GOLDENDALE ENERGY STORAGE HYDROELECTRIC PROJECT

Federal Energy Regulatory Commission Project No. 14861

Klickitat County, Washington

FINAL LICENSE APPLICATION
Exhibit B: Statement of Project Operation and Resource Utilization

For:

FFP Project 101, LLC

June 2020

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Acronyms and Abbreviations

AF	acre-foot
Applicant	FFP Project 101, LLC
cfs	cubic feet per second
KPUD	Public Utility District No. 1 of Klickitat County, Washington
MW	megawatt
NGVD 29	National Geodetic Vertical Datum of 1929
Project	Goldendale Energy Storage Project No. 14861
rpm	revolutions per minute

1.0 PROJECT SITE ALTERNATIVES CONSIDERED

No sites other than the current proposed Goldendale Energy Storage Project No. 14861 (Project) site were considered. The unique opportunity to re-use a previous industrial facility and the proximity to the John Day Substation, Bonneville Power Administration transmission lines, and nearby wind farms make the proposed Project site ideal for a closed-loop pumped storage facility. Additionally, the existing water right owned by Public Utility District No. 1 of Klickitat County, Washington (KPUD), enables supply to the Project with no new intake features, which presents another unique opportunity to develop a relatively low-environmental impact project to help balance the wind and hydro projects nearby.

2.0 PROJECT FACILITY ALTERNATIVES CONSIDERED

Several alternatives of overall Project arrangement and energy storage capacity were reviewed before selecting the arrangement and capacity presented in this Draft License Application. Conceptual plans and preliminary arrangements for pumped storage in this general location have been studied by various developers for decades. More recently, a conceptual facility design was developed as the JD Pool Pumped Storage Hydroelectric Project under a different FERC Project Number (P-13333). The following section describes the previous design alternative configuration and the review that led to the selected and current Goldendale Energy Storage Project alternative configuration.

2.1 Previous Design Alternative

The previous design included two upper reservoirs interconnected with a single high-pressure water conveyance shaft and tunnel; an underground powerhouse with appropriate access tunnels; a low pressure tunnel; and a lower reservoir located on the lands currently owned by the Columbia Gorge Aluminum smelter. Figures 2.1-1 and 2.1-2 show the general previous design arrangement.

2.1.1 Upper Reservoirs

The previous design of the upper reservoir facilities included two new upper reservoirs, with a combined active storage of 11,800 acre-feet (AF) and maximum/minimum water surface elevations of 2,940 and 2,785 feet. Upper Reservoir 1 had approximately 4,700 AF of active storage and a full pond surface area of 46 acres. Upper Reservoir 2 had approximately 7,100 AF of active storage and a full pond surface area of 67 acres. Upper Reservoir 2 was hydraulically connected to Upper Reservoir 1 such that water would be drawn/filled equally to and from the two reservoirs.

Both reservoirs were designed to:

- Be constructed to balance cut and fill, utilizing the excavated material for the embankment dams and minimizing the need to dispose of material elsewhere on the site;
- Be fully lined with concrete;
- Provide for 10 feet of freeboard for the embankment dam, in addition to a concrete parapet wall of at least 3 feet in height; and
- Include galleries to monitor any leakage.

2.1.2 Water Conveyances

Project waterways consisted of the following:

- Low level connection tunnel, approximately 2,010 feet long, connecting the two upper reservoirs and lined with concrete, sized so that the two reservoirs acted as one reservoir. The tunnel included the capability to isolate the two upper reservoirs from each other.
- Two 21-foot-diameter, concrete-lined, low-pressure tunnels, approximately 1,140 and 1,290 feet long, respectively, from the Upper Intake-Outlet structure.
- Two 21-foot-diameter, concrete-lined vertical power shafts, each approximately 2,100 feet deep.
- Two 21-foot-diameter, concrete-lined, high-pressure tunnels, approximately 4,050 and 3,420 feet, respectively, connecting the vertical shaft to the manifold.
- Two (diameter undefined) concrete-lined manifolds, approximately 270 feet each, splitting into four penstocks.
- Four (diameter undefined) unit penstocks (two per manifold), approximately 190, 410, 610, and 820 feet, respectively.
- Four (diameter undefined) unit draft tube tunnels, approximately 420, 320, 350, and 250 feet, respectively to the tailrace.
- Two (diameter undefined) concrete-lined tailrace tunnels, approximately 800 and 1,110 feet long, respectively, connecting the draft tubes to the Lower Intake-Outlet structure.
- All waterways would be lined with concrete, although the four penstocks and upstream manifold would also be steel-lined.

