PREPARED BY EES CONSULTING

Public Utility District No. 1 of Whatcom County

Electric System Expansion Feasibility Study DRAFT #3

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EES Consulting
a GDS Associates Company

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1.1 INTRODUCTION

Public Utility District No. 1 of Whatcom County (PUD) is located in Washington state. Whatcom County (County) is roughly 2,500 square miles with a current population of approximately 228,831.[1] The PUD was formed in 1937 by a vote of the people of the County, and has countywide authority to supply electric and water services. Currently, the PUD's 115 kilovolt electric system serves one industrial customer located at Cherry Point and its two water treatment plants. One hundred percent of the PUD's power supply requirements are provided by the Bonneville Power Administration (BPA). The PUD's industrial water system provides non-potable water supply to industrial customers and irrigators. In addition, the PUD has a separate water system, which provides potable water supply and fire flow to a complex of light industrial parks in the County.

The PUD released a request for proposal (RFP) and selected EES Consulting (EES), a GDS Associates Company, to evaluate the financial, engineering, operational and regulatory feasibility (the Study) of expanding the PUD to serve all electric customers within the County that are currently provided electric services by Puget Sound Energy (PSE), an investor-owned utility (IOU). PSE provides services to all electric customers within the County with the exception of the PUD's industrial customer at Cherry Point, and the cities of Sumas and Blaine, which both have their own municipal electric utility departments.

The goals for expanding the PUD service territory include the following:

1. Provide local control over programs and power supply choice
2. Provide reliable electric service at lower retail rates
3. Facilitate further reduction of carbon emissions in the County

The Study evaluates the cost to purchase PSE's distribution system in the County; PUD costs for power supply required to serve the expanded utility's service area; forecast future PSE retail rates; and potential generation cost stranding for the electric load transferred from PSE's service responsibility to the PUD. EES reviewed the distribution system using available GIS maps, Google Earth, and an on-site survey. The value of the system is calculated using a range of estimates, described in this Study.

Based on the results of this Study, the following observations are made:

- Based on field investigation work, PSE distribution system facilities appear to be in marginally adequate condition. The age and quality of the system varies throughout the County.

- If the PUD proceeds with the acquisition of PSE facilities and then serves the newly acquired electric load, the PUD may not need to pay generation stranding costs. Factors supporting this observation

[1] U.S. Bureau of the Census. Whatcom County, Washington. Estimate for July 2021. https://www.census.gov/quickfacts/whatcomcountywashington

include: the relevant Washington state utility requirements for clean energy acquisition; current high-power costs; and PSE's generation expansion plans.

- In order for the economics of expansion to be as positive as possible, the PUD will need access to BPA Tier 1 power. In order to receive Tier 1 power from BPA, acquired PSE customers must be served by a "new" public agency utility. As such, a new public agency utility must be formed initially (i.e. PUD #2). How to most efficiently form a new utility will take legal and regulatory input beyond the scope of this technical Study but should be undertaken. Forming a new utility will also likely require an affirmative vote by the County's citizens.

- For purposes of this Study, a "base case" option is analyzed and defined as:
  - A new public agency utility is formed in the County to serve electricity to all customers in the County currently served by PSE.
  - This new utility receives a full allocation of BPA Tier 1 power as quickly as possible per the terms of the currently applicable BPA Wholesale Power Sales Contract.
  - All prior PSE customers will begin taking service from the new utility concurrently.

This "base case" option will be the focus for the balance of this Study's analysis and comment.

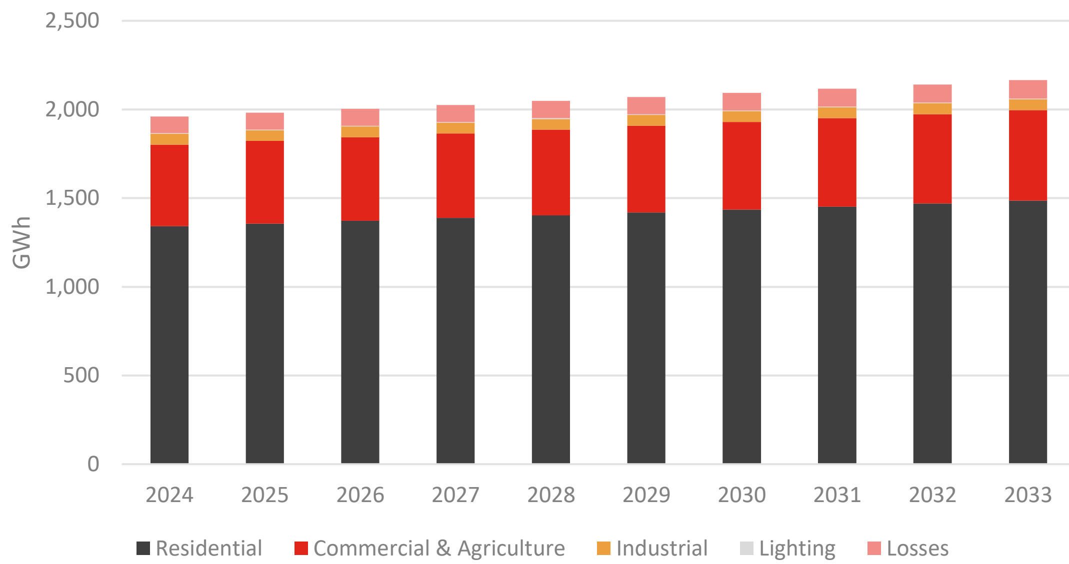
1.2 BASE CASE FINANCIAL ANALYSIS AND STUDY ASSUMPTION DETAILS

The detailed "base case" assumptions and analysis undertaken are presented throughout the balance of this Study. A summary of these assumptions and results are provided here. Under this "base case" analysis, it is assumed that the entire County load (less Cherry Point industrial, Sumas and Blaine) is served concurrently and the PUD acquires a maximum incremental amount of BPA Tier 1 power.

System loads are estimated based on PSE's publicly available County fact sheet and the average use data for similar electric customers in Washington state. PSE's 2021 community profile for the County[2] reported a total of 94,393 electric residential accounts, 15,061 commercial and 347 industrial accounts. Figure 1-1 shows the forecasted load based on customer class for all current PSE customers within the County.

[2] https://www.pse.com/en/about-us

FIGURE 1-1: LOAD FORECAST



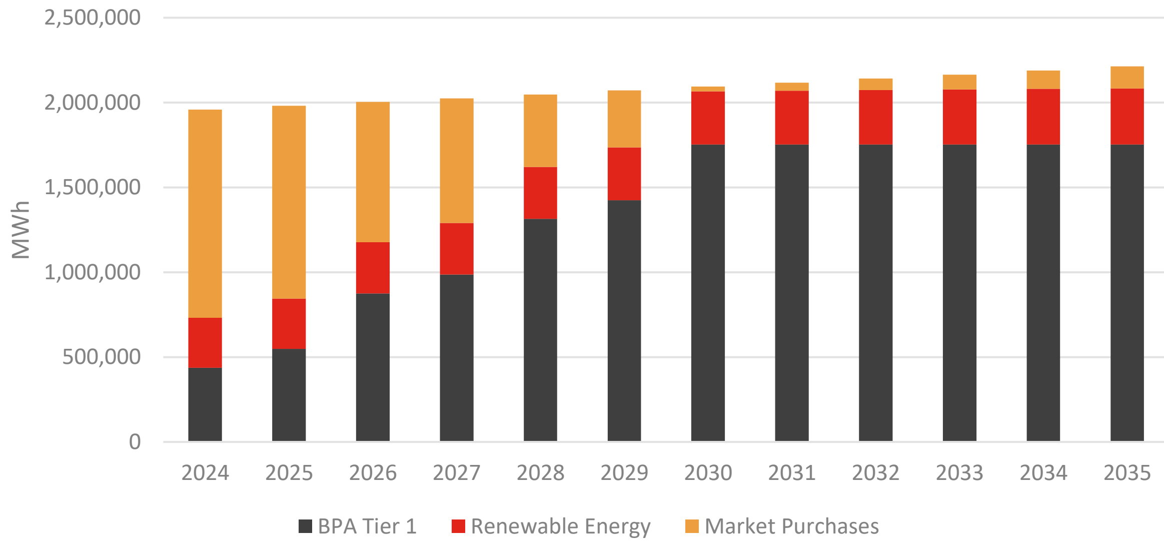
Power supply, transmission and ancillary services include all costs for power supply and related services necessary to energize and maintain the new utility's distribution system. It is assumed that the expanded electric utility would meet power requirements through a majority of public agency preference power (Tier 1) from BPA and power purchase agreements (PPA) with third parties. Newly formed public agency utilities in the BPA served region can by BPA policy obtain up to 50 aMWs of Tier 1 power each rate period. If more than one new public utility is formed, then the utilities are each apportioned a share of the 50 aMWs. The total amount of power available for new public utilities is capped at 250 aMWs for the twenty-year term of the current BPA power contracts but about 50 aMWs have already been taken.

