Energy Research and Development Division

FINAL PROJECT REPORT

Appendix I: Groundwater Bank Energy Storage Systems

A Feasibility Study for Willow Springs Water Bank

Attachments II-V: Supplementary Documents for Pumped Storage Analysis at Willow Springs Water Bank

California Energy Commission

Edmund G. Brown Jr., Governor

December 2017 | CEC-500-2017-042-API

Appendix I: Pumping Test Data Summary for Willow Springs Water Bank. HDR Memorandum.

Memorandum

To:	Zachary Ahinga and Mark Beuhler, Willow Springs Water Bank		
From:	John Koreny, HDR	Project:	Willow Springs Water Bank
CC:	Steve Friedman, HDR		
Date:	September 14, 2016	Job No:	10018518

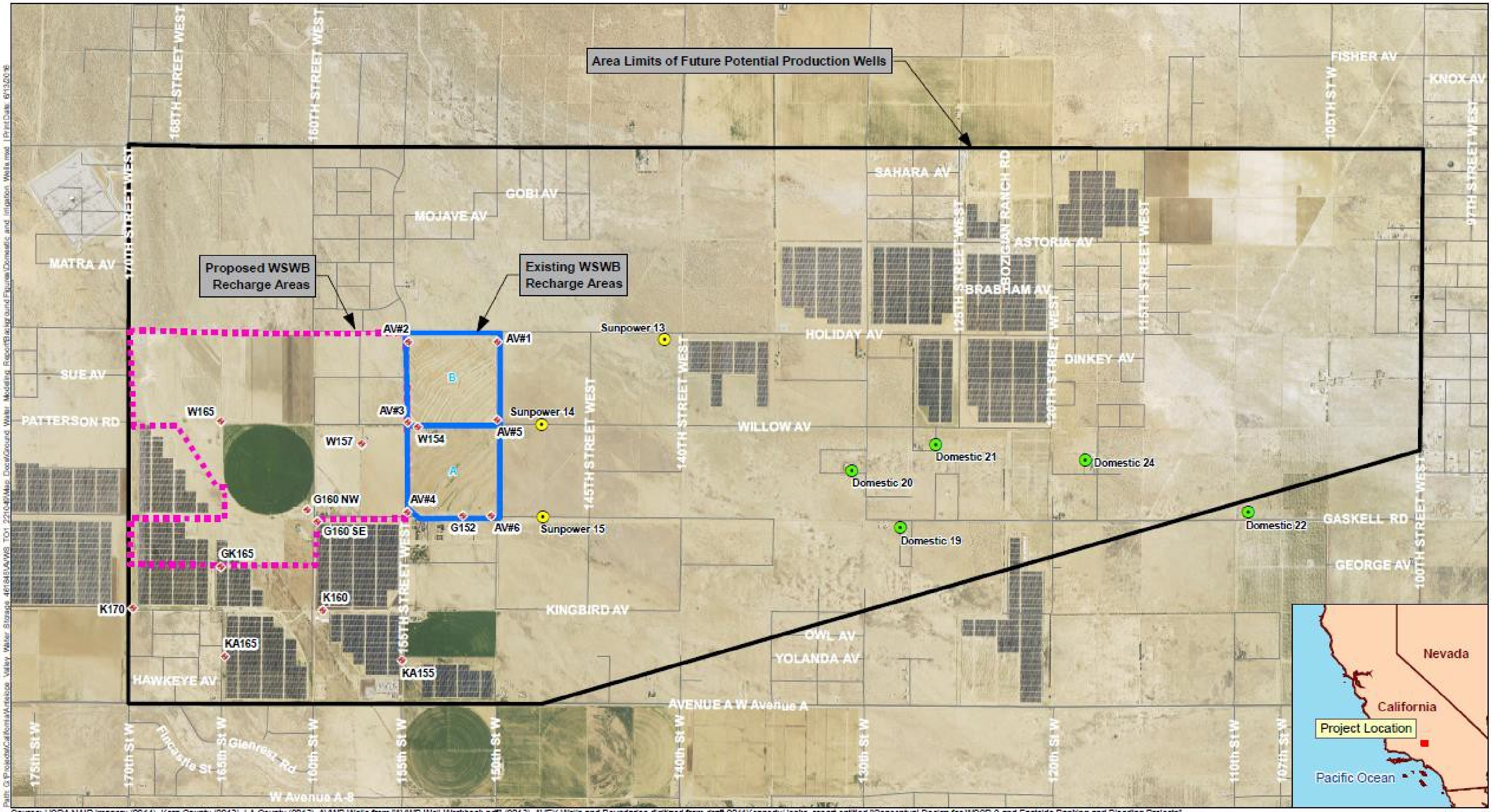
RE: AV-2, AV-3 and AV-5 Pumping Test Data Summary
Willow Springs Water Bank, Kern County, CA

Willow Springs Water Bank (WSWB) owns six large-diameter production wells (AV-1 to AV-6) surrounding the existing recharge basins. The well locations are shown on Figure 1. WSWB requested an evaluation of the approximate increase in ground water levels (mounding) that will occur if these wells were operated as injection wells.

The hydrologic response during the pumping tests at AV-2, AV-5 and AV-3 are summarized in Table 1 and shown in Figure 2 and Figure 3. The groundwater level increase in the production wells will be approximately the inverse of the ground water level decrease during pumping. For example, if the ground water level in the well decreases by 100 feet after pumping at 1,000 gpm, the ground water level in the well will rise by approximately 100 feet during injection at 1,000 gpm. This is only a rough approximation and the initial increase in ground water level mounding may vary depending on well screen intervals, aquifer lithology in the vadose zone and other factors.

Table 1. Summary of Pump Test Data for AV-2 , AV-3 and AV-5.

Well ID, Pumping Rate During Aquifer Test	Ground Water Level Decrease During Pumping Test			
	Well Drawdown (ft) After 1 Hour of Pumping	Well Drawdown (ft) After 2 Hours of Pumping	Well Drawdown (ft) After 3 Hours of Pumping	Well Drawdown (ft) After 4 Hours of Pumping
AV-2, 1400 gpm	115	120	125	133
AV-5, 2100 gpm	120	131	135	136
AV-3, 1300 gpm	101	124	140	158



Path: G:\Projects\California\Antelope Valley Water Storage 461846\AVWB TO1 2210\Map Docs\Ground Water Modeling Report\Background\Figures\Domestic and Irrigation Wells.mxd | Print Date: 6/13/2016

Source: USDA NAIP Imagery (2014), Kern County (2013), LA County (2013), AVWB Wells from "AVWB Well Workbook.pdf" (2013), AVEK Wells and Boundaries digitized from draft 2011Kennedy/Jenks report entitled "Conceptual Design for WSSP-2 and Eastside Banking and Blending Projects".

Figure 1

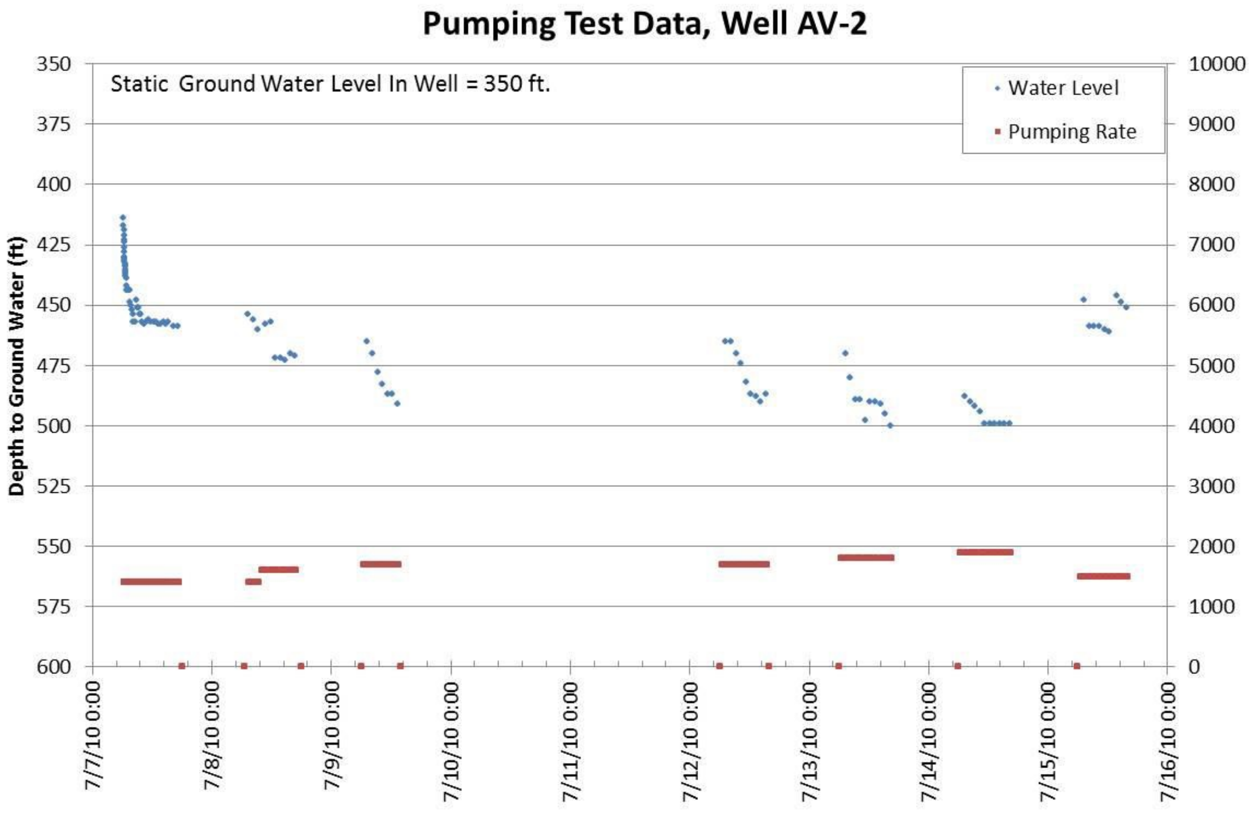
Domestic and Irrigation Wells

Ground Water Sampling Locations

April, 2016

Willow Springs Water Bank

Kern County | California


Pumping Test Data, Well AV-2

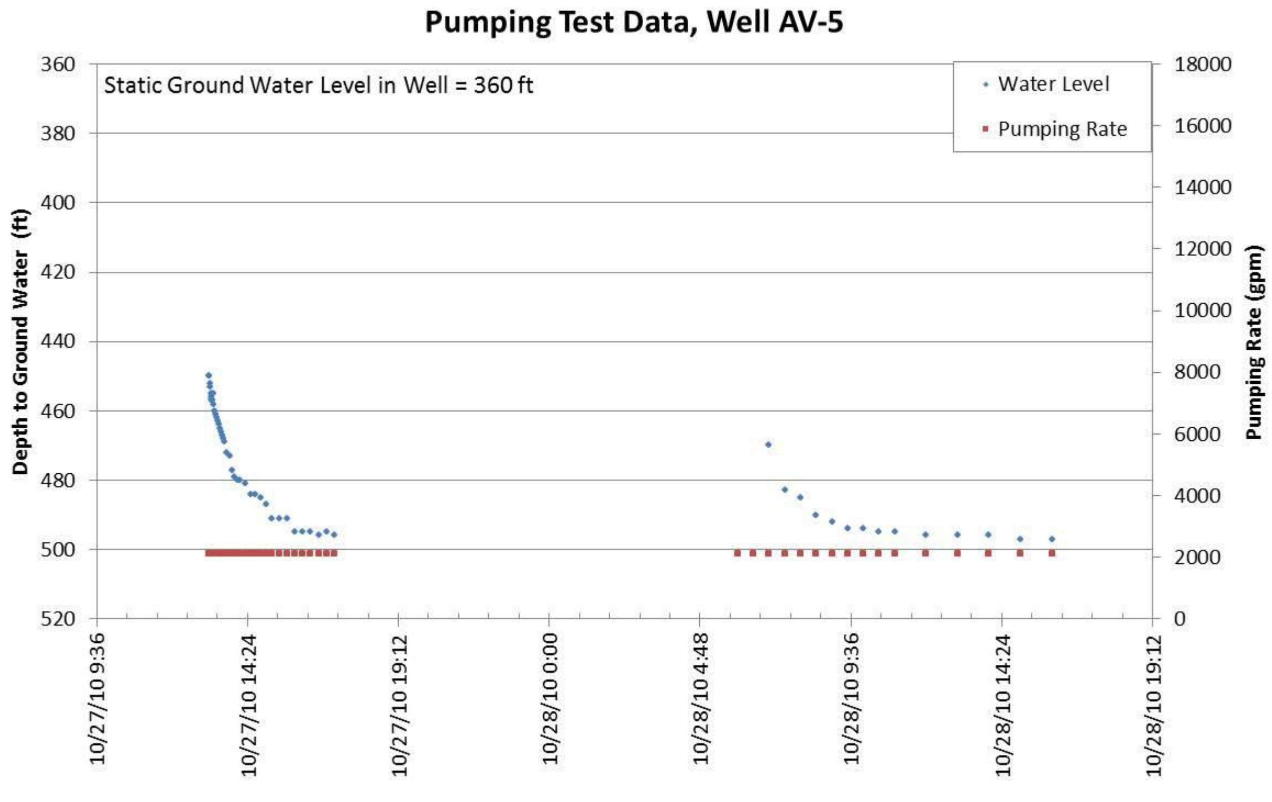

Pumping Test Data, Well AV-5

Figure 2. Pump Test Data for Wells AV-2 and AV-5.

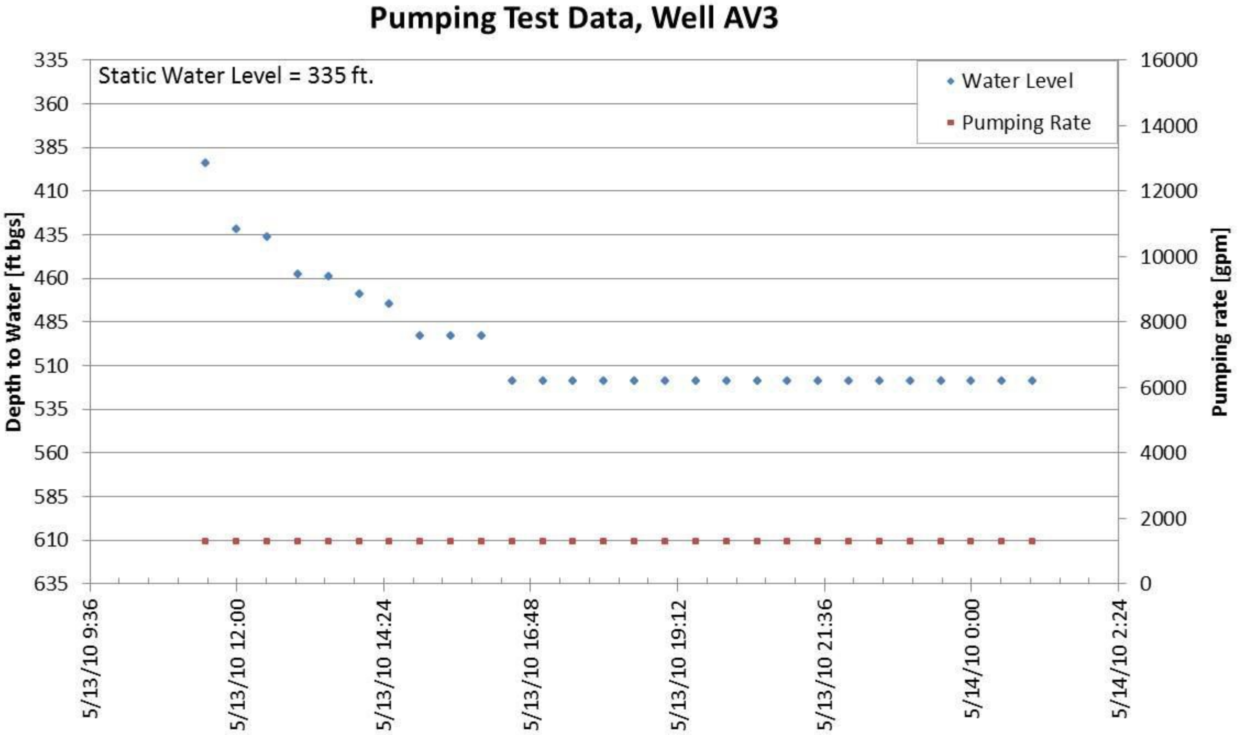


Figure 3. Pump Test Data for Well AV3

Attachment III: Antelope Valley Water Storage (AVWS) Project Pumped Storage Study

Antelope Valley Water Supply Project

Pumped Storage Study

Willow Springs Water Bank

Rosamond, California
April 20, 2017

Contents

Tables

Figures

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Executive Summary

The Willow Springs Water Bank (WSWB) is located on approximately 1,838 acres of agricultural land in the Antelope Valley near Rosamond, California. The WSWB offers municipal water authorities the ability to store up to 500,000 acre-feet of water in underground aquifers during wet years for use during droughts. HDR was enlisted to assist WSWB management with plans for developing hydropower capabilities on the WSWB site, with the concept of making dual use of existing or planned project features to support a new pumped storage facility referred to as the Antelope Valley Water Storage (AVWS) Project. The Project must not interfere with the primary operations of WSWB as a water bank, and will be designed to generate hydropower during hours of peak demand. Water used to generate electricity will be replaced during non-peak demand hours by pumping from the relatively small lower storage reservoir back to the aqueduct.

HDR completed an assessment of whether reversible, Francis type pump-turbines can be utilized for this application. Based on HDR's evaluation, it would be more technically and economically feasible to proceed with dedicated pumps and turbines rather than reversible pump-turbine technology. The reasoning behind this conclusion, as discussed in detail in this report, is due to two key factors:

- The predominant factor relates to hydraulic transients in the proposed 9.25-mile-long pipeline that would be utilized for the project. The massive water column must be slowed or accelerated very carefully or undesirable pressure fluctuations may occur. This is not readily possible with a reversible, Francis type turbine, which is classified as a reaction type turbine. In this type of turbine, the energy must be taken off the pump-turbine runner quickly to avoid high overspeed conditions. This can be accomplished with pressure relief / water bypass devices, which drive the cost up and complicate the control scheme. In some cases, the pressure may drop below the water vapor pressure. This would most likely occur on load acceptance. If the flow rate is increased too rapidly, the water may flash to steam at some point in the water conveyance system and a void will form. It can then suddenly collapse, creating a large spike in pressure. Performance of a hydraulic transient analysis is recommended to further evaluate this issue.