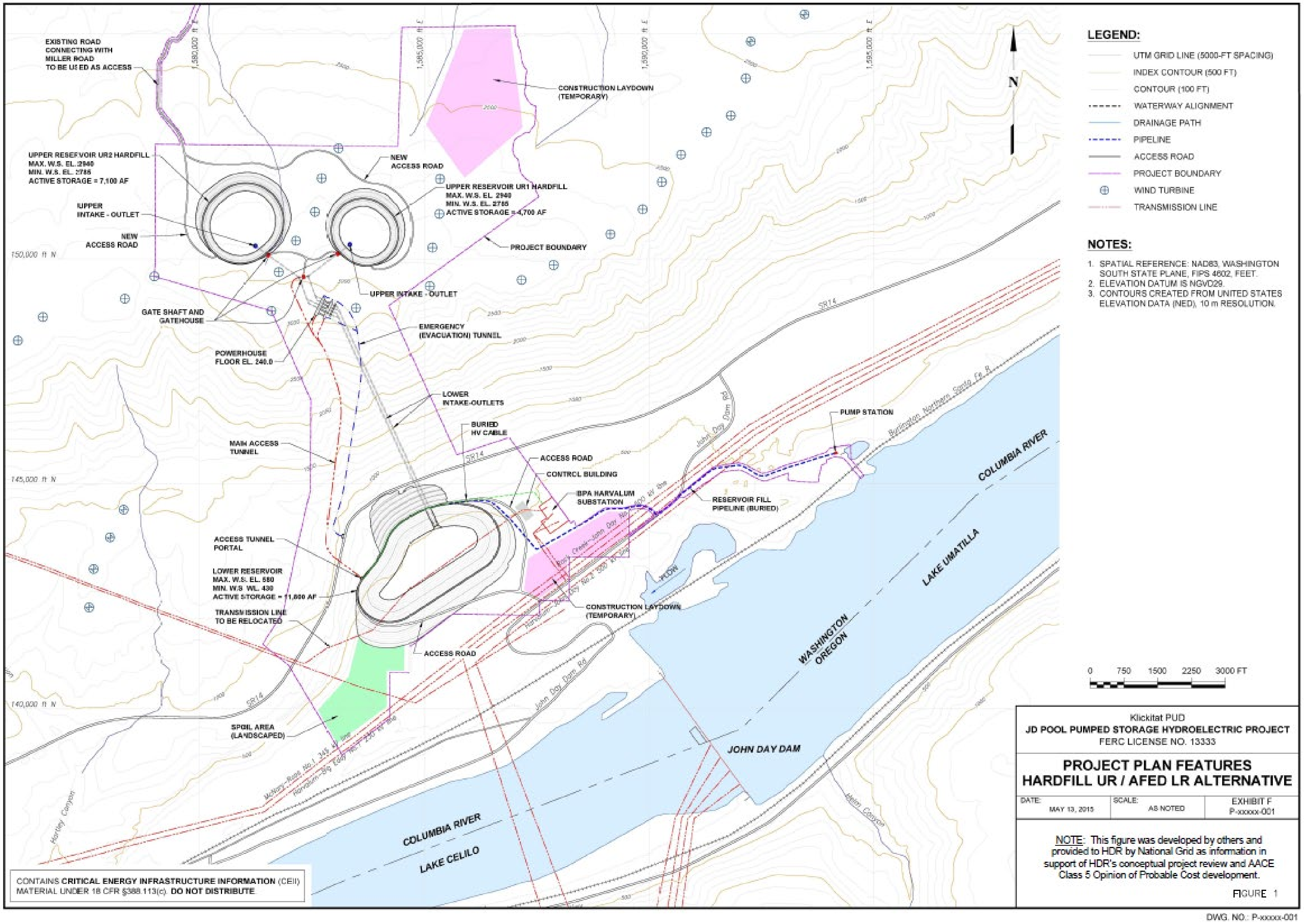

Figure 2.1-1: Previous Design Alternative Project General Arrangement—Plan

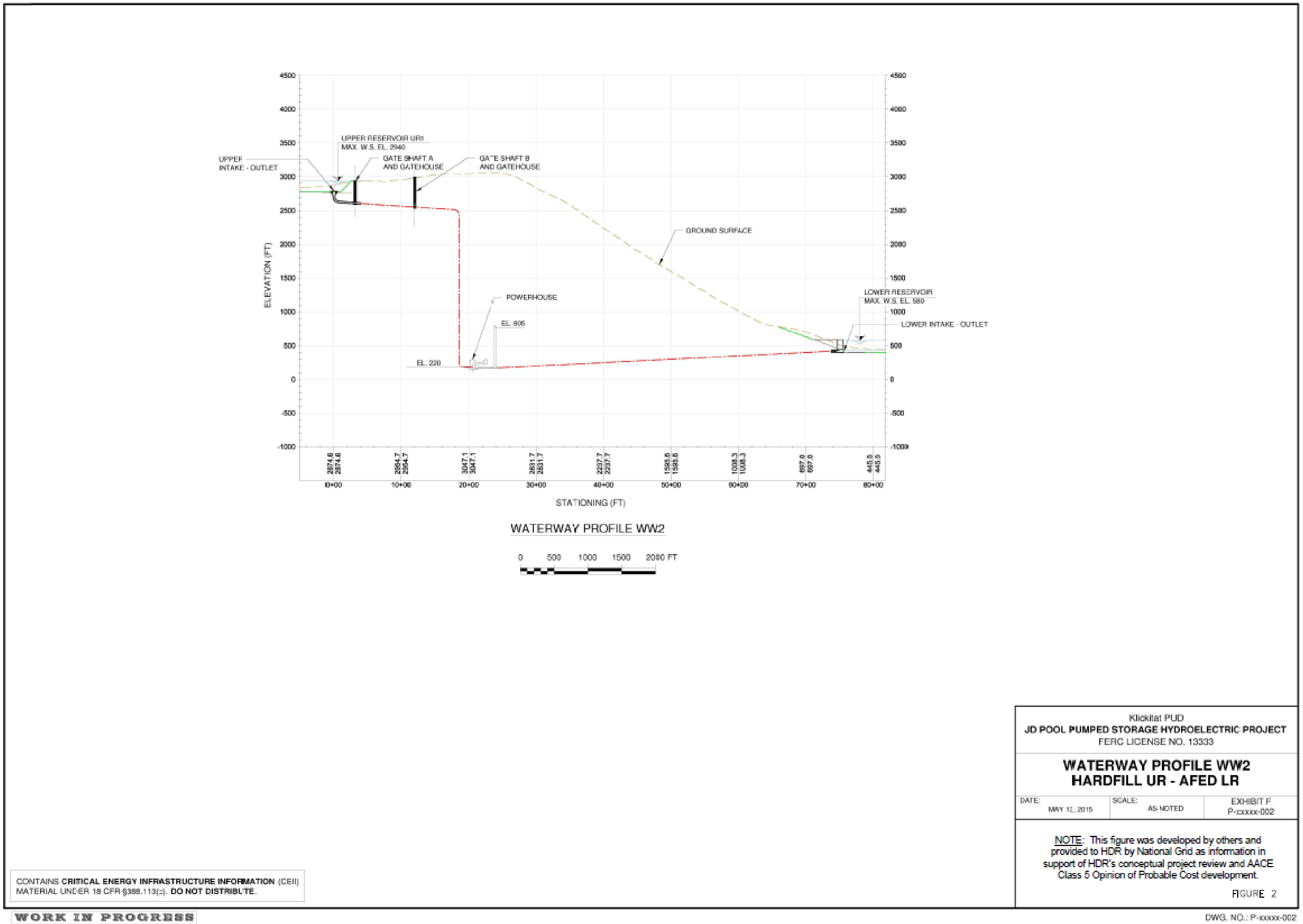

Figure 2.1-2: Previous Design Alternative Project General Arrangement—Profile

2.1.3 Powerhouse

The previous design alternative included an underground powerhouse with a unit centerline elevation of 220 feet located very close (in the horizontal direction) to the upper reservoir. The pump-turbine units included four adjustable speed, reversible pump/turbine motor/generator units with 300 megawatts (MW) per unit (334 million volt-amperes; 0.9 power factor). Therefore, the installed plant capacity included 1,200 MW (generating), and a rated flow of 1,750 cubic feet per second (cfs) per unit (approximately 7,000 cfs for the plant). The rated net head for the units would have been approximately 2,200 feet (generating).

2.1.4 Lower Reservoir

The previous design alternative for the lower reservoir included the following configuration:

- A new Lower Intake-Outlet concrete structure at the base of Lower Reservoir, founded on and in bedrock. The structure included the capability to isolate the Lower Reservoir.
- The new Lower Reservoir was designed to utilize the escarpment to the northwest of its planned location, and would have had 11,800 AF of active storage. At the maximum water surface elevation, the surface area of the Lower Reservoir was 100 acres. Similar to the upper reservoirs, its construction would have balanced the cut and fill, using the excavated rock in the embankment dam that forms the Lower Reservoir, minimizing the need to borrow or dispose of material elsewhere on the site. The rockfill embankment dam was approximately 165 feet high at its tallest, with a total length of 7,800 feet. There was 10 feet of freeboard for the embankment dam; in addition, there would have been a concrete parapet