In the Study's "base case", it is assumed the PUD would begin serving customers with 50 aMWs of BPA power priced at Tier 1 and add 50 aMWs of BPA power every two-year rate period until the total reaches 200 aMWs. The "base case" assumption is optimistic; it hinges on BPA designating the newly acquired service area as a new public utility. Absent this designation, the PUD would receive additional BPA power priced at the Tier 2 rate, which is essentially a market-based rate that is about 125% higher than Tier 1 power.

After acquisition of BPA power supply, it is assumed that the PUD would meet the remainder of its power supply obligations through market power purchases and renewable energy via purchased power agreements (PPAs). The majority of BPA's power supply is from the region's federal hydro system. Under current Washington state energy legislation, this supply is considered "Legacy" hydro and does not count for purposes of a public utility in the State meeting the State's renewable energy portfolio standard (RPS). Therefore, the expanded PUD would need to purchase additional renewable energy to meet the State's current RPS statute.

Additionally, the PUD would need to demonstrate progress toward meeting the State's Clean Energy Transformation Act (CETA) requirements, which mandates that a utility's power supply portfolio be 100% carbon emissions neutral by 2030. Under CETA, BPA Tier 1 power supply would be considered 95% carbon emissions free. Bundled renewable energy PPAs make up 15% of the PUD's power supply in each year of this Study. Market purchases are the remainder of the power resource need. Beginning in 2030, market purchases would need to be offset by renewable energy credits (REC) purchases. Figure 1-2 illustrates the power mix assumed over the Study period.

FIGURE 1-2: PUD POWER MIX ASSUMPTIONS



In addition to the above purchases, the PUD would need to comply with the Western Resource Adequacy Program (WRAP) requirements for loads not served by BPA. WRAP was started in 2019 to address concerns driven by thermal plant retirements and additions of intermittent, variable energy resources like renewables.[3] The WRAP initiative is intended to assess and ensure that there will always be enough capacity to meet customer demand. This is called resource adequacy (RA). RA costs are included in the power supply cost expenses for the expanded new utility. These RA requirements are significant expenses driven by the major transitions underway in our regional energy system.

In addition to power supply costs, an annual budget for the new utility was developed based on debt service needed to purchase PSE's distribution system. Other operating cost parameters were developed using data sourced from similarly sized public utilities. The initial funding for the expanded utility includes costs to separate from the PSE system, value of the system acquired, working capital, transaction costs, and start-up costs for items such as mapping, inventories, and other miscellaneous items not included in the purchase of the PSE system.

The resulting budget is shown for 2024 in Table 1-1. Note that this budget applies only to the new expansion area and does not include the PUD's current service expenses or revenues.

[3] https://www.bpa.gov/learn-and-participate/projects/western-resource-adequacy-program

TABLE 1-1: ANNUAL UTILITY REVENUE REQUIREMENT

	First Year Operations ($ million)
Power Supply	$146.15
Transmission	$7.60
Distribution O&M	$35.26
Customer Service	$7.70
A&G	$18.60
Debt Service	$25.86
Capital Projects Financed with Cash	$18.40
In Lieu of Property Taxes	$6.90
Revenue Requirement	**$266.50**
Average Retail Rate, $/MWh	**$139.12**

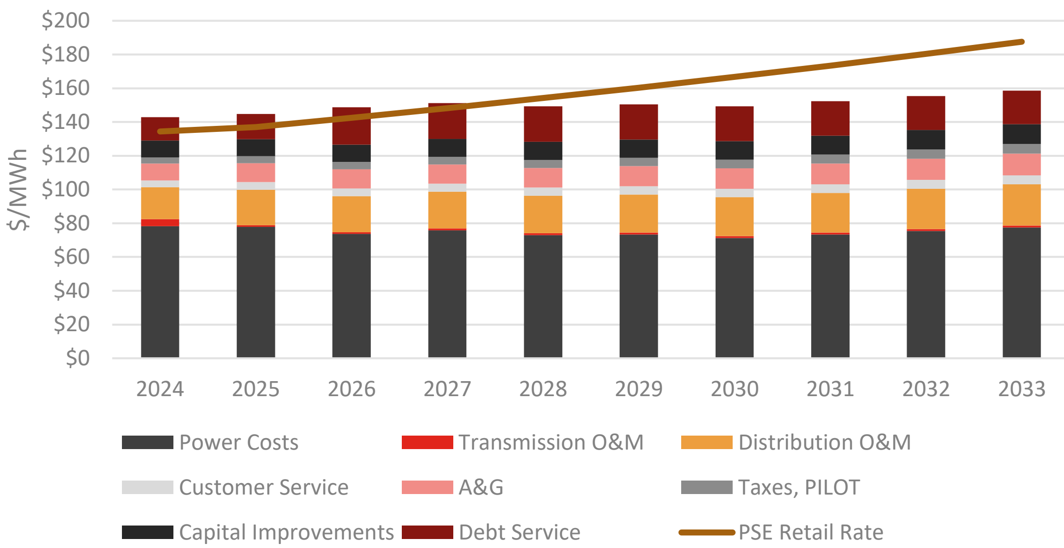
1.2.1 PSE Rate Forecast

In order to determine the feasibility of expanding the PUD's service area through acquisition of PSE facilities, the cost of service of the new utility is estimated and compared to continued service by PSE. The PSE retail rate forecast is based on PSE's most recent general rate case filing where retail rates were increased by 13.59% for 2023, 2.47% in 2024, and 1.22% in 2025. Starting in 2026, the rate forecast is escalated at 4% per year. This 4% assumption is conservative compared with PSE's average rate increase from 2022 through 2025 at 4.8% per year.

1.2.2 Results

Figure 1-3 compares the forecast retail rates in nominal dollars over the Study period assuming the entire County load is serviced initially (less Cherry Point industrial and Sumas and Blaine) and by a new utility. Even with assuming interest-only payments in the first two years of operation and a full allocation of Tier 1 power, the PUD expansion experiences negative net income. At rate parity with PSE, the cumulative net income in the first four years of the Study, assuming the entire County is initially serviced, is -$80.2 million. A 10-year proforma is included in Appendix A.

FIGURE 1-3: RATE COMPARISON RESULTS



The large PSE asset purchase price coupled with relatively high renewable PPA and market prices results in unfavorable economics if the PUD wishes to service the entire County's load initially. A range of sensitivities were performed under the "base case" on asset purchase price and all scenarios resulted in negative net income values in the first four years of operation if the entire County load is serviced initially.

1.3 SUMMARY OF STUDY FINDINGS

Based on the results of this Study, the expansion of the PUD service area is currently not financially feasible if the PUD wishes to service the entire County initially. The Project Team observes the following:

- Based on the field investigation work, the PSE distribution system is in marginally adequate condition.
- The most likely fair market asset value for PSE's distribution system is $492M.
- Expanding the PUD service area is not financially feasible if the entire County load is served initially due to a number of factors including high near-term power costs and large value of PSE distribution system.
- All transmission needs should be provided via contractual agreements with PSE and BPA.
- BPA Tier 1 power for new public utilities is available only in up to 50 aMW increments every BPA rate period (2 years). However, because the PUD has an existing BPA customer, a new utility would need to be formed to receive Tier 1 power from BPA. Load growth for an existing public utility, which is above its contract specified Tier 1 allocation can be provided by BPA but at a market-based Tier 2 rate. To avoid Tier 2 supply from BPA and form a new utility, an affirming vote by County residents would likely be needed for the establishment of an entirely new public utility, as a precursor to expansion.

