BLUEWATER
RENEWABLE ENERGY STORAGE

AMENDED APPLICATION FOR LICENSE OF MAJOR UNCONSTRUCTED PROJECT

EXHIBIT D
PROJECT COSTS AND FINANCING

BLUEWATER RENEWABLE ENERGY STORAGE PROJECT

The Nevada Hydro Company, Inc.
538 Monte Vista Ave
Glendale, California 91202
T: (951) 585 3277

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Approval for issue		
Paul Anderson		2022-10-20

Prepared by:	Prepared for:
The Nevada Hydro Company, Inc.	Federal Energy Regulatory Commission
Paul Anderson Director, Sustainability	Kimberly D. Bose Secretary
538 Monte Vista Ave Glendale, California	888 First Street, NE Washington, DC 20426
T +1 (951) 585.3277 E paul@bluerenew.life	Filed Electronically FERC Docket P-14227

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EXHIBIT D – PROJECTS COSTS AND FINANCING

As required by 18 CFR 4.41(e), the Applicant (all references to the Applicant herein refer to The Nevada Hydro Company, Inc.) must prepare a "statement of project costs and financing". The exhibit must contain"

1. A statement of estimated costs of any new construction, modification, or repair, including:
    a. The cost of any land or water rights necessary to the development;
    b. The total cost of all major project works;
    c. Indirect construction costs such as costs of construction equipment, camps, and commissaries;
    d. Interest during construction; and
    e. Overhead, construction, legal expenses, and contingencies;
2. If any portion of the proposed project consists of previously constructed, unlicensed water power structures or facilities, a statement of the original cost of those structures or facilities specifying for each, to the extent possible, the actual or approximate total costs (approximate costs must be identified as such) of:
    a. Any land or water rights necessary to the existing project works;
    b. All major project works; and
    c. Any additions or modifications other than routine maintenance;
3. If the applicant is a licensee applying for a new license, and is not a municipality or a state, an estimate of the amount which would be payable if the project were to be taken over pursuant to section 14 of the Federal Power Act, 16 U.S.C. 807, upon expiration of the license in effect including:
    a. Fair value;
    b. Net investment; and
    c. Severance damages;
4. A statement of the estimated average annual cost of the total project as proposed, specifying any projected changes in the costs (life-cycle costs) over the estimated financing or licensing period if the applicant takes such changes into account, including:
    a. Cost of capital (equity and debt);
    b. Local, state, and Federal taxes;
    c. Depreciation or amortization, and
    d. Operation and maintenance expenses, including interim replacements, insurance, administrative and general expenses, and contingencies;
    e. The estimated capital cost and estimated annual operation and maintenance expense of each proposed environmental measure;
5. A statement of the estimated annual value of project power based on a showing of the contract price for sale of power or the estimated average annual cost of obtaining an equivalent amount of power (capacity and energy) from the lowest cost alternative source of power, specifying any projected changes in the costs (life-cycle costs) of power from that source over the estimated financing or licensing period if the applicant takes such changes into account;

6. A statement describing other electric energy alternatives, such as gas, oil, coal and nuclear-fueled powerplants and other conventional and pumped storage hydroelectric plants;
7. A statement and evaluation of the consequences of denial of the license application and a brief perspective of what future use would be made of the proposed site if the proposed project were not constructed;
8. A statement specifying the sources and extent of financing and annual revenues available to the applicant to meet the costs identified in paragraphs (e) (1) and (4) of this section;
9. An estimate of the cost to develop the license application; and
10. The on–peak and off–peak values of project power, and the basis for estimating the values, for projects which are proposed to operate in a mode other than run–of–river.

1.0 ESTIMATED CONSTRUCTION COSTS

The Proposed Project costs are estimated to be ~$2.4 billion and are detailed in Table D-1. This Figure provides a complete listing of all estimated costs required for developing and constructing the Proposed Project.

Table D-1: Project Cost Summary

EPC Costs		x$1,000
Hydroelectric Pumped Hydro Facilities EPC Costs		$1,181,700
Primary Lines - EPC Cost (North only)		300,000
Network Upgrade costs		91,495
Contingency		311,638
Total EPC Costs (including contingencies)		**$1,884,833**
Other Project Costs		
Land Acquisition		$17,500
Title Insurance		2,000
Insurance During Construction		2,992
Mitigation Costs		16,420
Property Taxes During Construction		3,000
Overhead During Construction		60,000
Initial Spare Parts Inventory Budget		1,921
Other Project Costs		**$103,833**
Development Costs		
Total Development Costs		**$98,049**
Financial Costs		
Interest During Construction		$255,370
Other Financing Costs		67,951
Total Financial Costs		**$323,321**
	Total Project Cost	**$2,410,036**

Source: The Nevada Hydro Company

1.1 Land and Water Rights

Table D-1 provides a preliminary estimate of the cost of necessary land, including the acquisition of required private property and fees associated with the use of land of the Cleveland National Forest.

The applicant assumes that the cost for any water purchase will be classified as a mitigation cost, as such water additions will benefit water quality and recreation use of Lake Elsinore.

These estimates are subject to refinement.

1.1.1 Areas for which Rights to use are to be Obtained from State or Local Government

Areas for which rights to use may be obtained from State or Local Government include the following

- Easement from State of California to cross SR–74 and I–15; and
- Inlet and outlet structures and appurtenant facilities within Lake Elsinore.

1.1.2 Areas for which Rights to use must be Purchased or Condemned

Areas for which rights to use must be purchased or condemned may include the following:

- Portions of the new primary transmission line corridor to the existing SCE transmission line;
- Portions of substation location;
- Portions of powerhouse site, associated penstock and appurtenant facilities and construction laydown areas; and,
- Tailrace structures, appurtenant facilities and construction laydown areas.

1.1.3 Areas that the Applicant Owns

The Applicant presently does not own any areas of the Proposed Project.

1.2 Major Project Works Cost Estimate

The construction cost estimate total is shown on Table D-1. This cost is based on the project works proposed to be constructed by Applicant as set forth in Exhibit A. Most of the costs have been estimated by construction contractors and major suppliers on a unit price basis, using quantities of the major items of material taken from the preliminary drawings in Exhibit F. Unit prices for the major items of work have been provided by a construction contractor which were developed from standard publications on construction industry costs and adjusted for recent experience on similar contracts.

The costs of the major items of mechanical and electrical equipment have been based on budget price quotations from manufacturers. Appurtenant mechanical and electrical equipment have been estimated from other underground powerhouse designs.

All costs are given in Q3-2022 price levels unless otherwise noted.

Unit prices for minor items such as architectural finishes, miscellaneous metals and surface drainage have not been developed in detail, but allowances have been made based on experience with other projects.

1.3 Indirect Construction Costs

Indirect construction costs, such as the following, are included in the EPC costs shown in Table D-1 and are expected to total approximately $50 million.

- Management, supervision and support staff;
- Owned construction equipment; and,
- Overhead.