- The second factor is that, to date, no turbine vendor has been able to design and manufacture a pump-turbine in this size range (i.e., 5MW) that can compete with a separate pump and turbine system design. Reversible pump-turbines typically become technically and economically feasible at over 50 MW. HDR contacted a number of reputable turbine vendors and their feedback was consistent; no manufacturer in the industry has designed and manufactured a reversible pump-turbine of this size. It can be done, but the cost would be very high and therefore not economically viable. Consequently, HDR recommends a separate turbine/generator and pump/motor combination for this project.

Additional details of HDR's evaluation are presented herein. Further feasibility level study is recommended to determine the range of pump capacity that could be achieved with a variable speed option, and to optimize the design concept for the proposed facility including the layout of the powerhouse. The results of such a study would have an impact on the selection of the equipment.

1 Project Background

The Willow Springs Water Bank (WSWB), formerly known as the Antelope Valley Water Bank, provides water authorities the ability to store up to 500,000 acre-feet of water in the Neenach Sub-basin during wet years for use during droughts. Groundwater modeling has demonstrated that the bank could be expanded to 1,000,000 acre-feet in the future. The WSWB is located on 1,838 acres of agricultural land in the Antelope Valley near Rosamond, California. The area for recharge and recovery facilities is bounded by Rosamond Avenue to the north; Avenue A to the south (Kern County–Los Angeles County Line); 170th Street West to the west; and 100th Street West to the east.

The land is part of a natural aquifer, the Antelope Valley groundwater basin, and is located in close proximity to two of the largest north-south aqueducts in California, namely the California Aqueduct and the Los Angeles Aqueduct No. 2. In 2009, construction of recharge basins was completed, increasing the recharge capacity of the water bank to over 40,000 acre-feet per year. A combination of federal grant money and private funds was used for this purpose. The first recharge operations began in 2010. When not percolating, WSWB lands are used for agricultural purposes, mainly grazing lands and carrots, alfalfa, and cover crops.

The WSWB is an important component of the Antelope Valley Integrated Regional Water Management Plan. It is beneficial to Kern County, Los Angeles County, and other regions. The WSWB enhances the local economy by providing greater water reliability, facilitating solar developments, by maintaining agriculture. Ten percent of all imported water that is recharged is left behind during the recovery phase to help stabilize groundwater levels and mitigate basin over-drafting. The WSWB provides the Antelope Valley with an excellent and environmentally friendly way to store water, resulting in optimum water availability at competitive costs.

WSWB management is interested in exploring the possibility of adding pumped storage facilities to the water bank. WSWB has requested HDR to perform a high level conceptual study and cost opinion for these facilities.

2 Project Design Basis

The proposed AVWS Pumped Storage Project will generate electricity every day of every year. Power generation will occur regardless of whether the water bank is recharging, idle, or extracting water. It is expected that the WSWB will recharge water during wet years. Wet years occur about one in every three years ("wet" years as defined by the California Department of Water Resources have occurred 32 percent of the time based on historical record). Using a pumped storage concept as a means to allow generating peak power every year is more valuable than generating only once every three years.

2.1 Operating Scenarios

The following operating scenarios were evaluated and factored into HDR's study.

- **Recharge Year (wet) -** A recharge year involves up to 385 cubic feet per second (cfs) of recharge. It will occur during wet or normal year conditions, enabling a total recharge of 280,000 acre-feet per year. During a recharge year, 250 cfs will be used to generate electricity 24 hours a day. The estimated occurrence rate is one year in three based on historical record (32 percent).

- **Idle Year -** An idle year does not have any recharge or extraction activity. During an idle year, 250 cfs of water will be used to generate electricity for the four peak hours daily from the upper reservoir. The water will be replaced over the course of the remaining 20 hours. It will be pumped at a flow rate of 23 cfs to minimize pipe friction losses. Eighty-three (83) acre-feet of storage volume is needed to provide four hours of power generation. The estimated occurrence rate is one year in three based on the historical record (33 percent).
- **Extraction Year (dry) -** Extractions will occur in a dry year. During an extraction year, 250 cfs will be pumped back to the California Aqueduct and 60 cfs will be delivered to the Antelope Valley-East Kern Water Agency (AVEK) potable system for exchange or to the California Aqueduct. The total extraction is 310 cfs. During the four peak hours, electricity will be generated by conveying 250 cfs from the upper reservoir down to the turbine / generator. Eighty-three (83) acre-feet of storage volume is needed to provide four hours of 5 MW power generation. The estimated occurrence rate is one year in three based on historical record (35 percent).

2.2 New Pipeline Data

Data utilized in HDR's assessment for the proposed new pipeline installation was provided by the client and is presented in Table 1. This data was the basis for the friction loss calculation results presented in Table 2.

Table 1. New Pipeline Data

Pipeline Inner Diameter	84.0 in
Pipeline Length	9.25 miles / 48,840 ft
C/S Area	38.48 ft^2
Pipe Material	Welded Carbon Steel

3 Technical Evaluation

3.1 Static Head Available

A viable site for an upper reservoir must provide a large enough static head, or elevation difference between the upper reservoir and the lower reservoir. This elevation difference will determine the amount of energy produced. The greater the static head, the more ideal the project configuration.

The upper reservoir sites considered for the AVWS Project are located near the California Aqueduct at Avenue H and 170th St. W. The upper reservoir sites range in elevation from 2,930 feet to 3,000 feet. The lower reservoir sites range in elevation from 2,620 feet to 2,640 feet. This creates a range of potential head from 290 feet to 380 feet. A 330-foot static head has been assumed for power and hydraulic calculations in this evaluation. This is based on the sites most likely to be selected for the upper and lower reservoirs. Pipe friction and pump/turbine energy losses must be factored into the calculation of pumping power required as well as expected generating capacity.

3.2 Friction Loss Calculation

HDR performed a friction loss calculation as part of this study. Results of this calculation are provided in Table 2.

Table 2. Friction Loss Calculation Results

Pipeline Flow		Head loss (ft)	Velocity (ft/sec)
(cfs)	(gpm)		
0	0	**0.0**	0.0
50	22,440	**2.3**	1.3
100	44,880	**8.3**	2.6
125	56,100	**12.6**	3.2
140	62,832	**15.6**	3.6
200	89,760	**30.8**	5.2
250	112,200	**47.1**	6.5
300	134,640	**66.9**	7.8
310	139,128	**71.0**	8.1
385	172,788	**108.2**	10.0
450	201,960	**146.4**	11.7
500	224,400	**179.6**	13.0

Key flow values in Table 2 are shown in **red**. A graphical representation of this data is shown in Figure 1.

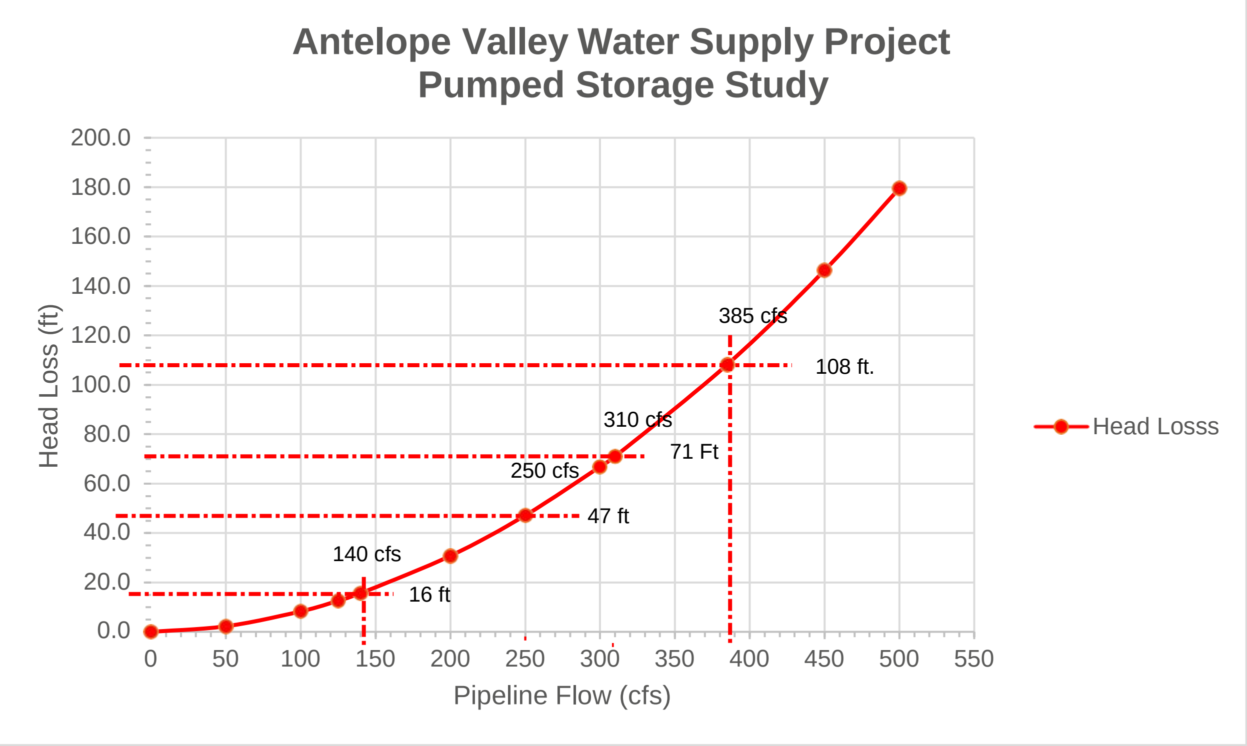

Figure 1. Water Conveyance System Friction Loss versus Flow

4 Projected Pumped Storage Operation

The proposed pumped storage facilities will be phased to match the build-out of WSWB facilities. The generating mode capacity (MW) potential is as follows for each phase:

- Project Phase 1: 140 cfs of flow
- Project Phase 2: 250 cfs of flow

4.1 Generating Mode

The projected pumped storage operation characteristics for the AVWS Project in the generating mode are presented in Table 3.

Table 3. Projected Pumped Storage Operation – Generating Mode

3,245 kW @ 140 cfs			
5,225 kW @ 250 cfs			
4,100 kW @ 250 cfs, max flow 385 cfs			
Flow (cfs)	**140**	**250**	**250/385 max**
Turb. Eff.	**0.91**	**0.91**	**0.91**
Gen. Eff.	**0.96**	**0.96**	**0.96**
Water Density	62.35	62.35	62.35
Gross Head (ft)	330	330	330
Head Loss (ft)	**16**	**47**	**108**
Net Head (ft)	314	283	222

During a recharge year, pipeline flow will be at 385 cfs. As can be seen in the table above, there is slightly greater than a 1 MW reduction due to increased friction loss if generating at 250 cfs while the maximum generate mode flow in the conduit is 385 cfs. When the flow progresses past around 250 cfs, the friction loss rate increases rapidly.

4.2 Pump Mode

The projected pumped storage operation characteristics for the AVWS Project in the pump mode are presented in Table 4.

Table 4. Projected Pumped Storage Operation – Pump Mode

4,905 kW @ 140 cfs			
9,540 kW @ 250 cfs			
10,150 kW @ 250 cfs, max conduit flow of 310			
Flow (cfs)	**140**	**250**	**250/310 max**
Pump Eff.	**0.87**	**0.87**	**0.87**
Motor Eff.	**0.96**	**0.96**	**0.96**
Water Density	62.35	62.35	62.35
Gross Head (ft)	330	330	330
Head Loss (ft)	**16**	**47**	**71**
Total Head (ft)	346	377	401

During an extraction year, pipeline flow will be at 310 cfs. As can be seen in the table above, the pump capacity required to transfer 250 cfs increases by 1.6 MW when the total pump mode flow in the water conveyance system is 310 cfs. The additional 60 cfs can be pumped by a smaller capacity pump either to the aqueduct or to a separate delivery point in the AVEK potable water system.

5 Major Equipment Selection

5.1 Reversible Francis Type Pump-Turbine Evaluation

HDR solicited information from three turbine suppliers that represent the full spectrum of design and manufacturing capability. The three vendors contacted by HDR were:

Mavel	http://www.mavel.cz/
SOAR Hydropower	https://soarhydro.com/
Voith Hydro	http://voith.com/en/products-services/hydro-power/turbines-559.html

Mavel stated that they have not manufactured a reversible pump-turbine of this size (i.e., 5 MW) to date. They believe it could be manufactured, but would be very costly. Given that there are other more standard alternatives (i.e., separate turbine/generator and pump/motor), they have not been able to justify the development of that technology, nor have they had a customer enter into contract for a small reversible pump-turbine.

SOAR is a manufacturer of smaller in-line pumps-as-turbines type of generating equipment. They are known to produce high quality small hydro generating units. SOAR indicated that a reversible pump-turbine of the size required for this project would exceed their manufacturing capability. As with Mavel, SOAR has not had an opportunity to develop or manufacture a reversible pump-turbine.

Voith Hydro is one of the most highly capable manufacturers of reversible pump-turbines in the global hydropower industry. They have previously explored developing and manufacturing small reversible pump-turbines. They participated in a U.S. Department of Energy-sponsored project to evaluate the feasibility of small pumped storage. Voith reached the conclusion that it was most economically feasible to evaluate pumped storage schemes in this size range utilizing separate turbine/generator and pump/motor combinations. Voith believes designing and manufacturing a small reversible pump-turbine is technically feasible, but cost prohibitive. Their feedback reinforced the feedback HDR received from Mavel.

5.2 Turbine and Generator

The proposed new 9.25-mile-pipeline will introduce several factors that must be considered in the design of the proposed pumped storage facility. Once the entire water column is moving at a constant velocity, there is tremendous momentum that must be overcome to alter the flow rate. If the flow rate is altered quickly, the result can be unacceptable pressure spikes (i.e., water hammer) that can cause serious, even catastrophic, damage.

With a reaction type turbine, such as a Francis type design that would be used for this application, the turbine wicket gates, which open and close to proportionally control flow, must close fairly quickly to avoid a high overspeed of the generating unit rotating assembly. If the actual overspeed exceeds the design overspeed, failures of the rotating components can occur. If the wicket gates are closed quickly to limit overspeed, the pressure rise may exceed the design pressure of the pipeline or the turbine spiral case. This may lead to rupture of the pipeline or failure of the turbine pressure boundary.

To address these issues, a reaction turbine must utilize a pressure relief or bypass scheme. This allows the water to be taken off of the turbine runner to limit overspeed and eliminates pressure spikes by slowly reducing the flow rate. The pressure relief or bypass arrangements can be difficult to achieve the required timing.

A better option in all cases for this application would be the use of an impulse type turbine. The most common types of impulse turbines are either the Pelton or Turgo design. Impulse turbines have one or more injectors (aka jets) that direct the water to a wheel with spoon-shaped buckets on the perimeter. The injectors are made up of a needle that moves in and out of a nozzle seat. The shape of the needle controls the amount of opening in the jet. A bucket of a Pelton turbine looks like a full spoon and the buckets of a Turgo turbine look like half a spoon (split axially). The jets of a Turgo are usually angled off the plane, which is perpendicular to the shaft whereas the Pelton turbine jets are in direct alignment with the center of the buckets. Multiple jets can be used to provide a wide operating range. Each jet has a deflector that can almost immediately remove the water from the turbine runner to avoid any overspeed. Then the jet needles can be slowly closed to limit pressure spikes in the water conveyance system.

The performance difference between a reaction turbine and an impulse turbine is that a reaction turbine will generally have a higher peak efficiency but a narrower operating range than an impulse turbine.

For this application, HDR recommends a multi-jet, impulse type turbine. Preliminary sizing shows that a vertical, five-jet, Pelton turbine with a runner diameter of approximately 56 inches and a rotational speed of 276.92 rpm (i.e., 26 salient poles) would pass up to 140 cfs of flow. The efficiencies shown in Table 3 above reflect this selection. The net head available is in the low range for a Pelton type turbine but would be an acceptable solution. The multi-jet configuration would provide a wide operating range for meeting demand. The runner could be loaded by a single jet or combinations of three or five to balance the loading on the runner.

One vertical, five-jet, Pelton turbine could utilize a range of flow from 140 cfs to 250 cfs. A 250 cfs Pelton turbine could also potentially turn-down the flow rate with all jets functioning to around 100 cfs with little effect on efficiency. For comparison purposes the runner diameter of this turbine would be approximately 84 inches at a rotational speed of 171.4 rpm (i.e., 42 poles). The cost of this generating unit would be approximately twice as much as the 140 cfs unit, but there would be one unit instead of two, so the civil construction costs would be less. Figure 2 below depicts an elevation and plan view of the selected Pelton turbine. The elevation view shows how the Pelton turbine would sit in the powerhouse and discharge to a chamber which is open to atmosphere. The plan view shows the 5 jet configuration.

