Nan Zhang
Energy Exemplar, LLC
3013 Douglas Blvd, Suite 120
Roseville, CA 95661

Eric Toolson
Pinnacle Consulting, LLC
8746 Pathfinder CT
Orangevale, CA 95662

Submitted to the

U.S. Department of the Interior,
Bureau of Reclamation
2800 Cottage Way
Sacramento, CA 95825

November 2013

This page intentionally left blank.

Acknowledgments

Many thanks go to the following individuals for their insightful comments and their contributions to this study.

- Mary Johannis – Bureau of Reclamation
- Sharon Mchale – Bureau of Reclamation
- Ronald Ganzfried –Bureau of Reclamation
- Eric Vogler – Bureau of Reclamation
- Jeff Herrin – URS Corp
- Joe Barnes – URS Corp
- Nik Carlson – URS Corp
- Ghassan Alqaser – California Department of Water Resources
- Tao Guo – Energy Exemplar, LLC
- Wenxiong Huang – Energy Exemplar, LLC

This page intentionally left blank.

Contents

Tables

Figures

This page intentionally left blank.

H2.1 Introduction

The economic viability study of the proposed North-of-the-Delta Offstream Storage (NODOS) pump storage project was originally completed by the United States Bureau of Reclamation (Reclamation) and the California Department of Water Resources (DWR) in early 2013. This document summarizes an update to that study performed for Reclamation, by Energy Exemplar (EE) and Pinnacle Consulting (Pinnacle), consulting firms specializing in the evaluation of power generation assets in California and in the Western Electricity Coordinating Council (WECC) system, which includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of 14 Western states in the United States including California.

The NODOS project is a potential storage facility designed for improved water supply reliability and Delta water quality (see www.usbr.gov/mp/nodos). The NODOS ***pump-storage project*** evaluation, which is the focus of this Appendix, analyzes the economic viability of enhancing the power operation of the NODOS project to provide pump storage sufficient for daily pump-back operations to facilitate reliable operation of the electric grid in California. The evaluation consists of a base and alternative case as summarized below:

> ***Base Case –*** uses existing Funks reservoir as the afterbay with a 1000 acre-feet of active storage.
>
> ***Alternative Case –*** expands the existing Funks reservoir to 6,500 acre-feet of active storage, with several other relatively minor project enhancements. The expanded reservoir is called Holthouse. In the DWR evaluation, this option is referred to as “Alternative C”.

H2.2 Purpose and Need of Project

The NODOS pump storage project is needed to provide peaking power and ancillary services in California. California has passed legislation which requires 33 percent of the electricity to serve customers be provided from defined renewable resources. Much of this renewable generation (such as solar photovoltaic and wind) is intermittent and not dispatchable. This means it may be available during the partial- or- off-peak hours, but cannot be counted upon to be available during all of the peak hours. Hence, additional new generation that is dispatchable and flexible will be required for the peak period. In addition to the peak-energy need, significant new renewable resources will also require additional ancillary services, or operational capacity that is available to compensate for the variability of the renewable resources in order to allow for the reliable operation of the electric grid.

H2.3 Purpose of Update

There are several primary reasons for the update including the following:

- Perform an economic valuation using an hourly, rather than a monthly sub-period model.
- Use a simulation model which directly models and co-optimizes Ancillary Services (AS)[1].
- Evaluate any enhancements to the long-term planning capacity due to additional Holthouse storage.

The previous study performed with DWR used a model that was based on two monthly time steps – on-peak and off-peak. This is a valid approach used frequently when hourly data may not be available or the simulation tool is not capable of hourly modeling. And while the monthly sub-period modeling is credible and acceptable, it is not considered as accurate as an hourly model which provides for anywhere from 672 (28 days) to 744 (31 days) hours or period of simulation each month, as compared to two periods for the monthly sub-period model. Particularly for a storage project, it is critical to pick up the hourly fluctuations in market prices for both generation and pumping. Thus, an hourly model can provide for a more accurate economic assessment.

A second major reason for the update is that the model used for the hourly simulations, PLEXOS, (developed by Energy Exemplar)[2] is capable of accurately representing the simultaneous commit and dispatch process utilized by the California Independent System Operator (CAISO). The CAISO procedure (which is performed for the day-ahead market) results in hourly energy as well as ancillary service prices. Using PLEXOS in this manner allows a resource to be accurately credited with AS contribution and revenue, thus providing a more accurate valuation.

The third reason is to evaluate any changes to the long-term planning capacity credit. All firm resources have a defined capacity capability which is used to meet required resource planning margins. California has a resource adequacy requirement, which mandates (12 months out) that 15 percent capacity in excess of projected peak load be available to the grid. This planning reserve margin is mandated in order to assure adequate resources are available to reliably meet the system electric load given uncertainties regarding load and increasing uncertainties regarding the availability of generation at the time it is needed most.

[1] Ancillary Services (AS) are different types of operating reserves and include regulation-up, regulation-down, spin, and non-spin. Similar to energy, these reserves have specific hourly market-clearing prices and differ in terms of their ability to respond to system uncertainties.

[2] See www.energyexemplar.com.

H2.4 Description of Base and Alternative Cases

The base case represents the water storage project as defined in 2006 and includes Sites pumping and once-through power generation. This evaluation allows for an accurate analysis of the incremental benefits achieved by the alternative case as compared to the base case. The alternative case represents the pumped-storage configuration that allows for a more optimal daily pump-back operation. These two cases are identical from a Sites powerhouse perspective. Each of these two configurations contains the following equipment:

Table H2-1. Sites Pumping-Generating Equipment

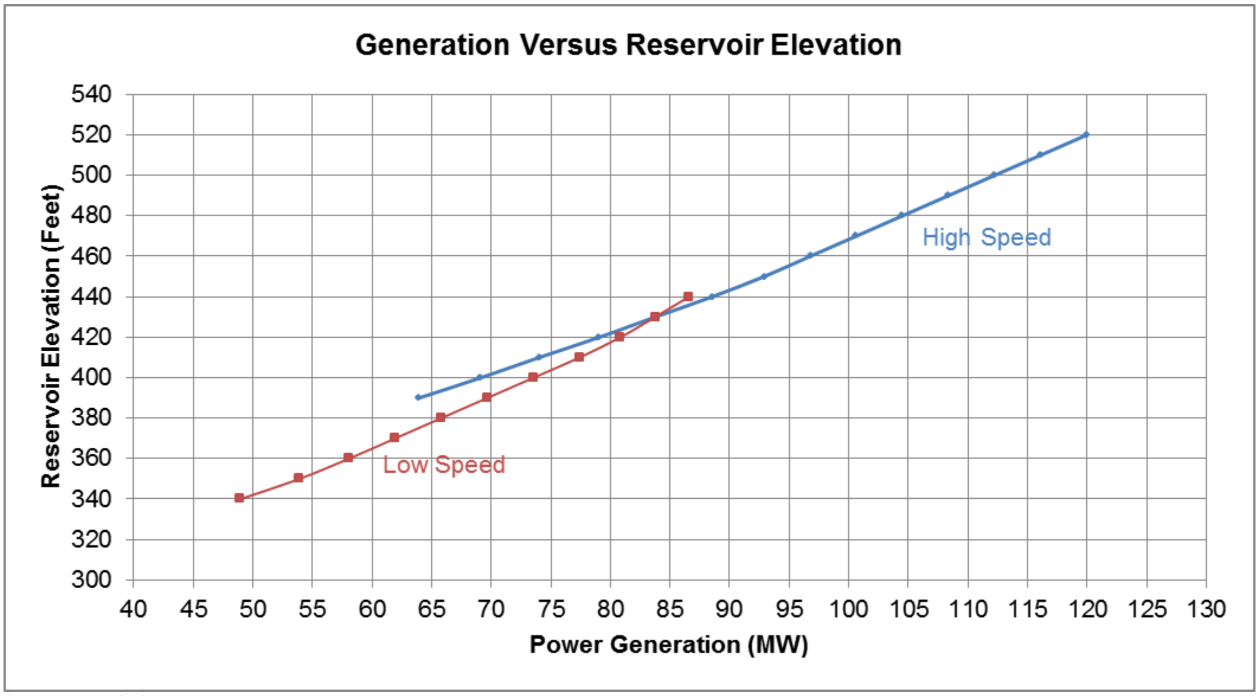
Unit Type	Number of Units	Net Head (feet)	Pumping Capacity/ Unit (cfs)	Generating Capacity/Unit (cfs)	Motor Power/ Unit (MW)	Generating Power/Unit (MW)
Pump -- Francis Vane Dual-Speed	2 (+1 standby)	330	870	n/a	27.6	n/a
		202	870	n/a	16.9	n/a
Pump -- Francis Vane Dual-Speed	2	330	435	n/a	13.8	n/a
		202	435	n/a	8.4	n/a
Pump / Turbine Reversible Francis, Dual-Speed	4 (+1 standby)	330 / 310	663	1020	19.7	24.6
		202 / 182	663	1020	11.6	14.5
Pump / Turbine Reversible Francis, Dual-Speed	2	330 / 310	332	510	9.9	12.3
		202 / 182	332	510	5.8	7.2
Total			**5,926**	**5,100**		

