Concept Study Report

Lake Sonoma Pumped Storage Hydropower Project

Prepared for Sonoma Water

Sonoma County, California

September 8, 2025

Contents

Tables

Figures

Appendices

Provided Separately

Reservoir Operations / Energy Model (spreadsheet)

This page is intentionally left blank.

Executive Summary

HDR was retained by Sonoma Water to perform a concept study for a proposed pumped storage hydropower development (referred to herein as the Project) located at a pre-determined site near Lake Sonoma in Sonoma County, California. This report presents a detailed description of existing conditions at the Project site, results of a preliminary geologic assessment, conceptual Project configuration, findings of initial energy modeling studies, construction considerations, Class 5 cost opinions prepared in accordance with AACE International (AACE) guidance, federal and state regulatory considerations, and an integrated development schedule.

Project Description

The Project capacity was selected as 20 megawatts (MW), which is the threshold between “large” and “small” generating facilities as defined by California Public Utility’s Rule 21. Furthermore, the Project’s energy storage capacity was established as 280 megawatt-hours (MWh) which equates to a constant generating output of 20 MW over a 14-hour period.

Warm Springs dam impounds Lake Sonoma which would serve as the Project’s lower reservoir. The lake is operated by Sonoma Water for water supply and by the U.S. Army Corps of Engineers (USACE) for flood control. Lake levels have historically ranged from approximate Elevation 376 feet North American Vertical Datum of 1988 (ft-NAVD88) to 478 ft-NAVD88. A minimum lake operating level (for pumped storage operations) was selected as Elevation 410 ft-NAVD88, which has historically been exceeded approximately 80 percent of the time. But with the expected implementation of the Forecast Informed Reservoir Operations program developed by USACE and Sonoma Water, the minimum operating level of Lake Sonoma is expected to be above this elevation a greater percentage of the time going into the future. Using historical data increases the elevation difference to which the pumps would need to operate, which increases pumping costs, and decreases the cost effectiveness of the project.

The relatively small capacity of the Project drove the decision to utilize a surface-type powerhouse arrangement rather than an underground arrangement, the latter of which is more common for larger pumped storage hydropower projects that can support this more costly arrangement. The surface-type powerhouse would house two Pelton-type turbines and four separate vertical turbine pumps. This equipment was selected to manage construction costs, as it limits the depth of excavation required to achieve the necessary hydraulic submergence of the machines.

The upper reservoir location was sited within a previously disturbed area that served as the borrow site for construction of the USACE’s Warm Springs Dam. The upper reservoir was situated as high in elevation as practical to optimize head for the Project. Known geologic conditions of the upper reservoir area indicated that a reservoir liner would be required to manage seepage water losses. To reduce visual impact and to manage dam safety requirements, the upper reservoir was configured as an excavation rather than a more conventional dammed impoundment. A dammed impoundment would likely reduce the capital cost and improve the cost effectiveness of the project but not substantially.

Water would be conveyed to and from the upper reservoir by a 78-inch-diameter steel penstock. The upper portion of the penstock would be underground and the remaining sections would be located along the ground surface (i.e., mounted on reinforced concrete saddles and/or ring girder supports).

An area adjacent to the Lake Sonoma shoreline was selected as the powerhouse site. The powerhouse itself would feature a reinforced concrete substructure and pre-engineered metal superstructure. The powerhouse would house the Pelton turbines and most of the electrical and controls equipment.

The Project's vertical turbine pumps would be contained within a reinforced concrete caisson that extends from below the surface down to an adequate submergence elevation for the vertical turbine pumps. Two 74-inch-diameter micro-tunnels would provide the hydraulic connection between the pump caissons and Lake Sonoma.

Access to the upper reservoir would be provided by improving an existing, rough-terrain road originally built to support construction of Warm Springs Dam. A new access road is required to serve the power complex and would extend from the Upper Reservoir Access Road approximately 1,000 feet west to the powerhouse.

Transmission and interconnection alternatives were investigated by Sonoma Clean Power. The concept selected for this report includes 9 miles of 115 kV transmission to the Cloverdale 115 kV Substation.

Geology

A preliminary geology evaluation was conducted based on published information and a one-day field reconnaissance visit. A summary of potential geologic hazards is as follows:

- Minimal slope instability was observed at the upper reservoir area. Evidence of slope instability is present along the upper reservoir/borrow area access road. The topography between the upper reservoir and Lake Sonoma may be susceptible to slides.
- No evidence of limestone, soluble formations, sinkholes, closed depressions, or disappearing streams was observed.
- The upper reservoir conglomerate materials are moderately soft to hard and appear to be generally excavatable, suggesting some potential for erosion.
- The Project site is considered to have moderate seismic risk.
- The risk of liquefaction is considered to be low.

The upper reservoir excavation would yield a significant amount of conglomerate comprised primarily of clasts (fragments) that are gravel-sized with minimal sand and fines content. The gravels could presumably be used for general fill or road base; however, the conglomerate would have to be processed to yield these materials. The gravels are likely too coarse for other fill materials. There is limited sand and fine content.

HDR did not identify any technical fatal flaws associated with geologic conditions. As with all hydropower projects, any unfavorable geologic conditions present risks, but these risks can typically be reduced or mitigated through further investigations, appropriate designs, and contingency planning.

Opinion of Probable Construction Cost

An Association of the Advancement of Cost Engineering (AACE) Class 5 opinion of probable construction cost (OPCC) was prepared in accordance with and has an expected accuracy range of -50 percent to +50 percent. The baseline OPCC is approximately $199 million with low- and high-range values of approximately $100 million and $299 million respectively. The most significant cost is that of the upper reservoir and optimization / cost reduction of that feature is recommended during future study phases.

A high-level cost comparison was made to battery energy storage system (BESS). The levelized cost for PSH and BESS are approximately $1063 / MWh and $764 / MWh respectively

Regulatory Considerations

Development of the pumped storage hydropower project would require issuance of an original license or exemption by the Federal Energy Regulatory Commission (FERC). The licensing process involves preparation of technical and environmental studies followed by execution of the National Environmental Policy Act (NEPA) analysis by the FERC and is anticipated to take approximately five years to complete.

California Environmental Quality Act (CEQA) compliance would also be required as it relates to both the Clean Water Act Section 401 and 404 permitting requirements.

A transmission interconnect agreement would be required with PG&E / CAISO with the next opportunity to apply estimated to be October of 2026. The approval process would typically take one calendar year.

Additional local, state, and regional permits/approval would also be required.

Integrated Development Schedule

HDR developed an integrated development schedule to establish an overall schedule that identifies major activities, their durations, and interdependencies. The schedule is intended to be a useful planning and tracking tool and should be considered a “living” document since projects of this magnitude can be influenced by many factors over time. The schedule includes planning and design, regulatory approvals, procurement, and construction. The current schedule has commercial operation of the Project beginning in the year 2026.

Energy Production and Use

HDR created an energy production model (spreadsheet) for use by Sonoma Water and Sonoma Clean Power to estimate net revenues based on forecasted energy pricing. Mean annual generating and pumping energies totaled approximately 34,970 MWh and 58,490 MWh respectively and Sonoma Clean Power forecasted a net annual revenue of approximately $3.5 million.

Summary of Salient Project Data

Table XS-1 presents a summary of pertinent Project data.

Table XS-1. Summary of Salient Project Data

Feature	Parameter	Units	Value	Comments
Upper Reservoir	Non-Overflow Crest Elevation	ft-NAVD88	1200.0	
	Maximum Operating Level	ft-NAVD88	1195.0	
	Minimum Operating Level	ft-NAVD88	1130.0	
	Active Storage	ac-ft	511	
	Nominal Floor Elevation	ft-NAVD88	1119.0	
	Emergency Spillway Crest Elevation	ft-NAVD88	1196.0	
Lower Reservoir	Maximum Operating Level	ft-NAVD88	451.0	Pumped Storage Operations Only (Not Water Supply or Flood Control)
	Minimum Operating Level	ft-NAVD88	410.0	
	Active Storage	ac-ft	511	
Conveyances	Upper I/O Type	--	Horizontal	
	Upper I/O Invert Elevation	ft-NAVD88	1119.0	
	Penstock Diameter	in	78	
	Penstock Material	--	Welded Steel	
	Lower I/O Type	--	Caisson / Wet Well	
	Tailrace Diameter	in	2 x 74"	From wet well to Lake Sonoma
	Tailrace Material	--	Micro-Tunneled Concrete	
Generating Equipment	Turbine Type	--	Pelton	
	Turbine Unit Capacity	MW	10	
	Number of Units	--	2	
	Plant Capacity	MW	20	
	Cycle Time	hr	14	
	Cycle Energy	MWh	280	
	Centerline Elevation	ft-NAVD88	515.0	
	Maximum Net Head	ft	680.0	
	Minimum Net Head	ft	604.0	
	Mean Discharge	cfs	427.0	
Pumping Equipment	Pump Type	--	Vertical Turbine	
	Intake Type	--	Open Wet Well	
	Pump Unit Capacity	MW	5	
	Number of Units	ea	4	
	Plant Capacity	MW	20	
	Cycle Time	hr	Varies	Depends on Lake Sonoma water level
	Cycle Energy	MWh	Varies	
	Maximum Net Head	ft	785	
	Minimum Net Head	ft	668	
	Maximum Discharge	cfs	269	At minimum net head
	Minimum Discharge	cfs	246	At maximum net head
Transmission	Line Capacity	kVA	115	
	Line Length	Miles	9	
	Point of Interconnection	--	Cloverdale	

1 Introduction

1.1 General

HDR was authorized by Sonoma Water in June 2024 to perform a conceptual engineering study for a new 10 to 20 MW (nominal) pumped storage hydropower project (referred to herein as the Project) that would use Lake Sonoma as its lower reservoir. The scope of work included the following tasks:

- Project Meetings and Information Gathering
- Geological Fatal Flaw Assessment
- Desktop Environmental Evaluation
- Project Layout and Configuration Development
- Energy Modeling
- Construction Cost Opinions and Schedule Development
- Energy Modeling (to support preliminary revenue forecast by others)
- Concept Study Report Development

1.2 Context

The development of a pumped storage hydropower project typically involves multiple stages of study that advance from a needs statement and area of interest to design and equipment supply and construction bids, culminating in commercial operation. The present scope of work represents the very beginning stages of development, with recommendations regarding the Project's potential viability and next steps for continued evaluation. The purpose of this report is not to present final conclusions regarding the Project's configuration, feasibility, or cost, but to provide inputs that inform Sonoma Water's decision regarding advancement of the Project to the next stage of study.

More specifically, the present study and results are only the first stage of a comprehensive, multi-stage process of pumped storage hydropower development planning and design that may progress through many stages, and if feasible (and depending on exact project delivery method) may ultimately culminate in development of bid specifications and design, request for construction proposals, and competitive selection of construction contractor(s) and equipment supply. Typical stages in this process, some of which may be conducted in parallel, include:

- **Conceptual-Level Screening Study.** A conceptual-level screening study typically involves a desktop review of publicly available data to assess whether a new pumped storage hydropower project may be possible within the identified study region that merits further consideration. No screening study was required for the proposed development since the general location of the Project was pre-determined by Sonoma Water.
- **Pre-Feasibility Study.** A pre-feasibility study advances a project's definition, enabling preparation of a more refined opinion of probable construction cost

(OPCC) for a specific site and a greater understanding of potential environmental impacts and permitting. The pre-feasibility study often begins to address questions posed by multiple internal owner interests and involves the following:

  - Development of additional topographic, bathymetric, and existing feature data to enable more accurate siting and analyses, including proximity to and siting of new transmission and interconnection facilities.
  - Operational modeling, using assumed unit capabilities, of potential unit outage impacts; pump/generating cycles in relation to estimated energy market demands; and water management, hydraulics, and availability.
  - Preliminary geologic evaluation, improved understanding of geotechnical risk through non-disturbing field reconnaissance (site visits), and an assessment of constructability.
  - Refinement of site conceptual layouts, power complex layouts (including consideration of alternative locations and types of principal structures), water conveyance sizing, and unit technology sizing to address structural and hydraulic stability requirements and the influence of those requirements on cost opinions.
  - Development of preliminary schedules for planning, design, and construction.
  - Assessment of stakeholder engagement/communications, permitting, and Federal Energy Regulatory Commission (FERC) licensing strategies and approaches to mitigate or overcome potential challenges.

- **Preliminary Quantification of Benefits and Value.** Quantification of energy storage benefits and value, including ancillary services, within decarbonizing power systems is a complex task and defines the assessment and modeling of operations with future assets including flexible and dispatchable pumped storage and non-dispatchable wind and solar assets. Using preliminary generating and pumping capabilities, characterization of dispatch flexibility, and energy storage (duration) capacities of potential pumped storage in power system models would enable Sonoma Water to compare benefits to cost opinions within decision-making about pumped storage and other energy storage options. In parallel with this concept study, Sonoma Water and Sonoma Clean Power (SCP) have begun quantifying the Project’s benefits and value.
- **Feasibility Study.** A feasibility study further defines engineering features and functional performance for all project components, including initial regulatory interface. The feasibility study also includes an initial geotechnical investigation (field sampling/testing and laboratory testing) and initial outreach to the original equipment manufacturer (OEM) community to obtain conceptual information for equipment sizing, budgetary data, and overall qualifications.
- **Original Equipment Manufacturer/Engineering, Procurement, and Construction (OEM/EPC) Engineering, Permitting, and Tender Support.** This stage involves developing the final functional design, identifying the project delivery method, and preparing supporting technical documents (design criteria, geotechnical baseline report, performance specifications, project drawings, work

scope, engineer's estimate, project schedule, environmental and regulatory requirements, etc.). OEM and EPC bidder prequalification, bidder evaluation and negotiation support, and project oversight, tracking, and trending services are performed during this phase (and may vary depending on specific project delivery method selected).

This staged approach is typical for large hydroelectric projects. It allows for cost-effective decisions to be made at key stages of project development and supports portfolio decision analysis and financing success while reducing implementation risks.

Based on the descriptions provided above, HDR considers this concept study to be representative of a pre-feasibility study effort.

1.3 Coordination

Several meetings between Sonoma Water and HDR were held over the course of this concept study. In addition, HDR participated in meetings with Sonoma Water, SCP, and Pacific Gas & Electric (PG&E). References to these meetings are included where appropriate in this report to document salient decisions and direction. Notes from project meetings have been provided to Sonoma Water under separate cover.

2 Existing Conditions

2.1 Baseline Topography

The baseline topography was obtained digitally from the Sonoma County Geographic Information Systems (GIS) Repository. Contours are at 20-foot intervals and vertical datum is in North American Vertical Datum of 1988 (NAVD88)[1].

2.2 Project Area

Figure 2-1 presents significant existing features in the Project area.

[1] For the balance of this report, elevations are reported in feet. Unless otherwise noted, reference to the elevation datum (NAVD88) is implied.

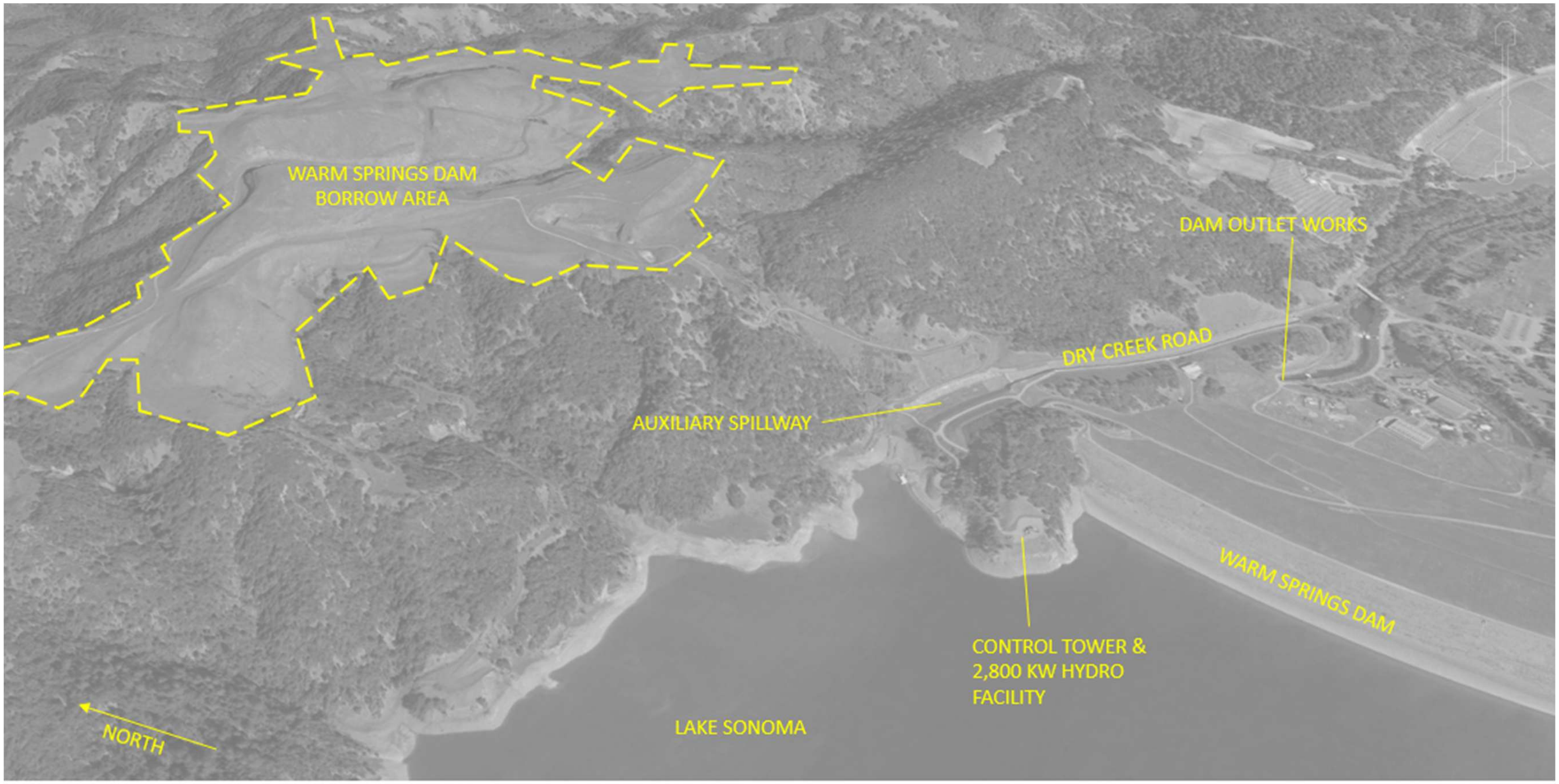


Figure 2-1. Project Area Existing Features

2.3 Lake Sonoma

2.3.1 Lake Sonoma Operations

The following description was taken from Sonoma Water's website (Sonoma Water 2024):

> *Sonoma Water is the local cost-sharing partner for Lake Mendocino and Lake Sonoma and determines the amount of water to be released from each reservoir when the lake levels are in the water supply pools. The U.S. Army Corps of Engineers determines the amount of water to be released when the lake levels are above the water supply pools and in the flood control pools.*
>
> *Lake Mendocino relies on year-to-year rainfall to fill as well as water diverted from the Potter Valley Project. Lake Mendocino is a key drinking water source for the cities of Ukiah, Healdsburg, Cloverdale and Hopland, and also provides water to Sonoma Water's Russian River water supply system. Water releases from Lake Mendocino support flows in the Russian River for the threatened Chinook salmon and steelhead trout during the fall and winter seasons.*
>
> *Lake Sonoma is about four times larger than Lake Mendocino and can provide multiple years of water supply. Lake Sonoma relies on rainfall to fill and supports a dynamic and fragile ecosystem in Dry Creek that includes the endangered coho salmon and threatened steelhead trout. Lake Sonoma provides a majority of Sonoma Water's service area with its drinking water.*
>
> *The Russian River is a managed river system with reservoir releases controlling river flows, especially throughout most of the summer and fall. When tributary stream flows are low, Sonoma Water releases water stored in the reservoirs to supplement the natural flows in the Russian River to provide adequate flows for water supply, recreation and aquatic habitat. A release from a reservoir can be categorized as being of 'pass-through water' or 'stored water.' The term 'project water' is often used instead of stored water and is used to describe water that is present because of the dam and reservoir project. Pass-through water is water flowing into the reservoir that is not stored in, but passes through, the reservoir. Project water releases to supplement the natural flows in the Russian River and Dry Creek are necessary to meet mandatory minimum streamflow requirements that exist for both of these watercourses.*

According to Sonoma Water (2022), Lake Sonoma has a constant (year-round) reservoir rule (storage) level of 245,000 acre-feet that delineates the water supply pool (< 245,000 acre-feet) and flood control pool (≥ 245,000 acre-feet). For reference, 245,000 acre-feet corresponds to a water surface elevation of 451.05 ft. In general, Sonoma Water controls Lake Sonoma water levels and releases water when the lake elevation is within the water supply pool and the U.S. Army Corps of Engineers (USACE) controls the lake when its elevation is within the flood control pool.

Minimum releases from the USACE's Warm Springs Dam are dictated by Sonoma Water's water rights permits. Minimum releases are based on water supply conditions as measured by inflows into Lake Pillsbury (upstream of Lake Sonoma). Although the minimum release requirements should not significantly impact pumped storage viability, the requirements are provided in Table 2-1 below (Sonoma 2022) as supporting information.

Table 2-1. Warm Springs Dam Minimum Release Requirements

Water Supply Condition	Date Range	Minimum Release (cfs)
Normal	Jan 1 – Apr 30	75
	May 1 – Oct 31	80
	Nov 1 – Dec 31	105
Dry	Apr 1 – Oct 31	25
	Nov 1 – Mar 31	75
Critical	Apr 1 – Oct 31	25
	Nov 1 – Mar 31	75

2.3.2 Lake Sonoma Characteristics

Lake Sonoma's historical water level and storage data was obtained from the USACE website[2]. Figure 2-2 shows a time series plot of Lake Sonoma water levels from 2003 through 2023. Figure 2-3 shows this same water level data but in a sorted format (i.e., a water level duration curve). As indicated in the figures, the high and low water levels over this period are 478.6 feet and 376.3 feet, respectively. This represents a range of approximately 102 feet. Figure 2-4 presents the relationship between Lake Sonoma water level and storage.

[2] Website accessed 10/17/2024: https://www.spk-wc.usace.army.mil/reports/hourly.html

Figure 2-2. Lake Sonoma Water Level Time Series, 2003 to 2023

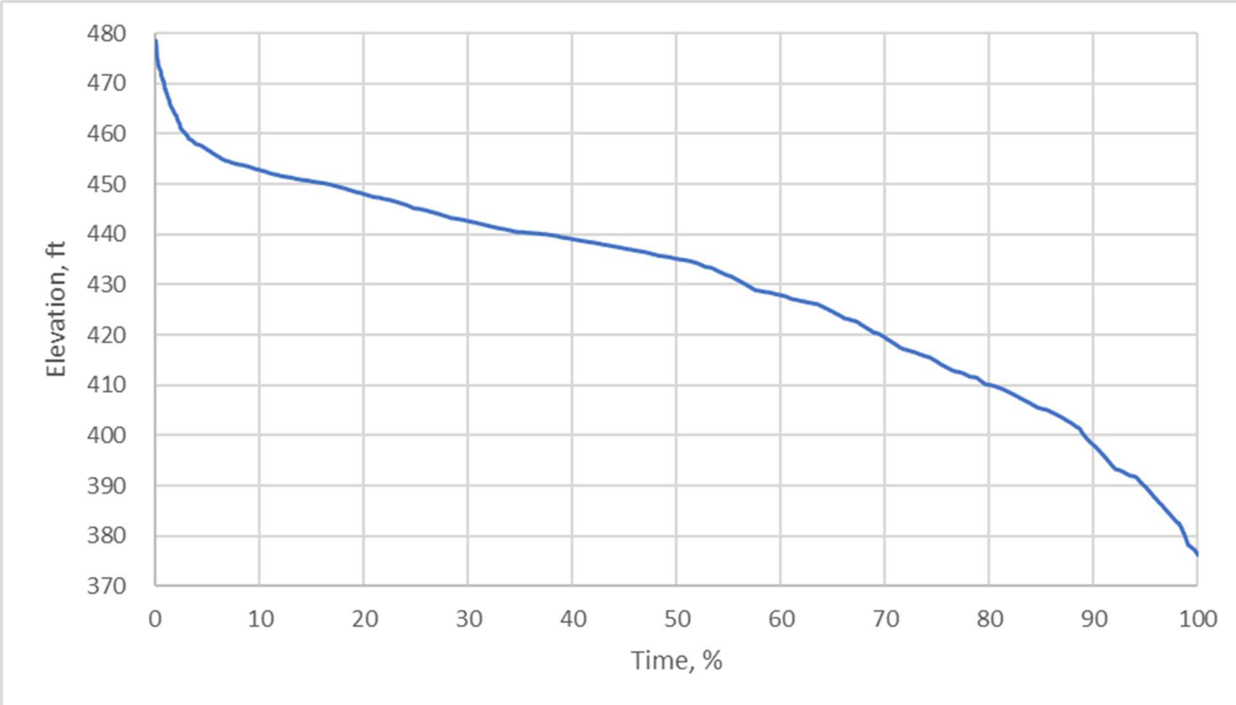


Figure 2-3. Lake Sonoma Water Level Duration, 2003 to 2023

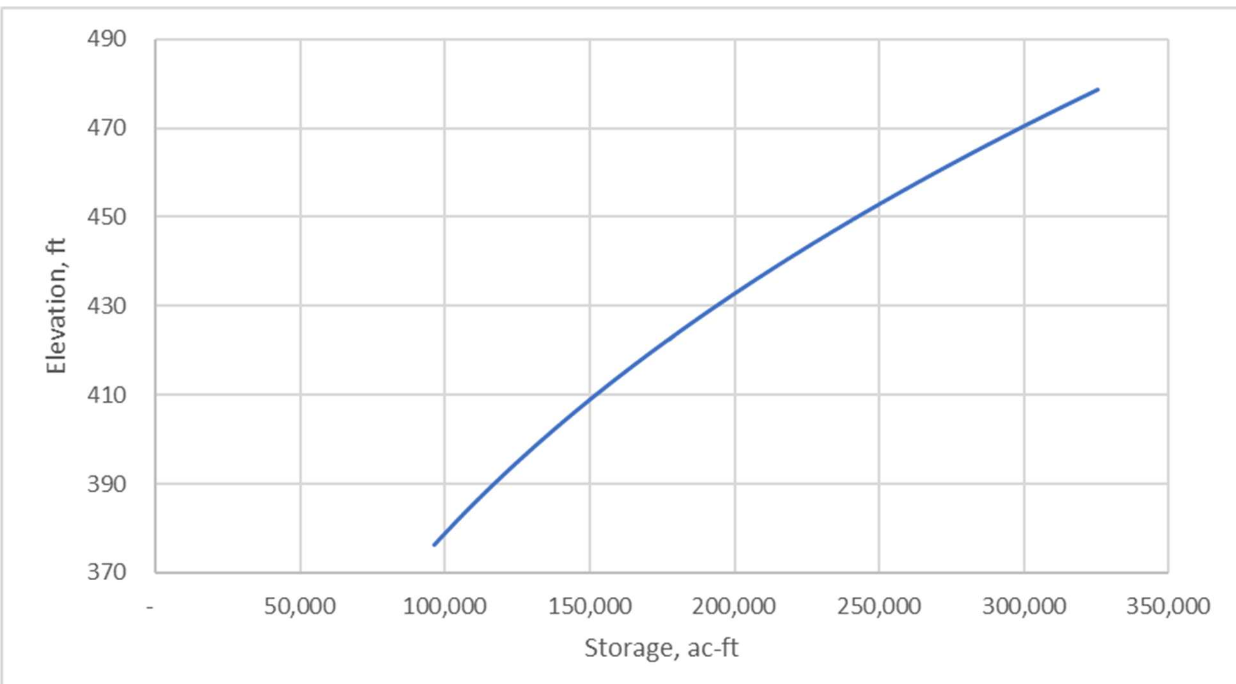


Figure 2-4. Lake Sonoma Stage-Storage Curve

The USACE plans to implement Forecast Informed Reservoir Operations (FIRO) at Lake Sonoma. Per Sonoma Water's website (2024), *"FIRO is a flexible water management approach that uses data from watershed monitoring and improved weather forecasting to help water managers selectively retain or release water from reservoirs for increased resilience to droughts and floods. FIRO applies emerging science and technology to optimize water resources and adapt to climate change without costly infrastructure."* As discussed in Section 4.1, HDR conservatively assumed that historic operations of Lake Sonoma would continue in the future (i.e., FIRO would not be implemented).

2.4 Upper Reservoir Hydrology

2.4.1 Precipitation

According to U.S. Climate Data (2024), the mean annual precipitation in Sonoma County is approximately 31 inches. According to the National Oceanic and Atmospheric Administration (NOAA 1999), the 24-hour probable maximum precipitation (PMP) for the Midcoastal Region of California is 42 inches (all-season, 10 square mile area).

2.4.2 Evaporation

Baldocchi et al. (2019) reported a mean annual evaporation of 590 millimeters (23 inches) for the Bay/Delta area of California. Applying this rate to the mean surface area of the upper reservoir (7.4 acres) results in an average annual evaporation of approximately 14 acre-feet.

At full conservation pool, Lake Sonoma has a surface area of approximately 2,700 acres and storage capacity of approximately 240,000 acre-feet. Upper reservation evaporation is considered insignificant and not considered further in this study.

2.4.3 Minimum Instream Flow

Minimum instream flow refers to the amount of water that must be continuously released from an artificial impoundment to preserve downstream aquatic life and habitat. The determination of minimum instream flows is typically dictated by state regulatory agencies as a computable flow rate or as a rate that must be determined on a case-by-case basis for one or more targeted species. For the purposes of this study, HDR assumed that the minimum instream flow for the upper reservoir would be based on similar criteria to that of Lake Sonoma and adjusted based on contributing drainage area.

The drainage areas of the Lake Sonoma and the upper reservoir watershed are 130 and 0.02 square miles, respectively. Based on normal water supply conditions, the mean minimum instream flow for Lake Sonoma / Warm Springs Dam (see Table 2-1) is 82.5 cubic feet per second (cfs) or 0.63 cfs / square mile (mi^2). Applying this rate to the upper reservoir watershed area results in a minimum instream flow of 0.01 cfs (4.5 gallons per minute [gpm]). Minimum instream flow is considered insignificant and not considered further in this study.

3 Preliminary Geologic Assessment

HDR's preliminary geologic assessment included a review of publicly available geologic information, a one-day site reconnaissance, and the evaluation of site geologic characteristics and their impacts to Project design and construction. The results of this assessment are summarized in the following subsections.

3.1 Geologic Setting

Lake Sonoma is located within the North Coast Ranges geomorphic province of California. Here, physiographic features trend northwest and weather into a knobby, nonuniform landscape (Farrar et al., 2006). The North Coast Ranges include three prominent pre-Tertiary rock groups: the Franciscan Complex, the Coast Range ophiolite, and the Great Valley Sequence (Blake et al., 2000; Farrar et al., 2006). Collectively, these rock groups represent marine basin lithologies that were accreted to the continental margin of California during the Cretaceous to Early Tertiary (Blake et al., 2000). Since the Cretaceous, these lithologies have been folded and faulted into mountain ranges and adjacent valleys. The topography is a tectonic response to regional stresses that produce northwest-trending, right-lateral, strike-slip faults (McLaughlin et al., 2005). These faults are associated with the San Andreas Fault system, which comprises a 50-mile-wide section of coastal California north of the San Francisco Bay (Farrar et al., 2006) and represents the transform plate margin.

The Franciscan Complex is a 12- to 20-mile subducted accretionary wedge that was transported from a Pacific Ocean marine basin to the continental margin of California sometime during the Late Jurassic to Late Cretaceous (Bennison et al., 1991; Blake et al., 2000). The Franciscan Complex is an assemblage of highly deformed, weakly to strongly metamorphosed sedimentary rocks, including sandstone, graywacke, shale, conglomerate, chert, greenstone, and serpentinite.

The Coast Range ophiolite is interspersed with the Franciscan Complex and represents a slab of oceanic upper mantle and crust that was restricted to the Sierran magmatic arc and Franciscan trench during the Middle to Late Jurassic (Farrar et al., 2006). The ophiolite consists of serpentinized peridotite, gabbro, and basalt (Farrar et al., 2006). While neither of these rock groups outcrop directly in the study area, Franciscan Complex sandstone and Coast Range serpentinite are mapped just southeast of the proposed site across Lake Sonoma (Figure 3-1).

The Late Jurassic to Cretaceous Great Valley Sequence overlies the Coast Range ophiolite as a thick layer of forarc-basin mudstone, sandstone, and conglomerate. The proposed Project site is located entirely within the Great Valley Sequence, and namely a group of rocks assigned to the Healdsburg Terrane (Blake et al., 2000) (Figure 3-1). These include an extensive conglomerate unit (map unit KJgvc) interfingering with a sandstone, siltstone, and shale unit (map unit KJgvs). Within the conglomerate unit, there are three types distinguished by the composition of their clasts: mixed-clast, volcanic-rich, and chert-rich (Seiders, 1988). The prominent conglomerate type at Lake Sonoma is the Early Cretaceous mixed-clast conglomerate, which consists of both chert and volcanic clasts (Seiders, 1988). The sandstone, siltstone, and shale unit is described as a dark-gray to black marine mudstone and shale predominantly, with occasional thin interbeds and thicker intervals of greenish-gray sandstone (Gutierrez et al., 2012).

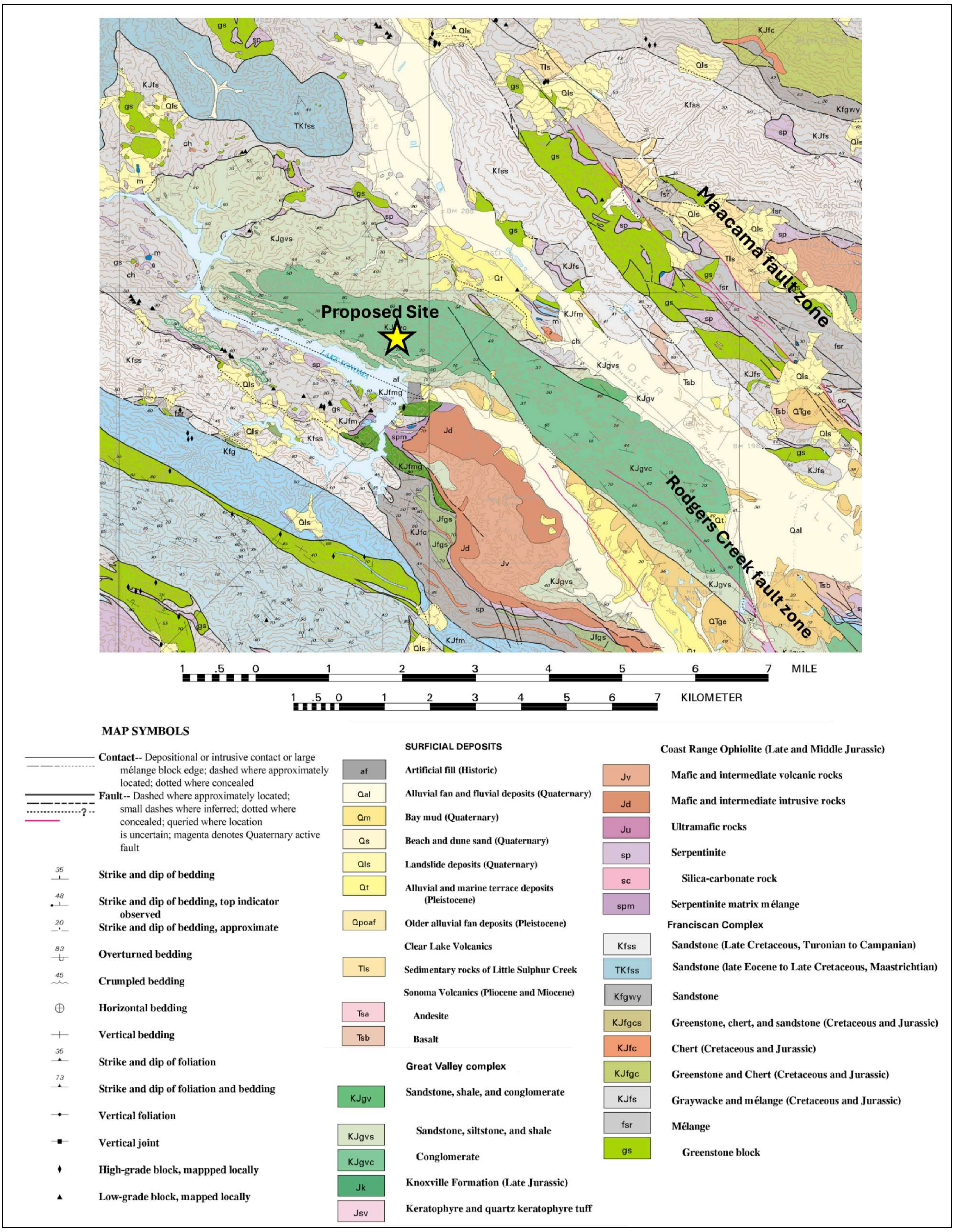


Figure 3-1. Project Area Geologic Map

3.2 Site Reconnaissance

On July 30, 2024, two HDR geologists conducted a one-day site reconnaissance accompanied by Nick Malasavage of the USACE and Dale Roberts of the Sonoma Water. The reconnaissance effort was focused on the proposed upper reservoir area as access was limited to the proposed powerhouse locations along the reservoir shoreline area (see Section 4.2).