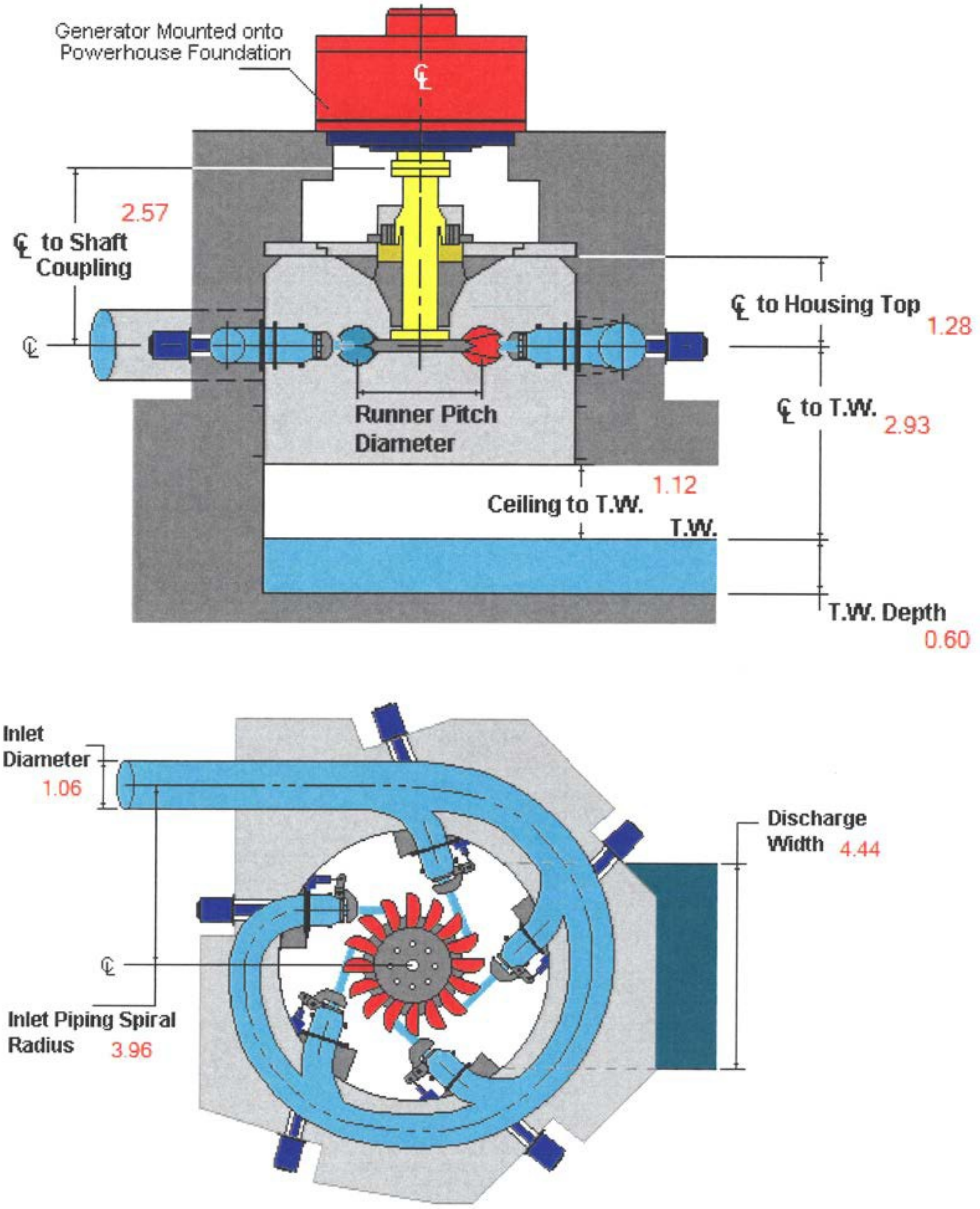

Figure 2. Pelton Turbine – 5 Jet Arrangement

Another consideration for the proposed new 9.25-mile-long pipeline is the potential difficulty of synchronizing the generator with the power grid. What can happen in this scenario is that a signal will be given to increase speed, but there will be limited change due the large mass of the water column so that another signal to increase flow is given. This repeats until the speed overshoots the target point. Then adjustments are made to decrease flow. An oscillation is set up that makes it very difficult to synchronize the unit to the power grid. This can be avoided by properly sizing the amount of rotational inertia required in the generating unit rotating assembly.

The best way to accomplish providing greater inertia for this size unit is by utilizing a flywheel connected to the generator shaft. The amount of inertia required can be readily determined by calculating the water start time (T_W), which is fixed for a given water conveyance system, and the mechanical start time (T_M) for the unit, which can be varied by changing the rotational inertia (wr^2) of the rotating assembly. The rotational inertia is heavily influenced by the generator rotor and any supplementary flywheel. Particular attention will need to be paid to sizing the rotational inertia as well as the capability of the electronic governor that will be used for regulation of speed.

5.3 Pump and Motor

There are two different possibilities for the pumps. In both cases, the pumps need to be located adjacent to the lower water storage reservoir.

There are horizontal, single stage, double suction pumps available that can provide the desired flow. These pumps could be set close to grade level and the suction line would require a foot valve to maintain prime. Two pumps would be required for a total flow of 140 cfs (i.e., approximately 63,000 gpm). It is possible that one large pump could be obtained, but two pumps would provide a level of redundancy and variability of pump capacity if combined with variable speed. A butterfly isolation valve and check valve would be provided on the discharge of each pump.

These two pumps would be driven by 3,000 kW rated motors each. The design point speed would be 900 rpm.

There is also a vertical turbine type pump configuration that could be considered. The pump(s) would be located in a wet pit. The wet pit would need to be deeper than the 5-foot-deep reservoir that is proposed since the pump would likely have four or more stages. The footprint would be smaller, but the sump would be more costly than setting the horizontal pump(s) on an equipment pad close to grade level. This design would not require a foot valve but would require a butterfly isolation valve as well as a check valve on the discharge. A vacuum / air release valve would be provided to handle the air in the pump column on either shutdown or start-up.

For this study, HDR has assumed that the horizontal pumps will be used primarily because of less structural impact. The horizontal versus vertical configurations could be compared as part of a more detailed feasibility study.

5.4 Pump Starting Equipment

Equipment to allow across the line starting of the pumps is available if the anticipated mode of operation is to always operate the pumps at a given design point. Since there are two pumps, pumping capacity could be added in a step function of 2.5 MW.

The motors can also be supplied with equipment that will enable “soft” starts, which will avoid voltage drops if that is of concern and variable speed control. Load flow analyses and speed variation studies can be performed to determine the benefit of variable speed motor control. The combination of two pumps each with variable speed control offers the ability to absorb varying amounts of power for the purpose of pumping. The variable speed control would also offer a slow ramp up in speed, which would be beneficial when pumping into the long pipeline. Further evaluation is recommended to determine the range of pump capacity that could be achieved. For the purpose of this study, HDR has assumed that variable speed motor control equipment will be beneficial and cost effective.

5.5 Powerhouse Location

The pumps and turbine(s) will need to be located adjacent to the lower reservoir. The preliminary concept is to set the pumps above grade level. The suction lines will be fitted with foot valves to maintain prime. The suction lines need to be as short as possible to maximize net positive suction head available (NPSHA). A Pelton turbine does not have a draft tube and must be set above tailwater. The turbine will discharge into a partially filled chamber and then the water will flow by a short open flume into the lower reservoir. This configuration will limit the amount of foundation work required. The footprint would be larger than if vertical pumps were used, but space does not appear to be a limiting factor for the proposed project. Overall, the cost of the civil works should be less. Further feasibility level study is recommended to optimize the design concept for the facility including the layout of the powerhouse. The results of such a study would have an impact on the selection of the equipment.

6 Major Equipment Cost Opinion

Table 5 provides an opinion of probable cost for major electrical and mechanical equipment required for the build-out of Phase 1.

The cost for Phase 2 would be the same as for Phase 1 since one turbine and two pumps of equal size would be added.

There may be some economies that could be realized for the turbine and associated auxiliaries. A single turbine capable of providing a discharge of 140 cfs through 250 cfs could be installed. This could be handled easily with a multi-jet, Pelton turbine.

Table 5. Cost Opinion – Phase 1 Build-Out (140 cfs Pumped Storage Capacity)

Major Equipment	Description	Quantity	Cost / Unit	Total Equipment Cost
Pump	Horizontal, Double Suction	2	$350,000	$700,000
Variable Speed Motor	2,500 kW, 4,160 v Motor w/ Med Voltage Inverter and associated variable speed drive equipment	2	$450,000	$900,000
Suction Line Foot Valve	28 inch, 150# class	2	$20,000	$40,000
Pump Discharge Check Valve	24 inch, 150# class	2	$20,000	$40,000
Pump Discharge Isolation Gate Valve	24 inch, 150# class	2	$20,000	$40,000
Instrumentation	Misc.	Lot	$30,000	$30,000
	Sub-Total			**$1,750,000**
Turbine	Pelton, 5 jet	1	$750,000	$750,000
Generator	3,750 kVA, 3,375 kW @ 0.9 pf, 4,160 v	1	$500,000	$500,000
Turbine Isolation Valve	36 inch, 150# class, Low Loss Butterfly	1	$50,000	$50,000
Speed Governor / Unit Controls	PLC Based	1	$100,000	$100,000
Governor HPU	HPU w/ Accumulators	1	$100,000	$100,000
	Sub-Total			**$1,500,000**
Relay Protection		1	$200,000	$200,000
Circuit Breaker		2	$50,000	$100,000
Switchgear		2	$250,000	$500,000
Main Transformer		1	$200,000	$200,000
	Sub-Total			**$1,000,000**
	Grand Total			**$4,250,000**

Notes: 1) Opinion of electrical and mechanical balance of plant costs not included per client direction.
2) Opinion of civil costs (i.e., structural, geotechnical) not included per client direction.

7 Recommendations for Further Study

HDR recommends conducting a more detailed feasibility-level study of the project including completion of the following activities:

- Identification of the conceptual layout of the powerhouse;
- Evaluation of the horizontal versus vertical pump configuration;
- Further assessment of variable speed technology to allow the pump capacity to vary;
- Performance of a hydraulic transient analysis to evaluate the effects of start and stop to the 9.25-mile-long pipeline; and
- Refinement of the cost opinion.

HDR would be pleased to continue assisting WSWB with further engineering analyses associated with the proposed project. We also understand that WSWB is developing civil / structural and electro-mechanical balance of plant costs; however, HDR is able to support the development of these estimates as well, if needed.

Attachment IV: EPC 15-049 Tech Memo No. 1 – Economic Potential of Peak Hour Pumped Storage and Aquifer Pumped Hydro Technologies at Willow Springs Water Bank

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EPC15-049 Tech Memo No. 1 –
Economic Potential of Peak Hour Pumped Storage and Aquifer Pumped Hydro Technologies at Willow Springs Water Bank

ABSTRACT

This Technical Memo No 1 is an economic assessment of Aquifer Pumped Hydro project (APH - using the existing underground aquifer as a lower storage reservoir and adding reversible pump turbines to pump water out of the ground or generate power when water is injected into underground storage) and Peak Hour Pumped Storage (PHPS) (adding onsite hydropower and surface storage reservoirs and using pumps and piping of the existing water bank) at the Willow Springs Water Bank (WSWB).

The WSWB operates in three different modes, depending upon the hydrologic year and the operation of any energy facilities has to be subservient to the water bank operation. These projects were evaluated during three different operating modes for this economic assessment. During a wet year the water bank is continuously recharging water into the water bank. During dry years the water bank is continuously extracting water from the water bank. During neutral or idle years the water bank is neither recharging nor extracting water.

The Aquifer Pumped Hydro round trip efficiencies are so low (~22%) that it was not an economic project. The cost of the necessary enhancements to the existing WSWB to develop an Aquifer Pumped Hydro project is estimated at $18.6 million. The NPV (net present value) of the operation of this facility as a generator is a negative $18 million for a 20-year investment horizon.

WSWB has most of the elements needed for a Peak Hour Pumped Storage project: topography that enables a large change in elevation, a big conveyance pipe, a pump station/turbine, and potential sites for large upstream and downstream reservoirs. Dual use of these facilities for hydropower as well as water storage reduces capital costs and the operation of that project was evaluated for this memo.

During a wet hydrologic year, the WSWB Is recharging water into the water bank. The Peak Hour Pumped Storage can operate as a hydroelectric generator. The annual value of this generation was estimated at $1,386,330 for a 5.2MW generator. The WSWB could be configured to curtail generation for 5 hours per day, ideally during the afternoon renewable generation over production period. The APH can’t operate as a generator during this year type because the recharge process would have to be by injection instead of percolation and the project would need to meet additional water quality requirements of the Regional Water Quality Control Board, which would increase the capital cost of the APH project.

During a neutral hydrologic year, the WSWB APH and PHPS can operate as a pumped storage facility, generating when electricity prices were high, and refilling storage when prices were low based upon Day Ahead Market prices PHPS can provide generation during the morning and evening ramp periods, and increased demand (load) during the afternoon periods to refill storage reservoirs, so it was evaluated for Flexible Ramping and Demand Response also. The annual value of this type operation was estimated $791,079. The APH response time and round-trip efficiencies were so low that it was not evaluated for Flexible Ramping nor Demand Response, and it only provides slightly over $4,000 in the Day Ahead Market.

The cost of the necessary enhancements to the existing WSWB to develop a Peak Hour Pumped Storage projects is estimated at $7.9 million. The NPV (net present value) of the probability weighted operation of this facility is operating as a generator (wet and neutral years) is a negative $0.99 million for the 20-year investment horizon.

During a dry hydrologic year, the WSWB operates as a load (27.3.MW pumping water out of the ground) and can be configured to accommodate 5 hours of demand response/curtailment to reduce load during the late afternoon ramping period and evening peak. There would need to be two additional extraction wells developed to compensate for the 5 hours curtailment daily during the summer season. The annual value of this demand response potential was estimated $2,795,520 (low value). The Net Present Value of providing demand response during dry years is $9 Million.

Adding dry year demand response to PHPS increases the NPV to about $8 million, but is still not enough to make APH cost effective.

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SUMMARY AND CONCLUSIONS

The purpose of this investigation was an economic analysis of the applicability of using a groundwater (aquifer) storage system as energy (electricity) bank, using the Willow Springs Water Bank (WSWB) as a specific example. Willow Springs Water Bank ("WSWB" or the "Bank") is a publicly owned and is a groundwater banking project that is located on approximately 1,838 acres of agricultural land in the Antelope Valley near Rosamond, California, in operation since 2010.

This investigation assesses the economic feasibility of WSWB developing the water bank for energy storage via two different approaches: 1) using the existing underground aquifer as a lower storage reservoir and adding reversible pump turbines to pump water out of the ground and generate power when water is injected into storage (Aquifer Pumped Hydro - APH), and 2) adding onsite hydropower using pipe, pump, and new surface reservoir facilities that are part of the existing water bank (Peak Hour Pumped Storage - PHPS). Table 1 shows the technology characteristics and analysis.

The Aquifer Pumped Hydro cost was so high and round-trip efficiencies so low that it was not cost effective. The cost of the necessary enhancements to the existing WSWB to develop an Aquifer Pumped Hydro project is estimated at $18.6 million. The NPV (net present value) of the probability weighted operation of this facility as a generator is a negative $18.3 million for a 20-year investment horizon.

In wet (recharge) years, WSWB will recharge water into the bank's percolation ponds for storage. During this year type PHPS was evaluated as a generator (5.2 MW generated constantly over the year). The annual value of this generation was estimated at $1,386,330. During an idle year, PHPS was evaluated in pumped storage mode, generating when electricity prices were high, and pumping water from the lower reservoir when prices were low in the Day Ahead Market (5.2 MW generation, 10.1 MW demand for pump station use), and for providing Flexible Ramping and Demand Response. The annual value of this type operation was estimated $791,079. The cost of the necessary enhancements to the existing WSWB to develop a Peak Hour Pumped Storage projects is estimated at $7.9 million. The NPV (net present value) of the probability weighted operation of this facility as a generator is a negative $0.99 million for a 20-year investment horizon.

In a dry year WSWB will extract water and pump it to the California Aqueduct. This year APH and PHPS can provide demand response (curtailing electricity use in response to system needs) if additional extraction wells are added to make up for the curtailed hours. The electricity demand is continuous from groundwater pumping (17.2 MW) plus power for the pump station (10.1 MW). This totals 27.3 MW of potential demand response. The annual value of this demand response potential was estimated $2,795,520 (low value). The Net Present Value of providing demand response during dry years is $9 Million.

Adding dry year demand response to PHPS increases the NPV to almost $8 million, but is still not enough to make APH cost effective.

There is additional flexibility possible with this technology. During a wet hydrologic year, when the PHPS can operate as a hydroelectric generator, it can be configured to curtail generation for 5 hours per day, ideally during the afternoon renewable generation over production period.

Table 1. Comparison of WSWB APH and PHPS Characteristics and Analysis

	Aquifer Pumped Hydro (APH)	**Peak Hour Pumped Storage (PHPS)**	**Demand Response**
Components needed	Reversible pump-turbines, surface storage reservoir, aquifer lower reservoir	Hydroelectric generator, upper and lower surface reservoirs	2 additional groundwater wells for 320 hours curtailment
Pumping Capacity	17.2 MW	10.1 MW	27.3 MW
Generating Capacity	3.7 MW	5.2 MW	-
Energy Storage	18.5 MWH	26.0 MWH	-
Pumping Efficiency	41.5%	83.4%	-
Generating Efficiency	51.7%	87.4%	-
Round Trip Efficiency	21.6%	72.9%	-
Capital Cost	$18.6M	$7.9M	$2.1M
Net Present Value	-$18.3M (operating as a generator - neutral year)	-$0.99M (operating as a generator – wet and neutral years)	$9.1M (dry years)
Capital Cost with Dry Year Demand Response	$20.3M	$10M	-
Net Present Value with Dry Year Demand Response	-$9.0M	$7.9M	-

PURPOSE

The purpose of this Technical Memo No 1 is an economic assessment of Peak Hour Pumped Storage and of Aquifer Pumped Hydro projects at the Willow Springs Water Bank (WSWB). This memo is an evaluation of the economic feasibility of the two pumped storage technologies at WSWB – a Peak Hour Pumped Storage project where two surface reservoirs are constructed and hydroelectric generators installed and of Aquifer Pumped Hydro project, where reversible pump turbines are installed in extraction wells and the aquifer itself is used for lower storage.

BACKGROUND

Underground pumped hydroelectric energy storage is a conceptual energy storage method that uses water stored underground as the lower reservoir of a pumped hydro system. Most of the studies of this technology are of the late

1970’s and early 1980’s vintage[1]. There has been a recent resurrection of interest in this concept, as the grid is experiencing increasing penetrations of renewable energy and the corollary requirement for energy storage expands[2].