1.4 Interest During Construction

Interest during construction was computed using an interest rate of 7.0 percent and a projected cash drawdown schedule. Permanent financing was assumed to be in place at the end of construction.

Depending upon interest rates at the time construction is undertaken and the total cost and duration of the construction, costs for interest during construction are estimated to be approximately $158 million.

1.5 Other Expenses

Overhead and miscellaneous construction expenses are included within the overall cost estimate and have not been calculated separately.

1.5.1 Contingencies

A contingency factor of 20% was added to the estimated construction costs in Table D-1. This contingency amount has been included to cover unknown and omitted items, such as variation in costs due to subsurface conditions or weather conditions during construction. This amount is also intended to cover local and periodic variations in labor, equipment, and materials or other unforeseen cost escalation.

The magnitude of this factor will be reduced as results from additional geotechnical studies are completed. At funding of the construction loan, this amount is anticipated to be between 8 and 10%.

2.0 EXISTING FACILITIES

There are no existing unlicensed waterpower structures or facilities that will be used or incorporated into the project.

3.0 PROJECT ESTIMATED AVERAGE ANNUAL COSTS

3.1 Cost of Capital

It is anticipated that the Proposed Project will be financed through a combination of long–term debt and equity. Depending upon the characteristics of the Proposed Project's final ownership structure and capital markets at the time financing is sought, the requirements for return on equity and the cost of debt could vary significantly.

For purposes of this application only, the Applicant has assumed a corporate debt and equity structure with the following characteristics:

- A fixed interest rate for long–term debt of 6.5%;
- Term of debt of 30 years; and,
- Expected after–tax return on equity (ROE) of approximately 15.0%.

The actual cost for debt and equity will be determined by the capital markets at the time financing is committed and the structure and type of financing available to the project at that time.

3.2 Taxes

The amount of income and property tax generated by the project will depend largely on the final corporate and capital structure as well as arrangements with taxing authorities.

For purposes of this application only, the Applicant has assumed that the following taxes are paid annually:

- Federal and State taxes have been calculated at current tax and depreciation rates, based on the profit generated by operation of the project.
- Property taxes. Because of the unique nature of the proposed project and its high capital cost, it is likely that its taxable-basis will be determined by Riverside County as a result of an individualized evaluation that considers the components of the project, their cost and net annual revenues. For purposes of this application only, the Applicant has assumed annual property taxes will total $5,000,000.

3.3 Depreciation and Amortization

The amount of depreciation and amortization due each year will be based on the final cost of the project and tax laws in place at the time the project begins operation. For purposes of this application only, the applicant has assumed 6-year costs at an average of $329 million annually.

3.4 Operation and Maintenance Expenses

A table of the estimated average annual cost of operation and maintenance expenses, including interim replacements, water services, insurance, administrative and general expenses and contingencies appears in Table D-2.

Table D-2: Annual O & M Expenses

Annual Expenses	$
Material & Supplies	500,000
Water Supply & Management Services	7,500,000
Insurance	6,000,000
G & A	4,000,000
Contingencies (incl. fees)	2,000,000

Source: The Nevada Hydro Company

3.5 Costs of Environmental Measure(s)

The costs of proposed environmental measures are dependent upon several factors including:

- Which specific project components are selected.
- Quantification of the extent of project related impacts (e.g., primary transmission line tower footprints, fuel modification zones, etc.).
- Negotiation with resource agencies relative to any multiplier that may be imposed or recommended as well as other issues.
- PME's accepted by the Commission

As these factors will be determined later in the licensing process, it is premature to estimate these costs at this time. Based upon the current estimate of project costs and project economics, the applicant has included within its budget an estimate of $16 million for environmental mitigation purposes.

4.0 ESTIMATED ANNUAL VALUE OF POWER

Advanced Pumped Storage (“APS”) facilities, such as the Proposed Project, are designed to provide the needed flexibility to the power system to match the increasing reliance on intermittent resources. Some revenues to provide these services are available from the market, but for many of the values APS can provide, there simply is no market from which values can be assessed.

Accurately estimating the annual value of power from a modern pumped storage facility is a complex and difficult task. The Applicant has not yet finalized this analysis, as many of the variables involved have yet to be determined by regulators. However, a very preliminary estimate of the annual value of project power and the method for determining such a preliminary estimate are described below.

Because only a limited market exists for the trading of power and other services and products within the state of California, and because the Proposed Project has not yet negotiated contracts for the sale of power, this section is intended to describe how the value of project power can be approximated.

As illustrated in Table D-3, the Proposed Project, an advanced pumped storage (“APS”) facility, is a unique resource when compared to other generation technologies.

Table D-3: Comparison of APS to other Generation Technologies

	Peaker	Combined Cycle	Pumped Storage (APS)
Air Quality Issues	NOx, CO, VOC, PM10 Offsets	NOx, CO, VOC, PM10 Offsets	None required
Dispatchability	10 – 60 minutes	1 – 4 hours	15 Seconds
Black Start	10 – 30 minutes	No	15 Seconds
Dispatchable Capacity	Can produce either energy or capacity	Dispatchable capacity limited between 70-100% full load	Dispatchable capacity from 1-100% of full load
Regulation	No	Yes; limited to 5 MW/min.	Yes; up to 500 MW/min.
Spinning Reserve	No	Yes; limited to 5 MW/min.	Yes; up to 500 MW/min.
Voltage Support	Yes; but typically not used for voltage support	Yes	Yes. When pumping and generating
Comparable Heat Rate	Appx. 10,000 - 12,000	7,000	Approx. 18% more efficient than lowest off–peak rate
Alternative Fuels or Renewables	No	No	Yes; can source pumping energy from renewables
Mitigation of Overgeneration Conditions	No	No	Yes; up to 600 MW of pumping load during off peak periods

Source: The Nevada Hydro Company

Advanced Pumped Storage facilities are uniquely suited for generating power during periods of high demand and for supplying reserve capacity to complement the output of large base load fossil-fueled and nuclear steam-electric plants. Start–up and ramping of pumped hydro storage projects is almost immediate, thus serving peak demand for power better than fossil–fueled plants that require significantly more start–up and ramping time.

APS facilities like the Proposed Project will provide peaking capacity, a full range of ancillary services and the ability to store off peak energy. Functionally, the facility is similar to a large simple cycle gas turbine based peaking power plant, which would consist of multiple fast response aero derivative type engines, able to deliver energy from capacity in 10 minutes. However, APS facilities are capable of much faster responsive times, as rapid as 15 seconds. In addition, APS provides a full range of ancillary services, including regulation, spinning and non-spinning reserves and replacement reserves, which represents superior services to the non-spinning reserve provided by a simple cycle peaker. Finally, the pumped hydro storage facility uses off peak energy for pumping, which helps the control area operator manage overgeneration conditions during off peak periods, helps store renewable energy with no fuel cost which may be generated during periods of low demand and helps keep base load units at steady state operations.