Source: DWR

The Sites pumped storage efficiency curves for the generating and the pumping modes of operation are provided by URS Corp and are shown in Figure H2-1 and Figure H2-2. These curves are the same for both the Base and the Alternative cases. At different reservoir elevations, the maximum generation output and the maximum pumping load are different, consistent with the maximum generation and pumping corresponding to that elevation shown in Figure H2-1 and Figure H2-2.

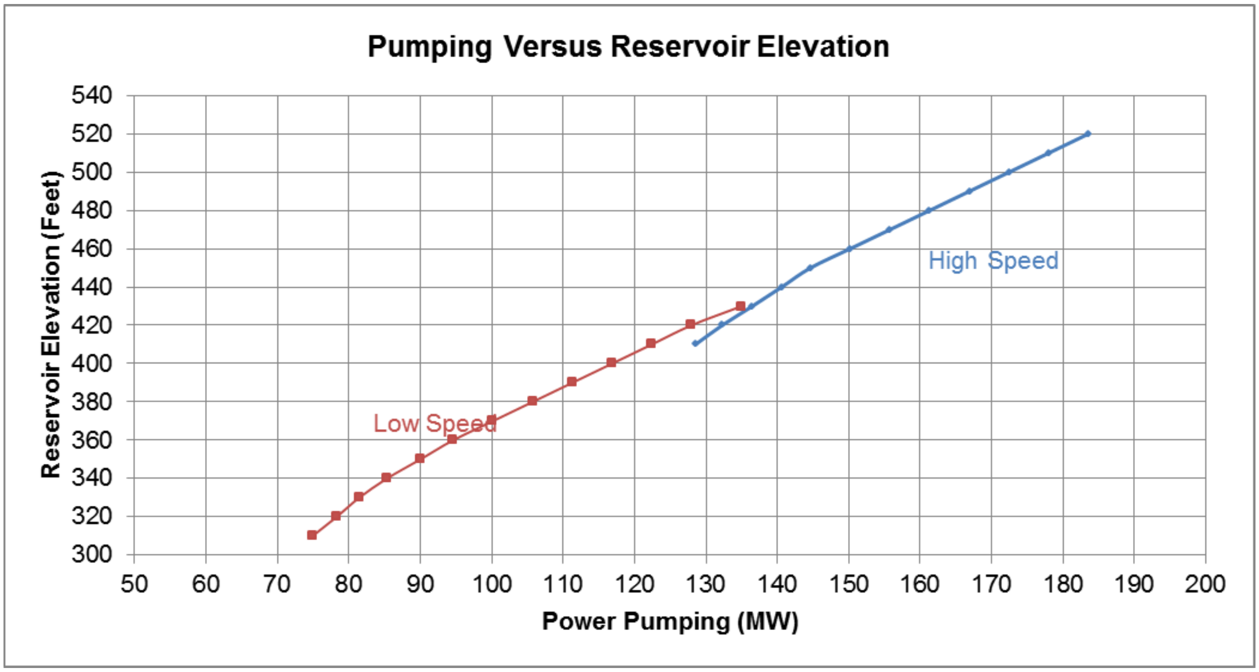
These two curves are translated into the PLEXOS simulation model as a series of pumped storage units with different efficiency points, as shown in Figure H2-3. Constraints are placed in the model to make sure each pumped storage unit is running at its desired water level and there are no two or more units operating at any time, which would result in a duplicate operation. This modeling technique was used for two reasons. First, it reduces the PLEXOS execution time significantly. Second, it simplified the modeling from 10 units to essentially one unit with 18 different efficiencies.

Figure H2-1. Sites Plant Generating Efficiency



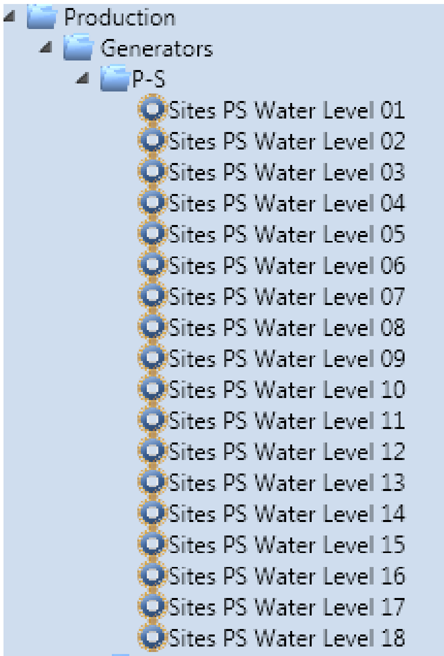
Source: URS Corp

Figure H2-2. Sites Plant Pumping Efficiency



Source: URS Corp

Figure H2-3. Sites Pump Storage Representation in PLEXOS



Since PLEXOS uses the volume model to represent the storage, the original efficiency curve was converted from an Elevation vs Megawatt (MW) representation to the Volume vs MW representation. The conversion curve from Elevation to the Volume was also provided by URS Corp, and is shown in Figure H2-4.

Although the pumping and generation equipment is identical between the base and alternative cases, the pumped storage case, (i.e., the “alternative” case) requires the following capital modifications to the base case [3] to enable a robust daily pump-back operation:

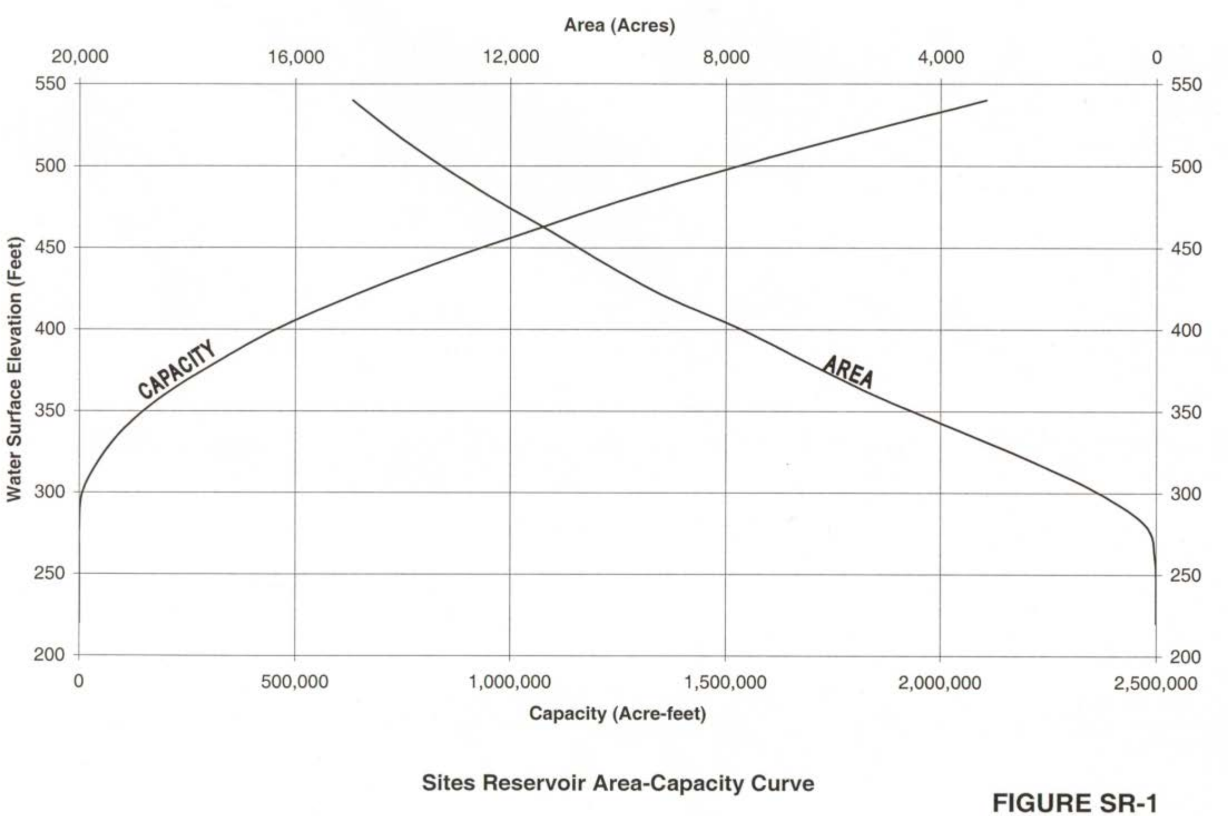
1. Enlarge Funks (Holthouse) Reservoir from its current 1,000 acre-feet active storage (originally 2,000 acre-feet, but now reduced due to siltation) to 6,500 acre feet. This modification is the most significant capital expenditure.
2. Increase length and depth of channel connecting Sites powerhouse with enlarged Funks Reservoir.
3. Modify Delevan and the Terminal Regulating Reservoir (TRR) pipelines to function with enlarged Funks Reservoir (could be a cost reduction depending on alignment selected).
4. Relocate WAPA transmission line to span the enlarged Funks Reservoir.
5. Develop pumping facilities to convey water to TC Canal downstream of Funks, when Funks is too low to provide water by gravity.

[3] Email from Joseph Barnes to Eric Toolson dated September 26, 2013 and entitled “Base Case for Power Generation” and subsequent conversations.

The estimated incremental costs for the Sites pumped storage alternative are currently estimated as follows:

- Incremental Capital Cost -- $120 million in 2012 dollars
- Incremental Fixed Operations and Maintenance (O&M) -- $0.5 million in 2012 dollars

Figure H2-4. Sites Reservoir Elevation to Volume Conversion Curve



Source: URS Corp

H2.5 Description of Benefits

The Sites pumped storage project would provide the following benefits:

- Energy
- Ancillary Services (operating capacity)
- Planning Capacity

The derivation of each of these benefits is described below.

***Energy and Ancillary Services Benefits* –** The energy production for the base case was determined by DWR and adhered to all water storage and other physical constraints. The energy production for the alternative case is a direct output from the PLEXOS model simulation. The energy production from both cases is valued by using the same market prices.

PLEXOS dispatches the Sites Pumped storage against the energy and ancillary services' market prices and maximizes the profit. As stated in the previous paragraph, the energy production for the base case was fixed, whereas the energy production for the alternative case was determined by PLEXOS. The pumped storage units are mostly pumping during the off-peak hours and generating during the on-peak hours whenever it is economic to go through this cycle. Also, PLEXOS determines the optimal timing and the amount of capacity to bid into the ancillary services market. Because of the co-optimization structure of the PLEXOS algorithm, it determines the best solution considering the energy market pricing and ancillary market pricing simultaneously.

Although this study only focuses on the benefits and costs of the daily pump-back operation at Sites power house, the study utilizes the monthly water diversion and release simulation between the Funks/Holthouse Reservoir and the other project facilities as a constraint. In this way, on a monthly basis the correct elevations are enforced on the pump-storage project operation to assure consistency between the water and power simulation for this project. The evenly distributed hourly water diversion to or release from Funks/Holthouse reservoir are derived from the DWR simulations.

***Planning Capacity Benefits* –** The two types of capacity benefits derived from the pump-storage project are operating and planning reserves. Operating reserves are generally considered to have the same meaning as ancillary services and are described in the previous section. Planning reserves are described in this section. In the WECC, balancing authorities are encouraged to have a specified level of planning capacity or reserves for the future in order to ensure resource adequacy and the ability to operate the grid reliably. These reserve amounts are usually calculated using detailed, probabilistic, regional models. In California, there is a mandated planning reserve margin, which requires utilities or other electric service providers to own or control generation equal to roughly 115 percent of their expected peak hourly load.

There are a variety of ways to evaluate the value of planning capacity. If the need is just for a single year, one can look to the current planning reserve market. If the need, however, extends for more than 5 to 10 years, generally the cost of the least expensive peaking unit (minus market revenue from energy and AS sales) is considered to be a valid proxy for the cost of future capacity. The least-cost central-station generating resource is commonly considered to be a Combustion Turbine (CT). And in California, aero-derivative CTs are now being built (rather than traditional industrial frame CTs) due to future renewable energy integration needs.[4]

[4] Aero-derivative CTs are reportedly similar to aircraft engines and are much more flexible than larger industrial-frame CTs.

H2.6 Simulation Methodology

The energy and ancillary services benefits are estimated using the PLEXOS market simulation model. The PLEXOS® Integrated Energy Model, developed by Energy Exemplar LLC, is a proven power market simulation software that uses cutting-edge mathematical programming and stochastic optimization techniques, combined with the latest user-interface and data handling approaches to provide the most comprehensive, easy-to-use and robust analytical framework for power market modelers. It is widely used by many users for the following purposes:

- Price Forecasting
- Power Market Simulation and Analysis
- Detailed Operational Planning and Optimization of Power Plants and Grid
- Trading and Strategic Decision Support
- Generation and Transmission Capacity Expansion Planning (Investment Analysis)
- Renewable Integration Analysis
- Co-optimization of Ancillary Services and Energy Dispatch
- Transmission Analysis and Congestion Management
- Portfolio Optimization and Valuation
- Risk Management and Stochastic Optimization

The PLEXOS software has many distinguishing capabilities which are particularly useful in performing this NODOS Study.

- **Hourly and sub-hourly dispatch time-step.** The 1, 10, 15, 30 minutes and hourly time steps are available.
- **Simultaneous optimization.** All decision variables are determined at the same time, thereby providing a fully-optimized resource solution. This algorithm encompasses the same algorithms used by many independent system operators to clear their day-ahead market.
- **Ancillary service modeling.** PLEXOS simultaneously solves for all specified ancillary services including hard-to-model parameters such as regulation-up, regulation-down, load following, and any user-defined ones.
- **Comprehensive modeling for Hydro and Pumped storage.** PLEXOS can model comprehensive setup for a hydro system, from run-of-river, hydro with storage, to cascade hydro system with complex waterway and inflow definition. Pumped storage units can be modeled with generator efficiency, round-trip efficiency and head effects at different water level.
- **Integrated resource and transmission optimization.** PLEXOS fully co-optimizes complex Security Constrained Unit Commitment and Economic Dispatch with DC-OPF

representation of regional transmission network and resource portfolios in the marketplace, including both energy and ancillary service production.

- **User-defined constraints and variables.** The user can add any linear or piecewise-linear constraint with a few simple steps in less than five minutes. This is a tremendous advantage over the traditional, time-consuming process of requiring the software developer to implement the constraint, test, document, etc. The user can also add user-defined decision variables, either linear or integer, and in this way enhance, expand or modify the intrinsic mathematical program at will.