Jefferson PUD purchased the PSE distribution system in Jefferson County in 2010. The purchase price for that system was $103 million. These assets served 18,000 customers. While the number of accounts in the PUD expanded service area is much greater (over 100,000), there have been several other changes since Jefferson PUD negotiated its deal with PSE:

1. Resource adequacy (RA) requirements were not in place at the time Jefferson PUD was established. RA costs are estimated at $25-$30 million per year. Without these costs, the Study's financial analysis is much more favorable.
2. CETA requirements were not in place. These requirements add approximately $1.2-$2 million per year beginning in 2034.
3. This Study assumes that the PUD would need to purchase transmission from both BPA and PSE's Open Access Transmission Tariff (OATT). This assumption doubles the annual transmission costs from approximately $9 million to $20 million.

Without the above, the PUD's power supply costs are reduced by over 25%. The expansion becomes favorable with this level of reduced power supply costs

1.4 NEXT STEPS

Due to the contractual limitations on the amount of available Tier 1 power, a new utility would need to be formed. Under this option, it may be feasible to evaluate a slower expansion plan where expansion keeps pace with additional allocation of BPA Tier 1 power. It takes 8 years to phase in BPA Tier 1 power supply for the whole County, based on BPA allocations for a new public utility. But over this 8 year "phase-in" expansion option, PUD rates would be lower than continued service from PSE. A thorough legal/regulatory analysis of forming a new public agency utility would be the next step if the PUD wants to expand its service territory. Then PSE and BPA should be engaged to determine their respective views on a "phase-in" option.

This "phase-in" approach would require some PSE cooperation to avoid multiple condemnation proceedings. The other changes that would make this expansion financially feasible are a significant reduction in wholesale power market prices and/or an increase in PSE rates above those forecast in this Study.

2 Introduction

Public Utility District No. 1 of Whatcom County (PUD) is located in Washington. Whatcom County (County) is approximately 2,500 square miles with a current population of approximately 228,831.[4] The PUD was formed in 1937 by a vote of the people of the County and has countywide authority to supply electric and water services. Currently, the PUD's 115 kilovolt electric system serves one industrial customer located at Cherry Point and its two water treatment plants. One hundred percent of the PUD's power supply requirements is provided by the Bonneville Power Administration (BPA). The PUD's industrial water system provides non potable water supply to industrial and irrigation customers. In addition, the PUD has a separate water system, which provides potable water supply and fire flow to a complex of light industrial parks located in the County.

The PUD (PUD) selected EES Consulting (EES), a GDS Associates Company, to evaluate the financial, engineering, operational and regulatory feasibility of expanding the PUD to serve electric customers located within the County, but who are currently served by Puget Sound Energy (PSE).

This Study estimates the electric retail rates that would be charged to customers within the County if they were served by the PUD. These rates are then compared with forecast rates where PSE continues to be the electricity provider.

2.1 STUDY FRAMEWORK

This Study was prepared using publicly available information; a site survey of relevant equipment; and EES's extensive experience with electric utility operations. The Study's analytical "base case" construct includes the following assumptions:

1. Expanded Electric Utility service provided by the PUD includes:
    a. All unincorporated areas of the County, including Lummi Island
    b. All Cities within the County except for Sumas and Blaine
    c. Lummi Nation Reservation
    d. Point Roberts
2. The Study does not consider the purchase of PSE generating assets located within the County
3. The PUD would not purchase PSE transmission level voltage facilities.
4. The PUD would purchase transmission service from PSE and Bonneville Power Administration (BPA) under standard open access tariffs (OATT).
5. All customers of the new utility would commence service simultaneously.
6. The PUD will meet power supply requirements through power purchase agreements (PPA) and market purchases. It is assumed that the maximum amount of BPA Tier 1 power allowed under BPA's Wholesale Power Purchase Agreement will be available to the PUD.

[4] U.S. Bureau of the Census. Whatcom County, Washington. Estimate for July 2021. https://www.census.gov/quickfacts/whatcomcountywashington

7. At a minimum, Washington's Renewable Portfolio Standard (Energy Independence Act, EIA), and Clean Energy Transformation Act requirements are met for both renewable energy content and greenhouse gas free/neutral power supply.
8. This Study assumes that the PUD can acquire 50 MW of Tier 1 Power during the first two years of operation and an additional 50 aMW every 2 years going forward up to a maximum of 200 aMW. However, in order to receive this allocation under current BPA policy a new utility (e.g., Whatcom PUD #2) will likely need to be formed via a vote of the County residents.

Acquired facilities and their values are estimated based on an inventory of PSE distribution assets. The values are benchmarked to values estimated from other sources including PSE's FERC Form 1, the PSE cost of service model filed in the 2022 General Rate Case, and a survey of plant data from similar situation public utilities. Operating costs and financing for the new utility are estimated based on current borrowing markets and a survey of public utility budgets. Rates are then compared between PSE and the new utility to evaluate the financial feasibility of the expansion. Lastly, next steps and general observations are offered.

3 County System Customer and Load Forecast

The load characteristics contained in this Study are evaluated based on publicly available information including the number of accounts PSE serves in the County and average customer use data.

3.1 COUNTY SYSTEM LOADS

System loads are estimated based on PSE's publicly available County fact sheet and average use for similar electric customers in Washington state. PSE's 2021 community profile for the County[5] reported a total of 94,393 electric residential accounts, 15,061 commercial and 347 industrial accounts. Residential and commercial accounts are forecast to grow 1.1% annually based on recent population growth rates. Industrial account growth is forecast to increase at 0.25% annually, as shown in Table 3-1 below.

TABLE 3-1: 2024 LOAD ESTIMATE

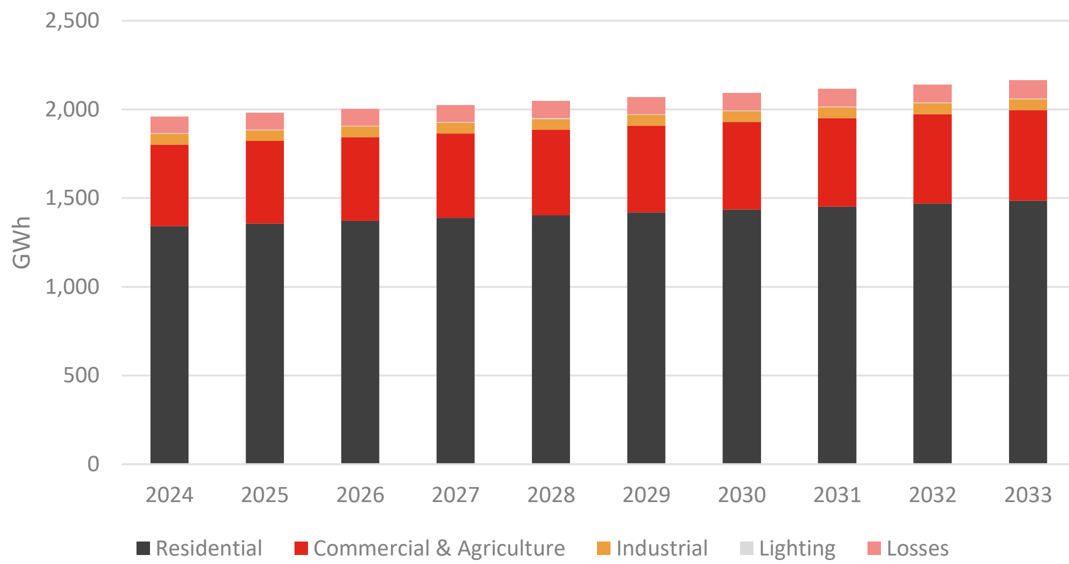
	Service Accounts	Average Use, kWh/month	Retail Sales, kWh*
Residential	97,673	1,507	1,341,391,984
Commercial & Agriculture	15,149	2,754	460,440,976
Industrial	347	14,715	60,120,173
Lighting	435	780	4,001,629
Total – kWh	113,604		1,865,954,763
Total – aMW			213

*Excluding 5% line losses.

An estimate of 5% for transmission and distribution system line losses is assumed to develop total system requirements. Figure 3-1 below illustrates the expected load breakdown for the expansion area.

[5] https://www.pse.com/en/about-us

FIGURE 3-1: LOAD FORECAST



The majority of load is estimated as residential. Since average use for industrial customers is based on the total PSE system, any new large industrial loads would not be represented in the above estimates.