The Healdsburg Terrane conglomerate was observed at four localities in the upper reservoir area (Figure 3-2). Generally, the conglomerate is moderately to intensely weathered and has hardness indices ranging from moderately soft to moderately hard. The conglomerate is clast supported consisting of well-rounded, approximately 3.5-inch average sized clasts in a sandstone matrix. The clasts themselves are a mix of basalt, granitic rock, and chert. There is mild to moderate surficial oxide staining, but little evidence of a deep chemical weathering profile. The unit is generally well indurated.

The degree of weathering, and consequently the hardness, of the conglomerate appear to vary depending on the orientation of the outcrop. North-facing exposures are observed to be more weathered than those facing south (see “A” in Figure 3-3) (Table 3-1). Conglomerate exposed in north-facing outcrops is moderately soft (hardness index of 5) and intensely to moderately weathered (weathering index of 6) (USBR, 2001). There is a prominent joint set that dips 60° to the east and discontinuities are irregular with sand and gravel infill. The surface of the conglomerate has a gray, weathered varnish that obscures and dulls the appearance of the clasts, with lichen covering about 40 percent of the exposed surface (see “A” in Figure 3-3).

Conglomerate exposed in south-facing outcrops is moderately hard (hardness index of 4) and moderately weathered (weathering index of 5) (USBR, 2001) (Table 3-1). There is some mild oxidation staining; however, the varnish development is weaker and clasts have more luster. Noticeably, there is less lichen growth on south-facing slopes, likely due to more direct sunlight throughout the day. A notable feature was observed (see “B” in Figure 3-3) along the access road that bisects the ridge top where a persistent, smooth joint plane characterized by sheared clasts is exposed. The surface does not exhibit any slickensides, but is evidence of shearing through the conglomerate after deposition and lithification. The feature is not interpreted to be an active or potentially active fault, but an older bedrock fault.

Some minor rock falls were observed in the upper reservoir area; otherwise, the material appears to weather and develop talus cones at the base of steep slopes (see “C” in Figure 3-3). A minor zone of alternation was observed (see “D” in Figure 3-3), likely related to fluid flow along discontinuities and possibly deformation of the conglomerate in the ancient past.

Table 3-1. Great Valley Sequence Conglomerate Characteristics

Weathering Index[1]	Hardness Index[1]	Estimated UCS* (MPa)	Location
6 - Intensely to Moderately Weathered	5 - Moderately Soft	5 - 24	North-Facing Outcrop
5 - Moderately Weathered	4 - Moderately Hard	24 - 50	South-Facing Outcrop

1. U.S. Bureau of Reclamation (2001)

***** Uniaxial compressive strength (UCS) values correlate to rock material hardness descriptions and are not directly measured (ASTM, 2002).

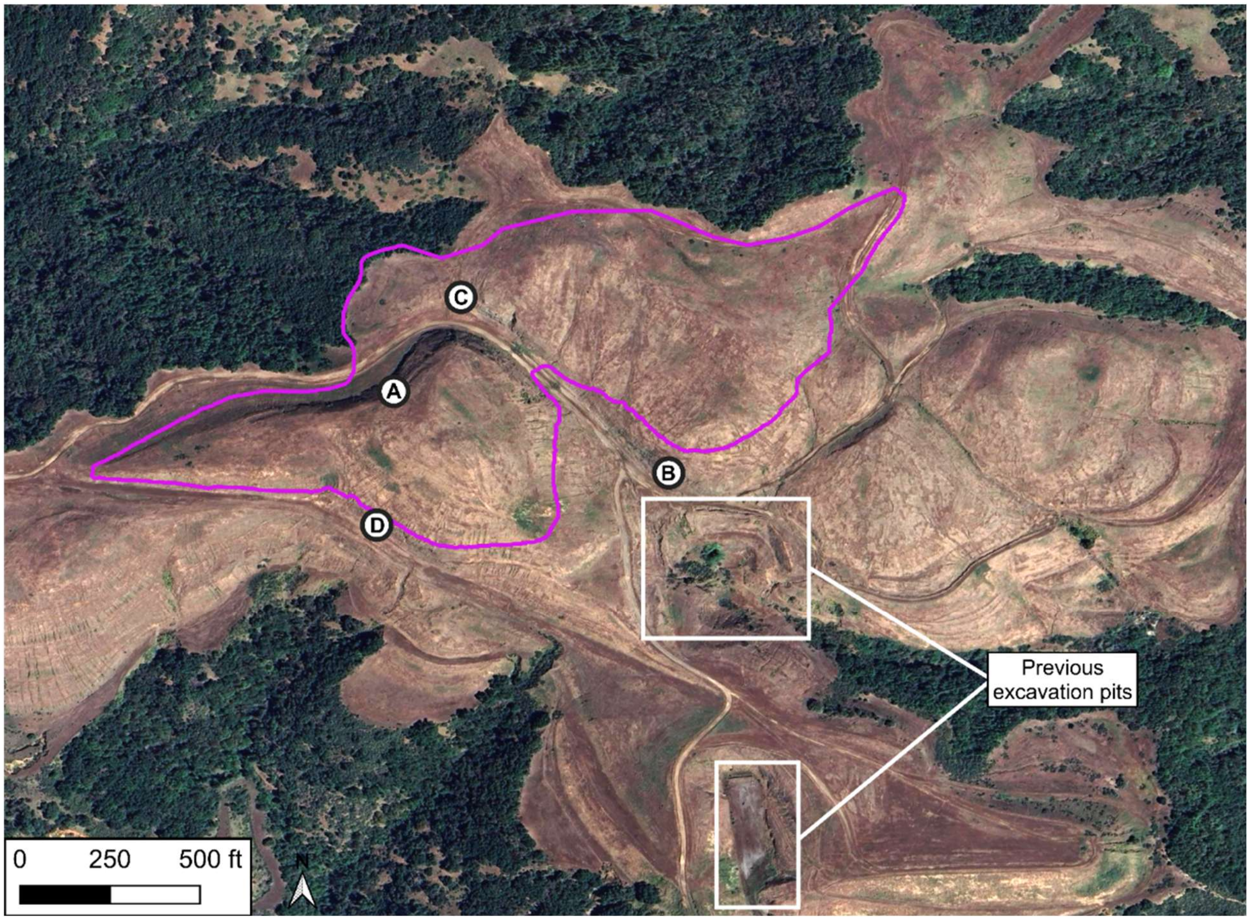


Figure 3-2. Locations of Select Site Reconnaissance Photographs

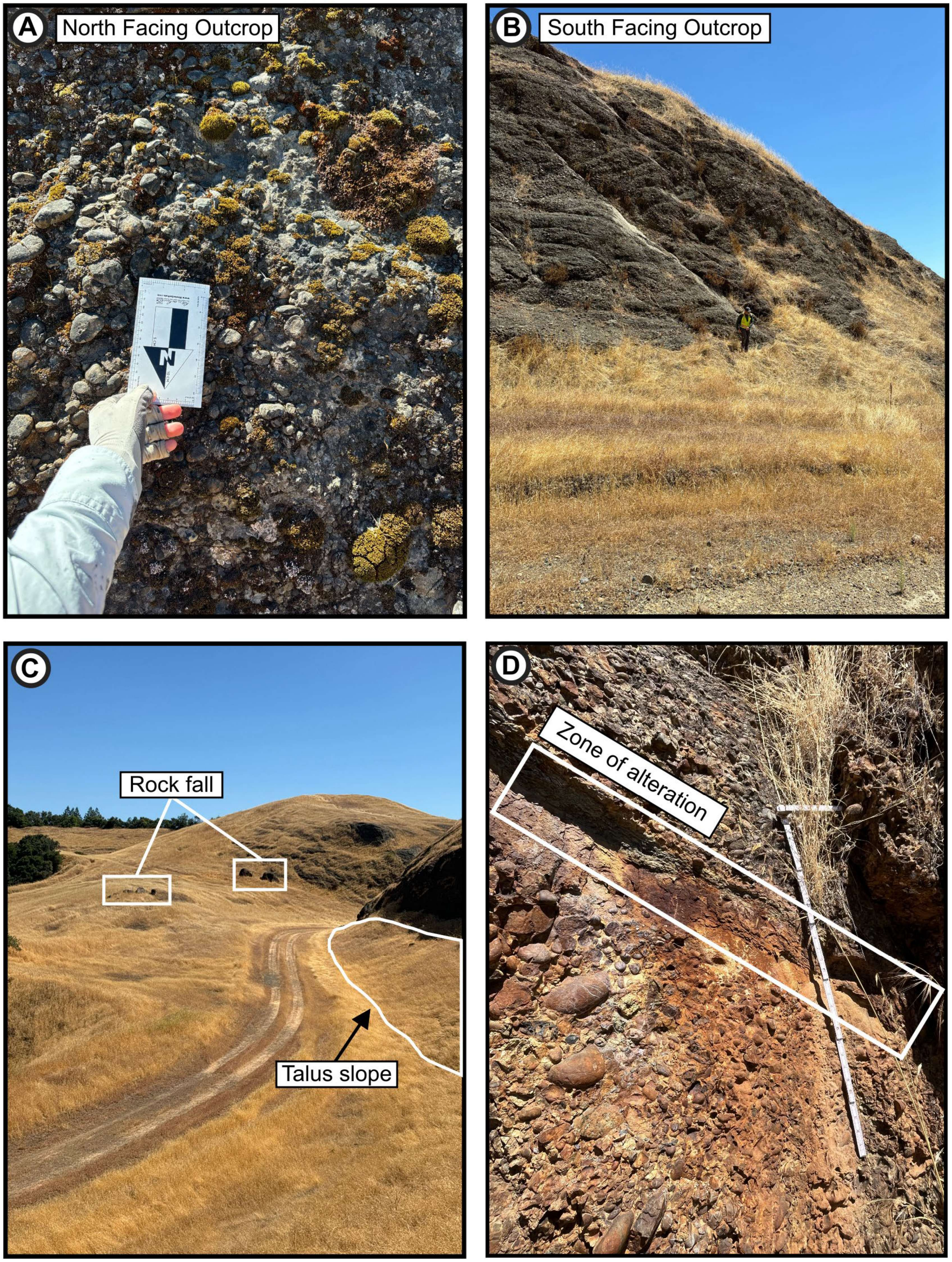


Figure 3-3. Reconnaissance Photographs of Upper Reservoir Area Materials

3.3 Potential Geologic Hazards

The following potential geologic hazards were evaluated at the Project site based on FERC (2021) and EPRI (1990) guidance. Potential geologic hazards include slide potential/slope instability; sinkholes, karst, or solutioning; weak or erodible materials; artesian sources; and seismicity.

- Minimal slope instability was observed at the upper reservoir area. Evidence of slope instability is present along an older access road. The topography between the upper reservoir and Lake Sonoma is steep and may be susceptible to slides.
- There are no limestone or soluble formations mapped in the Project area. No evidence of sinkholes, closed depressions, or disappearing streams was observed.
- The conglomerate materials are moderately soft to hard and moderately to intensely weathered. Presumably they are generally excavatable, suggesting some potential for erosion. Future studies should include evaluation of erosion potential for outflow or overflow structures.
- The Project site is considered to have moderate seismic risk. The closest Holocene-active fault is the right-lateral Rodgers Creek fault zone (Figure 3-1). Depending on the interpreted length of the fault, the site is located either approximately 2 miles southwest of the fault zone (Hecker and Loar, 2018), or about 5 miles west (Petersen et al., 2024). The Holocene-active Maacama fault zone is also located approximately 6 miles northeast of the site. Future studies should consider seismic ground motion for design of structures.
- The risk of liquefaction is considered to be low as the conglomerate is not anticipated to be susceptible to liquefaction. There is some potential for seismically induced landslides; however, Huffman et al. (1980) previously describe the site as “an area of relatively stable rock and soil unit, on slopes greater than 15%, containing a few landslides”.
- There are no active volcanoes in the region.

3.4 Evaluation of Geological Characteristics

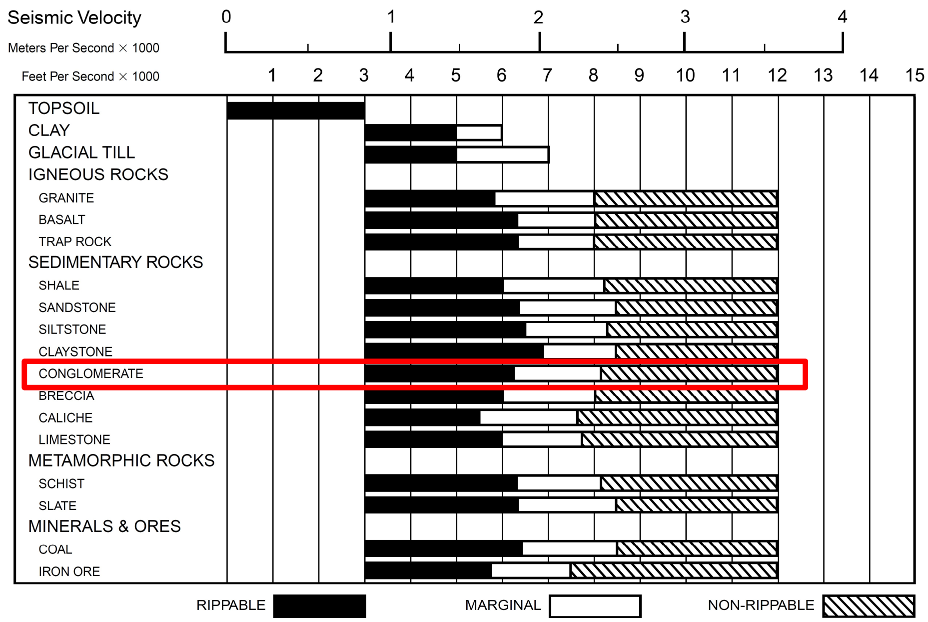
The evaluation of geologic characteristics and potential impacts to the proposed Project is based on published information, HDR’s conceptual layouts, and the geologic field reconnaissance conducted for this study. Detailed discussion of the potential geologic impacts to specific Project locations and facilities is presented in the following subsections. A summary of various geologic characteristics, their occurrence in the Project area, and their potential impacts to the Project design and construction is provided at the end of this section in Table 3-2.

3.4.1 Upper Reservoir Foundation

The upper reservoir area would need to be excavated and shaped to achieve its targeted storage capacity. The excavatability, or rippability, of rock depends on the geotechnical properties of the material, including rock type uniaxial strength, degree of weathering, and spacing of discontinuities. A rough guide for estimating rippability is tied to seismic velocities of the material in question. Figure 3-4 presents estimated rippability of conglomerate for both D8 and D9 rippers (Caterpillar Inc., 2022). Based on preliminary engineering judgment of the site materials, it is anticipated that the conglomerate would be possibly to marginally rippable with a D8 and very likely rippable with a D9. A seismic refraction survey of the upper reservoir area is recommended to better constrain in-situ conditions and rippability. Additionally, the use of scrapers may permit quicker excavation when coupled with a ripper. Scrapers alone are not well suited for the well-indurated conglomerate materials in the upper reservoir area (Caterpillar Inc, 2022) (see Figure 3-5) and would likely need to be ripped ahead of scraper loading and hauling.

D8R

- **Multi or Single Shank No. 8 Ripper**
- **Estimated by Seismic Wave Velocities**



D9R

- **Multi or Single Shank No. 9 Ripper**
- **Estimated by Seismic Wave Velocities**

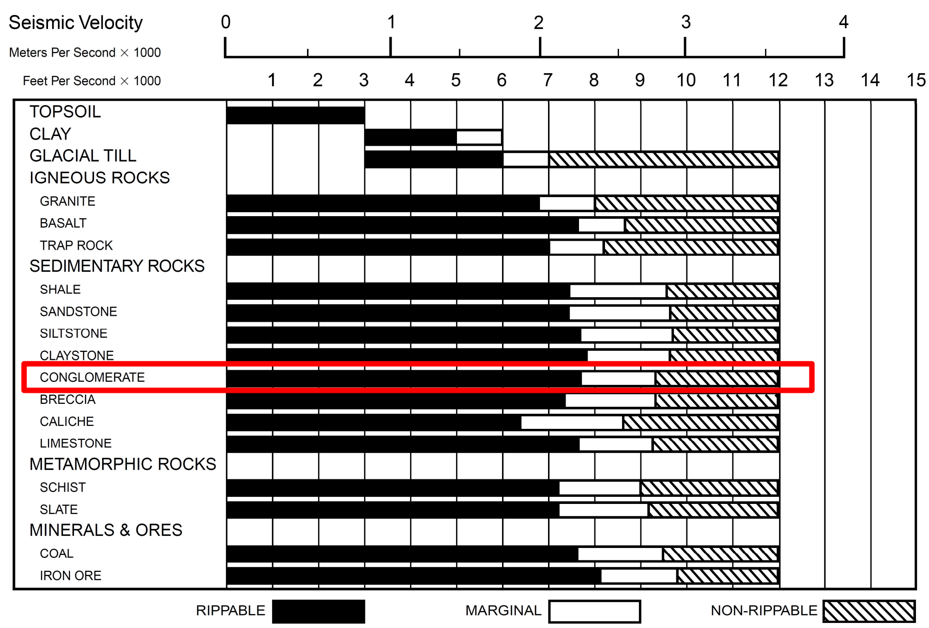


Figure 3-4. Rippability of Material Types based on Seismic Velocity - D8 vs D9

Material Application Guide	Elevator	Self-Load *Single and Tandem Engine*	Push-Load *Single and Tandem Engine*	Push Pull	Coal Bowl	Remarks
Decomposed Granite/Soil						Excellent loading
Decomposed Granite (Ripped)						Excellent loading by push- loading or push-pull to reduce cutting of tires
Moist Top Soil						Good to Excellent Loading
Top Soil						Excellent for WTS
Clay/Sand Mixture						Excellent for WTS
Sand						Good to Excellent loading, but some cases may need to be push loaded by a TTT or Push-Pull
Antigo						Excellent WTS material: lower portion may require ripping depending on material density
Coal						Excellent for WTS: ripping may be required in dense material
Limestone						In natural state, not suitable for WTS
Granite						Not suitable for WTS
Sandstone						For WTS to be productive in sandstone, material needs to be ripped. In some cases where density is high, WTS would not be a good fit
Shot Rock						Below 610 mm **(24")** good for WTS when push-loaded by a TTT to reduce cutting of tires
Loess Overtill (Banked)						Excellent for WTS: ripping may be required in dense material
Loess Overtill (Ripped)						Excellent WTS material provided rock size does not exceed 610 mm **(24")**
Aridisols						Excellent WTS material, ripping will decrease load times
Glacial Outwash/River Rock						Excellent WTS material provided rock size does not exceed 610 mm **(24")**

FOR MORE INFORMATION ON WHEEL TRACTOR-SCRAPER MATERIAL APPLICATIONS REFERENCE PUBLICATION AEXQ0442.

Figure 3-5. Material Application Guide for Wheel Tractor-Scrapers

The upper reservoir foundation design should consider the permeability of the conglomerate and was assumed to require a liner to manage seepage and infiltration. There is little information at hand regarding the permeability of the conglomerate. The unit is well-indurated, which may possibly limit permeability; however, the nature of the conglomeratic deposits is such that water pathways between clasts and the matrix may exist.

3.4.2 Powerhouse Area

The powerhouse is anticipated to be an above-ground structure situated along the shoreline of Lake Sonoma. Two potential locations under consideration are discussed below and shown on Figure 3-6.

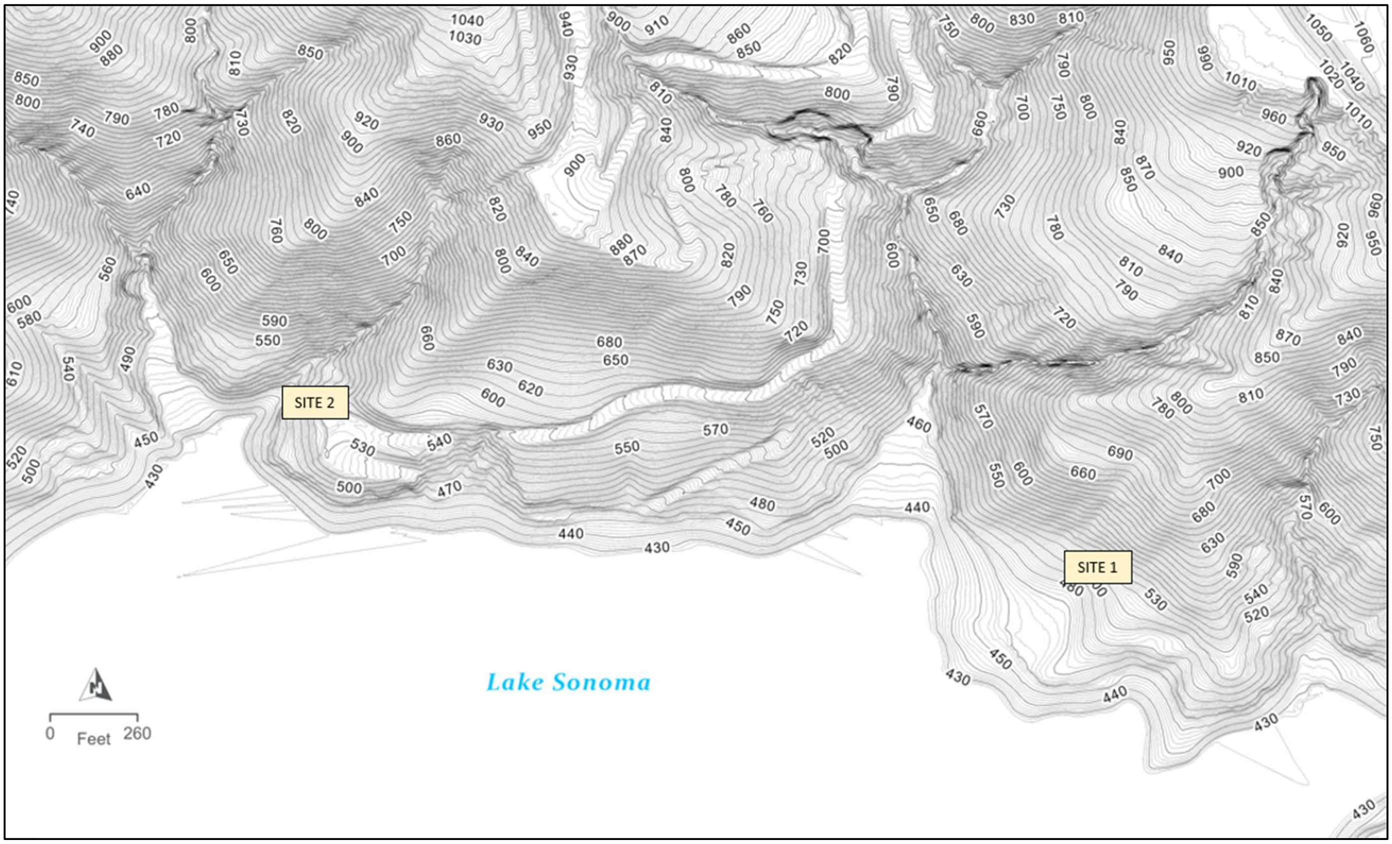


Figure 3-6. Alternative Powerhouse Sites

Site 1 is situated on what appears to be gently to moderately sloping beach rimmed by steep slopes. The geomorphology at this site suggests the possibility that the beach may be the head of a large, ancient landslide extending beneath the water line and the steep slopes behind it are the head scarp. Further investigations in this area are recommended to confirm the subsurface conditions and evaluate whether any new construction may negatively impact the stability of the feature.

Site 2 is located on a relatively flat area at a bend in an older site access road. This area appears generally stable; however, a slide immediately adjacent to the proposed location has occurred and damaged the older access road. Efforts to shore up this section would be needed to reuse the existing roadway for construction and site access.

3.4.3 Pump Wet Wells / Caissons

The pump wet well(s) or caisson(s) are anticipated to be excavated into the sandstone, siltstone, and shale unit of the Healdsburg terrane, which is comprised of primarily shale and mudstone with occasional sandstone beds. This unit was not observed during HDR's field reconnaissance; however, it is anticipated to be more readily excavatable when compared to the conglomerate in the upper reservoir area. Based on the published mapping, the bedding generally dips 30° to 50° with occasional instances of higher dip angles. Low to moderate dip angles are preferrable in vertical and subvertical installations as steeper bedding and discontinuity angles result in orientations parallel to excavation direction and can pose problems to excavation advancement and overall stability. Additional characterization of the materials in vicinity of the pump shafts is recommended.

3.4.4 Water Conveyance

Water conveyance between the upper reservoir and powerhouse is anticipated to be via a single penstock rather than a vertical shaft and underground tunnels. Consequently, the main consideration for this structure is slope stability. Several existing landslides were identified during the desktop assessment and field reconnaissance, suggesting the potential for slope instability. Penstock routing, foundation characterization, and appropriate footing design should be considered during subsequent phases of work.

3.4.5 Construction Aggregate and Embankment Materials

The proposed upper reservoir is anticipated to be constructed largely through the excavation and shaping of the existing ridge top. The excavation would yield a significant amount of conglomerate. The conglomerate is comprised primarily of clasts that are gravel-sized with minimal sand and fines content. The clasts are of varying lithology, but predominantly igneous material (i.e., granitic and volcanic) and chert. Both of these rock types are considerably strong and durable. Chert is composed of silica oxide (SiO_2) and future studies should explore if the aggregate poses issues for concrete mix due to alkali-silica reaction (ASR). The granitic and volcanic materials also contain silica, but to a lesser degree. The gravels could presumably be used for general fill or road base; however, the conglomerate would have to be processed to yield these materials. The gravels are likely too coarse for other fill materials. There is limited sand and fine content, and it is unlikely that a sufficient amount of such material can be produced from the conglomerate.

Table 3-2. Preliminary Summary of Geologic Site Characteristics and Potential Project Impacts

Geological Characteristics[1]	Relation to Project Areas	Potential Impacts on Constructability and Design
High seismic risk/active faulting within the Project Area	The Project area is considered to have moderate seismic risk.	Moderate impact. Engineering design would need to consider for critical structures.
Active volcanism	None.	No impact.
Active landslides/rock falls	There is evidence of localized slides and rockfall. Minimal rock fall was observed in the upper reservoir area. Some slides identified on steeper sections of existing access roads. Powerhouse sites may be impacted by slope instability.	Low to moderate impact. Penstock/conveyance structures would need to consider appropriate foundation design. Powerhouse areas would need to be assessed for stability.
Karst topography in reservoir area	No sink holes, closed depressions, disappearing streams were observed.	None.
Groundwater conditions in reservoir areas presenting controllable/uncontrollable leaking potential	Not known at this stage of the study.	To be further evaluated in subsequent phases.
Deep chemical weathering profile	Climate not conducive to deep chemical weathering. Observed site stratigraphy does not exhibit deep chemical weathering.	None.
Highly permeable rock	The conglomerate in the upper reservoir area is likely permeable, the degree to which is unclear at this stage of the study.	Low to moderate construction impact. Design impact on liner and dam seepage controls. Deep excavations may require dewatering systems.
Soluble rock material	None.	No impact.
Low strength, vibration-sensitive, friable, highly abrasive, slaking, or unlithified rock material	Conglomerate is generally well indurated. Shale unit to be further investigated for slaking potential.	No impact.
Highly faulted, folded, or fractured rock material	Localized areas of bedrock shears in the upper reservoir area.	No to low impact.
Thinly laminated, structurally deformed, fine-grained rock masses	Not observed in upper reservoir area. Powerhouse location may be within a more shale-like unit.	Low impact.
Stress-relieved reservoir rims	None.	None.
Soils conducive to liquefaction	Minimal soil cover in Project area. Any soil material underlying Project structures is anticipated to be removed.	No to low impact.
High in-situ stresses affecting underground excavation	High in-situ stresses may be present due to proximity to active tectonic structures.	Low impact. Large, deep underground excavation are not anticipated. Stresses may not be significant in shallower excavations.

4 Configuration

4.1 Desired Project Characteristics

A pumped storage hydropower project's configuration is developed based on the owner's desired capacity (MW) and duration (hours), which combined result in desired energy storage (MWh). Energy storage in MWh is then translated into acre-feet of active water storage that is required in both the upper and lower reservoirs. Active storage is dictated by water available in existing water bodies or, in the case of new impoundments, topography. Required unit ratings, conveyance discharge capacities and sizes, and key elevations can all be determined from these "boundary conditions." Given the size of Lake Sonoma, the capacity (in acre-feet or MWh) of the Project is dictated / limited by the upper reservoir.

Desired Project characteristics were discussed during a series of meetings between Sonoma Water, SCP, and HDR. Meetings were also held with PG&E regarding the capacity of PG&E's existing (or upgraded) transmission infrastructure to receive and provide power for the Project. Without first performing site-specific studies, PG&E was hesitant to provide salient information regarding this issue.

After several iterations, the following desired Project characteristics were established:

- Project capacity is set at 20 MW, which is the threshold between "large" and "small" generating facilities as defined by California Public Utility's Rule 21 (Cal PUC, 2023). Staying below this threshold reduces the risk (both schedule and cost) associated with obtaining an interconnection agreement with PG&E.
- Although the Project would be dispatched based on market conditions[3], for the purpose of this study, active storage is based on 14 hours of 20 MW generation (i.e., 280 MWh).
- Pumping input power is not to exceed 20 MW. The duration of a 280 MWh pumping cycle would vary depending on Lake Sonoma water level and a complete generating-pumping cycle would not necessarily be completed in 24 hours.
- With respect to pumped storage operations, the minimum operating level of Lake Sonoma is set to 410 feet [4].
- Based on the current understanding of upper reservoir area geology, HDR assumed that the entire upper reservoir would need to be lined to limit water losses via seepage.

[3] SCP prepared a preliminary energy market analysis for the Project that is discussed in Section 5.

[4] For the purposes of this study, HDR conservatively assumed that historic operations of Lake Sonoma would continue in the future (i.e., FIRO would not be implemented).

4.2 Upper Reservoir Siting

HDR performed an initial upper reservoir siting assessment regarding the upper reservoir location and configuration. Results are shown on Figure 4-1.

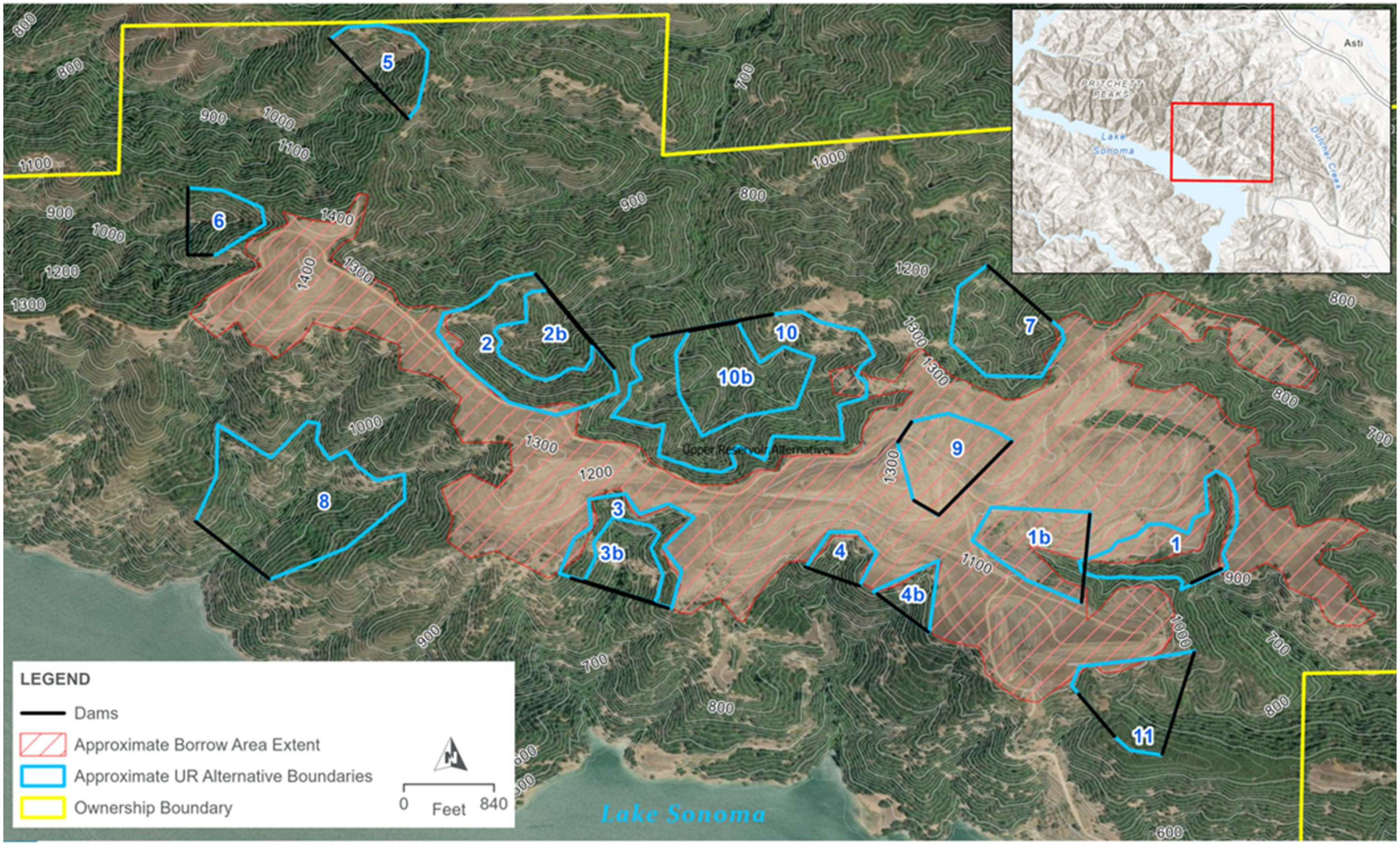


Figure 4-1. Initial Upper Reservoir Alternatives

The initial assessment was shared with Sonoma Water and the following additional project characteristics/constraints were established:

- To reduce the impact of the Project on existing land use and land cover, it was agreed that the upper reservoir would be fully contained within the area previously disturbed by material borrow operations for construction of the Warm Springs Dam.
- Ideally, the upper reservoir would be created through excavation of existing material, keeping the extent of any required dams to a minimum and minimal, if any, import or export of material to or from the site.

Incorporating the above constraints, the number of upper reservoir alternatives was then reduced. Additional considerations were also added including maximizing available head and reducing surface area to manage reservoir liner costs.