The range of services APS facilities can provide are shown in Table D-4 and Figure D-1. While valuing each remains a formidable undertaking, two attempts to value each service are summarized in Section 5.1.

There are only two existing similar 500+ MW facilities within the state of California. One, operated by Pacific Gas & Electric Company, is the 1,050-megawatt Helms pumped hydro storage project located in Fresno County, California. It has a head of 1,630 feet – currently the highest in the United States. The other facility, operated by the Los Angeles Department of Water and Power, is the 1,250 MW Castaic Pumped Storage Facility, located just north of the City of Los Angeles. However, appropriate locations for APS are geographically specific and rare, and the Proposed Project is unique because there is no other location for a pumped storage facility of this size in the southern California load pocket.

Table D-4: Range of APS Services

	PSH Contribution
1.	Inertial response
2.	Governor response, frequency response, or primary frequency control
3.	Frequency regulation, regulation reserve, or secondary frequency control
4.	Flexibility reserve
5.	Contingency spinning reserve
6.	Contingency non-spinning reserve
7.	Replacement/Supplemental reserve
8.	Load following
9.	Load leveling/Energy arbitrage
10.	Generating capacity
11.	Reduced environmental emissions
12.	Integration of variable energy resources (VERs)
13.	Reduced cycling and ramping of thermal units
14.	Other portfolio effects
15.	Reduced transmission congestion
16.	Transmission deferral
17.	Voltage support
18.	Improved dynamic stability

	PSH Contribution
19.	Black-start capability
20.	Energy security

Source: Argonne National Laboratory

4.1 Power Value Estimates

The Applicant is providing independent estimates of the value power from the Proposed Project. The first set of estimates is from several studies by the California Independent System Operator (CAISO). The second is from a 2014 report documenting results of a study process undertaken by the Argonne National Laboratory and funded by the Department of Energy (DOE). The last is from the Commission staff's final environmental impact statement for an APS project in the same general region as is the Proposed Project. All the studies referenced in this section may be found in Volume 3 of the original LEAPS Application.

4.1.1 CAISO Studies of Value of Proposed Project

The CAISO began studying the value of the LEAPS project as early as 2006, with extensive re–studies commencing in 2016. This subsection provides summaries of the CAISO studies, the assumptions underlying each study, and the findings and conclusions of each study.

4.1.1.1 2006 Study of the Proposed Project

In 2006, the CAISO commissioned the South Regional Transmission Planning group (CSRTP) to study three Southern California transmission projects: SDG&E's Sunrise Powerlink, SCE's Tehachapi project, and the then Proposed LEAPS Project.[1]

In its analysis, the CAISO used a production cost model to analyze the project. Note that the study did not capture all the ancillary benefits discussed above such as reduced RMR costs, market power mitigation, and improved system reliability. The CAISO intended to do further studies to quantify these and other benefits, but did not then complete the task.

The key takeaway from this analysis is that the CAISO independently quantified a net annualized benefit to consumers from the Proposed Project of approximately $120 MM per annum (in 2005 equivalent dollars).

The 2006 CAISO study is now out-of-date but has been supplemented by several additional studies (summarized below), including a "Bulk Energy Storage Case Study" from February 2016, which demonstrated significant value from APS facilities such as the Proposed Project to California ratepayers.

A presentation made by CAISO staff is provided in Volume 3 of the original September 2017 Application (CSRTP - LEAPS Project Benefits).

4.1.1.2 Studies of the value of the Proposed Project

As part of its 2015–2016 transmission planning process, in February 2016 the CAISO published "A Bulk Energy Storage Case Study with 40% RPS in 2024".[2] The study took assumptions provided by the California

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[1]/ As configured in the CSRTP, the Proposed Project was studied as a generation project that was connected to a transmission line that linked the SCE and SDG&E transmission systems and could provide transmission services independent from the generation project.

[2]/ "A Bulk Energy Storage Case Study with 40% RPS in 2024", CAISO, February 18, 2016. See also "A Bulk Energy Storage Resource Case Study updated from 40% to 50% RPS" and related reports in the CAISO annual Transmission Plans for 2015–2016 and for 2016–2017. All are available in Volume 3 of this Application.

Public Utilities Commission ("CPUC") and looked at the effect of large storage on several scenarios. The stated purpose of the study was:

- To explore solutions to curtailment of large quantity of renewable generation
- To assess a bulk storage resource's ability to reduce
  - production cost
  - renewable curtailment
  - CO_2 emission
  - renewable overbuild to achieve the 40% RPS target
- To analyze the economic feasibility of the bulk storage resource

Although never mentioned by name, the study assumed the specific parameters of the Proposed LEAPS Project as the "new pumped storage resource".[3] The study observed that "Bulk storage brings benefits in all cases." It "[r]educed curtailment, CO_2 emission, production costs and overbuild of renewables to achieve the 40% RPS target."

The CAISO incorporated the results of this study into its 2015–2016 Transmission Plan[4] and further concluded that the new pumped storage resource brought significant benefits to the system, including

- reduced renewable curtailment and reduced renewable overbuild needed to meet the 40% RPS target;
- lower CO_2 emissions, emission costs and production costs; and
- the flexibility to provide ancillary services and load-following and to help follow the load in the morning and evening ramping processes.

In September 2016, the CAISO expanded upon its previous study to assess the effect of pumped storage on the State's goal of a 50% RPS standard. The study observed that "as in the 40% RPS study, the pumped storage brings benefits to the system in reduction of overbuild needed to achieve the 50% RPS target, renewable curtailment, CO_2 emission, production cost". Additionally, the study observed that "[t]he pumped storage resource has net market revenue sufficient to meet its levelized revenue requirement in all three cases" studied.

In February 2017, the CAISO published an additional follow up study[5] with updated assumptions. Results of this study were included in the CAISO's 2016–2017 Transmission Plan, published early in 2017. The CAISO included an updated summary of the 50% RPS study, but this time identified the project site as "Lake Elsinore," and emphasized certain locational benefits.[6] The study included the following observations:

[3]/ Id. See table on page 7 that describes the LEAPS and no other proposed or existing project *precisely*. Nonetheless, the CAISO never referred to the project they analyzed as any specific project.

[4]/ 2015–2016 Transmission Plan, CAISO. Approved March 28, 2016. See Section 3.5 commencing on page 248.

[5]/ "Bulk Energy Storage Resource Case Study –Update with the 2016 LTPP Assumptions", CAISO, February 20, 2017.

[6]/ "2016–2017 Transmission Plan, CAISO, March 17, 2017. See Section 6.5 commencing on page 312.

1. "[W]ith the new pumped storage resource added to the system, the overbuild needed to achieve the 50% RPS target was reduced;"
2. "[T]he renewable energy recovered from curtailment by the pumped storage resource was used in later hours to displace generation of non-renewable resources and reduced CO_2 emissions;"
3. "[T]he new pumped storage resource helped further reduce production costs because it reduced curtailment and used the stored clean energy to displace higher cost energy in other hours;" and
4. "[T]he new pumped storage resource is very flexible. It can also provide ancillary services and load following to reduce the resilience on higher cost generation resource to stay online to provide these services."

