped into and out of a salt deposit to dissolve the salt and form the cavern.) The depth of the caverns is more than 600 m which ensures the stability of the air for several months' storage, and guarantees the specified maximum pressure of 100 bar. One cavern is cycled on a diurnal basis. The second cavern serves as a black start asset if the nearby nuclear power plant unexpectedly goes down.
Pollegio-Loderio Tunnel ALACAES Demonstration Plant	500	4:0.00	A demonstration plant to test a novel advanced adiabatic compressed air energy storage concept. An abandoned tunnel in the Swiss alps is used as the air storage cavern and a packed bed of rocks thermal energy storage is used to store the heat created during compression. The thermal energy storage is placed inside the pressure cavern. Project construction concluded in April 2016. The project is operating in the commissioning phase from April 2016 until June 2016. In June 2016 the plant will start full operation.
Pre-Commercial Liquid Air Energy Storage Technology Demonstrator	5,000	3:0.00	Highview and project partners, leading UK renewable energy and recycling company Viridor, were awarded funding of more than £8 million ($11.6 million) by the British Government Department of Energy & Climate Change (DECC) for a 5 MW Liquid Air Energy Storage (LAES) technology system. The funding is supporting the design, build and testing of a Pre-Commercial LAES Technology Demonstrator alongside Viridor's landfill gas generation plant at Pilsworth in Greater Manchester UK. In addition to providing energy storage, the LAES technology plant will convert low grade waste heat from the onsite landfill gas engines to electrical power. The project will operate for at least one year and will demonstrate LAES providing a number of grid balancing services in the UK, including Short Term Operating Reserve (STOR), Secondary frequency response testing, Triad Avoidance (supporting the grid during the winter peaks) and also testing for the US regulation market.
ATK Launch Systems Microgrid CAES [1]	80	0:45.00	The Alliant Techsystems (ATK) Launch Systems project takes place at a single customer site – but, it's a large one. ATK Launch Systems in Promontory, Utah comprises over 540 buildings on a sprawling 19,900-acre site accessible by 75 miles of roads. Their power system of three main substations and 60 miles of power lines deliver about 17 MW (on-peak) to the facilities, with an annual energy bill of over $15 million. In recent years, utility tariff changes have significantly increased the portion of the monthly bills attributable to demand charges. ATK's Corporate Energy Team, established in 2003, and has already implemented a number of energy saving projects, realizing energy costs reductions of $2 million/year or more. As a result of a comprehensive plant-wide energy assessment (partially funded by DOE) in 2006/2007, ATK identified a new set of energy projects at the Promontory site. This project will integrate an ambitious and highly diverse set of distributed resources. These include four heat recovery systems using organic Rankin cycle (ORC) generators connected to Ormat energy converters, for a total of 1400 kW. Heat for the system will be supplied by a concentrating solar thermal array, air compressor waste heat and low pressure steam. The project will also incorporate about 140 kW of wind turbines, a yet-to-be-determined amount of hydro turbine capacity, and about 40 kW of micro-hydro turbines. For storage, the project includes up to 1440 kW of pumped hydro capacity for two - four hours, and an above-ground compressed air energy storage (CAES) and generation system (80 kW capacity for 30-60 minutes).
Hybrid Compressed Air Energy Storage and Thermal Energy Storage - UCLA - Southern California Edison [1]	0	0:0.00	Engineers from the University of California Los Angeles Henry Samueli School of Engineering and Applied Science have won a $1.62 million grant to build a hybrid energy storage system. The team with work with Southern California Edison, which will help operate the system on the Cal Poly Pomona campus upon completion, to build a system to store "energy harvested from intermittently productive renewable sources such as solar panels and wind farms, then releases that energy into the grid when demand is high," according to a news release. Lead by Pirouz Kavehpour, a professor of mechanical and aerospace engineering at UCLA, the team will build a system that uses both compressed air and thermal energy storage technologies to enhance capacity and reduce costs. "Our estimated cost of energy for this unit is about $100 per kilowatt hour, which is much lower than any battery system of which we are aware," said Kavehpour, in a prepared statement.
Adele CAES Project [1]	200,000	5:0.00	The first adiabatic CAES project; the heat that appears during compression is also stored, and then returned to the air when the air is expanded. Construction will begin in 2013 in Staßfurt, a city in Sachsen-Anhalt, Germany (ADELE stands for the German acronym for adiabatic compressed air energy storage for electricity supply). The project is a joint effort between RWE, General Electric, Zueblin, and the German Aerospace Center. The German Federal Ministry of Economics is also providing state funding. Altogether, the project members will contribute an amount of EUR 10 million.

Note 1: DOE still verifying record entry.
Source: DOE Global Energy Storage Database (http://w w w .energystorageexchange.org/projects)

Table 11 Magnum CAES Data

RESOURCE	CAES
Installation Name	320 MW Magnum CAES
Base Capital ($)	556,800,000
Pro-rated site development cost ($)	included in Base Capital
Net Capacity (MW)	320
Rated Energy Capacity (MWh)	15,360
Expected use cases	Energy, capacity, spinning, regulation, non-spinning, black start
Total Implementation Time (yrs)	3
Commercial Operation Year	2021
Design Life (yrs)	30+
Base Capital ($/KW)	1,740
Var O&M ($/MWh)	0.77
Fraction Var O&M Capitalized	0.41
Fixed O&M ($/KW-yr)	18.9
Fraction Fixed O&M Capitalized	0
Average Full Load Heat Rate (HHV Btu/KWh)	4,227
EFOR (%)	3%
POR (%)	1.5%
Heat Input for Warm Start (HHV, MMBtu)	0
Water Consumed (Gal/MWh)	294
SO2 (lbs/MMBtu)	0.001
NOx (lbs/MMBtu)	0.009
Hg (lbs/TBTu)	N/A
CO2 (lbs/MMBtu)	117
Minimum Capacity (MW)	3.3
Spinning Reserves (MW)	156.7
Run-up Rate (first fire to min capacity, warm start, MW/hr)	180
Ramp Up Rate (min capacity to full load, MW/min)	32
Ramp Down Rate (full load to min capacity, MW/min)	32
Start-Up Time to Minimum Capacity (min)	5 min
Minimum Operational Up Time (hr)	N/A
Minimum Operational Down Time (hr)	N/A
Recharge rate (MWh/hour)	150
AC to AC efficiency (%) [1]	~50%

Note 1: The basis for this efficiency value is unclear. PacifiCorp has requested Magnum to clarify the definition used to determine this value but at the time of this report, clarification had not been received. Given the technology for CAES can include the use of fuel during the discharge mode, parameters for Energy Charge Ratio (kWh_{in}/kWh_{out}) and Net Heat Rate (Btu/kWh) during discharge mode (which considers the fuel added) are metrics typically used.