4 Plant Investigation and Separation Findings

For the purposes of this Study, EES conducted a technical investigation of the PSE transmission and distribution system in the County. In the fall of 2022, EES's engineers conducted a physical review of PSE system assets. The review confirmed the location and condition of the PSE system in and around the County, and it identified distribution stations that might serve PUD customers.

Below is a summary of the Project Team's analysis of PSE's electric system that would be acquired for the expansion.

4.1 SEPARATION PLAN

The acquisition of the distribution system in the County owned by PSE is based on some general assumptions related to the plant in question. The scope is to acquire all the distribution plant and all the substations with distribution voltage within the County. The scope excludes the facilities comprising the municipal electric systems in the cities of Blaine and Sumas.

The Lummi Nation is included in the analysis herein, but it is recognized that the acquisition of the distribution system within the Lummi Nation's territory may be complicated. If it is determined that the Lummi Nation wishes to opt out of this acquisition, then the acquisition cost will be reduced, and the separation plan will then require a new PSE substation to serve these Lummi Nation's facilities.

PSE will continue to own and operate the transmission voltage level facilities within the County. This allows PSE to continue to be interconnected with their generation assets within the County. Further, it minimizes any disruption in services or revenues between PSE and industrial customers who may have transmission and/or capacity services from PSE.

In PSE substations with distribution step down transformers and distribution feeders, it is assumed that PSE will continue to own and operate the high voltage side of these substations. These facilities would include the highside structures, highside breakers, associated relays, and bypass switches. The PUD would own and operate the power transformers, SPPC measures, lowside bus, relay controls for the lowside of the station, control house if any, fence, and real property (site). In each substation with distribution feeders, utility grade kWh and kVar meters will be installed to measure delivery of energy, as well as metering for sectionalized secondary buss with more than one distribution feeder. This configuration is similar to the current arrangement at the PUD's existing Enterprise substation served by PSE. A listing of the affected substations is attached as Appendix B.

Some modifications in loop feed substations related to relaying may be required as needed by the parties. It is also assumed that the underbuilt distribution lines on PSE owned transmission poles will be able to remain on the transmission poles. It is expected that a joint-use agreement will be executed and that a fee for leasing the space will be required.

There will be no changes to BPA facilities related to this separation plan.

Finally, there is existing broadband fiber used by PSE for communications between substations. This high-level analysis of acquisition does not specifically address to the use of shared or separate communications. It is assumed that PSE has the necessary permits and easements to own and operate distribution as they exist today within the County. Further, it is assumed that these permits will be transferable with the system.

As shown in Table 4-1, the system to be acquired includes:

TABLE 4-1: WHATCOM COUNTY DISTRIBUTION SYSTEM

Residential Meters	97,673
Commercial Meters	15,149
Industrial Meters	347
Overhead Distribution Lines	1,043 miles
Underground Distribution Lines	1,071 miles
Distribution Substations - Radial	9
Distribution Substations - Looped	19

A site visit by EES in the fall of 2022 revealed that the distribution and substation facilities appear to be in marginally adequate condition. The observation confirmed the PSE's depreciation study that the system is 40% depreciated. The AMI system is observed to be new.

4.2 SEPARATION AND REINTEGRATION

Separation of the distribution facilities from PSE will require some modifications to the remaining PSE system to make PSE whole after the acquisition. EES studied the distribution system with special focus on the southern County lines. Modification will be necessary for distribution facilities crossing Whatcom/Skagit County boundaries. Also metering packages would need to be added to the lowside of substations that the PUD would acquire. Further, some modifications to substation relaying may be required to allow PSE to operate as a transmission supplier within the County.

As part of the transition, there will be a need for contractual arrangements such as easements, permits, and joint use agreements. These are primarily legal and administrative costs and not construction costs. These costs are captured in the separation cost estimate total of $5.23 million. This value is included in the buyout financing separate from other near-term financing.

5 Feasibility Analysis Construct and Findings

As noted earlier, the feasibility for a utility system expansion turns on the relative retail rate levels for the incumbent utility, PSE, versus the retail rates of the expanded new public utility. To this end, this section of the Study develops a financial forecast for the expanded utility and then compares the resultant retail rates to forecast PSE retail rates.

To develop retail rates for a new public utility, a forecast of the documented costs of operating a similar public utility must be developed. These costs include capital costs to finance the necessary buyout of PSE facilities and operating costs such as power supply, transmission and distribution expenses, taxes, and other miscellaneous costs. The retail rate levels for the expanded PUD are followed by a forecast of comparable PSE rates. The following Section details this analytical process.

5.1 NEW UTILITY SERVICE AREA

The new public utility would serve all of the County currently served by PSE but excluding the cities of Sumas and Blaine and the PUD's Cherry Point industrial account. Point Roberts service would be provided by the PUD with power supplied via BC Hydro, similar to the current agreement between PSE and BC Hydro. The financial analysis does not estimate incremental costs for the Point Roberts area. This analysis is recommended for future study should the PUD pursue the expansion.

5.2 SYSTEM VALUATION

Washington Revenue Code Sections 8.04.005 to 8.29.070[6] states that "just compensation" must be paid in order for the condemning entity to purchase the subject facilities. This Study evaluates three different valuation methods to develop estimates for "just compensation." These methods include the following: (1) the sales comparison approach, (2) the income approach, and (3) the cost approach. The ultimate goal of these methodologies is to determine the "fair market value" for the subject property and equipment in a hypothetical open and free market transaction with a willing buyer and a willing seller.

Estimates for plant value are developed based on a detailed review of PSE assets including number of meters, line miles (underground and overhead), transformers, distribution substations, land, and services. Sensitivity is performed based on the replacement cost value estimates which flow through to depreciated replacement cost and original cost estimates.

5.2.1 Replacement Cost Approach

The Replacement Cost Approach uses an estimate of the cost of replacing or reproducing the existing facilities as a measure of value. This amount is then reduced to reflect the amount of depreciation that has accrued to the improvements being valued. The valuation under such a method is generally referred

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[6] Eminent domain laws and procedures.

https://leg.wa.gov/CodeReviser/RCWArchive/Documents/2016/Title%208%20RCW.pdf to as the Replacement Cost New Less Depreciation (RCNLD) value. Straight-line depreciation is used for the calculation of depreciation in the RCNLD value. This approach sets a ceiling for a system's fair market value.

As stated above, replacement costs are estimated for each plant item including meters, services, overhead lines, underground lines, streetlights, switches, and distribution level substations. The EES engineering team evaluated each substation and identified 27 stations that would be acquired for the expansion (note Appendix B). The resulting replacement cost value ranges from $1.0 to 1.4 billion for all PSE facilities considered for acquisition. Based on the PSE rate base information filed in its 2022 general rate case, distribution assets are depreciated by 40% on average. The resulting replacement cost and replacement cost less depreciation values are shown in Table 5-1.

TABLE 5-1: PLANT VALUE: REPLACEMENT COST ESTIMATES

	RCN	RCNLD
Low Estimate	$965,500,000	$579,300,000
Expected	$1,158,600,000	$695,200,000
High Estimate	$1,351,800,000	$811,100,000

5.2.2 Original Cost Approach

The Original Cost Approach uses the original cost of the existing facilities as a measure of value. The original cost of the facilities is reduced by the depreciation that has accrued since these facilities were placed into service. This results in what is commonly referred to as the Original Cost Less Depreciation (OCLD) value or sometimes referred to as the "Net Book Value." This value usually sets the floor for utility valuations assuming no contingent liabilities. This valuation methodology could be based on the utility's records of the original cost of plant and subsequent depreciation that has occurred over time. If such records are not available, original cost is typically estimated by adjusting current replacement cost by appropriate economic indices. Straight-line depreciation is then used to calculate the depreciated cost.

The Project Team adjusted the replacement cost using the Handy-Whitman index (HWI)[7] to determine original cost. The HWI was applied based on an average assumed age of the equipment of 16 years.[8] The resulting ONLD estimate is $387 million.

TABLE 5-2: PLANT VALUE: ORIGINAL COST LESS DEPRECIATION ESTIMATES

Low Estimate	$322,600,000
Expected	$387,100,000
High Estimate	$451,600,000

[7] Whitman, Requardt and Associates. Handy-Whitman Index of Public Utility Construction Costs. Bulletin No. 177. Baltimore, MD. 2013

[8] Based on 40% accumulated depreciation and a service life of 40 years.