wall of at least 3 feet in height. Galleries were incorporated to monitor any leakage. The freeboard was to be adjusted, if necessary, to contain any significant storm that would increase the total volume of water in the system; a spillway is not included in the current concept (reference Section 2.1.1 above).

2.1.5 Recommended Refinements

After discussions with the FFP Project 101, LLC (the Applicant) and early consultation with stakeholders, the following comments and recommendations led to refinements to the conceptual design.

- There appears to be sufficient real estate within the proposed Project Boundary to construct a single upper reservoir having an active storage capacity of approximately 11,800 AF and yet avoid the existing wind turbines. A single upper reservoir should be considered and could provide several potential advantages, including reduced earthwork; elimination of redundant inlet/outlets, reservoir connector tunnel, and headrace tunnel section; and lower construction costs. Recommendation: a single upper reservoir configuration impounded by a concrete face rockfill type dam having a crest width of 25 feet and side slopes of 1.5 horizontal to 1 vertical (1.5H:1V).

- Assuming a single upper reservoir, the project engineer, HDR, recommended a vertical (ungated) hooded type (for vortex suppression) upper reservoir inlet/outlet structure, single concrete-lined vertical shaft/headrace tunnel/manifold, three steel-lined penstocks (for a three-unit powerhouse), three steel-lined draft tube tunnels, and a single concrete-lined tailrace tunnel. This waterway configuration should result in substantial construction cost savings.

- Similar to the upper reservoir configuration, a single lower reservoir configuration was recommended with construction of a concrete face rockfill type dam having a crest width of 25 feet and side slopes of 1.5H:1V.