4.1.2 Argonne Laboratory Study

A project team, led by Argonne National Laboratory (Argonne), was tasked by the Department of Energy (DOE) to study the role and value of Pumped Storage Hydropower (PSH), also referred to as Advanced Pumped Storage (APS), in the United States. The study was funded by DOE's Office of Energy Efficiency and Renewable Energy (EERE). The project team for the study consisted of five organizations from national laboratories, the hydropower industry, and engineering and consulting companies. The final of seven reports is called "Modeling and Analysis of Value of Advanced Pumped Storage Hydropower in the United States," and provides an overview of all activities and work performed by the project team, as well the key results and findings of the various analyses performed during the study.[7]

A portion of the study focused on the western grid, and a portion focused on California exclusively. The report looked at three cases: (1) without any PSH, (2) with the two existing fixed speed ("FS") PSH plants, and (3) with existing FS and some proposed APS plants. All three cases were run for a Base and a High Wind renewable energy scenarios. The report identified a significant number of value streams through which the operation of APS facilities like the Proposed Project could impart benefit to the system and the State's ratepayers.

The investigators looked at the impact of several proposed projects, not including the Applicant's Proposed Project. Because the value of APS facilities can vary significantly based upon its physical location in the grid, the findings of the report are representative of what an update to the CSRTP study could conclude. Nonetheless, the report found significant value to these other proposed APS plants that are less efficient and are proposed in sub-optimal locations compared to the project proposed in this Application.

For example, the investigators found that production cost savings with certain existing and proposed APS facilities reduces system operating costs by up to a total of 9.1% or nearly $400 million under a high wind penetration scenario.[8]

With regard to energy arbitrage, PLEXOS (energy market) simulations of the California system in 2022 allowing for a detailed analysis of value of energy arbitrage based on the locational marginal prices (LMPs) of electricity in each hour of the year. Table D-5 summarizes results for both their base and high wind renewable energy scenarios.

With regard to operating reserves, the investigators found that pumped storage plants "provide a significant amount of operating reserves to the system", and that this contribution "to operating reserves

[7]/ "Modeling and Analysis of Value of Advanced Pumped Storage Hydropower in the United States", Argonne National Laboratory et.al., ANL/DIS–14/7, June 2014 ("Report").

[8]/ *Id*., and page ES–7.

increase significantly with the addition of [APS] plants to the system.”[9] Figure D-2 illustrates this finding for the California system, again for both their base and high wind renewable energy scenarios.

Table D-5: 2022 Energy Arbitrage Revenues in California

Parameter	Base Renewable Scenario		High Wind Renewable Scenario	
	FS PSH	FS & AS PSH	FS PSH	FS & AS PSH
PSH capacity (MW)	2,626	4,425	2,626	4,425
Energy generation (GWh)	2,725	5,313	5,299	9,456
Pumping energy (GWh)	3,840	6,856	7,501	12,521
PSH capacity factor (%)	11.85	13.71	23.04	24.39
Energy revenue ($1,000)	102,302	181,554	147,285	217,302
Pumping cost ($1,000)	65,768	164,508	-13,229	25,045
Net revenue ($1,000)	36,534	17,046	160,514	192,257
Net revenue ($/kW-yr)	13.9	3.9	61.1	43.4

Source: Argonne National Laboratory

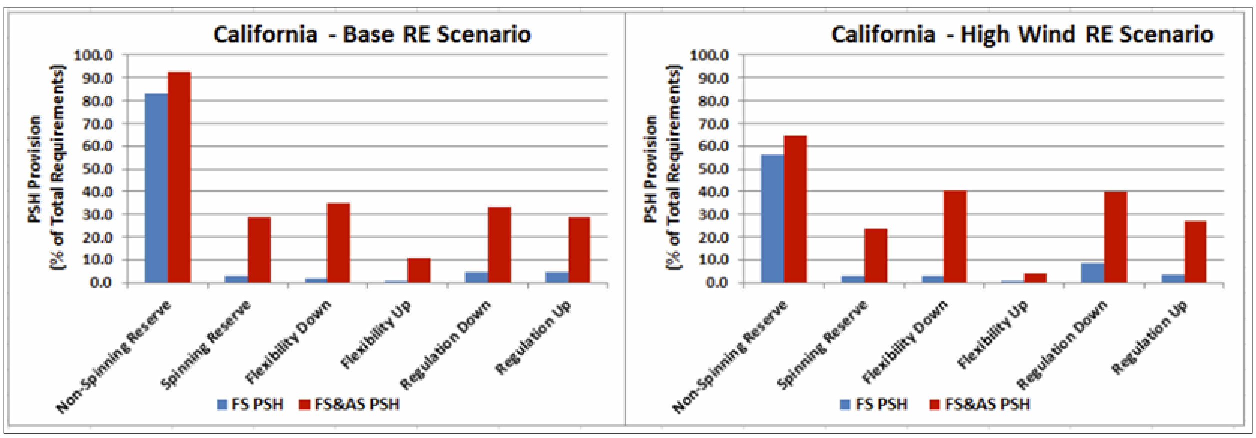

Figure D-1: Pumped Storage Contributions to California Operating Reserves in 2022
Source: Argonne National Laboratory

The report noted an especially large increase for the regulation down and flexibility down reserves, because APS can provide these services in the pumping mode of operation as well as the standard generation mode for FS PSH facilities. These reserves are especially needed during times of low flexibility in the power system, such as during the evening/night.

With regard to the monetary value of PSH contributions to operating reserves, market-based PLEXOS simulations allowed for individual pricing and revenue analysis of A/S. A summary of PSH total annual revenues for their provisions of operating reserves in 2022 is provided in Table D-7. Expressed per kW of PSH capacity, Figure D-2 shows that the average annual revenues are highest for the provisions of regulation down service.

9/ *Id.*, and page ES–9.

Table D-6: PSH Revenues for Provisions of Operating Reserves in California in 2022

Operating Reserve	Base Renewable Scenario		High Wind Renewable Scenario	
	FS PSH ($1,000)	FS & AS PSH ($1,000)	FS PSH ($1,000)	FS & AS PSH ($1,000)
Non-spinning reserve	7,557	8,563	5,246	6,184
Spinning reserve	1,218	8,588	1,515	6,208
Flexibility down	389	5,728	1,626	14,934
Flexibility up	43	731	80	412
Regulation down	4,562	20,360	19,511	49,885
Regulation up	4,436	7,935	4,144	8,528
Total	**18,205**	**51,905**	**32,122**	**86,151**

Source: Argonne National Laboratory

Table D-7: Average Annual PSH Revenues for Operating Reserves in California in 2022

Operating Reserve	Base Renewable Scenario		High Wind Renewable Scenario	
	FS PSH ($/kW-yr)	FS & AS PSH ($/kW-yr)	FS PSH ($/kW-yr)	FS & AS PSH ($/kW-yr)
Non-spinning reserve	2.88	1.94	2.00	1.40
Spinning reserve	0.46	1.94	0.58	1.40
Flexibility down	0.15	1.29	0.62	3.37
Flexibility up	0.02	0.17	0.03	0.09
Regulation down	1.74	4.60	7.43	11.27
Regulation up	1.69	1.79	1.58	1.93
Total	**6.93**	**11.73**	**12.23**	**19.47**

Source: Argonne National Laboratory

As shown in Figure D-2, the investigators found that in California, the average annual revenue per kW of PSH capacity is higher when both FS and APS facilities, like the Proposed Project, operate within the system.