Figure 4-2 shows the narrowed field of prospective upper reservoir sites. An initial crest elevation of 1200 feet was selected since existing topography at this elevation would provide for natural confinement with no or limited low areas requiring the addition of dams. Assuming 5 feet of freeboard sets the maximum upper reservoir operating level at 1195 feet.

Earthwork would begin with removal of material above Elevation 1200 feet. From there, a 30-foot-wide flat bench was assumed (for access and stability) and from that point, excavation would advance at side slopes of 1 horizontal to 1 vertical (1H:1V) (similar to existing slopes).

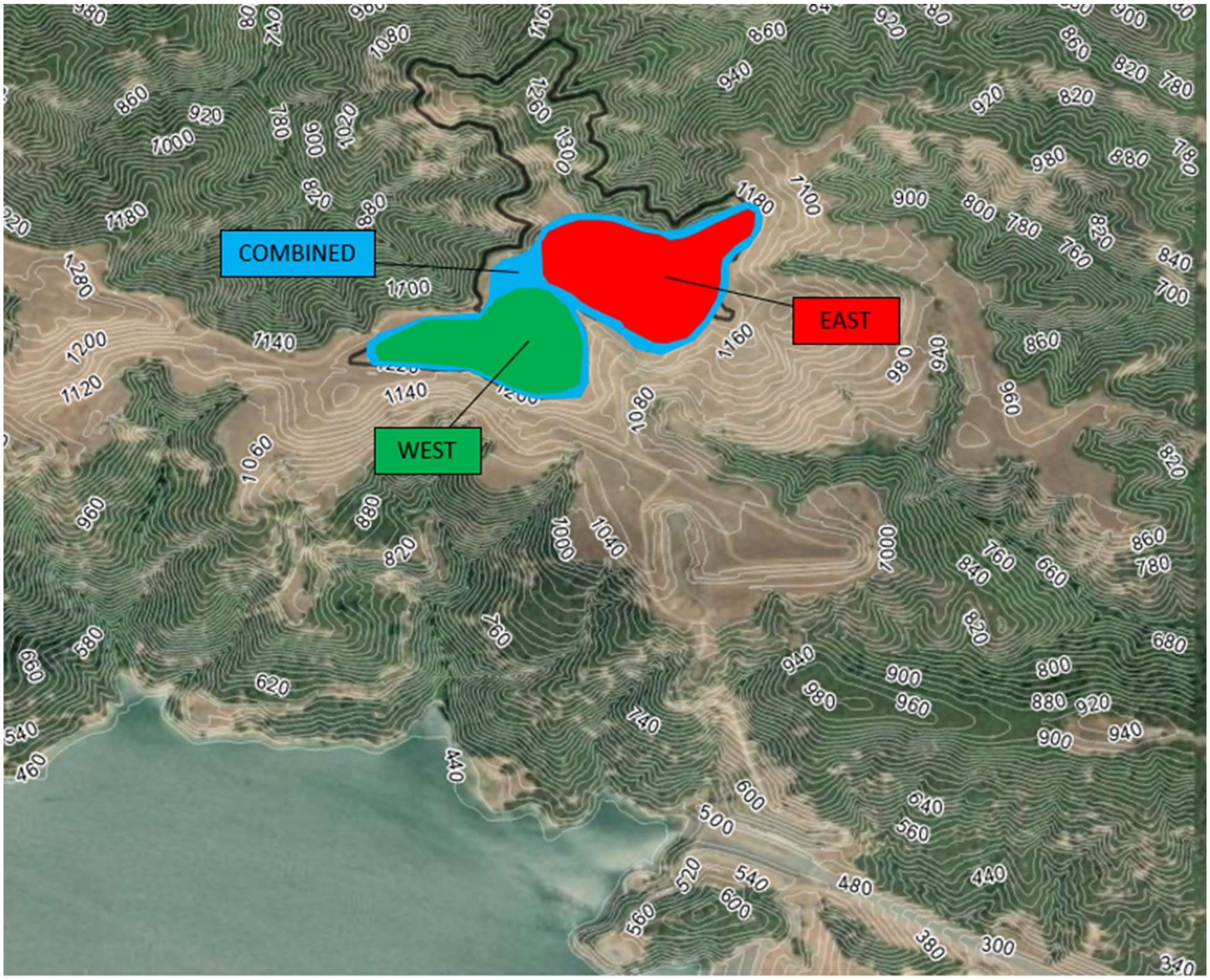


Figure 4-2. Refined Upper Reservoir Alternatives

Figure 4-3 presents the storage relationships of the three alternative upper reservoir sites with storage on the x-axis and excavation elevation on the y-axis. Additional key characteristics are shown below in Table 4-1. Observations are as follows:

- The Combined Alternative requires the least excavation depth (below 1200 feet) to achieve any given active storage, but requires the largest volume of overburden (above 1200 feet) initial excavation. Additionally, this alternative requires ground disturbance of approximately 31.1 acres. The Combined Alternative is therefore dismissed.
- The East Alternative requires less excavation depth (to achieve any given active storage) than the West Alternative, but requires 30 percent more overburden excavation. However, the East Alternative is more uniform in shape and thus more conducive to a) excavation by scrapers, and b) liner installation. Note the shape of the East Alternative was later refined into an oval to facilitate construction and the balance of this study is based on this refinement.

Based on the above, the East Alternative was selected to advance in this study.

Table 4-1. Alternative Upper Reservoir Characteristics

Parameter	Units	Value for Given Reservoir Alternative			
		Combined	West	East	East Refined
					13.0
					1.24

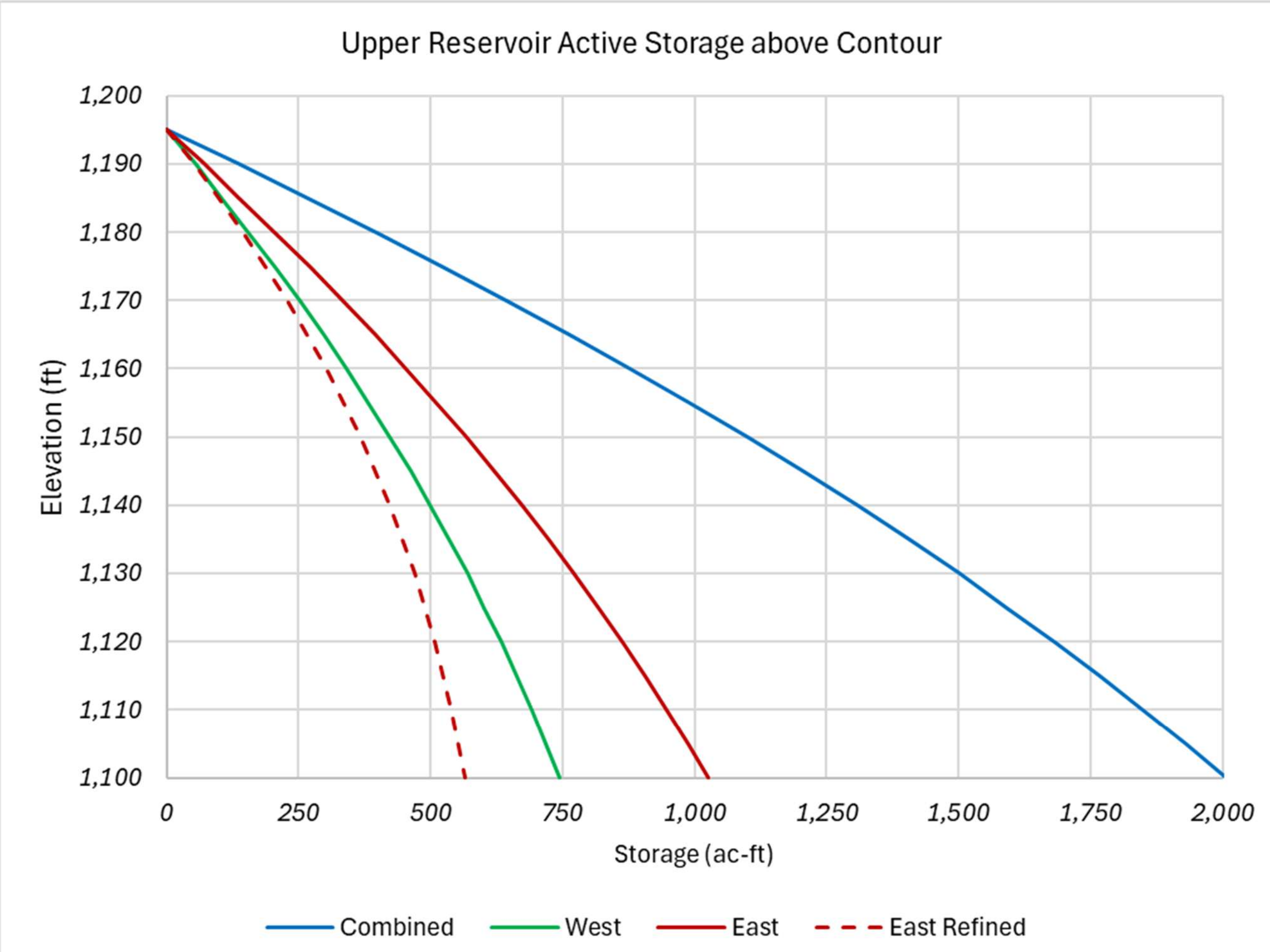


Figure 4-3. Preliminary Upper Reservoir Active Storage Curves

4.3 Preliminary Sizing Study

Based on the Project characteristics discussed in Section 4 and assuming the East upper reservoir alternative is selected, HDR performed a preliminary sizing study to establish additional key Project parameters. The first step was to determine the generating flow associated with maximum head conditions (i.e., upper reservoir level of 1195 feet). Assuming a Pelton turbine centerline elevation of 515 feet:

H_{gross} = 1195 feet – 515 feet = 680 feet

H_{net} = 657 feet (assumes 4.1 percent headloss)

P = 20 MW (limitation)

Q = 418.0 cfs (power equation with assumed combined efficiencies of 87 percent)

Then, various upper reservoir minimum operating levels were assumed to determine mean generating flow (i.e., [Q_{max} + Q_{min}] ÷ 2). Active storage was then determined by multiplying the mean generating flow by 14 hours. Results are shown in Table 4-2 and Figure 4-4. As shown, required active storage matches available active storage (444 acre-feet) at a minimum operating level of approximately 1119 feet. The maximum generating flow associated with this arrangement is approximately 471 cfs.

The pumping cycle time associated with an active storage of 511 acre-feet (ac-ft) (and Lake Sonoma levels between 410 feet and 451 feet) ranges from approximately 25.7 and 24.3 hours.

These results form the basis of the more detailed project configuration discussed in subsequent sections.

Table 4-2. Preliminary Sizing Results

Min U.R. Operating Level (ft)	Q_{gen} @ Min Operating Level (cfs)	Mean Q_{gen} [a] (cfs)	Required Active Storage (ac ft)	Available Active Storage (ac ft)
1190	417.9	416.3	481.7	51.5
1180	424.2	419.5	485.4	146.0
1170	430.6	422.7	489.1	229.9
1160	437.3	426.1	493.0	303.5
1150	444.2	429.5	497.0	367.6
1140	451.3	433.1	501.1	422.6
1130	458.7	436.7	505.3	469.2
1120	410.3	440.5	509.7	508.0
1110	474.1	444.4	514.2	539.5

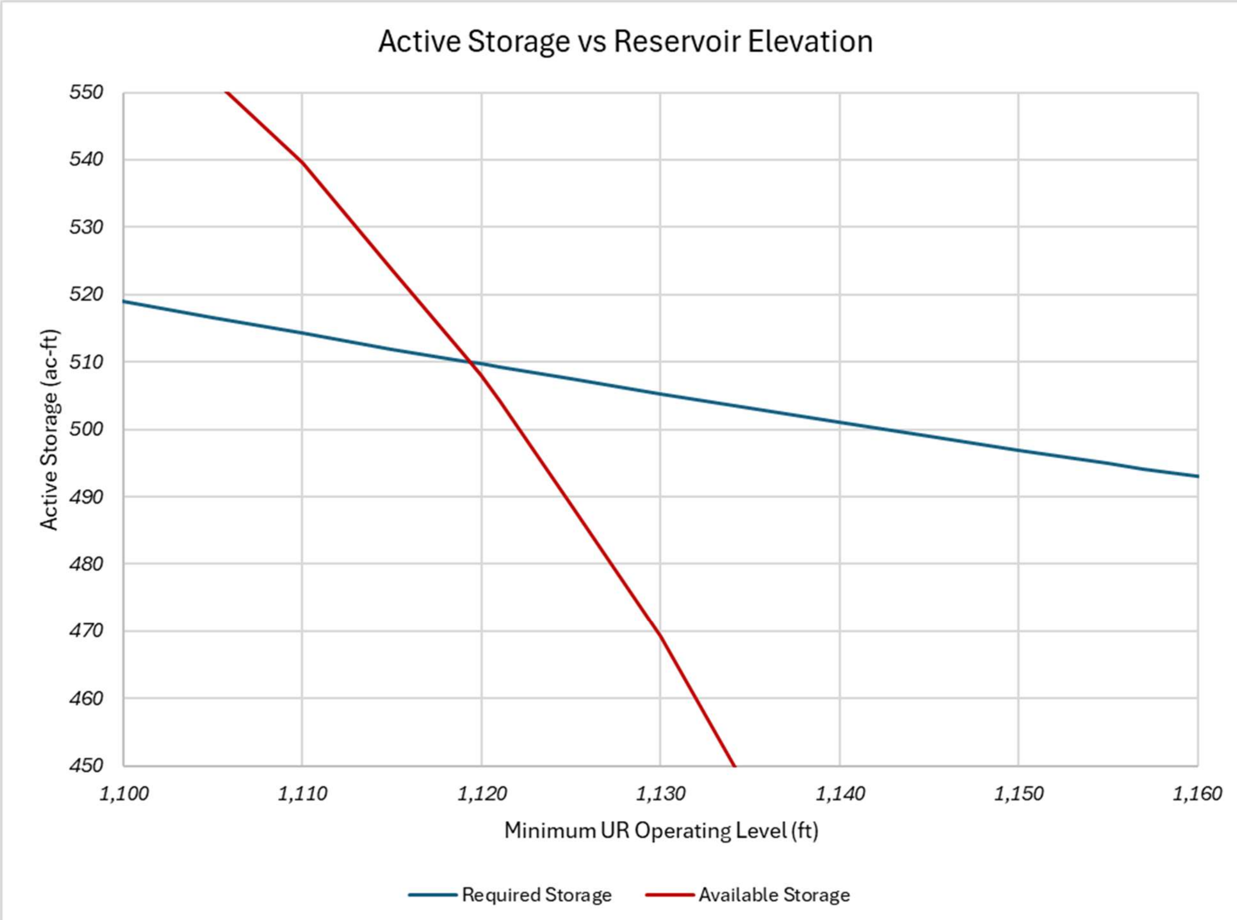


Figure 4-4. Required vs. Available Active Storage

4.4 Configuration Options

4.4.1 Underground Powerhouse

Larger (≥ 100 MW) pumped storage hydropower projects commonly feature reversible pump-turbines coupled with generator-motors. These pump-turbines usually feature Francis (reaction-type) runners that require submergence below minimum reservoir operating levels for proper operation. The elevation or setting of the pump-turbines is established based on their submergence requirement and the lowest operating level of the lower reservoir. Generating equipment and ancillary systems are typically contained within surface or underground powerhouses, the former requiring deep supported excavations and the latter, underground cavern construction. Both surface and underground powerhouses require tunnels for water conveyance. Underground (and some surface) powerhouses also require tunnels for general access. Figure 4-5 shows a schematic layout of an underground pumped storage hydropower project.

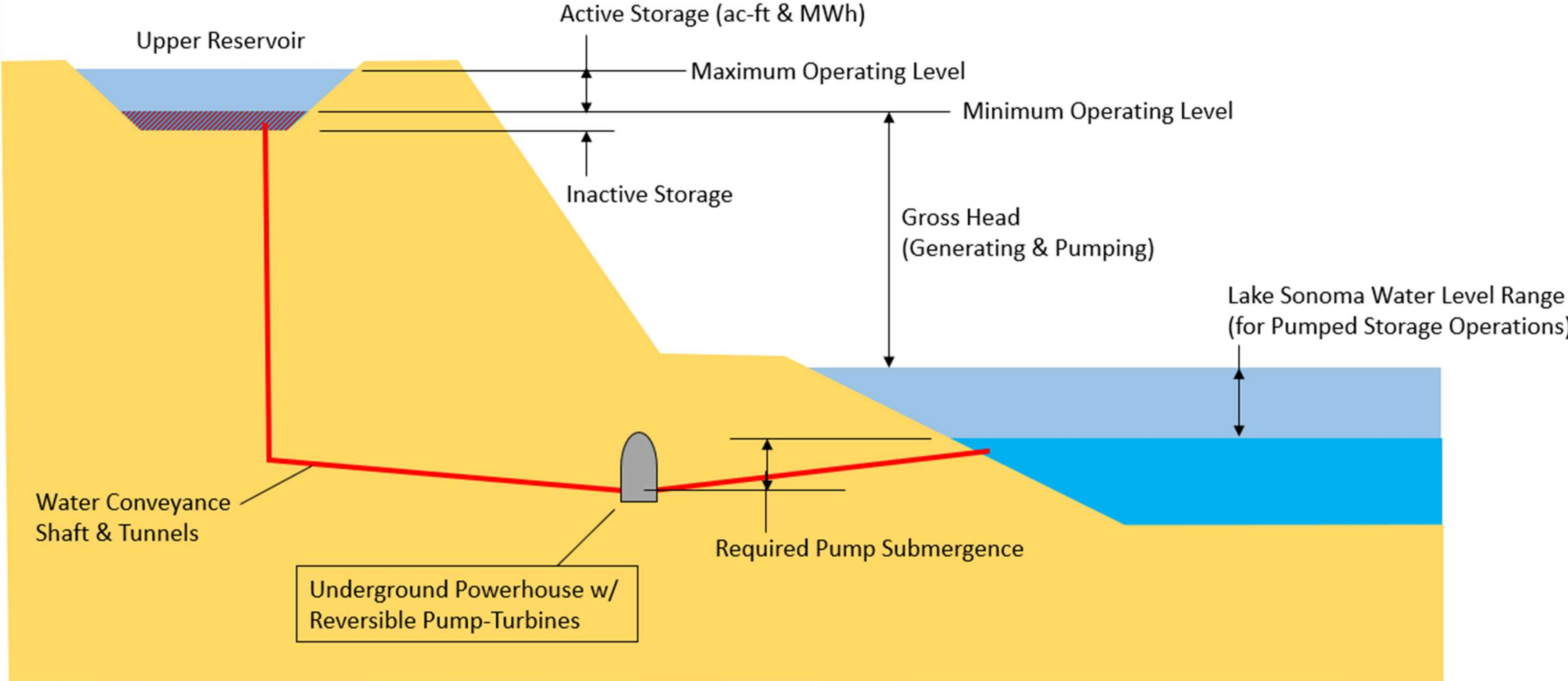


Figure 4-5. Underground Powerhouse Schematic

4.4.2 Surface Powerhouse

By observation, one can conclude that a 10 to 20 MW project cannot support the costs associated with significant underground works or excessive deep excavations. A surface-type powerhouse was therefore selected for advancement.

To eliminate the constraint of turbine submergence, Pelton (impulse-type) turbines were assumed. Pelton units operate at atmospheric pressure by converting water's momentum (mass and velocity) into mechanical power. The advantage of Pelton turbines for the Project is that the units (and ancillary equipment) can be set at the surface, above Lake Sonoma.

Pelton turbines are not reversible and therefore a separate pumping system is required. The Project requires relatively high pump flow rates and heads, which make equipment selection a challenge, but it appears that vertical turbine pumps (such as products available from Trillium Flow Technologies™) could serve this duty. The pumps would be contained within a circular wet well (i.e., reinforced concrete caisson) that is constructed adjacent to the powerhouse. The hydraulic connection between the pump shaft / wet well and Lake Sonoma would be provided by two tailrace micro-tunnels.

The surface powerhouse concept is illustrated in Figure 4-6.

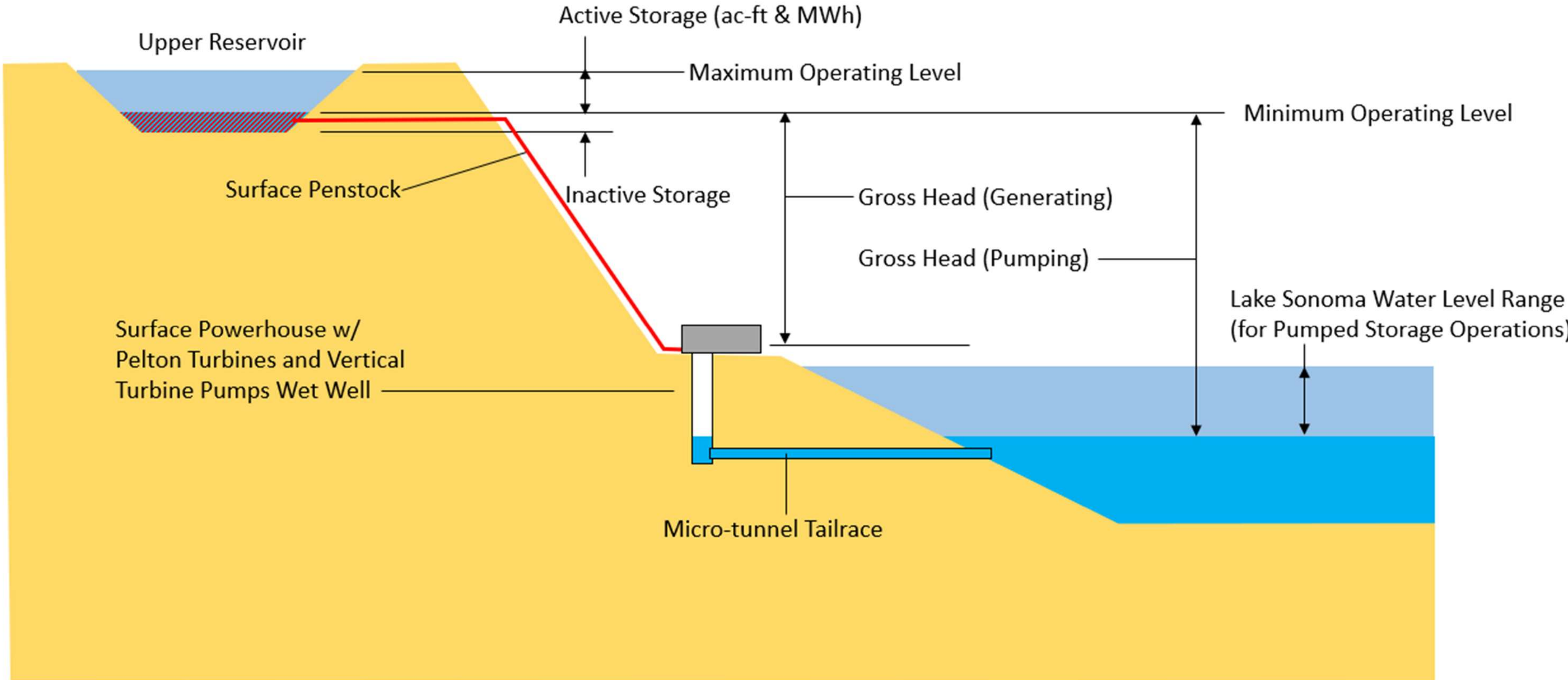


Figure 4-6. Surface Powerhouse Schematic

4.5 Powerhouse Arrangement

4.5.1 Location and Elevation

The location of the powerhouse (shown on Exhibit 1 in Appendix A) was selected based on existing terrain, its proximity to the upper reservoir, its proximity to existing roadways, and its ability to accommodate a reasonable penstock alignment. Elevations of Warm Springs Dam crest and emergency spillway are 519 feet and 495 feet, respectively. To provide a level of flood protection matching the dam crest, a powerhouse site elevation of 519 feet was selected. To create a relatively flat yard area, reinforced rock cuts are required on the high side of this area and retaining walls are required on the low side. Conceptual grading and earthwork requirements are shown on Exhibit 4 in Appendix A.

4.5.2 Turbines

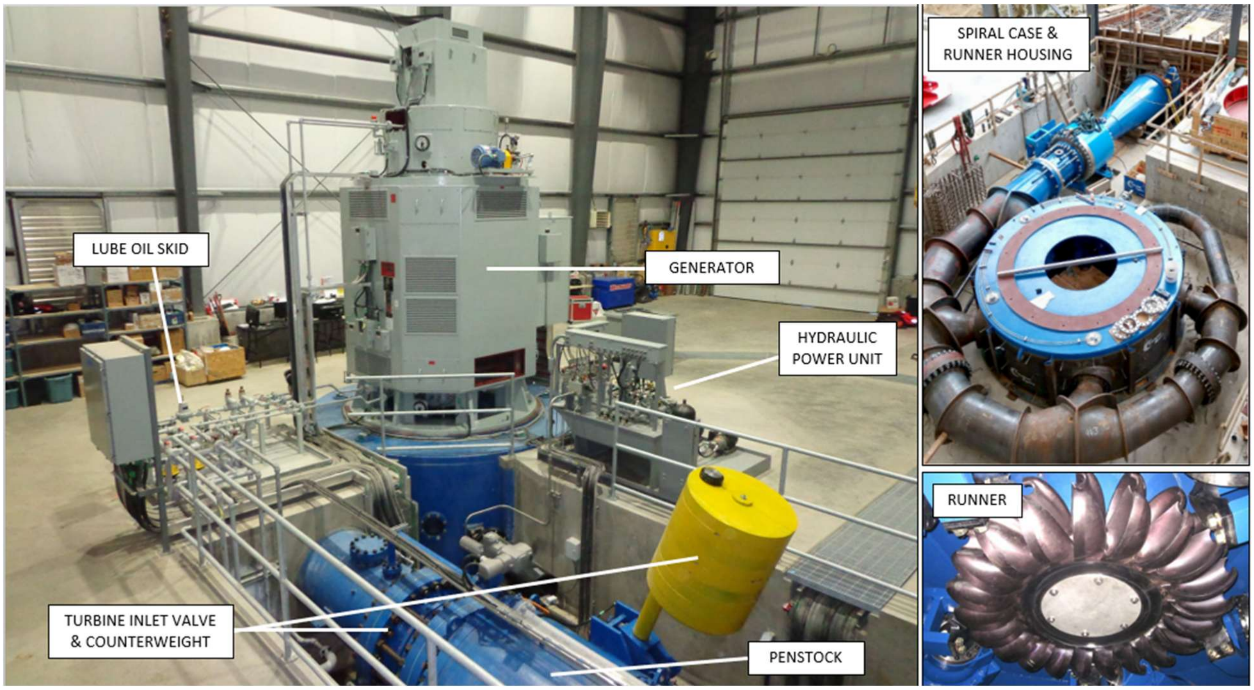
As discussed previously, Pelton-type turbines were selected based upon the head and flow conditions and operational flexibility. Considering the head and flow conditions dictated by the site and selected capacity, HDR assumed vertical Pelton units would be utilized. Based upon preliminary sizing and vendor recommendations, two 10 MW units were selected.

The procurement package for the turbines would likely include the following components:

- Turbine including runner, shaft, bearings, housing, and inlet valve
- Hydraulic power units (HPU)
- Generator including stator, rotor, bearings, and lube oil system
- Excitation system
- Local unit control systems
- Unit switchgear

HDR solicited preliminary information and budgetary costs from Canyon Hydro. Photographs of an example Canyon Hydro Pelton unit are shown on Figure 4-7. Appendix B1 includes preliminary layout and dimensional data for the proposed Project units.

Based on site topography, the centerline of the Pelton turbines was assumed at Elevation 515 feet.



Courtesy Canyon Hydro

Figure 4-7. Example Vertical Pelton Turbine

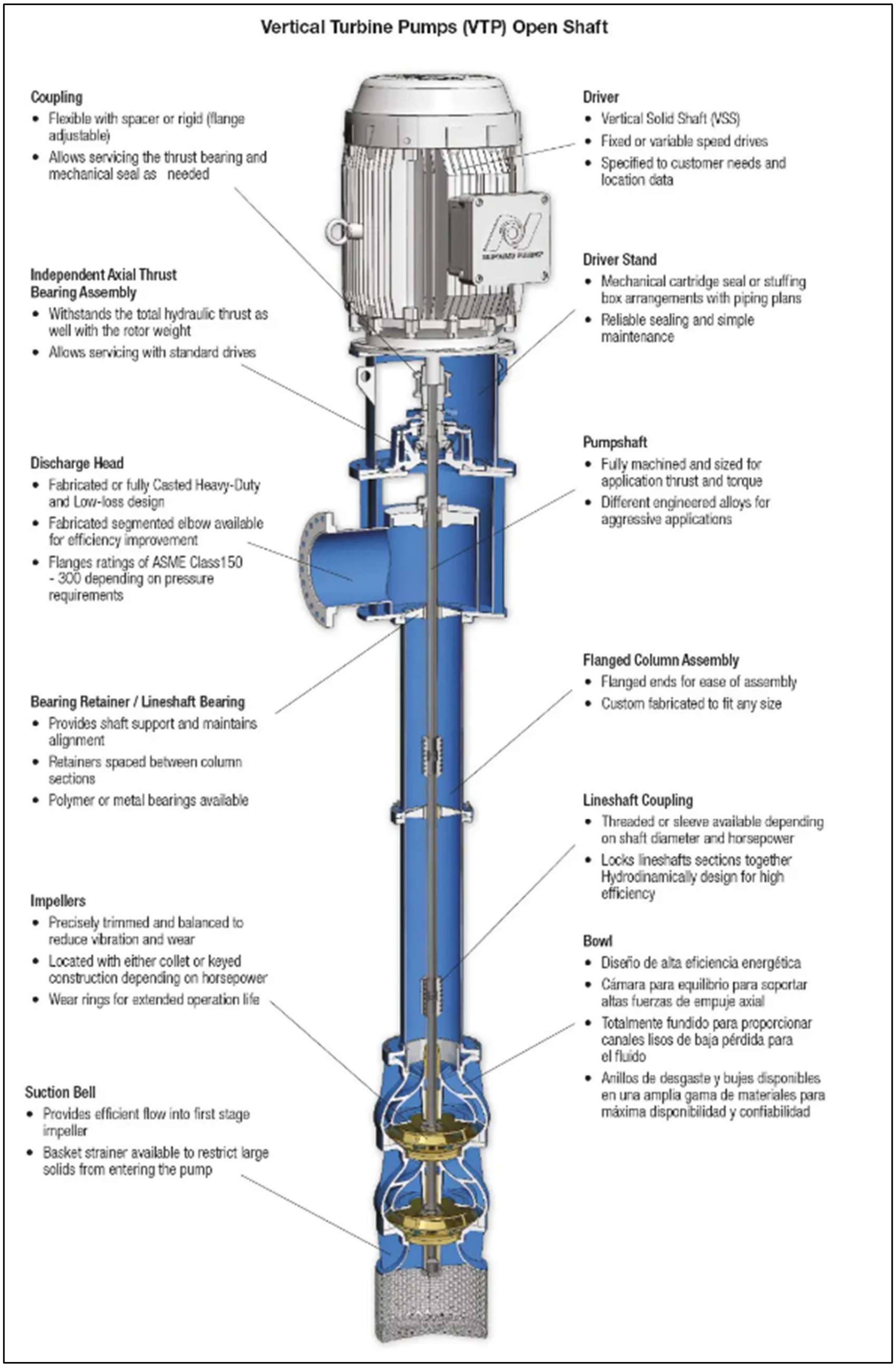
4.5.3 Pumps and Wet Well

The wet well arrangement is shown schematically on Figure 4-8. The vertical turbine pump column/shaft and impellers would be situated within the caisson with their suction bell set below the design low water level of the lake, including provisions for net positive suction head (NPSH) and inlet pipe headloss. Vertical turbine pump motors and controls would be set in a superstructure located on top of the caisson and above the design flood level.

The caisson itself would be approximately 40 feet in diameter and of reinforced concrete construction, likely installed as a sinking cut where excavation and concrete works are progressed downward in steps. It is anticipated that additional support would be required in the form of rock bolts or reinforced concrete ring beams. The former was assumed in the current cost opinion.

The top of the shaft would be at or above Elevation 519 feet. At approximate Elevation 394.5 feet, two 74-inch-diameter micro-tunnels would be driven out from the caisson to Lake Sonoma. An additional 4 feet of depth was added to account for sedimentation and pump floor clearance requirements. The floor elevation of the shaft is 400 feet.

Figure 4-8 and Figure 4-9 show example vertical turbine pumps and wet well/caisson, respectively. Appendix B2 includes dimensions and performance data (from Trillium Flow Technologies) for a prospective, site-specific pump.



Courtesy Neptuno Pumps®

Figure 4-8. Example Vertical Turbine Pump

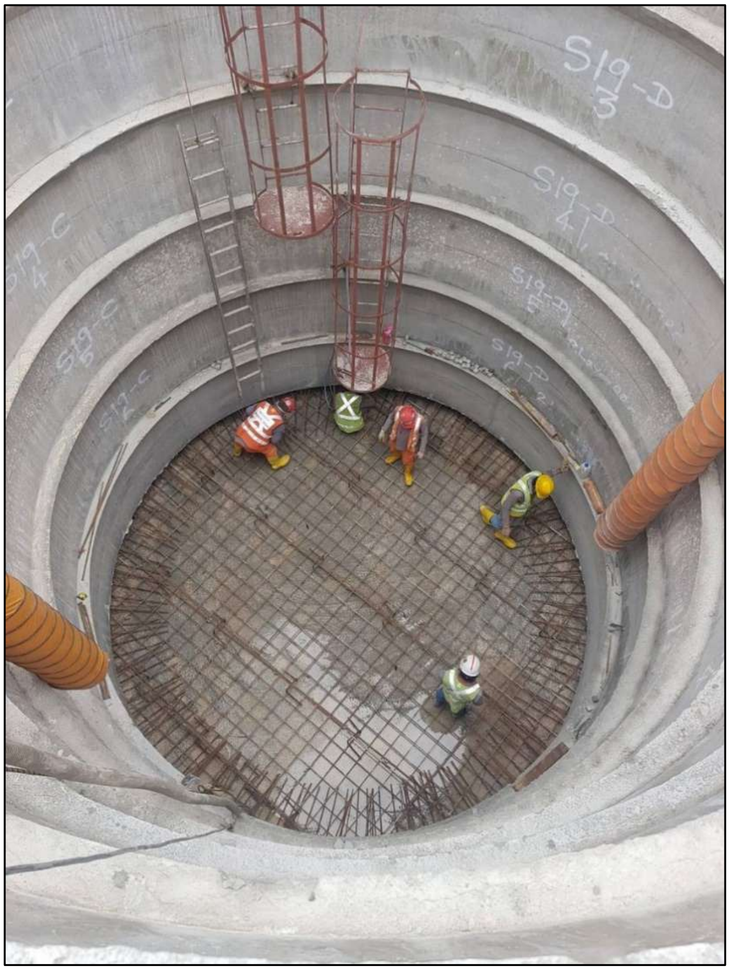


Figure 4-9. Example Sinking Shaft Construction

4.5.4 Balance of Plant Systems

4.5.4.1 Mechanical

Mechanical balance of plant systems would include the following.

- Governor System
- Lube Oil System
- Powerhouse Drainage System
- Service Water System
- Drinking Water System
- Station Compressed Air System
- Heating, Ventilation and Air Conditioning System (HVAC)
- Fire Detection and Suppression
- Overhead Crane

4.5.4.2 Powerhouse Electrical Concept

The plant would feature electrical equipment and systems at different voltages to meet plant electrical needs and provide an adequate level of reliability and safety. The main indoor medium voltage (MV) electrical switchgear would be connected to the outdoor generator step-up transformer via a 4,000-amp, 5-kilovolt (kV) Class, non-segregated, outdoor-rated enclosed bus. Major electrical equipment and systems in the powerhouse would be as follows:

- Three 5kV Class MV metal clad lineups with motor circuit breakers and Variable Frequency Drives (VFDs) to supply 4,160 volts (V) to the main pumps and circuit breakers for the generators, feed 480V station service substation, and excitation systems for the generators.
- 480V Station Service Switchgear
- 480V Motor Control Centers (MCCs) for various powerhouse auxiliary loads
- 20V/120V lighting center for lights and receptacles
- Static Excitation System
- Generator and Motor Circuit Breakers
- Variable Frequency Pump Drives
- AC Auxiliary Power System
- DC Auxiliary Power System
- Relays, Metering, and Controls
- Communication and Security

4.5.5 General Arrangement

Figure 4-10 illustrates the general arrangement of the power complex. The powerhouse would house the turbines, HPUs, and electrical/controls rooms. The pump wet well would be located adjacent to the powerhouse.