The energy and ancillary service co-optimization is the basis of the PLEXOS algorithm. The PLEXOS Mixed Integer Programming Algorithm (MIP) produces the optimal decision on the generation and reserve provisions from each generator to meet the system energy demand and reserve requirements.

The hourly (or even sub-hourly) simulation is important for evaluating the benefits of the pumped storage plant. The pumped storage plant makes profits by pumping the water into upper reservoir during the off-peak hours and releasing water during on-peak hours to generate power. It is important to capture the price difference at each individual hour to make the decision on when to pump and when to generate in order to maximize the profit.

In this study, the PLEXOS model is configured to dispatch against the energy and ancillary service market prices.

The energy prices and ancillary services prices used in this study (which are described in Section 7) are input into the PLEXOS model. The Sites pumped storage facility (with physical constraints) is modeled in PLEXOS to pump and dispatch based on the market prices. PLEXOS automatically finds the optimized way to allocate the capacity into Energy market and Ancillary Service market to make the maximum profit. The simulation is based on an hourly chronological dispatch for 30 different hydrological years.

Ancillary services are used to provide sufficient generating capacity to ensure the power system can be operated in a reliable and stable manner on a four-second by four-second basis. A pumped storage power plant is very valuable in providing ancillary services due to its ability to provide flexible generation, which can be ramped up and down very quickly. This capability becomes increasing important, given the high percentage of renewable penetration mandated for California by the year 2020.

When a generator is to provide the upward ancillary services, the same amount of capacity is withheld from contributing to the energy market. How much capacity is contributing to the energy market and how much capacity is providing ancillary services to reach the maximum profit is a complex software optimization. Similarly, when a generator is to provide the downward ancillary services, the generator is operated at least the same amount of capacity above its minimum capacity.

Additional modeling constraints were also incorporated to correctly represent energy and ancillary service sales. Specifically, these constraints include the following:

- The maximum energy and regulation-up sales in any given hour cannot exceed the maximum generating capacity available in that hour.
- Regulation-up sales will be called upon roughly 20 percent of the time to provide energy. Thus, if 100 MW of regulation-up sales are desirable in a given hour, 20 percent of that amount, or 20 MW would be sold as energy associated to the 80 MW regulation-up sales.
- The reservoir storage must be available to provide energy for the full amount of regulation-up sales for a given hour, if the Sites pumped storage is called up to provide energy.

In summary, the derivation of the benefits for the two cases is summarized in Table H2-2 below:

Table H2-2. Source of Benefit Derivation for the Base and Alternative Cases

Benefit	Base Case (1,000 AF)	Alternative Case (6,500 AF)
Energy	DWR	PLEXOS
Ancillary Services	PLEXOS	PLEXOS
Planning Capacity	Spreadsheet	Spreadsheet

AF = acre feet

Given the time and resource constraints of this study, the energy benefits for the base case were not optimized in PLEXOS. Since the storage in this case is very limited (1,000 acre-feet [AF]), the energy benefits are not expected to be significantly greater than those derived in the DWR study. In a later phase of the study, it may be interesting to allow PLEXOS to optimize the energy output in the base case subject to all the water storage and physical constraints.

H2.7 PLEXOS' Assumptions [5]

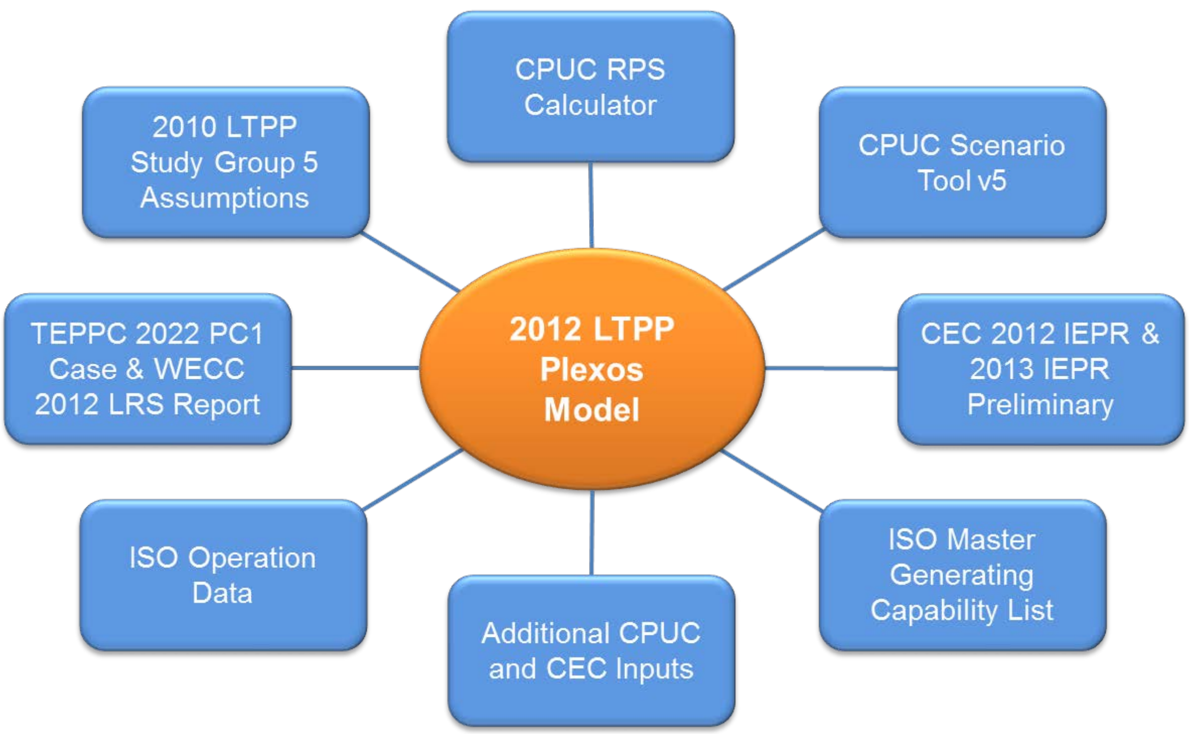
Under the California Assembly Bill 57 (PU Code 454.5), which passed in 2002 after the California energy crisis, the Investor-Owned Utilities (IOUs) resumed electricity procurement. Every 2 years, the California Public Utilities Commission (CPUC) holds a ***Long-Term Procurement Plan (LTPP)*** proceeding to review and adopt the IOUs' 10-year procurement plans. The LTPP evaluates the utilities' need for new resources and establishes rules for rate recovery of procurement transactions[6].

[5] This section discusses the primary assumption changes which differ from the DWR work done previously.
[6] See http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/index_2012.htm

For the 2012 LTPP, the CPUC requested that the California ISO conduct a system operational flexibility modeling study. PLEXOS was selected to perform this study for the California ISO to study the system situation in year of 2022[7].

For this NODOS benefit study, several assumptions and outputs from this 2012 LTPP study were used in the PLEXOS modeling because this study reflects the inputs from multiple resources and has been reviewed by multiple stakeholders in the California power sector, as shown in Figure H2-5. WECC's Transmission Expansion Planning Policy Committee (TEPPC) oversees and maintains a public database for production cost and related analysis[8]. In the 2012 LTPP study, the latest TEPPC 2022 base case, along with the 2012 WECC Loads and Resources Subcommittee (LRS)'s report, were used for the majority of the assumptions. The assumptions within California were further updated with CPUC's inputs from 2010 LTPP assumptions, Renewable Portfolio Standards (RPS), and scenario selection tool; with California Energy Commission (CEC)'s inputs on load forecast from Integrated Energy Policy Report (IEPR) and natural gas price forecast; with California ISO's inputs on generator data and operation data, etc.

