Agenda
Utility Advisory Committee Meeting
Tuesday, November 12, 2024
Richland City Hall ~ Council Chambers
625 Swift Boulevard

Committee Members: Chair Larkin, Vice-Chair Porter, and Members Hofstetter, Hyson, Richmond, and Staven

Council Liaison: Councilmember Whitten

Staff Liaison: Energy Services Director Whitney

Regular Meeting - 3:00 p.m.

Call to Order/Attendance:

Approval of Agenda: (Approved by Motion)

Approval of Minutes: (Approved by Motion)

1. Approval of the September 10, 2024 Utility Advisory Committee Meeting Minutes

Public Comments:

Items of Business:

2. Status of Each City Utility (10 minutes each)
   - Carlo D'Alessandro, Public Works Director
     Tom Huntington, Fire Chief
     Clint Whitney, Energy Services Director

3. Approach to Financing Landfill Expansion Project (10 minutes)
   - Carlo D'Alessandro, Public Works Director

4. Bonneville Power Administration White Book - 2024 Pacific Northwest Loads & Resources Study (15 minutes)
   - Clint Whitney, Energy Services Director

5. Ruby Flats Solar - Letter of Intent Opportunity (15 minutes)
   - Clint Whitney, Energy Services Director

6. Next Steps for Utilizing AMI Data (10 minutes)
   - Clint Whitney, Energy Services Director

7. Energy Northwest Agreement with Amazon for Partial Small Modular Reactor Funding (10 minutes)
   - Clint Whitney, Energy Services Director

Unfinished Business:

Other Informational Items:

8. Bonneville Power Administration Provider of Choice - Post 2028 Contract Schedule and Comparison
   - Clint Whitney, Energy Services Director
9. Bonneville Power Administration Quarterly Report - September 2024
   - Clint Whitney, Energy Services Director
10. 3Q24 Electric Utility Financial Statements
    - Clint Whitney, Energy Services Director
11. 2025 Capital Work Plan
    - Clint Whitney, Energy Services Director
12. Capital Work Plan Update - November 2024
    - Clint Whitney, Energy Services Director
13. Forward Agenda

Adjournment

Richland City Hall is ADA accessible. Any individual who has difficulty attending the meeting in-person may request to provide comments remotely. (Ch. 42.30 RCW) Requests for sign interpreters, audio equipment, and/or other special services must be received 48 hours prior to the meeting by calling the City Clerk's Office at 509-942-7389.

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 11/12/2024 Agenda Category: Approval of Minutes

Prepared By: Arturo Mata, Administrative Assistant II

Subject:
Approval of the September 10, 2024 Utility Advisory Committee Meeting Minutes

Department:
Energy Services

Recommended Motion:
Approve the minutes of the UAC meeting held on September 10, 2024.

Summary:

Fiscal Impact:
None.

Attachments:
1. 2024.09.10 UAC Minutes

MINUTES
UTILITY ADVISORY COMMITTEE REGULAR MEETING
Tuesday, September 10, 2024
Richland City Hall ~ Council Chamber
625 Swift Boulevard

Utility Advisory Committee Regular Meeting – 3:00 p.m.
Vice-Chair Porter called the meeting to order at 3:06 p.m.

Attendance: Vice-Chair Daniel Porter, Committee Members Monica Hofstetter, Bill Richmond, and Harry Staven were present. Also present were Staff Liaison and Energy Services Director Whitney, Chief Tom Huntington, Public Works Director Carlo D'Alessandro, Finance Director Brandon Allen, Council Liaison and Councilmember Ryan Whitten, and Administrative Assistant II Arturo Mata.

Absent members: Chair David Larkin, Charles Lo Presti, Ricky Hyson

Approval of Agenda

MEMBER STAVEN MOVED AND MEMBER RICHMOND SECONDED THE MOTION TO APPROVE THE AGENDA AS PUBLISHED. THE MOTION CARRIED 4-0.

Minutes

1. Approval of the July 09, 2024 Utility Advisory Committee Regular Meeting Minutes.

MEMBER STAVEN MOVED AND MEMBER RICHMOND SECONDED THE MOTION TO APPROVE THE JULY 09, 2024 MEETING MINUTES. THE MOTION CARRIED 4-0.

Public Comments

None.

Items of Business

2. Status of Each City Utility

Director D'Allesandro provided status updates for departments within Public Works. He provided updates for current projects in Water, Wastewater, and Landfill. Director D'Alessandro also mentioned Public Works is currently working on budgets and CIP projects for 2025. Director D'Alessandro answered member questions.

Chief Huntington provided status updates for Fire and Emergency Services. He mentioned there will be a ribbon cutting event for the Grand Opening of Station 76. Chief Huntington also provided an update for ambulance and fire call volumes. There were no member questions.

Director Whitney provided status updates for Energy Services. He went over CIP, AMI project update, staffing and other financials. Director Whitney answered member questions.

3. Proposed Low Income Program Presentation

Director Allen presented the Proposed Low-Income Program. He also provided the reason for the proposed changes and went into detail of the program structure. The proposed Low-Income Program will be submitted for Council's consideration during the next Council Meeting. Director Allen asked the UAC to support the program. Director Allen answered member questions.

UAC MEMBERS SUPPORT THE CONCEPT OF THE PROPOSED LOW-INCOME PROGRAM. THE MOTION CARRIED 4-0.

4. Budget Discussion

Director Allen went over the budget structure for Energy Services and explained budgeting is done at the fund level. Director Allen answered member questions, and feedback was provided.

5. 2025 Medical Utility Rate Setting Recommendations

Chief Huntington presented the 2025 Medical Utility Rate Setting Recommendations. He explained the reason for the increase in monthly household ambulance utility fee, mileage and transportation fees. Fire and Emergency Services will present the 2025 Medical Utility Rate Setting Recommendations to Council before the end of 2024. Chief Huntington asked the UAC to support the recommendations. Chief Huntington answered member questions.

MEMBER STAVEN MOVED AND MEMBER HOFSTETTER SECONDED THE MOTION TO SUPPORT THE 2025 MEDICAL UTILITY RATE SETTING RECOMMENDATIONS. THE MOTION CARRIED 3-1.

6. Electric Utility Wildfire Mitigation Plan

Director Whitney went over the reason the Electric Utility Wildfire Mitigation Plan was created. He went over current fire mitigation practices and asked the UAC to support the Electric Utility Wildfire Mitigation Plan. Director Whitney answered member questions.

MEMBER STAVEN MOVED AND MEMBER HOFSTETTER SECONDED THE MOTION TO SUPPORT THE ELECTRIC UTILITY WILDFIRE MITIGATION PLAN. THE MOTION CARRIED 4-0.

7. 2023 Fuel Mix Report

Director Whitney provided a description of what the fuel mix is and how it is calculated. The 2023 Fuel Mix is expected to be like the reported 2022 Fuel Mix. The attached 2020-2022 Fuel Mix Report was referenced for additional information. Director Whitney answered member questions.

Unfinished Business

None.

Other Informational Items

- Next Steps for Utilizing AMI Data – November 2024
- Ambulance Mileage – November 2024
- Resource Adequacy – November 2024
- Electric Rates Review with Presentation by FCS – September 2025
- Energy Northwest, SMR updates
- Atlas Agro Updates
- BPA Updates

The following informational handouts were provided to Members:

- Low-Income Proposal
- 2025 Medical [Ambulance] Utility Rate Setting Presentation
- 2024 Richland Energy Services Wildfire Mitigation Plan
- 2020-2022 RES Fuel Mix
- 2Q24 Energy Services Financial Statement
- Final FY 2024 BPA Power Reserve Distribution Credit Estimates by PF Customer

Adjournment

Vice-Chair Porter adjourned the meeting at 4:54 pm.

Prepared by: _____
Arturo Mata, Administrative Assistant II

Reviewed by: _____
Clint Whitney, Energy Services Director

Approved by: _____
David Larkin, Chair

DATE APPROVED:

DATE PUBLISHED:

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 11/12/2024 Agenda Category: Items of Business

Prepared By: Carlo D'Alessandro, Public Works Director
Tom Huntington, Fire Chief
Clint Whitney, Energy Services Director

Subject:
Status of Each City Utility (10 minutes each)

Department:
Energy Services

Recommended Motion:
This item is informational only.

Summary:
A representative from each of the City's utilities will provide a status update.

Fiscal Impact:
There is no fiscal impact.

Attachments:

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 11/12/2024 Agenda Category: Items of Business

Prepared By: Carlo D'Alessandro, Public Works Director

Subject:
Approach to Financing Landfill Expansion Project (10 minutes)

Department:
Public Works

Recommended Motion:
None.

Summary:
The City is preparing to construct the Horn Rapids Landfill Phase 2 Expansion Project to extend the life of the current cell of the landfill in support of continued solid waste disposal services to City residents. The City has contracted with Great West Engineering, Inc. for design engineering services for the Project. Design is being performed and is anticipated to be completed in spring of 2025. The Solid Waste Fund does not have capacity to fund the Project with available fund balances. The City's best interests are served by utilizing low-interest financing to fund the Project.

The City was unsuccessful in obtaining financing through a Washington State Department of Commerce's Public Works Board loan. The Washington State Office of the State Treasurer (OST) offers a local financing program as a cost-effective way for the City to finance construction. The local financing program is structured as a lease contract. The OST pools the lease contracts as security that is sold to investors similar to bonding. The benefit to the City is that we can anticipate more favorable interest rates by pooling debt with access to the national tax-exempt market through this program. Though the contract is called a lease, the City retains ownership of the property throughout the term of the lease. A notice of intent from the City is required in November 2024 to ensure fund availability by February 2025.

A rate study will be performed if the City is successful in obtaining funding through OST's local program. City staff will address the committee requesting a recommendation to accept the funds in a future meeting.

Fiscal Impact:
Applying for a program in and of itself has no fiscal impact until it is approved. Fiscal impacts will be outlined when funding amounts, terms and interest rates have been determined and will be presented to UAC and Council for consideration to authorize acceptance.

Attachments:

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 11/12/2024 Agenda Category: Items of Business

Prepared By: Clint Whitney, Energy Services Director

Subject:
Bonneville Power Administration White Book - 2024 Pacific Northwest Loads & Resources Study (15 minutes)

Department:
Energy Services

Recommended Motion:
This item is informational only.

Summary:
Bonneville Power Administration (BPA) released its White Book on August 2024 which is the annual study of the Pacific Northwest (PNW) Loads and Resources. Additional information on BPA's resource planning is available at: Resource Planning - Bonneville Power Administration (bpa.gov). The White Book includes different types of power planning forecasts and if there is any surplus or deficit to meet BPA loads under different conditions and time periods. It provides BPA meaningful planning forecasts for the operating years (OY) 2025 through 2034.

The summary results for the federal system's firm loads and resources are projected to have annual energy deficits during low water years, ranging from 79aMW to 303aMW. However, with median water conditions, the federal system is projected to have annual energy surpluses. When looking at the PNW and including Independent Power Production (IPP), the region is projected to have an annual energy surplus of 1,426aMW in 2025 and a sharp deficit of 2,738aMW by 2034. With "median water conditions, the PNW region would begin to see energy deficits in the out years." The deficits are largely driven by significant increases in loads.

The White Book does not include benefits from the Columbia River Treaty or reflect significant federal load obligations from Snohomish PUD, Clark PUD and Emerald PUD when the utilities switched from a Slice/Block product to the Load Following product beginning in fiscal year 2026.

The White book also does not include risks to the loss of generation from the Lower Snake River Dams (LSRD) resources. The LSRD provides approximately 1aGW of BPA's 7aGW generation resource portfolio. Several recent political pressures have been created, included:

- WA Senator Murray and WA Governor Inslee summary on breaching the LSRD, August 25, 2022
- National Oceanic and Atmospheric Administration (NOAA) lone report, September 23, 2022
- US Government MOU, December 23, 2023
- US Department of Interior announcement and Report, June 18, 2024
- PNNL Regional Energy Planning Project (PREPP)
- Potential upcoming Environmental Impact Study (EIS) despite the $50M Columbia River System Operations EIS completed September 18, 2020.

BPA will be releasing updated resource adequacy information in 1Q25 as part of its resource planning refinements.

Fiscal Impact:
There is no fiscal impact from this informational business item.

Attachments:
1. BPA White Book - 2024 PNW Loads & Resources Study

2024 Pacific Northwest Loads and Resources Study

August 2024

2024 PACIFIC NORTHWEST LOADS AND RESOURCES STUDY

The White Book

BONNEVILLE POWER ADMINISTRATION
August 2024

Cover Picture:
Source: BPA Photo Archive https://river.bpa.gov

The John Day Dam is one of the four Federal projects located on the Lower Columbia River in the Pacific Northwest; it is part of the Columbia River Basin hydro projects. It is located to the east of The Dalles and right near the mouth of the John Day River. The John Day Dam was constructed between 1958 and 1971, it was built and operated by the U.S. Army Corps of Engineers.

The John Day Dam is a run-of-river type of Dam, and it has a navigation lock, as well as fish ladders on both sides of the project.

For more information on The John Day Dam, please visit John Day Lock & Dam at https://www.nwp.usace.army.mil/John-Day/

ACKNOWLEDGMENTS

Preparation of the annual Pacific Northwest loads and resources study is a complex, multidisciplinary effort. BPA wishes to acknowledge the team—BPA staff and others—whose diligence and dedication result in a reliable, high quality document.

Bonneville Power Administration

Generation Asset Management:

Long Term Power Planning Group
Regional Coordination Group
Operational Planning Group

Customer Support Services:

Load Forecasting and Analysis Group

Bulk Marketing and Transmission Services:

Long Term Sales and Purchasing Group

NW Requirements Marketing:

Office of General Counsel

Pacific Northwest Utilities Conference Committee

Northwest Power & Conservation Council

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Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

August 15, 2024

In reply refer to: PGPR-5

Dear Interested Parties:

The Pacific Northwest Loads and Resources Study, commonly called "The White Book", is the Bonneville Power Administration's (BPA) annual publication of the Federal system and the Pacific Northwest (PNW) region's loads and resources for the upcoming ten-year period.

The White Book is used by BPA as a planning tool, as an information source for customers, as a published source of loads and resources information for regional interests, and as a data source for the Columbia River Treaty studies. The White Book is not used to guide day-to-day operations of the Federal Columbia River Power System (FCRPS) or to determine BPA revenues or rates.

In recent news, the U.S. and Canada have reached a historic milestone in the years-long effort to modernize the Columbia River Treaty. The two countries reached an agreement in principle outlining a framework for managing our shared resource, the Columbia River, in a way that will deliver tremendous value on both sides of the border. However, since this news is so late breaking, the 2024 White Book does not reflect the agreement in principle. BPA plans to incorporate these changes in future studies including the next white book. For more information, see statement from the White House or fact sheet from the State Department.

The White Book has traditionally included different types of power planning forecasts showcasing BPA's and the region's ability to meet loads under different conditions and time periods. Some examples of the generation metrics include:

- Average energy per month,
- Average energy per year,
- 1 hour peak capacity per month,
- 50 hours per week sustained capacity, and
- 120 hours per month (January) sustained capacity

BPA's goal is to provide meaningful planning forecasts to the region by keeping up with emerging power markets, regional resource adequacy programs, FCRPS capabilities, climate change signals, and a host of other factors. To that end, BPA has decided not to include data related to its 120hr January sustained capacity metric in the 2024 White Book. BPA plans to review its capacity metrics and potentially make changes that would lead to more meaningful forecasts for regional stakeholders.

This 2024 White Book presents Federal system and the region's load obligations, contracts, and resources as of December 2023 for operating years (OY) 2025 through 2034. The 2024 White Book includes the following studies:

- **Federal System Analysis—**forecast of Federal system firm loads and resources based on expected load obligations and different levels of generating resources that vary by different energy planning. The results are summarized below:
  - Annual Energy Surplus/Deficits: Under firm; the Federal system is projected to have annual energy deficits across the study period, ranging from deficits of 79 aMW to 303 aMW. Overall, these annual energy deficit projections are less than those projected in the 2023 White Book. Under median water conditions, the Federal system is projected to have annual energy surpluses through the study period.
- **PNW Regional Analysis—**forecast of regional firm loads and resources, based on expected retail loads and different levels of generating resources that vary by water conditions. The decommissioning of existing resources, the availability of uncommitted PNW Independent Power Producer (IPP) generation, and new resource additions are key variables in the results of this analysis. The results are summarized below:
  - Annual Energy Surplus/Deficits: Under firm water conditions, the PNW region is projected to have an annual energy surplus as large as 1,426 aMW in OY 2025, rather sharply decreasing to a deficit of 2,738 aMW by OY 2034. This result was mainly driven by the increasing PNW Retail Loads. These annual energy projections are more deficit throughout the study period than was forecasted in the 2023 White Book. Under median water conditions, the PNW region would begin to see energy deficits in the out years.

BPA is currently working on its 2024 Resource Program designed to evaluate long-term power resources acquisition strategies. Many factors contribute to the uncertainty of the longer-term resources outlook for the region, such as resource retirements and development, resource adequacy and the efforts surrounding it, carbon free resource requirements, and the most recent Climate Resiliency efforts. As with resources, there is also much uncertainty with loads including the potential for electrification. The 2024 White Book is available on BPA's website: *https://www.bpa.gov/energy-and-services/power/resource-planning* or from BPA's Visitor Center, which you can reach toll-free at 800-622-4520 (or 503-230-4636). Details regarding regional loads, contracts, and generating resources are available upon request. The available report list can be found in the Appendix.