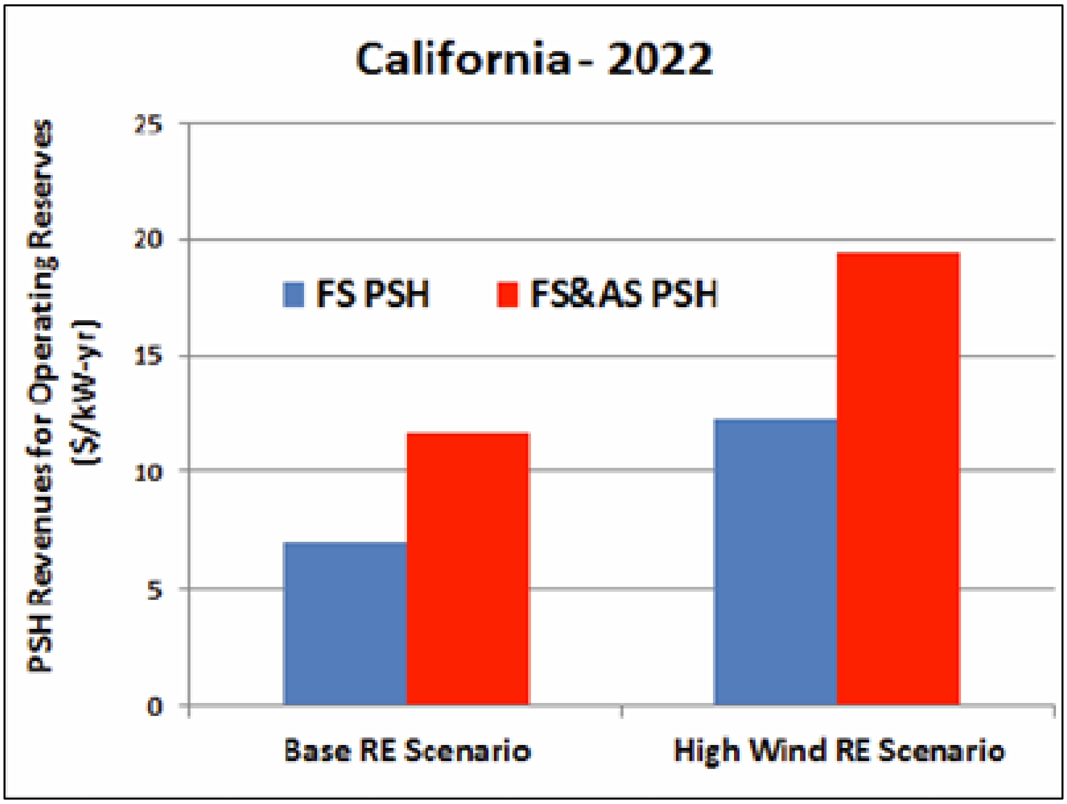

Figure D-2: Average Annual PSH Revenues for Operating Reserves (per kW of PSH Capacity)
Source: Argonne National Laboratory

Regarding the integration of variable energy resources, the investigators found that, "[i]n California, under the Base renewable energy scenario, the curtailments of [variable energy resource ("VER")] generation are reduced from 155 GWh in the case without PSH plants to 46 GWh (70% reduction) if FS PSH plants are operating in the system, and to 14 GWh (91% reduction) if both FS and [APS] plants are operating. Under the High Wind scenario, the curtailments are reduced from 618 GWh in the case without PSH plants to 380 GWh (39% reduction) if FS PSH plants are operating in the system, to 275 GWh (55% reduction) if both FS and [APS] plants are operating."[10]

The investigators found also that, "[t]he flexibility of PSH capacity, its fast ramping characteristics, and load-leveling operation creates a flatter net load profile for thermal generating units. This allows them to operate in a steadier mode, thus reducing the need for their ramping and frequent start-ups and shutdowns."[11] The reductions in start-up costs, as a percentage of total start-up costs in California, are illustrated in Figure D-3.

[10]/ *Id*. at Page ES–12.

[11]/ *Id*. at Page ES–13.

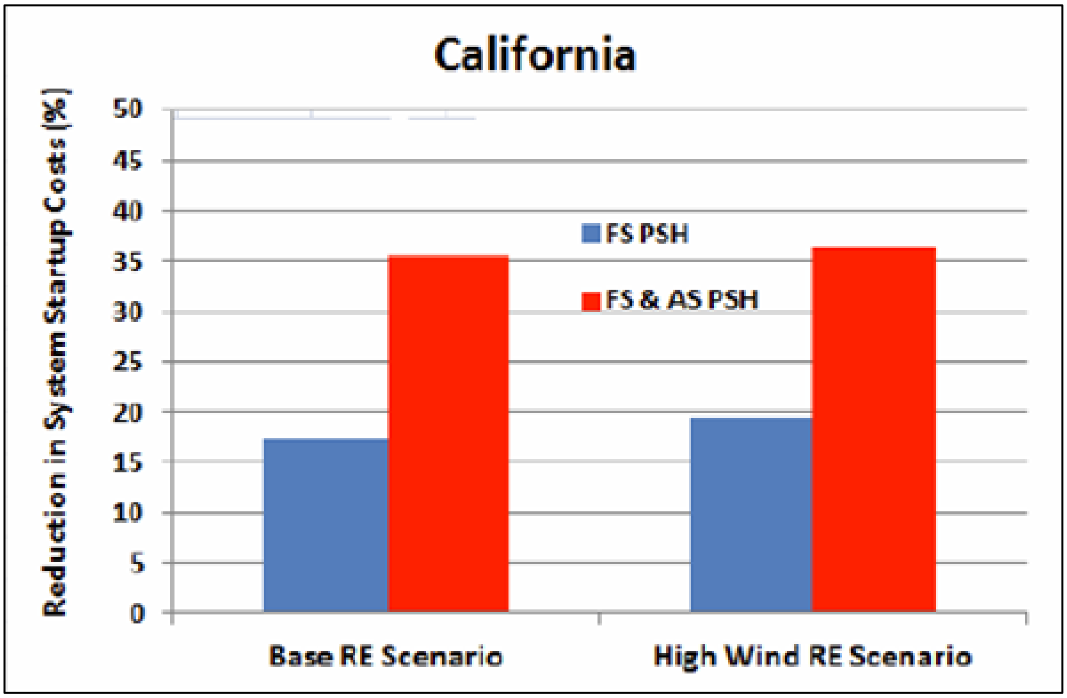

Figure D-3: Reduction in Thermal Start-up Costs Due to PSH Capacity in California in 2022
Source: Argonne National Laboratory

In addition, the investigators found that for California in 2022, under the High Wind renewable energy scenario, "FS PSH reduces the ramp-up needs of thermal generators by 531 GW, and ramp-down needs by 945 GW. If both FS and AS PSH plants are operating in the system, the ramp-up needs of thermal generators are reduced by 1,214 GW and ramp-down needs by 1,943 GW",[12] as shown in Figure D-4.