4.5.6 Superstructures

For the purposes of developing cost opinions, HDR assumed both the pumphouse and powerhouse superstructures would be pre-engineered structural steel / metal buildings. The pumphouse superstructure roof would be removeable or fitted with removeable hatches to allow for removal of the pump motors / columns with a mobile crane. The powerhouse pre-engineered metal building is anticipated to be 12,000 square feet (200 feet long x 60 feet wide) with a ceiling height of 24 feet. The pumphouse pre-engineered metal building is anticipated to be 6,400 square feet (80 feet long x 80 feet wide) with a ceiling height of 24 feet.

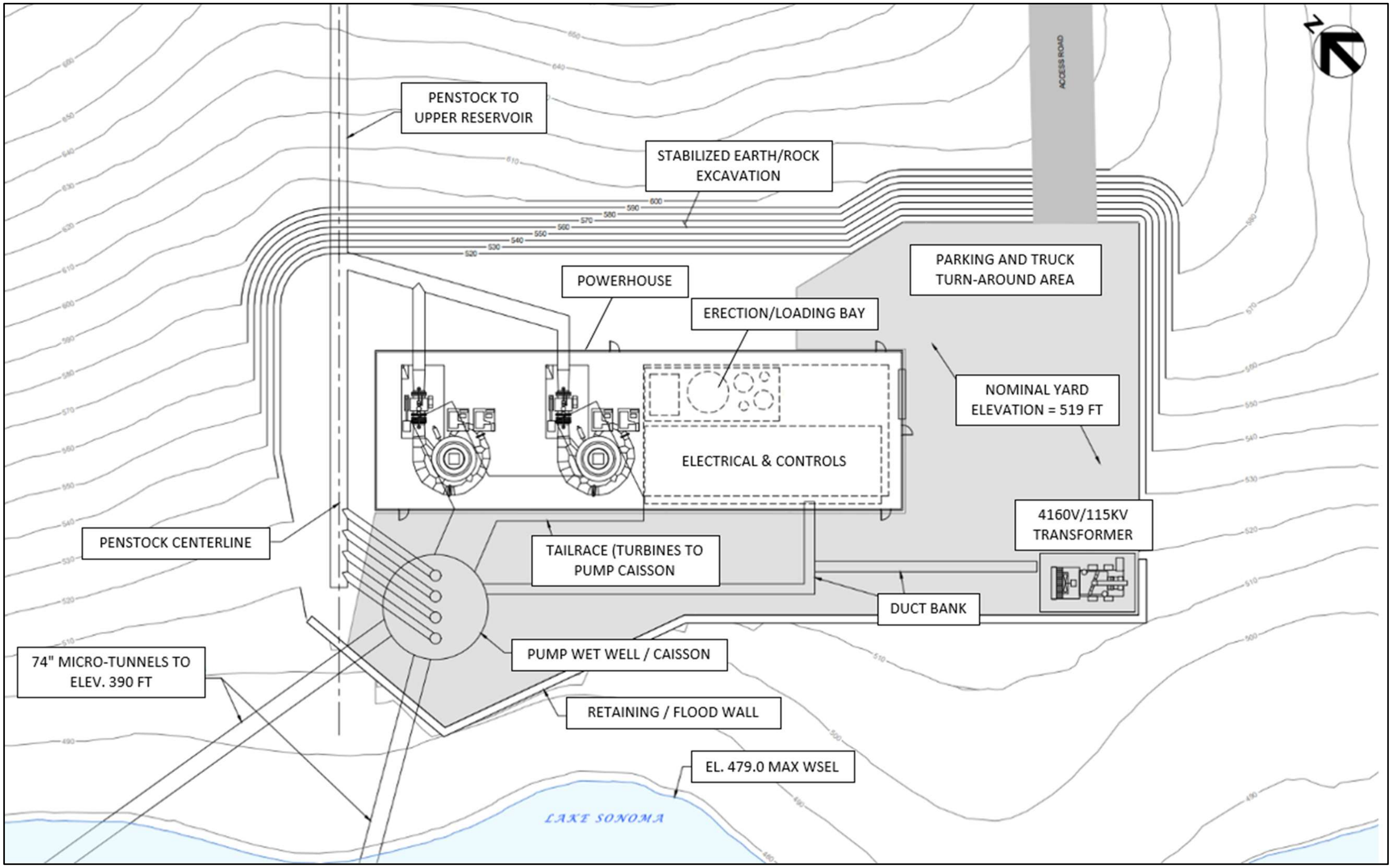


Figure 4-1010. Conceptual Power Complex Arrangement

4.6 Upper Reservoir Facilities

4.6.1 General

As described in Section 4.2, the upper reservoir would be created through excavation activities (i.e., first removing material down to Elevation 1200 feet to create a flat area, then continuing down at a 1H:1V slope to achieve the required active storage). Figure 4-11 presents a plan view of the reservoir, and the resulting stage-storage relationship is shown on Figure 4-12. Approximately 2.3 million cubic yards of earth material handling would be required to excavate and grade the upper reservoir.

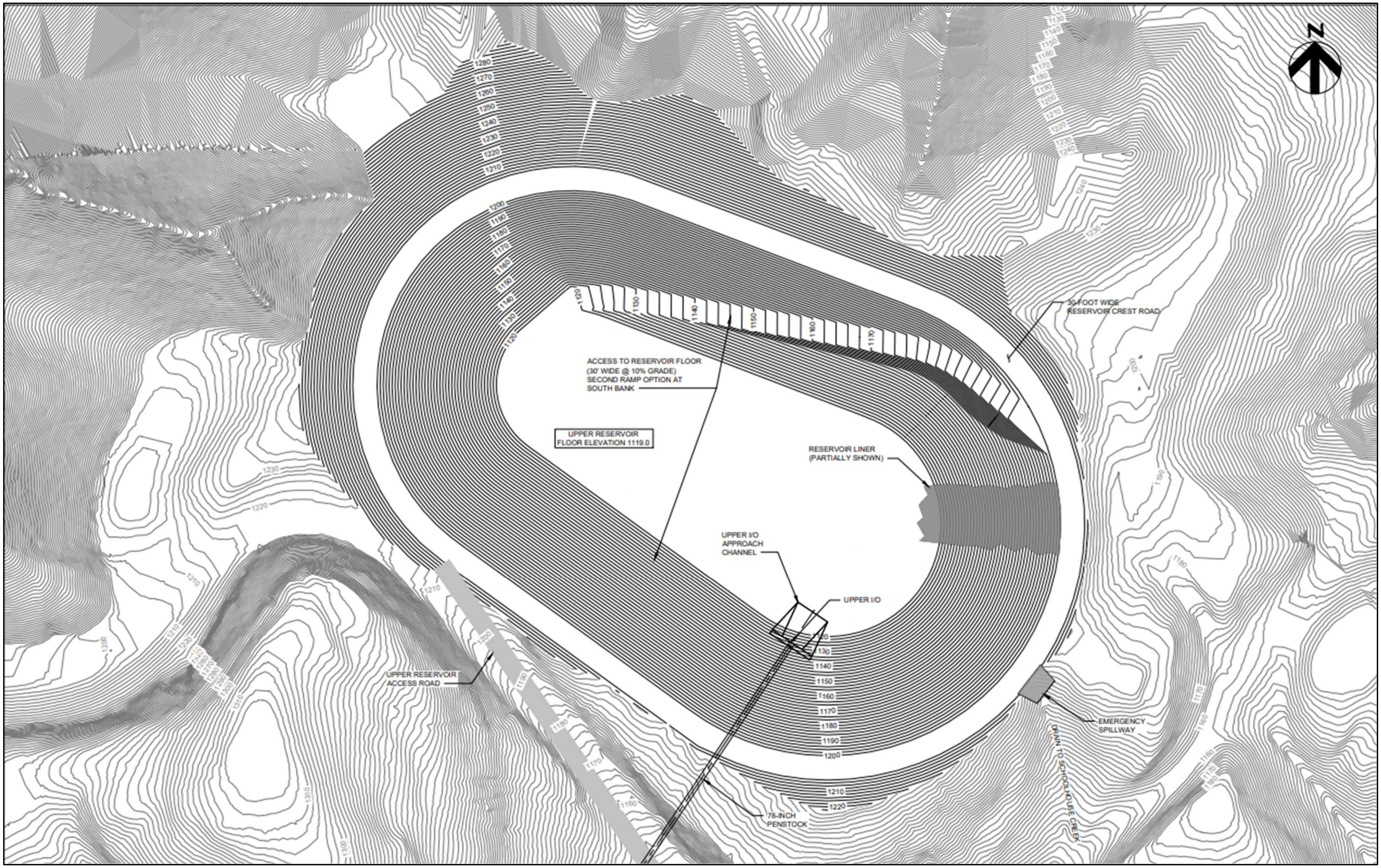


Figure 4-11. Conceptual Upper Reservoir Configuration

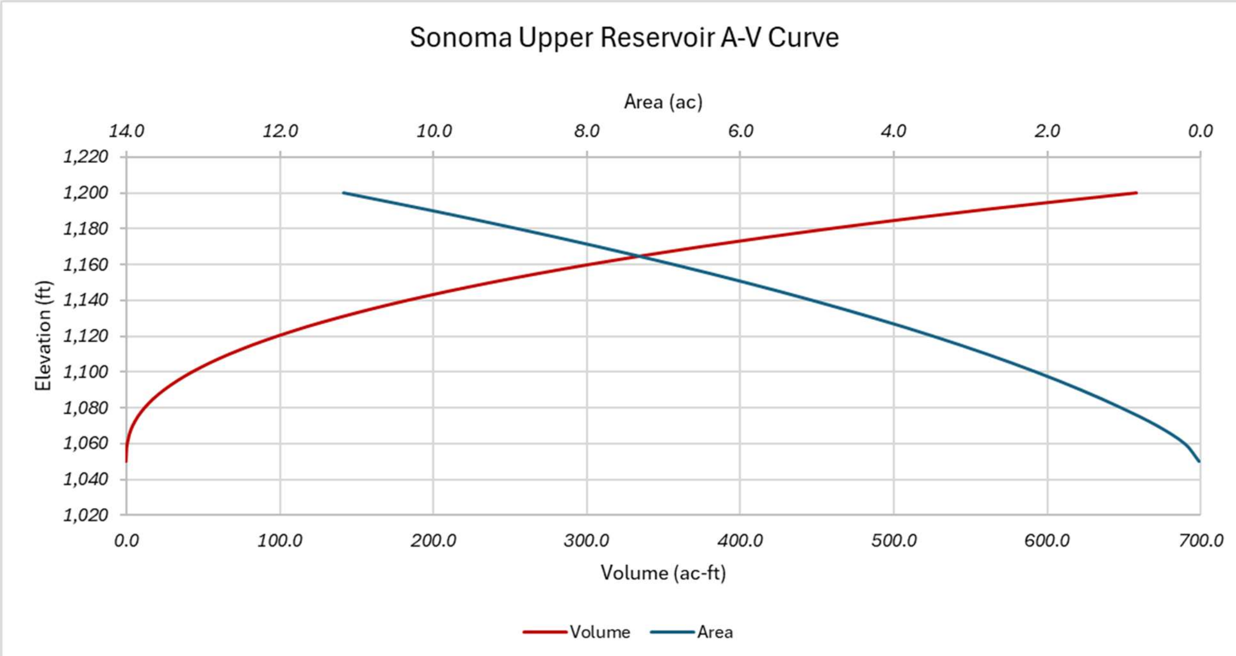


Figure 4-12. Upper Reservoir Stage-Storage

Although the upper reservoir would be created without the use of “conventional” dams, the interior cut slopes and outboard natural slopes may be scrutinized by the FERC and the California Department of Natural Resources, Division of Safety of Dams (DSOD). Future stages of design would include appropriate seepage, slope stability, and global stability analyses. Figure 4-13 is provided for information and shows DSOD (2025) jurisdiction based on dam size (height and storage).

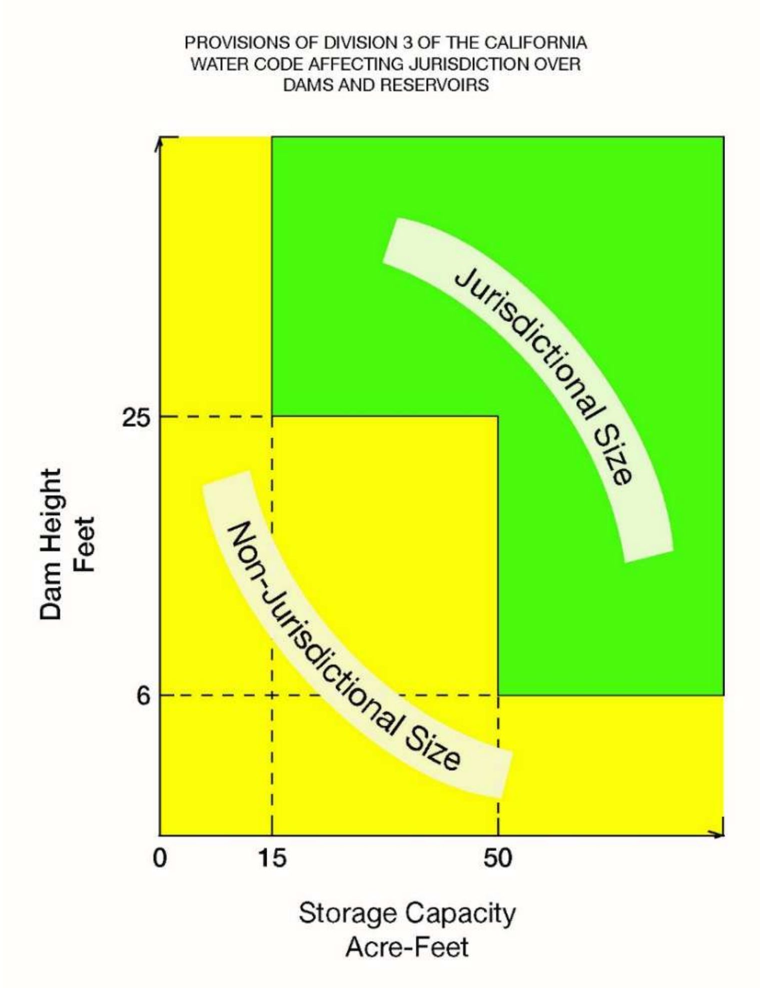


Figure 4-13. DSOD Dam Jurisdiction

Additional upper reservoir features illustrated on Figure 4-11 are described in the following subsections.

4.6.2 Upper Reservoir Liner

Multiple materials are commercially available that can be used for a liner system, each with respective benefits and drawbacks such as variability in characteristics or performance such as ultraviolet ray (UV) degradation rate, resistance to tearing or puncturing, pliability in cold weather, and overall estimated cost of the liner or liner system. The primary objective for this study was to select a representative liner system based on site characteristics and to support the construction cost opinion. Additional liner system types and materials should be evaluated and assessed as value engineering alternatives as the design advances and more site-specific information is obtained.

In a recent study, HDR met with and obtained budget estimates from both WALO (a bituminous concrete liner) and Carpi (geo-composite liner). Example liner systems from WALO and Carpi are presented in Figure 4-14.

Figure 4-14. Example Liner Systems: WALO Asphalt (Left) and Carpi Geomembrane (Right)

For purposes of this concept study, HDR assumed an exposed dense asphaltic concrete liner system would be selected. The asphaltic concrete liner system would be installed on the excavation side slope and reservoir floor.

The asphaltic concrete liner system consists of high-grade aggregates, sands, fillers, and bitumen. The liner system is created by layers of materials placed on top of a stable, well-compacted embankment or subgrade. The liner system's first layer is a dense asphaltic concrete layer, followed by a binder and bituminous drainage layer. Mastic sealant is then applied with a non-bituminous filter and drainage layer capped with a stabilizing and protection layer. The drainage layer has an approximate minimum thickness of 6 to 7 inches thick but may be thicker depending on the liner design and the need for multiple drainage layers to address moisture and gases produced during the construction process. Although the liner is deemed exposed, the system's mastic sealant provides for UV protection. The sealant would require replacement after approximately 25 years.

Specialized paving and compacting equipment (similar to roadway construction operations) places asphaltic materials using self-propelled equipment or equipment winched from the top slopes. Either an on-site asphalt plant or a regional commercial asphalt plant may be used to supply the asphalt and in either case, the liner contractor's quality control of the specialized mix design would be required.

A standard component of a liner system is a drainage system, which typically allows for groundwater, gases, and leakage from the liner system to escape and reduce the risk of buildup of water or air pressures beneath the liner, which can result in damage due to uplift. For purposes of this concept study, the drainage system was assumed to consist of gravel drains along the reservoir floor, a drainage layer beneath the dense asphaltic concrete liner system along the reservoir walls and upstream slope of the embankment dams, and perimeter drains around the reservoir floor that daylight through the embankment dams on the downstream side.

The upper reservoir plan presented in Figure 4-11 above yields approximately 60,300 square yards of surface area requiring a liner.

4.6.3 Upper Reservoir Discharge Facilities

4.6.3.1 Emergency Spillway

Two independent scenarios were evaluated to size the upper reservoir dam spillway: over-pumping from the lower reservoir and the PMP.

Over-Pumping from the Lower Reservoir

The Project would likely include robust instrumentation and controls systems coupled with required visual verification capability to protect against over-pumping into the upper reservoir from Lake Sonoma. Regardless, it would be prudent for (and the FERC may require that) provisions for emergency releases in case of over-pumping be incorporated in the design of the upper reservoir to avoid damage and potential failure of the reservoir.

The maximum pumping flow is estimated at 269 cfs. Preliminary computations indicate that this over-pumping flow could be accommodated by 77-foot-wide uncontrolled spillway with crest elevation of 1196 feet. The maximum water level during an over-pumping event would be approximately 1197 feet or 3 feet below the reservoir crest.

Probable Maximum Precipitation

According to NOAA (1978), the PMP for the Project area is approximately 42 inches (all-season for 24-hour and 10 square mile area). The contributing drainage area to the upper reservoir is approximately 11.7 acres. Conservatively assuming that 100% of this runoff enters the upper reservoir, the resulting volume from the event is approximately 41 ac-ft. The Project's 5 feet of freeboard equates to approximately 50 ac-ft of storage, therefore the PMP would be contained within the freeboard storage.

The over-pumping scenario controls and the assumed spillway configuration was adopted for the purposes of this study.

4.6.3.2 Upper Reservoir Low-Level Outlet

In its Engineering Report (ER) 1110-2-1156, the USACE (2014) states:

> *"It is the policy of the Chief of Engineers that all future lakes impounded by Civil Works projects be provided with low level discharge facilities to meet the criteria for drawdown. Low level discharge facilities, capable of essentially emptying the lake, provide flexibility in future project operation for unanticipated needs such as major repair of the structure, environmental controls or changes in reservoir regulation. The criteria will govern in the majority of impoundment projects. However, it may be impracticable to provide the drawdown capability to meet the criteria for certain projects because of their size (unusually small or large) or because of their unique function…As a minimum, low level discharge facilities will be sized to reduce the pool, within a period of four months, to … A pool level which will result in an amount of storage in the reservoir that is 10 percent of that at the beginning pool level."*

HDR estimates that a 3- to 4-inch-diameter outlet would be required to meet the 4-month criterion. For the purposes of this study, HDR assumed that the Project's upper reservoir would be exempt from a low-level outlet requirement (i.e., the upper reservoir could rely upon the penstock and other infrastructure to draw the upper reservoir down).

4.6.3.3 Instream Flow System

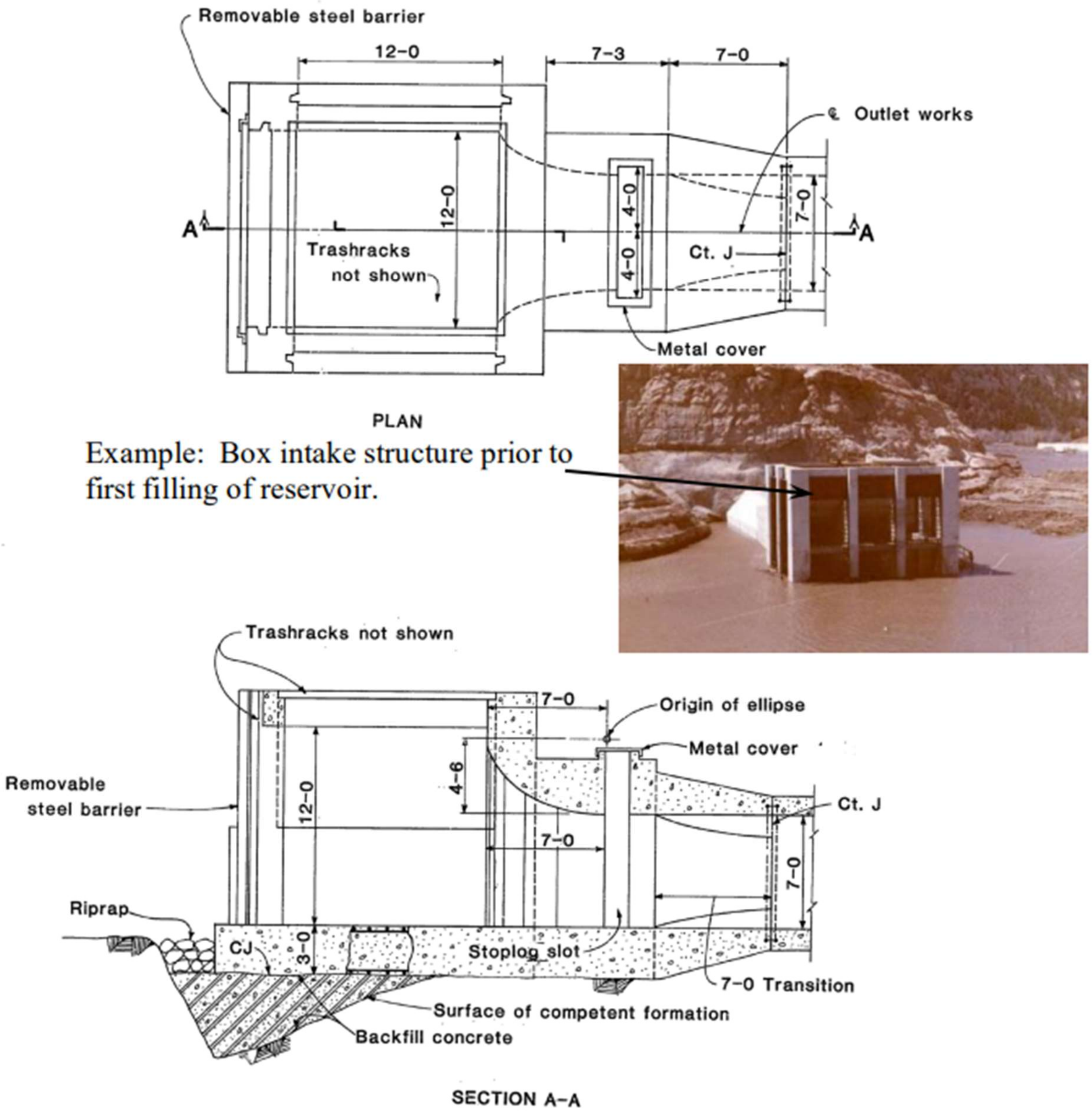
As discussed previously in Section 2.4.3, the minimum instream flow for the upper reservoir appears to be insignificant; therefore, no infrastructure is included for this purpose.

4.6.4 Upper Reservoir Inlet / Outlet Structure

4.6.4.1 Description

The upper reservoir inlet / outlet (I/O) structure was assumed to be a horizontal type. Although vertical bell mouth structures (also known as a “morning glory”) I/Os can be more hydraulically efficient and result in less required submergence (and thus reduce inactive storage), a horizontal arrangement was selected to improve constructability.

An example horizontal-type I/O is presented on Figure 4-15 (USBR 2022). Note that the dimensions shown on the figure do not apply to the Project.



Source: USBR (2022)

Figure 4-15. Example Horizontal-Type I/O Structure

It is anticipated that the upper reservoir perimeter would be provided with security fencing to reduce the risk of public access and animal intrusion. Given this along with the upper reservoir's relatively small contributing drainage area, it is not anticipated that trash/debris racks would be required for the I/O structure.

The need for isolation of the low-pressure segment of penstock varies from project to project. In this application it is anticipated that bulkhead slots would be provided with the I/O, but that bulkheads themselves are not procured until if and when needed.

4.6.4.2 Submergence

The upper reservoir and I/O would be arranged to provide adequate submergence (below minimum operation level) to reduce the potential of vortexes and air entrainment. For this study, required submergence was estimated using the relationship suggested by Gordon (1970) and illustrated on Figure 4-17.

$S = 0.4\ VD^{1/2}$ (horizontal intakes)

Where:

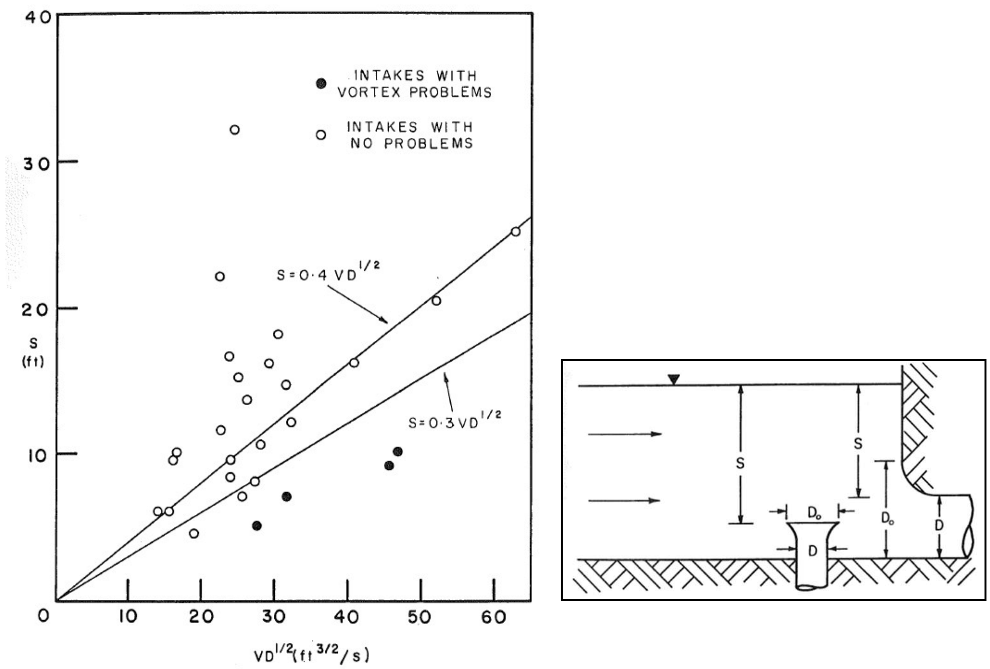
S = Submergence above horizontal intake conduit crown, feet

V = Water velocity, feet per second (fps)

D = Conduit diameter, feet

The resulting required submergence (based on flow at the end of a generating cycle) is approximately 11 feet. This translates to crown and invert elevations of approximately 1107.5 feet and 1101 feet, respectively.

It is anticipated that the required submergence would be achieved through a localized excavated "sump" and approach channel as opposed to lowering the grade of the entire upper reservoir floor.



Source: Gordon (1970)

Figure 4-16. Dimensional Plot Relating Submergence to $VD^{1/2}$

4.7 Penstock

4.7.1 Diameter

The most economical diameter of a penstock can be determined based on comparisons between the cost of materials and installation (larger diameter comes with more cost) versus benefit (larger diameter comes with less headloss and more energy revenue). Based on prior experience, HDR believes a maximum water velocity of approximately 10-15 fps is typical. At the maximum design flow of 472 cfs the selected diameter of 78 inches results in a water velocity of approximately 13 fps.

4.7.2 Material and Construction

Ultimately, the material and construction of the penstock would be established based on future engineering and economic evaluations. Commonly used pipe materials include steel, concrete, and fiberglass reinforced pipe (FRP). For the purposes of this report, welded steel was assumed.

As described in Section 4.6.4.1, the initial (approximate 1,500-feet-long) segment of penstock would be installed using open excavation techniques. The remaining length of penstock would consist of welded steel pipe mounted on reinforced concrete saddles and/or ring girder supports. Figure 4-17 shows an example surface penstock arrangement.

Figure 4-17. Example Surface Penstock Arrangement

The determination of penstock thickness can depend on several factors including but not limited to internal and external pressures, hydraulic transients, lifting and transportation loads, and bending loads (between reinforced concrete saddles and/or ring girder supports). For the purposes of this study, a 125-percent transient pressure was assumed. Preliminary analysis results in thicknesses ranging from 5/16 (0.31) inch in the low-pressure segment near the upper reservoir to 13/16 (0.81) inch in the high-pressure segment near the power complex.

Pending future soil and water corrosivity testing, HDR assumed that cathodic protection is required and would come in the form of sacrificial anodes or impressed current. A cost allowance for corrosion protection has been included in the OPCC. Cathodic protection Penstock coatings have also been included as part of the OPCC as an additional measure against internal and external corrosion.

4.7.3 Alignment and Profile

A preliminary penstock alignment was established based on cost (i.e., the shortest route between the upper reservoir and power complex and minimizing the number of bends/thrust blocks). The selected alignment is approximately 3,600 linear feet and is shown on Exhibit 1 and resulting profile on Exhibit 3 (see Appendix A).

HDR assumed that the initial approximate 2,000 feet of penstock would be underground and the balance (steep slope portion) would be above ground. Construction of the penstock along this relatively steep terrain could be installed using a cable crane system (as illustrated on Figure 4-19) but would require a straighter alignment.

Construction would require approximately 10 acres of tree clearing.

Figure 4-18. Example Cable Crane System

4.8 Tailrace

The hydraulic connection between the pump shaft / wet well and Lake Sonoma would be provided by two tailrace micro-tunnels. The tunnels would be sized to convey maximum pumping flows with reasonable headloss to manage the required pump setting and depth of pump shaft. Conveyance during the generating cycle is also a consideration but is less critical.

The Hazen-Williams equation was used to calculate the headloss in the tailrace. The Hazen-Williams equation is valid for water at room temperatures. It is not valid for extreme velocities. The Darcy-Weisbach equation is generally considered to be a more accurate solution for estimating headloss, however it is significantly more complex than the Hazen-Williams. The proposed project configuration and required accuracy for a feasibility study mean the Hazen-Williams equation is appropriate for this study.

$$h_{100ft} = 0.2083\left({}^{100}/_{c}\right)^{1.852}(448.8 * q)^{1.852}/d^{4.8655}$$

Where:

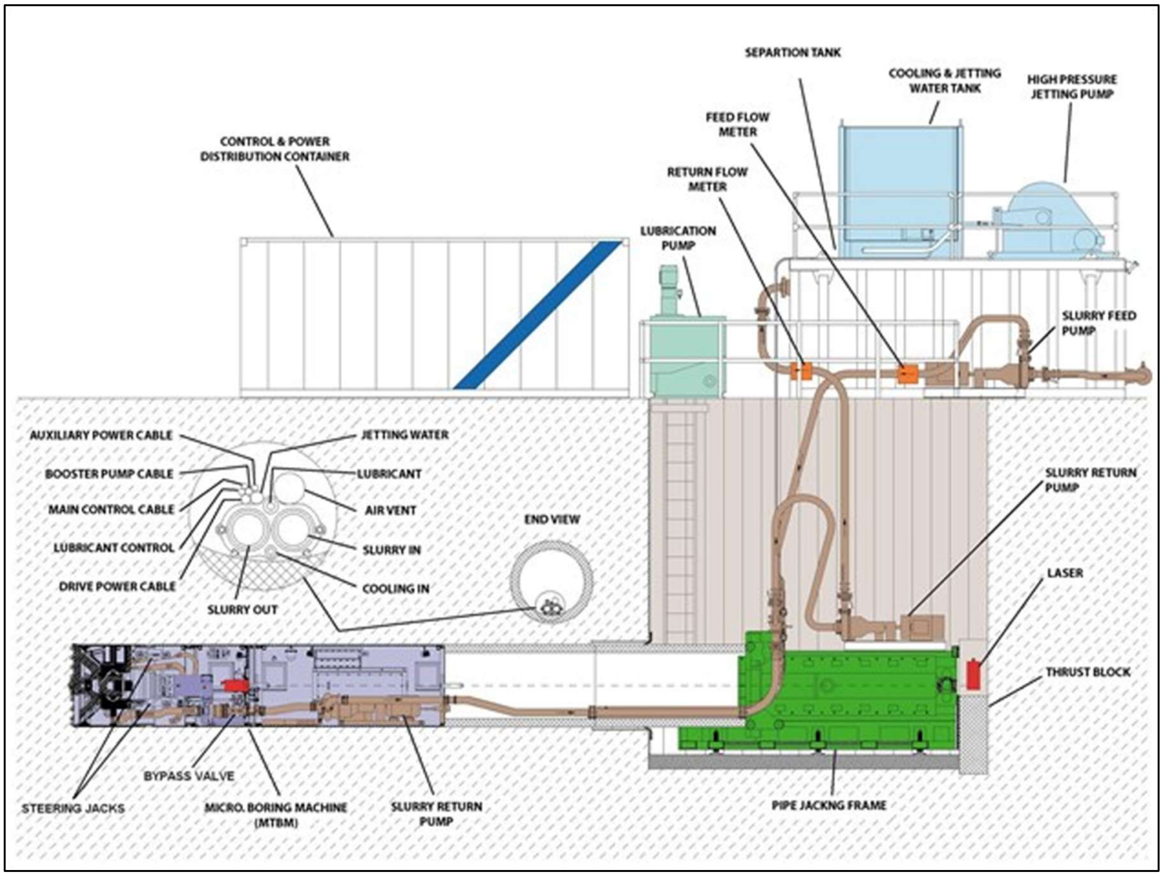
- h is the headloss per 100 ft of pipe (feet),
- c is the Hazen-Williams roughness constant (100 for steel pipe),
- q is the volume flow rate (cfs),
- d is the inside diameter of the pipe (inches).

Two 74-inch-diameter tailrace tunnels were selected and the resulting headloss per pipe is approximately 0.3 feet at the maximum pump flow of 269 cfs. The velocity at the maximum pumping flowrate is approximately 4.5 fps for a 74-inch diameter pipe[5]. The Hazen-Williams equation is appropriate for this velocity.

Figure 4-20 illustrates a typical micro-tunnelling operation setup. Major equipment includes a micro-tunnel boring machine (MTBM), hydraulic jacking system, slurry supply and treatment system, and pipe installation system. The basic sequence is to excavate rock using MTBM, remove the rock material using the slurry system, and install/connect permanent piping segments as rock is removed. In addition to facilitating material removal, the slurry system pressurizes the tunnel to reduce the risk of water intrusion and can be used to power the MTBM itself.

Two basic alternatives are available for the final penetration into Lake Sonoma. The more cost-effective alternative would be to continue the micro-tunneling operation to the lake. The other alternative would be to cease micro-tunnelling operations in advance of penetrating into the actual lake (i.e., leaving a natural rock plug). The rock plug would be removed using marine-based rock excavation techniques. Both of these alternatives may spur regulatory scrutiny. The Micro-tunneling penetration technique (that has been used with success in other projects) was assumed for purposes of developing cost opinions.

[5] The target maximum approach velocity to the vertical turbine pumps is 5.0 fps.