Please send questions and/or comments to whitebook@bpa.gov.

Sincerely,

MICHELLE CATHCART

Digitally signed by MICHELLE CATHCART
Date: 2024.08.26 19:13:13 -07'00'

Michelle Cathcart
Vice President| General Asset Management
Bonneville Power Administration
Enclosure

Table of Contents

SECTION 1: SUMMARY

Planning Context

The Pacific Northwest Loads and Resources Study, commonly referred to as the White Book, is a planning document produced by the Bonneville Power Administration (Bonneville) that presents its projection of load and resource conditions for the upcoming 10-year period. The White Book includes analysis of Bonneville's forecasts of expected power obligations and resource generation for both the Federal system and the Pacific Northwest[1] (PNW) region. Information contained in the White Book is used for: 1) long-term planning studies for Bonneville; 2) planning studies for the Columbia River Treaty (Treaty); and 3) as a published record of information and data for customers and other regional planning entities. The White Book is not used to guide day-to-day operations of the Federal Columbia River Power System (FCRPS).

Bonneville's White Book traditionally focuses on long-term deterministic power planning for the Federal system and the PNW region. The load and resource balance is calculated by comparing expected loads and contract obligations to forecast resource generation and contract purchases under the Federal system. In the same manner, Bonneville's PNW regional analysis calculates the PNW regional load and resource balance by comparing expected regional retail loads and contract obligations to forecasted regional resource generation and contract purchases. Hydropower resources for the Federal system and PNW regional include variability by incorporating a variety of generation forecasts, associated with streamflow from the most recent 30-historical water conditions[2] of the 2020 Modified Flows. These deterministic analyses are modeled by operating year (OY[3]), defined as August to July, to be consistent with regional coordination of the Treaty and Pacific Northwest Coordination Association (PNCA). Analytical results are presented in annual and monthly energy, expressed in average megawatts (aMW). The Federal System Analysis is presented in Section 2, and the Pacific Northwest Regional Analysis in Section 3.

Bonneville, like the rest of the electric power industry, continues to explore ways to comprehensively assess the ability of the power system to meet long-term load obligations. Periodically, Bonneville incorporates additional studies and data into its planning that look at different analytical methods and evaluate different scenarios. This year's White Book does not incorporate any other special studies.

The total retail load, contracts, and generation forecasts used in this study were updated as of December 31, 2023. The 2024 White Book supersedes the 2023 White Book and is published as a single summary document.

[1] As defined in the Northwest Power Act

[2] Bonneville Power Administration Climate Change & FCRPS

[3] Operating Year (OY) is the time frame August 1 through July 31. For example, OY 2024 is August 1, 2023 through July 31, 2024.

A list of technical reports can be located at the end of this summary document in the Appendix, individual reports are available upon request only. Request for these reports can be made by emailing WhiteBook@bpa.gov.

Load Obligations

The load obligations for the Federal system and PNW region contain multiple components in this study, forecasts are categorized as: 1) Total Retail Loads (TRL), defined as each individual utility's total retail electric power consumption on its system, including electrical system losses; and 2) contract obligations, which include reported PNW utility long-term contract sales within the PNW region as Intra-Regional Transfers (Out) and outside the PNW region as Exports. Contract obligations also include Federal system power sales delivered to Federal agencies, public bodies, cooperatives, and tribal utility as preference customers, as described under section 5 of the Northwest Electric Power Planning and Conservation Act (NW Power Act), 16 U.S.C. 839 et seq., (December 5, 1980).

Forecasts of the regional TRL and Federal system load obligations are produced by Bonneville's Agency Load Forecasting (ALF) system. ALF forecasts are completed for individual PNW entities under one of two approaches, the largest share of load forecasts is now based on statistically adjusted end-use models while other forecasts are based on time-series-based regressions that follow the fundamental assumptions of historical retail electricity consumption patterns continuing. The statistically adjusted end-use models include calculated indexes for heating and cooling equipment, and other components. ALF forecasts also assume normal weather conditions and do not include any explicit adjustments for the impacts of climate change or the Inflation Reduction Act[4] (IRA); however, the forecasts do use normalized temperatures based on recent history in order to incorporate recent climate trends. Contract obligations not associated with Bonneville's Preference Power Sales Contracts follow individual contract terms through the life of the contract and are not assumed to be renewed. All Federal system load and contract obligations are assumed to be firm and served by Bonneville regardless of weather, water, or economic conditions.

Resource Types

Regional resources consist of physical generating facilities (currently on-line and under construction) and contract purchases that are used to serve retail loads. PNW resources, with Federal systems included, are predominantly hydro based; therefore, generation levels can vary greatly both from month-to-month and from year-to-year. This analysis classifies resources as: 1) Hydro resources, which include regulated, independent, and small hydro projects; 2) Non-hydro renewable resources, which include wind, solar, and other renewable projects; 3) Thermal resources, which include nuclear, coal, natural gas, petroleum, biofuel and cogeneration projects; 4) Contract purchases, which include reported PNW utility long-term contract purchases from within the PNW regional as Intra-Regional Transfer (In) and from outside the PNW regional as Imports. Generation forecasts for these resources are provided by Bonneville models or from the project owners, and those are described in detail in the following sections.

[4] Inflation Reduction Act | U.S. Department of the Treasury

Hydro Resources

- Regulated Hydro – Regulated hydro projects mainly consist of PNW Columbia River Basin hydro power projects for which the operation and generating capability is hydraulically linked. Bonneville forecasts the coordinated energy and capacity production from these hydro power projects using its Hydro-system Simulator (HYDSIM) model. The HYDSIM model considers individual project operating characteristics and conditions to determine energy production expected on a project-to-project basis. Generation forecasts for these projects incorporate the month-to-month power and non-power requirements under each of the 30-historical streamflow conditions of record, 1989 through 2018. The HYDSIM model is described further in the Hydro Resource Modeling section.
- Independent Hydro - Independent hydro projects include those hydro projects whose generation output typically varies by water condition and are not operated or hydraulically linked to part of the Columbia River Basin. Independent hydro generation forecasts can vary month-to-month for energy and capacity and are developed and provided by individual project owners/ operators for the same 30-historical water conditions as the Regulated Hydro projects (1989 through 2018).
- Small Hydro – Small hydro project generation forecasts are either provided by individual project owners or are based on historical actual generation. These generation forecasts vary month-to-month, however they are not assumed to vary by water conditions.

Non-Hydro Resources

- Wind – Firm wind generation incorporates the statistical modeling of wind generation based on historical weather data and actual generation from currently operating PNW wind projects. The single operating year with the lowest total PNW wind generation is selected as firm wind year. The firm wind year generation performance determines each project's energy forecast. The Federal system and PNW regional capacity analysis assume zero capacity contribution from wind resources.
- Solar – Solar projects are utility scale solar facilities that are metered, and the generation is being sent to the grid, and does not include any behind the meter resources, generation forecasts are either provided by individual project owners or are based on historical actual generation. The Federal system and PNW regional capacity analyses assume zero capacity contribution from solar resources.
- Other Renewable – Other renewable resources include all other projects identified as renewable, including geothermal and biomass/biogas waste projects. Generation forecasts for these resources are based on energy and capacity forecasts submitted by individual project owners.

Thermal Resources

- Thermal resources include nuclear, coal, natural gas, petroleum, biofuel (not identified as renewable), and cogeneration projects. Generation forecasts for these projects are based on energy and capacity capabilities submitted by project owners. These forecasts typically vary month-to-month, and total plant generation is reduced to account for scheduled maintenance.

Forecasts are adjusted to show actual operational capabilities and expectations, and not to reflect economic dispatch.

Contract Purchases/ Imports

- Contract purchases include signed Federal system purchases and regional contract purchases with power delivered to PNW entities reported by utilities publicly and in data submittals. These purchases are treated as resources in both the Federal system and PNW regional analyses. Purchases between entities within the PNW are called Intra-regional Transfer (In) and purchases from entities outside the PNW are categorized as Imports. Except for contracts associated with the Treaty, all existing Federal system and regional contract purchases follow individual contract terms throughout the life of the contract and are not assumed to be renewed. Current Treaty power deliveries are assumed to be in place through the study period.

Adjustment to Resources

The White Book assumes that resource generation and contract purchases are reliably delivered to load centers. To take this assumption into account, this study adjusts generation forecasts for 1) Operating and Balancing Reserves, held to meet reliability standards; and 2) Transmission losses, associated with power deliveries. These adjustments are considered as reductions to both energy and capacity and are described below:

- Operating and Balancing Reserves: Operating reserves consist of both spinning and non-spinning contingency reserves that respond to the unforeseen loss of a resource, which are calculated by summing three percent of forecast load and three percent of forecast generation. Balancing reserves consist of regulating, load following, and imbalance reserves that are dedicated to maintaining within-hour load and resource balance. Details in modeling of reserves are described in the Hydro Resource Modeling section. Reserve forecasts included in this White book are modeled consistent with those used in Bonneville's BP-24 Rate Case process.
- Transmission Losses: During the transmission of power to load centers some of the electrical energy is lost, typically in the form of heat, which is categorized as transmission losses. Transmission loss factors are calculated monthly and vary by seasonal generation, e.g. summer months versus winter months. Transmission Loss factors are applied to the sum of all generation and contract purchase forecasts. The monthly transmission loss factor has several components that combine to give the estimate of losses associated with Federal system generation: 1) step-up transformers from generation to the high-voltage transmission network; 2) high-voltage network transmission; 3) transfers to Federal loads over non-Federal transmission systems; and 4) step-down transformers from high-voltage transmission to low-voltage delivery. The Federal system transmission loss factors used in this White Book are consistent with those used in Bonneville's BP-24 Rate Case process:
    - Energy: 3.11 percent from September through May, and 3.16 percent from June through August.

- Capacity: 3.16 percent from September through May, and 3.21 percent from June through August.

Hydro Resource Modeling

The HYDSIM hydro regulation model forecasts the energy production from the regulated hydroelectric power projects in the PNW. This includes the 14 federal hydroelectric projects that make up the Columbia River Federal system, and other major hydro projects in the PNW. Project level generation forecasts are produced in a continuous study for each month of the 30 year-historical streamflow record[5]: October 1989 through September 2018. Energy production is maximized by coordinating hydro operations while meeting power and non-power requirements. HYDSIM produces results for 14 periods: ten complete months plus two periods each for April and August. April and August are divided, first half -second half, due to natural streamflow and significant operational changes happening during these two months. Consequently, generations can differ significantly between the beginning and end of these months. For simplicity, the 14-period results are referred to as "monthly" values in this report.

The HYDSIM studies encompass both power and non-power operating requirements. Each hydro study specifies particular non-power hydroelectric project operations for fish, such as seasonal flow objectives, minimum flow levels for fish, spill for juvenile fish passage, reservoir target elevations and drawdown limitations, and turbine operation requirements. The operations modeled include the following as outlined in the U.S. Army Corps of Engineers Pacific Northwest Coordination Agreement (PNCA) data submittals:

- National Marine Fisheries Services 2008 Willamette Biological Opinion (BiOp) (July 11, 2008)
- 2020 Columbia River System Operations Environmental Impact Statement (CRSO EIS), (Sept. 28, 2020)
- 2020 NOAA Fisheries Federal Columbia River Power System Biological Opinion (2020 NMFS BiOp) (July 24, 2020)
- 2020 U.S. Fish and Wildlife Service Biological Opinion (November 12, 2019)

The PNCA coordinates the planning and operation of the members' hydroelectric power projects in the PNW. PNCA project owners provide physical plant data as well as power and non-power constraints in an annual data submittal to the Western Power Pool (WPP). Bonneville incorporates this data into HYDSIM to simulate the coordinated operation of the PNW hydro system. This coordination agreement expires on September 15, 2024. As with previous White Books, PNCA assumptions were included past the PNCA expiration date through the 10-year study horizon. The 2025 White Book will include studies that reflect the expiration of the PNCA.

The construction of the three storage projects in Canada - Mica, Arrow, and Duncan - under the Treaty between the United States and Canada enhanced the volume of storage in the Columbia River Basin. These projects provide downstream power benefits by increasing the firm power generating capability of U.S. hydro projects. The Treaty calls for an Assured Operating Plan (AOP) to be completed six years prior to each operating year and allows a Detailed Operating Plan (DOP) to be

[5] 2020 Modified Flows

completed, if agreed upon, in the year prior to the operating year. The Canadian project operations simulated in HYDSIM are based on the best available information from the Treaty planning and coordination process. Canadian operations included in this White Book are based on the official 2022 AOP studies, with additional modifications that reflect updates used in the official 2024 DOP studies.

Both the United States and Canada can terminate most of the provisions of the Treaty any time after September 16, 2014, with a minimum of 10 years advance notice. Neither Canada nor the United States have provided notice of termination; therefore, this study assumes the Treaty continues throughout the study period. Flood Risk Management (FRM) provisions in the Treaty are specified to change in OY25; as of the study vintage the way the FRM will change remained uncertain. This study extends FRM provisions in place for OY24 through the study period.

Bonneville has other operational agreements with Canada that are not part of the Treaty. One operational agreement is the Non-Treaty Storage Agreement (NTSA) that allows additional shaping of Columbia River flows for fish and power operations by utilizing storage not specified by the Treaty from Canadian reservoirs. The NTSA allows water to be released from Canadian project storage during the spring of dry years, it also allows water to be stored in the spring during years when flow targets from the 2008 NOAA BiOp would be met with a subsequent release of water in the summer. These operations are included in this study based on the NTSA signed with British Columbia Hydro in April 2012, which expires on September 15, 2024. This study assumes the NTSA continues through the study period.

Balancing reserves, both incremental and decremental, reduce the ability to shape the Federal system generation. Incremental reserves are modeled by reducing the generation capability of projects. In this study, the impacts of incremental reserves are shown as a reduction in the capacity analyses and are categorized as operating and balancing reserves. Decremental reserves are not specifically reported in this study as they do not cause a limitation in generation capability.

Firm planning

Bonneville bases its resource planning on firm expected generation to ensure sufficient generation to meet obligation loads. Firm conditions are defined as when the PNW hydro system would be the most limited, due to a combination of operational constraints and low water conditions. For the Federal System this is established by considering the historical streamflow record, power and non-power operation constraints, the planned operation of non-hydro resources, combined with the system load requirements. For operational purposes, Bonneville considers firm condition to be the tenth percentile (P10) of the monthly Tier One System Firm Critical Output (T1SFCO) system results. The percentile approach eliminates the anomalies observed in any single water year, e.g. 1937; it also aligns with metrics used in Bonneville's Resource Program. For additional details, please refer to Bonneville's news release BPA adopts new streamflow forecast to reflect changing climate (Augus 1st, 2022) and Climate Change Resiliency Letter to the region (June 6, 2022).

Variability of Hydro Generation

The generating capacity of the Federal system and PNW regional hydro projects depends on several factors: 1) the amount of water flowing through the facilities, 2) the physical capacity of the facilities, 3) any flow or operating requirements, including those pursuant to biological opinions, court orders or

applicable agreements, and 4) other operational limitations. Water conditions cause hydro generation to vary greatly year to year depending on weather factors such as precipitation, snowpack, and temperature. Project-level generation forecasts for regulated hydro resources are produced using HYDSIM for each of the 30 historical streamflow conditions of record, which are based on the period from 1989 through 2018. Additionally, Federal independent hydro project generation was updated by the Army Corps of Engineers, the Bureau of Reclamation, and other project owners incorporating the 2020 modified flows and up to date project operations.

This White Book study uses three generation scenarios to demonstrate the magnitude of hydro generation variability:

- Firm water: tenth percentile (P10) of system generation by month, it represents the firm water condition for energy and capacity of the hydro system.
- Median water: 50th percentile (P50) of system generation by month, it represents the exact middle value of generation distribution for energy and capacity of the hydro system.
- High water: 90th percentile (P90) of system generation by month, this represents the high generation scenario of the energy and capacity of the hydro system.

Hydro Capacity Modeling

Bonneville uses the RiverWare model to forecast usable hydro capacity for long-term planning purposes. RiverWare incorporates the monthly historical 30 water year reservoir storage and flows from HYDSIM to simulate the relationship of hydro energy to hydro peaking capability for Federal system regulated hydro resources. For each month, RiverWare forecasts hourly Federal system hydro generation by maximizing generation while meeting non-power requirements. The forecasts consider scheduled hydro maintenance and reserves.

For hydro resources, the 120-hour capacity forecasts are created by evaluating hourly generation from RiverWare over a specific period of time. This capacity metric is defined as the average generation forecasts from the six highest heavy load hours (HLH) per day, five days per week, and for four weeks per month (6x5x4 = 120 hours). While available, the White Book does not include 1-hour capacity forecasts because this metric does not represent a sustainable generation but rather a single hour peak, meaning it does not consider the ability of the hydro system to sustain generation level over a multiple hour period

The 120-hour capacity forecasts are not included in this (2024) White Book as Bonneville is currently working on improving its capacity metrics to better inform the region of the system's capacity while incorporating climate change, hydro modeling updates, and many ongoing improvements.