5.2.3 Market Approach

The Market Approach looks at a comparison of sales for comparable utilities. This approach is sometimes difficult because sales of comparable utilities that are geographically close are infrequent. This approach generally looks at the percent premium over book value paid by the purchasing utility. Some recent acquisitions provide a range in the percent premium from 19% to 36% with an average level of 27%. These premiums were applied to the book value, or OCNLD. Based on the average value, the market approach yields a value of $492 million.

5.2.4 Summary of System Valuation

The valuation results in the expected OCLD value of $387 million and the RCNLD value of $695 million for all PSE distribution and general facilities within Whatcom County. A range of premium over book value under the market approach was also calculated and is shown in Table 5-3 below.

TABLE 5-3: ESTIMATED PSE DISTRIBUTION SYSTEM VALUE IN WHATCOM COUNTY, MILLIONS

	Expected	Low	High
OCNLD	$387	$250	$452
RCNLD	$695	$579	$811
Premium Over Book			
Low, 19%	$461		
Average, 27%	**$492**	$410	$573
High, 36%	$526		

Based on this valuation exercise, the value of PSE distribution and general plant facilities in the County is set at a medium value of 27% premium over book or $492 million. The fair market value is estimated to range from $387 million to $811 million. Sensitivities are included to evaluate this range.

5.3 DETAIL OF PROXY NEW UTILITY BUDGET

Next, an estimate of capital and operating costs for a new utility is presented. These costs have been quantified conservatively. The basis for these cost assumptions is noted below.

5.3.1 Power Supply, Transmission and Ancillary Cost Projections

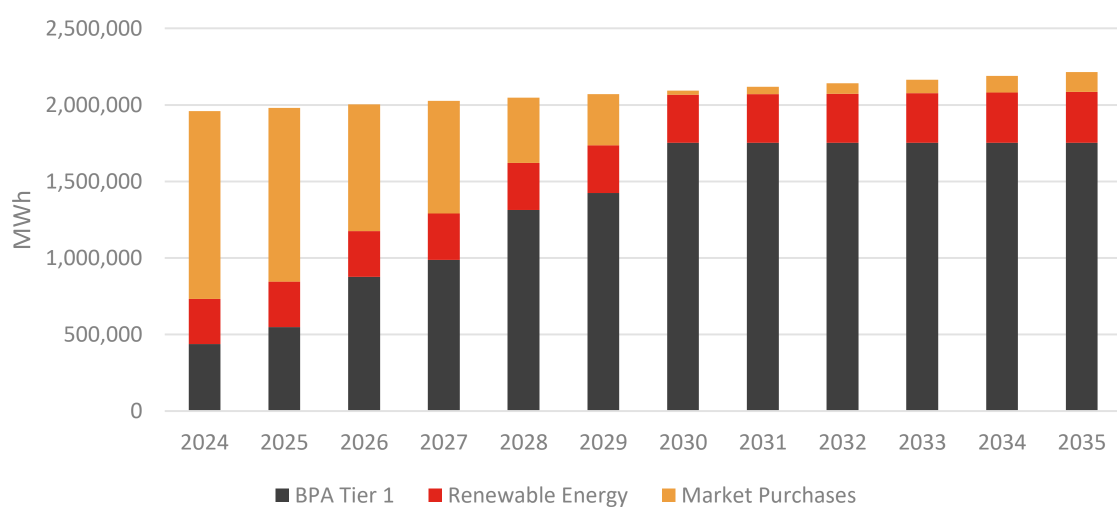
This section describes the power cost assumptions for the new utility's service area. If service is provided to Point Roberts, power supply and transmission services to that area will be different due to the noncontiguous nature of the service area. Point Roberts would be served power and transmission through BC Hydro. Additional analysis would be needed to determine if the cost of power supply to Point Roberts is significantly different than service to the rest of the PSE service area. For this initial Study, it was assumed that service to Point Roberts customers does not cost significantly more than service to the rest of the County.

Power supply, transmission and ancillary charges include all costs for power supply and related services necessary to energize the new utility's distribution system. It is assumed that the new electric utility would meet the majority of its power requirements through a combination of preference power from BPA and power purchase agreements (PPA). New public utilities in the BPA region can obtain up to an aggregate of 50 aMWs of preference power at the Tier 1 rate each rate period up to the cap of 250 aMWs over the term of the BPA power contract. In the base case, it is assumed the PUD would begin serving customers with 50 aMWs of BPA power and add 50 aMWs of BPA power every two years until the total reaches 200 MW. To date, 45 MW have already been appropriated; therefore, it is assumed that 200 MW would be available to the new utility. If multiple new public utilities ask for Tier 1 power supply, BPA's Tiered Rates Methodology (TRM) establishes a multi-step process for allocating and phasing in new Preference Customer loads. It is further assumed in the "base case" that all new utility customers commence service simultaneously.

It is important to note that BPA's current wholesale power contracts expire at the end of September 2028. Beginning October 1, 2028, new contracts will be effective, and the standards and availability for BPA power supply to a new utility may or may not be included under the new contract provisions. The terms for the new contracts are currently under development. However, given the current framework, a "new: utility would likely receive some allocation of Tier 1 priced power. BPA is statutorily obligated to serve new PUDs who qualify for service under the standards outlined above. Whether service is provided through Tier 1 resources/rates or some other product is the question. Likely the new contracts in 2028 will contain similar provisions about the availability of Tier 1 power to serve a portion of a new utility's net requirements subject to rate period and contract term cumulative caps (average MWs). For loads above the new utility's Tier 1 allocation, the new utility could be served by BPA at the Tier 2 product price (assuming a similar contract post 2028) or from market purchases.

After BPA power, it is assumed that the new utility would meet the remainder of its power supply obligations through market power purchases and renewable energy PPAs. BPA power has some renewable energy content; however, the new utility would need to purchase additional renewable energy to meet State RPS requirements of 15%. Additionally, the new utility would need to demonstrate progress toward meeting the Clean Energy Transformation Act (CETA) requirements for 100% greenhouse-gas neutral energy by 2030. Bundled renewable energy PPAs are assumed to make up 15% of the new utility's power supply in each year. Market purchases are the remainder of the resource need. Beginning in 2030, market purchases would need to be offset by REC purchases. Figure 5-1 illustrate the power mix assumed over the study period.

FIGURE 5-1: PUD POWER MIX ASSUMPTIONS



In addition to the above purchases, the new utility would need to comply with the Western Resource Adequacy Program (WRAP) requirements for capacity showings for loads not served by BPA. BPA plans to include RA in its power supply services to load following customers. The additional cost of RA is included in the BPA rate forecast. The cost of the remaining resource adequacy (RA) need is assumed at $6.50/kW-mo which is slightly lower than the fixed capital costs for a new natural gas plant of $7.65/kW-mo.[9]

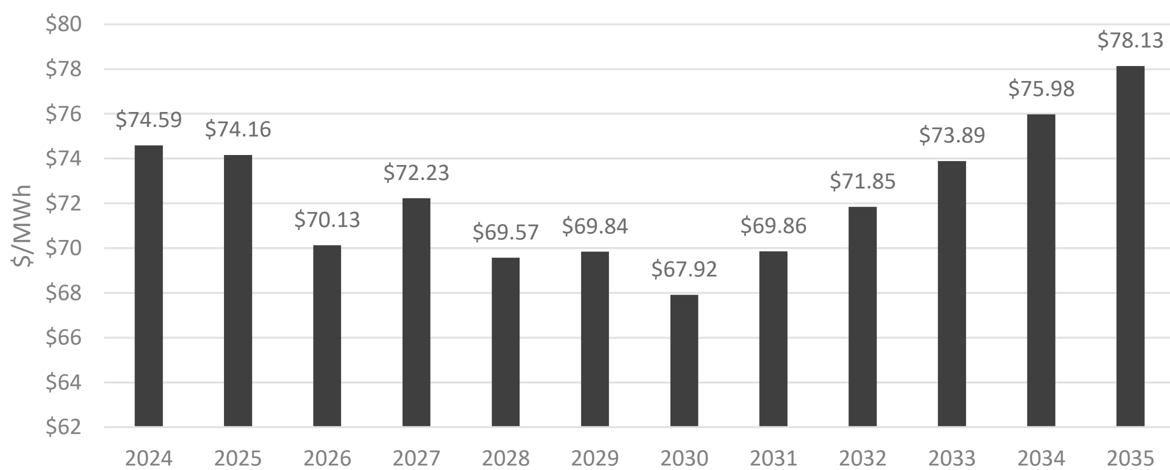
5.3.1.1 Summary of Power Supply Assumptions

Power costs assumptions are summarized below.