Courtesy Akkerman

Figure 4-19. Slurry Micro-Tunneling Setup

The approximate length of the tailrace tunnel was determined based on a topographic map (USGS 1944) that pre-dates construction of Warm Springs Dam / Lake Sonoma. The ground slope from the east powerhouse site toward southwest toward the lake is approximately 32 percent. Setting the tailrace tunnel at Elevation 390 feet therefore results in a tunnel length of approximately 365 feet.

Based on the published geologic mapping, it is theorized that the micro-tunnel could lie within the sandstone unit or near the sandstone / conglomerate contact. Future phases of design should include geotechnical investigations to better understand actual rock conditions and better inform the micro-tunnel design and cost.

4.9 Power Delivery

4.9.1 Generator Step-up Transformer

The incoming 115kV PG&E line would connect to a plant switch yard consisting of a high-voltage circuit breaker with safety disconnects and generator step-up transformer (GSU). It is anticipated that with the proposed powerhouse equipment the GSU would be rated approximately 22 megavolt-amperes (MVA).

The GSU would step the voltage down to 4,160V for use in the powerhouse. Alternative voltages can be discussed based on subsequent direction and goals of the project.

4.9.2 Transmission and Interconnection

SCP (2024) evaluated three options to interconnect the pumped storage hydropower project to the PG&E system. A summary of the three options is provided in Table 4-3. Option 2 was assumed for the purposes of developing the Project cost opinion, noting that Option 1 could be considered if Sonoma Water decides to proceed with a FERC exemption and pursue a 9.9 MW project.

Table 4-3. Transmission and Interconnection Options

Item	Results for Given Option		
	Option 1 – 12 kV Feeder to Geyserville Substation	Option 2 – 115 kV Interconnection to Cloverdale 115 kV Substation	Option 3 – 60 kV Interconnection to New Switching Station
Interconnection Voltage	12 kV	115 kV	60 kV
Maximum Capacity	12 MW	100 MW	50 MW
Gen Tie Length	6.5 miles	9 miles	6.5 miles
Gen Tie Capital Cost	$5.4 million	$19.1 million	$13.8 million
Substation Work Capital Cost	$1.5 million	$2.1 million	$27.0 million
Total Capital Cost	$7.0 million	$21.2 million	$40.8 million
	$580,000 / MW	$212,000 / MW	$826,000 / MW
Cost of Ownership (Monthly)	$60,000	$183,000	$351,000
Cost of Ownership (Lump Sum)	10,264,000	31,315,000	60,155,000

4.10 Civil / Site Work

4.10.1 Access

4.10.1.1 Existing Access

The site can be accessed from USACE's Visitor Center off Skaggs Springs Road in Geyerville, California. Once on site, a road crosses the emergency spillway and continues generally north (approximately 3,300 feet) to the Warm Springs Dam borrow area. This ”Borrow Area Road” has an average grade of approximately 19 percent and is in fair to poor condition.

Existing Project access roads are illustrated on Figure 4-20.

4.10.1.2 Proposed Access

Access to the upper reservoir site would be provided by existing Borrow Area Road. Although this road has steep segments, HDR assumed that it would be adequate for construction (as it has served this purpose previously). Relatively minor improvements would be required to improve the surface and provide drainage. The upper reservoir would also have a perimeter road and an access ramp to the reservoir floor.

The proposed penstock alignment was previously discussed in Section 4.7. The underground portion of the penstock would generally be accessible along the Upper Reservoir Access Road. It is anticipated that clearing and grading activities would accommodate a buffer zone along the alignment, which may facilitate future maintenance and construction activities. Construction of a parallel maintenance road along the overland section of the penstock is not feasible due to the topography and grade slopes along the alignment.

Access to the power complex would be provided by a new access road spurring off of the Upper Reservoir Access Road and generally parallelling Lake Sonoma shoreline. This new “Powerhouse Access Road” would be approximately 1,000 feet long. This road's starting and ending points are at roughly equal elevations and the road alignment would be selected so as to control grades, minimize tree removal, and minimize erosion potential. For the purposes of developing cost opinions, the Powerhouse Access Road was assumed to be 25 feet wide and surfaced with crushed rock. Based on existing topography, it is anticipated that several culverts would be required to maintain drainage.

Access to the Project site requires crossing over the existing Warm Springs Dam emergency spillway. Upgrades to the spillway crest may be required to facilitate construction but have not been considered at this time. Vehicle access to the Project would not be possible during an emergency spill event.

Figure 4-20 presents existing and proposed access roads in the Project area.

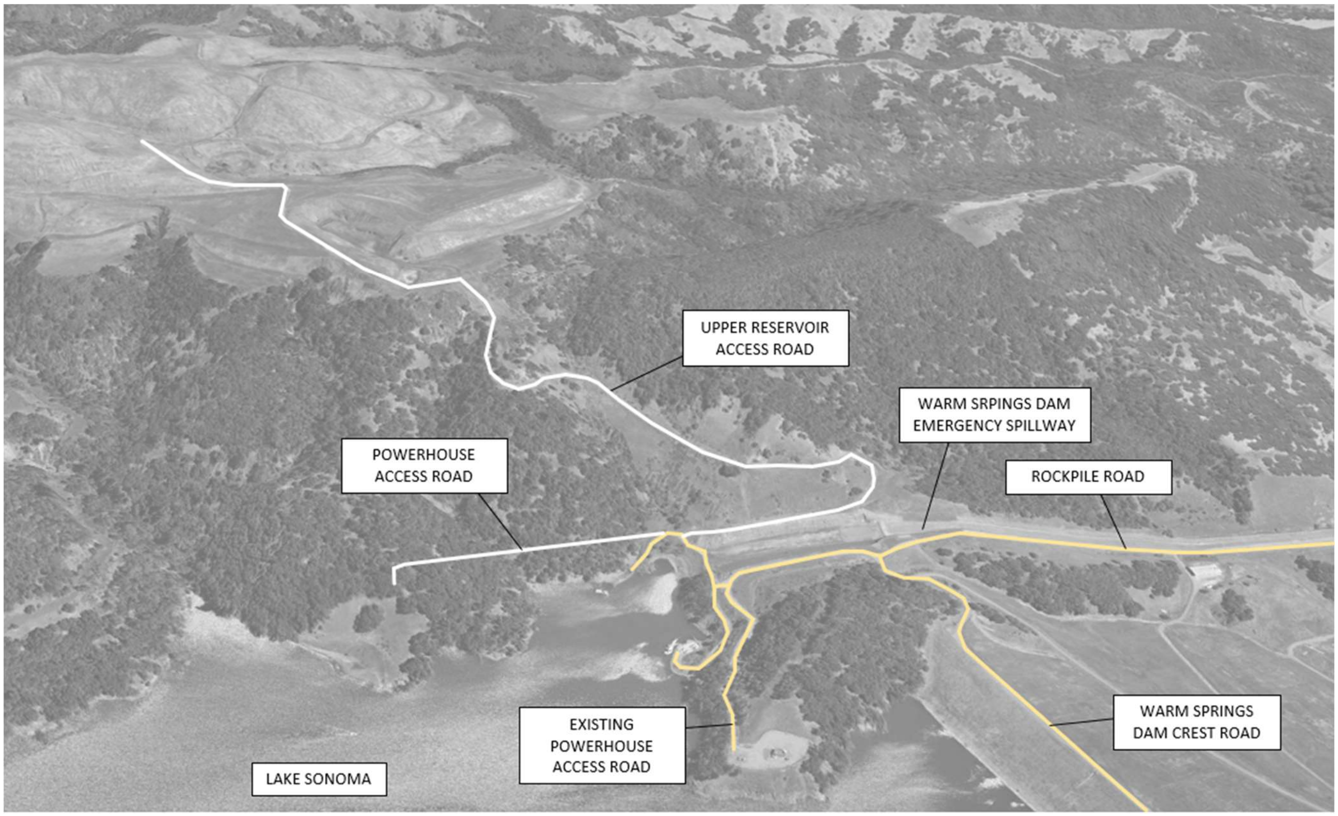


Figure 4-20. Project Area Access Roads

4.10.2 Powerhouse Site

As discussed in Section 4.5.1, the powerhouse site was selected based on existing terrain, its proximity to the upper reservoir, its proximity to existing roadways, and its ability to accommodate a reasonable penstock alignment. The powerhouse site was set at Elevation 519 feet to match the Warm Springs Dam crest elevation.

Approximately 50,000 cubic yards of earth and rock material handling is required for the grading and soil/rock retention measures to prepare the powerhouse site. See Exhibit 4 in Appendix A. The soil/rock retention wall is approximately 80 feet high with a wall face area of 38,200 square feet. Stabilization measures are anticipated to include soil nails, rock anchors, reinforced shotcrete facing, seepage/drainage features, and an uphill rock catch/drainage swale. A retaining wall is also required on the downhill side of the powerhouse site. This retaining wall would be approximately 30 feet tall with a wall face surface area of approximately 11,100 square feet.

5 HDR Energy Model

Pumped storage hydropower energy and operations are commonly evaluated using a spreadsheet model with inputs including upper and lower reservoir stage-storage relationships, conveyance lengths and sizes, headloss factors, pump and turbine performance parameters, and generating and pumping operation times.

Projects that feature isolated upper and lower reservoirs can be accurately modeled using a typical 24-hour cycle. Projects that feature upper and/or lower reservoirs that are influenced by other operations (e.g., water supply) are typically modeled over longer (multiple years) time periods with known historic water levels for one or both reservoirs.

The Project is somewhat unique for several reasons:

- The lower reservoir level varies significantly due to natural inflows and water supply operations.
- The Project would not have the ability to complete a generating and pumping cycle within a 24-hour period. Therefore, energy was modeled month-by-month using a lower reservoir (Lake Sonoma) water level duration approach.
- Due to transmission constraints, both generating and pumping power was assumed to be constant at 20 MW, unless operating at 20 MW would overfill or over-pump the upper reservoir.
- Since the Project turbines would be of the reaction (Pelton) type, output is not influenced by lower reservoir levels. Active storage is determined by applying the 20 MW criterion to the lowest head (lowest upper reservoir level) generating condition.

Lake Sonoma baseline water levels were obtained from the USACE and represent actual water levels from 2003 through 2023. This data was separated by month and sorted to create level-duration relationships at 2-percent (~14-hour) time increments. A median daily level was then calculated from this 20-year record. The model simulates one year of pumped-storage operations using the mean daily Lake Sonoma water levels.

At each time step, the model computes gross head, headlosses, and net head. Based on the dispatching schedule provided by SCP, pumping or generating flow is then determined using the power equation with net head and performance as inputs. Energy is then determined based on the pumping/generating power multiplied by the one-hour time step interval.

Cycle efficiency is defined as the ratio of the energy produced to the energy used to complete a full cycle, i.e., completely use and completely restore the design active storage. The key factors that contribute to cycle efficiency include equipment performance (efficiencies) and water conveyance headloss. These factors adversely affect both generating and pumping (i.e., gross generating energy is reduced by the factors and gross pumping energy is increased). A third factor that affects the cycle efficiency of the Project is that gross pumping head exceeds gross generating head due to the use and setting of the Pelton generating units. The estimated overall cycle efficiency of the Project is approximately 60%.

Energy model results are presented in Table 5-1.

Table 5-1. Energy Model Results

Parameter	Units	Jan	Feb	Mar	Apr	May	Jun	Jul
Mean Lake Level	ft	1,165	1,164	1,163	1,157	1,166	1,163	1,154
Average Generation Power	MW	19.9	19.8	19.8	19.7	19.9	19.9	19.7
Generation Energy	MWh	2,443.4	2,884.9	3,390.8	3,489.1	3,673.1	3,179.4	2,791.0
Average Pump Power	MW	19.9	20.0	19.9	20.0	19.9	19.9	20.0
Pump Energy	MWh	3,914.5	4,697.8	5,874.7	5,588.5	6,316.8	5,226.0	4,688.5

Parameter	Units	Aug	Sep	Oct	Nov	Dec	Annual
Mean Lake Level	ft	1,159	1,160	1,161	1,165	1,156	1,161
Average Generation Power	MW	19.7	19.8	19.6	19.7	19.3	19.7
Generation Energy	MWh	2,504.9	2,770.1	2,998.7	2,605.0	2,235.8	34,966.2
Average Pump Power	MW	20.0	19.9	20.0	20.0	20.0	19.9
Pump Energy	MWh	4,340.0	4,520.7	5,170.4	4,691.9	3,460.0	58,489.7

6 Sonoma Clean Power Revenue Model

Sonoma Clean Power (SCP) prepared a preliminary energy market analysis for the Project that included a hypothetical schedule for Project dispatching (pumping, generating, or idle) based on projected hourly energy pricing for the year 2030.

The SCP model was originally tailored to forecast Battery Energy Storage (BES) systems and was therefore modified to more accurately reflect pumped storage hydropower operations, i.e., the addition of the overall aggregate cycle efficiency discussed in the previous section.

SCP's forecast for hourly energy pricing is derived from a model that incorporates expected changes in the state's generation fleet as the capacity of renewables and battery storage continue to grow. The model also calibrates locationally specific pricing characteristics due to transmission congestion in Northern Sonoma County. The dispatch schedule of the system is optimized to maximize revenues in the day-ahead market. If discharge prices aren't expected to be sufficient to recoup potential losses, the system will idle. The optimization is based on perfect foresight of the hourly price forecast, which is likely optimistic. But the model also does not incorporate the upside of operating in ancillary or real-time markets, which leads to a reasonable forecast in balance. The model SCP used for evaluating the project's potential is the same model

SCP uses for its own resource planning, Power Purchase Agreement (PPA) evaluation, and portfolio risk management.

6.1 Sonoma Clean Power Forecasted Revenues

Results of the two energy modeling efforts were very similar and are presented below in Table 6-1. Note that energy is measured at the high side of the Project step-up transformer and excludes losses beyond that point.

Applying SCP's forecasted energy pricing results in annual energy arbitrage revenues of approximately $2.28 million. A $10 / kW / month resource adequacy (capacity credit) allowance results in annual revenues of approximately $2.4 million. Combined forecasted revenues total approximately $4.68 million.

Table 6-1. Sonoma Clean Power Revenue Model Results

Parameter	Units	Jan	Feb	Mar	Apr	May	Jun	Jul
Mean Lake Level	ft	1,164.8	1,163.6	1,162.7	1,157.3	1,166.3	1,163.0	1,153.8
Generation Revenue	$	$400,919	$375,673	$362,801	$354,423	$319,856	$343,880	$400,814
Pumping Cost	$	(242,486)	(163,343)	(166,561)	(137,912)	(116,661)	(141,184)	(199,441)
Net Revenue	$	$158,433	$212,330	$196,240	$216,511	$203,196	$202,696	$201,372

Parameter	Units	August	Sep	Oct	Nov	Dec	Annual
Mean Lake Level	ft	1,159.3	1,160.0	1,160.7	1,165.4	1,156.1	1,161.1
Generation Revenue	$	$491,334	$470,811	$288,842	$270,261	$353,130	$4,432,744
Pumping Cost	$	(234,880)	(206,169)	(160,671)	(160,245)	(223,436)	$(2,152,989)
Net Revenue	$	$256,454	$264,641	$128,171	$110,016	$129,693	$2,279,754

7 Construction Considerations

7.1 Site Preparation

Site preparation activities would include improvements to the upper reservoir access road, construction of the power complex access road, and preliminary works associated with the power complex site. These activities would require controlled vegetation and tree removals. It is not anticipated that any significant demolition (of existing structures) would be required.

An advance traffic impact study would likely be required to reduce the potential impact of construction traffic on ongoing commercial and tourism traffic.

7.2 Staging Areas

Construction staging and laydown for the upper reservoir is anticipated to be relatively straightforward given available space in that area. The primary penstock construction staging and laydown areas would also be located in this area.

The power complex presents a challenge given the limited space available. The temporary use of nearby lands owned by the USACE, the Lake Sonoma Fish Hatchery (owned and operated by the California Department of Fish and Wildlife), and Sonoma County should be explored should the project move forward.

7.3 Material Sourcing

7.3.1 On-Site Sources

See discussion in Section 3.

7.3.2 Commercial Sources

Construction materials required for the Project would include but not be limited to concrete, aggregates, and riprap. A detailed material sourcing study is recommended for the next phase of study to identify the local market material providers, obtain their availability to supply adequate amounts of materials for the Project, and to consider additional sources outside the local market area.

There are multiple ready-mix suppliers and aggregate quarries within a 1.5 hour driving radius from lake Sonoma. Some of the ready-mix plants are smaller batch plants with limited yard space and may not be as suitable for production of large quantities. Concrete quantities for the project are not large enough to require an onsite concrete batch plant. However, the site is a bit remote in regard to the distance to a commercial supplier of ready-mix concrete and a contractor may choose to use an on-site concrete batch plant.

Granite Construction has a sizable aggregate quarry in Lakeport, approximately 40 miles from the Project site.

7.4 Waste Material Disposal

Excavation of the upper reservoir would generate approximately two million cubic yards of waste material. It is anticipated that this material would be deposited within the existing disturbed area.

Development of the power complex site would generate approximately 50,000 cubic yards of waste material. It is not anticipated that any material can be disposed of in or near the power complex site; therefore, it is anticipated that this material would be deposited in the upper reservoir area.

7.5 Care of Water During Construction

Given the relatively small upper reservoir watershed area and absence of any active streams, it is anticipated that care of water during construction would be handled with localized sumps and dewatering pumps.

8 Cost Opinions

8.1 Capital Costs

8.1.1 Definition

An AACE Class 5 OPCC has been prepared in accordance with AACE International (AACE) guidance to provide a budgetary cost for the concept presented in this report as noted below.

The costs presented should be considered an approximate value of the work and not necessarily reflective of market conditions. Market conditions include contractor interest, contractor availability, forecasted project delivery date, material/commodity fluctuations, and other market cost drivers.

Listed below are the basic definitions of an AACE Class 5 cost opinion:

- **Level of Project Definition:** Between 0 and 2 percent complete
- **End Usage:** Concept screening or feasibility
- **Methodology:** Assembly model estimating, parametric models, judgement
- **Expected Accuracy Range:** Low = -20 to -50 percent; High = +30 to +100 percent
- **Definition of Estimate:** Class 5 estimates are generally prepared based on very limited information, and subsequently have very wide accuracy ranges. As such, some companies and organizations have elected to determine that due to the inherent inaccuracies, such estimates cannot be classified in a conventional and systematic manner. Often, little more than proposed site layout, plant type, location, and capacity are known at the time of estimate preparation. Special site conditions (e.g., rock, piles, environmental) are not considered at this level.
- **Estimating Methods:** Class 5 estimates generally use stochastic estimating methods such as cost/capacity curves and factors, Timberline Model Estimates, or in-house capacity curves for similar plants, prior experience with similar projects, or other parametric and modeling techniques. For the Lake Sonoma project, quantities for significant work components are generated or readily available as a result of conceptual design tasks and are therefore used to inform the OPCC. This is further discussed in the next section.

8.1.2 Civil Works

Table 8-1 presents conceptual-level quantity takeoffs and costs.

Table 8-1. Civil Works Cost Summary

Item	QTY/Unit	Cost
Roads and Site Preparations		
Clearing & Grubbing	10 AC	$100,000
Upper Reservoir Access	5,200 LF	$494,000
Upper Reservoir Perimeter	2,780 LF	$264,100
Powerhouse Access	1,300 LF	$1,235,000
Upper Reservoir		
Earthwork	2,336,000 CY	$58,400,000
Liner	60,300 SY	$2,170,800
I/O Structure	1,000 CY	$1,200,000
Emergency Spillway	500 CY	$450,000
Penstock		
Penstock	3,600 LF	$6,300,000
Saddles	50 EA	$1,500,000
Corrosion Protection	3,600 LF	$180,000
Penstock Civil Grading	1 LS	$500,000
Powerhouse		
Tie-back Walls	38,200 SF	$2,865,000
Retaining Walls	11,100 SF	$1,387,500
Earthwork	50,000 CY	$1,250,000
Substructure	1 LS	$250,000
Superstructure	12,000 SF	$1,800,000
Pumphouse		
Wet Well	123.5 VLF	$8,027,500
Micro tunnel(s) to Lake	730 LF	$4,599,000
Superstructure	6,400 SF	$960,000
Total		**$93,392,900**

8.1.3 Turbines

Budgetary cost information from Canyon Hydro is included in Appendix B1. The Canyon Hydro package includes the following equipment:

- Two 48-inch ball-type turbine inlet valves with hydraulic open and counterweight closures
- Two 48-inch dismantling joints
- Two Pelton turbines with hydraulic actuation
- Two 10.8 MW / 4160VAC / 3-phase / 60 Hz synchronous generators
- Two oil lube skids
- Two hydraulic power units

- MV switchgear
- Two PLC-based controls panels

Turbine costs are summarized in Table 8-2.

Table 8-2. Turbine Cost Summary

Item	Cost
Equipment Package	$12,574,500
Delivery	$50,000
Commissioning and Training	$60,000
Total	**$12,684,500**

8.1.4 Pumps

HDR received a budgetary estimate of $4.2 million for the vertical turbine pumps from Trillium Flow Technologies.

8.1.5 Balance of Plant

HDR utilized a scaled percentage of the OEM pump-turbine costs to parametrically evaluate the costs for mechanical balance of plant (BOP), electrical BOP, and OEM equipment installation. This approach served to evaluate the pump BOP separately from the turbine BOP with varying percentages based on engineering judgment. OEM installation and BOP cost percentages are presented in Table 8-3. The vertical turbine pump mechanical BOP percentage is higher due to the increased complexity of this work.

Table 8-3. OEM Installation and BOP Costs

Item	Pelton Turbine OEM	Vertical Turbine Pump OEM
OEM Equipment Install	15%	5%
Mechanical BOP	15%	25%
Electrical BOP	10%	15%

8.1.6 Interconnection Cost

As introduced earlier, SCP (2024) evaluated three options to interconnect the pumped storage hydropower project to the PG&E system. Option 2 was selected for the purposes of this study with an overall cost of $21.2 million. An additional $1.75 million was allocated for the powerhouse transformer yard, bringing the transmission and interconnection cost to $23 million.

8.2 Capital Cost Summary

A summary of the OPCC is provided in Table 8-4. The summary includes the estimated direct construction cost, overhead and profit, contingencies, and non-contract costs, and is presented in 2025 dollars. The base cost was first determined and then used to generate the low- and high-cost ranges, within which eventual bids are expected fall.

The costs were derived from HDR's recent experience with cost estimating on similar pumped storage hydropower projects and engineering judgement represented in 2025 dollars.

Table 8-4. Opinion of Probable Construction Cost

Item	Cost ($millions)
Roads & Site Preparations	2.1
Upper Reservoir	62.3
Penstock	8.5
Powerhouse	12.7
Pumphouse	15.6
Subtotal	101.2
Erosion & Sediment Control (2% of subtotal)	2.1
Mobilization & Demobilization (5% of subtotal)	5.1
Direct Construction Cost Subtotal	108.4
OEM Equipment	20.5
Transmission & Interconnection	23.0
Direct Cost + Owner Procurement Subtotal	151.9
Design & Regulatory Services (10% of Direct Cost + Owner Procurement Subtotal)	15.2
Project Subtotal	166.9
Contingency (25% of Project Subtotal)	41.8
Total Baseline Project Cost	**208.7**
Low Range (-50%)	**104.4**
High Range (+50%	**313.1**

8.3 Capital Cost Commentary

The baseline OPCC of the Project is approximately $199 million or $9,950/kW. As indicated in Table 8-4, the most significant Project cost is development of the upper reservoir. It is suggested that future studies explore optimizing the configuration of the upper reservoir. This would likely require deviation from the desired Project characteristic/constraint discussed in Section 4.2, i.e., "*the upper reservoir is to be created through excavation of existing material…*"

The U.S. Bureau of Reclamation (Reclamation) (2014 and 2020) performed a system-wide screening evaluation of potential pumped storage hydropower projects. Costs in the Reclamation reports represented an AACE Class 5" cost opinion based on very conceptual layout information and derived from cost curves provided in EPRI's Pumped Storage Planning and Evaluation Guide. Figure 8-1 shows a comparison between Reclamation costs for lower capacity pumped storage hydropower projects and that presented in this report. Note that Reclamation costs were escalated to 2025 dollars. Figure 8-1 also shows costs developed by HDR for a confidential client. These costs (depicted as red triangles) were for lower capacity pumped storage hydropower projects that did not require new upper or lower reservoirs. Figure 8-1 also shows a computed trend line based on the Reclamation and HDR data. As shown, the cost per kW for the Project lines up reasonably well with the comparative cost data.

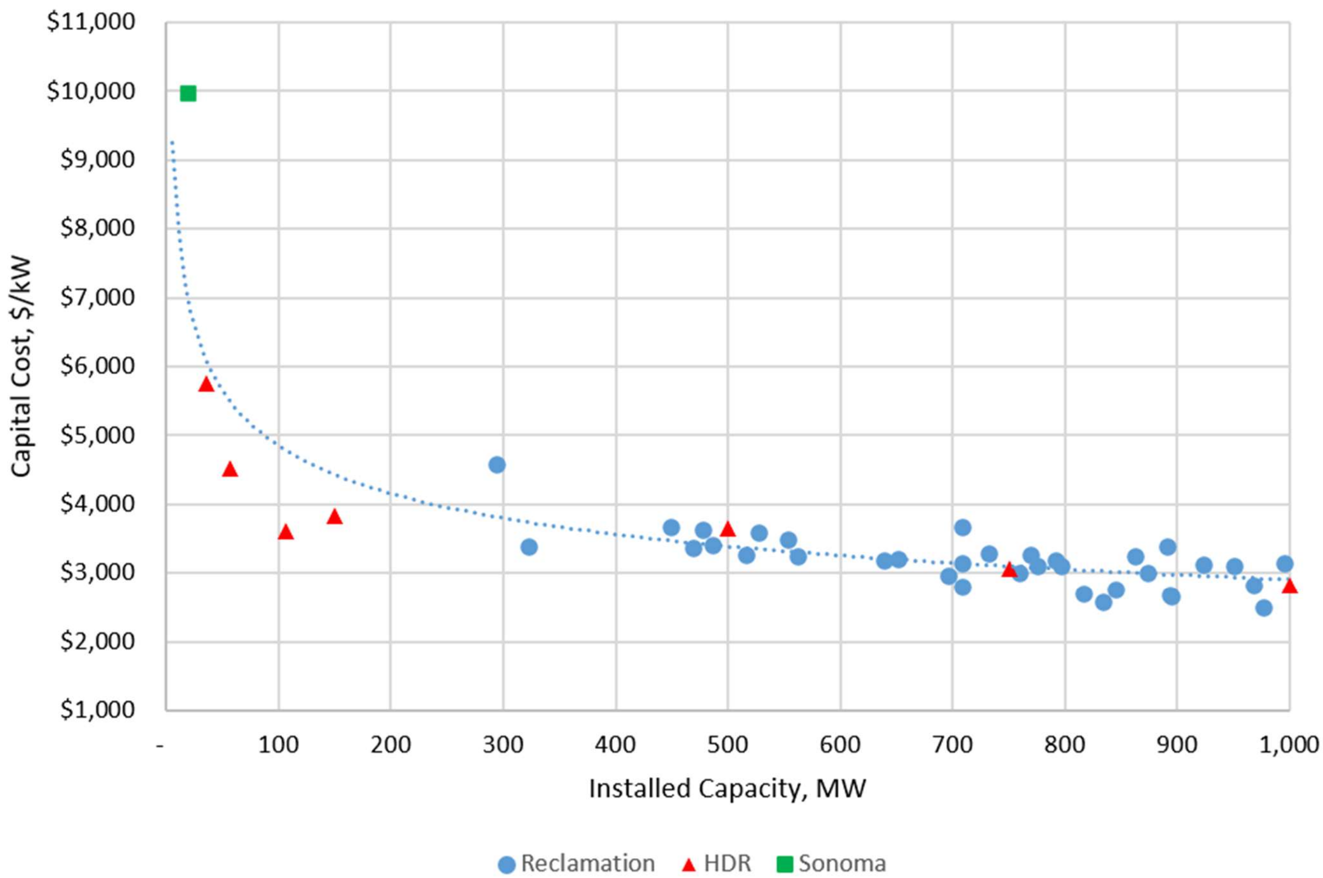


Figure 8-1. Unit Cost Comparison

8.4.1 Routine Operations and Maintenance

Typically, for initial concept studies, cost approaches developed by EPRI (2011) and the Oak Ridge National Laboratory (ORNL 2015) are utilized as it is understood that they aggregate significant amount of industry reported FERC Form 1 data and other reported historical data and can be a reasonable basis for O&M costs. The raw data used by ORNL are shown graphically in Figure 8-2.

USBR (2024) O&M cost indexes (i_{year}) were used to escalate these costs from the EPRI and ORNL publications' basis years (2011 and 2015) to 2024:

i_{2011} = 4.33

i_{2015} = 4.79

i_{2024} = 6.76 (extrapolated)

Both cost equations are presented below, and results are shown in Table 8-5.

EPRI: $O\&M = 86{,}825\ C^{0.32}\ E^{0.33}\ i_{2024}/i_{2011}$

ORNL: $O\&M = 225{,}417\ C^{0.547}\ i_{2024}/i_{2015}$

Where:

C = capacity, MW

C = 20 MW

E = average annual energy[6], GWh

E = 150 GWh

Table 8-5. Annual O&M Costs based on Published Methods

Reference	2022 O&M Cost
	$1.8 million
	$1.6 million

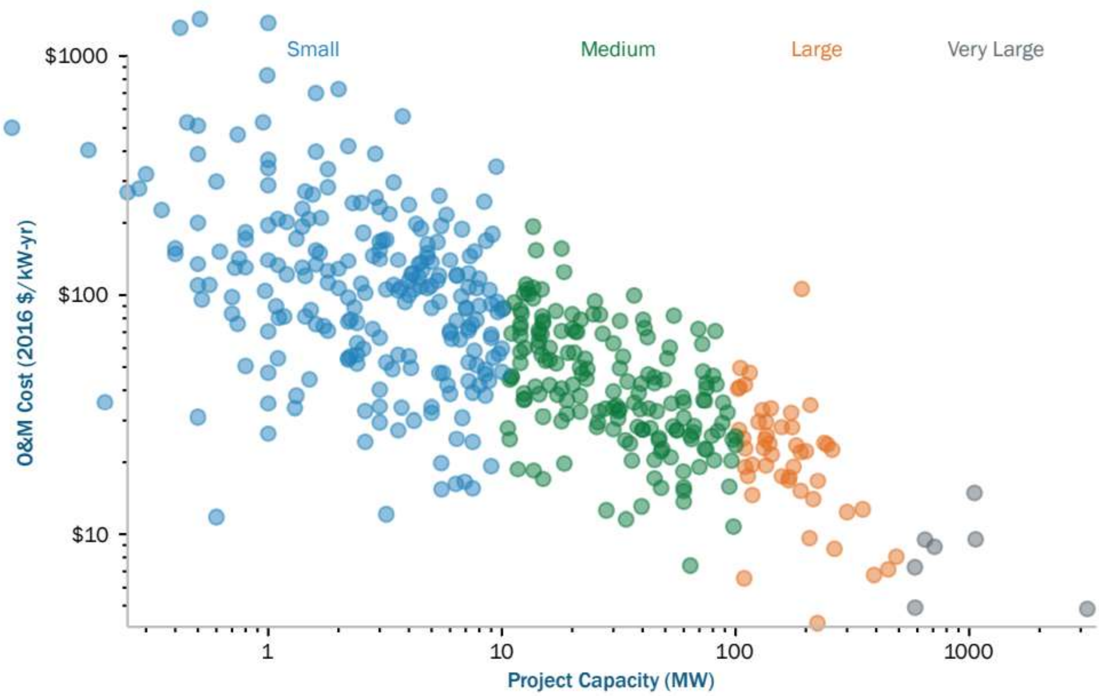


Figure 8-2. Hydropower O&M Expenditures Reporting on FERC Form 1

As shown in Table 8-5, results of the two published-method O&M estimates compare reasonably well. O&M costs for any given facility depend on many factors such as the extent and location of the owner's operations staff and how administration and management staff costs are accounted for.

[6] Annual energy includes generating and pumping and assumes a 33-hour cycle and 10% annual outages.

Based on HDR's experience with hydropower projects of this size, a range of potential annual O&M costs should be considered (e.g., $0.5 to $1.0 million).

8.4.2 Interconnect Cost of Ownership

As indicated previously in Table 4-3, the monthly cost of ownership for the PG&E interconnection for the assumed Option 2 (115 kV interconnection to Cloverdale 115 kV substation) is $183,000. The single (lump sum) cost of ownership is $31,315,000. The lump sum cost of ownership would be the more attractive option for a Project life in excess of approximately 14 years.

8.4.3 Excluded Costs

HDR's cost opinion excludes the following owner costs with the understanding that Sonoma Water may apply these costs separately:

- General (project management, corporate staff, overhead, legal, administration, overall project development)
- Land acquisition
- Insurance
- Property taxes
- Foreign equipment / material tariffs
- Telecommunications and supervisory control and data acquisition (SCADA)
- Construction administration
- Allowance for funds used during construction (AFUDC)

8.5 Comparison to Battery Energy Storage System

During the later stages of this report's development, Sonoma Water request that a high-level cost comparison be made between pumped storage hydropower and battery energy storage system (BESS). The complete BESS comparison memo is included in Appendix D and results are summarized in Table 8-6 below.

Table 8-6. BESS Comparison Summary

Parameter	Units	PSH	Li Ion BESS
Power Output	MW	20	20
14-hour Energy Storage	MWH	280	280
14-hour Discharge Duration	hr	14	14
30 Year Lifecycle Cost			
NPV of Total Lifecycle Cost (US$)	$MM	$368	$265
Levelized Cost (US$)	$/MWH	$1,063	$764
Levelized Cost (US$)	$/kw-mo	$157	$113

9 Regulatory Considerations

9.1 Overview

Construction of the Project would require authorization from the FERC, with FERC acting as the lead federal agency pursuant to its authority under the Federal Power Act (FPA) to license non-federal hydropower projects.

Authorization would come in the form of either a license or an exemption from licensing (exemption). Licenses are issued for periods of 30 to 50 years, at the end of which must be renewed. Per the FERC,

> *"In certain cases, projects may qualify for an exemption from licensing. Those receiving an exemption are exempt from the requirements of Part I of the Federal Power Act. However, the exempted project is subject to mandatory terms and conditions set by federal and state fish and wildlife agencies and by the Commission, and do not convey the right of eminent domain. Getting an exemption can be a more simplified process than applying for a license. Exemptions are issued in perpetuity."*

FERC can issue two types of exemptions:

a. *"Small hydropower projects, which are 10 megawatts or less, that will be built at an existing dam, or projects that utilize a natural water feature for head…*

b. *Conduit exemption that would be issued for constructing a hydropower project on an existing conduit (for example irrigation canal). Conduit exemptions are authorized for generating capacities 40 megawatts or less. The conduit has to have been constructed primarily for purposes other than power production."*

Based on the current configuration, it is not anticipated that the Project could qualify for an exemption. Since the Project involves a new upper reservoir, it does not appear that a Type "a" exemption would apply. Since the Project penstock's primary purpose would be for power production, it does not appear that a Type "b" exemption would apply.

The balance of this section assumes that the licensing process would apply for the Project.

The FPA requires FERC to consider both power and non-power uses of the lands affected by the Project, including fish and wildlife resources, cultural resources, water quality, and recreation. Key FPA components and additional major statutes pertinent to these resources and Projects in general are described below.

- Section 4(e) of the FPA requires FERC to give "equal consideration" to power and non-power benefits in its licensing decisions, and provides federal agencies managing lands occupied by a hydropower project the authority to impose mandatory license conditions for the protection of affected resources. FERC cannot modify these conditions and must impose them on a licensee for the duration of project operation.
- Section 10(j) of the FPA requires FERC to include license conditions to adequately and equitably protect, mitigate damage to, and enhance fish and wildlife (and their habitats), based on recommendations of state and federal fish

and wildlife agencies (unless FERC determines that said recommendations are inconsistent with the FPA or other statutes).