The basic focus of these prior assessments was using a large underground cavern, either available from abandoned mines[3] or excavated for this purpose[4], as the lower reservoir. Almost all the recent evaluations are for large-scale utility sized projects (1,000-3,000MW)[5] using underground caverns. While none of these projects have been built[6], there are existing permits at the Federal Energy Regulatory Commission for some of these projects[7].

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[1] Allen, R. D., Doherty, T. J. and Kannberg, L. D. *Underground Pumped Hydroelectric Storage*, 1984; Blomquist, C. A., Frigo, A. A., Tam, S. W. and Clinch, J. M. *Underground Pumped Hydroelectric Storage(UPHS). Program Report*, April 1-September 30, 1979. ANL Activity No. 49964 1979; Braat, K. B., van Lohuizen, H. P. S. and de Haan, J. F. *Underground Pumped Hydro-Storage Project for the Netherlands*, 1985; Chang, G. C., Thompson, P. A., Allen, R. D., Ferreira, A. and Blomquist, C. A. *Pumped-Storage Hydroelectric Plants with Underground Lower Reservoirs*, 1980; Doherty, T. J. *Report on Technical Feasibility of Underground Pumped Hydroelectric Storage in a Marble Quarry Site in the Northeast United States*, 1982; Farquhar, O. C. *Geotechnical Basis for Underground Energy Storage in Hard Rock*. Final Report, 1982; Frigo, A. A., Blomquist, C. A. and Degnan, J. R. *Evaluation of Advanced Hydraulic Turbomachinery for Underground Pumped Hydroelectric Storage. Part 1. Single-Stage Regulated Pump Turbines for Operating Heads of 500 to 1000M*, 1979; Blomquist, C. A., Frigo, A. A. and Degnan, J. R. *Evaluation of Advanced Hydraulic Turbomachinery for Underground Pumped Hydroelectric Storage. Part 2. Two-Stage Regulated Pump /Turbines for Operating Heads of 1000 to 1500M*, 1979; Frigo, A. A., Pistner, C. *Evaluation of Advanced Turbomachinery for Underground Pumped Hydroelectric Storage. Part 3. Multistage Unregulated Pump /Turbines for Operating Heads of 1000 to 1500M*, 1980; Ridgway, S. L., Dooley, J. L. and Hammond, R. P. *Underground Storage of Off-Peak Power*, 1979; Rogers, F. C., Larson, W. E. *Underground Energy Storage (Hydroelectric Plant*), 1974; Rogers, Franklyn C. *Existing Hydroelectric Generation Enhanced by Underground Energy Storage,* 1975; Scott, Frank M. *Hydro-Power from Underground Pumped-Storage*, Journal Name: Am. Chem. Soc., Div. Fuel Chem., Prepr.; (United States); Journal Volume: 19:4; Conference: 168. National meeting of American Chemical Society, Atlantic City, NJ, USA, 8 Sep 1974; Willett, D. C., Warnock, J. G. *Evolution of a Technological Opportunity: Underground Pumped Hydro Storage*, 1983.

[2] Fairley, Peter, *A Pumped Hydro Energy-Storage Renaissance*, IEEE Spectrum, March 18, 2015, http://spectrum.ieee.org/energy/policy/a-pumped-hydro-energystorage-renaissance.

[3] For example, Madlener, Reinhard, Jan Specht, *An Exploratory Economic Analysis of Underground Pumped-Storage Hydro Power Plants in Abandoned Coal Mines*, RWTH Aachen University, FCN Working Paper No. 2/2013.

[4] Uddin, N. & Asce, M. *Preliminary Design of an Underground Reservoir for Pumped Storage*, Geotechnical and Geological Engineering (2003) 21: 331. doi:10.1023/B:GEGE.0000006058.79137.e2

[5] Tam, S.W., C. A. Blomquist, G.T. Kartsounes, *Underground Pumped Hydro Storage – An Overview*, Argonne National Laboratory, April 27, 2007, http://dx.doi.org/10.1080/00908317908908068; Scott, Frank, *Hydropower from Underground Pumped Storage*, Harza Engineering, April 25, 2007, http://dx.doi.org/10.1080/00908317508945949; Pickard, William, *The History, Present State, and Future Prospects of Underground Pumped Hydro for Massive Energy Storage*, Proceedings of the IEEE, Volume: 100 Issue: 2, February 2012.

[6] The Elmhurst Quarry Pumped Storage Project is a conceptual underground pumped storage project of between 50 MW and 250 MW that would utilize an abandoned mine and quarry for the both upper and lower reservoirs. Located in DuPage County, Illinois, project would divert water from above-ground source into an underground powerhouse. The water would then be stored in abandoned mine caverns before being pumped back to the surface to renew the cycle. Riverbank Wisacasset Energy Center is a proposed 1,000-MW pumped hydroelectric storage facility located 2,200 feet underground in Wisacasset, Maine. The RWEC project would divert water into its underground shaft down 2,000 vertical feet to drop into a powerhouse containing four 250-MW pump-turbines. Gravity Power-Grid-Scale Electricity Storage System is a conceptual underground pumped hydro project that uses a large piston that is suspended in a deep, water-filled shaft. As the piston drops, it forces water down the storage shaft, up the return pipe and through the turbine, and spins a pump-turbine motor/generator to produce electricity. To store water the pump-turbine in operated in reverse, spinning the pump to force water down the return pipe and into the shaft, lifting the piston.

[7] For example, FERC Project No. 14612-000, New Summit Hydro LLC, is for 1,500 MW pumped hydro storage project in Ohio using an abandoned underground limestone mine as the lower reservoir.

The concept of using the aquifer, rather than an underground cavity, as the lower storage has very scant literature associated with it. There are a host of issues associated with trying to use the aquifer as the lower reservoir. Failures of past aquifer storage projects in California were due to 1) physical and chemical clogging or biological fouling, 2) changes in geochemistry or water quality changes induced by quality of injection water which may include arsenic, metals mobilization and disinfection by-products such as trihalomethanes, and 3) inability to adequately recover injected water[8]. A study in Colorado in 2007 looked at using an existing aquifer to store the water underground along with the installation of a new surface storage tank as a pumped hydro system[9]. This was a small project (~10kW) and, while the paper recommended a proof of concept test, none was ever conducted. There was also an assessment made for South Africa that looked briefly at aquifer storage as well as underground cavity storage[10].

There have been several articles in WaterWorld that look at the concept of using existing aquifers and water towers for very small (kW) sized pumped storage projects[11], but none of these have been tested or evaluated.

STORAGEVET MODEL[12]

Energy storage recognized as being critical to California's energy future, to accommodate intermittent renewable generation[13]. Energy storage can provide two types of services: long duration services, for example charging during periods of renewable overgeneration and generating during periods, and short duration services, such as ancillary services[14].

The Storage Value Estimation Tool (StorageVET™) is a publicly available, web-hosted, energy storage value simulation tool available via the EPRI website (http://www.storagevet.com/). Development of this model was made possible through funding support from the California Energy Commission. The goals behind the development of this model include:

- Provide a consistent platform for communication of site-specific storage value between stakeholders of utilities, regulators, and vendors,

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[8] Bloetscher, F., Sham, C.H., Danko III, J.J. and Ratick, S. (2014). *Lessons Learned from Aquifer Storage and Recovery (ASR) Systems in the United States*, Journal of Water Resource and Protection, 6, 1603-1629. http://dx.doi.org/10.4236/jwarp.2014.617146.

[9] Martin, Gregory and Frank Barnes, *Aquifer Underground Pumped Hydroelectric Energy Storage for Agriculture*, University of Colorado at Boulder, September 30, 2007, available at: www.colorado.edu/engineering/energystorage.

[10] Khan S.Y., Davidson I.E. *Underground Pumped Hydroelectric Energy Storage in South Africa using Aquifers and Existing Infrastructure*. In: Schulz D. (eds) NEIS Conference 2016. Springer Vieweg, Wiesbaden, 2017

[11] Budris, Allan, *How to Reduce Municipal Electric Bills by Using Existing Water Towers and Aquifer Well Pumps to Store Energy for Peak Demand Period*s, in Pump Tips & Techniques Column, WATERWORLD, June 2014; Summary report of Aquifer Based Hydroelectric Systems (ABHS), *Preliminary Design of an Aquifer Pumped Storage System (*study conducted by Stevens Institute of Technology, Hoboken, NJ, May 4, 2008).

[12] *ESIC Energy Storage Implementation Guide 2016*, 3002008899, Electric Power Research Institute, December 2016.

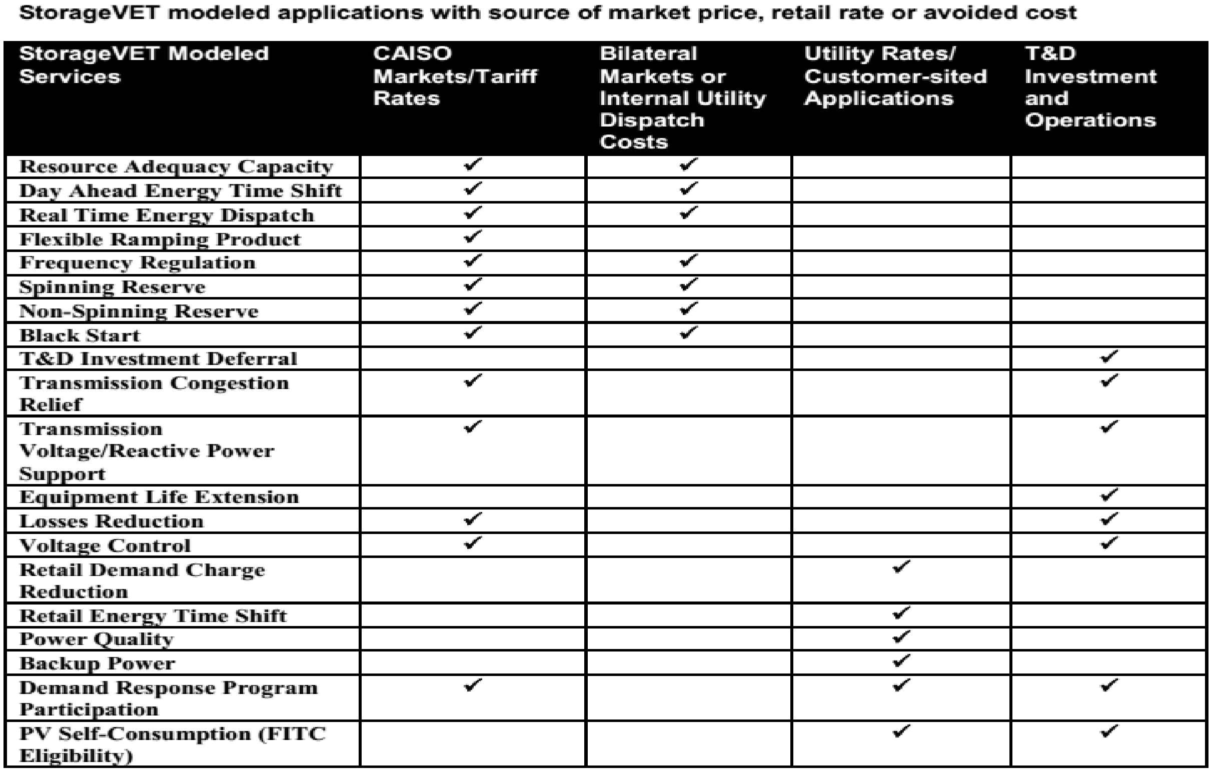
[13] *Advancing and Maximizing the Value of Energy Storage Technology – A California Roadmap*, California ISO, December 2014.

[14] Mathias, John, Collin Doughty, and Linda Kelly. *Bulk Energy Storage in California*. California Energy Commission. Publication Number: CEC-200-2016-006, 2016.

- Provide a publicly available tool and method to fairly, transparently, and consistently estimate the benefits and costs of energy storage projects across all cases; Grid Services, Technologies and Sizes, Locations.
- Provide guidance to identify and characterize high value locations to deploy energy storage, so that early successes in energy storage maximize value to all stakeholders.

It has been initially customized for California market services, reference scenarios, and data sets with direct import to the model[15] and has been used in evaluation of storage technologies[16].

Table 2. StorageVet Applications[17]



StorageVET modeled applications with source of market price, retail rate or avoided cost

StorageVET Modeled Services	CAISO Markets/Tariff Rates	Bilateral Markets or Internal Utility Dispatch Costs	Utility Rates/ Customer-sited Applications	T&D Investment and Operations
Resource Adequacy Capacity	✓	✓		
Day Ahead Energy Time Shift	✓	✓		
Real Time Energy Dispatch	✓	✓		
Flexible Ramping Product	✓			
Frequency Regulation	✓	✓		
Spinning Reserve	✓	✓		
Non-Spinning Reserve	✓	✓		
Black Start	✓	✓		
T&D Investment Deferral				✓
Transmission Congestion Relief	✓			✓
Transmission Voltage/Reactive Power Support	✓			✓
Equipment Life Extension				✓
Losses Reduction	✓			✓
Voltage Control	✓			✓
Retail Demand Charge Reduction			✓	
Retail Energy Time Shift			✓	
Power Quality			✓	
Backup Power			✓	
Demand Response Program Participation	✓		✓	✓
PV Self-Consumption (FITC Eligibility)			✓	✓

Ancillary services are those functions performed by electrical generating, transmission, system-control, and distribution system equipment and people to support the basic services of generating capacity, energy supply, and power delivery. The Federal Energy Regulatory Commission (FERC 1995) defined ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the

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[15] "StorageVET™ Software User Guide: User and Technical Documentation for the Storage Value Estimation Tool," Electric Power Research Institute (EPRI), 3002009357, 2016.

[16] For example, see: *Cost-Effectiveness of Energy Storage in California: Application of the Energy Storage Valuation Tool to Inform the California Public Utility Commission,* Proceeding R. 10-12-007, Electric Power Research Institute (EPRI), 3002001162, 2013.

[17] *Energy Storage Valuation in California*, Electric Power Research Institute, 3002008901, December 2016, pg. viii.

obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system.”.

OPERATION OF WILLOW SPRINGS WATER BANK

OPERATION

The operation of the hydroelectric generation must be subservient to the normal operations of the water bank, which is to store water. The water bank operates very differently, depending upon the hydrologic year. Consequently, three operating scenarios were assessed: a recharge year, an idle (neutral) year, and an extraction year.

> **Recharge Year (wet)** A recharge year involves up to 385 cubic feet per second (cfs) of recharge. That enables a total recharge of 280,000 acre-feet per year to the water bank. 250 cfs will be used to generate electricity 24 hours a day and 135 cfs will be bypasses around the turbine. The estimated occurrence rate is 1 year in 3 based on historical record (32%).
>
> **Idle (Neutral) Year** An idle year does not have any predetermined recharge or extraction activity. 250 cfs of water can be used to generate electricity for the 5 peak hours daily from the upper reservoir. The water can be replaced over the other 19 hours. The estimated occurrence rate is 1 year in 3 based on the historical record (33%).
>
> **Extraction Year (dry)** Extractions of water from the water bank will occur in a dry year. 250 cfs will be pumped back to the California Aqueduct and 60 cfs will be delivered to the AVEK potable system for exchange or to the Aqueduct. The total extraction requirement is 310 cfs. The estimated occurrence rate is 1 year in 3 based on historical record (35%).

The operation under these three scenarios for Peak Hour Pumped Storage (PHPS) is shown graphically in Figure 1.

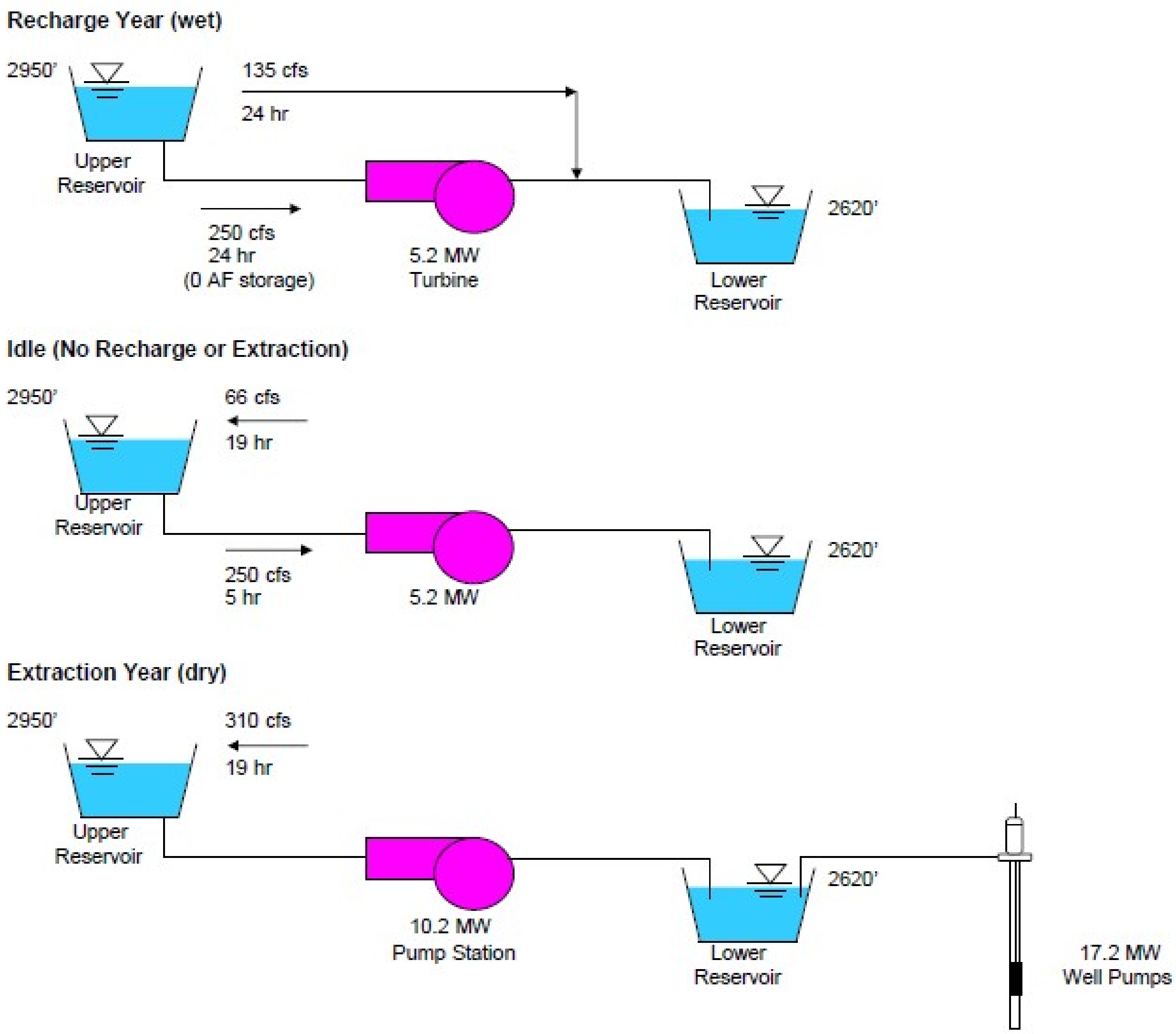

Figure 1. WSWB Pumped Storage Operation By Year Type

Table 3 provides a summary of the operational characteristics of these facilities during various hydrologic years.