- Moving the underground powerhouse in the direction of the lower reservoir was recommended to reduce the length of the powerhouse main access and high voltage/emergency evacuation tunnels.

- A 3 × 400 MW unit arrangement was recommended as the preferred configuration for the following reasons:

  - The pump-turbine units for the 3 × 400 MW alternative would be a conventional design with a specific speed of approximately 30, with better efficiency and more stable operation.

  - The 4 × 300 MW alternative would require a rotating speed of 600 revolutions per minute (rpm). Hitachi-Mitsubishi is the only supplier that manufactures 600 rpm generator-motors, and there are reports of many problems with this equipment. Equipment suppliers other than Hitachi and Mitsubishi would likely consider this speed excessive.

  - The vast majority of variable speed generator-motors have a rotating speed of 500 rpm, which is the same as would be required for the 3 × 400 MW arrangement for the previous design of the Project.

  - The maximum gross head for the previous design of the Project was foreseen as very close to the Kazunogawa Pumped Storage Project in Japan (2,556 feet), currently the highest head for single stage pump-turbines. The equipment at that plant is rated at 400 MW and rotating at 500 rpm. Two single speed units have operated there since the early 2000s and one variable speed has been in operation since 2014. There are no plants with 300 MW single stage pump-turbines operating at such head.

  - A 3 × 400 MW powerhouse would be more cost effective than a 4 × 300 MW arrangement.

As described in Exhibit A, the Project team selected a project arrangement with an active storage size of 7,100 AF of water, representing an energy storage capacity of approximately 12 hours of 1,200 MW of power, or approximately 14,745 megawatt-hours.

3.0 PROJECT OPERATION

3.1 Proposed Project Operation

The proposed Project will operate as an energy storage project. At the initiation of an operating cycle, approximately 7,100 AF of water will be pumped from the lower reservoir through a large-diameter conveyance system to the upper reservoir using three variable speed, reversible pump-turbines located in the underground powerhouse and operating in pump mode. To generate power, water will be released from the upper reservoir and passed through the three 400 MW variable speed, reversible pump-turbine units operating in turbine mode. The Project is designed to generate for 12 hours a day of full power generation, at a maximum of 1,200 MW and a minimum of 100 MW, and pump water from the lower reservoir to the upper reservoir in about 15 hours. This operating cycle of pumping and generating will be dictated by market demand, but is limited to a maximum of 12 hours of generation per day at maximum generating output, without repeating the cycle during the day.

3.2 Initial Fill

The volume of water required to initially fill the Project is estimated as 7,640 AF, equal to the sum of the active storage (7,100 AF), the combined dead storage for both reservoirs (340 AF), and the volume contained within the conveyance system (200 AF). It is assumed that the initial fill will be completed over a period of 6 to 12 months, depending on the construction schedule. Timing of the initial fill will depend on the timing of construction activities—principally, the lower reservoir construction, completion of liner installation, and the completion of the reservoir fill pipeline to the lower reservoir. The duration of fill operations will also depend on the construction schedule and activities, but also by any potential adjustments in the fill rate necessary to ensure that settlement of the embankment and liner leakage is within acceptable limits. Settlement and leakage monitoring equipment will be used to monitor the fill progress, and the data will be used to inform any adjustments in the filling rate.

3.3 Make-Up Water

Table 3.3-1 presents the estimated water losses (evaporation and leakage) and gains (precipitation) for the Project. The estimated evaporation and precipitation were based on long-term data recorded by the Goldendale, Washington, AgriMET weather station operated by the U.S. Bureau of Reclamation, which is the closest station from which long-term precipitation or evaporation data were available.

The lower reservoir, which will be built with a double liner and interstitial water monitoring between liners (similar to the stringent criteria used in hazardous waste Subtitle D landfills), will prevent leakage. The upper reservoir will use a single liner, and will also be monitored. Tunnel and turbine-house piping leakage is not expected due to the use of concrete and steel tunnel liners. However, as a conservative assumption, the Applicant has assumed total annual seepage from the upper reservoir and tunnels of approximately 100 AF, representing approximately 1.5 percent of the active storage. Table 3.3-1 summarizes the estimated annual Project water budget based on the estimated losses (evaporation, leakage) and gains (precipitation). The table indicates that the annual average expected Project water balance will be a loss of 360 AF (the negative number in Table 3.3-1 indicating a loss), which will have to be made-up by adding water. The exact schedule of the refill—whether the refill will be once per year, or over multiple, shorter withdrawals per year, along with details regarding time of year—will be established later.

Table 3.3-1: Estimated Project Annual Water Balance

	Gain(+)/Loss (-)
Estimated evaporation (AFY)	-390
Estimated precipitation (AFY)	130
Estimated seepage (AFY)	-100
Estimated net loss (-)/estimated net gain (+) (AFY)	-360
Total Annual Refill Volume (AF)	***360***

AF = acre-feet; AFY = acre-feet per year

3.4 Manual Operation

The Project will be staffed with on-site operations staff 24 hours a day, 7 days a week.