- Section 10(a) of the FPA requires FERC to consider resource agency recommendations in determining a project's consistency with federal and state comprehensive plans.
- Section 18 of the FPA provides federal resource agencies mandatory conditioning authority regarding the prescription of fishways, including upstream and downstream passage requirements.
- The Fish and Wildlife Coordination Act requires federal agencies issuing water resource permits to consult with U.S. Fish and Wildlife Service (USFWS), the National Marine Fisheries Service (NMFS) and state fish and wildlife agencies regarding potential impacts on fish and wildlife and to require resource protection, mitigation, and/or enhancement measures.
- Section 401 of the Clean Water Act (CWA) requires the applicant to seek certification that the project would comply with state water quality standards as defined by the California State Water Resources Control Board (SWRCB). Any conditions included in the certificate are mandatory and may not be dismissed by FERC. As part of the Section 401 application process, the proposed Project would need to be evaluated under the California Environmental Quality Act (CEQA).
- Section 404 of the CWA authorizes a separate permit program for the disposal of dredged or fill material in the nation's waters, to be administered by the USACE. When issuing this permit in California, the USACE would consult with the SWRCB regarding compliance with Section 401 of the CWA and with the USFWS regarding compliance with Section 7 of the Endangered Species Act (ESA).
- The National Environmental Policy Act (NEPA) requires the lead federal agency (FERC) to evaluate environmental impacts and the significance of those impacts. FERC would prepare an Environmental Assessment or Environmental Impact Statement to fulfill its obligations under NEPA. Under FERC's default Integrated Licensing Process, FERC performs NEPA scoping prior to the applicant's filing of the license application, and the applicant prepares an Exhibit E (Environmental Report) in the general format of an Environmental Assessment, to facilitate FERC's preparation of the NEPA document.
- Section 7 of the ESA requires the lead federal agency to consult with the USFWS and National Marine Fisheries Service to ensure that its actions and authorizations do not jeopardize the continued existence of any species of plant of animal listed as threatened or endangered under the Act, or adversely affect any designated critical habitat for listed species.

The scope of the current study included an overview of the regulatory process only. However, a cursory review of listed species was performed to inform certain aspects of the Project. A search of the USFWS Information, Planning and Consultation (IPaC) and on-line critical habitat mapping system (USFWS 2024) databases identified the following terrestrial animal and plant species that may be potentially affected by activities in this location:

- Northern spotted owl (*Strix occidentalis caurina*)
- Northwestern pond turtle (*Actinemys marmorata*)
- Monarch butterfly (*Danaus plexippus*)
- Marbled murrelet (*Brachyramphus marmoratus*)

Further evaluation is required to determine if suitable habitat for each species is present within the Project area and if the Project activities could potentially impact each species.

- A search of the California Department of Fish and Wildlife RareFind database (CDFW 2024) identified five special-status species that could occur in the Project area:
  - California giant salamander (*Dicamptodon ensatus*)
  - Foothill yellow-legged frog (*Rana boylii*)
  - Hoffman's bristly jewelflower (*Streptanthus glandulosus ssp. hoffmanii*)
  - Morrison's jewelflower (*Streptanthus morrisonii ssp. morrisonii*)
  - Red-bellied newt (*Taricha rivularis*)

  None of these species have federal or state endangered species level protections, but do have other special status designations. Further evaluation is required to determine if suitable habitat for each species is present within the Project area and if the Project activities could potentially impact each species.

- Section 106 of the National Historic Preservation Act (NHPA) requires the lead federal agency to consider the effects of their actions on properties that may be eligible for listing, or currently listed, on the National Register of Historic Places (NRHP), and afford the State Historic Preservation Officer (SHPO) and the Advisory Council on Historic Preservation (ACHP) a reasonable opportunity to comment. To determine if an undertaking could affect NRHP-eligible properties, all cultural sites that could be impacted by the Project must be inventoried and evaluated for inclusion in the NRHP. A license applicant may be designated by FERC to act as its non-federal representative for purposes of consulting with the SHPO and other interested parties, including affected Native American tribes. Consultation is intended to avoid adverse effects and generally culminates with the preparation and implementation of a Historic Properties Management Plan (HPMP). Known cultural resource and sites are maintained and curated by the California Historical Resources Information System (CHRIS). On the state level, the Section 106 process is administered by the California Office of Historic Preservation (OHP).

9.2 FERC Licensing

9.2.1 Assumed Licensing Process

As indicated previously, FERC is responsible for licensing non-federal hydropower projects in the United States, including pumped storage facilities. The Project would be FERC-jurisdictional, requiring completion of an intensive licensing process that provides FERC with sufficient information to meet its obligations under the FPA, NEPA, ESA, NHPA, and other statutes.

FERC's three licensing processes, and a fourth "hybrid" approach each have strategic and procedural benefits and costs (see Table 9-1). For the purposes of this study, HDR assumed that the Integrated Licensing Process (ILP) would be undertaken as it is the default process FERC expects a liscenee to utilize. The ILP is reflected in the integrated development schedule discussed in Section 9.

Table 9-1. Comparison of FERC Licensing Processes

Activity	Integrated Licensing Process (ILP)	Traditional Licensing Process (TLP)	Alternative Licensing Process (ALP)
Consultation w/ Resource Agencies and Indian Tribes	• Integrated	• Paper-driven	• Collaborative
FERC Staff Involvement	• Pre-filing [beginning at filing of Notice of Intent (NOI)] • Early and throughout process	• Post filing (after the application has been filed) • Available for education and guidance	• Pre-filing (beginning at filing the NOI) • Early involvement for NEPA scoping as requested
Deadlines	• Defined deadlines for all participants (including FERC) throughout the process	• Pre-filing: some deadlines for participants • Post-filing: defined deadlines for participants	• Pre-filing: deadlines defined by collaborative group • Post-filing: defined deadlines for participants
Study Plan Development	• Developed through study plan meetings with all stakeholders • Plan approved by FERC	• Developed by applicant based on early stakeholder recommendations • No FERC involvement	• Developed by collaborative group • FERC staff assist as resources allow
Study Dispute Resolution	• Informal dispute resolution available to all participants • Formal dispute resolution available to agencies with mandatory conditioning authority • Three-member panel provides technical recommendation on study dispute • Office of Energy Projects (OEP) Director opinion binding on applicant	• FERC study dispute resolution available upon request to agencies and affected tribes • OEP Director issues advisory opinion	• FERC study dispute resolution available upon request to agencies and affected tribes • OEP Director issues advisory opinion
Application	• Preliminary licensing proposal or draft application and final application include Exhibit E (environmental report) with form and contents of an Environmental Assessment	• Draft and final application include Exhibit E	• Draft and final application with applicant-prepared Environmental Assessment or third-party Environmental Impact Statement
Additional Information Requests	• Available to participants before application filing • No additional information requests after application filing	• Available to participants after filing of application	• Available to participants primarily before application filing • Post-filing requests available but should be limited due to collaborative approach
Timing of Resource Agency Terms and Conditions	• Preliminary terms and conditions filed 60 days after Ready for Environmental Analysis (REA) notice • Modified terms and conditions filed 60 days after comments on draft NEPA document	• Preliminary terms and conditions filed 60 days after REA notice • Schedule for final terms and conditions	• Preliminary terms and conditions filed 60 days after REA notice • Schedule for final terms and conditions

Source: FERC (2020)

9.2.2 Preliminary Permit

While not required, a FERC-issued Preliminary Permit protects a site from development by other parties while engineering studies and licensing proceedings are conducted. FERC issues Preliminary Permits for a term of up to four years and would consider applications for extensions.

9.2.3 Closed-Loop Classification

In 2019, FERC issued Order No. 858, revising its regulations to conform with the America's Water Infrastructure Act (AWIA), which added Section 35 to the FPA authorizing FERC to expedite the licensing process for closed-loop pumped storage hydropower projects. According to the FERC (2019), criteria for projects to qualify as closed-loop facilities are as follows:

i. *cause little to no change to existing surface and groundwater flows and uses;*

ii. *is unlikely to adversely affect species listed as a threatened species or endangered species, or designated critical habitat of such species, under the Endangered Species Act of 1973;*

iii. *utilize only reservoirs situated at locations other than natural waterways, lakes, wetlands, and other natural surface water features; and*

iv. *rely only on temporary withdrawals from surface waters or groundwater for the sole purposes of initial fill and periodic recharge needed for project operation.*

Based on HDR experience but pending future investigations, it recommended that a closed-loop classification not be pursued for the Project.

9.2.4 Licensing Process

9.2.4.1 General

The initial steps in the licensing process include preparation and filing of a Notice of Intent (NOI) and Pre-Application Document (PAD). The NOI includes a statement of intent to file a license application and any request to use a licensing process other than the default ILP. The NOI also includes general Project information and lists of potentially interested parties. The PAD is a more comprehensive document that includes the following:

- Project description (including proposed Project boundary, proposed installed capacity, proposed operations, proposed Project facilities and components, etc.);
- Description of the Project area's existing environment and resources;
- Potential effects of the Project on existing environment and resources;
- List of studies proposed to gather additional information on environment and resources; and
- Process plan and schedule for preparing the license application.

Following submittal of the NOI and PAD, FERC licensing consists of the following general components:

- Agency and stakeholder meetings and consultation;
- Negotiation and development of study plans for potentially affected resources;
- Implementation of field studies; and
- Development and submittal of FERC license application materials sufficient to support FERC's environmental and developmental analyses.

9.2.4.2 Environmental Studies

The environmental studies represent the most significant cost and schedule unknowns for the Project since no FERC or resource agency consultation has taken place yet. The following is a list of potential studies that may be required for the Project. This list was developed based on HDR's experience with other recent, hydropower projects located in the western United States and may not be reflective of the specific issues and associated studies that would be required for this Project.

Habitat Assessment and Threatened and Endangered Species Study

The purpose of this study is to develop the information needed to complete ESA Section 7 consultation with USFWS. The study should also include other special-status species, especially those likely of interest to federal and state agencies.

Recreation Resources Study

The purpose of this study is to identify potential benefits and impacts to recreational opportunities in the Project area.

Cultural Resources Study

The purpose of this study is to identify existing cultural, historic, and tribal resources that could be impacted by the Project.

Stream and Wetlands Delineation Study

The purpose of this study is to assess the nature and degree of the Project's potential impacts on areas subject to the jurisdiction of USACE under Section 404 of the CWA.

Water Quality and Water Quantity Studies

The following water quality and water quantity studies may be required:

- If Project water use would significantly change the timing, magnitude, or duration of water withdrawals from existing conditions, perform studies to determine if the changes from current water practices would impact downstream water users or resources in affected water bodies.
- Review proposed construction plans for roads, dams, reservoirs, the powerhouse, transmission lines, and Project-related buildings to identify potential resource impacts (e.g., erosion, sedimentation) of water resources in the Project area.

- Develop construction and operation spill management plans.
- Determine the existing water surface water resources within and downstream of the FERC Project Boundary in support of required CWA Section 404/401 permitting related to impacts due to impoundment/flooding, fill, and/or desiccation.
- Pre- and post-construction water quality monitoring would be required to support the CWA Section 401 Water Quality Certification. Monthly water quality samples (grab and in situ samples) should be collected (if not already being done). Typical water quality monitoring includes the following variables: temperature, pH, dissolved oxygen (DO), conductivity, nutrients, hardness, alkalinity, suspended sediment, and turbidity.
- Pre- and post-construction geomorphology surveys of Schoolhouse Creek may be required prior to initiation of construction activities and annually for some period (e.g., 5 years) following Project completion. Changes in stream geomorphology would indicate downstream Project effects due to alterations in flow volume, frequency, and/or velocity. Monitoring would be conducted prior to initiation of construction activities, and following Project completion / commencement of normal operations.

Fish and Aquatic Resources

Construction of the proposed Project may impact fish and other aquatic resources. The following studies may be required:

- Conduct aquatic community sampling of streams within and downstream of the FERC Project Boundary including in Lake Sonoma near the proposed Project area.
- Consult with agencies to identify additional information needs or protection measures, if any, for any federally or state-listed species identified as likely to occur in the Project area that could be affected by Project construction and operation.

9.3 CEQA Process

CEQA compliance would be required as it relates to both the CWA Section 401 and 404 permitting requirements. As a public agency, Sonoma Water can serve as the lead agency for CEQA compliance and prepare the environmental document (i.e., resource studies) to support the process. Other permitting activities should also be considered to satisfy CEQA requirements, to the extent possible.

First, an “initial study” is prepared. The initial study is a preliminary analysis prepared by the lead agency (e.g., Sonoma Water) to determine whether an Environmental Impact Report (EIR) or negative declaration (ND) would be prepared using CEQA regulatory guidance (i.e., CEQA Guidelines Appendix G). The purpose of the initial study is to determine whether there may be a significant environmental impact. Depending on the initial study, an ND, Mitigated Negative Declaration (MND), or EIR may be required, as further described below.

Negative Declaration: If the initial study concludes that the Project would not cause a significant effect on the environment, the lead agency can prepare an ND, which is a written statement that an EIR is not required because the Project would not have a significant adverse impact on the environment.

Mitigated Negative Declaration: The lead agency may attach conditions to an ND for the purpose of mitigating potential environmental effects. An MND states that revisions in the Project made by the applicant (e.g., mitigation measures) would avoid the potentially significant adverse impacts, and that there is no substantial evidence that the Project would have a significant effect on the environment. An MND includes a Mitigation Monitoring and Reporting Program (MMRP), which describes the necessary mitigation measures required to reduce potentially significant impacts to a less than significant level for the proposed Project, as required, in accordance with CEQA. The MMRP would specify the Project impacts to be mitigated, initiation/timing of mitigation, monitoring frequency, responsibility for verification of compliance, performance criteria, and the anticipated date when compliance would be completed. A Notice of Completion, Intent to Adopt an MND, and summary forms are submitted to the State Clearinghouse with the initial study/MND.

Environmental Impact Report: If the agency determines that the Project may have a significant effect on the environment, an EIR must be prepared. The first step in preparing an EIR is to determine the scope of the EIR in consultation with agencies and the public. Following the scoping process, a draft EIR is prepared and must be released for public comment for a 30- to 60-day review period. The final EIR would include the draft EIR; comments and recommendations received on the draft EIR; responses to the significant environmental points; a list of persons and agencies that commented on the draft EIR; and any other information added since the draft EIR. The EIR would include three formal notices in addition to the EIR: Notice of Preparation, Notice of Completion, and Notice of Approval or Determination. The EIR also requires a public scoping meeting.

9.4 Water Quality Certification

After FERC issues its Ready for Environmental Analysis (REA), Sonoma Water would need to apply to the SWRCB for a CWA Section 401 Water Quality Certification. No later than 30 days prior to submitting its CWA Section 401 application, Sonoma Water must offer to meet with the SWRCB to hold a pre-filing meeting.

The SWRCB would expect that Sonoma Water, as the lead agency for CEQA, complete its CEQA process (Section 9.3) with enough time so that the SWRCB may use the CEQA analysis to support development of its Water Quality Certification.

In accordance with the Environmental Protection Agency's (EPA) implementing regulations (40 Code of Federal Regulations [C.F.R.] § 121.6) and FERC's recent Final Rule[7] establishing the "reasonable period of time" for state action under CWA section

[7] Establishing Reasonable Period of Time and Clarifications Regarding Clean Water Act Section 401(a)(1) Certifications for Hydroelectric Proceedings, 89 Fed. Reg. 96,524 (Dec. 5, 2024). This Final Rule goes into effect on January 5, 2025.

401(a)(1), the SWRCB would have a maximum one-year period to issue the CWA Section 401 Water Quality Certification.

9.5 Local, State, and Regional Permits

In addition to the regulatory requirements discussed in previous sections, various other local, state, and regional permits would likely be required for Project approval. Should the Project be advanced beyond the concept stage, a comprehensive permitting matrix, schedule, and plan would be established.

10 Integrated Development Schedule

The goal of an integrated development schedule (IDS) is to establish an overall schedule that identifies major activities, their durations, and interdependencies. The IDS is intended to be a useful planning and tracking tool and should be considered a “living” document since projects of this magnitude can be influenced by many factors over time.

The IDS was generated using Microsoft® Project software. The schedule begins in 2024 with this concept study and ends with the projected Commercial Operation Date (COD) of the facility. The schedule was developed under the following salient premises:

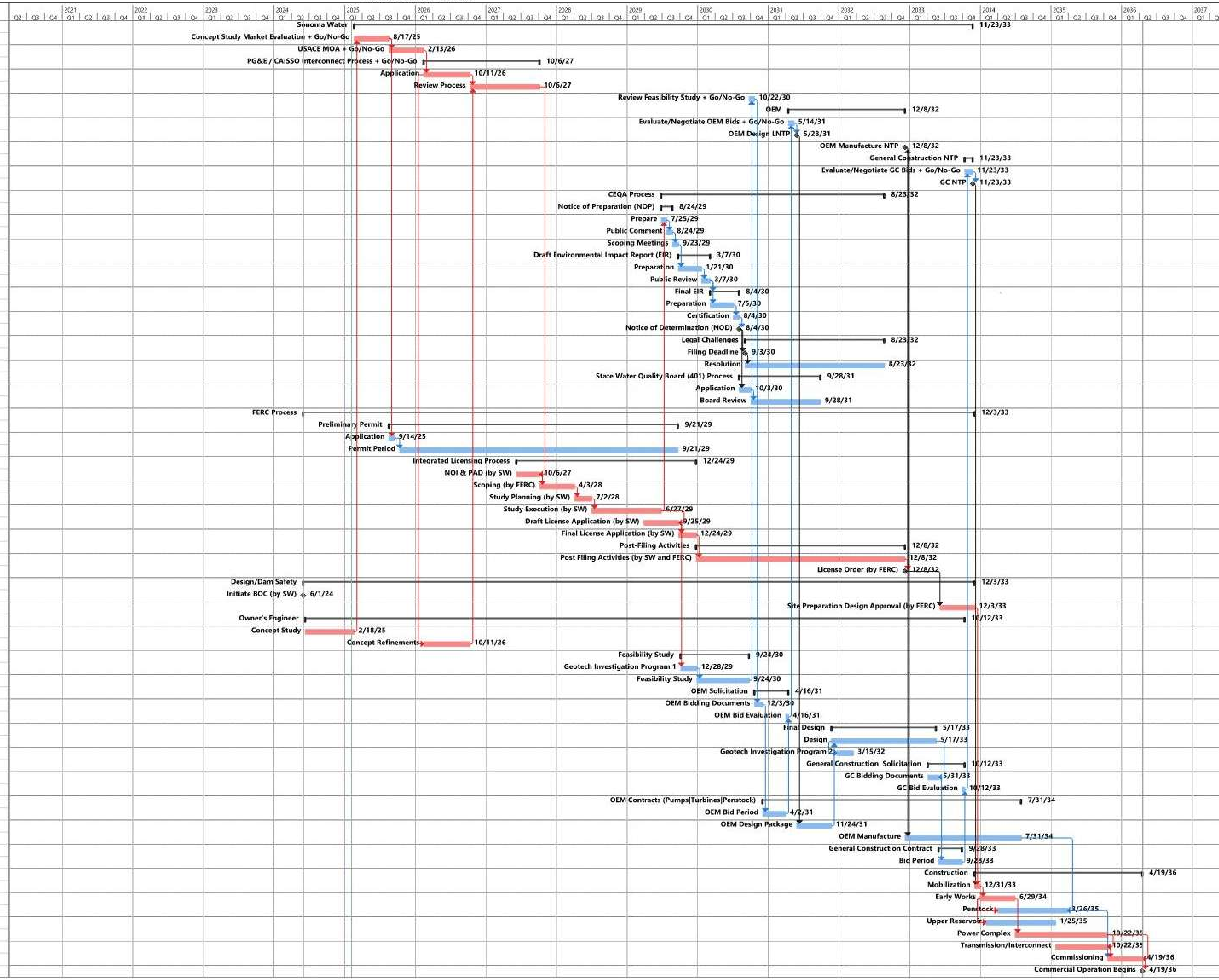
- A memorandum of agreement or similar document would be executed with the USACE.
- An interconnect agreement would be required with PG&E / CAISO with the next opportunity to apply in October of 2026. The approval process would take one calendar year.
- \The ILP would be used to obtain the FERC license. Alternative methods are available; however, this assumption is appropriate for the time being as the overall regulatory timeline can be assumed to be similar at this early stage of study. However, smaller projects often have shorter licensing timelines (https://www.energy.gov/eere/water/articles/new-report-examines-us-hydropower-permitting-process).
- The CEQA process would take place concurrent with the FERC licensing process.
- The Project would be delivered via a conventional design-bid-build contract with owner-supplied equipment.
- Major equipment and materials would be procured directly by Sonoma Water for installation by the general contractor. Major equipment and materials are anticipated to include the following:
  - Pumps and associated motors, variable frequency drives, valves, controls, and switchgear
  - Pelton turbines (two) including turbines, generators, valves, controls, and switchgear
  - GSUs

- Penstock

The IDS is presented on Figure 10-1 with critical tasks shown in red.

Lake Sonoma Pumped Storage Project
Integrated Development Schedule

ID	Task Name	Duration	Start	Finish
1	**Sonoma Water**	**2286 days**	**2/18/2025**	**11/23/2033**
2	Concept Study Market Evaluation + Go/No-Go	6 emons	2/18/2025	8/17/2025
3	USACE MOA + Go/No-Go	6 emons	8/17/2025	2/13/2026
4	**PG&E / CAISSO Interconnect Process + Go/No-Go**	**428 days**	**2/13/2026**	**10/6/2027**
5	Application	8 emons	2/13/2026	10/11/2026
6	Review Process	12 emons	10/11/2026	10/6/2027
7	Review Feasibility Study + Go/No-Go	4 ewks	9/24/2030	10/22/2030
8	**OEM**	**430 days**	**4/16/2031**	**12/8/2032**
9	Evaluate/Negotiate OEM Bids + Go/No-Go	4 ewks	4/16/2031	5/14/2031
10	OEM Design LNTP	0 days	5/28/2031	5/28/2031
11	OEM Manufacture NTP	0 days	12/8/2032	12/8/2032
12	**General Construction NTP**	**30 days**	**10/12/2033**	**11/23/2033**
13	Evaluate/Negotiate GC Bids + Go/No-Go	6 ewks	10/12/2033	11/23/2033
14	GC NTP	0 days	11/23/2033	11/23/2033
15	**CEQA Process**	**823 days**	**6/27/2029**	**8/23/2032**
16	**Notice of Preparation (NOP)**	**42 days**	**6/27/2029**	**8/24/2029**
17	Prepare	4 ewks	6/27/2029	7/25/2029
18	Public Comment	30 edays	7/25/2029	8/24/2029
19	Scoping Meetings	30 edays	8/24/2029	9/23/2029
20	**Draft Environmental Impact Report (EIR)**	**118 days**	**9/23/2029**	**3/7/2030**
21	Preparation	4 emons	9/23/2029	1/21/2030
22	Public Review	45 edays	1/21/2030	3/7/2030
23	**Final EIR**	**107 days**	**3/7/2030**	**8/4/2030**
24	Preparation	4 emons	3/7/2030	7/5/2030
25	Certification	30 edays	7/5/2030	8/4/2030
26	Notice of Determination (NOD)	0 days	8/4/2030	8/4/2030
27	**Legal Challenges**	**514 days**	**9/3/2030**	**8/23/2032**
28	Filing Deadline	0 days	9/3/2030	9/3/2030
29	Resolution	24 emons	9/3/2030	8/23/2032
30	**State Water Quality Board (401) Process**	**300 days**	**8/4/2030**	**9/28/2031**
31	Application	2 emons	8/4/2030	10/3/2030
32	Board Review	12 emons	10/3/2030	9/28/2031
33	**FERC Process**	**2480 days**	**6/1/2024**	**12/3/2033**
34	**Preliminary Permit**	**1069 days**	**8/17/2025**	**9/21/2029**
35	Application	4 ewks	8/17/2025	9/14/2025
36	Permit Period	48 emons	10/12/2025	9/21/2029
37	**Integrated Licensing Process**	**664 days**	**6/8/2027**	**12/24/2029**
38	NOI & PAD (by SW)	4 emons	6/8/2027	10/6/2027
39	Scoping (by FERC)	6 emons	10/6/2027	4/3/2028
40	Study Planning (by SW)	3 emons	4/3/2028	7/2/2028
41	Study Execution (by SW)	12 emons	7/2/2028	6/27/2029
42	Draft License Application (by SW)	6 emons	3/29/2029	9/25/2029
43	Final License Application (by SW)	3 emons	9/25/2029	12/24/2029
44	**Post-Filing Activities**	**772 days**	**12/24/2029**	**12/8/2032**
45	Post Filing Activities (by SW and FERC)	36 emons	12/24/2029	12/8/2032
46	License Order (by FERC)	0 days	12/8/2032	12/8/2032
47	**Design/Dam Safety**	**2480 days**	**6/1/2024**	**12/3/2033**
48	Initiate BOC (by SW)	0 days	6/1/2024	6/1/2024
49	Site Preparation Design Approval (by FERC)	6 emons	6/6/2033	12/3/2033
50	**Owner's Engineer**	**2436 days**	**6/11/2024**	**10/12/2033**
51	Concept Study	36 ewks	6/11/2024	2/18/2025
52	Concept Refinements	8 emons	2/13/2026	10/11/2026
53	**Feasibility Study**	**252 days**	**10/5/2029**	**9/24/2030**
54	Geotech Investigation Program 1	12 ewks	10/5/2029	12/28/2029
55	Feasibility Study	9 emons	12/28/2029	9/24/2030
56	**OEM Solicitation**	**126 days**	**10/22/2030**	**4/16/2031**
57	OEM Bidding Documents	6 ewks	10/22/2030	12/3/2030
58	OEM Bid Evaluation	2 ewks	4/2/2031	4/16/2031
59	**Final Design**	**386 days**	**11/24/2031**	**5/17/2033**
60	Design	18 emons	11/24/2031	5/17/2033
61	Geotech Investigation Program 2	12 ewks	12/22/2031	3/15/2032
62	**General Construction Solicitation**	**136 days**	**4/5/2033**	**10/12/2033**
63	GC Bidding Documents	8 wks	4/5/2033	5/31/2033
64	GC Bid Evaluation	2 ewks	9/28/2033	10/12/2033
65	**OEM Contracts (Pumps|Turbines|Penstock)**	**954 days**	**12/3/2030**	**7/31/2034**
66	OEM Bid Period	4 emons	12/3/2030	4/2/2031
67	OEM Design Package	6 emons	5/28/2031	11/24/2031
68	OEM Manufacture	20 emons	12/8/2032	7/31/2034
69	**General Construction Contract**	**86 days**	**5/31/2033**	**9/28/2033**
70	Bid Period	4 emons	5/31/2033	9/28/2033
71	**Construction**	**620 days**	**12/3/2033**	**4/19/2036**
72	Mobilization	4 ewks	12/3/2033	12/31/2033
73	Early Works	6 emons	12/31/2033	6/29/2034
74	Penstock	12 emons	3/31/2034	3/26/2035
75	Upper Reservoir	12 emons	1/30/2034	1/25/2035
76	Power Complex	16 emons	6/29/2034	10/22/2035
77	Transmission/Interconnect	9 emons	1/25/2035	10/22/2035
78	Commissioning	6 emons	10/22/2035	4/19/2036
79	Commercial Operation Begins	0 days	4/19/2036	4/19/2036



Page 1

Figure 10-1. Integrated Development Schedule

11 Summary and Recommended Next Steps

11.1 Summary

As described in this report, HDR conducted a concept-level evaluation of the identified site near Lake Sonoma for development of a pumped storage hydropower project. Several configuration alternatives were considered, and one was advanced to illustrate key project components and inform a preliminary geological assessment, environmental assessment, AACE Class 5 OPCC, and IDS.

HDR did not identify any technical fatal flaws associated with constructing the Project based on this stage of conceptual study. As with all hydropower projects, any unfavorable geologic conditions present risks, but these risks can be reduced or mitigated through further investigations, appropriate designs, and contingency planning.

This report includes an overview of the FERC licensing/exemption process, which includes consultation and compliance with various regulatory agencies. Environmental desktop research and field investigations were outside the scope of this study; however, resource studies that may be required in future phases of study have been identified for reference.

The preliminary Project configuration would result in nominal pumping and generating capacities of 20 MW. Based on these capacities and energy modeling, Sonoma Water and SCP estimated a mean annual net revenue of approximately $3.48 million, consisting of approximately $2.28 million and $1.20 million for energy arbitrage and resource adequacy respectively. Assuming an annual operations and maintenance cost of $1 million (see Section 8.4), results in the following cursory payback period:

$$N = CAP \div (REV - OM)$$

Where:

N = Payback period, years

CAP = Capital Cost, $

REV = Annual Revenue, $

OM = Annual operations and maintenance costs, $

Table 11-1 below presents two alternative approaches to estimating the Project payback period, one conservative and one unconservative. Differences between the two approaches include a) transmission cost of ownership with monthly being conservative and lump sum being unconservative, and b) including or excluding a 40% investment tax credit[8].

[8] The Inflation Reduction Act of 2022 includes provisions for a 40% investment tax credit for energy storage projects that meet certain criteria including but not limited to prevailing wages, apprenticeship programs, energy community impacts, and start of construction.

Table 11-1. Approximate Project Payback Periods

Item	Conservative	Unconservative
Capital Cost	$208,700,000	$208,700,000
Transmission Cost of Ownership (Lump Sum)	$0	$31,300,000
Investment Tax Credit	$0	$83,480,000
Net Capital Cost	$208,700,000	$156,520,000
Annual O&M Costs	$1,000,000	$1,000,000
Transmission Cost of Ownership (Annual)	$0	$31,300,000
Annual Energy Revenue	$2,280,000	$2,280,000
Annual Capacity Revenue	$2,400,000	$2,400,000
Approximate Payback Period, years	141	43

11.2 Recommended Next Steps

HDR understands that Sonoma Water will further evaluate the potential benefits of the Project as well as requirements associated with interconnection to the PG&E transmission system. Should Sonoma Water decide to advance the Project to the next phase of study, the following immediate steps are recommended. These and future steps are identified in the IDS.

Sonoma Water could explore ways to improve the cost effectiveness of this pumped storage hydropower project including:

- Configure the upper reservoir as a dammed impoundment rather than an excavated reservoir. A dammed impoundment would be less capital cost and would improve the cost effectiveness of the project.
- Configure the upper reservoir as large as practical based on the Army Corps property limits, not based on keeping the power utility interconnection below the 20 MW Rule 21 threshold. The unit capital cost could then potentially go from $10,000/kW to the values shown on Figure 8,1 in the $5,000/kW to $3,000 kW range.
- Do not use actual historical lake elevations as the assumption for lower reservoir level. Instead, use the median historical lake elevations as the basis for lower reservoir level since incorporation of FIRO should result in higher lake elevations in the future. A higher lake elevation of the lower reservoir would result in lower pumping costs and improve the life cycle cost effectiveness of the project.

- Supplement the project funding with external state or federal funding that incentivizes energy resiliency.

At this time, none of these actions are expected to improve the cost effectiveness and payback of the project substantially.

Should Sonoma Water decide to advance the Project to the next phase of study, the following immediate steps are recommended. These and future steps are identified in the IDS.

- Perform additional studies to select and refine the desired Project capacity and configuration.
- Apply for interconnect approval from PG&E / CAISO.
- Apply for a FERC Preliminary Permit.
- Perform a Feasibility Study including formal geotechnical investigation program, formal OEM outreach, refinement of Project components, and updated OPCC.
- Prepare a PAD as part of the FERC licensing or exemption process.

Note that the IDS also identifies several milestones/gateways that provide an opportunity for Sonoma Water to re-evaluate Project costs, construction risks, geological risks, and environmental risks and make go/no-go decisions regarding whether to continue advancing the Project design.

12 References

ASTM International (ASTM), 2002, ASTM D2938-95(2002): Standard Test Method for Unconfined Compressive Strength of Intact Rock Core Specimens: ASTM International, West Conshohocken, PA, 6 p.

Baldocchi, D., Dralle, D., Jiang, C., and Ryu, Y. 2019. How Much Water is Evaporated Across California? A Multiyear Assessment using a Biophysical Model Forced with Satellite Remote Sensing Data. Water Resources Research, 55, 2722–2741. April 5, 2019.

Bennison, A.P., Blake, M.C., Cox, B.F., Elder, W.P., Ernst, W.G., Harms, T., and Nilsen, T.H. 1991. Franciscan Complex, Coast Range ophiolite and Great Valley sequence: Pacheco Pass to Del Puerto Canyon, California, in Geologic excursions in northern California: San Francisco to the Sierra Nevada, p. 85–100.

Blake, M.C., Jr., Graymer, R.W., and Jones, D.L. 2000. Geologic map and map database of parts of Marin, San Francisco, Alameda, Contra Costa, and Sonoma Counties, California: U.S. Geological Survey Miscellaneous Field Studies, MF-2337, 29 p.

California Department of Fish and Wildlife (CDFW). 2024. California Natural Diversity Database (CNDDB). [Online] URL: https://wildlife.ca.gov/Data/CNDDB

California Division of Dam Safety (DSOD). 2025. Jurisdictional Sized Dams. [Online] URL: https://water.ca.gov/Programs/All-Programs/Division-of-Safety-of-Dams/Jurisdictional-Sized-Dams.

California Public Utilities Commission (Cal. PUC). 2023. “Electric Rule No. 21 – Generating Facility Interconnections (Sheet No. 53279-E)”, August 29, 2023.

Caterpillar Inc. (2022). Caterpillar Performance Handbook. Caterpillar Inc., Peoria, IL, 33 p.

Electric Power Research Institute (EPRI). 1990. Pumped-Storage Planning and Evaluation Guide, Report GS-6669, January 1990. Palo Alto, CA: EPRI

Electric Power Research Institute (EPRI). 2011. Quantifying the Value of Hydropower in the Electric Grid: Plant Cost Elements. Palo Alto, CA: EPRI.

Farrar, C.D., Metzger, L.F., Nishikawa, T., Koczot, K.M., and Reichard, E.G. 2006. Geohydrologic characterization, water-chemistry, and ground-water flow simulation model of the Sonoma Valley area, Sonoma County, California, with a section on basement rock configuration interpreted from gravity data by Victoria E. Langenheim: U.S. Geological Survey Scientific Investigations Report 2006-5092, 167 p

Federal Energy Regulatory Commission (FERC). 2021. Engineering guidelines for the Evaluation of Hydropower Projects, Chapter 15 – Supporting Technical Information Document and Digital Project Archive, December 2021.

Federal Energy Regulatory Commission (FERC). 2020. Licensing Processes - Matrix Comparing Three Licensing Processes. [Online] URL: Licensing Processes - Matrix Comparing Three Licensing Processes | Federal Energy Regulatory Commission.

Gutierrez, C.I., Holland, P.J., and Delattre, M.P. 2012. Preliminary geologic map of the Geyserville 7.5' quadrangle, Sonoma County, California: A digital database. California Geological Survey, Preliminary Geologic Maps PGM-12-01. 1:24,000.

Hecker, S., and Randolph Loar, C.E. 2018. Map of recently active traces of the Rodgers Creek Fault, Sonoma County, California: U.S. Geological Survey Scientific Investigations Map 3410, 7 p., 1 sheet

Huffman, M.E., Armstrong, C.F., and Greensfelder, R.W. 1980. Geology for Planning in Sonoma County: California Department of Conservation, Division of Mines and Geology, Special Report 120, 29 p.

McLaughlin, R.J., Wagner, D.L., Sweetkind, D.S., Sarna Wojcicki, A.M., Rytuba, J.J., Langenheim, V.E., Fleck, R.J., Jachens, R.C., and Deino, A. 2005. Late Neogene transition from transform to subduction margin east of the San Andreas Fault in the wine country of the northern San Francisco Bay Area, California, in Fieldtrip Guidebook and Volume Prepared for the Joint Meeting of the Cordilleran Section, GSA and Pacific Section, AAPG, April 29–May 1, 2005, San Jose, California: Society for Sedimentary Geology, Stevens, C. and Cooper, J., eds., 112 p.

Oak Ridge National Laboratory (ORNL). 2015. Hydropower Baseline Cost Modeling, Version 2; ORNL/TM-2015/471. Oak Ridge, TN.