Table 3. Willow Springs Water Bank Aquifer Pumped Hydro and Peak Hour Pumped Storage Operation Scenarios

Hydrologic Year Type	Probability of Occurrence	WSWB Operation Type	Electricity Demand Potential	Electricity Generation Potential	Evaluated As
APH					
Wet	32%	Recharge	0	0	
Neutral	33%	Idle	17.2 MW	3.7 MW for 5 hours daily	Pumped Storage
Dry	35%	Extraction	17.2 MW groundwater pumping + 10.1 MW pump station use	0	Demand Response
PHPS					
Wet	32%	Recharge	0	5.2 MW 24 hours daily	Generator
Neutral	33%	Idle	10.1 MW pump station use	5.2 MW for 5 hours daily	Pumped storage
Dry	35%	Extraction	17.2 MW groundwater pumping + 10.1 MW pump station use	0	Demand Response (demand reduction)

AQUIFER PUMPED HYDRO (APH) ANALYSIS

Aquifer Pumped Hydro at WSWB will require the addition of reversible pump turbines to existing recovery wells[18]. The existing system has a surface storage reservoir and pumps to pump the water into the aqueduct.

Neutral year operation of WSWB APH was assessed as an energy storage operation in StorageVet[19], using 2015 SCE DLAP prices (Default Load Aggregation Point - reflects the costs SCE avoids in procuring power during the time

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[18] Antelope Valley Water Storage (AVWS. *Assess Report Part 1: Technical Evaluation of Pumped Storage Technologies at Willow Springs Water Bank,* 2017

[19] StorageVet Technology Parameters Used for WSWB APH Simulation

Pumping Capacity [kW]	17,236 kW

period). It was evaluated in the Bulk Energy Market (Day Ahead Energy Market). It was not evaluated in either the Flexible Ramping or the Demand Response markets. Both these markets require that the upper surface reservoir be full to be able to participate in these markets – the round-trip efficiency was so low that it was impractical to keep that reservoir full and the operational characteristics of the project prevented it from providing these additional services.

During wet years the water bank is being recharged around the clock. However, APH can't operate as generator year-round during a wet year. During the wet year, some of the water being recharged (State Water Project water) could potentially be injected into the ground; however, because the process would be by injection instead of percolation by recharge the project would need to meet additional water quality requirements of the Regional Water Quality Control Board, which would increase the capital cost of the APH project and make it infeasible.

The following table provides a summary of the benefit from WSWB operating as pumped storage unit. As expected, APH virtually never runs – the round-trip efficiency is so low there is rarely enough of a daily price spread to economically pump and generate. Because it rarely operates in this mode, the Net Present Value is a large negative number.

Table 4. WSWB APH Operated as Pumped Storage Generator

		Value
Benefit	**MARKET**: Day Ahead Energy	$4,044 per year
Cost	Debt Service	-$1,599,072 per year
	O&M	0
Net Present Value	(20 year, 6% discount rate)	-$18,294,846

Source: StorageVet Simulation using 2015 SCE DLAP prices

Generating Capacity [kW]	3,700 kW
Energy Storage Capacity [kWh]	18,500 kWh (3.7 MW*5 hours)
Upper Limit, Operational State of Charge [%]	100
Lower Limit, Operational State of Charge [%]	0
Pumping (Charge) Efficiency [%]	0.416
Generating (Discharge) Efficiency [%]	0.518
Max Discharge Ramp [kW / min]	1,000
Annual O&M	0
Capital Cost	$18.6M

EVALUATION OF PEAK HOUR PUMPED STORAGE (PHPS)

CONFIGURATION

Two additional components must be added to the existing WSWB to develop a Peak Hour Pumped Storage Project: above ground (reservoir) storage of water, and hydroelectric generators. These components are described in detail in other reports for this project[20].

OPERATIONAL BENEFITS ECONOMIC ASSESSMENT

In wet (recharge) years, WSWB will recharge water into the bank's percolation ponds for storage. Recharge flow is a constant 250 cfs. This will generate electricity 24 hours a day for the entire year. During this year type the project was evaluated as a generator (5.2 MW generated constantly over the year).

During a neutral year, the project was evaluated in pumped storage mode, generating when electricity prices were high, and recharging water into the ground when prices were low (5.2 MW generation, 10.1 MW demand for pump station use). This operation was assessed using the energy storage assessment model StorageVet in the Day Ahead Market (DAM) and in the Flexible Ramping and Demand Response markets.

Neutral Year (33% probability) – PHPS Operated as Pumped Storage

Energy storage recognized as being critical to California's energy future, to accommodate intermittent renewable generation[21]. Energy storage can provide two types of services: long duration services, for example charging during periods of renewable overgeneration and generating during periods, and short duration services, such as ancillary services[22]. This project assesses both these attributes.

The operation of WSWB was assessed as an energy storage operation in StorageVet[23], using 2015 SCE DLAP prices (Default Load Aggregation Point - reflects the costs SCE avoids in procuring power during the time period). It

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[20] Antelope Valley Water Storage (AVWS). *Assess Report Part 1: Technical Evaluation of Pumped Storage Technologies at Willow Springs Water Bank,* 2017

[21] *Advancing and Maximizing the Value of Energy Storage Technology – A California Roadmap*, California ISO, December 2014.

[22] Mathias, John, Collin Doughty, and Linda Kelly. *Bulk Energy Storage in California*. California Energy Commission. Publication Number: CEC-200-2016-006, 2016.

[23] StorageVet Technology Parameters Used for WSWB Pumped Storage Simulation

Pumping Capacity [kW]	10,124 kW
Generating Capacity [kW]	5,223 kW
Energy Storage Capacity [kWh]	26,000 kWh (5.2 MW*5 hours)
Upper Limit, Operational State of Charge [%]	100
Lower Limit, Operational State of Charge [%]	0
Pumping (Charge) Efficiency [%]	0.834
Generating (Discharge) Efficiency [%]	0.874
Max Discharge Ramp [kW / min]	1,000
Annual O&M	$100,000
Capital Cost	$7.9M

was evaluated in the Bulk Energy Market (Day Ahead Energy Market), Flexible Ramping, and Demand Response. Table 5 provides a summary of the annual benefit from WSWB operating as pumped storage during a neutral year.

Table 5. WSWB PHPS Operated as Pumped Storage (Neutral Year – 33% Probability)

Market	Annual Value
Day Ahead Market (Energy)	$94,852
Flexible Ramping	$384,637
Demand Response	$384,637
Total	**$791,079**

Source: StorageVet Simulation using 2015 SCE DLAP prices

Wet Year (32% probability) – Operated as a Hydroelectric Generator

During wet years, the water bank is storing water, and can operate as a hydroelectric generator year-round. For this case, the project was evaluated as a 5.2 MW hydroelectric generator operating 24 hours a day. The electricity was evaluated using the 2015 SCE DLAP hourly prices. Table 6 shows the annual benefit during wet years of WSWB operating as a hydroelectric generator[24].

Table 6. WSWB PHPS Operated as a Hydroelectric Generator (Wet Year – 32% Probability)

Market	Annual Value
Day Ahead Energy	**$1,386,330**

Aggregate Year Summary As a Generator

The Peak Hour Pumped Storage project WSWB operation as a generator was evaluated based upon standard evaluation protocol for two of the three hydrologic year types (wet and neutral) in two different operating modes (as a hydroelectric generator and as pumped storage[25]). The following Table 7 provides a probability weighted summary of the cost effectiveness of making these PHPS generation changes to the existing WSWB configuration. The $7.9 million has a NPV (net present value) potential of -$0.99 million[26].

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[24] 5.2 MW operating 24/7, priced at 2015 SCE DLAP prices, assuming no curtailment or load following.

[25] DNV-GL, *Energy Storage Cost-Effectiveness Methodology and Results*, Final Project Report, Energy Research and Development Division, Final Project Report, DNV GL Energy and Sustainability, CEC 500-2014-068, August 2013.

[26] Assuming no escalation annual benefits, a 20-year horizon, and a 6% discount rate.

Table 7. WSWB Peak Hour Pumped Storage Generator Cost Effectiveness

Year Type	Probability	Operated As	Annual Value
Wet	32%	Generator	$1,386,330
Neutral	33%	Pumped Storage	$791,079
Probability Weighted Annual Benefit			$704,682
Annual O&M			-$100,000
Annual Debt Service ($7.9M at 6% for 20 years)			-$691,243
Annual Net Benefit			-$86,561
NPV of WSWB PHPS			**-$992,853**

DRY YEAR OPERATIONS AQUIFER PUMPED HYDRO (APH) AND PEAK HOUR PUMPED STORAGE (PHPS)

Dry Year (35% probability) – Operated as a Continuous Load (both PHPS and APH)

During dry years, the water bank is extracting water (using pumps), and will operate as a continuous load year-round. For this case, the project was evaluated as a 27.3 MW load operating 24 hours a day, with the ability to be curtailed up to 5 hours per day for up to 320 hours per year.

Demand response is the ability to reduce or vary use of electricity use when needed. This is possible at WSWB in an extraction year. Pumps at the pumping plant could be shut off for 5 hours a day during years that water is being pumped back to the California Aqueduct. The demand response potential of the pumping plant corresponds to the size of the pumps, or 10.1 MW. It can be realized by shutting down the pumping plant to the Aqueduct for 5 hours a day. In addition, the extraction wells (17.2 MW) could be curtailed for those 5 hours also. 62 production wells are planned for WSWB. Each production well is expected to have a 300-horsepower motor, or 0.225 MW. Combined, the 62 wells represent a demand reduction of 14.0 MW. The lower reservoir will enable a constant flow to the WSWB pump station. The lower reservoir buffers any impact on WSWB operations. To provide for this level of demand response two additional extraction wells would need to be added.

The project was evaluated for demand response using values from 2025 California Demand Response Potential Study[27]. This study recognizes three primary types of demand response: Shift, Shed, and Shimmy.

> The Shift service type is demand response that moves load to desired times during the day, increasing energy consumption during periods of the day when there is surplus generation, and reducing consumption during periods of the day when there is excess load.
>
> The Shed service type describes loads that can occasionally be curtailed to reduce customer demand during peak net load hours.
>
> The Shimmy service type involves using loads to dynamically adjust demand on the system to alleviate ramps and disturbances at timescales ranging from seconds up to an hour.

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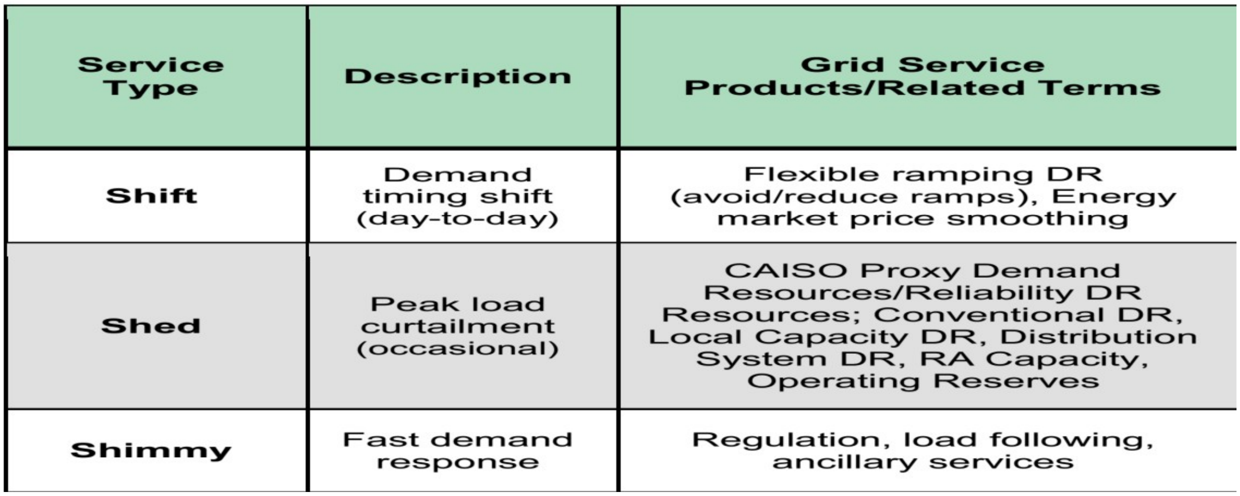
[27] *2025 California Demand Response Potential Study*, Final Report on Phase 2 Results, Lawrence Berkeley National Laboratory, March 1, 2017.

Figure 2. Types of Demand Response[28]



Service Type	Description	Grid Service Products/Related Terms
Shift	Demand timing shift (day-to-day)	Flexible ramping DR (avoid/reduce ramps), Energy market price smoothing
Shed	Peak load curtailment (occasional)	CAISO Proxy Demand Resources/Reliability DR Resources; Conventional DR, Local Capacity DR, Distribution System DR, RA Capacity, Operating Reserves
Shimmy	Fast demand response	Regulation, load following, ancillary services

Table 8 shows the annual benefit during a dry year of WSWB providing demand response services.

Table 8. WSWB Operated as a Continuous Load (Dry Year – 35% Probability)

Demand Response Service	Market Value (low)	Market Value (high)	Unit	WSWB Annual Value (low)	WSWB Annual Value (high)
Shed	$4	$4	$/kW-yr	$109,200	$109,200
Shift (1)	$20	$52	$/MWh	$174,720	$454,272
Shimmy – load following	$35	$45	$/kW-yr	$955,500	$1,228,500
Shimmy - regulation	$57	$98	$/kW-yr	$1,556,100	$2,675,400
			Total	$2,795,520	$4,467,372
Assuming up to 5 hours of daily curtailment available, 27.3 MW curtailable up to 320 hours per year.					

ADDING DRY YEAR DEMAND RESPONSE TO AQUIFER PUMPED HYDRO (APH) AND PEAK HOUR PUMPED STORAGE (PHPS)

Table 9 provides a summary of adding dry year demand response to APH and PHPS to complete operations analysis for all three-year types.

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[28] Ibid, pg. 3-16.

Table 9. Comparison of WSWB APH and PHPS Operational Analysis

	Aquifer Pumped Hydro (APH)	Peak Hour Pumped Storage (PHPS)	Demand Response
Components needed	Reversible pump-turbines, surface storage reservoir, aquifer lower reservoir	Hydroelectric generator, upper and lower surface reservoirs	Additional groundwater wells for 320 hours curtailment
Capital Cost	$18.6M	$7.9M	$2.1M
Net Present Value	-$18.3M (operating as a generator – neutral years)	-$0.99M (operating as a generator – wet and neutral years)	$9.1M (dry years)
Capital Cost with Dry Year Demand Response	$20.3M	$10M	-
Net Present Value with Dry Year Demand response	-$9.1M	$7.9M	-

Attachment V: EPC 15-049 Tech Memo No. 2 – Statewide Benefits of Pumped Storage at Groundwater Banks

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EPC15-049 Tech Memo No. 2 – Statewide Benefits of Pumped Storage at Groundwater Banks

ABSTRACT

This Technical Memo No 2's purpose is to report on the benefits associated with adding pumped storage to existing aquifer (groundwater) storage facilities. Pumped storage additions to groundwater banks may be able to provide electrical system benefits from: 1) generation of electricity during period of high system demand, 2) increasing pumping demand (load) during renewable over generation periods to reduce the risks of overgeneration, 3) reducing load during high system ramping requirements and system demand, and 4) provide a plethora of ancillary services, depending upon the configuration of the generation and groundwater storage bank.

There are a multitude of ancillary services that could be possible from new pumped storage facilities at groundwater banks – if they were configured properly and if the water bank was willing to turn over operational control of the facilities to the Independent System Operation. Willow Springs Water Bank's (WSWB) primary purpose is as a water storage facility and it is reluctant to invest in the additional facilities necessary to perform many of the ancillary services nor turn over operation of the water bank to the ISO in order to participate in many of these markets, so the types of ancillary services that could be provided were limited from their facilities.

The WSWB operates in three different modes, depending upon the hydrologic year and the operation of any energy facilities has to be subservient to the water bank operation. During a wet year the water bank is continuously recharging water into the water bank. During dry years the water bank is continuously extracting water from the water bank. During neutral or idle years the water bank is neither recharging nor extracting water.

This project[1] shows that there is a 44 MW potential statewide for adding Peak Hour Pumped Storage (PHPS), adding upper and lower surface storage reservoirs with hydroelectric generators and associated components, and 220 MW potential statewide for using existing extraction well load for demand response. Using WSWB PHPS as a typical example, then the 44 MW of generation would have an annual net benefit of $5.9M and the 220 MW of load used as demand response would have an annual net benefit of $6.3M.