3.5 Annual Plant Factor

The Project is designed to generate for up to 12 hours each day at maximum generating capacity. The actual run time of the Project will be dependent on market demands. It is projected that the annual electrical energy production will be 5,382 gigawatt-hours, assuming the Project is in generating mode for the full 12 hours each day at maximum capacity, resulting in a plant factor of approximately 50 percent. Plant factor is defined as the average production for a given time divided by the total maximum production at full design capacity. The actual generation will be dependent on the market.

3.6 Operations during Adverse, Mean, and High Water Years

The initial approximately 7,640 AF of water to fill the Project system would be supplied by KPUD via an industrial and metered water tap connection to their system. Following the initial fill, approximately 360 AF per year of supplemental water would be supplied to the system on a periodic basis to restore water loss from evaporation and seepage. Due to the storage function of the Project and its lack of connectivity to natural bodies of water, Project operation would not be directly impacted by adverse, mean, and high water years.

4.0 DEPENDABLE PROJECT CAPACITY AND ENERGY PRODUCTION

The capacity of the Project is estimated to be a maximum of 1,200 MW at rated head. The Project will provide a dependable capacity of at least 1,100 MW and up to 1,200 MW for

12 hours per day. The actual run time of the Project will be dependent on the market. It is projected that the annual electrical energy production will be 5,382 gigawatt-hours, assuming the Project was in generation mode for 12 hours each day. The minimum hydraulic capacity will be approximately 1,400 cfs (one unit operating at minimum flow); the maximum hydraulic capacity will be approximately 7,200 cfs (3 units operating at maximum flow). See also Section 4.3, Project Flow Range, below.

Pumped storage projects are designed to provide dependable capacity to the regional electric grid and are specifically configured based upon these anticipated grid requirements. Since the Project is proposed as a closed-loop configuration, it will not be subject to river flows, meteorological cycles, or other adverse external events. The dependable capacity for the Project is based on a maximum of 12-hour daily generation at least 1,100 MW and up to 1,200 MW, or 14,745 megawatt-hours per day, 7 days per week. The reservoirs are sized for the anticipated duration of generation (how long to provide dependable generation) and the equipment nameplate generation (how much dependable energy is needed). In its simplest context and exclusive of ancillary services values, the Project is tailored to the needs of the grid for load during peak demand periods. In other words, the Project is tailored to serve the load cycle within that region or other regions served by the regional grid, and this has been supported by modeled operations.

Modern pumped storage projects can operate in a highly flexible regimen apart from the simple daily generation cycle, depending on grid needs at the time. Grid demands will ultimately determine the optimum operating protocols for the Project.

4.1 Project Flow Data

The proposed reservoirs are new and off-channel, therefore there are no flow data available in relation to the Project. Based on preliminary estimates, approximately 360 AF of net precipitation, evaporation, and leakage is expected to be lost from the combined reservoir system each year. The initial water available to fill the Project system as well as any supplemental water needed on a periodic bases to replace net water losses would be supplied by KPUD from an industrial water supply tap.

4.2 Reservoirs

4.2.1 Upper Reservoir

At the proposed maximum normal operating pool elevation of 2,940 (National Geodetic Vertical Datum of 1929 [NGVD 29]), the upper reservoir has a storage volume of 7,400 AF and a surface area of approximately 60 acres at full pool. A preliminary elevation storage curve for the upper reservoir is shown in Figure 4.2-1. The minimum water level of 2,785 feet in the upper reservoir will be maintained such that the vertical intake/outlet is completely submerged at all times to prevent vortices from entering the intake and vertical shaft during power generation. The proposed minimum pool elevation of 2,785 feet above mean sea level submerges the low-level outlet by 4 feet.