The investigators found that the presence both FS and APS facilities in California would also show "a decrease in CO_2 and NOx emissions, and an increase in SO_2 emissions under both the Base and High Wind renewable energy scenarios",[13] as shown in Figure D-5.

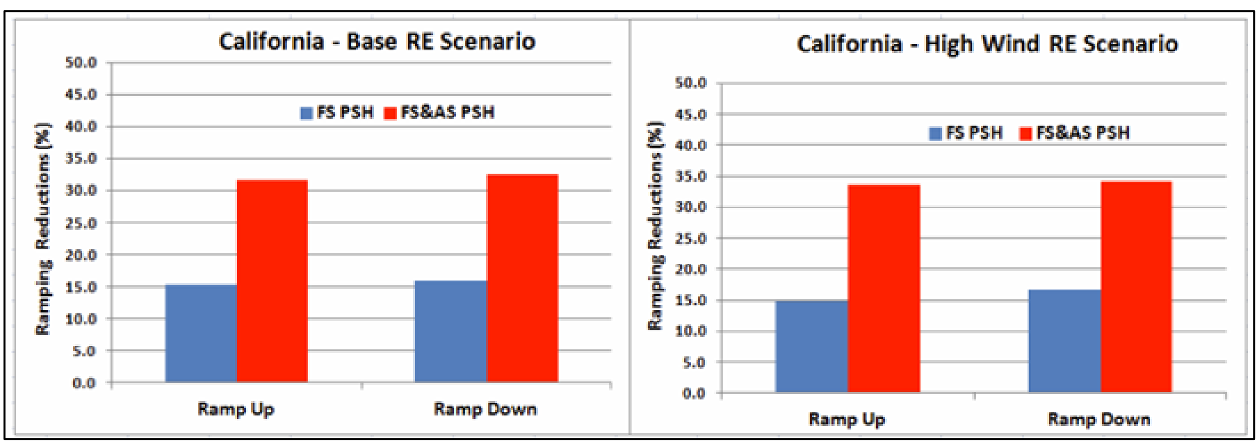

Figure D-4: Reductions in Thermal Capacity Ramping Needs in California in 2022 Due to PSH Capacity
Source: Argonne National Laboratory

[12]/ *Id*.

[13]/ *Id*. at Page ES–15.

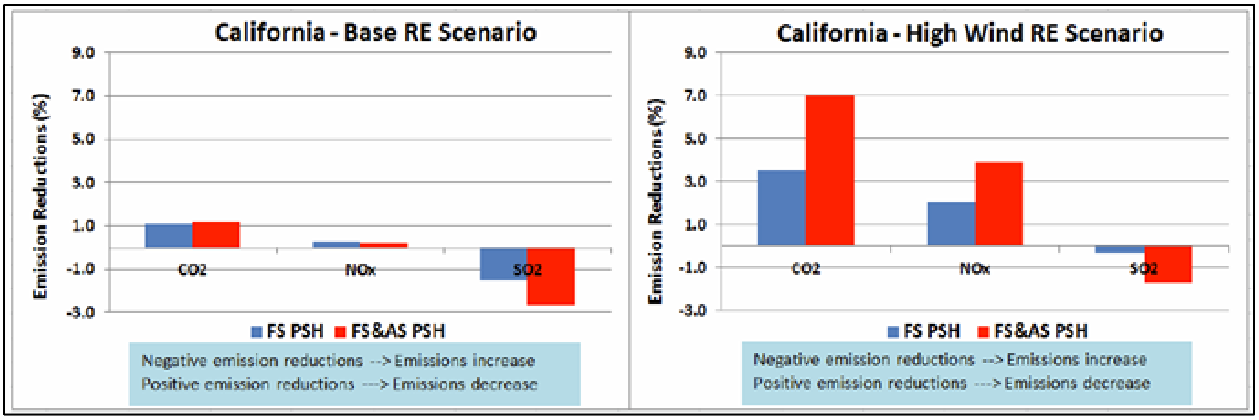

Figure D-5: Emission Reductions Due to PSH Capacity in California in 2022
Source: Argonne National Laboratory

Finally, in markets like California that use Locational Marginal Pricing (LMP), a component of the price is based on transmission congestion and the transmission congestion price is an indicator of the congestion on the transmission grid. The investigators found that lower transmission congestion prices were realized in cases with PSH plants indicated "that they help mitigate the costs associated with transmission congestion."[14] Specifically, the investigators found as follows:

> *the average transmission congestion prices decrease from $3.51/MWh in the case with no PSH plants operating in the system, to $0.40/MWh in the case with FS PSH plants, and further to $0.24/MWh in the case with both FS and [APS] plants operating in the system. Under the High Wind renewable scenario, the average transmission congestion prices in California decrease from $1.79/MWh in the case without PSH plants, to $0.56/MWh in the case with FS PSHs, and further to $0.37/MWh in the case with both FS and [APS] plants operating in the system.*[15]

The report describes a number of additional valuation analyses, all of which found value to the presence of PSH and APS systems within the California grid, and the Applicant encourages the Commission to review the report directly to fully understand the value of the Applicant's Proposed Project. Finally, as the investigators did not assess the value of the Proposed Project in their report, the results reported may not be directly comparable to the results found in the earlier CSRTP study of the Proposed Project.

A report on this study is available in Volume 3 of the original LEAPS Application.

4.1.3 The Eagle Mountain FEIS

The Commission staff, in its final environmental impact statement published for the Eagle Mountain Pumped Storage project,[16] provided a reasonable estimate of energy values and costs for a project proposed in somewhat the same general region as the Proposed Project. Table 34 of that document identifies an energy value of $40.00 MWh, a capacity value of $154.00 per kW–year, an ancillary services value of $95.00 per kW–year, and a cost for pumping energy of $20 per MWh. While the Applicant does not believe this analysis is as comprehensive as the reports described above, it can be used as a meaningful proxy for determining the value of a pumped storage facility.

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[14]/ *Id*. at Page ES–16

[15]/ *Id*.

[16]/ Final Environmental Impact Statement for Hydropower License, Eagle Mountain Pumped Storage Hydroelectric Project—FERC Project No. 13123-002, FERC Office of Energy Projects, FERC/FEIS–F–0238, January 2012.