This analysis, using Willow Springs Water Bank as a specific example, found that Aquifer Pumped Hydro (APH) project (using the existing underground aquifer as a lower storage reservoir and adding a surface storage reservoir and reversible pump turbines to pump water out of the ground or generate power when water is injected into underground storage) was too expensive, the round trip efficiencies were too low, and the operational characteristics too restricting to be cost effective but that Peak Hour Pumped Storage (adding onsite hydropower and surface storage reservoirs and using pumps and piping of the existing water bank) would be a cost effective

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[1] Antelope Valley Water Storage, LLC. *Assess Report Part II: Groundwater Bank Energy Storage Systems – A Feasibility Study,* 2017

investment if demand response ability is added to the pumped storage project. APH was limited to participation in the Day Ahead Market as a pumped storage facility, but PHPS could provide generation during wet (recharge) years, pumped storage operation during a neutral year in the Day Ahead Market and Flexible Ramping and Demand Response markets as pumped storage, and if configured properly, both could provide Demand Response during dry (extraction) years.

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SUMMARY AND CONCLUSIONS

This Technical Memo No 2's purpose is to report on the benefits associated with adding pumped storage to existing aquifer (groundwater) storage facilities. Pumped storage additions may be able to provide electrical system benefits from: 1) generation of electricity during period of high system demand, 2) increasing pumping demand (load) during renewable over generation periods to reduce the risks of overgeneration 3) reducing load during high system ramping requirements and system demand and, and 4) provide a plethora of ancillary services, depending upon the configuration of the generation and groundwater storage bank.

This memo reports on the markets and services potential of adding pumped storage to existing groundwater storage facilities using Willow Springs Water Bank (WSWB) as a specific example: 1) using the existing underground aquifer as a lower storage reservoir and adding reversible pump turbines to pump water out of the ground and generate power when water is injected into storage (Aquifer Pumped Hydro - APH), and 2) adding onsite hydropower using pipe, pump, and reservoir facilities that are part of the existing water bank (Peak Hour Pumped Storage - PHPS). Table 1 provides a summary of the characteristics and analysis of these two options for WSWB.

As Table 1 shows, there are a multitude of ancillary services that could be possible using these technologies – if they were configured properly and if the water bank was willing to turn over operational control of the facilities to the Independent System Operation (Frequency Regulation, Spinning Reserve, Non-Spinning Reserve, Regulation Energy Management [REM], Reactive Power/Voltage Support, and Black Start require the generation facilities to be under ISO control). WSWB's primary purpose is as a water storage facility and is reluctant to invest in the additional facilities necessary to perform these services nor turn over operation of the water bank the ISO in order to participate in many of these markets, so the ancillary services options were limited.

The operation of the water bank varies significantly depending upon the type of water year, so operation had to be assessed for three water year types (wet - 32% probability, neutral - 33% probability, and dry - 35% probability).

In wet (recharge) years, WSWB will recharge water into the bank's percolation ponds. During this year type the PHPS was evaluated as a generator (5.2 MW generated constantly over the year). The APH can't operate as a generator during this year type because the recharge process would have to be by injection instead of percolation and the project may need to meet additional water quality requirements of the Regional Water Quality Control Board, which would increase the capital cost of the APH project.

During an idle year in which the WSWB is neither recharging nor extracting, the PHSP and APH were evaluated in pumped storage mode, generating when electricity prices were high, and refilling storage when prices were low based upon Day Ahead Market prices. PHPS can provide generation during the morning and evening ramp periods, and increased demand (load) during the afternoon periods to refill storage reservoirs, so it was evaluated for Flexible Ramping and Demand Response also. The APH response time, round-trip efficiencies, and operational constraints so limited that it was not evaluated for Flexible Ramping nor Demand Response.

In a dry year WSWB will extract water and pump it to the California Aqueduct. This year was evaluated for both PHPS and APH for demand response (curtailing electricity use in response to system needs). Two additional extraction wells would be necessary to recover from curtailing the wellfield for up to 320 hours per year..

There is additional flexibility possible with this technology. During a wet hydrologic year, when the PHPS can operate as a hydroelectric generator, it could be configured to curtail generation for 5 hours per day per year, ideally during the afternoon renewable generation over production period.

This project[2] shows that there is a 44 MW potential statewide for adding Pumped Storage (adding upper and lower surface storage reservoirs with hydroelectric generators and associated components) and 220 MW potential statewide for using existing extraction well load for demand response. If these projects had similar characteristic to the WSWB PHPS then the 44 MW of generation would have an annual net benefit of $5.9 million and the 220 MW of load used as demand response would have an annual benefit of 6.3 million.

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[2] Antelope Valley Water Storage, LLC. *Assess Report Part II: Groundwater Bank Energy Storage Systems – A Feasibility Study,* 2017

Table 1. Comparison of WSWB APH and PHPS Characteristics and Analysis

	WSWB Aquifer Pumped Hydro (APH)	**WSWB Peak Hour Pumped Storage (PHPS)**	**Demand Response**
Components needed	Reversible pump-turbines, surface storage reservoir, aquifer is lower reservoir	Hydroelectric generator, upper and lower surface reservoirs	2 additional groundwater wells for 320 hours curtailment
Pumping Capacity	17.2 MW	10.1 MW	27.3 MW
Generating Capacity	3.7 MW	5.2 MW	
Energy Storage (5 hours of generation)	18.5 MWH	26.0 MWH	Curtailable up to 320 hours per year
Pumping Efficiency	41.5%	83.4%	
Generating Efficiency	51.7%	87.4%	
Round Trip Efficiency	21.6%	72.9%	
Capital Cost	$18.6M	$7.9M	$2.1M
Net Present Value (@6%, 20 years)	-$18.2M (generator operating in neutral years)	-$0.9M (generator operating during wet and neutral year)	$9.1M (dry year)
Capital Cost with Dry Year Demand Response	$20.3M	$10M	
Net Present Value (@6%, 20 years) with dry year demand response	-$9.1M	$8.1M	
Markets/Services:			
Day Ahead Hourly Market	Yes	Yes	
Flexible Ramping	No, response time too slow, operational parameters preclude	Yes	
Demand Response	Yes	Yes	
Real Time Energy Time Shift	No	No	
Retail Energy Time Shift	No, lack of load on site	No, lack of load on site	
Frequency Regulation	No, not configured for, wish to maintain local control of operations	No, not configured for, wish to maintain local control of operations	
Spinning Reserve	No, not configured for, wish to maintain local control of operations	No, not configured for, wish to maintain local control of operations	
Non-Spinning Reserve	No, not configured for, wish to maintain local control of operations	No, not configured for, wish to maintain local control of operations	
Regulation Energy Management (REM)	No, not configured for, wish to maintain local control of operations	No, not configured for, wish to maintain local control of operations	
Investment Deferral	No. Area of WSWB is an unconstrained SCE area	No. Area of WSWB is an unconstrained SCE area	
Reactive Power/Voltage Support	No, not configured for, wish to maintain local control of operations	No, not configured for, wish to maintain local control of operations	
Resource Adequacy Capacity (RA)	No, expected operations preclude	No, expected operations preclude	
Black Start	No, not configured for	No, not configured for	

PURPOSE

This Technical Memo No 2's purpose is to report on the potential benefits associated with adding pumped storage to existing aquifer (groundwater) storage facilities. Pumped storage additions may be able to provide electrical system benefits from: 1) generation of electricity, 2) increasing demand (load) during renewable over generation periods and reducing load during ramping periods and 3) ancillary services, depending upon the configuration of the groundwater storage bank and the ability of the water bank to cede operational control to the ISO. This memo is a summary of the potential benefits that could be associated with pumped storage additions to aquifer storage projects.– a Peak Hour Pumped Storage project where two surface reservoirs are constructed and hydroelectric generators installed and of Aquifer Pumped Hydro project where reversible pump turbines are installed on extraction wells.

BACKGROUND

There are a multitude of water banks existing in California today[4]. These are known variously as aquifer storage, groundwater storage, and conjunctive use projects. Their purpose is to store water underground. They all take surface water and store it underground for usage later.

These storage projects come in a variety of configurations, depending upon sources of water, the configuration of the underground storage basin, method of getting water underground (either passive via recharge basins that let the water percolate into the ground or, less frequently, actively injecting water into the ground). While they all may not have enough topographical variation to support hydroelectric generation, they all have one thing in common, an electricity demand when they are extracting the water from underground for delivery to customers. And, depending upon their delivery requirements, they may have the ability to vary that pumping load to accommodate electrical system needs.

POTENTIAL BENEFITS ASSOCIATED WITH PUMPED STORAGE ADDITIONS TO GROUNDWATER STORAGE PROJECTS

A summary of the various market/service characteristics and their applicability to groundwater energy storage banks, and WSWB in particular, are provided in Table 2.

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[4] Antelope Valley Water Storage, LLC. *Assess Report Part II: Groundwater Bank Energy Storage Systems – A Feasibility Study,* 2017

Table 2. Potential Markets and Services for Groundwater Pumped Storage Projects

Market/Service	Definition	Time Period	Applicable to Groundwater Energy Bank Storage System	Willow Springs Water Bank APH Simulation	Willow Springs Water Bank PHPS Simulation
Day Ahead Energy Time Shift	Hourly market energy prices established for the next day. Based upon unit commitment on the day prior to the actual operating day.	Hour	In both generating and pumping mode.	Yes	Yes
Real Time Energy Time Shift	The real-time market is a spot market in which utilities can buy power to meet the last few increments of demand not covered in their day ahead schedules.	15-minute procurement, 1-hour continuous requirement	In both generating and pumping mode.	No	Yes
Retail Energy Time Shift	Hourly energy and demand prices based upon utility retail tariffs.	Hour	If significant on-site electricity use	No	No
Frequency Regulation	Maintaining the grid frequency within the given margins by continuous modulation of active power. Capacity that follows (in both the positive and negative direction) a 4-second ISO power signal.	Seconds	Have to be operating and have special generation configuration for rapid response.	No	No
Spinning Reserve	Spinning reserve is standby capacity from generation units already connected or synchronized to the grid and that can deliver their energy in 10 minutes when dispatched. Dispatched within 10 minutes in response to system contingency events. Must be frequency responsive and be able to run for 2 hours.	10 minutes	If generation configured properly, and operating, could be provided in generating mode.	No	No
Non-Spinning Reserve	Non-spinning reserve is Off-line Generation Resource capacity that can be synchronized to	10 minutes	If generation configured properly, and operating,	No	No

Market/Service	Definition	Time Period	Applicable to Groundwater Energy Bank Storage System	Willow Springs Water Bank APH Simulation	Willow Springs Water Bank PHPS Simulation
	the grid and ramped to a specified load within 10 minutes and run for at least 2 hours.		could be provided in generating mode		
Regulation Energy Management (REM)	Regulation energy is used to control system frequency, which must be maintained very narrowly around 60 hertz. Composed of regulation up (increased generation) and regulation down (decreased generation). Capacity that follows (in both the positive and negative direction) a 4-second ISO power signal. It requires 1 -hour of continuous response. Capacity is limited by the resource's 5-minute ramp.	5-10 minute, must be available for 60 minutes	Have to be operating and include equipment necessary to follow regulation signal.	No	No
Flexible Ramping	The ability to change generation (ramp) in response to system needs. Requires participation in market with bids and 3-hour continuance response capability.	5 minutes	Depends upon pump and generator characteristics	No, response time too slow	Yes
Investment Deferral	The ability to defer additional investment in distribution system, substations, or transmission lines. Resource capable of reliably and consistently reducing net loading on desired infrastructure.	Year	Depends upon location of groundwater bank	No. Area of WSWB is an unconstrained SCE area	No. Area of WSWB is an unconstrained SCE area
Reactive Power/Voltage Support	The injection or absorption of reactive power to maintain transmission system voltages within required ranges. Resource	Seconds	If generation configured properly	No	No

Market/Service	Definition	Time Period	Applicable to Groundwater Energy Bank Storage System	Willow Springs Water Bank APH Simulation	Willow Springs Water Bank PHPS Simulation
	capable of dynamically correcting excursions outside voltage limits as well as supporting conservation voltage reduction strategies in coordination with utility voltage/reactive power control systems.				
Resource Adequacy Capacity (RA)	Assurance that there is adequate physical capacity in existence to serve likely peak load and the ability of the ISO to call on it to perform when needed for system reliability. Must provide net qualifying capacity (NQC) for 4 hours over 3 consecutive days up to a total of 24 hours per month. The resource must bid into the ISO day-ahead and real-time markets.	Hour	For flexible capacity, and be 2 hours charging and 2 hours discharging.	No	No
Demand Response	Demand response is a change in the power consumption of an electric utility customer in response to utility system needs (typically a reduction in customer demand)	Hour	In both generating and pumping mode project could	Yes, if additional extraction wells added.	Yes, if additional extraction wells added.
Black Start	Generation able to start itself without support from the grid and with sufficient real and reactive capability and control to be useful in system restoration.	Minutes	If water stored at elevation, and generation configured appropriately.	No	No

PATICIPATION IN ISO MARKETS

The California Independent System Operator (ISO) provides markets for various services and access to the transmission grid. Groundwater bank pumped storage could participate as either a generator or as a demand (load), but not all markets/services are available to both operations. The ISO currently runs three primary wholesale energy markets: Day-Ahead, Real-Time, and Ancillary Services.

Day-ahead market. The day-ahead market is made up of three market processes that run sequentially. First, the ISO runs a market power mitigation test. Bids that fail the test are revised to predetermined limits. Then the integrated forward market establishes the generation needed to meet forecast demand. And last, the residual unit commitment process designates additional power plants that will be needed for the next day and must be ready to generate electricity. Market prices set are based on bids. The day-ahead market opens for bids and schedules seven days before and closes the day prior to the trade date. Results are published at 1:00 p.m.

Real-time market. The real-lime market is a spot market in which load serving entities can buy power to meet the last few increments of demand not covered in their day ahead schedules. It is also the market that secures energy reserves, held ready and available for ISO use if needed, and the energy needed to regulate transmission line stability. The market opens at 1:00 p.m. prior to the trading day and closes 75 minutes before the start of the trading hour. The results are published about 45 minutes prior to the start of the trading hour. The real-time market system dispatches power plants every 15 and 5 minutes, although under certain grid conditions the ISO can dispatch for a single 1-minute interval.

Ancillary service market. Ancillary services are energy products used to help maintain grid stability and reliability. There are four types of ancillary services products currently procured: regulation up, regulation down, spinning reserve and non-spinning reserve. Regulation energy is used to control system frequency, which must be maintained very narrowly around 60 hertz, and varies as generators change their energy output. Resources providing regulation are certified by the ISO and must respond to automatic control signals to increase or decrease their operating levels depending upon the need. Spinning reserve is standby capacity from generation units already connected or synchronized to the grid and that can deliver their energy in 10 minutes when dispatched. Non-spinning reserve is capacity that can be synchronized to the grid and ramped to a specified load within 10 minutes.

Generators participating in the ISO markets are limited to one megawatt or more. Their ability to participate in the various markets is limited by their configuration (various ancillary service markets have response/performance requirements) and their operation (many of the ancillary services markets require direct ISO control of the generator).

Load can also participate in ISO markets. ISO rules allow load and aggregation of loads capable of reducing their electric demand to participate as price responsive demand in the ancillary services market and as curtailable demand in real-time markets. Load can participate in some ISO markets via a Proxy Demand Resource (PDR) or via a Reliability Demand Response Resource (RDRR). PDR and RDRR only allow for load curtailment, not load consumption or the export of energy to the grid.

Proxy Demand Resource (PDR) is a participation model for load curtail introduced in 2010 to increase demand response participation in the ISO's wholesale Energy and Ancillary Services markets. PDR helps in facilitating the participation of existing retail demand response into these markets: Day-ahead, Real-time, Spinning and Non-

Spinning Reserves like a generator resource, but it cannot ever inject energy into the grid. PDR can only be dispatched in one direction – to reduce load.

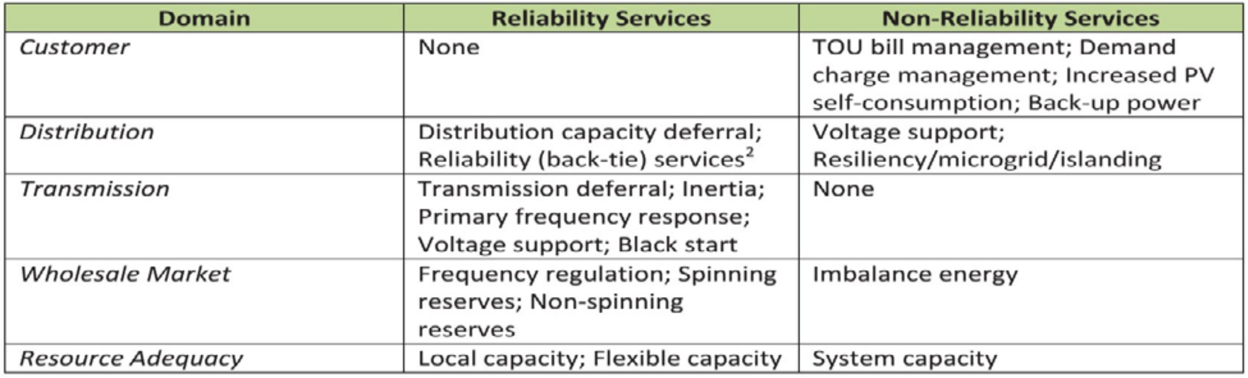
Reliability Demand Response Resource (RDRR) is a product created to further increase demand response participation in the ISO markets by facilitating the integration of existing emergency-triggered retail demand response programs and newly configured demand response resources that have reliability triggers and desire to be dispatched only under certain system conditions. RDRR may participate in the Day-Ahead and Real- Time markets like a generator resource, but may not submit Energy Self-Schedules, may not Self-Provide Ancillary Services, and may not submit RUC Availability or Ancillary Service bids.

Electricity storage can participate in the ISO markets also. A storage device could participate using the ISO's non-generating resource (NGR) participation model. The main difference of NGR compared to a generator is that the NGR can have negative output (absorbing electricity from the grid). Additionally, NGRs are ISO metered entities requiring them to comply with ISO metering and telemetry requirements. All utility interconnection requirements would need to be met which may include the need to obtain a WDAT interconnection, similar to any other generator connected at the distribution level that participates in the wholesale market.

OTHER MARKETS/SERVICES

There is a CPUC proceeding (R.15-03-011) and an ISO stakeholder initiative on Energy Storage and Distributed Energy Resources that is investigating additional markets/service for energy storage and distributed energy resources. Table 3 provides a summary of the reliability and non-reliability services that are being investigated in these proceedings. It should be emphasized that there are a number of services listed in this table for which there is currently no existing market (back-tie services, inertia, primary frequency response, resiliency). For reliability services, there can be reliability impacts to the system if the resource does not follow instructions from the ISO or utility distribution company (UDC).