- Wholesale market energy price/BPA Tier 2 = $63/MWh levelized over 10 years
- Washington Renewable Energy Credits (REC) = $6.00/MWh, escalated at 2.5% annually
- Long term renewable PPA price = $50/MWh for 10-year term including resource shaping
- Resource Adequacy, $6.50/kW-mo escalated at 3%/year
- Network Transmission and Ancillary Services BPA = $5.50/MWh
- PSE OATT Network: $4.50/MWh[10]

Figure 5-2 illustrates that as BPA power is integrated into the expanded PUD's resource mix, power costs decrease over the Study period until the full 200 MW of BPA power is realized. Average power costs then increase as CETA requirements are met with additional GHG free power and general cost escalations.

FIGURE 5-2: ESTIMATED AVERAGE POWER COSTS FOR EXPANDED PUD



[9] Western Resource Adequacy Program CONE Penalty Task Force Proposal. $91.81/12 months = 7.65/kW-mo. https://www.westernpowerpool.org/private-media/documents/2022-02-10__CONE_Penalty_Proposal.pdf

[10] Weighted average on-peak and off-peak network rate. http://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/PSEI_Current_OATT_Prices_2022_6_1.pdf

After 2030, power costs increase by an average of 3% per year. Once fully allocated, BPA Tier 1 is estimated to serve approximately 80% of the expanded area loads, assuming the expansion can attract 200 aMW of Tier 1 power.

5.3.1.2 Transmission & Distribution System O&M

Distribution expenses includes all costs to operate and maintain the distribution system including substations. Distribution O&M costs were estimated by looking at comparable public agency utilities. Distribution O&M costs per customer and per kWh from four comparable municipal utilities. These costs were then applied to the new utility weighting 50% to customer and 50% to MWh. The resulting average cost is approximately $38 million per year.

Similarly, Transmission O&M is calculated. Together distribution and transmission O&M is estimated at $40 million annually as shown in Table 5-4.

TABLE 5-4: TRANSMISSION & DISTRIBUTION O&M ESTIMATES

	Transmission		Distribution	
	$/Service Account	$/MWh	$/Service Account	$/MWh
Average O&M from Surveyed Utilities	$17.88	$0.85	$381.75	$17.99
PUD Service Accounts or MWh Load	113,604	1,865,955	113,604	1,865,955
Estimated O&M	$2,031,488	$1,584,249	$43,368,159	$33,566,925
Average	**$1,807,868**		**$38,467,542**	
Total Transmission & Distribution O&M				**$40,275,411**

5.3.2 Customer Service

Customer service expenses include labor and expenses incurred to provide customer service such as billing, meter reading, programs, customer information and advertising, records, and collection. Customer service costs may vary by type of account based on usage profile or meter type. For example, a large industrial customer with a special contract for rates would require significantly more resources to bill compared with the average residential customer on a general rate schedule. This Study takes the average of $110/Customer and $4.50/MWh to develop customer service costs for the new utility. These averages were developed based on expenses reported for 2018-2022 by 11 sample public agency utilities. The resulting annual customer service cost is estimated at $8.4 million.

5.3.3 Administrative and General Expense

Administrative and General expenses include all other labor and expenses necessary to run the electric utility. Labor includes personnel in accounting, information systems, and management. Office supplies and equipment includes the cost of purchasing (in the case of consumables such as paper and toner) or depreciation (in the case of depreciable assets such as computers, printers, and furniture). Facilities O&M includes the cost of operating and maintaining office space to house new employees, fleet trucks, storage, and work yards. Miscellaneous costs include other administrative and general expenses not included in the categories listed above such as maintenance and depreciation of additional modules for a new billing/customer information system necessary for the electric utility. Based on the surveyed utilities, administrative and general expenses are estimated at $20.1 million per year.

5.3.4 Payments in Lieu of Taxes

Generally, a public utility will not pay taxes. However, because a goal of this Study is to hold impacted taxing authorities harmless, a 3% payment in lieu of taxes (PILOT) is included in the new utility budget.

5.3.5 Capital Improvement Projects (CIP) Expenditures

The expanded utility would need to routinely undertake capital projects. Estimates for capital improvement are based on estimated depreciation expense for the plant replacement value and a 40-year straight line method. The resulting CIP is $18.4 million per year escalated at the inflation (3%).

5.3.6 Non-Operating Expenses

Non-Operating Expenses include debt service, stranded generation costs, if any, and miscellaneous revenues. These are discussed below.

5.3.6.1 Debt Service

The desired PSE distribution plant was valued according to the market and cost approach using the field work completed for this Study. Under the cost approach, values were calculated based on both the Replacement Cost New Less Depreciation (RCNLD) and Original Cost Less Depreciation (OCLD).

For the entire PSE distribution system and general plant, the RCNLD method results in value of $695 million. The OCLD method resulted in a net book value of $387 million. The true fair market value of the subject facilities likely lies between these two values. In order to be conservative, this Study assumes the medium plant value of $492 million as the value of the subject PSE facilities.

In order to alleviate immediate cash requirements, the Study assumes the new utility will make interest-only payments in the first 2 years for the plant purchase amount.

5.3.6.2 Stranded Generation Costs

Because market wholesale power prices are high currently and PSE must replace its power supply with GHG free or neutral sources, the Study assumes there will be no stranded generation costs. Specifically, PSE's 2022 rate case filing summarizes PSE power cost only rate at $63.962/MWh[11] which is approximately the same as the market value of $64/MWh and near-term forecasts of $70/MWh or more.

5.3.6.3 Legal Costs

Legal costs for the acquisition are estimated at $5 million. These costs can vary widely depending on the duration and nature of the legal process to acquire the subject facilities.

[11] NEW-PSE-Exh-SEF-12-1-31-22.xlsx. Exhibit A-1. Table 22GRC Rate Year 1 – 2023 line 38.

5.3.6.4 Start-Up Costs and Working Capital

Start-up costs include cash for working capital, start-up expenditures such as staffing and equipment, and facilities and inventory costs. Because the PUD is already operating, inventory is assumed to be slightly less than 5% of the RCNLD value. Start-up and reintegration costs are estimated at $22 million.

5.3.6.5 Separation

Because the subject PSE system is neatly contained within the County, separation costs would be minimal. For example, utility scale meters would need to be installed in each substation. An estimate of $5.23 million is included for separation costs. Any additional separation requirements such as mapping, billing systems, and other operations components are part of the start-up cost estimate.

The annual debt service payment includes the above components as described in Table 5-5.

TABLE 5-5: TOTAL FINANCING REQUIREMENTS

	$Millions
Distribution and General Plant System Value at RCNLD	$491.6
Transaction Legal Costs	$5.0
Working Capital	$5.0
Start-up Costs	$22.0
Separation Costs	$5.2
TOTAL	**$526.6**

5.4 ANNUAL BUDGET

The resulting first year budget is shown in Table 5-6. Note that this budget applies only to the expansion area and does not include the PUD's current expenses and revenues.

TABLE 5-6: ANNUAL UTILITY REVENUE REQUIREMENTS

	First Year Operations ($ million)
Power Supply	$146.15
Transmission	$7.60
Distribution O&M	$35.26
Customer Service	$7.70
A&G	$18.60
Capital Improvement Financed with Cash	$18.44
Debt Service	$25.86
PILOT	$6.90
Revenue Requirement	**$266.50**
Average Retail Rate, $/MWh	**$139.12**

The average retail rate for the new utility is $139.12/MWh in its first year of full operations.

5.5 PSE RATE FORECAST

In order to determine the feasibility of expanding the PUD's current service area, an estimate of continued service by PSE is needed. The PSE retail rate forecast is based on PSE's most recent general rate case filing where retail rates were increased by 13.59% for 2023, 2.47% in 2024, and 1.22% in 2025. Starting in 2026, the PSE rate forecast is escalated at 4% per year. This 4% assumption is conservative compared with PSE's average rate increase from 2022 through 2025 at 4.8% per year as shown in Table 5-7.