4.1.4 The 2019-2020 CPUC Integrated Resource Plan

In California's most recent Integrated Resource Plan developed by the California Public Utilities Commission (CPUC), there is a recognition of the different attributes between 4-hour battery energy storage and the need for longer duration energy storage, typically 8 hours or more.[17] The state has several large PSH plants in operation that can supply long duration energy storage. During times of stress, these plants are relied on to help stabilize the grid. As GHG emissions are reduced to meet low carbon emissions targets in 2030, significant amounts of 4-hour energy storage will be used to help flatten the gross peak demand and net peak demand (load minus solar and wind generation). As GHG emissions are further reduced and natural gas plants are retired, long duration energy storage provided by PSH is needed to extend the delivery of renewable energy and provide grid resiliency throughout the day. In California, PSH was identified as the preferred source of long duration energy storage. The 2019–2020 IRP currently shows a need for 0.9 GW of PSH starting in 2026 for California to meet the 2030 GHG reduction goals.

[17]/ CPUC 2019-2020 Electric Resource Portfolios to Inform Integrated Resource Plans and Transmission Planning

5.0 OTHER ELECTRIC ENERGY ALTERNATIVES

Other electrical energy alternatives include natural gas fired generation (large and small combined cycle), oil-fired generation, coal fired generation, nuclear-fueled generation, renewable resources, other pumped storage facilities, and conventional hydropower facilities. However, under state law and policy, renewable resources must be considered first.

5.1 State law and policy requires that renewable energy resources be considered first

California's Renewables Portfolio Standard (RPS) program was established in 2002 by Senate Bill (SB) 1078 with the initial requirement that 20% of electricity retail sales must be served by renewable resources by 2017. The program was accelerated in 2015 with SB 350 which mandated a 50% RPS by 2030. SB 350 includes interim annual RPS targets with three-year compliance periods and requires 65% of RPS procurement to be derived from long-term contracts of 10 or more years. In 2018, SB 100 was signed into law, which again increases the RPS to 60% by 2030 and requires all the state's electricity to come from carbon-free resources by 2045.

The “loading order” is a policy that specifies priorities for both demand side and supply side projects. The demand side projects, energy efficiency and demand response, are assigned the highest priority in the order followed by renewables and clean fossil projects on the supply side. The loading order establishes a priority for making judgments based on the cost effectiveness of each program. These programs are then balanced to address the current needs of providing energy services, with long-term goals of providing it efficiently. The loading order in practice is a guideline for portfolio management that establishes criteria for weighting and accounting for the uncertainty in demand side programs and supply side projects.

The California Global Warming Solutions Act (AB32) also established a cap-and-trade system that has established a price on carbon emissions and in essence tightens emission constrains on energy consumption.

In California’s most recent Integrated Resource Plan developed by the California Public Utilities Commission (CPUC), there is a recognition of the different attributes between 4-hour battery energy storage and the need for longer duration energy storage, typically 8 hours or more.[18] The plan adopts an optimal portfolio of energy resources that includes approximately 14,500 MW of new supply-side renewables, 8,900 MW of new battery storage and 1,000 MW of new long-duration storage resources by 2030.

5.2 Natural Gas Fueled Generation

Most existing and new generation located in California uses natural gas to meet stringent California Air Resources Board and local air district regulations. Natural gas fueled generation can consist of either simple cycle power plants operating for limited periods as peaking facilities, and as larger, combined cycle power plants operating as baseload facilities.

Some smaller peaking facilities are in various stages of development across California. These are generally smaller facilities and are either located to meet localized grid reliability need or to provide balancing energy during periods of rapid load changes. The 2019/2020 Integrated Resource Plan prepared by the CPUC retains nearly all existing gas generation because natural gas capacity is needed for reliability before and immediately after 2030, despite being dispatched for relatively few hours of the day. By 2045,

[18]/ CPUC 2019-2020 Electric Resource Portfolios to Inform Integrated Resource Plans and Transmission Planning

however, approximately 4,500 MW of gas capacity is not retained in order to achieve the SB 100 2045 goal of 100% of electricity to come from carbon-free resources.

Combined cycle power plants offer a low-cost energy supply with certain limitations: start-ups require 1 to 4 hours; ramping is limited to 1 to 5 MW/minute; dispatch cycling is limited to 70% to 100% of full load. A major constraint for all natural-gas-fired plants is finding sites where connecting to grid is feasible and where emissions offsets can be obtained. As an alternate to the Proposed Project, these units could provide energy, but cannot provide the grid reliability features the Proposed Project can including:

- Rapid ramping of up to 500 MW in less than 15 seconds;
- Rapid cycling from 0% to 100% load; and,
- The ability to manage off peak overgeneration conditions by absorbing and using excess off peak energy.

5.3 Oil Fueled Generation

There is little oil-fueled generation in California due to emissions restrictions imposed by state agencies. Air districts have implemented restrictions on oil firing to limit use to periods when natural gas curtailments are ordered by the gas transporter or the local distribution company. New or large oil fueled generation is infeasible to site in California.

5.4 Coal Fueled Generation

There are no coal-fueled generation in California due to emissions restrictions imposed by state agencies. There are a few coal-fired units with special emissions systems and special contracts that provide a payment stream sufficient to bear the extra costs associated with emissions reductions that feed power to California. Now and for the foreseeable future, it is infeasible to permit and construct coal-fired generation in California.

5.5 Nuclear Fueled Generation

The Applicant does not have any reason to believe that new nuclear generation power plants will be proposed or constructed in the foreseeable future. The nearby San Onofre Nuclear Generating Station was shuttered, and the remaining Diablo Canyon was slated to close its reactors in 2024 (Unit 1) and 2025 (Unit 2) since they would likely only be running half-time due to priorities given to renewable energy generation by loading ordering described in Section 5.1. However, given the current state of energy reliability[19] and capacity shortfalls forecasted in California in the coming years and the delayed on-stream dates of new generation and energy storage projects, a 10-year extension is being proposed at a cost of $1.0B of relicensing costs. Historical cost and schedule overruns and the problems associated with storing nuclear waste make development and permitting of a new nuclear power plant improbable.

Presently, two large base load nuclear generating facilities provide power to the California grid: Palo Verde (3,733 MW) located in Arizona and Diablo Canyon (2,174 MW). These units currently operate at full load regardless of conditions on the grid. When the control area operator is experiencing supply greater than demand, and it is infeasible to back down nuclear power plants, the control area operator must arrange to accommodate the excess power. The Proposed Project is well suited to assist the control

[19]/ As recently as August 16, 2022 the CAISO has called for conservation of electricity to avoid blackouts amid heat wave during evening time periods which this proposed project is intended to serve: https://www.bnnbloomberg.ca/california-seeks-power-conservation-to-avoid-blackouts-amid-heat-1.1806593

area operator by converting from a supply resource to a load resource, and its pumping operation can consume, depending upon its final configuration, up to 600 MW of load.