Notable Updates

The 2024 White Book includes updated forecasts of Federal system power sales contracts (PSC) obligations, PNW regional Total Retail Loads (TRL), contract purchases, and generation as of December 1, 2023, including:

- Hydro generation modeling excluded Lack-of-Market Spill study which puts upward pressure on generation values especially during runoff periods i.e. April through June.

- Updated RiverWare calibration on project behavior to correct 1) unrealistic results on peaking capacity and 2) violations to meeting Chum salmon requirements in the lower Columbia River and lower Snake River projects.
- Retirement dates associated with planned thermal generation projects.

Hydro capabilities in this study also reflect the updated Resilient Columbia Basin Agreement (RCBA, also known as the 12/14 agreement), published on 12/15/2023. Key items include:

- Spilling most projects in the spring to 125% Total Dissolved Gas (TDG) gas cap in the spring 24/7.
- John Day spills 40% of outflow for 16 hours during the day, and 125% TDG for 8 hours at night.
- Little Goose spill includes 8 hours of spill totaling 30% of outflow allowing for adult passage and 125% TDG for the remaining 16 hours, except 30% of outflow spill early in season does not begin until the sooner Apr 24th or adult criteria are met.
- Late summer spill transitions on August 1st instead of August 15th.
- Steelhead spill Sept-Nov 15th is everyday instead of every other day (4 hours per day via 1 Spillway Weir).
- Steelhead and early run juvenile spill is 24/7 beginning March 21st until the start of juvenile spill.

Sources of Uncertainty

Forecasts presented in this document represent the best information currently available under the defined metrics for loads and resources. However, all forecasts are affected by uncertainty in economic conditions, weather, environmental and governmental policies, and a variety of other factors that could significantly affect the magnitude, duration, and timing of projected surpluses and/or deficits. Uncertainties include:

- Changes to hydro system operations in response to Endangered Species Act requirements or other environmental considerations,
- Changes to hydro system operations in response to court actions and/or operational agreements,
- Natural variations in weather affecting electrical power demand and streamflow runoff that result in hydroelectric power generation changes,
- Potential new large individual retail load and/or other changes to major industrial operations,
- Potential service to new load such as new customers or the Department of Energy's Richland vitrification plant operations,
- Potential future policy requirements at local, state, and federal levels regarding the amount and type of renewable resources, conservation standards, electric vehicle saturation, and/or carbon emissions,
- Fuel cost and availability, which may be affected by environmental factors or competing uses for industry, transportation, and import/export markets,
- Changes to operating limits on existing and future thermal resources,
- Changes to retirement dates associated with resources,
- Failures of resources to operate at anticipated times and/or output levels,

- Changes to Treaty obligations and/or operations at the time the study was run,
- PNW entities' ability to purchase power from new and existing uncommitted regional resources to serve retail load,
- PNW entities' ability to purchase and transmit power from extra-regional import/export markets,
- Future climate change impacts to retail loads, streamflow, and resources,

The potential impacts of these and other sources of uncertainty are not quantified in this study.

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SECTION 2: FEDERAL SYSTEM ANALYSIS

The Federal System Analysis provides a deterministic forecast of the federal system loads and resources over a 10-year period from OY2025 through 2034. This analysis incorporates forecasts of the Federal system's firm requirement PSC obligations, contract sales and purchases, and resource generations. This section presents firm Federal system load and resource forecasts for energy. Additional detailed components of the Federal system study are available only upon request, a list of available reports can be found in the Appendix.

Load Obligations

Bonneville's ALF system is used to forecast Federal system load obligations, as described previously in Section 1: Summary – Load Obligations. Types of Federal system load obligations include: 1) Federal reserve power obligations to the U.S. Bureau of Reclamation (USBR), 2) Bonneville's Regional Dialogue PSC obligations to public, cooperative, and tribal utilities, and Federal agency customers, 3) contract obligations to investor-owned utilities (IOUs), 4) contract obligations to Direct Service Industry (DSI) customers, and finally 5) other Bonneville contract obligations including contract sales to entities within the PNW region (Intra-Regional Transfers (OUT)) and to those outside the PNW region (Exports). These load obligations are all considered firm power deliveries and are assumed to be served by the Federal system regardless of weather conditions, water supply, or economic environments. Bonneville's forecasts are these obligations are categorized in the following sections.

USBR obligations

USBR must meet statutory directives to provide reserve power to irrigation district facilities associated with USBR projects. Individual USBR project authorizations provide for irrigation districts to receive reserve power from specific FCRPS projects. The remaining power from USBR projects are marketed by Bonneville in the PNW.

Regional Dialogue (RD) Contract High Water Mark (CHWM) PSC obligations to Public & Federal agency customers

In December of 2008, Bonneville executed RD PSCs with public, cooperative, and tribal utilities, as well as federal agency customers. Bonneville is obligated to provide firm power deliveries from October 1, 2011, through September 30, 2028. Customers were offered three types of products: Load Following, Slice/Block, and Block. A total of 134 customers signed the RD contracts, and in this current period 121 are Load Following customers, 10 are Slice/Block, and three are Block.

Under the RD PSCs, customers must make periodic elections of how to serve their Above Rate Period High Water Mark (A-RHWM)[6] load by 1) adding new non-Federal resources; 2) acquiring power from

[6] "Through the contracts and rate methodology, each public utility will get a High Water Mark (HWM) that defines its right to buy an amount of power at BPA's lowest cost-based Tier 1 rate. Power above the HWM must be purchased from either non-Federal resources or from BPA at rates reflecting BPA's marginal cost of acquiring the additional power, or through a mix of BPA Tier 2 priced power and non-Federal resources. (P.4 Regional Dialogue July 2007)

non-Federal resources; and/or 3) requesting Bonneville to supply additional power. The current customer elections have been set through fiscal year (FY) 2025, and this study assumes that current elections for FY2025, continue throughout the study period. Based on this assumption, Federal system RD PSC obligation forecasts include elected and forecasted A-RHWM load for the study period. Table 2-1 presents the A-RHWM load included in Bonneville's obligations by FY, which are consistent with the BP-24 Final Rate Proposal following the Rate Settlement for BP24 Rate Case.

Table 2-1 Above Rate-High-Water-Mark Obligations (BP24 Rate Case)

FY	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy aMW	382.1	407.6	433.9	460.3	495.4	515.7	536.2	548.6	575.4	602.9

IOU Load Service under Regional Dialogue (RD) PSCs

There are six IOUs in the PNW region, and they are: Avista Corporation, Idaho Power Company, Northwestern Energy Division of Northwestern Corporation, PacifiCorp, Portland General Electric Company, and Puget Sound Energy, Inc. Although these IOUs all signed Bonneville RD PSCs for FY 2011 through FY 2028, no IOUs have elected to take power service under these contracts thus no net requirement power sales are assumed for the IOUs through this study period.

Direct Service Industrial (DSI) Contracts

Bonneville currently has one DSI customer, Port Townsend Paper Corporation. DSI deliveries are forecasted at 11 aMW and expected to remain at that level throughout the study period.

Other Contract Obligations

Bonneville provides federal power under a variety of additional contract arrangements. These contracts obligations are categorized as: 1) power sales; 2) power or energy exchanges; 3) capacity sales or capacity-for-energy exchanges; 4) power payment for services; and 5) power commitments under the Treaty. These arrangements, collectively referred to as "Other Contract Obligations", are determined by individual contract provisions and have various delivery arrangements and rate structures. These contracts include power deliveries to entities within the PNW region as Intra-Regional Transfers (Out), and to those outside of the PNW region as Exports.

Treaty, RD PSCs, and DSI power deliveries are assumed to remain in place throughout the study horizon. Bonneville's Other Contract Obligations follow individual contract terms and are not assumed to be renewed after the expiration date.

Conservation

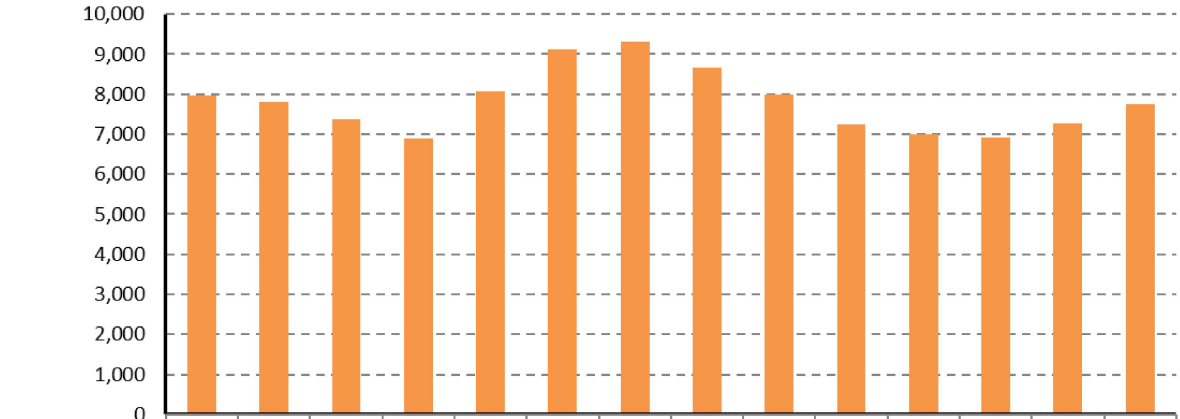
The PSC obligation forecasts developed by the ALF are expected load forecasts, which include conservation identified by individual Bonneville customers. As an embedded assumption in the load forecasts, it is expected that the historically embedded amount of conservation acquired will continue at the same rate going forward across the study period.

Firm Loads

The federal system total firm load forecast shows a 0.24 percent average annual load growth over this study period. While Bonneville's forecast of PSC requirement loads increased roughly 8 percent over the study period, Bonneville's Exports and Intra-Regional Transfers significantly decreased (almost 40%) due to the expiration of contracts. Other Contract Obligations that expire this time include Federal system power sales and Federal system capacity sales.

Overall, the total Federal system load obligations remain relatively flat on an annual basis over the study period which is consistent with previous White Book studies due to the nature of Bonneville's RD PSCs. While on an annual basis these obligations demonstrate little variation across the study period, Bonneville's loads can vary greatly throughout the year. At a high level, Bonneville[7] experiences its highest loads in the late fall and winter months (November through March) primarily due to heating loads, with lower loads during spring, early summer and early fall months when temperatures are mild. July and August loads tend to be slightly higher than the rest of the summer months due to increasing air conditioning demands. Table 2-2 illustrates the monthly shape of the forecasted Federal system firm load obligations for OY2025.

Table 2-2 Federal System Firm Obligations for OY2025 - Monthly



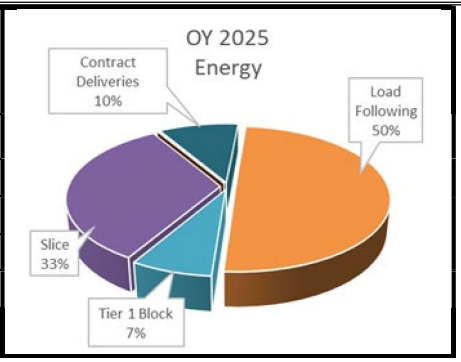
	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	7961	7810	7365	6892	8076	9131	9300	8658	8000	7230	7005	6908	7277	7756

Table 2-3 shows the annual Federal system firm load obligations for OY2025 in Energy aMW.

[7] This is reflective of Bonneville's total aggregate loads, individual customers highest loads vary by month and season.

Table 2-3 Federal System Annual Firm Obligations by Category OY2025

Customer Class	Energy (aMW)	Percent of Firm Energy
Load Following	3,914	50%
Tier One Block	570	7%
Slice	2,595	33%
DSI	11	0%
Contract Deliveries	772	10%
Total Firm Obligations	**7,861**	**100%**



As previously noted, RD contracts expire at the end of FY2028, and negotiations for new 19-year Provider of Choice (PoC) PSCs are ongoing with contracts expected to be executed in December 2025. Given the uncertainty around post-2028 obligation levels, this study assumes a continuation of RD PSC load levels for planning purposes.

Resources

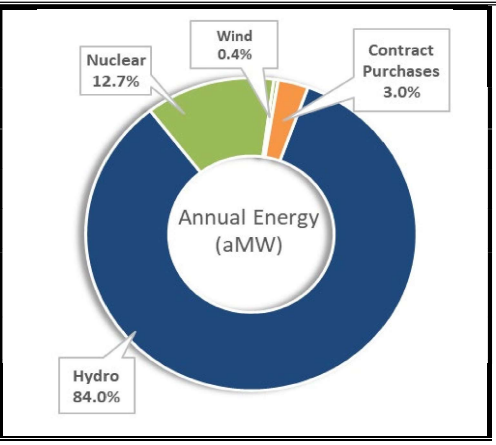
In the PNW, Bonneville is directed to market power from Federal hydroelectric projects and other resources acquired to meet firm power contractual obligations. By Statute, Bonneville does not own generating resources, but instead, Bonneville markets power from Federal resources and non-Federal generating resources whose output Bonneville has acquired under contract. These resources and contract purchases are collectively referred to as "Federal system resources" in this study. Federal system resources are currently comprised of: 1) Hydro resources, which include regulated, independent, and small hydro projects; 2) Non-hydro renewable resources (wind projects); 3) Thermal resources, (Columbia Generating Station); and 4) Contract purchases, which are purchases from entities within the PNW region as Intra-Regional Transfers (In), including the Mid-C Non-Federal Canadian Entitlement Return power and from those outside of the PNW region as Imports.

Federal System Resource Types

Table 2-5 summarizes Bonneville's resources and contract purchases available to meet the Federal system load obligations. For OY2025, Federal system resources are forecast to produce 7,602 annual aMW of generation under Firm water conditions, after reserves and losses are included.

Table 2-5 Federal System Generations by Resource Type for OY2025 - Firm Water Conditions

Resource Type	Annual Energy (aMW)	Percent of Firm Energy
Hydro	6,589	84%
Nuclear	994	12.7%
Wind	33	0.4%
Contract Purchases	233	3%
Total Federal Resources	7,849	100%
Reserves & losses	-247	--
Total Net Resources	7,602	--



Federal system contract purchases

Bonneville purchases or receives power under a variety of contract arrangements from entities within the PNW region as Intra-Regional Transfers (In) and from outside the region as Imports, to meet Federal system load obligations. These contract purchases, presented in Table 2-7 are made up of: 1) power purchases; 2) power or energy exchange purchases; 3) power assigned to Bonneville under Treaty-related agreements; and 4) transmission loss returns under Slice/Block contracts. Bonneville's contract purchases are considered firm resources that are delivered to the Federal system regardless of weather, water, or economic conditions. Transmission loss returns capture the return of Slice/Block transmission losses to the Federal system as specified in the Slice/Block contract, and these returns are treated as Federal system resources. Except for deliveries from Treaty-related contracts and transmission loss return of Slice/Block contracts, each contract purchase follows specific delivery terms and expiration dates and is not assumed to be renewed. Treaty-related and Slice/Block contracts are assumed to remain in place through this study horizon.

The Federal system resources are comprised of:

- Federal system hydro resources: Table 2-6 details the Federal system hydro resources from which Bonneville markets firm and non-firm power. Additionally, it shows the variability of individual Federal system hydro project generation for the three water conditions: firm, median, and high.
- Federal system non-hydro resources: Federal system non-hydro resources are generating resources whose output has been purchased by Bonneville. Table 2-7 details these generating resources, which include: 1) Columbia Generating Station; and 2) wind projects (non-hydro renewable resources). Forecasts for these resources are generally consistent from year to year but may change annually based on scheduling of annual maintenance, refueling, and capital improvements.