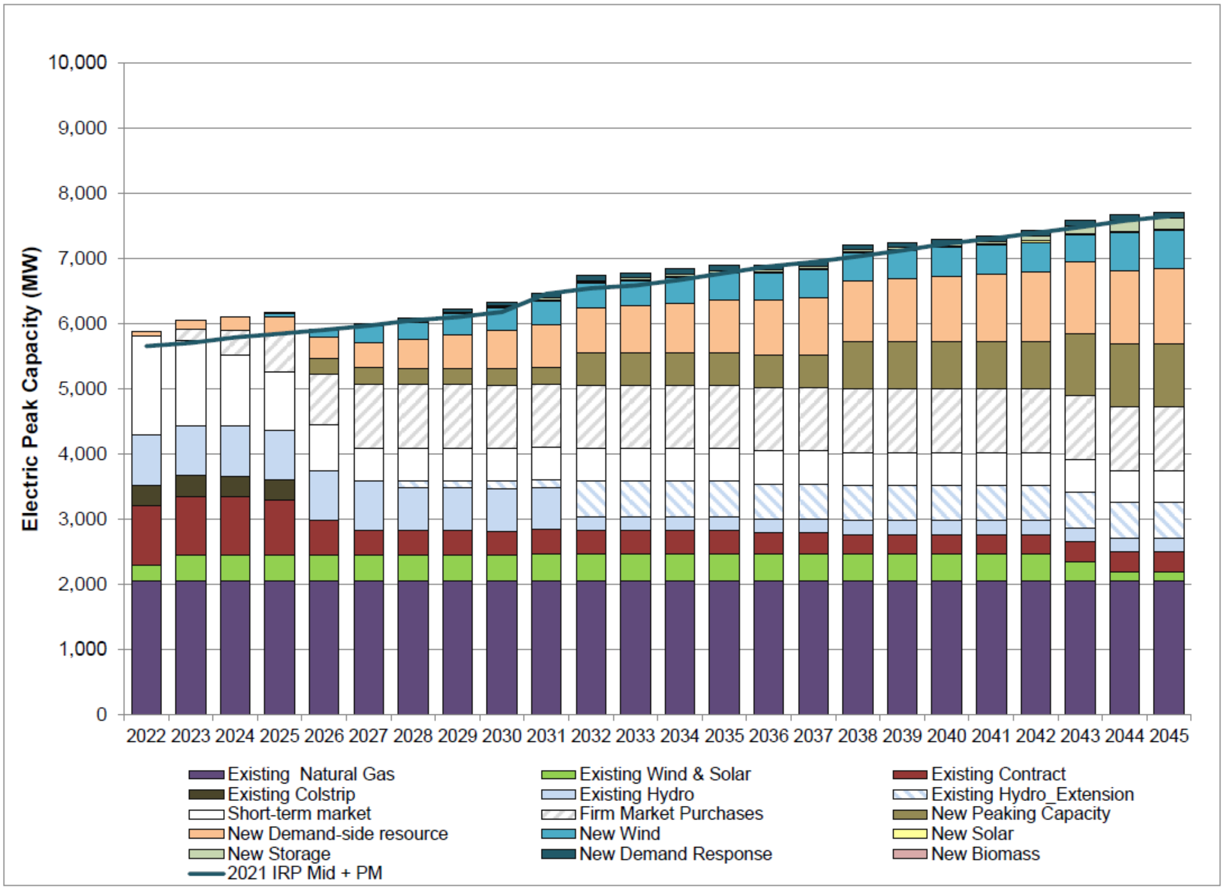
TABLE 5-7: PSE RETAIL RATE FORECAST ESCALATION RATES

Rate Forecasts	2023	2024	2025	2026
PSE Rate Forecast	**13.59%**	**2.47%**	**1.22%**	**4%**
Residential	14.59%	2.64%	1.92%	4%
Commercial & Ag	12.73%	2.55%	2.12%	4%
Industrial	9.72%	2.42%	2.20%	4%
Lighting	21.22%	4.10%	1.59%	4%

5.5.1 PSE 2021 Integrated Resource Plan

PSE must meet Washington's renewable portfolio standards, CETA mandates for GHG free or neutral energy, and WECC's resource adequacy program requirements. Figure 5-3 summarizes PSE's preferred portfolio from the most recent IRP. Additions for peaking capacity along with renewable energy will put upward pressure on PSE retail rates. The figure also shows that PSE plans to increasingly rely on market purchases for firm energy over the IRP study period.

FIGURE 5-3: PSE PREFERRED PORTFOLIO MEETING 2021 IRP[12]

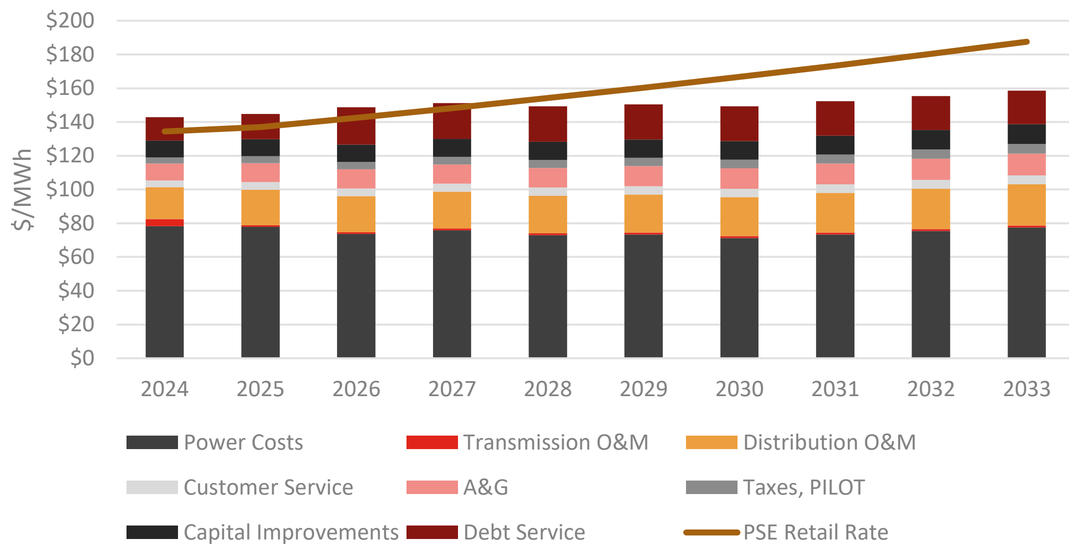


5.6 RATE COMPARISON

This section presents the results of the analysis comparing forecast PSE rates with forecast rates for the new utility. Figure 5-4 compares the forecast retail rates in nominal dollars over the Study period. Even assuming interest-only payments in the first 2 years of operation and a full allocation of BPA Tier 1 power, the PUD expansion experiences negative net income. At rate parity with PSE, the cumulative net income in the first 4 years of the Study is -$80.2 million. An annual detailed proforma is included in Appendix A.

[12] PSE 2021 IRP. https://www.pse.com/IRP/Past-IRPs/2021-IRP

FIGURE 5-4: RATE COMPARISON RESULTS



The large purchase price coupled with relatively high market prices results in unfavorable economics. If the PUD were able to obtain a larger share of BPA Tier 1 power, the feasibility would improve.

5.7 SENSITIVITY ANALYSIS

In addition to the base case analysis noted above, a sensitivity analysis is presented in Table 5-8 below to determine if certain assumptions would result in feasibility. Primarily the fair market value of the subject PSE assets is adjusted.

TABLE 5-8: SCENARIO ANALYSIS

Plant Valuation Method	Plant Value ($Millions)	Energy Portfolio	Net Income First 4 Years, Millions
OCNLD Low	$250	15% Renewable, BPA Power	-$33.0
OCNLD	$387	15% Renewable, BPA Power	-$53.9
OCNLD	$387	15% Renewable, No BPA Power	-$130.5
27% Premium over Book	$492	15% Renewable, BPA Power	-$80.2
27% Premium over Book	$492	15% Renewable, No BPA Power	-$138.9
RCNLD	$695	15% Renewable, BPA Power	-$131.4

With no access to additional BPA Tier 1 power, the expansion area power costs are significantly higher resulting in negative net income beyond the first four years in all cases.