Figure H2-5. LTPP Assumptions from Multiple Sources



Source: R.12-03-014: LTPP Track II Workshop – Operating Flexibility Modeling Results

[7] See http://www.caiso.com/informed/Pages/StakeholderProcesses/RenewableIntegrationMarketProductReviewPhase2.aspx
[8] See https://www.wecc.biz/committees/BOD/TEPPC/Pages/TEPPC_Home.aspx

Year of Study:

2022 -- Same year as in 2012 LTPP study, assuming the major electricity mandates such as 33 percent renewable portfolio standard, greenhouse gas legislation, once-through cooling retirement, replacement for SONGS nuclear plant retirement, are all in place in California.

Gas Price:

The PG&E gas burner tip prices are from the 2012 LTPP study base case, and are provided by California Energy Commission, which is shown in Table H2-3.

CO_2 Price:

Carbon dioxide (CO_2) price in 2022 is also provided by California Energy Commission (CEC).

Nominal Dollars: $**26.13/US Short ton**

2012 Dollars: **$21.89/US Short ton**

Energy and Ancillary Services Prices:

Energy and Ancillary Services prices are the simulation output from the PLEXOS 2012 LTPP simulation, as shown in Table H2-4. Here we only list the regulation up and regulation down prices because they are the highest among the ancillary services prices and Sites is capable of providing these services.

Table H2-3. PG&E Gas Price Assumption in 2022

	Nominal $	**2012 $**
Jan-22	5.38	4.50
Feb-22	5.08	4.25
Mar-22	4.97	4.17
Apr-22	5.12	4.29
May-22	5.28	4.42
Jun-22	5.36	4.49
Jul-22	5.43	4.55
Aug-22	5.04	4.23
Sep-22	4.99	4.18
Oct-22	5.18	4.34
Nov-22	5.58	4.68
Dec-22	5.64	4.73
Annual Avg	5.25	4.40

Source: 2012 LTPP Base Case Input

Table H2-4. PG&E Energy and Ancillary Service Prices from 2012 LTPP Run

	Energy $/MWh Nominal	Energy 2012$/MWh	RegUp $/MW Nominal	RegUp 2012$/MW	RegDn $/MW Nominal	RegDn 2012$/MW
Jan-22	50.45	42.27	7.21	6.04	0.23	0.19
Feb-22	47.05	39.41	6.69	5.61	0.33	0.28
Mar-22	42.10	35.27	7.44	6.24	0.71	0.60
Apr-22	37.41	31.34	7.57	6.35	1.55	1.30
May-22	37.34	31.29	7.88	6.61	1.90	1.59
Jun-22	42.53	35.63	8.71	7.29	2.45	2.05
Jul-22	58.15	48.72	10.48	8.78	0.36	0.30
Aug-22	48.16	40.34	6.25	5.24	0.10	0.08
Sep-22	48.84	40.91	8.18	6.85	0.23	0.19
Oct-22	50.38	42.21	10.15	8.51	0.74	0.62
Nov-22	51.68	43.30	9.61	8.05	0.87	0.73
Dec-22	54.40	45.58	7.94	6.65	0.37	0.31

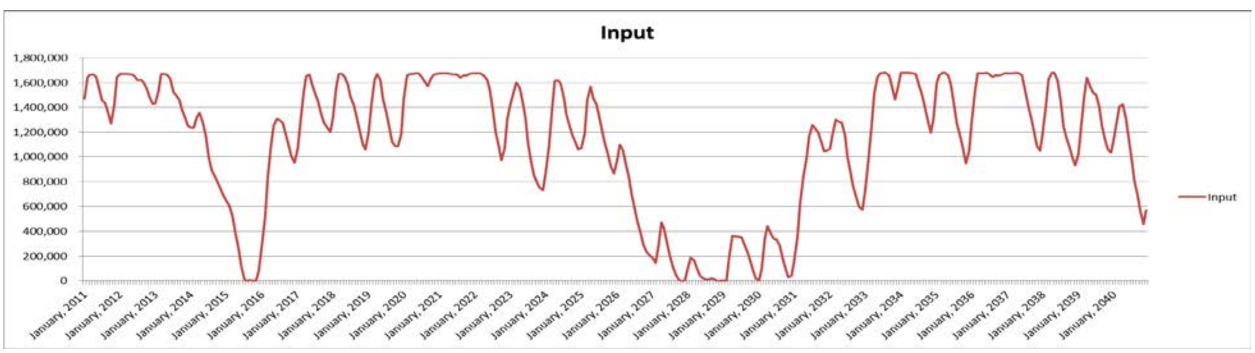
Source: 2012 LTPP Base Case Result

Water Year Consideration:

Weather is an important factor in California affecting the water operation and pumped storage operations. During a dry year, there is not enough water to be diverted to the upper reservoir during the off-peak season, and therefore the low elevation of the upper reservoir will limit the maximum generation output of the pumped storage operation.

From the DWR simulation, a 30-year historical water- year window was used. The monthly Sites Reservoir storage volume is the output from that study, as shown in Figure H2-6, and is the input constraint for the PLEXOS simulation.

Figure H2-6. Active Monthly Sites Reservoir Volume for 30 Hydrological Years

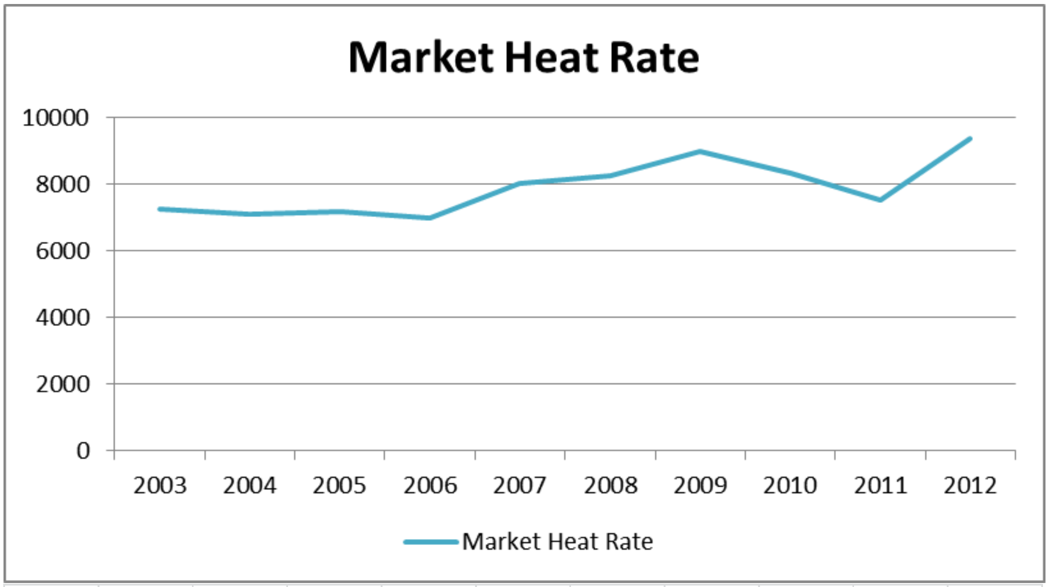


Source: DWR Simulation Result

In PLEXOS model, that monthly information is translated to a flat hourly water diversion or release to/from the Funks/Holthouse Reservoir for the applicable monthly sub-period. The Sites pumped storage facility is dispatched against the market prices, but also honors the water operation obligation for different hydrological years. The results from these 30 hydrological years are averaged into a single year result to avoid the result being biased to any certain type of hydro condition.

Another impact from the water condition is the energy market price. It is intuitive to think in a dry year condition, the available hydro generation to the system is much less than usual. Therefore a portion of base load generation is removed from the system generation supply stack. That forces the system to switch on more expensive generators in order to compensate for the loss of the hydro energy. As a result, energy prices are higher during droughts than during periods of normal generation.