Petersen M.D., Shumway A.M., Powers P.M., et al. 2024. The 2023 US 50-State National Seismic Hazard Model: Overview and implications. Earthquake Spectra. 2024;40(1):5-88.

Seiders, V.M. 1988. Origin of conglomerate stratigraphy in the Franciscan assemblage and Great Valley sequence, northern California: Geology, v. 16, p. 783-7871.

Sonoma Clean Power (SCP). 2024. "Lake Sonoma Pumped Hydro Storage Interconnection Options and Cost Estimates (presentation)", November 2024.

Sonoma County Water Agency and Mendocino County Russian River Flood Control & Water Conservation Improvement District (Sonoma). 2022. "Technical Memorandum – Lake Mendocino Storage and Russian River Water Supply Planning for 2022/2023", December 14, 2022.

Sonoma Water. 2024. [Online] URL: https://www.sonomawater.org.

U.S. Army Corps of Engineers. 2014. "ER 1110-2-1156 - Safety Of Dams – Policy And Procedures, March 2014.

U.S. Climate Data. 2024. [Online] URL: https://www.usclimatedata.com.

U.S. Department of Commerce, National Oceanic and Atmospheric Administration (NOAA), U.S. Department of the Army Corps of Engineers (USACE). 1999. "Hydrometeorological Report No. 59 – Probable Maximum Precipitation for California", February 1999.

U.S. Department of the Interior, Bureau of Reclamation (USBR). 2024. Historical O&M Cost Index Values. [Online] URL: https://www.usbr.gov/assetmanagement/O&M%20Cost%20Index/Att1-Historical-Indexes.pdf.

U.S. Department of the Interior, Bureau of Reclamation (USBR). 2022. Design Standards No. 14 - Appurtenant Structures for Dams (Spillways and Outlet Works) - Chapter 4: General Outlet Works Design Considerations - Phase 4 Final, February 2022.

U.S. Department of the Interior, Bureau of Reclamation (Reclamation). 2020. Reclamation-Wide Pumped Storage Screening Study. Issued September 2014 and revised February 2020.U.S. Department of the Interior, Bureau of Reclamation (USBR). 2001. Engineering Geology Field Manual, 2nd Ed.

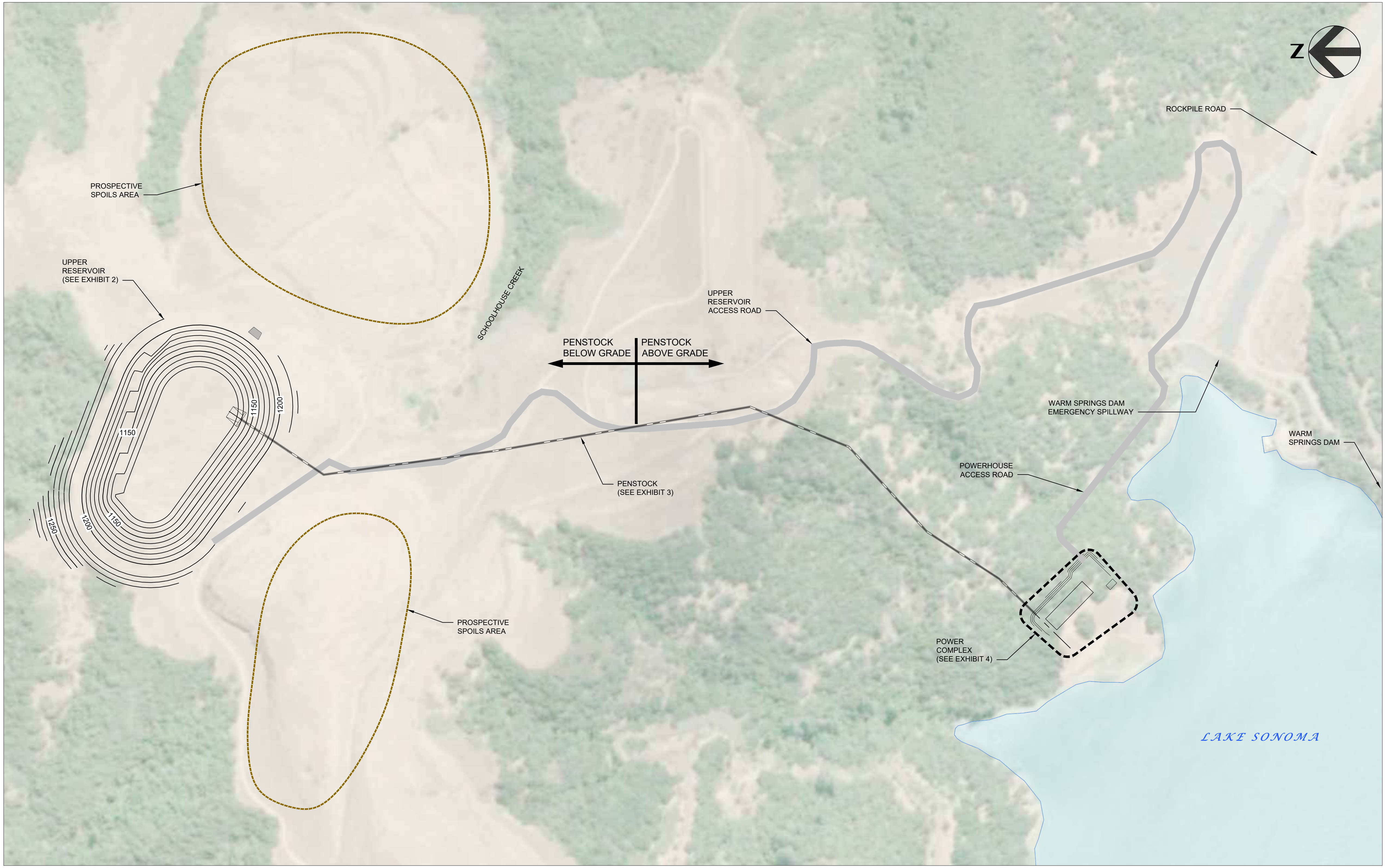
U.S. Department of the Interior, Bureau of Reclamation (USBR). 2001. Engineering Geology Field Manual, 2nd Ed. Vol I.

U.S. Fish and Wildlife Service (USFWS). 2024. Information for Planning and Consultation (IPaC). [Online] URL: https://ipac.ecosphere.fws.gov/

U.S. Geologic Survey (USGS). 1944. 7.5-Minute Topographic Map, "Skaggs Spring Quadrangle", Edition of 1944.

Appendix A

Exhibits



PLAN

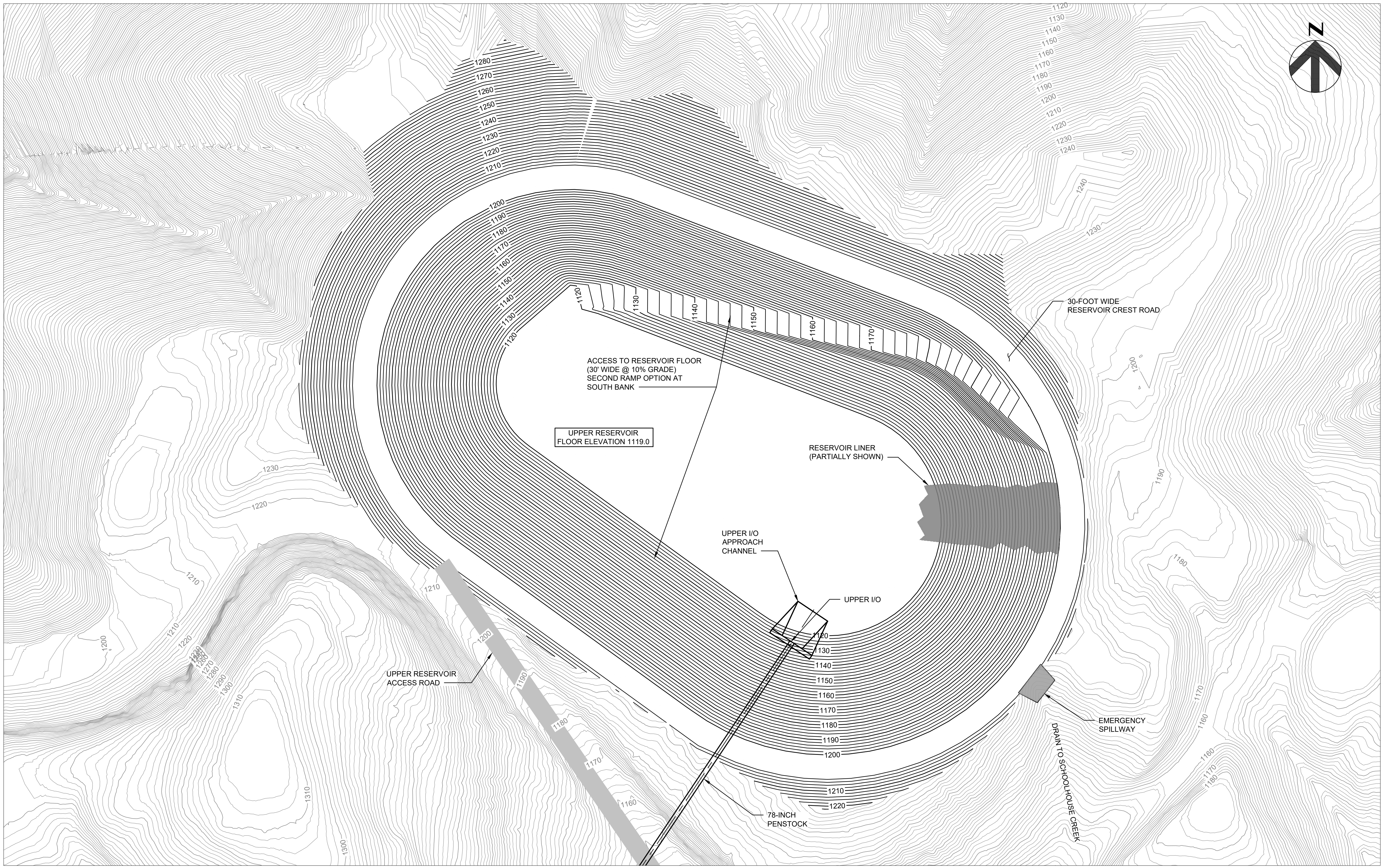
0 100 200 400
SCALE IN FEET

HDR C:\pwworking\west01\d3823896\Sheet_1.dwg PRINTED: 2/4/2025 9:10:38 AM BY: RCARPENT

HDR | 75 YEARS Sonoma Water SERVING THE COMMUNITY SINCE 1949

OVERALL SITE LAYOUT

PUMPED STORAGE HYDROPOWER CONCEPT



PLAN

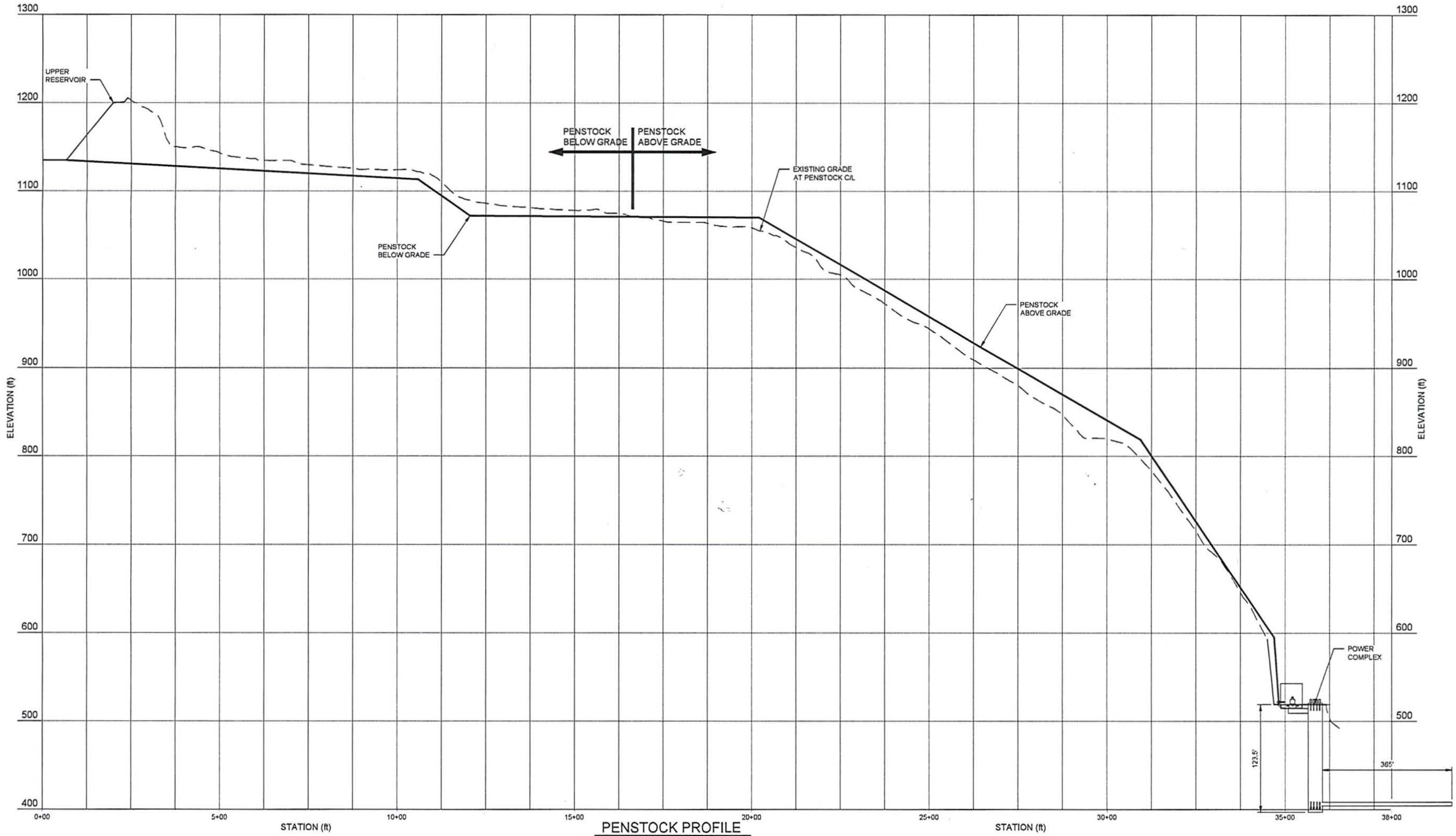
0 35 70 140

SCALE IN FEET

HDR | Sonoma Water 75 YEARS — SERVING THE COMMUNITY SINCE 1949

UPPER RESERVOIR PLAN

PUMPED STORAGE HYDROPOWER CONCEPT

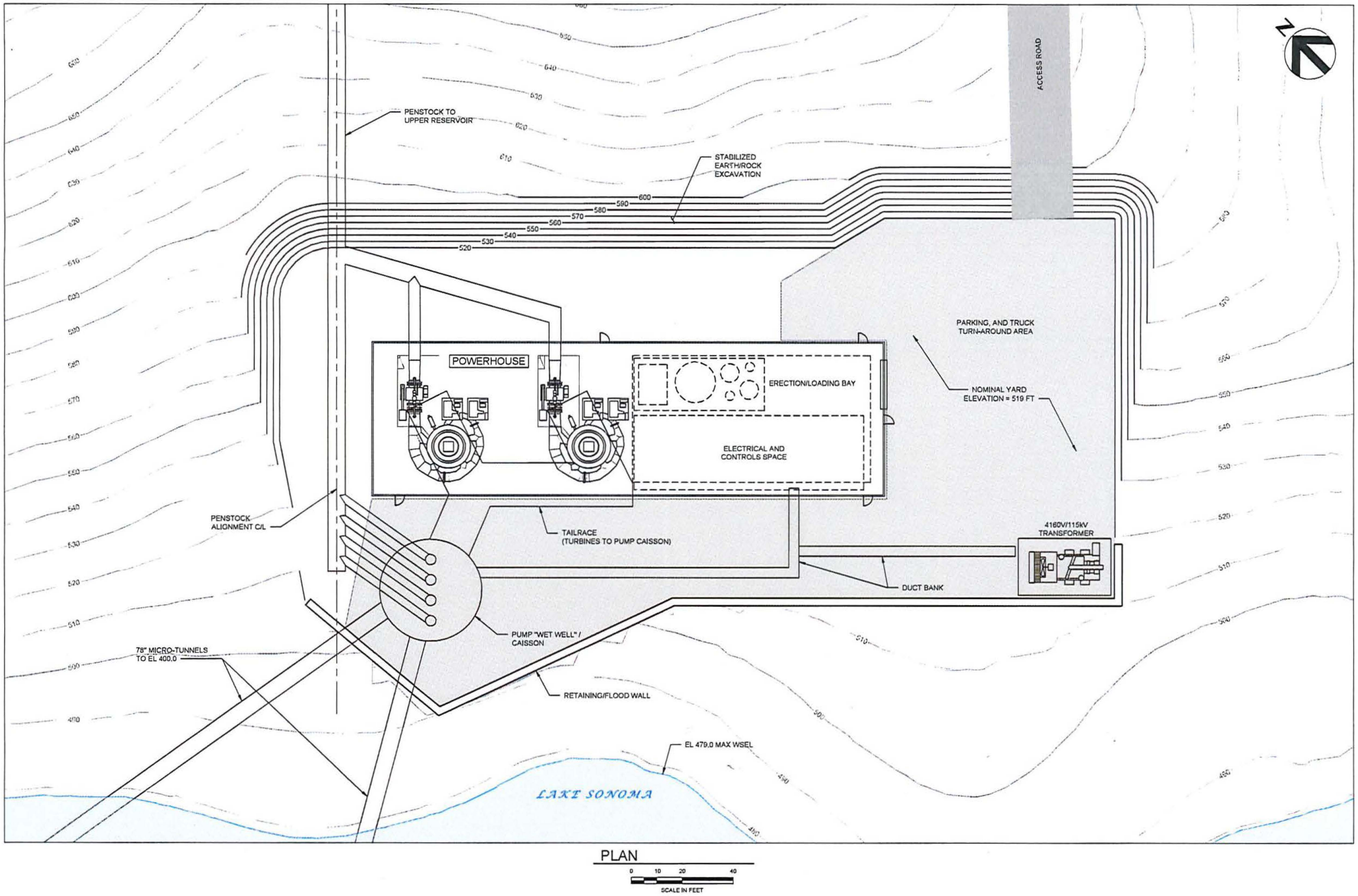


PENSTOCK PROFILE
SCALE: 1" = 140' H 1" = 56' V

Sonoma Water
75 YEARS
SERVING THE COMMUNITY SINCE 1949

PENSTOCK PROFILE
Exhibit 3

PUMPED STORAGE HYDROPOWER CONCEPT



HDR | 75 YEARS Sonoma Water SERVING THE COMMUNITY SINCE 1949

POWER COMPLEX PLAN
Exhibit 4

PUMPED STORAGE HYDROPOWER CONCEPT

Appendix B

OEM Information

Appendix B1

Canyon Hydro

Canyon Hydro

December 5, 2024

Paul Berkshire, P.E.
HDR
907-360-1015
paul.berkshire@hdrinc.com

Dear Mr. Berkshire,

Thank you for the opportunity to assist you with evaluating the Lake Sonoma project. Canyon Hydro specializes in manufacturing Pelton turbines and providing complete powerhouse equipment packages for the conditions at this site.

Canyon Hydro has been building high quality turbine systems in the USA for over 48 years. From day one, we have remained committed to three guiding principles:

1. **Efficiency:** Efficiency has undergone continual refinement over the years, and we believe our turbines match or exceed the efficiency of any other turbine manufacturer. Our entire staff recognizes the critical nature of the hydraulic design resulting in the best possible performance.
2. **Durability:** We recognize that a turbine system must run continuously for years at a time. For this reason, we use only the highest quality alloys, bearings, and controls.
3. **Customer Support:** We are often told our customer support is the best in the business. We work closely with you throughout the process, and if an outage should occur, system recovery becomes our highest priority.

Based on your correspondence, we are considering a net head of 700 feet and a required output of 20 MW. For these conditions, we recommend a design flow of approximately 400 cfs. Based on these parameters, we offer an equipment package based on Canyon Hydro twin, vertical Pelton turbines. Our suggested equipment package includes: (2) 48" ball type turbine inlet valves with hydraulic open and counterweight closure, (2) 48" dismantling joints, (2) Canyon Hydro custom Pelton turbines with hydraulic actuation, (2) 10.8 MW-4160VAC-3ph-60Hz synchronous generators, (2) oil lube skids (2) hydraulic power units, medium voltage switchgear to parallel the generators with the local electrical grid and (2) PLC based controls panels with OIU, metering and utility grade protective relays. Expected system production for this equipment package is 20.4 MW.

Budget estimate 20.4 MW equipment package, as described…………………..………….$12,574,500.00

Estimate FOB Deming, Washington

Normal Terms	15% to begin final design
	30% to begin construction following final design approval
	25% mid-project
	20% upon notice of readiness to ship and prior to shipment
	10% upon successful startup or 120 days following notice of readiness to ship, whichever is first

Submittals	3-4 months following receipt of final design payment
Normal Delivery	10-12 months following design approval and receipt of construction payment

*We suggest budgeting $50,000.00 for freight to the site.
*We suggest budgeting $60,000.00 for startup, commissioning and training services.

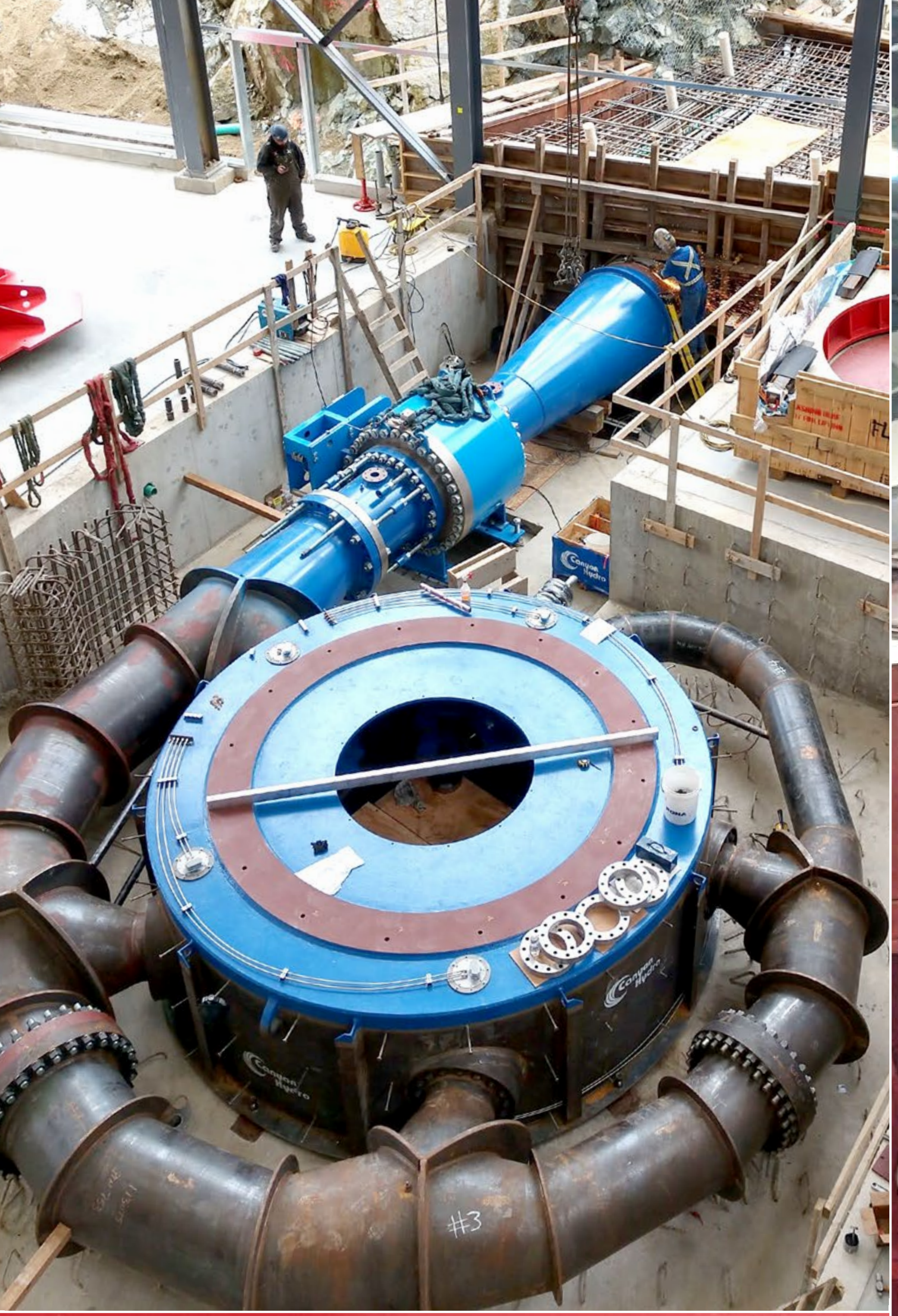
The equipment package described will be custom designed to meet the particular requirements of the Lake Sonoma site and project. As the project progresses and requirements are defined, we will be pleased to refine our estimate or offer a firm quotation. Budget estimates are offered for planning purposes only but are often within 10% of an actual quotation for the same equipment package.

This estimate does not include equipment installation or electrical wiring required to connect the equipment in the powerhouse or to the electrical grid. Transformer equipment is not included in this estimate. Our estimate is based on typical requirements for a project this size. Special requirements may affect pricing.

As always, we thank you for the opportunity to work with HDR and we appreciate your continued interest in working with Canyon Hydro. Please contact me as questions arise or as additional project information becomes available.

Sincerely,

Eric Melander
Vice President of Sales

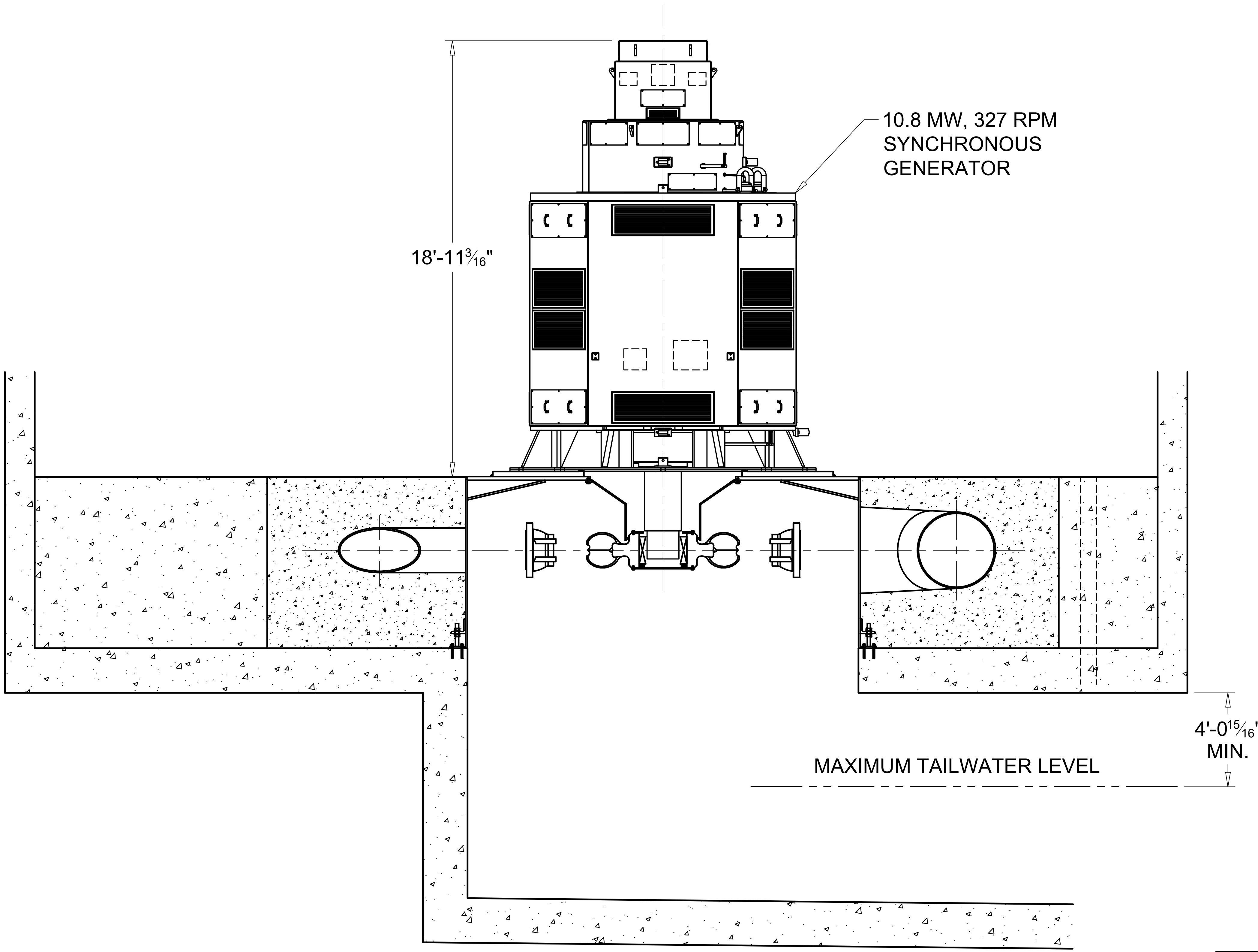


Canyon Hydro

Trio Creek

Harrison Lake, British Columbia — 25 MW 5-Nozzle Pelton


WESTWARD

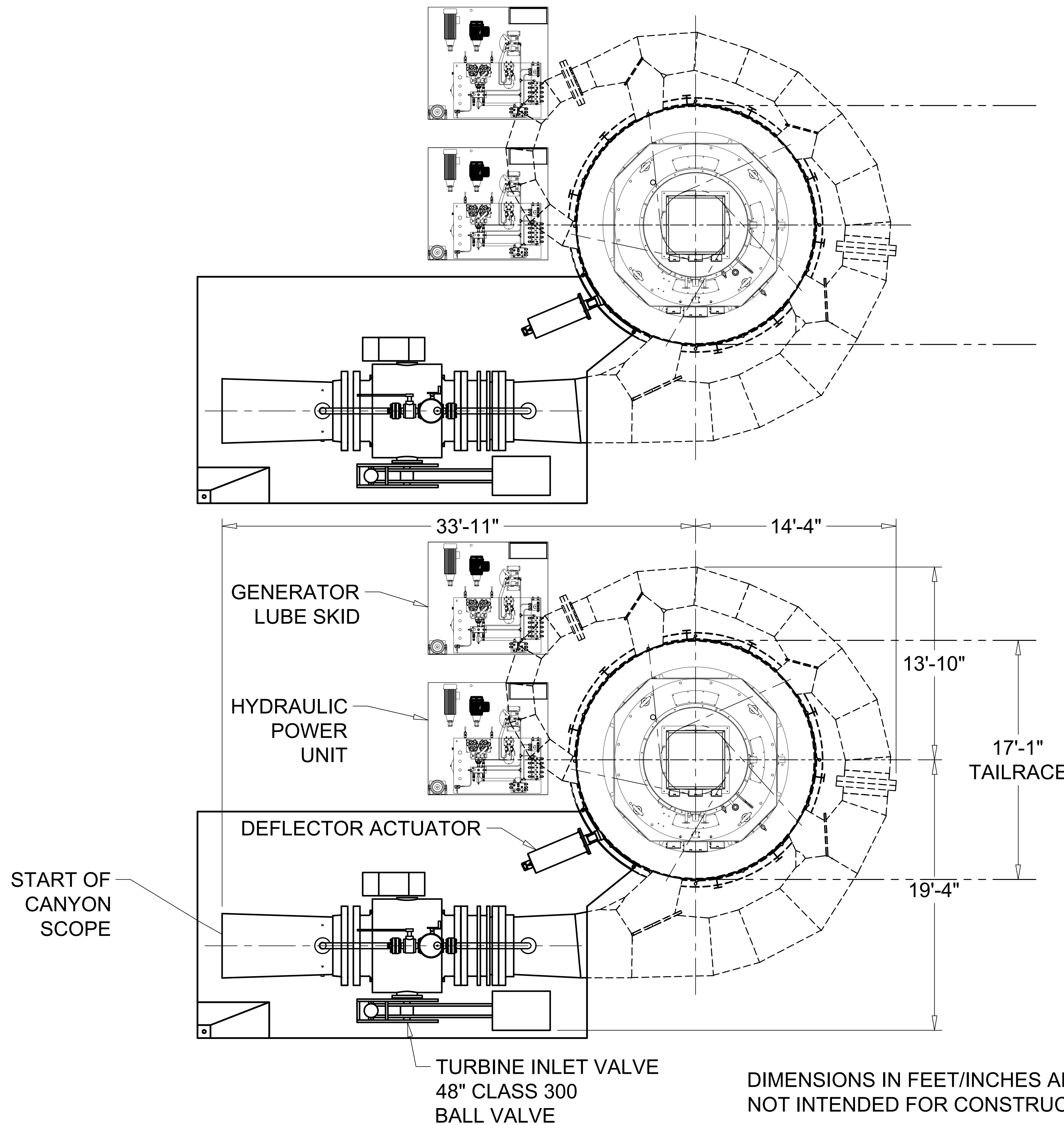


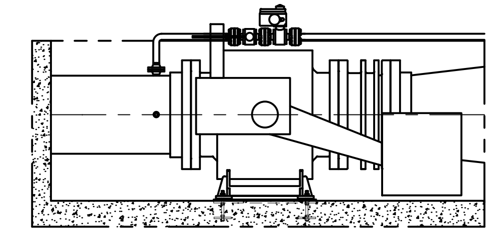
DIMENSIONS IN FEET/INCHES ARE APPROXIMATE
NOT INTENDED FOR CONSTRUCTION

LAKE SONOMA

Canyon Hydro
5500 Blue Heron Lane
Deming, Washington 98244
(360) 592-5552
the water power division of Canyon Industries, Inc

FILE: ELEVATION VIEW | DATE: 2024-12-04





TIV PIT SECTION

DIMENSIONS IN FEET/INCHES ARE APPROXIMATE
NOT INTENDED FOR CONSTRUCTION

LAKE SONOMA

Canyon Hydro
5500 Blue Heron Lane
Deming, Washington 98244
(360) 592-5552
the water power division of Canyon Industries, Inc

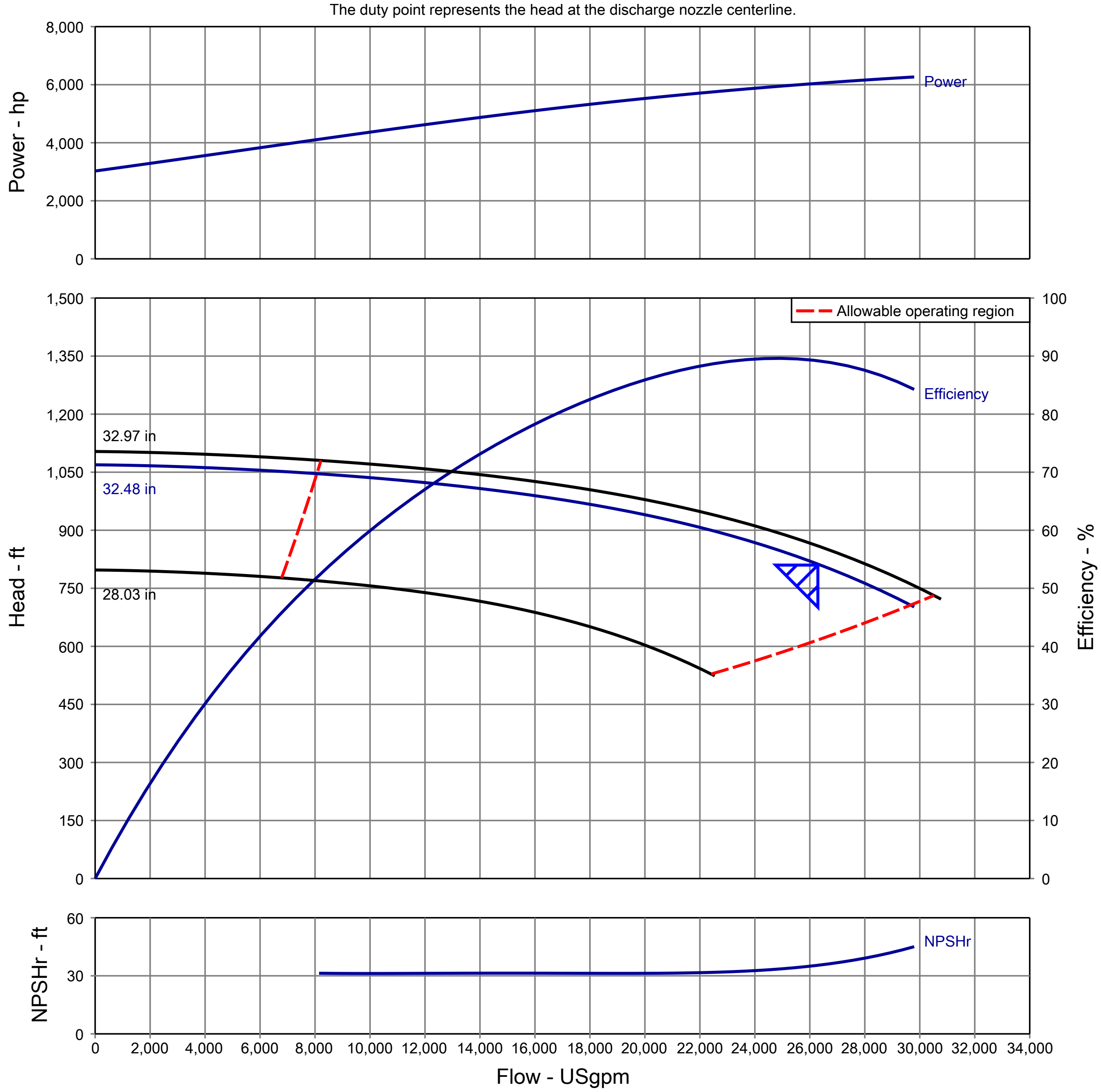
FILE: PLAN VIEW | DATE: 2024-12-04

Appendix B2

Trillium Flow Technologies

Customer : HDR, Inc.
Quote number : WG-2400924
Project name : Lake Sonoma Pumped Storage

Pump performance. Adjusted for construction, viscosity, friction and power losses of lineshaft and thrust bearings. Not adjusted for any static lift.
The duty point represents the head at the discharge nozzle centerline.