Table 2-6 Federal System Hydro Project Generation Forecasts by Streamflow Conditions[8] – OY2025

Project	Initial Service Date	Operator	Number of Units	Maximum Capacity d/ (MW)	High c/ Energy (aMW)	Median c/ Energy (aMW)	Firm Energy a/c/ (aMW)	
Regulated Hydro								
1. Albeni Falls	1955	USACE	3	50	21.5	25.8	25.3	
2. Dworshak	1974	USACE	3	465	304	193	155	
3. Hungry Horse	1952	USBR	4	310	129	94	88	
4. Libby	1975	USACE	5	605	280	236	193	
5. Grand Coulee / GCL Pumping	1941	USBR	27	6,684	3,063	2,306	1,872	
	1973		6	314				
6. Chief Joseph	1955	USACE	27	2,614	1,780	1,372	1,106	
7. Lower Granite	1975	USACE	6	930	295	190	139	Lower Snake River Projects
8. Little Goose	1970	USACE	6	930	312	207	155	
9. Lower Monumental	1969	USACE	6	930	297	203	147	
10. Ice Harbor	1961	USACE	6	693	260	190	144	
11. McNary	1953	USACE	14	1,120	626	545	451	Lower Columbia River Projects
12. John Day	1968	USACE	16	2,480	1,374	994	787	
13. The Dalles	1957	USACE	22	2,080	1,081	817	642	
14. Bonneville b/	1938	USACE	18	1,221	722	527	387	
15. Total Regulated Hydro Projects			**169**	**21,426**	**10,546**	**7,901**	**6,291**	
Independent Hydro Projects								
16. Anderson Ranch	1950	USBR	2	40	16	12	13	
17. Big Cliff	1954	USACE	1	21	14	11	11	
18. Black Canyon	1925	USBR	2	8.5	8	6	7	
19. Boise Diversion	1908	USBR	3	2.5	1	1	1	
20. Chandler	1956	USBR	2	12.2	9	7	6	
21. Cougar	1964	USACE	2	28	9	5	5	
22. Cowlitz Falls	1994	LCPD#1	2	70	33	29	29	
23. Detroit	1953	USACE	2	115	33	26	23	
24. Dexter	1955	USACE	1	17	10	8	8	
25. Foster	1968	USACE	2	23	10	8	8	
26. Green Peter	1967	USACE	2	92	22	16	16	
27. Green Springs	1960	USBR	1	18	7	7	7	
28. Hills Creek	1962	USACE	2	34	24	19	17	
29. Lookout Point	1954	USACE	3	138	17	15	20	
30. Lost Creek	1975	USACE	2	56	42	37	31	
31. Minidoka	1909	USBR	4	28	19	14	11	
32. Palisades	1957	USBR	4	177	100	92	77	
33. Roza	1958	USBR	1	14	9	8	6	
34. Total Independent Hydro Projects			**38**	**894**	**381**	**320**	**296**	
Small Non-Federally Owned Hydro Projects								
35. Dworshak/Clearwater Small Hydro	2000	ID DWR	1	5.4	2.6	2.6	2.6	
36. Rocky Brook	1985	MCPD#1	1	1.6	0.3	0.3	0.3	
37. Total Non-Federally Owned Hydro			**2**	**7**	**2.9**	**2.9**	**2.9**	
38. Total Hydro Generation *(line 15 + line 34 + line 37)*			**209**	**22,327**	**10,930**	**8,223**	**6,589**	

a/ Firm energy is the 12-month annual average for OY 2025 assuming 10th percentile (P10) water conditions

b/ Bonneville Dam generation totals include Bonneville Fishway

c/ High Energy = 90th percentile, Median Energy = 50th percentile, Firm Energy = 10th percentile

d/ Maximum Capacity represent full capacity of resource including overload.

[8] Streamflow conditions do not always have a linear correlation with generation output. Projects with smaller head (head = forebay level minus tailwater level) are susceptible to having the inverse effect between flow and generation, e.g. Albeni Falls. Higher flow passes through the project increasing the tailwater level which results in less head, this results in lower generation than in other lower flow conditions.

Table 2-7 Federal System Non-Hydro Project Generation Forecast and Contract Purchase – OY2025

	Project	Initial Service Date	Resource Type	Operator	Maximum Capacity [a/] (Peak MW)	Firm Energy (aMW)
	Non-Hydro Resources					
1	Columbia Generating Station	1984	Nuclear	ENW	1,178	994
2	Stateline Wind Project [b/]	2001	Wind	PPM, FLP	0	21.2
3	Klondike Phase III [c/]	2007	Wind	NW Wind Power	0	11.8
4	Fourmile Hill Geothermal [d/]	Not in Service	Geo.	Calpine	0	0
5	**Total Federal System Non-Hydro Resources**				**1,178**	**1,027**
	Contract Purchases					
6	Canadian Entitlement for Canada (non-Federal)				237	135
7	Canadian Imports				1	1
8	Pacific Southwest Imports				0	0
9	Intra-Regional Transfers In (Pacific Northwest Purchases)				175	69
10	Slice Transmission Loss Return				41	28
11	**Total Federal System Contract Purchases**				**454**	**233**
12	**Total Federal System Non-Hydro Resources and Contract Purchases**				**1,632**	**1,259**

a/ This is the maximum generation for January 2025
b/ Stateline Wind Project contract expiring in 2028
c/ Klondike Phase III Project expiring in 2029
d/ Fourmile Hill is not assumed to be in operation within the study period

Federal System Hydro Generation Variability

The generating capacity of Federal system hydroelectric projects depends on the amount of water flowing through the facilities, the physical capacity of the facilities, flow requirements pursuant to biological opinions, a combination of other power and non-power constraints, and other operating limitations. Table 2-8 shows the annual variability of hydro generation under the three water conditions. Although hydro generation changes drastically from different water conditions, within each condition, however, it changes only slightly from year to year.

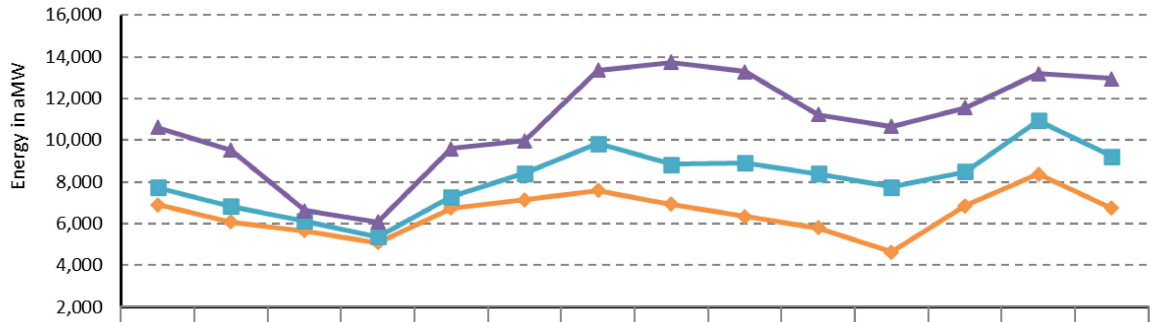
Table 2-8 Federal System Variability of Annual Hydro Generation by Streamflow Conditions – OY2025 – OY2034

Energy (aMW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Firm Water (p10)	6,589	6,536	6,614	6,544	6,628	6,633	6,633	6,642	6,623	6,688
Median Water (p50)	8,223	8,237	8,244	8,250	8,274	8,294	8,294	8,307	8,286	8,419
High Water (p90)	10,930	10,825	10,911	10,799	10,952	10,963	10,966	10,996	10,965	11,146

In OY2025, annual Federal system hydro energy generation is forecasted to be 6,589 aMW under Firm Water conditions. However, under the High Water conditions these same Federal system hydro

resources could generate as much as 10,930 aMW for OY2025. Table 2-9 displays the monthly variability of the Federal system hydro generation forecasted for OY2025, under the same three water conditions. Higher generation levels from January through March are largely due to drafting reservoirs for flood control and power production. The available water in those months depends greatly on annual rainfall and snowpack levels in the Columbia River Basin, and thus the generation exhibits large variability from year to year. Power production from April through July is variable based on the timing and amount of Columbia River Basin snowmelt runoff. Power production decreases through the end of summer and early fall as stream flows decline due to depleted snowpack and lower precipitation levels. Annual water volume variability generally has minimal impact on generation from the Federal system hydro resources in September and October. As observed from Table 2-9, hydro generation can vary by close to 7,000 aMW in a single month, almost double in this case March, depending on operations and availability of water.

Table 2-9 Federal System Monthly Hydro Generation Variability by Streamflow Conditions – OY2025

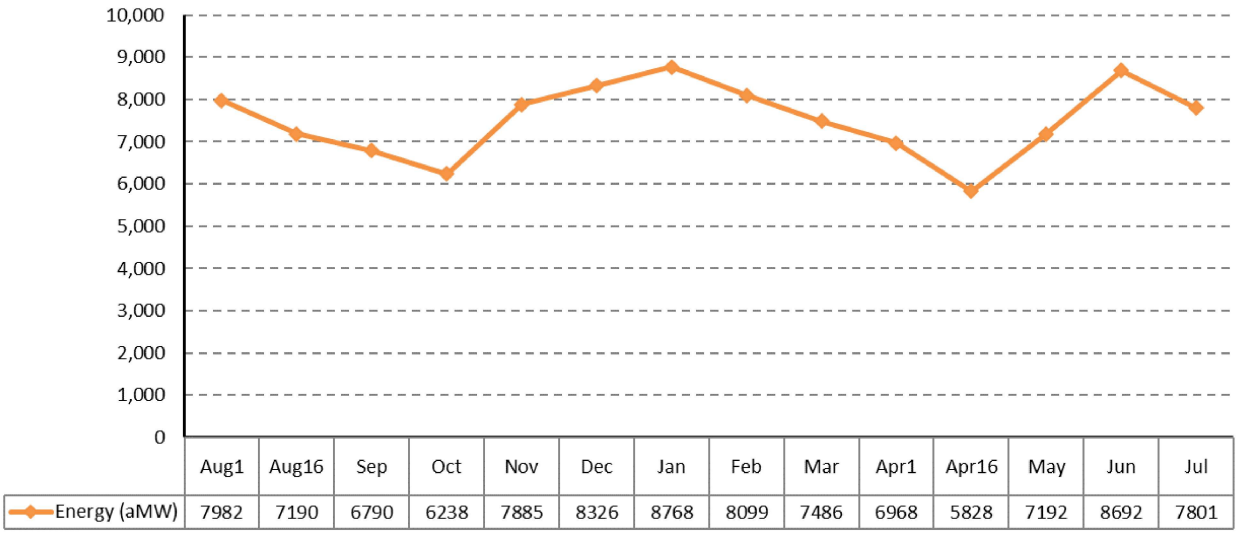


	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Firm Water (P10)	6,905	6,077	5,649	5,072	6,731	7,148	7,586	6,928	6,333	5,800	4,635	6,856	8,360	6,732
Median Water (P50)	7,727	6,835	6,121	5,357	7,284	8,416	9,840	8,830	8,904	8,395	7,748	8,484	10,931	9,220
High Water (P90)	10,620	9,522	6,620	6,070	9,601	9,962	13,355	13,732	13,291	11,224	10,652	11,567	13,185	12,956

Total Federal System Resources

Table 2-10 shows the monthly shape of forecasted total Federal system generation for energy (in aMW) for OY2025, under Firm water conditions. This includes generation from all Federal system hydro and non-hydro resources, as well as contract purchases. Overall, the Federal system maintains similar monthly shapes over the study period, with the highest generation forecasted in late fall and winter (Nov-March) and mid-summer periods.

Table 2-10 Federal System Monthly Generation for OY2025 under Firm Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	7982	7190	6790	6238	7885	8326	8768	8099	7486	6968	5828	7192	8692	7801

Key Results

Annual Energy

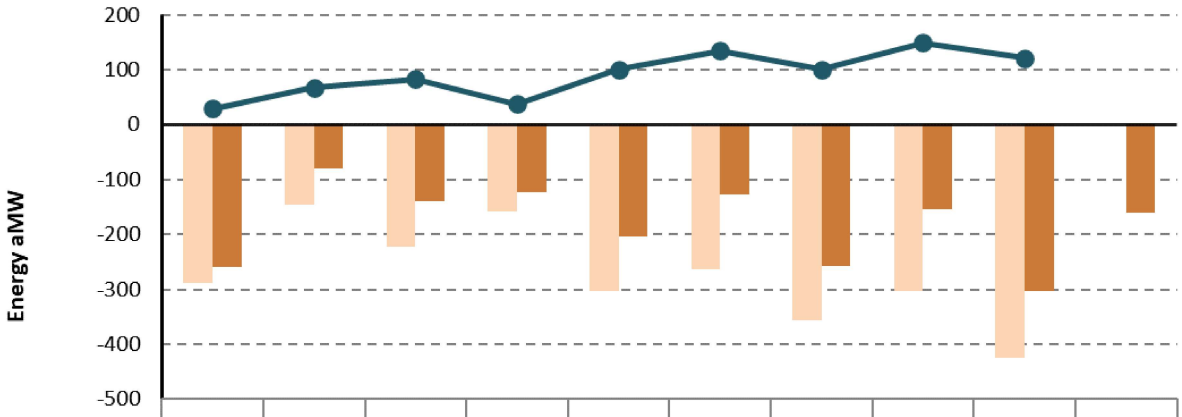
Table 2-11 shows that the Federal system is forecasted to have annual energy deficits throughout the study period. The individual components of the Federal system annual energy loads and resources are shown in Exhibit 4-1 for OY2025 through OY2034. The Federal system detailed monthly energy loads and resources are shown in Exhibit 4-2 for OY2025.

Table 2-11 Federal System Annual Energy Surplus/Deficit under Firm Water Conditions

Energy (aMW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Surplus/ Deficits	-260	-79	-139	-122	-203	-128	-257	-153	-303	-161

Table 2-12 compares the 2024 White Book Federal system annual firm energy surplus/deficit results to those from the 2023 White Book. Compared with the previous White Book, the 2024 White Book shows a slight decrease in deficits annually throughout the studying period. These results reflect changes in both load obligations and Federal system generation.

Table 2-12 Federal System Annual Energy Surplus/Deficits Comparison under Firm Water

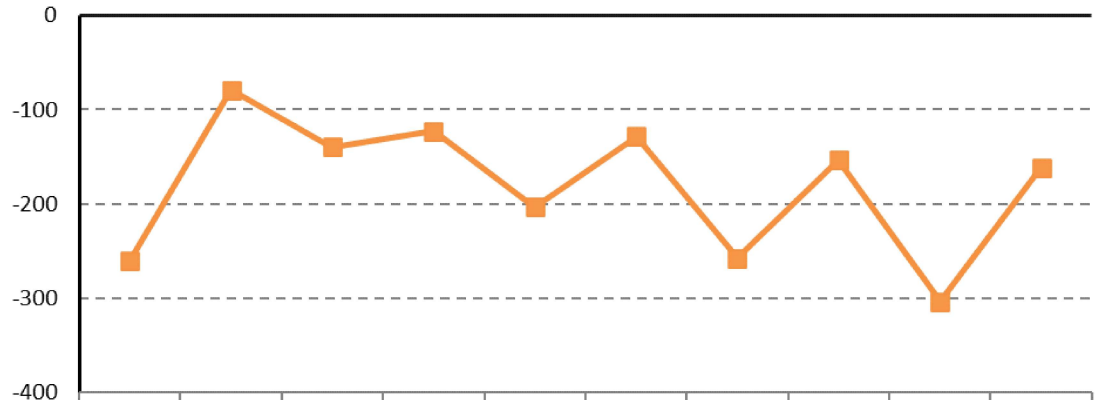


	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
2023 White Book	-289	-147	-223	-159	-303	-263	-357	-303	-424	
2024 White Book	-260	-79	-139	-122	-203	-128	-257	-153	-303	-161
Delta	29	67	83	37	100	134	100	149	121	

Federal System Annual Surplus/ Deficit

Table 2-13 graphically presents the annual firm energy surplus/deficits. Over the study period, the Federal system is forecasted to have a deficit in annual firm energy as high as 303 aMW near the end of the study period. Some differences in annual energy between odd and even years can be attributed to the biennial Columbia Generation Station (CGS) maintenance schedule[9].

Table 2-13 Federal System Annual Surplus/ Deficits Under Firm Water Conditions



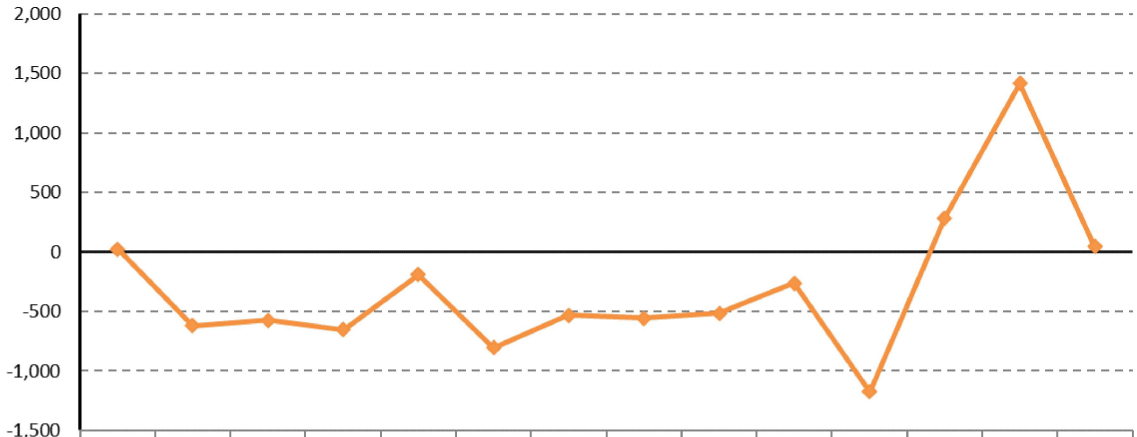
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy (aMW)	-260	-79	-139	-122	-203	-128	-257	-153	-303	-161

[9] CGS has routine maintenance cycle scheduled in odd calendar years, specifically in months of May and June. CGS is forecast to produce 994 aMW annually during maintenance years, and 1,116 aMW annually during non-maintenance years.

Federal System Monthly Surplus/ Deficit

Table 2-14 displays a graphic look at the Federal system monthly firm energy surplus/deficits for OY2025. Both forecasts maintain similar monthly shapes over the other Operating Years in this study period. With highest deficits comes in the second half of April and better positions come in May, June, and July.

Table 2-14 Federal System Monthly Surplus/ Deficits OY2025 under Firm Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	22	-620	-575	-654	-191	-805	-531	-559	-513	-262	-1177	284	1415	45

Conclusion

Under Firm water conditions, the Federal system shows annual firm energy deficits through the 2025-2034 study period. These annual energy deficits range from 79 aMW in OY2026 to as high as 303 aMW in OY2032. At a monthly resolution under Firm water conditions, the Federal system generally shows larger energy deficits across the winter and early spring periods until spring runoff starts, which then turns into surplus from May and to the early summer periods.