Figure H2-7. Recent Year Market Heat Rate (BTU/KWh) – Load Adjusted



2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
D	AN	BN	AN	W	D	C	D	BN	W	BN

BTU/KWh = British thermal units to kilowatt-hour

Historical Water year type from DWR: W – Wet, AN – Above Normal, BN – Below Normal, D – Dry, C – Critical Historical Energy Price Source: CAISO; Historical Gas Price Source: ICE index; Historical load: CEC Market Heat Rate is calculated by **Energy Price / Gas Price * (Load Adjustment factor)** Load Adjustment factor is the factor to divide each year's annual load by the 2012 annual load.

Exactly measuring the water condition impact on the energy price is difficult, as the energy price is a result of a complex unit commitment and dispatch problem at a given system condition. However, the annual average energy price in California is largely affected by three key factors, the natural gas price, the total system load and the hydro condition. The hydro condition impact can be roughly estimated by removing the other two factors. Although historical information is limited to recent years, the load adjusted market heat rates in recent years can be calculated and are plotted in Figure H2-7, where we can see the water condition does make a difference on the market heat rates (2012 is an outlier because the gas price was too low in that year).

From the observation of historical heat rates, four types of water conditions are categorized in our study, and the adjustment factor for the energy price is listed below. Those factors are applied to the hourly energy prices according to the water year type of each of the 30 hydrological years in this study.

Table H2-5. Adjustment Factor for 4 Different Water Year Combinations

WY Type*	Factor
N-N	1.000
N-D	1.115
D-N	1.159
D-D	1.196

*The first letter represents the previous year water type as DWR definition.
The second letter represents the current year water type.
N stands for Normal and Wet, including Wet, Above Normal, and Below Normal.
D stands for Dry, including Dry, and Critical.

The water year condition impact on the Ancillary Service prices are unknown and hard to measure, therefore there is no adjustment applied to Ancillary Service prices for different water conditions.

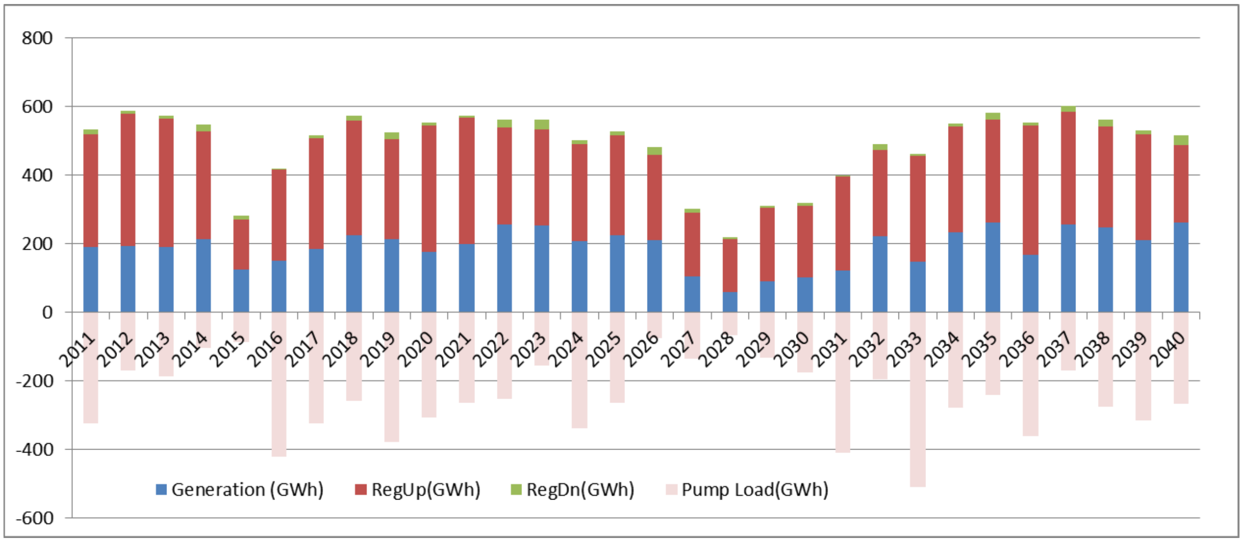
H2.8 Year 2022 Draft Results

Energy and Ancillary Services – For the Alternative Case, the annual Sites pumped storage operation for the 30 hydrological years is plotted in Figure H2-8, and the net revenue for each hydrological year is plotted in Figure H2-9. The averaged summary from the 30 years of results is placed in Table H2-8. For the base case, the DWR provided the incidental pumping and generating schedule for each month of the 30 hydrological years. This schedule is multiplied by the power prices in this study to derive the Energy benefits or costs for the base case.

As discussed in previous section, the software model PLEXOS was used to determine the optimal energy and ancillary services sales in the alternative case (6,500 AF). The energy production for the base case (1,000 AF) was derived by DWR based on their simulation. To make the results compatible, the same market energy prices for the alternative case were used in the base case. In other words, the generation amount and timing was developed by DWR, but the pricing for this energy was made consistent with the alternative case and relied on the LTPP hourly energy prices.

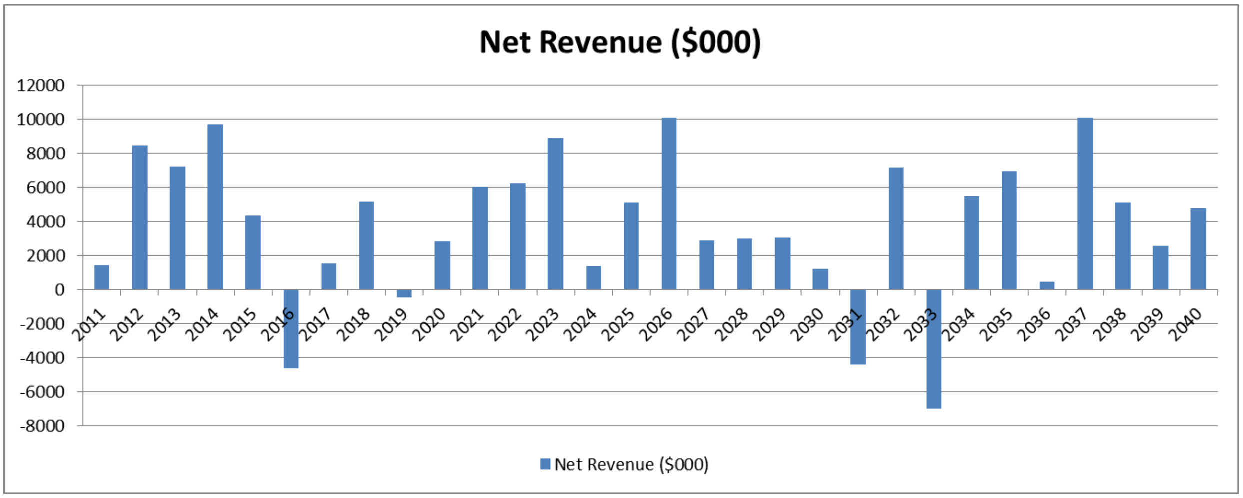
The ancillary service production for both cases was determined in PLEXOS using its energy/ancillary services co-optimization capability. For the base case, the generation production pattern determined by DWR was fixed and the remaining capacity was available for regulation-up sales subject to the constraints discussed on page 14 (which apply to both the base as well as the alternative case). This approach may result in an overstatement of the potential ancillary service benefits for the base case since no pump storage energy production is modeled. If there are pump storage opportunities in the base case with limited storage, then the ancillary services would likely be reduced but the net energy benefits would be increased, thus mitigating the potential AS overstatement.

Figure H2-8. Annual Pump Load, Generation and A/S Contribution for Each Hydrological Year*



*The horizontal axis indicates the hydrological year matching DWR's result, not the calendar year.