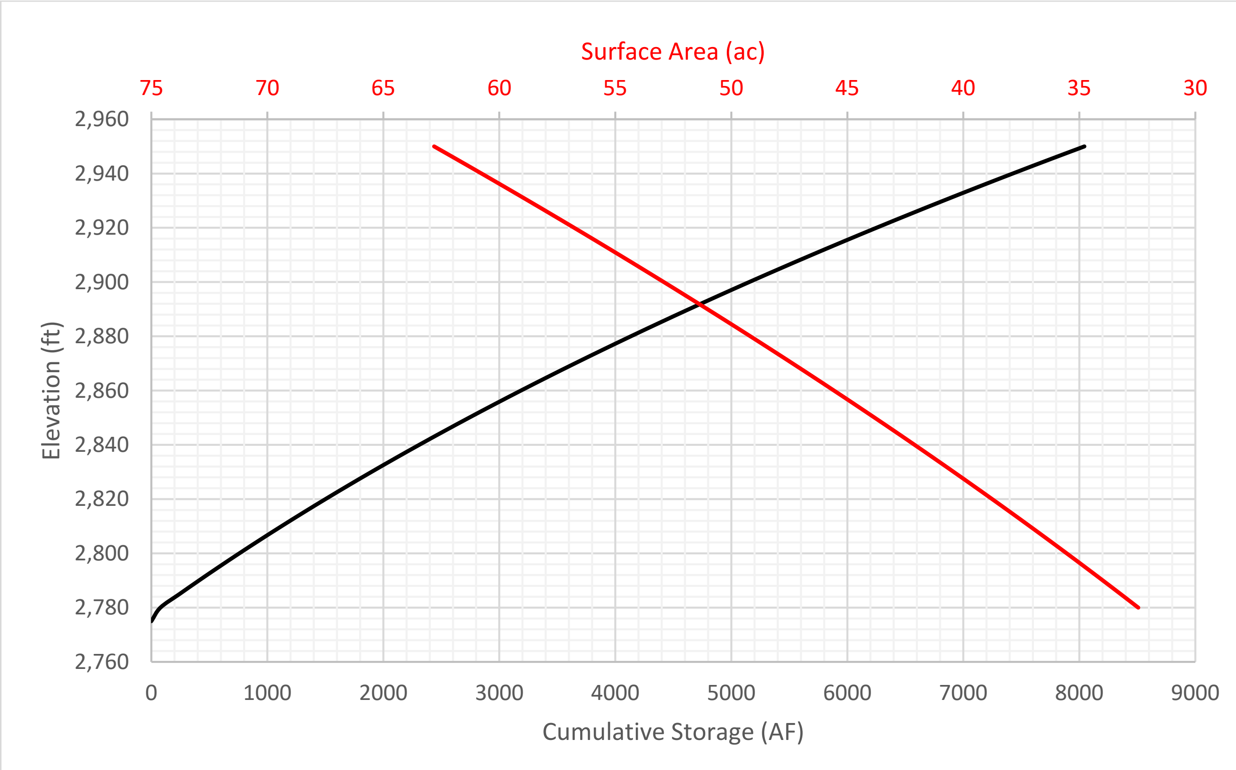

Figure 4.2-1: Upper Reservoir Elevation Capacity Curve

4.2.2 Lower Reservoir

At the proposed maximum normal operating pool elevation of 580 feet (NGVD 29), the lower reservoir has a gross storage capacity of 7500 AF and a surface area of 63 acres at full pool. A preliminary elevation capacity curve for the lower reservoir is shown in Figure 4.2-2. Similar to the upper reservoir, the water level in the lower reservoir will be maintained such that the intake/outlet is completely submerged at all times to prevent an intake vortex from forming during pumping mode of operation. The proposed minimum pool elevation of 430 feet (NGVD 29) submerges the low-level outlet by approximately 30 feet.

During generation mode, water stored in the upper reservoir will be released through the upper reservoir intake/outlet and flow through the large-diameter water conveyance system, pass through the pump-turbines, and discharge into the lower reservoir. The upper reservoir water surface elevation decreases as the lower reservoir water surface elevation increases. During the pumping mode, this process is reversed. The generating and pumping times will be dependent on the market needs; however, if a 12-hour generating period occurred continually, the upper reservoir will be at its minimum pool level after 12 hours and the lower reservoir would be at its maximum normal pool level. Project operation can alternate between pumping and generating modes quickly and for different lengths of time to respond to market needs.