5.6 Renewable Resources

With the State's mandating the increased use of renewable generation resources to supply the State's generation needs, the Proposed Project can work in tandem with renewable resources that presently exist and which may be developed in the region. These resources are designed to operate as a function of fuel supply, such as biomass–fueled generation, geothermal electric generation or wind power electric generation. Many have a zero fuel cost. These units do not cycle off during off–peak periods due to their low fuel cost but may, like solar and wind, be dependent on presence of sunshine and wind. Thus, the Proposed Project is well suited to help shift off–peak power generated by non–dispatchable renewables to peak usage periods.

5.7 Other Conventional and Pumped Storage Hydroelectric Plants

As previously discussed, there are two other large pumped storage hydropower facilities in the State. However, neither are geographically situated to provide the benefits to the grid required in this location. In addition, neither is able to provide the benefits to Lake Elsinore, which is used as the lower reservoir, as can the Proposed Project. Thus, this location's geography and grid location make the location of the Proposed Project strategic and unique.

5.8 Conclusion

In conclusion, the Proposed Project provides a unique resource superior to conventional gas-fired generation as an electric supply resource. It places up to 500 MW of peaking generation in the middle of a rapidly growing area. It would be impossible to put a similar quantity of conventional gas fired generation in the same location due to the difficulty of obtaining air quality permits.

6.0 CONSEQUENCE OF DENIAL OF APPLICATION

Denial of the license application would eliminate a vital means for funding stable water levels in Lake Elsinore and significantly improving water quality within the lake. Denial would also contribute to continued electrical system instability and brown/blackouts in southeast Riverside County and the Temescal Valley-Lake Elsinore area by denying the CAISO a valuable grid management tool. It would also deny the State an important tool with which to manage its emerging portfolio of renewable resources.

6.1 No Stability in Lake Water Level

The lead responsibility for providing a stable water elevation in Lake Elsinore was accepted by the Elsinore Valley Municipal Water District ("EVMWD") when it received ownership of the lake from the State of California in the 1990's. This responsibility is shared with the City of Lake Elsinore (the "City") as part of the same State transfer of the lake and accompanying State Park lands to the city. An agreement between EVMWD and the City further defines and allocates a Lake Maintenance Fund for the purpose of providing for lake stabilization. As a result, the Proposed Project can contribute to this presently ill-funded stabilization effort by providing to either party funds they can use under their agreement. The funding should provide for adequate sources of supply from EVMWD reclaimed water, EVMWD ground water, imported reclaimed water and imported untreated water.

Without lake stabilization or water level control of Lake Elsinore, which is classified as a eutrophic ephemeral lake, primary beneficial uses will only be available part time without certainty. The primary beneficial uses of the lake are for body contact, recreation, boating, fishing and water-skiing and jet skiing activities. Lake hydrologic records show that in the past roughly 75 years there were natural flows into the lake large enough to match annual evaporation for only 13 years. Evaporation amounts to a loss averaging approximately 14,000 acre feet per year. During the same period, there were 5 years when no flows were recorded entering the lake and 47 years, or 65% of the time, when flows were less than 800 acre-feet per year. Flow data is on record from the USGS from Stream Gauge Station No. 11070500. These highly seasonal fluctuating flows define the ephemeral nature of the lake.

The major drawbacks to recreational uses are unpredictable fish kills in the lake and high turbidity due to the algae growth. These conditions define the eutrophic nature of the lake. For example, despite the addition of alum to the lake in October 2021 and April 2022, as recently as August 19, 2022, an algal bloom in Lake Elsinore prompted the state to issue a "danger alert " indicated that all recreational activity should be discontinued. Without lake stabilization, these conditions are likely to continue unabated.

With the project in place, the need for a failsafe water supply to feed the hydro power generators is paramount. The project will provide financial resources to supplement nature's lack of natural runoff to provide adequate water levels. With a stable lake elevation investment, and significant investments by the proposed project in water treatment and supplemental oxygen, improved lake water quality can be reasonably expected to succeed.

Without the project, the lake would have periods where it could completely dry up and prohibit any investment in water quality improvement.

The project brings potential water quality improvement in three areas:

1. The stable levels will allow natural vegetation to proliferate in the undeveloped shoreline regions that are in an integral part of the natural cleansing of the lake. This vegetation can provide shoreline protection for aquatic ecology that can help balance the food chain of the lake.
2. The injection of oxygen into water returned to the lake during the power generation cycle will increase dissolved oxygen concentrations in Lake Elsinore preventing fish kills and the growth of

cyanobacteria, a group of organisms that form harmful algal blooms creating hypoxic conditions and can produce potent toxins.

3. The proposed project's commitment to invest in additional or expanded water treatment facilities for water entering Lake Elsinore will result in significant improvements in water quality in Lake Elsinore and enable the treatment of more reclaimed water for lake level stabilization.
4. The daily operation of the pump/turbines results in pressurization of water which, if it contains blue green algae, can destroy the algae and their ability to float by collapsing internal gas vacuoles.

6.2 Upper reservoir as a firefighting resource

The upper reservoir would provide a large water resource directly within the Cleveland Forest that could be used for firefighting. Without the proposed project, firefighting equipment would have to use the Lake, nearly 1600 feet below the elevation of the upper reservoir, which presents added time and difficulty for firefighting aircraft.

6.3 Other Consequences

Denial will also make it more difficult for the State to manage the electric grid and achieve some of its goals for electricity and fuel–diversity. Grid management issues would include:

- Unavailability of LEAPS as a Grid Management Tool
- Unavailability of LEAPS Load Shifting Peaking Facility

In addition, and with the State's intention of increasing its reliance on renewable energy sources, LEAPS would also be unavailable to help manage these resources:

- Unavailability of LEAPS as a Renewable Energy Storage Tool

7.0 SOURCES AND EXTENT OF FINANCING

Funding during the construction and operation phases of the project is anticipated to be a combination of debt and equity. The debt service, return on equity, and annual operating costs would be paid out of revenues derived from the sale of energy and capacity.

The anticipated debt structure, interest rates and terms are described above in Section 3.0.

8.0 COST TO DEVELOP LICENSE APPLICATION

The Applicant intends to use private sources to finance costs to complete the licensing phase of the project. Total costs, associated with engineering and environmental studies, public relations, project management, legal services, option payments, and power sales negotiations, are included in the Project Development Costs (inclusive of previously incurred costs) in Table D-1: Project Cost Summary.

9.0 ON–PEAK AND OFF–PEAK VALUES OF PROJECT POWER

Forecasting the on– and off–peak values of project power assumes either a market in place, with pricing history, or contracts for the purchase and sale of project power well into the negotiation stage. There is no reliable market price history in California, and it is premature for the applicant to enter into negotiations for the purchase or sale of energy or capacity. However, in Section 4.0, above, the Applicant provides estimates of the value of project power.

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