Figure H2-9. Annual Sites Pump Storage Net Revenue for Each Hydrological Year (2012 $000)



*Net Revenue = Energy Revenue + A/S Revenue – Pumping Cost

Planning Capacity –As discussed in Section 5, Description of Benefits, the value of long-term capacity is often viewed as the least-cost source of capacity, minus any energy or ancillary services net revenues from the market. In other words, in order to induce developers to build and maintain long-term peaking facilities, these developers would need to recover at a minimum as a capacity payment, all forward-looking capital and fixed operating costs, minus the profit they made in the energy and ancillary service market. That methodology is summarized in Table H2-6 below:

Table H2-6. Value of Planning Capacity per Kilowatt (kw)-Year

Parameter	Units	Value
CA CT capital cost	2012 $/kw-year	$ 155
CA CT fixed O&M	"	$ 35
Total annual fixed costs	"	$ 190
CA CT NP15 net revenue	"	$ 38
Peak hour derate	percent	5 %
Value of planning capacity	2012 $/kw-year	$ 160

The California Independent System Operator (in their annual market report[9]) estimated the total annual fixed cost of a California-built combustion turbine to be $190/kilowatt (kw)-year (includes both annual capital and fixed O&M costs). [10] The net revenue from energy and AS sales was estimated to be $38/kw-year. Adjusting for a 5 percent reduction in capacity during the peak hour, results in a planning capacity value of $160/kw-year in 2012 dollars.

The second part of this exercise is to estimate the difference in planning capacity for the base and alternative cases. Since both cases have the identical generating equipment and capability in the Sites powerhouse, one might conclude that there is no difference in long-term planning capacity. However the pump storage alternative has more active storage at Funks/Holthouse reservoir, thus allowing the pump storage option to generate longer.

In Figure H2-10 below, the peak week in 2012 is modeled with the two generating alternatives being evaluated in this report (pumping loads are not shown).[11]

During some hours of the week, both alternatives are able to generate 118 MW. Due to limited storage, that level of generation is available for only two hours for the base case (1,000 AF). However, in the alternative case (6,500 AF), that level of generation is available up to eight hours. To reflect this difference between the capabilities to maintain generation across the peak hours, the average generation for the four-hours of 3, 4, 5, and 6 pm was determined and compared. These results are shown in Table H2-7 below.

The difference between the two cases is 33.3 MW. At $160/kw-yr, this differential in capacity is $5.33 million in 2012 dollars.

A summary of the benefits is contained in Table H2-8.

[9] "CAISO 2012 Annual Report on Market Issues & Performance". http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf.

[10] It is not clear at this point whether the $190/kw-year represents an industrial or aero combustion turbine. The CAISO states that they received this information from the California Energy Commission (CEC) and is equivalent to whatever the CEC used in their generation analysis.

[11] "Peak week" is considered to be the week in the summer when the CA loads are highest. This week changes from year-to-year, but in 2012, this occurs in the last week of July. In this case, the 2012 hydrology is used and 2012 is considered a very dry year.

Figure H2-10. Hourly Generation during Peak-Load Week and Low Hydro Conditions for the Base and Alternative Cases [12]

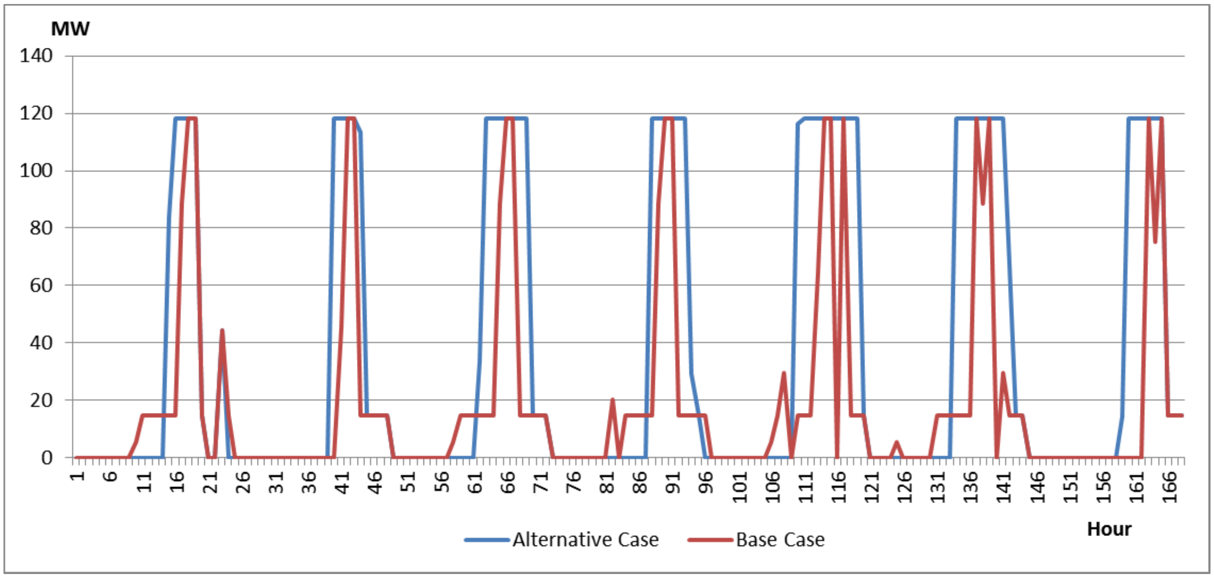


Table H2-7. Comparison of Planning Capacities

Alternative	Average 4-Hour Duration	Units
Base Case (1,000 AF)	84.8	MW
Alternative Case (6,500 AF)	118.1	MW
Difference	33.3	MW

AF = acre feet

Table H2-8. Summary of Annual Benefits for Expected-Gas-Price Case (2012 $)

Net Benefit	Base Case (1,000 AF)	Pump Storage (6,500 AF)	Value (mil. $)
Energy	$ -1.56 mil.	$ 1.37 mil.	$ 2.93 mil.
Ancillary Services	$ 1.68 mil.	$ 2.45 mil.	$ 0.77 mil.
Capacity	$ 13.57 mil.	$ 18.9 mil.	$ 5.33 mil.
Total	$ 13.69 mil.	$ 22.72 mil.	$ 9.03 mil.

AF = acre feet

The total annual benefits are estimated to be $9.03 million in 2012 dollars as shown in Table H2-8. If we make the conservative assumption that the benefits will escalate at inflation or a greater rate, and that the costs between now and the project online date will escalate at inflation or a

[12] In order to determine the maximum energy output, the ancillary services market was removed from this simulation for this given week.

lower rate, we can compare the annual benefits and costs to determine the economic viability of the proposed pump storage project.

Table H2-9. Summary of Annual Costs, Benefits, and Overall BCR (2012 $)

Parameter	Value
Incremental capital cost [13]	$120 million
Federal real discount rate	3.75 percent
Economic life [14]	100 Years
Capital recovery factor	3.8 percent
Annual capital cost	$4.56 million
Incremental fixed O&M [15]	$0.5 million
Annual fixed cost	$5.06 million
Annual benefit	$9.03 million
Net Annual Benefit	$3.97 million
Benefit-Cost Ratio	1.78

H2.9 Comparison with DWR Results

Before comparing the PLEXOS results to the DWR simulation result, it is appropriate to list several key differences between the two models and the two assumptions.

- PLEXOS is a production cost model and details in the hourly and sub-hourly optimized unit commitment and economic dispatch. Although PLEXOS is capable for doing stochastic studies, only deterministic runs have been performed for this evaluation due to the time constraint. DWR's model is focused on a probabilistic Monte-Carlo based approach. The hourly optimization might not be as intensive as in PLEXOS model.
- DWR's simulation is based on the view of a generally higher gas forecast. At the timing that the study was accomplished, the massive Shale gas production, commonly referred to as fracking, had not yet been fully implemented; therefore higher gas prices are forecasted in that study. Pumped storage plant will benefit from a higher gas price because that will enlarge the difference between on-peak and off-peak energy prices, assuming the market heat rate does not change too much. Therefore the Pumped storage has more room to arbitrage the price difference.
- The water year treatment is different in two models. DWR selected a 30 water year window and projected that window into the simulation horizon. If that window shifts a few years it might derive a quite different result. There was also no adjustment to energy prices for different water conditions. In PLEXOS, the simulation result is based on the

[13] Source --- URS.
[14] The economic life represents the period of time over which the asset is assumed to be available and useful. If a present-value calculation were performed, the period over which the costs and benefits would be compared, is 100 years. If there is no assumed real escalation rate for the costs or benefits, the Benefit-To-Cost ratio is the same when comparing the present value or the annual costs and benefits.
[15] Source -- URS

average of the 30 hydrological years so the bias to a certain type of water condition is largely removed. Also the Energy prices are adjusted for water years as described in the Section 7.