The Federal system surplus/deficit forecasts generally have a positive relationship with water conditions. Better water conditions generally yield more surplus overall. For example, the annual energy surplus can increase by over 4,000 aMW under better water conditions, while monthly surplus or deficit position can vary by close to 7,000 aMW within the same year.

The range of Federal system monthly surplus and deficit forecasts under all 30-water years is presented in Exhibit 4-3. Additional monthly and annual details for OY2025 through OY2034 are available upon request, a list of available data reports can be found in the Appendix. Reminder: Data Report requests can be received via email to WhiteBook@bpa.gov.

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SECTION 3: PACIFIC NORTHWEST REGIONAL ANALYSIS

The PNW Regional Analysis is an OY analysis that provides Bonneville's deterministic forecast of the PNW region's loads and resources over a 10-year period from OY 2025 through OY 2034. Firm load and resources forecasts are presented in energy based on regional retail loads, contract obligations, and resources. This White Book analysis assumes that generation from all regional uncommitted Independent Power Producer (IPP) projects is available to meet regional load. Regional retail loads, contract sales and purchases, and generating resources forecasts incorporate annual regional utility data submittals received by Bonneville.

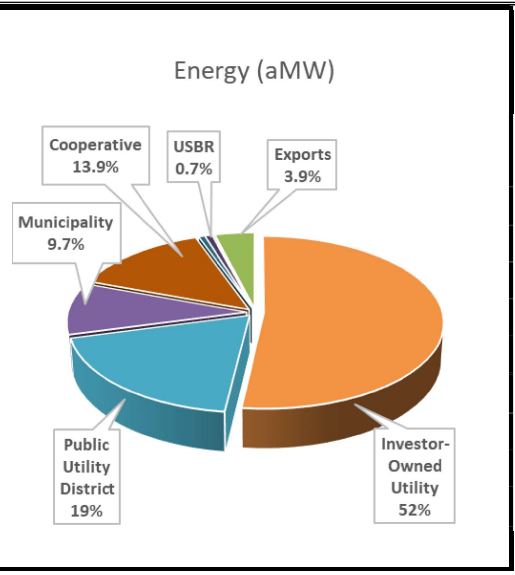
Regional Loads

The regional analysis incorporates regional load projections, which consist of two separate components: 1) Total Retail Loads (TRL), which is the sum of individual utilities' retail power consumption within the PNW region; and 2) Regional contract sales (Exports), which are the sum of all reported long-term regional contract deliveries to entities outside the PNW region. The TRL forecasts for the regional analysis are developed by Bonneville's ALF system. TRL forecasts reflect normal weather conditions, include historical conservation savings, and do not include specific adjustments for future climate change impacts. Apart from power commitments under the Treaty, all Export contract deliveries follow individual contract terms and are not assumed to be renewed after their expiration dates. Treaty power deliveries are assumed to be in place through the study period. The sum of the forecasted TRL and Export contracts represent the regional loads for the PNW.

Regional loads are comprised of roughly 96 percent retail loads and four percent exports. Table 3-1 shows the forecasted composition of PNW regional load for OY2025.

Table 3-1 PNW Region Firm Loads by Customer Class – OY2025

Customer Class	Energy (aMW)	Percent of Firm Energy
Investor-Owned Utility	13,566	52%
Public Utility District	4,963	19%
Municipality	2,545	9.7%
Cooperative	3,642	13.9%
Federal Agency	160	1%
USBR	186	0.7%
DSI	53	0.2%
Marketer	0	0.0%
Total Retail Load	**25,115**	**96%**
Exports	1,030	3.9%
Total Regional Load	**26,145**	**100%**



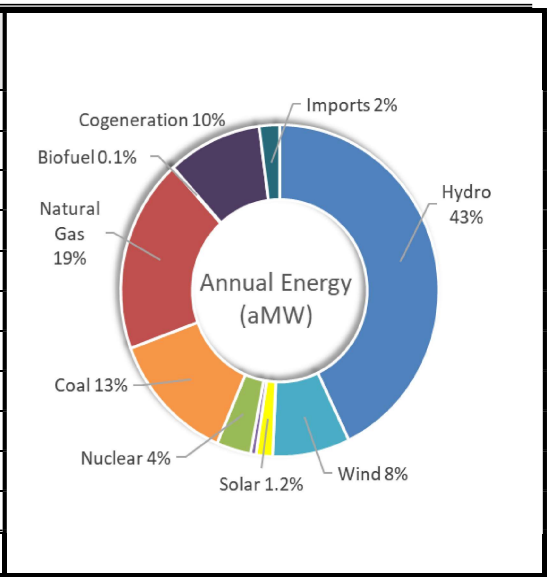
Regional Resources

PNW resources and contract purchases are collectively called "regional resources" in this study. Similarly to the Federal system resources, regional resources vary monthly by water conditions, resource type, and seasonality of generating resource potential. This analysis classifies resources as 1) Hydro resources, which include regulated, independent, and small hydro projects; 2) non-hydro renewable resources which include wind, solar, and other projects; 3) Thermal resources which include nuclear, coal, natural gas, petroleum, biofuel and cogeneration projects; and 4) Contract purchases which are identified as Imports.

Table 3-3 summarizes the resource generation available to meet PNW regional loads. The generation forecasts for these resources are provided by Bonneville models or the project owners. New regional generating projects are included when those resources begin operating or are under construction and have a scheduled on-line date; similarly, retiring resources are removed from the forecasts based on the data of the announced retirement date. Regional resource forecasts assume the retirement of the following coal projects over the study period: Centralia 2 (December 1, 2025) and Valmy 2 (January 1, 2026). Contract purchases are provided by the individual utility, follow specific contract provisions, and can have various delivery arrangements.

Table 3-3 PNW Regional Generations by Resource Type – OY2025 Firm Water Conditions

Project Type	Annual Energy (aMW)	Percent of Energy
Hydro	12,196	43%
Wind	2,238	8%
Solar	479	1.7%
Other Renewable	158	0.6%
Nuclear	994	3%
Coal	3,676	13%
Natural Gas	5,372	19%
Petroleum	0	0%
Biofuel	26	0.1%
Cogeneration	2,728	10%
Imports	591	2%
Total Regional Resources	**28,457**	**100%**



Regional Hydro Generation Variability

The generating capacity of regional hydroelectric projects depends upon the amount of water flowing through the facilities, the physical capacity of the facility, flow requirements pursuant to non-power requirements, and other operating limitations. Similarly to the Federal hydro resources, Bonneville utilizes the 30-year streamflow record and percentile of T1SFCO results for planning purposes. Again, three water conditions are presented here to represent the magnitude of hydro generation variability.

Table 3-4 shows the annual variability of the region's hydro generation under the three streamflow scenarios. Details on the different streamflow scenarios please refer to Hydro Resource Modeling section.

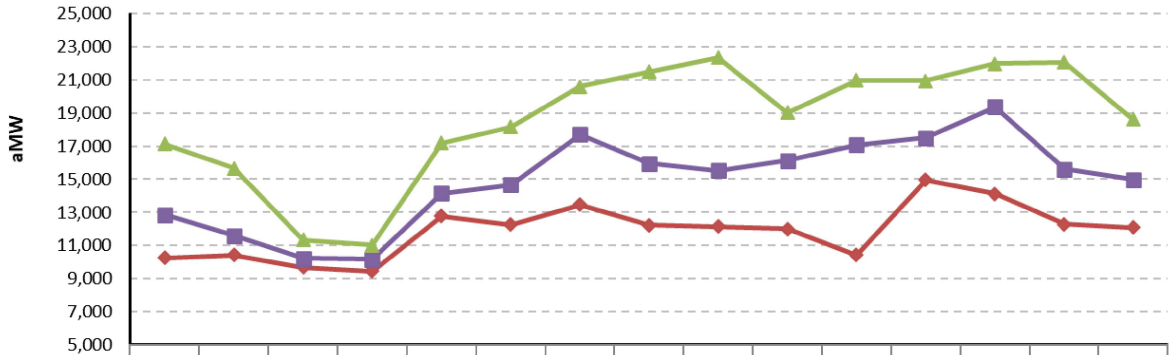
In OY2025, annual firm energy generation from regional hydro projects is forecasted to be 12,196 aMW under the firm water conditions, and this represents about 43% percent of the region's resources. However, the generating potential from regional hydro projects can vary annually by over 6,000 aMW between firm and high water conditions.

Table 3-4 PNW Regional Annual Variability of Hydro Generation by Streamflow Conditions

Energy (aMW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Firm Water (p10)	12,196	11,888	12,201	11,958	12,212	12,216	12,216	12,225	12,149	12,238
Median Water (p50)	14,729	14,807	14,727	14,820	14,756	14,786	14,786	14,800	14,819	14,932
High Water (p90)	18,817	18,751	18,854	18,708	18,885	18,893	18,922	18,957	18,929	19,110

Table 3-5 shows the monthly variability of regional hydro generation under the same three water conditions for OY2025. The increased level of generation in January through March period is largely due to drafting reservoirs for power production and flood control, which can vary widely due to rainfall and snowpack levels in the Columbia River Basin. Power production fluctuations in the second half of April through July are highly related to the timing and amount of Columbia River Basin snowmelt runoff. Power production decreases through the end of summer and early full as streamflow are reduced due to depleted snowpack and lower precipitation levels. Water variability does not have a substantial impact on regional hydro generation from September through November. Regional hydro generation capability can vary by as much as 10,000+ aMW between firm and high water conditions within the same month.

Table 3-5 PNW Regional Hydro Generation Monthly Variability by Streamflow Conditions - OY2025



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
Firm Water (P10)	10,268	10,424	9,680	9,468	12,772	12,264	13,459	12,220	12,157	12,010	10,436	14,953	14,121	12,294	12,081
Median Water (P50)	12,868	11,591	10,237	10,180	14,150	14,681	17,712	15,952	15,523	16,130	17,067	17,499	19,372	15,600	14,970
High Water (P90)	17,128	15,680	11,353	11,036	17,178	18,161	20,582	21,478	22,334	19,026	20,956	20,936	21,970	22,056	18,617

Uncommitted IPP Generation Delivered to the PNW Region

The PNW regional study includes uncommitted PNW IPP generation as regional resources. These resources, or the share of these resources, that are not committed to serving specific loads represent approximately 2,793 aMW of energy for OY2025. The inclusion of this uncommitted IPP generation is reasonable from the long-term planning perspective because the PNW Regional Analysis does not include any reliance on market purchases. However, PNW utilities may have to compete with other western markets to secure this generation to meet electricity demands. Table 3-6, next, details the region's total uncommitted IPP annual energy generation forecasts over the OY2025 through OY2034 study period.

Table 3-6 PNW Regional Annual Uncommitted IPP Generation

Regional Uncommitted IPP	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Annual Energy (aMW)	2,793	2,790	2,629	2,546	2,586	2,592	2,592	2,592	2,591	2,601

Table 3-7 details the region's uncommitted IPP projects and the associated fuel types. If uncommitted IPP generation is secured for long-term periods by load serving entities within the region or outside the region, the IPP forecasts will be updated in future studies to reflect those changes.

Table 3-7 PNW Regional Uncommitted Independent Power Producer Projects – OY2025 Firm Water Conditions

Project	Fuel Type	Energy (aMW)	Peak (MW)
Airport Solar	Solar	13	0
Centralia Complex [a/b/]	Coal	260	290
Condon Wind	Wind	12	0
Cosmopolis Specialty Fibres	Wood Waste	14	14
Hermiston Power Project	Wood Waste	567	630
International Paper Energy Center	Wood Waste	17	22
Juniper Canyon Wind	Wind	36	0
Kittitas Valley Wind	Wind	24	0
Klamath Generation Facility	Natural Gas	436	484
Klamath Generation Peakings (CT)	Natural Gas	90	100
Klondike Wind 1	Wind	6	0
Klondike Wind 3	Wind	23	0
Klondike Wind 3a	Wind	18	0
Leaning Juniper Wind	Wind	47	0
Longview Fibre Paper & Packaging	Wood Waste	35	35
Nippon Paper Cogen (Port Angeles)	Wood Waste	0	6
Pelton	Hydro	14	41
Priest Rapids	Hydro	85	154
Rock Island	Hydro	168	154
Rocky Reach	Hydro	155	339
Round Butte	Hydro	31	99
Satsop Combustion Turbine Project	Natural Gas	584	650
SDS Lumber	Wood Waste	1	1
Smith Creek (Idaho)	Hydro	7	0

Project	Fuel Type	Energy (aMW)	Peak (MW)
Stateline Wind	Wind	8	0
Stimson Lumber (Plummer)	Wood Waste	44	7
Tacoma Biomass (WestRock)	Wood Waste	0	0
Tieton Dam (Yakima)	Hydro	0	0
Vansycle Wind	Wind	23	0
Wanapum	Hydro	25	60
Weyerhaeuser Longview	Wood Waste	35	44
Willow Creek Wind	Wind	16	0
Total Uncommitted IPP Generation		**2,793**	**3,129**

[a/] Centralia #2 (670 MW) is scheduled for retirement on Dec 1, 2025. Puget purchased an increasing amount of this project beginning Dec 1, 2014 and ending Nov 30, 2025.

Key Results

Annual Energy

Table 3-8 shows annual energy surpluses for the PNW region in the first two operating years, then increasingly more deficit going forward to outyears. This study assumes that 100 percent of the PNW region's uncommitted IPP generation (2,793 aMW in OY2025) is available to serve regional loads. The individual components of the PNW regional annual energy loads and resources for OY2025 through OY2034 are shown in Exhibit 5-1, and OY2025 monthly PNW regional details are shown in Exhibit 5-2. Other details of each component for OY2025 through OY2034 are available upon request via email at WhiteBook@bpa.gov.

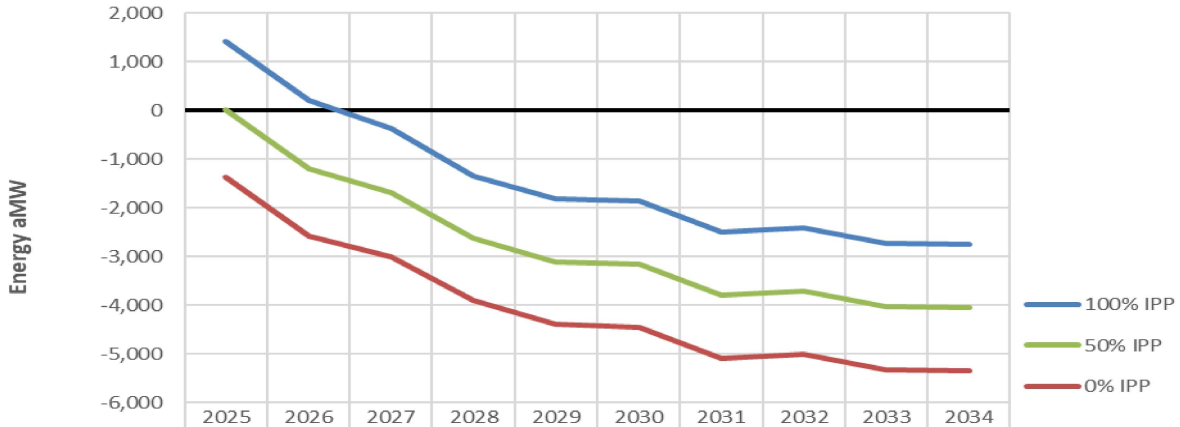
Table 3-8 PNW Regional Annual Energy Surplus/ Deficit - Firm Water Conditions

Assuming 100% of Uncommitted IPP Generation is Available to the Region

Energy (aMW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Surplus/ Deficit	1,426	207	-370	-1,352	-1,808	-1,861	-2,492	-2,407	-2,725	-2,738

Table 3-9 shows the significant variability in PNW regional annual firm energy surplus/deficit forecasts depending on the level of uncommitted IPP generation available to the region. IPP generation is detailed in Tables 3-6 and 3-7.