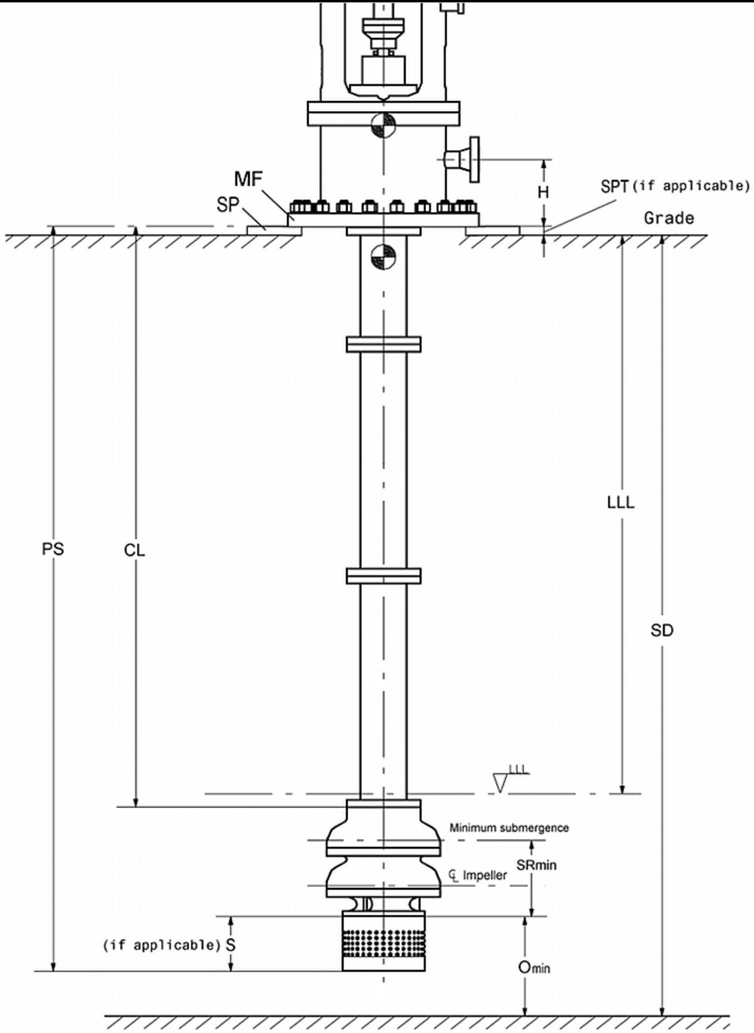


Item number	: 001	Size	: 51 CPP 40
Liquid description	:	Stages	: 4
Quantity	: 4	Speed, rated	: 890 rpm
Quote number	: WG-2400924	Efficiency (bowl / pump)	: 89.22 / 89.20 %
Date last saved	: 04 Dec 2024 5:21 PM	Power (bowl / pump)	: 6,047 / 6,047 hp
Flow, rated	: 26,293.0 USgpm	NPSH required	: 35.44 ft
Differential head / pressure, rated	: 810.0 ft	Viscosity	: 1.00 cP
		Cq/Ch/Ce/Cn [ANSI/HI 9.6.7-2010]	: 1.00 / 1.00 / 1.00 / 1.00
Fluid density, rated / max	: 1.000 / 1.000 SG	Ns (imp. eye flow) / Nss (imp. eye flow)	: 2,503 / 10,318 US Units

General Arrangement

FLANGE	SIZE	RATING	FACING	POSITION
SUCTION	-	-	-	-
DISCHARGE	26	150	RF	Side

WEIGHT	-
PUMP	26,951.9 lb
DRIVER	0.00 lb
TOTAL	26,951.9 lb



Dimensions	
PS	Pump length
CL	Column length
LLL	Low liquid level
SR min	Minimum submergence to prevent vortexing
O min	Minimum clearance below suction bell
S	Strainer Length
H	Discharge nozzle centerline height
SPT	Soleplate thickness
MF	Mounting Flange
SD	Sump Depth

Notes

All Dimensions are to be considered preliminary.

SRmin is minimum submergence required to prevent vortex. It does not consider any NPSH margin

PS	CL	LLL	SR min	O min	S	H	SPT	MF	SD
227 in	51.18 in	0.00 in	78.74 in	21.65 in	19.69 in	29.53 in	-	50" ANSI B16.47 B	240 in

Customer	: HDR, Inc.	Quote number	: WG-2400924	Driver Rating	: 6,303 hp
Customer reference	: RFQ for Vertical Pumps	Pump Size	: 51 CPP 40	Quantity of pumps	: 4
Item number	: 001	Stages	: 4	Date last saved	: 04 Dec 2024 5:21 PM
Service	:	Pump Speed	: 890 rpm		

Appendix C

Sonoma Clean Power Interconnection Evaluation

Lake Sonoma Pumped Hydro Storage Interconnection Options and Cost Estimates

Sonoma Clean Power

Cost Comparison for Options

Interconnection Options	Option 1 : New 12 kV feeder to Geyserville Sub	Option 2: 115 kV Interconnection to Cloverdale 115 kV Sub	Option 3: 60 kV Interconnection to Geyserville 60 kV Sub
Interconnection Voltage	12 kV	115 kV	60 kV
Maximum Interconnection Capacity (MW)	12	100	50
Gen Tie Length	6.5 Miles	9 Miles	6.5 Miles
Gen-Tie Cost	$ 5,440,000	$ 19,134,000	$ 13,819,000
Substation Work Cost	$ 1,525,000	$ 2,115,000	$ 27,000,000
Total Cost $	$ 6,965,000	$ 21,249,000	$ 40,819,000
$/MW	$ 580,416.67	$ 212,490.00	$ 816,380.00

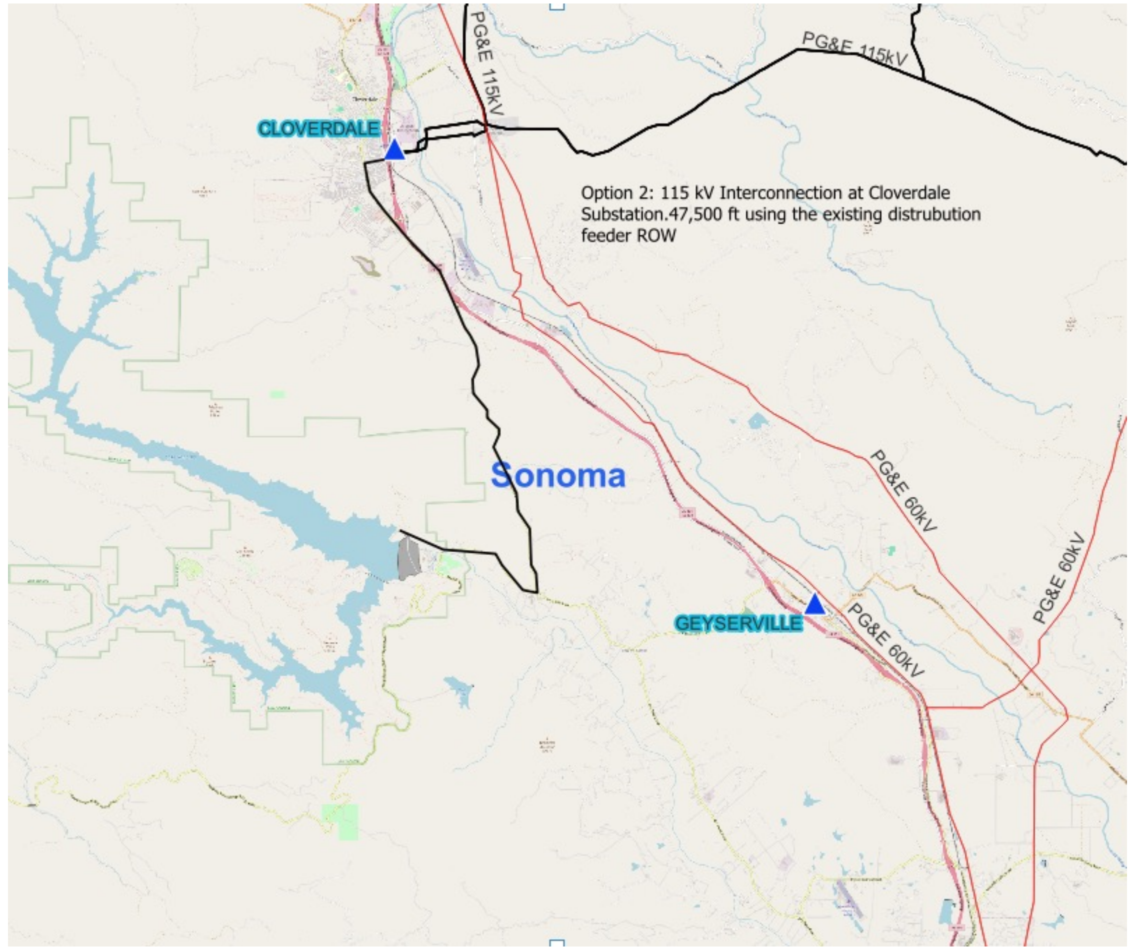
Option 1: New 12 kV circuit out of Geyserville Substation

Addition of 12 kV Feeder Breaker at Geyserville Substation

Option 1 : Cost Estimates

Distribution Upgrades	Cost ($)	
Dedicated gen tie feeder breaker and recloser block at Geyserville Substation	$	1,400,000
New Gen Tie Feeder - 34,000 ft of OH conductor from substation to POI at $160/ft	$	5,440,000
Generating Facility (Metering & Commissioning)	$	125,000
Total	$	6,965,000
Monthly Cost of Ownership (Total * 0.86 %)	$	59,899
One-Time COO in lieu of Monthly COO (Total*0.86%*14.28*12)	$	10,264,293

Option 2: 115 kV interconnection to Cloverdale Substation

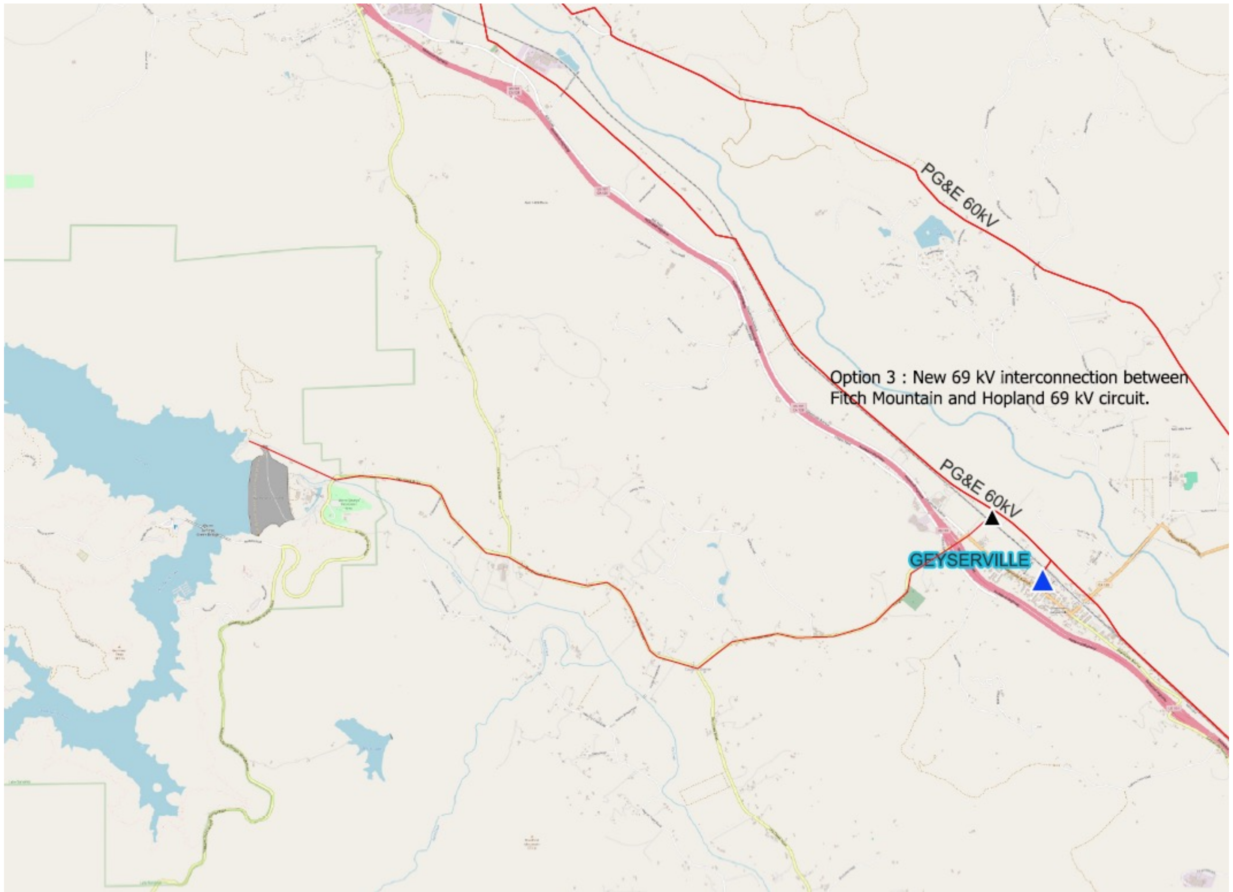


Cloverdale 115 kV substation Layout should allow expansion at 115 kV

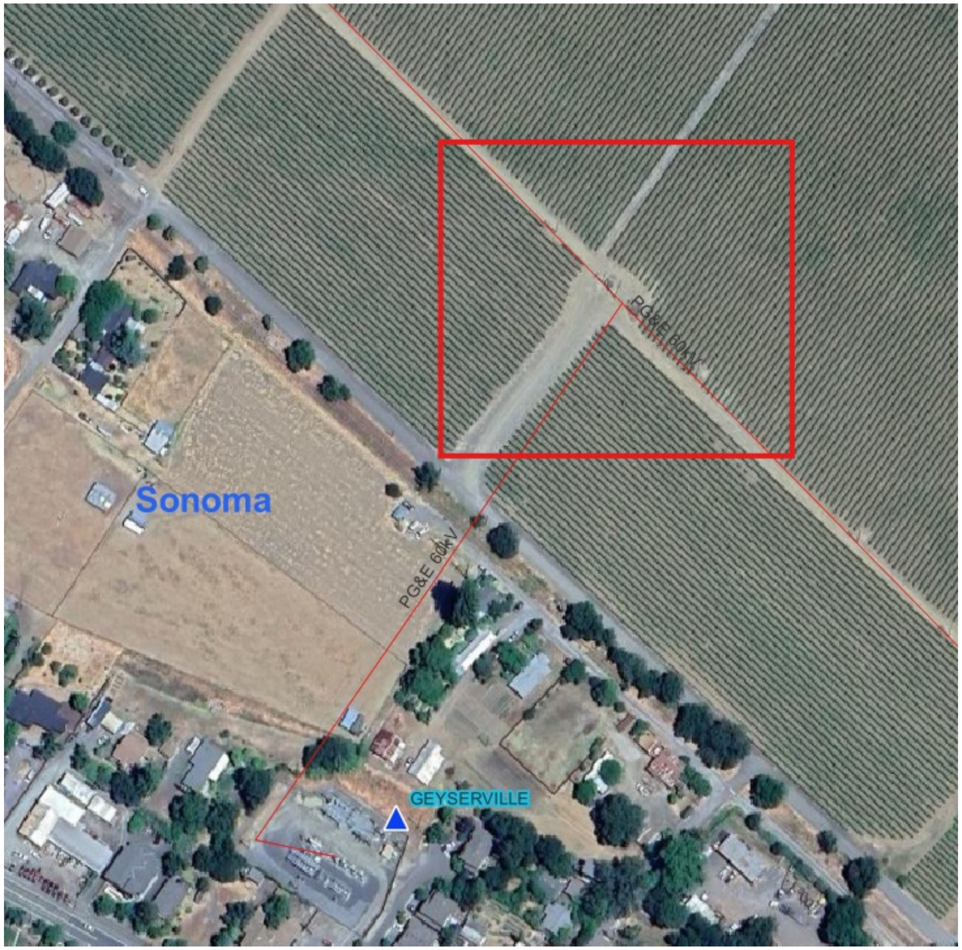
Option 2 : Cost Estimate

Interconnection Facilities	Cost ($)
Substation Work (Add Single Breaker) & Telemetry	$ 2,115,000
115 kVTransmisison Line Cost (Tubular Construction) -9 miles at $2,126,000 per mile	$ 19,134,000
Total	$ 21,249,000
Monthly Cost of Ownership (Total * 0.86 %)	$ 182,741
One-Time COO in lieu of Monthly COO (Total*0.86%*14.28*12)	$ 31,314,566

Option 3: New 60 kV interconnection



60 kV interconnection at Geyserville JCT 60 kV with a new 60 kV substation.



Option 3: Cost Estimates

Interconnection Facilities	Cost ($)
New Substation Total	$ 27,000,000
60 kV Transmisison Line Cost - 6.5miles at $2,126,000 per mile	$ 13,819,000
Total	$ 40,819,000
Monthly Cost of Ownership (Total * 0.86 %)	$ 351,043
One-Time COO in lieu of Monthly COO (Total*0.86%*14.28*12)	$ 60,154,797

Appendix D

PSH vs BESS Lifecycle Cost Evaluation

Memo

Date:	Thursday, August 28, 2025
Project:	PSH vs BESS Lifecycle Cost Evaluation
To:	Lake Sonoma Development
From:	HDR

Executive Summary

Sonoma Water retained HDR to perform a conceptual-level study for a new pumped storage hydropower (PSH) project that would utilize the existing Lake Sonoma as its lower reservoir. The project would be capable of producing 20MW over a 14-hour period. As the PSH concept study report was near completion, Sonoma Water requested that HDR compare the economics of this PSH project to a hypothetical alternative facility implementing Lithium Ion (Li-Ion) battery energy storage system (BESS) technology. The table below summarizes the alternatives and provides a comparison of the operating and maintenance (O&M) cost associated with each technology (excluding auxiliary load) over a 30-year evaluation period. Additional comparative details are provided in the sections below.

Table EX-1. Summary of Alternatives

Parameter	Units	Alternative 1 PSH	Alternative 2 Li Ion BESS
Power Output	MW	20	20
14-hour Energy Storage	MWH	280	280
14-hour Discharge Duration	hr	14	14
30 Year Lifecycle Cost			
NPV of Initial Capital Cost (2025 US$)	$MM	$261	$94[1]
NPV of Annual O&M (2025 US$)	$MM	$19	$10
NPV of Financing Cost (2025 US$)	$MM	$56	$38
NPV of Charging Cost (2025 US$)	$MM	$32	$22
NPV of Maintenance Cost (2025 US$)	$MM	$0	$100
NPV of Total Lifecycle Cost (US$)	$MM	$368	$265
Levelized Cost (US$)	$/MWH	$1,063	$764
Levelized Cost (US$)	$/kW-mo	$157	$113

1 See Appendix A

1. Background

Sonoma Water retained HDR to perform a conceptual-level study for a new pumped storage hydropower (PSH) project that would utilize the existing Lake Sonoma as its lower reservoir. The project would be capable of producing 20MW of output over a duration of 14 hours, i.e., 280 MWh. As the concept study report was near completion, Sonoma Water requested HDR to compare the lifecycle cost of the PSH with a similarly sized battery energy storage system (BESS) facility over a 30-year operating period.

The comparative BESS system would be dispatched similarly to the PSH system as modeled by Sonoma Clean Power.

1.1 Resource Alternatives Description

For this evaluation, two technology options were considered:

- 20 MW 14-hour PSH
- 20 MW 14-hour BESS

Details of the pumped hydro facility are provided in HDR's 2025 Concept Study Report. The facility is envisioned to operate as a closed cycle pumped hydroelectric facility with an upper and lower reservoir. Warm Springs dam impounds Lake Sonoma which would serve as the Project's lower reservoir. Excess grid energy can be stored as potential energy by pumping water from the lower reservoir to the upper reservoir allowing it to be discharge through the turbines when called to dispatch later.

The Li-Ion BESS facility is envisioned as an array of individual containerized Li-Ion battery modules covering approximately 7 acres for 20MW 14-hour capability including future augmentation. The BESS would likely be constructed as three, 20MW 4-hour systems and one, 20MW 2-hour system since Li-ion battery and inverter suppliers have narrowed their offerings to primarily 2 to 4-hour systems. The BESS systems will then be dispatched sequentially to achieve the 14-hour discharge. Excess grid energy can be stored as chemical energy within the battery to be released as DC electrical energy when called to dispatch later. This facility will require multiple inverters to convert the DC energy of the batteries to AC energy that can be exported to the grid.

1.2 Dispatch Scenarios

The dispatch of the two technologies corresponds to the Sonoma Clean Power energy model provided by Sonoma Water as reported in Table 1-1 below. For the purposes of this comparison, the number of BESS cycles per year corresponds to the number of PSH discharge cycles per year. Per the Sonoma Clean Power energy model, it is anticipated the PSH will discharge, approximately 1,781 hours per year resulting in 127 discharge cycles per year. It is important to note, typical applications for utility scale energy storage systems (both BESS and PHS technologies) include arbitrage, firm capacity, and operating reserves. For this comparison the BESS cycles per year are the same as the PSH system strictly for comparison purposes. However, due to operational flexibility of these systems, additional cycles may be realized by depending on how Sonoma Water dispatches the systems.

Table 1.2-1. Dispatch Scenarios

		Alternative 1	Alternative 2
		PSH	BESS
Charge Hours Per Year	Hours	1,781	1,781
Full Cycles per Year	#	127	127
Energy Discharged per Cycle	MWH	280	280
Annual Energy Discharged	MWH	35,560	35,560

2. Technical Characteristics

Energy storage technologies have a number of technical characteristics that will impact the feasibility of installation and the results of a lifecycle cost analysis. The table below provides a high-level comparison of generic technical parameters associated with both PSH and BESS technologies. These parameters are provided for reference only and to aid in the comparison of the two technologies.

Table 2-1. Technical Characteristics

Performance Characteristics		Alternative 1	Alternative 2
		PSH	BESS
Power Output	MW	20	20
14-hour Energy Storage	MWH	280	280
Discharge Duration	hr	14	14

3. Opinion of Capital Cost

HDR generated opinions of probable costs for the Lake Sonoma Pumped Storage Hydropower Project. For the purpose of this study HDR developed a comparable estimate for a similarly sized BESS facility. An Association for the Advancement of Cost Engineering (AACE) Class 5 (-50% to +100%) conceptual project capital cost estimate was developed based on an overnight Engineer Procure Construct (EPC) project cost basis for 2025. All costs presented herein are based on current day cost expectations and supported by representative project data and quotations from other efforts where available. These costs are intended to reflect the current status of the industry with respect to recent material and labor inflation; however, due to the volatility of the power generation marketplace, actual project costs should be expected to vary. Table 3-1 provides estimated project costs for each alternative. The capital cost estimate for the BESS option included an allocation for project development fees, land purchase, transmission line and substation upgrade cost to provide a common basis for comparison against the PHS.

Table 3-1. Project Estimated Cost Summary.

Project Costs (2025 US$)	Units	Alternative 1	Alternative 2
		PSH	BESS
14-hour EPC Plant Cost	$MM	$208.7	$121.5[1]
EPC Plant Cost	*$/kWh*	*$745.36*	*$434.10*

1 See Appendix A

4. Lifecycle Cost Assumptions

The lifecycle cost comparison was completed as a spreadsheet-based proforma evaluation that considered multiple categories of cost anticipated with the operation of each alternative. The assumptions used to generate cost are described below.

4.1 Financial Assumptions

The table below shows the financial assumptions that were used in the lifecycle cost evaluation. These inputs determined rate of capital recovery, escalation, and discount rate applied to the costs.

The lifecycle cost comparison was conducted as a high-level comparison of the two technologies. The evaluation focused on capital costs and maintenance costs that are anticipated to be substantially different between the two options. This evaluation was not intended as a full bankable proforma capturing all expected cost and should not be relied on for any purpose beyond comparing the merits of the two technologies under consideration. Corporate income tax, depreciation, and auxiliary load costs were not considered in this evaluation. Dispatch cost and revenue are equivalent between the two technologies since the dispatch parameters were held constant between the two technologies.

Table 4-1. Economic Assumptions

Common Proforma Parameters	
Discount Rate	4.85%
Interest Rate	4.85%
Capital Escalation	3%
Evaluation Period (yrs)	30
First Year of Operation	2Q2036
Year Funding is Received for BESS	2Q2034
Year Funding is Received for PSH	1Q2031
Property Taxes (% of Property Value)	0
Insurance Cost (% of Asset Value)	0.1
Charging Cost ($/MWh)	36.81
BESS RTE (%)	85
PSH RTE (%)	60
BESS PG&E Interconnection Cost of Ownership ($)	6,204,000
PSH PG&E Interconnection Cost of Ownership ($)	31,315,000

Economic Assumption Clarifications

- All future costs are discounted to present value terms using a discount rate. The analysis only considers lifecycle costs and excludes potential state or federal incentives. The analysis also implicitly assumes that potential revenue earned from BESS and PSH is similar.
- The cited nominal interest rate reported in Table 4-1 above is based on 30-year A-rated municipal bond[1]. The discount rate typically assigned is the weighted average cost of capital (WACC) associated with the entity seeking funding. The WACC is calculated from the interest rate, return on equity, corporate tax rate, and debt and equity ratio. However, since Sonoma Water is a municipality, doesn't pay taxes, and typically only has debt financing structures, the discount rate is the same as the interest rate.
- The year funding is received for the BESS and PSH as indicated in the table above is the year interest begins accruing.
- The economic analysis assumes both the PSH and BESS projects are capitalized, resulting in the project's capital cost and accumulated interest during construction being recognized during project construction, while the interest portion of the debt service is recognized the year it is anticipated to be incurred. Capitalizing the project allows regulated utilities to earn a rate of return from ratepayers while O&M expenses are pass through costs.
- Financing costs are evaluated for BESS and PSH since they differ due to different construction costs of the two alternatives and different timing of when loans are taken out (starting 2031Q1 for PSH and 2034Q2 for BESS).
- Charging costs of the two technologies were included to capture the effects of different round trip efficiencies (RTE) between the two technologies. The charging cost reported in the table above is the estimated annual pumping cost divided by the estimated annual pumping energy provided in the Sonoma Clean Power energy model. Per the Sonoma Clean Power energy model, the anticipated annual pumping cost is $2,152,989 and the annual pump energy is 58,489.72 MWh. Therefore, the cost to charge the PSH and BESS systems used for the analysis is 36.81 $/MWh ($2,152,989/58,489.72 MWh). The number of charge cycles per year used to estimate charging cost corresponds to the number of cycles per year reported in Table 1.2-1 above. For an equivalent comparison, we have assumed a consistent number of charging cycles for PSH and BESS.
- PSH and BESS will incur a fee from PG&E for interconnection. The economic analysis assumes these costs are incurred at the same time capital is deployed for each technology. Per the PSH Concept Study Report, the monthly cost of ownership for the PG&E interconnection to the Cloverdale Substation is $183,000 for PSH. The single lump sum cost of ownership for the PSH interconnection is $31,315,000. The equivalent

[1] Municipal Bonds Market Yields | FMSbonds.com, Accessed May 28, 2025

cost for BESS was estimated as the ratio of transmission line and substation capital costs for the BESS and PSH and multiplied by the PSH interconnection cost of $31,315,000. Capital cost for transmission and substation upgrades for PSH were estimated at $21.2 million. This includes 2.1 million for substation upgrade cost and 19.1 million for transmission cost. PSH transmission cost is based on a nine mile transmission line length per Table 4-3 in the PSH Concept Study report. The transmission line length for the BESS is assumed to be one mile from the Cloverdale substation, therefore the BESS capital cost for transmission and substation upgrades were estimated at 4.2 million. This includes 2.1 million for substation upgrades and 2.1 million for transmission (1 mile / 9 miles x $19.1 MM). Therefore, the lump sum cost of ownership for the PG&E interconnection cost is calculated as follows:

BESS Lump Sum Interconnection Cost = 4.2 / 21.2 x $31,315,000 = $6,204,000

- Allowance for funds used during construction (AFUDC) is included in the economic evaluation to capture the interest paid during the construction phase.
- The difference in financing cost between BESS and PSH is captured through the annual interest expense from the debt service calculations. This is meant to capture the differences in timing and additional cost that the loans will generate for the alternative technologies considered.
- BESS O&M cost was established assuming the BESS assets will be charged and discharged fully on a nearly daily basis to support grid operation. Therefore, since the anticipated dispatch of the BESS reported in Table 1.2-1 above, is less than once per day, lower O&M costs for the BESS system will likely be realized. It is possible that if the BESS was dispatched more frequently, the revenue potential of the BESS would exceed that of the PSH, though the charging costs would also increase.
- Levelized costs per MWh are calculated based on total estimated electricity discharged, while levelized costs per kW-mo are calculated based on nameplate capacity.

4.2 PSH O&M and Major Maintenance

Annual O&M costs for any given facility depend on many factors such as the extent and location of the owner's operations staff and how administration and management staff costs are accounted for. Based on HDR's experience with hydropower projects of this size, a range of potential annual O&M costs should be considered (e.g., $0.5 to $1.0 million). For the economic comparison, $1.0 million in annual O&M was used for the PSH. Due to the duration of the analysis period, it is anticipated that the pump hydro system will not require major maintenance overhauls. For additional details on how this cost was developed please refer to the Sonoma Concept Study Report, Section 8.4.1.

4.3 BESS O&M and Major Maintenance

The useful life of a typical Li-Ion battery module is considerably shorter than the 30 years being considered as part of this evaluation. Each battery module degrades over time, but it can take up to 20 years before the individual battery modules are rendered uneconomical. Many BESS suppliers have developed maintenance strategies such that a few additional battery modules are added periodically to maintain the required discharge capacity of the BESS – this is known as augmentation. Eventually, each battery module will degrade to a point that is beyond the ability to augment the degradation economically and will be replaced with a new battery module.

BESS maintenance is expected to consist of multiple different maintenance activities to extend the overall life of the facility. These include:

- Ongoing equipment maintenance, which is assumed to be covered by a long-term service agreement (LTSA) provided by a battery vendor.
- Augmentation of the installed capacity to combat degradation associated with Li-Ion cells. For the purposes of this analysis, battery modules would be augmented in 5-year increments over the course of a 15-year maintenance cycle to maintain required capacity.
- Replacement of battery modules as they reach end-of-life. The life cycle of Li-ion batteries is impacted by a number of factors including depth of discharge, charge/discharge rates, and operating temperature. However, the typical life cycle of Li-ion batteries ranges between 15-20 years. For the purposes of this evaluation, it is assumed that end-of-life occurs in year 15.

The table below documents the assumptions associated with each of these activities.

Table 4-3. Estimated BESS O&M and Major Maintenance Cost Summary

Li Ion BESS O&M and Major Maintenance Item	Maintenance Type	Interval	Cost (2025 US$)
Annual LTSA	O&M	1	$401,000
Augmentation	Major Maintenance	5	$8,830,500
Battery Removal	Major Maintenance	15	$4,200,000
Battery Replacement	Major Maintenance	15	$116,766,000

5. Lifecycle Cost Comparative Analysis

5.1 Results

Lifecycle cost estimates were calculated according to the assumption described in the sections above over a 30-year period. The results of this evaluation were reduced to a single present value for each of the energy storage options. Note that all O&M costs as well as total costs of storage are preliminary and indicative in nature and are to be used for comparative purposes only.

Table 5-1. Levelized Cost Comparison Results

	PSH	BESS
30-Year Operation Period		
NPV of Initial Capital Costs ($MM)[1]	$261	$94
NPV of Annual O&M Costs ($MM)	$19	$10
NPV of Annual Financing Costs, interest payments ($MM)	$56	$38
NPV of Fuel/Charging Cost ($MM)	$32	$22
NPV of Major Maintenance Costs ($MM)	$0	$100
NPV of Total Lifecycle Costs ($MM)	$368	$265
Levelized Cost ($/MWh)	$1,063	$764
Levelized Cost ($/kw-mo)	$157	$113

[1] *Includes EPC Capital Cost, Lump Sum Cost of Ownership for Transmission and AFUDC*

5.2 Summary

In this study, the lifecycle cost of Pumped Storage Hydropower is compared to the cost of Li-Ion Battery Storage. It is assumed that either facility would have a capacity of 20 MW and dispatched 127 times per year for the 30-year analysis period. It was found BESS resulted in a lower levelized cost. This is due to the large initial capital costs associated with the PSH. BESS installations do typically have high maintenance costs due to degradation, and this can be seen in the 30-year analysis.

Appendix A:

Battery Energy Storage Class 5 Cost Estimate

Description	Total Amount	% Total
BESS Facility		
Major Equipment		
BESS Equipment	**77,000,000**	63%
PCS & XFMR	**9,800,000**	8%
OEM Indirects	**6,496,000**	5%
Balance of Plant Construction		
Civil	**1,624,000**	1%
Structural	**2,240,000**	2%
BOP Electrical	**6,496,000**	5%
Controls	**840,000**	1%
Substation upgrade cost	**2,100,000**	2%
Transmission Line	**2,100,000**	2%
land purchase	**3,300,000**	3%

Estimate Totals

Description	Amount	Totals	Rate
Direct Subtotal	**111,996,000**	**111,996,000**	
Construction Management & Field Indirects	2,105,000		
Engineering and Project Management	585,000		
Project Indirects	468,000		
Contractor Overhead & Profit	1,403,000		
Contingency	4,991,000		
Indirect Subtotal	**9,552,000**	**9,552,000**	
EPC Total		**121,548,000**	
Owner's Costs			
Total		***121,548,000***	

Lower Range: -50% AACE Classification Accuracy Range Upper Range: +100%