Table H2-10. DWR Simulation Result

Pumping-Generation Site	**CALSIM Deliveries**					
Planning Alternative	**Alternative A**		**Alternative B**		**Alternative C**	
Operations Strategy	**Incidental**	**Optimized**	**Incidental**	**Optimized**	**Incidental**	**Optimized**
NODOS Pumping	**Period Total, Annual Revenues ($1,000s)**					
Tehama-Colusa Canal Pumping	-341	-341	-421	-421	-325	-325
Glenn-Colusa Irrigation District Pumping	-566	-566	-646	-646	-559	-559
Sacramento River Pumping	-3,001	-3,001	N/A	N/A	-3,320	-3,320
Terminal Regulating Reservoir Pumping	-557	-557	-923	-923	-664	-664
Sites Pumping	-8,377	-7,706	-8,284	-8,284	-9,659	-8,853
Subtotal	**-12,842**	**-12,171**	**-10,274**	**-7,465**	**-14,524**	**-13,720**
Preliminary Results						
NODOS Generation						
Sites Generation	6,118	6,809	6,240	7,039	7,528	8,390
Terminal Regulating Reservoir Generation	1,102	1,144	384	401	1,143	1,191
Sacramento River Generation	2,797	2,797	N/A	N/A	2,815	2,815
Subtotal	**10,017**	**10,751**	**6,624**	**7,439**	**11,487**	**12,396**
NODOS Pump-Back Operations						
Pump-back During Diversion Cycle	N/A	394	N/A	785	N/A	418
Pump-back During Release Cycle	N/A	1,290	N/A	1,026	N/A	1,209
Pure Pump-back Operations Cycle	N/A	978	N/A	837	N/A	976
Subtotal		**2,662**		**2,648**		**2,603**
NODOS Total Net Revenues	**-2,825**	**1,242**	**-3,650**	**632**	**-3,040**	**1,279**
NODOS Project Optimization Potential		**4,067**		**4,282**		**4,319**

Source: DWR

Table H2-10 is the simulation result from the DWR study. At the last column, it indicates the annual benefit for the NODOS project (from energy market only) Alternative C is $4.319 million in terms of 2010 dollars. Using an inflation rate derived from California Energy Commission, 2.71 percent, it is equivalent to $**4.436 million** in 2012 dollars. From PLEXOS results shown in Table H2-8, if not considering the A/S benefits and capacity benefits, the equivalent NODOS Alternative C benefits from the Energy market is $**2.93 million** in 2012 dollars. It is worth noting that if the plant were dispatched in the energy only market, the total revenue would be larger than $2.93 million because this would be the only market the pump storage could take advantage of. Because the PLEXOS co-optimizes both energy and ancillary services market, some capacity will be withheld to contribute to ancillary services market to increase profit. Because DWR did not consider the AS market during their simulation, the results are not perfectly comparable for revenues just from the energy market.

H2.10 Sensitivities

Because the gas price would have a big impact on our evaluation compared to other factors, a pair of sensitivity studies was performed to assess the value of the Sites pumped storage operation under a high gas price scenario and a low gas price scenario. For the high gas scenario, we adopted the 2022 gas price forecast as in the DWR study, which is $6.27/MMBtu in 2012 dollar. This can be viewed as a case with stricter regulation in fracking and more gas demand from the power sector due to the future expansion of the gas fired plants nationwide. A low gas price of $3.7/MMBtu was derived by the research from other public resources[16]. A conversion factor was calculated to scale up the original $4.40/MMBtu to the high gas and low gas prices. Then the conversion factor was applied to energy prices assuming the market heat rate is constant.

The results for the high gas study are summarized below in Table H2-11. The results for the low gas study are summarized in Table H2-12.

16 http://www.energy.ca.gov/2013_energypolicy/documents/2013-10-01_workshop/presentations/03_Weng-Gutierrez_Electricity_Rate_Assumptions.pdf

Table H2-11. Summary of Annual Benefits for High-Gas-Price Case

Net Benefit	Base Case (1,000 AF)	Pump Storage (6,500 AF)	Value (mil. $)
Energy	$ -2.22 mil.	$ 2.89 mil.	$ 5.11 mil.
Ancillary Services	$ 1.21 mil.	$ 1.77 mil.	$ 0.56 mil.
Capacity	$ 13.57 mil.	$ 18.9 mil.	$ 5.33 mil.
Total	$ 12.56 mil.	$ 23.56 mil.	$ 11.0 mil.

AF = acre feet

Table H2-12. Summary of Annual Benefits for Low-Gas-Price Case

Net Benefit	Base Case (1,000 AF)	Pump Storage (6,500 AF)	Value (mil. $)
Energy	$ -1.31 mil.	$ 0.22 mil.	$ 1.53 mil.
Ancillary Services	$ 1.53 mil.	$ 2.23 mil.	$ 0.70 mil.
Capacity	$ 13.57 mil.	$ 18.9 mil.	$ 5.33 mil.
Total	$ 12.56 mil.	$ 23.56 mil.	$ 7.56 mil.

AF = acre feet

H2.11 Conclusions

Based on the analysis summarized in this study, the pump storage project appears to be economically viable with a relatively strong Benefit-to-Cost Ratio of 1.8. There also several factors which could impact the economic viability. These factors are summarized below:

- As demonstrated in the previous section, the results are quite sensitive to changes in gas prices. However, even in the low-gas-price case, the project still has annual benefits of $7.56 million compared to annual costs of $5.06 million.
- This analysis was based on a 33 percent renewable energy requirement in 2020. However, over the 100-year economic life of the project, it is likely that the renewable requirement will be increased to 40 or 50 percent, or higher. Increased renewables requires increased ancillary services requirements and a likely increase in AS prices. Since this project provides a significant amount of AS, these increased needs for ancillary services would be expected to increase the net benefit.
- As more renewables are added to the generation mix in the WECC, more hours will result in an “overgeneration” situation, which already exists in the Northwest resulting from the simultaneous hydro and wind production in the spring and early summer. Market prices during overgeneration conditions are typically very low and often negative. These “overgeneration” prices have not been fully captured in this analysis and would increase the differential between off-peak and on-peak prices, thus further benefiting the alternative project.
- Changes in the CO_2 emission rate are also expected to have an impact on the economic viability of the NODOS pump storage project, but not as large as the impact of the gas

price. If CO_2 emission prices are higher than those forecast for this study, the energy benefits would likely be decreased as approximately 1.3 MWh of pumped energy is required for each 1 MWh of generation. Thus, the pricing differential between off- and on-peak would be decreased.

Acronyms and Abbreviations

AF	acre-feet
BTU/KWh	British thermal units to kilowatt-hour
CAISO	California Independent System Operator
CEC	California Energy Commission
CEC	California Energy Commission
CO_2	Carbon dioxide
CPUC	California Public Utilities Commission
CT	Combustion Turbine
DWR	California Department of Water Resources
EE	Energy Exemplar
IEPR	Integrated Energy Policy Report
IOUs	Investor-Owned Utilities
kw	kilowatt
LRS	Loads and Resources Subcommittee
LTPP	Long-Term Procurement Plan
MIP	Mixed Integer Programming Algorithm
MW	Megawatt
NODOS	North-of-the-Delta Offstream Storage
O&M	Operations and Maintenance
Reclamation	United States Bureau of Reclamation
RPS	Renewable Portfolio Standards
TEPPC	Transmission Expansion Planning Policy Committee
TRR	Terminal Regulating Reservoir
WECC	Western Electricity Coordinating Council