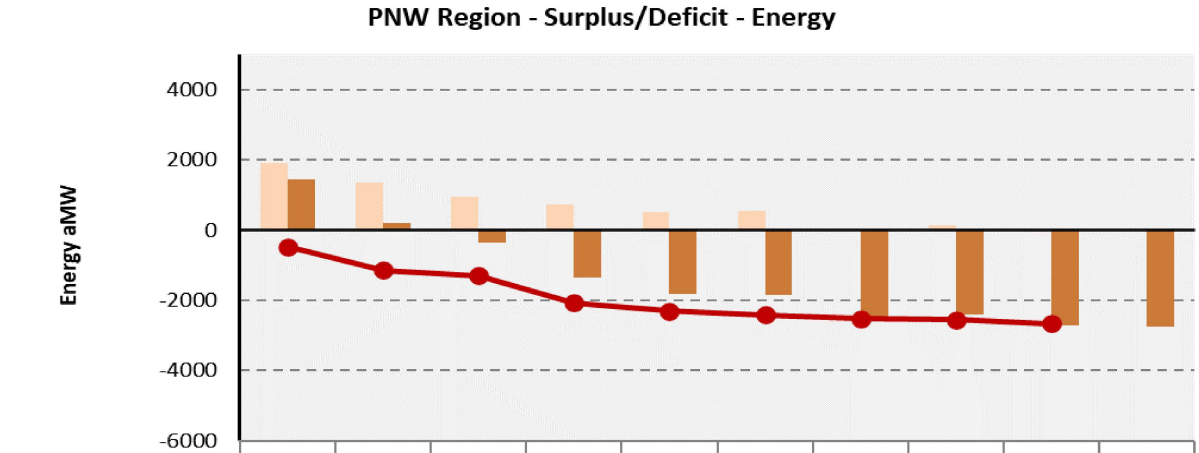
Table 3-9 PNW Regional Annual Energy Surplus/ Deficit by Uncommitted IPP Generation %



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
100% IPP	1,426	207	-370	-1,352	-1,808	-1,861	-2,492	-2,407	-2,725	-2,738
50% IPP	29	-1,189	-1,684	-2,625	-3,101	-3,158	-3,788	-3,703	-4,020	-4,038
0% IPP	-1,367	-2,584	-2,999	-3,898	-4,393	-4,454	-5,085	-4,999	-5,316	-5,339

Table 3-10 compares the 2024 White Book PNW regional annual firm energy surplus/ deficit forecasts to that of the 2023 White Book. Immediately, the comparison results show significant differences where OY2025 is less surplus in this study, and the difference gets more pronounced beginning in OY2026 and extends out all outyears where surplus became large deficits. This change is mainly driven by an increase in the PNW Regional Retail Load, more specifically in the new large industrial loads.

Table 3-10 PNW Regional Annual Surplus/ Deficit Comparison – Firm Water Conditions Assuming 100% Uncommitted IPP Generations available to the Region

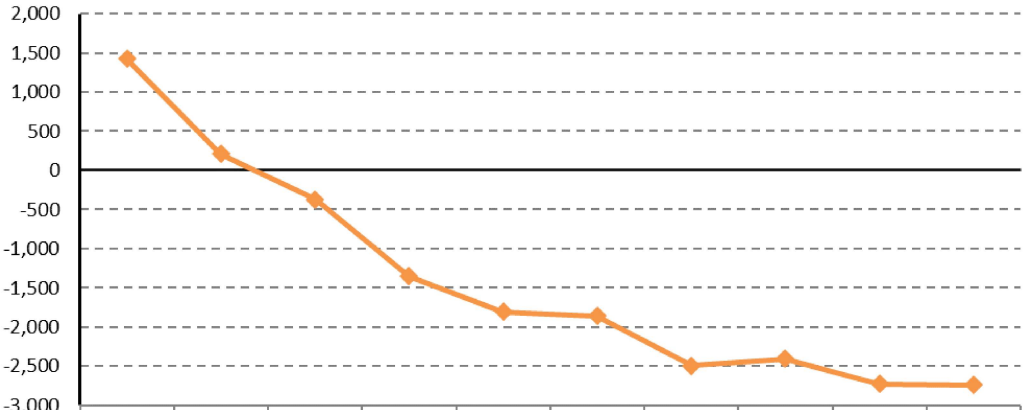


	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
2023 White Book	1905	1357	932	728	509	553	40	144	-61	
2024 White Book	1426	207	-370	-1352	-1808	-1861	-2492	-2407	-2725	-2738
Delta	-479	-1150	-1302	-2080	-2317	-2414	-2533	-2551	-2664	

Regional Annual Surplus/ Deficit

Table 3-11 graphically presents the annual firm energy surplus/ deficit forecasts for the PNW region. These forecasts assume 100 percent availability of the PNW uncommitted IPP generation to serve the region's loads. The regional annual energy surplus/ deficit declines over the 10-year study period.

Table 3-11 PNW Regional Annual Surplus/ Deficit – Firm Water Conditions

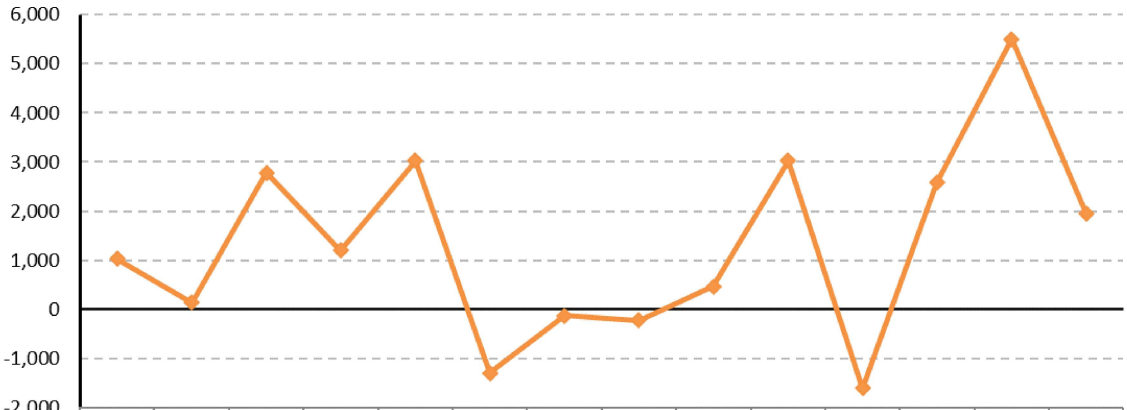


	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energy (aMW)	1,426	207	-370	-1,352	-1,808	-1,861	-2,492	-2,407	-2,725	-2,738

Regional Monthly Surplus/ Deficit

Table 3-12 shows the monthly energy surplus/ deficit forecast for OY2025. Again, these forecasts assume 100 percent of uncommitted IPP generation serving the region. This monthly view shows how both metrics follow a similar monthly shape with most surplus months in late spring to beginning of summer, and most deficits around the second half of April, before the runoff begins historically and as fish operations begin.

Table 3-12 PNW Regional Monthly Surplus/ Deficit – OY2025 Firm Water Conditions



	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul
Energy (aMW)	1,032	143	2,784	1,203	3,027	-1,300	-122	-224	464	3,026	-1,600	2,584	5,496	1,953

Conclusion

The PNW region is projected to have annual firm energy surpluses in the first two operating years then surpluses sharply declined and quickly becoming deficits, then continued with larger deficits going into the outyears, under the assumption of 100 percent of the PNW region's uncommitted IPP generation available to serve the region's load. Additionally, due to the fact that 100 percent of the uncommitted IPP generation is assumed to be available to serve the region's load, with its uncommitted nature, the supply of power within the region can change dramatically and quickly if those resources were to be used to serve loads outside of the region or retire early or unexpectedly.

Detailed surplus/deficit forecasts for all 30-historical water conditions are presented in Exhibit 5-3; monthly and annual details for OY2025 through OY2034 are available upon request with the itemized list located in the Appendix.

The regional energy and capacity deficits identified in this study may be mitigated through resource options discussed in the NWPCC's Power Plan publications, NWPCC is currently working on updating their 2021 Northwest Power Plan[10] and it is updated roughly every 5-year. Bonneville provides this PNW regional planning analysis for informational purposes only.

[10] The 2021 Northwest Power Plan (nwcouncil.org)

SECTION 4: FEDERAL SYSTEM ANALYSIS EXHIBITS

Exhibit 4-1: Annual Energy – Federal System Surplus/ Deficit:

Operating Years 2025 – 2034, Firm Water Conditions

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Loads and Resources - Federal System Percentile
Operating Year: 2025 to 2034 Percentile: 10
White Book 2024 Report Date: **6/7/2024**

S251-WB-20240606-131030

	Energy-aMW	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Firm Obligations										
1	**Load Following**	3914	3981	4024	4058	4096	4136	4160	4173	4196	4214
2	Preference Customers	3578	3639	3680	3712	3747	3786	3809	3823	3844	3862
3	Federal Agencies	150	156	158	160	163	164	165	165	165	166
4	USBR	186	186	186	185	186	186	186	185	186	186
5	Federal Diversity	0	0	0	0	0	0	0	0	0	0
6	**Tier 1 Block**	570	569	570	568	569	568	569	567	568	567
7	Tier 1 Block	570	569	570	568	569	568	569	567	568	567
8	**Slice**	2595	2591	2591	2586	2590	2604	2590	2602	2591	2615
9	Slice Block	1227	1210	1221	1208	1219	1207	1217	1204	1220	1208
10	Slice Output from T1 System	1368	1381	1370	1378	1371	1396	1373	1398	1371	1407
11	**Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
12	Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
13	**Contract Deliveries**	772	591	490	478	479	475	473	473	473	473
14	Exports	477	468	468	468	468	464	464	464	464	464
15	Intra-Regional Transfers (Out)	295	123	22.4	10.7	10.7	10.7	9.44	9.44	9.44	9.44
16	**Total Firm Obligations**	**7861**	**7743**	**7686**	**7702**	**7745**	**7793**	**7803**	**7827**	**7839**	**7880**
	Net Resources										
17	**Hydro**	6589	6536	6614	6544	6628	6633	6633	6642	6623	6688
18	Regulated Hydro - Net	6291	6258	6313	6264	6342	6349	6349	6361	6371	6433
19	Independent Hydro - Net	296	275	298	277	283	281	281	278	249	252
20	Small Hydro - Net	2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.87	2.88	2.88
21	**Non-Hydro Renewable**	33.0	33.0	19.8	1.90	0	0	0	0	0	0
22	Wind - Net	33.0	33.0	19.8	1.90	0	0	0	0	0	0
23	Other - Net	0	0	0	0	0	0	0	0	0	0
24	**Thermal**	994	1116	994	1116	994	1116	994	1116	994	1116
25	Nuclear - Net	994	1116	994	1116	994	1116	994	1116	994	1116
26	**Contract Purchases**	233	227	164	164	164	165	164	165	164	165
27	Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
28	Intra-Regional Transfers (In)	68.6	63.0	0	0	0	0	0	0	0	0
29	Non-Federal CER	135	135	135	135	135	135	135	135	135	135
30	Slice Transmission Loss Return	28.0	28.2	28.0	28.2	28.0	28.6	28.1	28.6	28.0	28.8
31	**Reserves & Losses**	-247	-249	-245	-246	-245	-249	-245	-249	-245	-251
32	Operating Reserves	0	0	0	0	0	0	0	0	0	0
33	Balancing Reserves	0	0	0	0	0	0	0	0	0	0
34	Transmission Losses	-247	-249	-245	-246	-245	-249	-245	-249	-245	-251
35	**Total Net Resources**	**7602**	**7664**	**7546**	**7580**	**7541**	**7665**	**7546**	**7673**	**7536**	**7719**
36	**Total Surplus/Deficit**	**-260**	**-79.3**	**-139**	**-122**	**-203**	**-128**	**-257**	**-153**	**-303**	**-161**

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Exhibit 4-2: Monthly Energy – Federal System Surplus/ Deficit: Operating Year 2025, Firm Water Conditions

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Loads and Resources - Federal System Percentile
Operating Year: 2025 Percentile: 10
White Book 2024 Report Date: **6/11/2024**
S251-WB-20240606-131030

	Energy-aMW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
	Firm Obligations															
1	**Load Following**	3843	3845	3356	3422	3725	4520	4532	4186	3809	3716	3716	3679	3939	4231	3914
2	Preference Customers	3369	3373	2936	3163	3559	4336	4348	3988	3592	3344	3344	3209	3436	3659	3578
3	Federal Agencies	136	136	125	138	159	181	176	184	159	141	141	129	127	142	150
4	USBR	338	336	295	121	7.27	3.43	7.16	13.7	57.7	231	231	342	376	429	186
5	Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	**Tier 1 Block**	379	379	636	522	877	865	953	898	853	410	410	137	9.50	327	570
7	Tier 1 Block	379	379	636	522	877	865	953	898	853	410	410	137	9.50	327	570
8	**Slice**	2506	2349	2285	2244	2768	3040	3108	2866	2635	2401	2176	2389	2626	2473	2595
9	Slice Block	1113	1113	1092	1128	1310	1502	1489	1373	1265	1164	1164	1117	1069	1106	1227
10	Slice Output from T1 System	1393	1235	1192	1117	1458	1537	1620	1493	1371	1237	1013	1272	1557	1366	1368
11	**Direct Service Industries**	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11
12	Direct Service Industry	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11
13	**Contract Deliveries**	1222	1226	1078	693	695	694	696	696	692	693	693	692	692	714	772
14	Exports	644	649	508	454	454	454	454	454	454	454	454	454	454	477	477
15	Intra-Regional Transfers (Out)	578	578	570	238	241	240	241	242	237	238	238	237	237	237	295
16	**Total Firm Obligations**	**7961**	**7810**	**7365**	**6892**	**8076**	**9131**	**9300**	**8658**	**8000**	**7230**	**7005**	**6908**	**7277**	**7756**	**7861**
	Net Resources															
17	**Hydro**	6905	6077	5649	5072	6731	7148	7586	6928	6333	5800	4635	6856	8360	6732	6589
18	Regulated Hydro - Net	6558	5744	5356	4805	6462	6981	7295	6685	6130	5522	4424	6438	7889	6358	6291
19	Independent Hydro - Net	344	330	291	265	267	164	288	241	201	274	208	416	469	372	296
20	Small Hydro - Net	2.63	2.63	2.63	2.67	2.84	3.19	3.21	3.05	3.10	3.09	3.09	2.83	2.72	2.63	2.9
21	**Non-Hydro Renewable**	22.6	33.8	31.5	25.3	36.2	27.6	14.8	24.4	28.1	50.2	42.3	45.2	44.7	43.7	33
22	Wind - Net	22.6	33.8	31.5	25.3	36.2	27.6	14.8	24.4	28.1	50.2	42.3	45.2	44.7	43.7	33
23	Other - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	**Thermal**	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	360	409	1116	994
25	Nuclear - Net	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	360	409	1116	994
26	**Contract Purchases**	202	200	213	226	256	303	335	292	251	228	223	164	165	166	233
27	Imports	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.0
28	Intra-Regional Transfers (In)	34.7	35.0	57.0	64.5	88.9	138	164	125	89.0	64.4	64.4	0	0	0	69
29	Non-Federal CER	137	138	131	138	137	132	137	135	133	137	137	137	132	137	135
30	Slice Transmission Loss Return	29.0	25.7	24.2	22.7	29.6	31.2	32.9	30.3	27.9	25.1	20.6	25.9	32.4	28.4	28
31	**Reserves & Losses**	-262	-236	-220	-202	-255	-269	-283	-262	-242	-225	-189	-234	-287	-257	-247
32	Operating Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	Balancing Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Transmission Losses	-262	-236	-220	-202	-255	-269	-283	-262	-242	-225	-189	-234	-287	-257	-247
35	**Total Net Resources**	**7982**	**7190**	**6790**	**6238**	**7885**	**8326**	**8768**	**8099**	**7486**	**6968**	**5828**	**7192**	**8692**	**7801**	**7602**
36	**Total Surplus/Deficit**	**22**	**-620**	**-575**	**-654**	**-191**	**-805**	**-531**	**-559**	**-513**	**-262**	**-1,177**	**284**	**1,415**	**45**	**-260**

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Exhibit 4-3: 30-Water Year Conditions Monthly Energy – Federal System Surplus/ Deficit: Operating Year 2025

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Federal Report Surplus Deficit By Water Year