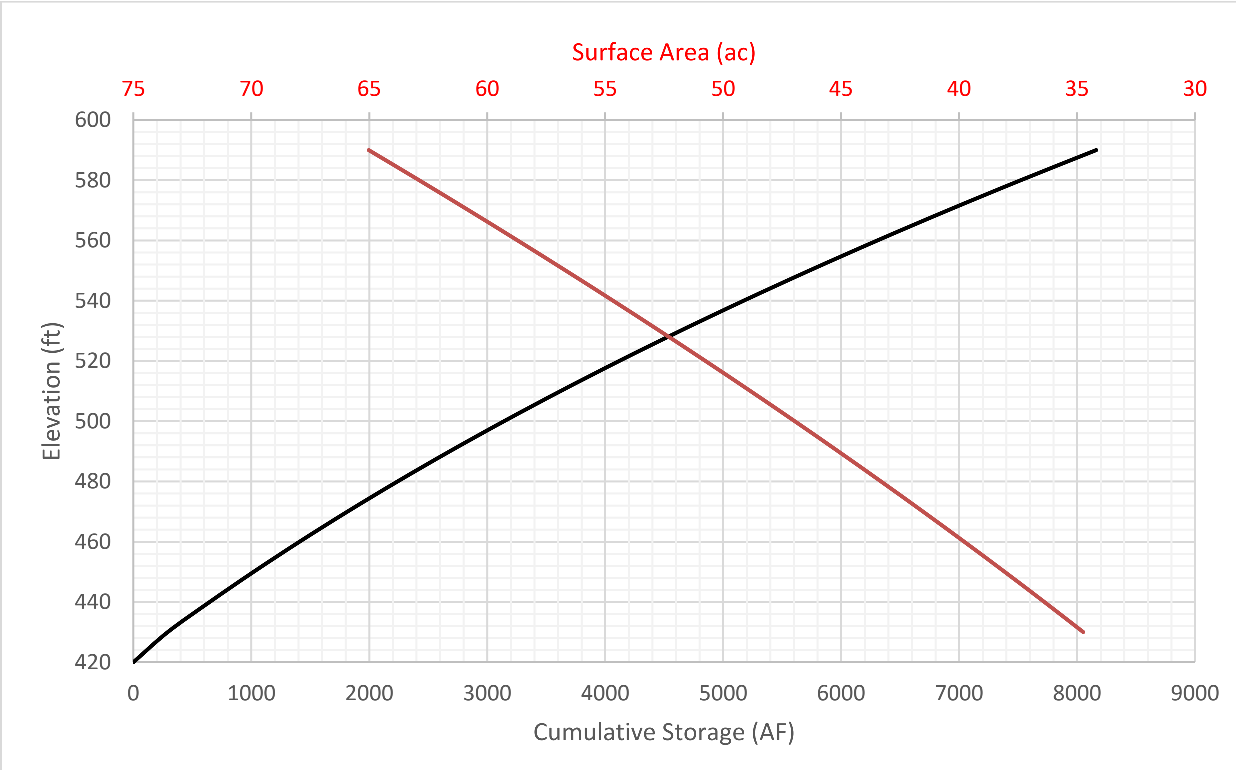

Figure 4.2-2: Lower Reservoir Elevation Capacity Curve

4.3 Project Flow Range

The Project has an estimated operating flow range in generating mode of approximately 1,400 cfs to up to 8,280 cfs at the maximum generation capacity of 1,200 MW. The Project has an estimated operating flow of up to 6,600 cfs in pumping mode at the maximum pumping load of 1,550 MW.

4.4 Tailwater Rating Curve

The lower reservoir is considered the Project tailwater. There is no tailwater rating curve since this is a closed-loop system; the tailwater elevation increases as a function of reservoir volume instead of Project flow.

4.5 Project Capability versus Head

The Project is designed to maintain at least 1,100 MW of capacity throughout a 12-hour period. As water is released from the upper reservoir into the lower reservoir, the head is reduced as the upper reservoir elevation decreases and the lower reservoir level increases. The changing reservoir levels and resulting head impacts the maximum generation level achievable falling from 1,200 MW at a full upper reservoir to 1,100 MW at the lowest operational level of the upper reservoir. The maximum gross head would occur when the upper reservoir is at maximum surface elevation and the lower reservoir is at its minimum surface elevation. The minimum gross head would be when the upper reservoir is at its minimum surface elevation and the lower reservoir is at its maximum surface elevation. The range of generating mode capacity (and pumping mode capacity) is shown in Figures 4.5-1 and 4.5-2.