Table 3. Storage Reliability Services and Non-Reliability Services[5]



Domain	Reliability Services	Non-Reliability Services
Customer	None	TOU bill management; Demand charge management; Increased PV self-consumption; Back-up power
Distribution	Distribution capacity deferral; Reliability (back-tie) services[2]	Voltage support; Resiliency/microgrid/islanding
Transmission	Transmission deferral; Inertia; Primary frequency response; Voltage support; Black start	None
Wholesale Market	Frequency regulation; Spinning reserves; Non-spinning reserves	Imbalance energy
Resource Adequacy	Local capacity; Flexible capacity	System capacity

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[5] California Public Utilities Commission, R.15-03-011, Joint Workshop Report and Framework Multiple-Use Applications for Energy Storage CPUC Rulemaking 15-03-011 and CAISO ESDER 2 Stakeholder Initiative, May 15, 2017, gg. 7.

A summary of the available and potential markets and services as applicable to groundwater pumped storage projects is found in Table 4.

Table 4. Groundwater Bank Operation Potential Markets and Services

Market or Service	Groundwater Bank Operation	Comments
Bulk Energy Supply (day ahead, real time, retail energy shift)	Generation Load	If there is water available at elevation to run through hydroelectric generators If operating via PDR or RDRR
Frequency Regulation	Generation (currently) Load (theoretically as dedicated Demand Response)	If generation configured properly, is operating and under ISO (AGC) control If configured properly, load operating and dedicated to ISO control
Spinning Reserves	Generation Load	If generation configured properly, is operating and under ISO control If operating via PDR
Non-Spinning Reserves	Generation Load	If generation configured properly If operating via PDR
Regulation Energy Management	Generation Load (theoretically)	If configured properly and participating in ISO regulation up/down markets If configured properly and participating in ISO regulation up/down markets
Flexible Ramping	Generation Load (theoretically)	If configured properly. If configured properly and allowed to provide service
Investment Deferral	Generation Load	Generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure.
Reactive Power/Voltage Support	Generation Load	If configured properly and operated under ISO control Not applicable.
Resource Adequacy	Generation Load	If configured and operated properly and participates in ISO markets
Demand Response	Generation Load	Not applicable Depends upon ability to curtail/shift load
Black Start	Generation Load	Only if there is water available at elevation to run through hydroelectric generators and configured for black start. Not applicable.

A key point to remember from this table is that all these markets/service have specific performance requirements which may not be compatible with groundwater bank operations. The primary purpose of groundwater storage banks is to store water and the operation of a pumped storage project cannot interfere with that water storage priority, and a pumped storage addition will need to be carefully configured to provide some of these services without compromising the water bank operation. Water bank operator may be reluctant to turn operation of their facility over to the ISO in order to participate in some ancillary markets.

For example, Resource Adequacy (RA) capacity is classified as system, local, or flexible. The rules for system and local RA define the qualifying capacity (QC) of a storage resource to be the maximum discharge rate the resource can sustain for four hours[6]. If a storage resource is counted toward a load serving entity's resource adequacy obligation, then it must participate in the wholesale market and be subject to a must-offer obligation. A must-offer obligation requires the resource to participate in the market during specific time periods and with specific rules, it is a requirement to bid or schedule the capacity into the ISO's day-ahead and real-time markets in accordance with specific ISO tariff provisions, and to be able to perform to fulfill its ISO schedule or dispatch instructions. A groundwater pumped storage facility would have to maintain sufficient water in elevated storage for 4 hours of operation at all times to qualify for Resource Adequacy.

In the WSWB example of this investigation, there are years (extraction years) in which the Peak Hour Pumped Storage Project operates as a load year-round (extraction years), as a pumped storage project (neutral years), and as a generator year-round (wet years) . While there is some flexibility in operations (Figures 4, 5, and 6) there are years in which participation in the markets/services in Table 4 will be impractical.

CASE STUDY: WSWB AQUIFER PUMPED HYDRO (APH) AND PEAK HOUR PUMPED STORAGE (PHPS) BENEFITS ANALYSIS[7]

ANALYSIS OF WSWB APH AND PHPS ECONOMIC BENEFITS

As Technical Memo No. 1 discussed, the WSWB Aquifer Pumped Hydro and Peak Hour Pumped Storage project was assessed based upon groundwater bank operation during various hydrologic years[8]. In wet (recharge) years, WSWB will recharge water into the bank's percolation ponds for storage. During this year type the PHPS project was evaluated as a generator (5.2 MW generated constantly over the year). ACH cannot generate during this type year. During an idle year, the projects were evaluated in pumped storage mode, generating when electricity prices were high, and refilling storage when prices were low (5.2 MW generation, 10.2 MW demand for pump station use). In a dry year WSWB will extract water and pump it to the California Aqueduct. This year was evaluated for demand response (curtailing electricity se in response to system needs). The electricity demand is continuous from groundwater pumping (17.2 MW) plus power for the pump station (10.2 MW). The addition of two additional extraction wells would allow 27 3 MW of potential demand response for 5 hours daily for up to 320 hours per year.

The projects electrical operation parameters are summarized in Table 5.

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[6] A storage resource that can store 4 MWh of energy would typically be able to sustain a 1 MW discharge rate for 4 hours and would therefore qualify to provide 1 MW of system or local RA capacity.

[7] Details in Technical Memo No. 1.

[8] The Aquifer Pumped Storage Project was too expensive, the efficiencies too low, and operational constraints too limiting to operate during wet (generation) years.

Table 5. Willow Springs Water Bank Aquifer Pumped Hydro and Peak Hour Pumped Storage Operation Scenarios

Hydrologic Year Type	Probability of Occurrence	WSWB Operation Type	Electricity Demand Potential	Electricity Generation Potential	Evaluated As
APH					
Wet	32%	Recharge	0	0	
Neutral	33%	Idle	17.2 MW	3.7 MW for 5 hour daily	Pumped Storage
Dry	35%	Extraction	17.2 MW groundwater pumping + 10.1 MW pump station use	0	Demand response
PHPS					
Wet	32%	Recharge	0	5.2 MW 24 hours daily	Generator
Neutral	33%	Idle	10.1 MW pump station use	5.2 MW for 5 hours daily	Pumped storage
Dry	35%	Extraction	17.2 MW groundwater pumping + 10.1 MW pump station use	0	Demand Response (demand reduction)

Table 6 provides a summary of the annual benefit from WSWB operating as pumped storage (both APH and PHPS) during a neutral year[9]. It is of interest to note that the traditional way for evaluating pumped storage - using day ahead energy market prices and generating when prices are high and extracting water when prices are low, is the least valuable of the services evaluated.

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[9] Using the StorageVet simulation model.

Table 6. WSWB Operated as Pumped Storage (Neutral Year – 33% Probability)

Market	APH Annual Value	PHPS Annual Value
Day Ahead Energy	$4,044	$94,852
Flexible Ramping	0	$384,637
Demand Response	0	$311,590
Total	**$4,044**	**$791,079**

Source: StorageVet Simulation using 2015 SCE DLAP prices (Default Load Aggregation Point prices - reflects the costs SCE avoids in procuring power during the time period).

During wet years, the water bank is storing water, and can operate as a hydroelectric generator year-round. For this case, PHPS was evaluated as a 5.2 MW hydroelectric generator operating 24 hours a day. The electricity was evaluated using the 2015 SCE DLAP hourly prices. APH is not able to operate as a generator during this type year due to water quality requirements. Table 7 shows the annual benefit during wet years of WSWB operating as a hydroelectric generator[10].

Table 7. WSWB Operated as a Hydroelectric Generator (Wet Year – 32% Probability)

Market	APH Annual Value	PHPS Annual Value
Day Ahead Energy	N/A	$**1,386,330**

During dry years, the water bank is extracting water (using pumps), and will operate as a continuous load year-round. For this case, the project was evaluated as a 27.3 MW load operating 24 hours a day, with the ability to be curtailed up to 5 hours per day for up to 320 hours during the year[11].

The project was evaluated for demand response using values from 2025 California Demand Response Potential Study[12]. This study recognizes three primary types of demand response: Shift, Shed, and Shimmy.

> The Shift service type is demand response that moves load to desired times during the day, increasing energy consumption during periods of the day when there is surplus generation, and reducing consumption during periods of the day when there is excess load.
>
> The Shed service type describes loads that can occasionally be curtailed to reduce customer demand during peak net load hours.

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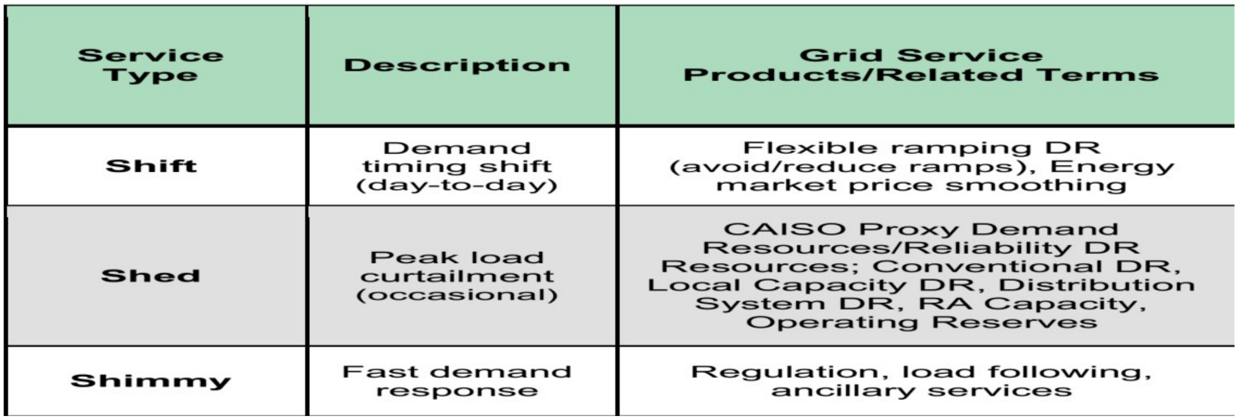
[10] 5.2 MW operating 24/7, priced at 2015 SCE DLAP prices, assuming no curtailment or load following.

[11] Additional curtailment would require the addition of additional extraction wells. Two additional wells would be necessary to accommodate curtailments up to 320 hours per year.

[12] 2025 California Demand Response Potential Study, Final Report on Phase 2 Results, Lawrence Berkeley National Laboratory, March 1, 2017.

The Shimmy service type involves using loads to dynamically adjust demand on the system to alleviate ramps and disturbances at timescales ranging from seconds up to an hour.

Figure 1. Types of Demand Response[13]



Service Type	Description	Grid Service Products/Related Terms
Shift	Demand timing shift (day-to-day)	Flexible ramping DR (avoid/reduce ramps), Energy market price smoothing
Shed	Peak load curtailment (occasional)	CAISO Proxy Demand Resources/Reliability DR Resources; Conventional DR, Local Capacity DR, Distribution System DR, RA Capacity, Operating Reserves
Shimmy	Fast demand response	Regulation, load following, ancillary services

Table 8 shows the annual benefit during a dry year of WSWB providing demand response services.

Table 8. WSWB Operated as a Continuous Load (Dry Year – 35% Probability)

Demand Response Service	Market Value (low)	Market Value (high)	Unit	WSWB Annual Value (low)	WSWB Annual Value (high)
Shed	$4	$4	$/kW-yr	$109,200	$109,200
Shift (1)	$20	$52	$/MWh	$174,720	$454,272
Shimmy – load following	$35	$45	$/kW-yr	$955,500	$1,228,500
Shimmy - regulation	$57	$98	$/kW-yr	$1,556,100	$2,675,400
			Total	$2,795,520	$4,467,372
(1) Assuming up to 5 hours of daily curtailment available, 27.3 MW curtailable up to 320 hours per year.					

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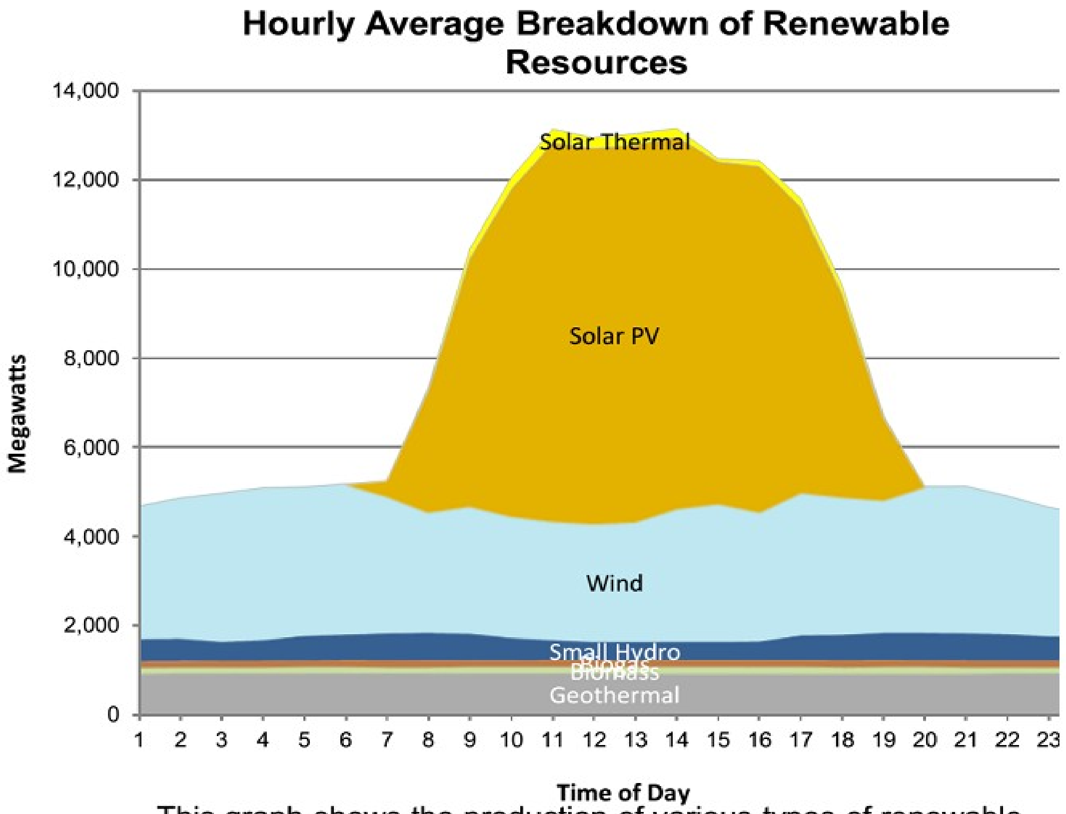
[13] Ibid, pg. 3-16.

DISCUSSION OF WSWB PUMPED STORAGE PROJECT BENEFITS

California is experiencing a plethora of abundance in renewable generation, and this is causing system operating issues. As the following Figure 2 illustrates, there is a huge amount of solar generation occurring during the afternoon hours.



This graph shows the production of various types of renewable generation across the day.

System Peak Demand (MW) **28,702**
***one minute average**

Time: **20:11**

Figure 2. Renewable Energy Generation, April 27, 2017
Source: California ISO data for April 27, 2017

This overabundance of solar generation during afternoon hours has resulting in an operating phenomenon known as the “duck curve”, so named by ISO staff due to its resemblance to the bird profile.

The ISO “duck curve” is shown in Figure 3. The “duck curve” is the net generation load – generation requirements after renewable generation has been subtracted out. This figure illustrates the operational issues facing California: specifically, an overabundance of renewable generation during the afternoon hours, a very steep ramping requirement during the late afternoon, and a peak generation requirement during the evening. The “duck curve” is forecasted to only get worse as California installs more and more renewable generation.

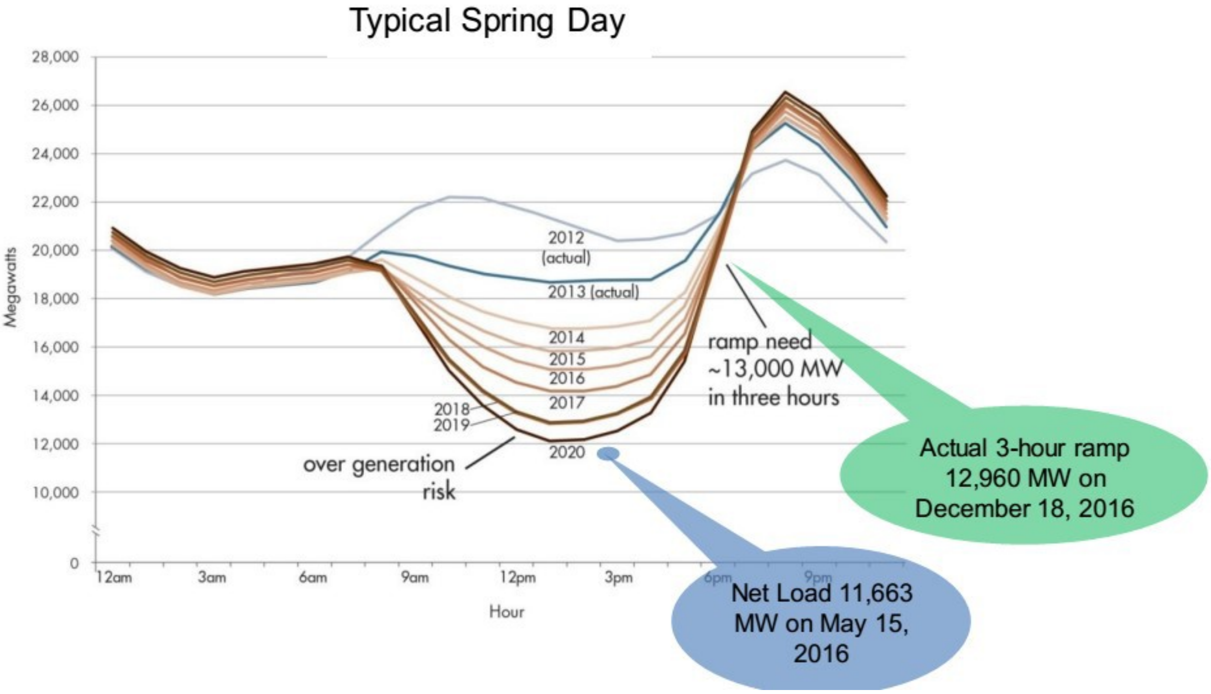


Figure 3. California ISO “Duck Curve”
Source: California ISO[14]

There have been a number of methods proposed for coping with an increasing “duck curve”, including:

- Exploiting regional diversity in generation resources and demand
- Installing more dispatchable generation
- Adding more energy storage
- Increased demand management:
    - Time-of-use pricing (TOU) and real-time pricing
    - Increased demand response
    - Smart grid technology.