Operating Year 2025

White Book 2024 Report Date: **6/12/2024**

S251-WB-20240606-131030

	Energy-aMW - Surplus Deficit	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
1	1989 Federal Report Surplus Deficit	165	720	-595	-750	-89.4	-61.7	-379	-1582	1010	1762	1538	1897	1096	579	281
2	1990 Federal Report Surplus Deficit	263	-323	-322	-375	363	1250	1386	2959	1050	1757	1832	1135	4061	3543	1387
3	1991 Federal Report Surplus Deficit	2448	1783	10.3	-557	2156	1325	2885	3853	2345	2527	1264	1529	3433	3947	2065
4	1992 Federal Report Surplus Deficit	2923	1505	-384	-446	184	-1251	-345	69.6	-513	361	-1177	662	2044	-262	127
5	1993 Federal Report Surplus Deficit	295	-354	-345	-657	5.21	-799	-934	-1812	45.9	-175	-1243	2052	1852	1905	60.5
6	1994 Federal Report Surplus Deficit	880	59.0	3.11	-452	122	-749	-1008	-386	-550	-473	161	284	1945	367	-12.4
7	1995 Federal Report Surplus Deficit	249	-600	-207	-532	-87.3	-438	8.22	926	2561	248	-192	1078	3358	2160	719
8	1996 Federal Report Surplus Deficit	1481	373	184	658	2864	5213	5859	5939	5958	2553	3179	2580	5048	4715	3555
9	1997 Federal Report Surplus Deficit	2666	2075	290	-97.3	899	1390	5700	6078	4929	4079	4884	5676	6092	4905	3544
10	1998 Federal Report Surplus Deficit	3102	2699	1029	2053	1696	343	1227	2280	1102	105	-4.86	4008	3881	2471	1919
11	1999 Federal Report Surplus Deficit	2786	1240	6.38	-350	-280	763	3971	3461	4916	2123	2643	1608	4099	5309	2321
12	2000 Federal Report Surplus Deficit	4177	3353	271	123	2224	1826	2389	2447	2242	2097	2603	1802	1415	2016	1904
13	2001 Federal Report Surplus Deficit	2052	-461	-252	-415	-179	-944	-867	-204	-627	-1133	-1752	-445	325	-79.1	-366
14	2002 Federal Report Surplus Deficit	557	-509	-598	-771	-385	-172	-435	-84.5	-39.2	1704	1407	1146	4371	3370	664
15	2003 Federal Report Surplus Deficit	519	-200	-168	-422	241	-805	-531	207	1592	483	1011	750	3312	321	445
16	2004 Federal Report Surplus Deficit	-362	-673	-528	-584	648	-274	-148	-559	-2.77	302	522	573	2791	685	207
17	2005 Federal Report Surplus Deficit	-44.5	188	125	226	680	554	960	2200	293	-592	-204	601	1808	1387	699
18	2006 Federal Report Surplus Deficit	544	-449	-317	-654	705	349	2848	3649	1492	3081	1861	3573	3579	1703	1603
19	2007 Federal Report Surplus Deficit	657	-344	-435	-477	294	394	2250	1216	3538	3638	888	1390	1993	1514	1174
20	2008 Federal Report Surplus Deficit	351	-578	-575	-585	415	-9.96	97.8	169	395	564	-827	2244	4735	3026	806
21	2009 Federal Report Surplus Deficit	1255	1256	-18.7	-383	371	-556	1621	457	-206	1863	1249	1324	1745	1098	688
22	2010 Federal Report Surplus Deficit	21.7	-873	-378	-389	-90.5	-972	-313	-625	-775	-262	-1313	-25.7	3907	1988	91.3
23	2011 Federal Report Surplus Deficit	664	-145	-21.6	-528	-191	896	4049	4813	2755	3971	1251	2374	6134	6497	2454
24	2012 Federal Report Surplus Deficit	3584	1513	17.1	0.97	155	212	2372	2598	2441	4420	4363	2745	5182	5513	2342
25	2013 Federal Report Surplus Deficit	2864	2070	-93.9	-377	1352	1961	1074	842	334	3563	1801	1949	3797	2054	1503
26	2014 Federal Report Surplus Deficit	1212	-28.0	72.3	-248	111	-40.0	1675	32.9	3464	2974	1486	1986	3422	3352	1396
27	2015 Federal Report Surplus Deficit	1262	21.4	17.5	-481	1229	1317	2831	3756	4315	1596	-324	-201	834	-364	1194
28	2016 Federal Report Surplus Deficit	105	-664	-666	-432	155	-194	47.7	102	3280	3495	3518	1554	1835	45.4	745
29	2017 Federal Report Surplus Deficit	16.1	-620	-268	-108	2049	948	3132	3986	6193	5323	4112	3960	5272	2052	2620
30	2018 Federal Report Surplus Deficit	1872	565	-292	-523	-602	184	3432	4752	2782	2508	1859	4957	3734	1141	1896

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SECTION 5: PACIFIC NORTHWEST REGIONAL ANALYSIS EXHIBITS

Exhibit 5-1: Annual Energy – PNW Regional Surplus/ Deficit: Operating Years 2025 – 2034, Firm Water Conditions

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Loads and Resources - Pacific Northwest Region Percentile
Operating Year: 2025 to 2034 Percentile: 10
White Book 2024 Report Date: **6/12/2024**
S251-WB-20240606-131030

	Energy-aMW	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
	Regional Loads										
1	**Retail Loads**	25115	25734	26358	27131	27747	27984	28140	28242	28451	28587
2	Federal Agency	160	166	168	170	172	173	173	173	174	174
3	USBR	186	186	186	185	186	186	186	185	186	186
4	Cooperative	3642	4156	4666	5329	5791	5912	5960	5979	6055	6100
5	Municipality	2545	2546	2545	2547	2551	2555	2562	2558	2567	2571
6	Public Utility District	4963	5011	5068	5116	5181	5242	5289	5324	5374	5406
7	Investor-Owned Utility	13566	13617	13673	13730	13813	13864	13917	13968	14042	14096
8	Direct-Service Industry	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3
9	Federal Diversity	0	0	0	0	0	0	0	0	0	0
10	**Exports**	1030	1021	1021	1020	1019	1013	765	670	670	670
11	Canada	468	468	468	468	468	464	464	464	464	464
12	East Continental Divide	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
13	Pacific Southwest	561	552	552	552	550	548	300	205	205	205
14	**Total Regional Loads**	**26145**	**26755**	**27379**	**28151**	**28765**	**28997**	**28905**	**28911**	**29121**	**29256**
	Regional Resources										
15	**Hydro**	12196	11888	12201	11958	12212	12216	12216	12225	12149	12238
16	Regulated Hydro - Net	11030	10763	11026	10832	11029	11034	11034	11044	10974	11076
17	Independent Hydro - Net	922	881	931	883	939	939	939	938	932	919
18	Small Hydro - Net	244	244	244	243	244	244	244	243	244	244
19	**Non-Hydro Renewable**	2875	2902	2902	2901	2903	2902	2886	2897	2902	2902
20	Wind - Net	2238	2238	2238	2236	2238	2238	2222	2233	2238	2238
21	Solar - Net	479	508	508	507	508	508	508	507	508	508
22	Other - Net	158	157	157	158	158	157	157	157	157	157
23	**Thermal**	12796	12444	12176	12198	12103	12280	12029	12198	12158	12195
24	Nuclear - Net	994	1116	994	1116	994	1116	994	1116	994	1116
25	Coal - Net	3676	3201	3049	2955	2981	3034	2948	2962	3034	2948
26	Natural Gas - Net	5372	5371	5371	5373	5372	5368	5371	5372	5371	5371
27	Petroleum - Net	0	0	0	0	0	0	0	0	0	0
28	Biofuel - Net	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5	25.5
29	Cogeneration - Net	2728	2730	2737	2729	2730	2737	2691	2722	2734	2734
30	**Imports**	591	595	599	603	607	610	130	36.5	36.4	36.4
31	Canada	38.8	38.8	38.8	38.8	38.8	38.8	36.7	36.5	36.4	36.4
32	Inland Southwest	506	509	513	517	521	525	93.6	0	0	0
33	Pacific Southwest	47.1	47.1	47.1	47.1	47.1	47.1	0	0	0	0
34	**Reserves & Losses**	-887	-867	-868	-861	-867	-873	-849	-852	-849	-853
35	Operating Reserves	0	0	0	0	0	0	0	0	0	0
36	Balancing Reserves	0	0	0	0	0	0	0	0	0	0
37	Transmission Losses	-887	-867	-868	-861	-867	-873	-849	-852	-849	-853
38	**Total Regional Resources**	**27571**	**26962**	**27009**	**26799**	**26958**	**27136**	**26412**	**26504**	**26396**	**26518**
39	**Total Surplus/Deficit**	**1426**	**207**	**-370**	**-1352**	**-1808**	**-1861**	**-2492**	**-2407**	**-2725**	**-2738**

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Exhibit 5-2: Monthly Energy – PNW Regional Surplus/ Deficit: Operating Year 2025, Firm Water Conditions

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Loads and Resources - Pacific Northwest Region Percentile

Operating Year: 2025 Percentile: 10

White Book 2024 Report Date: **6/11/2024**

S251-WB-20240606-131030

	Energy-aMW	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
	Regional Loads															
1	**Retail Loads**	24827	24844	22311	23053	24979	28759	28248	27123	24977	23475	23475	23070	24606	25969	25115
2	Federal Agency	147	148	136	150	167	189	184	192	167	153	153	140	139	154	160
3	USBR	338	336	295	121	7.27	3.43	7.16	13.7	57.7	231	231	342	376	429	186
4	Cooperative	3165	3167	2881	3487	3656	4087	4070	3886	3659	3583	3583	3573	3762	3894	3642
5	Municipality	2281	2284	2200	2382	2676	3096	3106	2946	2716	2448	2448	2220	2202	2290	2545
6	Public Utility District	4664	4668	4354	4498	5122	5857	5871	5582	5085	4730	4730	4474	4574	4765	4963
7	Investor-Owned Utility	14179	14189	12392	12362	13297	15473	14956	14449	13238	12277	12277	12269	13501	14385	13566
8	Direct-Service Industry	52.2	52.2	52.9	53.8	54.2	53.9	54.3	54.0	53.5	53.9	53.9	52.4	52.1	52.1	53
9	Federal Diversity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Exports**	1186	1361	1167	846	1003	873	679	825	880	1215	1102	1147	1192	1306	1030
11	Canada	589	593	454	454	454	454	454	454	454	454	454	454	454	477	468
12	East Continental Divide	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.0
13	Pacific Southwest	596	767	712	390	548	417	223	369	425	760	647	692	737	829	561
14	**Total Regional Loads**	**26013**	**26205**	**23478**	**23898**	**25982**	**29631**	**28927**	**27948**	**25857**	**24690**	**24578**	**24217**	**25798**	**27275**	**26145**
	Regional Resources															
15	**Hydro**	11631	10145	10313	9577	12623	12376	13860	12109	11280	12153	9151	13884	16585	12258	12196
16	Regulated Hydro - Net	10309	8944	9277	8644	11686	11528	12810	11121	10273	11035	8014	12282	14797	10860	11030
17	Independent Hydro - Net	997	878	791	771	809	723	926	857	845	838	855	1200	1366	992	922
18	Small Hydro - Net	325	323	244	163	128	126	124	132	162	280	282	403	422	405	244
19	**Non-Hydro Renewable**	2348	3106	2800	2292	2868	2222	1431	2134	2521	4083	3553	3870	3935	3855	2875
20	Wind - Net	1592	2338	2160	1742	2428	1869	1046	1661	1895	3311	2799	3023	3046	2951	2238
21	Solar - Net	597	608	483	390	281	194	237	314	467	616	596	687	755	724	479
22	Other - Net	159	159	157	160	159	159	148	158	158	157	157	160	134	181	158
23	**Thermal**	13425	13433	13454	13530	13750	13843	13803	13738	12829	11885	10532	9375	11207	13423	12796
24	Nuclear - Net	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	1116	360	409	1116	994
25	Coal - Net	3821	3822	3825	3826	3824	3828	3828	3827	3580	2989	2792	3202	3842	3824	3676
26	Natural Gas - Net	5585	5592	5654	5716	5851	5921	5914	5853	5804	5484	4427	3381	4262	5587	5372
27	Petroleum - Net	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Biofuel - Net	23.6	23.6	25.4	26.7	27.0	24.6	24.3	24.4	27.0	25.4	25.4	27.2	25.0	25.8	26
29	Cogeneration - Net	2879	2879	2833	2844	2933	2954	2920	2918	2301	2271	2171	2404	2669	2869	2728
30	**Imports**	586	586	514	484	671	773	608	608	511	458	458	506	663	715	591
31	Canada	20.8	20.8	15.8	22.0	38.9	49.3	62.3	70.8	62.7	30.2	30.2	28.9	38.6	27.0	39
32	Inland Southwest	565	565	498	462	452	488	458	473	448	428	428	477	624	688	506
33	Pacific Southwest	0	0	0	0	181	235	87.4	63.3	0	0	0	0	0	0	47
34	**Reserves & Losses**	-946	-922	-818	-782	-903	-882	-897	-863	-820	-863	-716	-835	-1095	-1022	-887
35	Operating Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	Balancing Reserves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Transmission Losses	-946	-922	-818	-782	-903	-882	-897	-863	-820	-863	-716	-835	-1095	-1022	-887
38	**Total Regional Resources**	**27045**	**26347**	**26263**	**25102**	**29009**	**28331**	**28805**	**27725**	**26321**	**27716**	**22978**	**26801**	**31294**	**29229**	**27571**
39	**Total Surplus/Deficit**	**1,032**	**143**	**2,784**	**1,203**	**3,027**	**-1,300**	**-122**	**-224**	**464**	**3,026**	**-1,600**	**2,584**	**5,496**	**1,953**	**1426**

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Exhibit 5-3: 30-Water Year Conditions Monthly Energy – PNW Regional Surplus/ Deficit: Operating Year 2025

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Regional Report Surplus Deficit By Water Year
Operating Year 2025
White Book 2024 Report Date: **6/12/2024**
S251-WB-20240606-131030

	Energy-aMW - Surplus Deficit	Aug1	Aug16	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr1	Apr16	May	Jun	Jul	Avg
1	1989 Regional Report Surplus Deficit	1,113	2,481	2,207	958	3,232	475	-161	-1,949	3,336	6,643	5,604	5,716	4,685	3,262	2,494
2	1990 Regional Report Surplus Deficit	1,382	889	2,852	1,661	4,402	3,609	4,191	6,433	3,745	6,695	5,442	4,145	9,646	8,534	4,676
3	1991 Regional Report Surplus Deficit	5,236	4,663	3,377	1,625	8,218	3,391	5,888	8,450	6,127	7,974	4,018	5,115	8,629	9,858	5,941
4	1992 Regional Report Surplus Deficit	6,293	4,361	2,848	1,440	3,332	-1,485	-44	1,392	464	3,994	-1,600	2,369	4,504	933	1,846
5	1993 Regional Report Surplus Deficit	816	347	2,241	962	2,846	-1,354	-1,664	-2,176	1,621	2,898	-1,078	6,179	5,591	5,591	1,797
6	1994 Regional Report Surplus Deficit	2,908	1,474	3,402	1,523	2,967	-1,013	-1,483	59	816	1,901	2,329	2,584	5,060	2,301	1,704
7	1995 Regional Report Surplus Deficit	919	90	2,777	1,275	2,831	153	790	3,227	6,636	3,218	684	4,585	8,909	6,034	3,296
8	1996 Regional Report Surplus Deficit	4,135	2,043	3,693	3,845	9,510	10,638	11,355	12,937	12,891	8,755	8,925	7,319	11,370	10,834	8,829
9	1997 Regional Report Surplus Deficit	5,941	5,338	4,071	2,483	5,022	3,643	11,142	12,581	11,329	11,554	10,839	12,084	13,252	11,634	8,643
10	1998 Regional Report Surplus Deficit	7,189	6,676	5,977	7,313	6,865	1,839	3,538	5,466	4,128	3,772	1,924	9,320	9,824	6,841	5,906
11	1999 Regional Report Surplus Deficit	6,008	3,713	3,628	1,824	3,111	2,724	8,168	7,702	10,925	7,691	6,901	5,896	10,596	12,529	6,597
12	2000 Regional Report Surplus Deficit	9,000	7,826	4,056	2,872	8,154	4,806	5,168	5,680	5,577	7,626	7,169	5,610	5,496	5,820	5,748
13	2001 Regional Report Surplus Deficit	4,498	1,135	2,905	1,660	2,564	-1,590	-1,825	117	-17	1,270	-2,154	361	2,255	1,334	836
14	2002 Regional Report Surplus Deficit	1,244	140	1,763	989	1,989	205	14	894	1,678	6,537	4,537	4,307	10,342	8,546	3,076
15	2003 Regional Report Surplus Deficit	2,208	887	3,119	1,332	3,158	-1,300	-122	1,451	4,524	3,542	3,188	3,316	8,056	2,247	2,544
16	2004 Regional Report Surplus Deficit	-119	-92	2,266	1,526	4,043	203	181	-224	1,528	3,617	2,378	3,017	7,020	3,266	2,142
17	2005 Regional Report Surplus Deficit	599	1,685	3,917	2,894	4,307	1,844	2,343	4,487	1,995	1,580	898	2,941	5,191	4,035	3,011
18	2006 Regional Report Surplus Deficit	1,685	306	2,630	1,203	4,097	1,342	6,401	7,786	4,484	9,023	5,624	8,826	9,544	4,974	4,932
19	2007 Regional Report Surplus Deficit	2,183	749	2,572	1,644	4,397	1,656	4,554	3,355	8,699	9,752	3,426	4,788	5,944	4,637	4,189
20	2008 Regional Report Surplus Deficit	1,632	326	2,784	936	3,243	590	359	1,016	2,129	3,525	-775	6,358	11,031	8,087	3,242
21	2009 Regional Report Surplus Deficit	3,654	3,499	3,208	1,542	3,801	-714	3,212	1,488	722	6,195	3,896	4,798	6,248	4,160	3,088
22	2010 Regional Report Surplus Deficit	1,032	-87	2,497	1,533	3,047	-1,269	375	-348	248	3,026	-1,177	1,661	9,501	5,998	2,051
23	2011 Regional Report Surplus Deficit	2,341	1,406	3,359	1,386	3,027	2,460	8,317	9,988	7,428	11,260	5,052	6,832	13,250	14,608	6,692
24	2012 Regional Report Surplus Deficit	8,325	4,719	3,735	2,487	3,545	857	5,023	5,857	6,310	11,648	10,072	7,336	11,329	12,437	6,346
25	2013 Regional Report Surplus Deficit	6,165	5,103	3,382	1,665	5,973	4,472	2,122	2,359	2,127	9,847	4,542	5,728	9,118	5,562	4,609
26	2014 Regional Report Surplus Deficit	2,842	1,332	3,648	2,081	3,153	148	3,654	1,032	8,135	8,354	4,563	5,845	8,465	8,480	4,447
27	2015 Regional Report Surplus Deficit	3,193	1,462	3,289	1,624	5,725	3,555	5,998	8,433	9,366	6,180	534	679	2,827	749	3,957
28	2016 Regional Report Surplus Deficit	395	-165	2,649	1,097	2,907	701	1,088	1,796	7,794	9,490	8,261	5,009	5,082	1,953	3,248
29	2017 Regional Report Surplus Deficit	667	143	2,555	2,954	7,526	2,262	5,877	8,822	13,417	13,316	9,751	9,334	12,203	5,709	6,849
30	2018 Regional Report Surplus Deficit	4,676	2,425	2,889	1,574	2,745	1,234	6,867	9,751	6,755	8,087	6,210	10,367	9,120	4,356	5,492

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APPENDIX – REPORTS AVAILABLE UPON REQUEST

Please send request via email to WhtieBook@bpa.gov, and allow three to five business days for turn-around time.