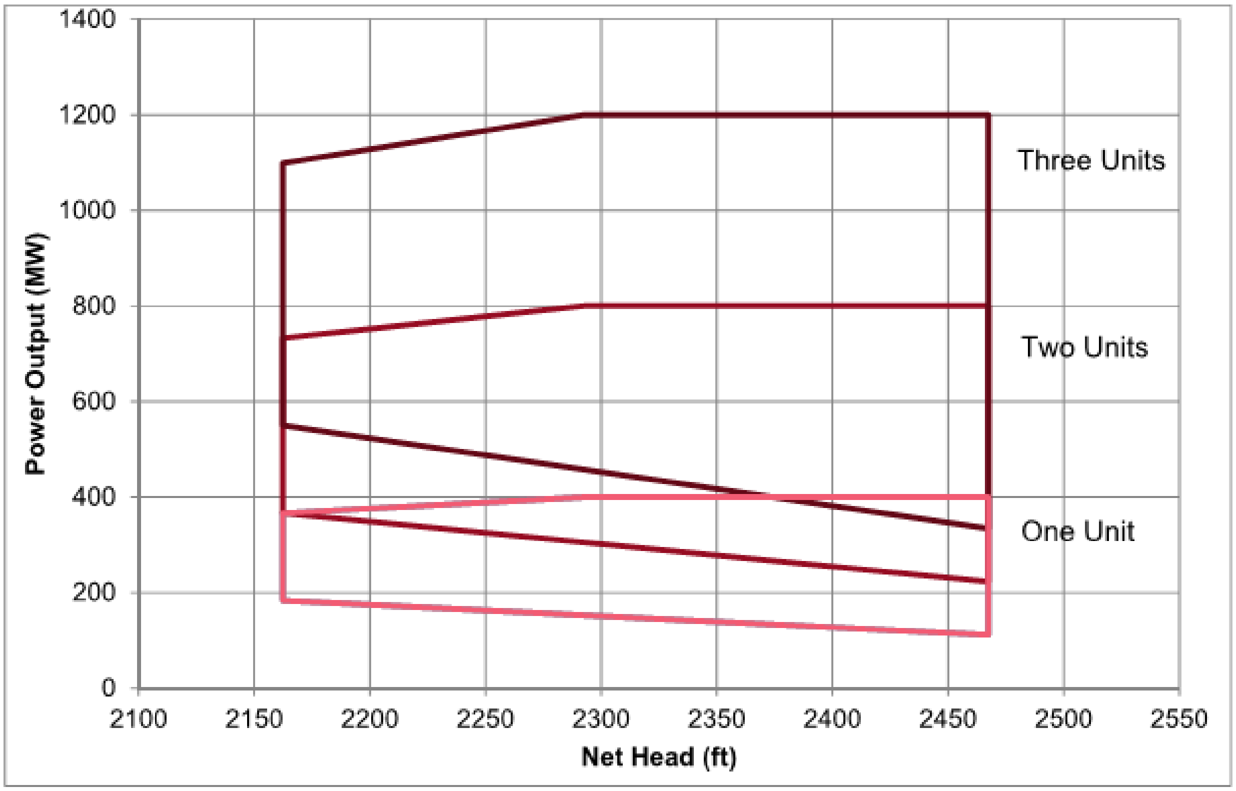

Figure 4.5-1: Goldendale Reversible Units Characteristics Turbine Modes

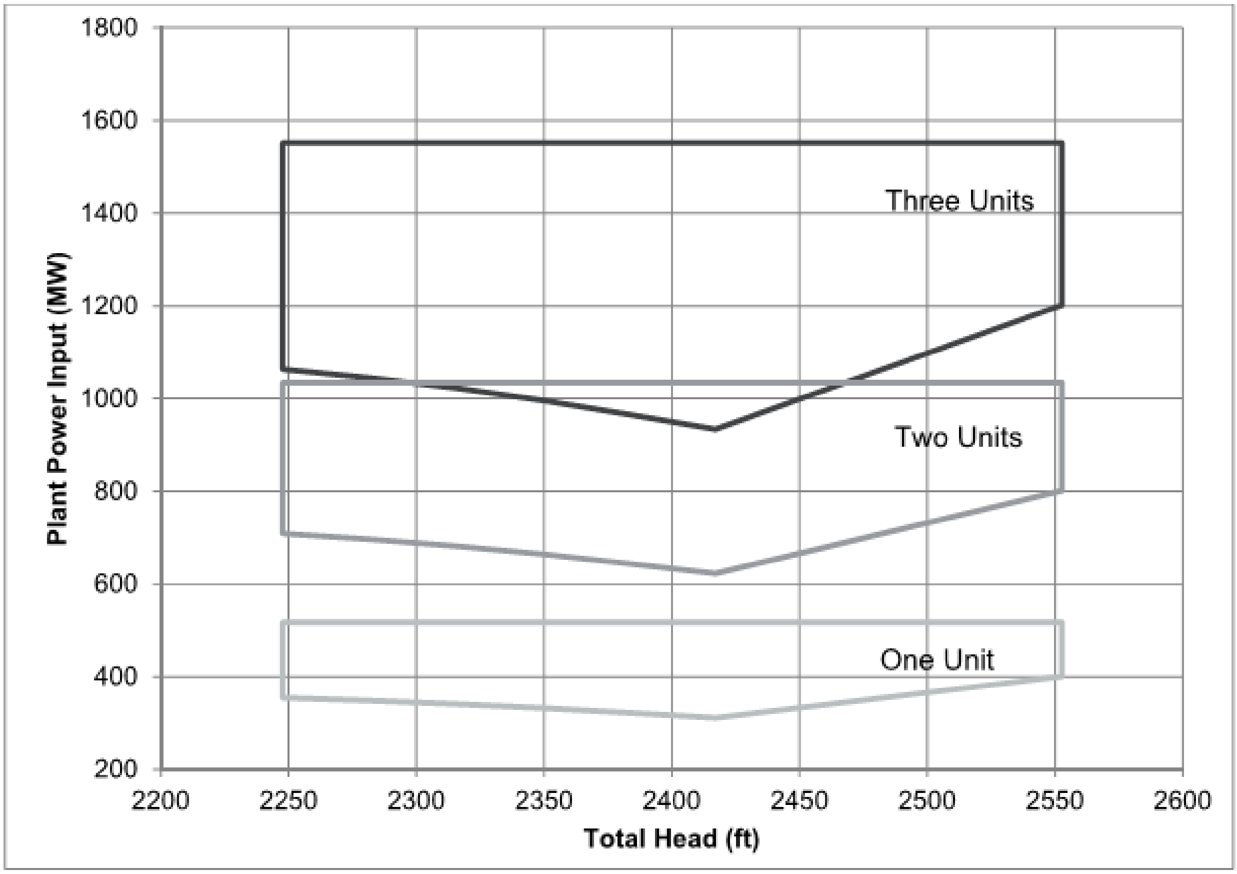

Figure 4.5-2: Goldendale Reversible Units Characteristics Pump Modes

5.0 REGIONAL POWER NEEDS AND USE OF PROJECT POWER

The electrical energy produced at the Project will be marketed to electric utilities servicing this region. The electrical energy used on site will include basic utilities and the energy needed to pump the water to the upper reservoir. For every 12 hours of full power generation, at a maximum of 1,200 MW and a minimum of 1,100 MW, the Project is assumed to have a 15-hour pumping cycle.

The power absorbed during pumping mode will come from the wholesale energy market and will be purchased when the energy system is imbalanced and is in surplus. The energy created during generation mode and delivered to the wholesale market will help satisfy periods of peak demand and when grid flexibility is required. All of the power generated, up to 1,200 MW/hour, will be sold in the wholesale market to purchasers that may include Portland General Electric, Puget Sound Energy, Bonneville Power Administration, Pacific Gas and Electric, Southern California Edison, and PacifiCorp.

The Applicant is an independent power producer building a single Project for grid interconnection and is not responsible for system or regional planning needs.

6.0 FUTURE DEVELOPMENT PLANS

The Applicant has no plans for future development of the Project or of any other existing or proposed water power at this site beyond what has been proposed in this application.