6 Summary of Study Findings

Based on the results of this Study, the expansion of the PUD service area is currently not financially feasible if the PUD wishes to service the entire County initially. The Project Team observes the following:

- Based on the field investigation work, the PSE distribution system is in marginally adequate condition.
- The most likely fair market asset value for PSE's distribution system is $492M.
- Expanding the PUD service area is not financially feasible if the entire County load is served initially due to a number of factors including high near-term power costs and large value of PSE distribution system.
- All transmission needs should be provided via contractual agreements with PSE and BPA.
- BPA Tier 1 power for new public utilities is available only in up to 50 aMW increments every BPA rate period (2 years). However, because the PUD has an existing BPA customer, a new utility would need to be formed to receive Tier 1 power from BPA. Load growth for an existing public utility, which is above its contract specified Tier 1 allocation can be provided by BPA at a market-based Tier 2 rate. To avoid Tier 2 supply from BPA by forming a new utility, an affirming vote by County residents would likely be needed.

Jefferson PUD purchased the PSE distribution system in Jefferson County in 2010. The purchase price for that system was $103 million. These assets served 18,000 customers. While the number of accounts in the PUD expanded service area is much greater (over 100,000), there have been several changes since Jefferson PUD negotiated its deal with PSE:

4. Resource adequacy (RA) requirements were not in place at the time Jefferson PUD was established. RA costs are estimated at $25-$30 million per year. Without these costs, the financial analysis is much more favorable.
5. CETA requirements were not in place. These requirements add approximately $1.2-$2 million per year beginning in 2034.
6. This Study assumes that the PUD would need to purchase transmission from both BPA and PSE's Open Access Transmission Tariff (OATT). This assumption doubles the annual transmission costs from approximately $9 million to $20 million.

Without the above, the PUD's power supply costs are reduced by over 25%. The expansion becomes favorable with this level of reduced power supply costs

6.1 NEXT STEPS

Due to the limitation on BPA Tier 1 priced power supply, a new utility would need to be formed. Under this option, it may be feasible to evaluate a slower expansion plan where expansion keeps pace with additional allocation of BPA Tier 1 power. It takes 8 years to phase in BPA Tier 1 power supply for the whole County, based on BPA allocations for a new public utility. But over this 8 year "phase-in" expansion option, PUD rates would be lower than continued service from PSE. A thorough legal/regulatory analysis of forming a new public agency utility would be the next step if the PUD wants to expand its service territory. Then PSE and BPA should be engaged to determine their respective views on a "phase-in" option.

This "phase-in" approach would require some PSE cooperation to avoid multiple condemnation proceedings. The other changes that would make this expansion feasible are a significant reduction in wholesale power market prices and/or an increase in PSE rates above those forecast in this Study.

Appendix A 10-Year Proforma (Assuming a 2024 Launch)

TABLE A-1: 10-YEAR PROFORMA WITH 27% PREMIUM OVER BOOK, $MILLIONS

Plant Value: $492 million	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Revenues										
Retail Rate Revenues	$250.8	$258.6	$271.9	$286.0	$300.7	$316.3	$332.6	$349.7	$367.8	$386.8
Uncollectible	-$0.7	-$0.7	-$0.7	-$0.8	-$0.8	-$0.9	-$0.9	-$0.9	-$1.0	-$1.0
Total Rate Revenue	$226.9	$256.5	$268.8	$282.7	$297.3	$312.6	$328.8	$345.7	$363.6	$382.4
Expenses										
Power Supply										
BPA Tier 1	$15.6	$18.1	$26.5	$34.5	$46.5	$51.3	$64.6	$65.9	$67.2	$68.5
Renewable Energy	$14.7	$15.2	$15.6	$16.1	$16.6	$17.1	$18.9	$19.5	$20.2	$21.0
Non-Renewable Energy	$71.2	$67.2	$49.9	$45.3	$26.8	$21.5	$1.8	$3.2	$4.6	$6.1
Transmission & Ancillary	$19.6	$20.4	$21.3	$22.1	$23.1	$24.0	$25.0	$26.0	$27.1	$28.2
Capacity/Resource Adequacy	$25.0	$26.1	$27.2	$28.3	$29.5	$30.7	$32.0	$33.3	$34.7	$36.1
Total Power Supply	**$146**	**$147**	**$140**	**$146**	**$142**	**$145**	**$142**	**$148**	**$154**	**$160**
Operating and Administrative										
Transmission O&M	$7.6	$1.9	$1.9	$2.0	$2.0	$2.1	$2.2	$2.2	$2.3	$2.4
Distribution O&M	$35.3	$39.6	$40.8	$42.0	$43.3	$44.6	$45.9	$47.3	$48.7	$50.2
Customer Service	$7.7	$8.6	$8.9	$9.2	$9.4	$9.7	$10.0	$10.3	$10.6	$10.9
Administrative and General	$18.6	$20.9	$21.5	$22.2	$22.8	$23.5	$24.2	$25.0	$25.7	$26.5
Taxes, PILOT	$6.9	$8.0	$8.4	$8.8	$9.3	$9.7	$10.2	$10.7	$11.3	$11.9
Total O&M and A&G	**$76.1**	**$79.0**	**$81.5**	**$84.1**	**$86.9**	**$89.7**	**$92.6**	**$95.5**	**$98.6**	**$101.8**
Debt Service Payment on Financing	$25.9	$28.2	$42.1	$41.3	$41.1	$41.1	$41.1	$41.1	$41.1	$41.1
Capital Projects	$18.4	$19.0	$19.6	$20.1	$20.8	$21.4	$22.0	$22.7	$23.4	$24.1
Total Expenses	$266.5	$273.1	$283.7	$291.9	$291.2	$296.8	$297.9	$307.2	$316.9	$327.0
Net Income	-$39.6	-$16.6	-$14.8	-$9.2	$6.1	$15.9	$30.9	$38.5	$46.7	$55.4
Cash From Operations and Financing										
Net Income From Operations	-$39.6	-$16.6	-$14.8	-$9.2	$6.1	$15.9	$30.9	$38.5	$46.7	$55.4
Cash from Financing	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Change in Cash Available	($40)	($17)	($15)	($9)	$6	$16	$31	$39	$47	$55
Net Income Allocation										
Reserve Fund Contribution	-$41.6	-$16.6	-$14.8	-$9.2	$6.1	$15.9	$30.9	$38.5	$46.7	$8.7
Start-up Funding Payments + Collateral	$2.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Discretionary Programs/Additional Rate Discounts	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$46.7
Total Cash Outlays	($40)	($17)	($15)	($9)	$6	$16	$31	$39	$47	$55
Rate Stabilization Reserve Balance	-$41.6	-$58.2	-$73.0	-$82.2	-$76.1	-$60.2	-$29.3	$9.2	$55.9	$64.6
Reserve Balance Target	$54.8	$55.7	$54.7	$56.8	$56.6	$57.8	$57.9	$60.0	$62.3	$64.6

Appendix B List of Substations

Substation Name	Owner
Bellingham N State Rd/York St	Puget
Bellingham	Puget
Bellingham (Dewey Rd)	BPA/Puget
Bellis	Puget
Berthusen	Puget
Birch Bay	Puget
Blaine	Puget
Britton	Puget
Diablo	Puget
Cherry Point North	Puget
Cherry Point South	Puget
Cherry Point West	Puget
Custer	Puget
Encogen	Puget
Ferndale	Puget
Glacier	Puget
Hannegan	Puget
Happy Valley	Puget
Intalco	BPA
Kendall	Puget
La Bounty	Puget
Lake Louise	Puget
Laurel	Puget
Lehigh	Puget
Lynden	Puget
Mckenzie	Puget
Nooksack	Puget
Nugents corner	Puget
Old Town	Puget
Plymouth	Puget
Portal Way	BC Hydro, BPA, Puget
PUD (without the water ponds)	Puget
PUD (with water)	Puget
Roeder	Puget
Schuett	Puget
Sehome	Puget
Semiahmoo	Puget
Slater	Puget
Sumas	Puget
Sumas Generation Facilities	Puget
Van Wyck	Puget
Viking	Puget
Victor	Puget

Substation Name	Owner
Vista	Puget
Whatcom St	Puget
Whitehorn	Puget
Unknown 200858	Puget
Unknown 206044	Puget
Unknown 201414	Puget
Bakerview	Puget
Baker Lake	Puget