The WSWB PHPS could assist in addressing “duck curve” operation issues in all hydrologic years.

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[14] Using Renewables to Operate a Low-Carbon Grid, California ISO, pg. 11, http://www.caiso.com/Documents/UsingRenewablesToOperateLow-CarbonGrid.pdf

Wet Hydrologic Year

During a wet hydrologic year, the WSWB PHPS can operate as a hydroelectric generator. As Figure 4 shows, the PHPS can be configured to curtail generation for 5 hours per day, ideally during the afternoon renewable generation over production. This would assist with the “belly” of the “duck curve” the period of renewable energy overgeneration.

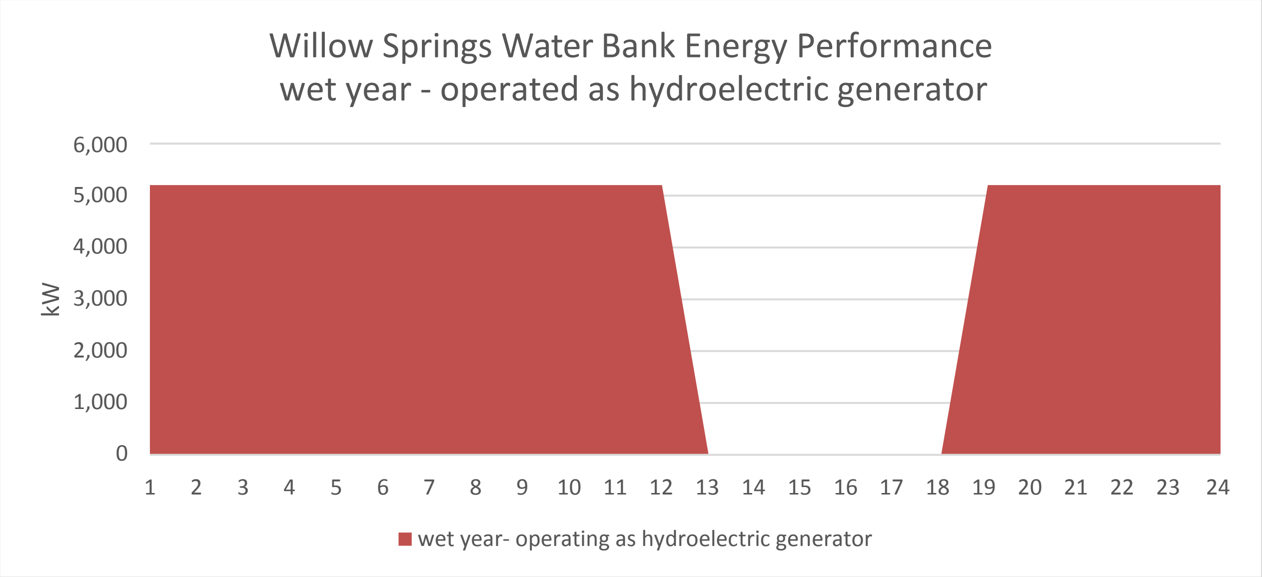

Figure 4. WSWB PHPS Hypothetical Operation During Wet Year – Operating as Generator

Neutral Hydrologic Year

During a neutral hydrologic year, the WSWB PHPS can operate as a pumped storage facility. Figure 5 show the PHPS operation, from the StorageVet simulation for the day of April 15th based upon Day Ahead Market Prices PHPS provides generation during the morning and evening ramp periods, and increased demand (load) during the afternoon periods to refill storage reservoirs.

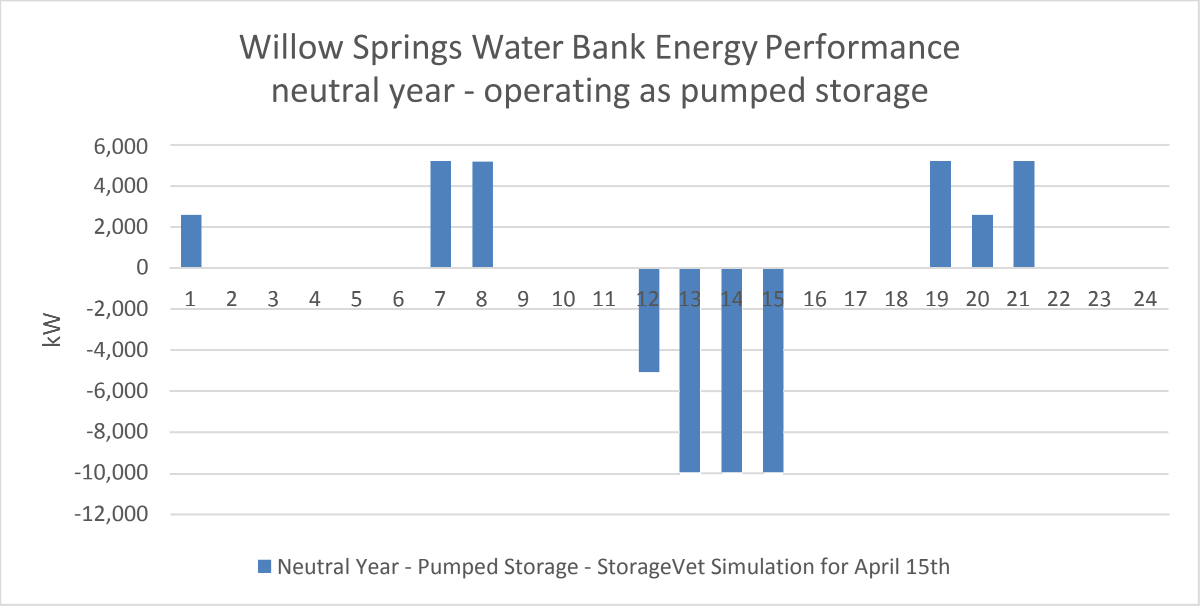

Figure 5. WSWB PHPS Hypothetical Operation During Neutral Year – Operating as Pumped Storage
Source: StorageVet simulation for April 15th, using SCE DLP prices

Dry Hydrologic Year

During a dry hydrologic year, the WSWB operates as a load (pumping water out of the ground and delivering it to Aqueduct) and could be configured to accommodate 5 hours of curtailment if necessary. Figure 6 show hypothetical WSWB operation during this period, using the surface reservoirs. WSWB can be configured to reduce load during the late afternoon ramping period and evening peak.

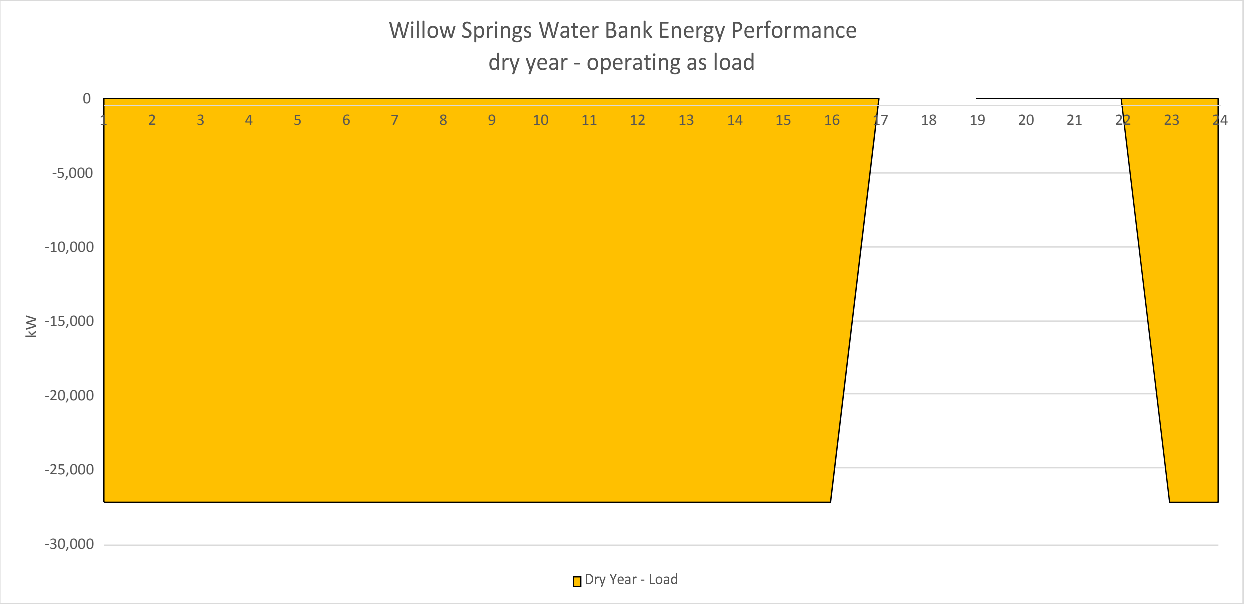

Figure 6. WSWB Hypothetical Operation During Dry Year – Operating as a Load

STATEWIDE POTENTIAL FROM ADDING PUMPED STORAGE TO GROUNDWATER BANKS

A part of this investigation the statewide potential of using groundwater storage banks as energy storage facilities was prepared. Table 9 provides an estimate of the statewide potential for these facilities, the annual benefit, and the expected capital cost associated with these type of projects using WSWB as a specific example. Demand Response is very cost effective investment. Aquifer Pumped Hydro (APH) never pays for itself, due to high capital cost, low round trip efficiencies, and limited operating flexibilities. PHPS is cost effective, if demand response is added to its operation.

Table 9. Statewide Potential, Benefits, and Costs From Energy Storage at Groundwater Banks.

Type	MW potential	Annual Net Benefit	Facilities Needed	Capital Cost	NPV per kW[15]
Peak Hour Pumped Storage – PHPS Generation	44 MW	-44K[16]	Upper and lower surface storage reservoirs, connecting piping, hydroelectric generators and controls, utility interconnection	$66.8M ($1,518/W)[17]	-$190/kW
Aquifer Pumped Hydro - APH		[-$431/kW]	Surface storage reservoir, reversible pump turbines and controls, connecting piping, utility interconnection	[$5,000/kW][18]	-$4,945/kW
Flexible Load (Demand Response)	220 MW	$6.3M[19]	Surface storage reservoir and additional extraction wells	$18M ($82/kW)[20]	$332/kW

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[15] Assuming a 20-year life and a 6% interest rate. Based upon generating capacity for pumped storage, and curtail capacity for demand response.

[16] The probability weighted annual net benefit for WSWB PHPS generation was -17/kW.

[17] The capital cost of WSWB PHPS was $1,518/kW.

[18] The capital cost of WSWB APH was $5,000/kW.

[19] The annual net benefit for demand response was $29/kW.

[20] The capital cost of adding a 5 hours surface storage reservoir (320 hours) and additional extraction wells was $82/kW.

APPENDIX A: List of Required Permits and Registrations

Note- not all of these may be applicable to all groundwater energy storage projects.

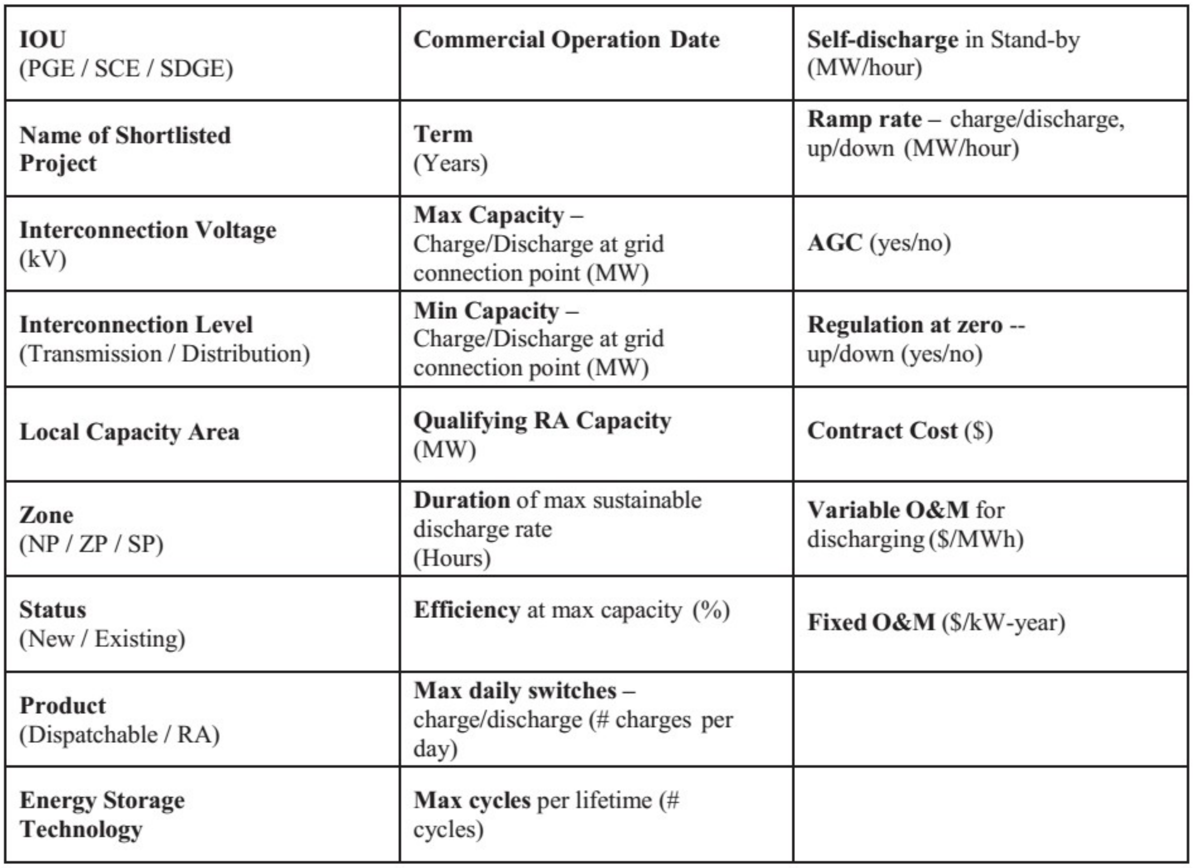
Agency	Permit / Registration	Criteria	Comments
FERC – Federal Energy Regulatory Commission	Hydro exemption or license	Will need either a conduit exemption, a 10-MW exemption, or a license, depending upon characteristics of hydro generator	Consult FERC small hydro website: https://www.ferc.gov/industries/hydropower/gen-info/licensing/small-low-impact.asp
	Qualifying Facility	80 MW or less using renewable generation	Form 556
EIA - Energy Information Administration	Generator Registration	1 MW or larger	EIA Form 860
CalSO – California Independent System Operator	FNM – Full Network Model	1 MW or larger	GRDT – Generation Resource Data Template
	Interconnection	If connected to transmission system	FERC wholesale interconnection application http://www.caiso.com/planning/Pages/GeneratorInterconnection/InterconnectionRequest/Default.aspx
	NRI – New Resource Integration	1 MW or larger (occasionally 500 KW or larger)	http://www.caiso.com/Documents/NewResourceImplementationGuide.doc
CEC – California Energy Commission	Small Hydro Certification	Required for RPS (Renewable Portfolio Standard)	CEC RPS-1
	Generating Unit ID	1 MW or larger	CEC-1304

WREGIS – Western Renewable Energy Generation Information System	QRE (Qualified Reporting Entity) Generating Unit ID		Credit for RECs (Renewable Energy Certificates)
SWRCB – State Water Resources Control Board	Nonconsumptive Water Use Right		
	401 permit	Water Quality Certification	
Electric Utility	Interconnection	If connected to Distribution System	
	PPA (Power Purchase Agreement)	If selling output to utility	
Environmental Documents	CEQA (California Environmental Quality Act)	EIR (Environmental Impact Report)	
	USACE (U S Army Corps of Engineers) 404 permit	Discharge permit	
	CDFW (California Department Fish and Wildlife) 1602 permit	Streambed alteration permit	

CEP: In 2014, the California Public Utilities Commission established a Consistent Evaluation Protocol (CEP) for jurisdictional utilities to provide offer results confidentially for regulatory review in a common data format, for “benchmarking and general reporting purposes”.

Descriptive Information Included in the CEP Spreadsheet. The following shows the descriptive information about offers required in the CEP spreadsheet:

Descriptive information included in the CEP Spreadsheet



IOU (PGE / SCE / SDGE)	**Commercial Operation Date**	**Self-discharge** in Stand-by (MW/hour)
Name of Shortlisted Project	**Term** (Years)	**Ramp rate** – charge/discharge, up/down (MW/hour)
Interconnection Voltage (kV)	**Max Capacity** – Charge/Discharge at grid connection point (MW)	**AGC** (yes/no)
Interconnection Level (Transmission / Distribution)	**Min Capacity** – Charge/Discharge at grid connection point (MW)	**Regulation at zero** -- up/down (yes/no)
Local Capacity Area	**Qualifying RA Capacity** (MW)	**Contract Cost** ($)
Zone (NP / ZP / SP)	**Duration** of max sustainable discharge rate (Hours)	**Variable O&M** for discharging ($/MWh)
Status (New / Existing)	**Efficiency** at max capacity (%)	**Fixed O&M** ($/kW-year)
Product (Dispatchable / RA)	**Max daily switches** – charge/discharge (# charges per day)	
Energy Storage Technology	**Max cycles** per lifetime (# cycles)	