A. Annual Energy (aMW) – Operating Years 2025 – 2034
B. Monthly Energy (aMW) – Operating Years 2025 – 2034

Report #	Report Descriptions
1	Federal Report Surplus/ Deficit
2	Regional Report Surplus/ Deficit
3	Regional Total Retail Load
4	Regional Exports
5	Regional Imports
6	Regional Intra-Regional Transfer
7	BPA Sales to Preference and Legacy Customers
8	Regional Regulated Hydro
9	Regional Independent Hydro
10	Regional Small Hydro
11	Regional Non-Hydro Renewable – Wind
12	Regional Non-Hydro Renewable – Solar
13	Regional Non-Hydro Renewable – Other
14	Regional Thermal – Nuclear
15	Regional Thermal – Coal
16	Regional Thermal – Natural Gas
17	Regional Thermal – Petroleum
18	Regional Thermal – Biofuel
19	Regional Thermal – Cogeneration
20	Non-Federal CER Deliveries to BPA
21	Federal Report Surplus/ Deficit by 30 Water Year
22	Regional Report Surplus/ Deficit by 30 Water Year

BONNEVILLE POWER ADMINISTRATION
DOE/BP-5289 ▪ August 2024

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 11/12/2024 Agenda Category: Items of Business

Prepared By: Clint Whitney, Energy Services Director

Subject:
Ruby Flats Solar - Letter of Intent Opportunity (15 minutes)

Department:
Energy Services

Recommended Motion:
RES Staff recommends UAC support for Council approval of a Letter of Intent with Energy Northwest.

Summary:
Energy Northwest (ENW) received 300 acres of land at the same time when the City and the Port of Benton received 1,341 acres transferred from the Department of Energy (DOE). Tucci Energy Services is now working with ENW for development of the 300 acres with a 127.5MWac/170MWdc solar project called Ruby Flats Solar (RFS). The RFS project will interconnect with BPA at the Benton Substation about seven miles north of the City, and the RFS has an interconnection date after BPA completes the South Tri-Cities Reinforcement project scheduled for 4Q27.

A draft Power Purchase Agreement (PPA) for energy generated from RFS will be available to interested participants by the end of the year 2024 and the final PPA is expected for interested participants by September 30, 2025. The RFS commercial operation date is tentative at December 31, 2028, and dependent upon transmission interconnection with BPA.

The City approved a 2020 Integrated Resource Plan and an updated Resource Plan in 2024 which identifies the need for renewable energy to meet the State's Renewable Portfolio Standard (RPS) requirements of 3% beginning January 1, 2026, through December 31, 2028. The City also approved a 2021 Clean Energy Implementation Plan (CEIP) on October 19, 2021. The CEIP identifies existing BPA Tier 1 Renewable Energy Credits (RECs) and the renewable energy PPA Tucci Energy Services at Horn Rapids Solar, Storage and Training Site (HRSST) as sufficient for the initial 3% RPS requirement. After 2028, the City's Energy Services (RES) will be required to purchase 9% of its wholesale energy from renewable resources or purchase RECs.

The total retail load forecast for 2030 is 989,309MWh with a 6% RPS difference equal to 59,359MWh or 6.8aMW (59,359MWh/8760hr=6.8aMW). Solar generation projects typically have a 20% effective load carrying capacity (ELCC) which will require an approximate 34MW solar site (6.8aMW/0.20 aELCC=34MW) to meet the additional 6% renewable energy requirement beyond the existing 3% renewable energy and RECs.

RES staff is recommending submitting a letter of intent to Energy Northwest for 5MW of renewable energy from the RFS project. The project timing aligns the future 6% RPS requirement and the site location could result in a BPA transmission short distance discount. The cost of solar projects continues to decrease. Renewable energy regulations may also change that increase or decrease requirements. However, tariffs on solar infrastructure imported could increase project costs. Purchasing other solar projects over time will reduce the cost of solar risks.

Attached is a Letter of Intent (LOI) for the City to consider entering into a later Power Purchase Agreement (PPA) with ENW for renewable energy from the RFS project. There is a $25k/MW reservation premium that will be credited to power purchased or forfeited if the City does not complete the PPA. The cost of energy for RFS has

been estimated to be $65/MWh with shaping into a flat block by BPA adding another $20/MWh. Current BPA Tier 2 energy is being subsidized by BPA at $65/MWh with recent non-federal market costs of $70-75MWh.

If supported by UAC, a PPA will be presented at a meeting in 2025 for review and support before Council's consideration.

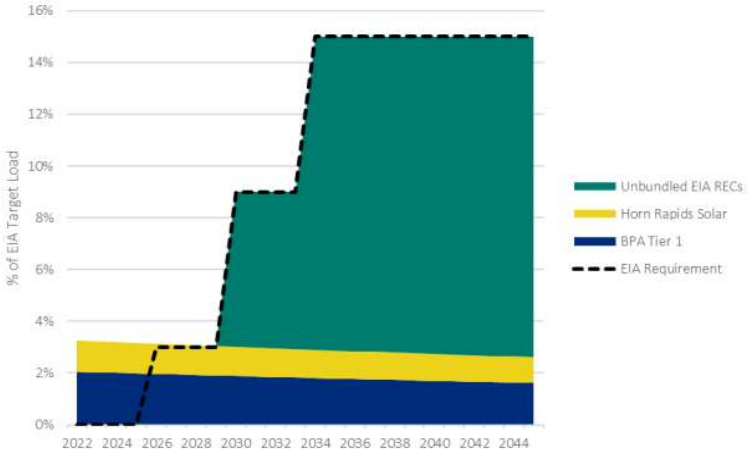
Fiscal Impact:

The Letter of Intent has a $25k/MW Reservation Premium risk.

Attachments:

1. 2021 CEIP Page 4 Energy Indepence Act for Renewable Portfolio Standards
2. Forward Price Curves
3. LOI 10-17-2024

Figure 2: Projected EIA Compliance



Forward Price Curves

Mid-C Weekly Price Summary

2024				2023		
Fiscal Year	9/13/2024	9/27/2024	Change	9/15/2023	9/29/2023	Change
FY 2024	42.71	48.37	13.25%	82.85	86.05	3.86%
FY 2025	54.43	59.76	9.79%	80.52	83.47	3.66%
FY 2026	65.41	67.00	2.43%	82.68	83.74	1.28%
FY 2027	70.55	71.75	1.71%	80.62	82.57	2.42%
FY 2028	72.84	73.98	1.56%	78.13	79.98	2.37%
FY 2029	70.90	72.37	2.07%	76.42	78.21	2.34%
FY 2030	70.32	71.79	2.09%	75.82	77.60	2.35%
FY 2031	75.12	76.44	1.76%	74.92	76.64	2.29%

2022				2021		
Fiscal Year	9/16/2022	9/30/2022	Change	9/17/2021	10/1/2021	Change
FY 2022	$ 108.42	$ 69.33	36.05%	$ 66.56	$ 64.74	-2.74%
FY 2023	$ 89.73	$ 82.42	-8.14%	$ 50.52	$ 51.93	2.79%
FY 2024	$ 73.30	$ 73.37	0.09%	$ 46.32	$ 46.70	0.82%
FY 2025	$ 65.90	$ 66.09	0.29%	$ 44.98	$ 44.50	-1.07%
FY 2026	$ 56.93	$ 57.39	0.80%	$ 45.57	$ 44.97	-1.31%
FY 2027	$ 58.86	$ 59.09	0.40%	$ 46.11	$ 45.51	-1.30%
FY 2028	$ 59.21	$ 59.50	0.50%	$ 47.03	$ 46.41	-1.31%
FY 2029	$ 58.77	$ 58.95	0.30%	$ 47.41	$ 46.84	-1.20%

Attachment C

Draft Letter of Intent

Letter of Intent between Energy Northwest and [Utility]
for a renewable energy generation facility located in
Benton County, Washington.

This Letter of Intent ("LOI") is intended (i) to set forth certain preliminary understandings as of the date hereof by and between Energy Northwest, a municipal corporation and joint operating agency of the State of Washington, doing business through its Business Development Fund"), and [Utility name], a _____utility organized under the laws of the State of Washington ("Utility"), and (ii) to serve as a basis for further discussions and negotiations between EN and [Utility] and other off-taker utilities, with respect to the Proposed Transaction (as defined below). Each of [Utility] and EN is sometimes hereinafter referred to as a "Party" and they are collectively referred to as the "Parties." The multiple off-takers envisioned hereunder, including [Utility] and other off-taker utilities, are hereinafter referred to collectively as "Counterparty Off-Takers".

1. Proposed Transaction. EN, through its designated special purpose affiliate ("EN SPV") will own all of the right, title and interest in the output of Ruby Flats Solar, a 127.5 MWac solar generating facility located in Benton, Washington (the "Project)". [Utility] is contemplating entering into a power purchase agreement with EN SPV for a to-be-specified percentage of energy generated by the Project for a term of 30 years. The proposed legal structure and financial terms of the Proposed Transaction and the related conditions will be negotiated between the Parties during the Longstop Date (as hereinafter defined).

2. No Solicitation or Negotiation. EN, on behalf of itself, EN SPV and its other affiliates and their respective officers, directors, employees, partners, members, agents, advisors and other representatives (collectively, the "EN Entities"), agrees that from the date of signing indicated below (the "Effective Date") until the earliest of (i) the date of execution and delivery of a power purchase agreement for the energy generated by the Project, or an alternative transaction structure providing for a combination of the foregoing, together with all related agreements (collectively, the "Definitive Agreements"), (ii) the termination of this Letter of Intent without execution and delivery of the Definitive Agreements in the manner provided below, or (iii) the date that is one hundred and eighty (180) days after the Effective Date, as such date may be extended by the mutual agreement of the Parties (the "Longstop Date"), EN shall not engage in any activity, directly or indirectly, the purpose or intent of which would be the solicitation, offer or negotiation of or agreement to terms and conditions, regarding any sale, transfer, conveyance or disposition of the Project's energy with or to any person other than the Counterparty Off-Takers (collectively, the "Exclusivity Agreement").

3. [Utility] Interest in Project. [Utility] has a *bona fide* interest in purchasing energy generated by the Project as an off-take purchaser from EN or EN SPV. [Utility] is interested in a minimum of

___ MWac (the "Minimum Reservation"), and a maximum of ____ MWac (the "Maximum Reservation"). (Maximum nameplate capacity is 127.5 MWac.)

4. [Utility] Representations. By executing this LOI, [Utility] represents that its governing body has been briefed on EN's development of the Project and on Utility's interest in purchasing energy generated by the Project. [Utility] further represents that, to the best of its knowledge, it is not prohibited by law or regulation or its own charter or bylaws from participating in the Project as a Counterparty Off-Taker. No vote of the public, or of Utility's members or customers, would be required in order for [Utility] to participate in the Project as a Counterparty Off-Taker.

5. Reservation Premium. By executing this Letter of Intent, [Utility] commits to paying, within 45 days after the Effective Date, a Reservation Premium to EN in the amount of [$_____] per MW of its maximum reserved capacity for the Project. Such fee shall be credited, on a dollar-for-dollar basis, to [Utility's] earliest payments due as a Counterparty Off-Taker for power purchased pursuant to any signed Definitive Agreements, after commercial operation date (" Project COD". In the event the Project does not achieve Project COD by June 30, 2029 (which date may be extended by mutual agreement), then EN shall return such Reservation Premium, to [Utility] without interest. In the event the Project achieves COD by such date, as extended, and [Utility] does not enter a power purchase agreement to purchase energy from the Project at no less than the Minimum Reservation, the Reservation Premium may be retained by EN.

6. Timing. Subject to Section 2 and 10 hereof, the Parties shall employ commercially reasonable efforts and cooperate in good faith to seek to complete the negotiation, execution and delivery of mutually acceptable Definitive Agreements on or prior to the Longstop Date (defined below).

7. Due Diligence. During the Effective Period (defined below), [Utility] shall be entitled to conduct, and EN shall fully cooperate with [Utility] and facilitate, an in-depth due diligence review of the status and prospects for development, financing, construction, operation and performance of the Project and any matters relating thereto, including, but not limited to, the technical, construction, engineering, transmission and operation arrangements and agreements therefor, including reasonable access to the Project site for such purposes.

8. Access. During the Effective Period (as hereinafter defined in Section 10 hereof), EN shall, subject to reasonable advance notice from Utility, afford [Utility] representatives the opportunity to obtain information pertaining to the Project and perform on-site inspections and due diligence of the Project's assets, during normal business hours.

9. Expenses. Each Party shall bear its own legal, accounting, consulting, regulatory, tax and other professional fees and expenses and other transaction costs, regardless of whether the Proposed Transaction is consummated.

10. Effective Period; Termination. This Letter of Intent shall remain in effect from the Effective Date until the earliest of (a) the Longstop Date; (b) the date of execution and delivery of the Definitive Agreements; or (c) the termination of this Letter of Intent by [Utility] at its sole discretion at any time, effective upon written notice to EN (the "Effective Period"). Termination of this Letter of Intent by [Utility] without execution and delivery of the Definitive Agreements

will release EN from the exclusivity provisions of Section 2 hereof effective as of such termination, for that portion of the Project in which [Utility] was interested. Sections 5, 9, 11, 12, 13 and 14 of this Letter of Intent shall remain binding on both parties, notwithstanding termination hereof.

11. Confidentiality. This Letter of Intent and all materials, studies, documents, models and other information made available by EN to [Utility] pursuant to the provisions of this Letter of Intent that are not generally available to the public shall be deemed to be confidential information and is made with the express understanding that except as required by law it will be kept confidential and will not be disclosed to any party other than the Parties and their respective officers, directors and other advisors solely in connection with the evaluation of the Proposed Transaction.

Notwithstanding the requirements for disclosure under the Public Records Act as stated in the "Public Disclosure" provision, it is the intent of the Parties to maintain this Contract in a confidential manner. Therefore, unless the requirements set forth in the "Public Disclosure" provision apply, the Parties agree not to divulge to third parties, without the written consent of the other Party, any information that relates to the technical or business activities of the disclosing Party in connection with the performance of this Contract unless: (a) The information was known to the receiving Party prior to obtaining the same from the disclosing Party; (b) The information is at the time of disclosure then in the public domain; or (c) The information is obtained by the receiving Party from a third party who did not receive the same, directly or indirectly, from the other Party and who has no obligation of nondisclosure with respect thereto.

The Parties further agree that they will not, without the prior written consent of the other Party, disclose to any third party any information developed or obtained in the performance of this Contract except to the extent that such information falls within one of the categories described in (a), (b) or (c) above. Finally, neither party shall release any information concerning the Work under this Contract or any part thereof in the form of advertising or publication, including news releases or professional articles, without the prior written agreement of both parties.

12. Governing Law. This Letter of Intent shall be governed by the laws of the State of Washington, without regard to principles of conflict of laws that would call for the application of any laws other than the laws of the State of Washington.

13. Counterparts. This Letter of Intent may be executed in several counterparts, each of which shall be deemed to be an original and all of which shall constitute one and the same instrument. The Parties acknowledge and agree that any document or signature delivered by PDF or other electronic transmission shall be deemed to be an original executed document for the purposes hereof, and such execution and delivery shall be considered valid, binding and effective for all purposes.

14. Effect of this Letter of Intent. This Letter of Intent is not an offer or a commitment on the part of [Utility] or EN or EN SPV or any other affiliate of any of them to enter into the Proposed Transaction. The Parties understand that except as expressly set forth in this Letter of Intent, specifically Sections 2, 5, 11 and 12 hereof, this Letter of Intent constitutes a non-binding statement of the Parties' respective intentions with respect to the Proposed Transaction, does not contain all matters upon which agreement would need to be reached in order for the Proposed Transaction to

be consummated, and therefore does not constitute a binding commitment or agreement with respect to the Proposed Transaction itself. Any transaction which might arise from discussions shall be contingent upon (i) negotiation and execution of the Definitive Agreements, which will contain customary provisions including those relating to indemnities, defaults, remedies for nonperformance, and credit support, and (ii) receipt of necessary or appropriate approvals, including, to the extent necessary or appropriate, those of the management and board of [Utility] and EN. No binding commitment shall arise prior to then even if the Parties reach some understanding(s) or agreement(s) in principle. The closing of such transaction shall be contingent upon receipt of all required governmental approvals and such other conditions precedent to closing as shall be set forth in the Definitive Agreements. Any actions taken by a Party in reliance on the non-binding terms expressed herein or on statements made during negotiations pursuant to this Letter of Intent shall be at that Party's own risk, and this Letter of Intent shall not be the basis for a contract by estoppel, implied contract or any other legal theory. Notwithstanding the foregoing, the Parties acknowledge and agree that Sections 2, 5, 11 and 12 of this Letter of Intent create, and are intended to create, binding legal and contractual obligations of the Parties.

If the foregoing is satisfactory to you and reflects your understanding with respect to the matters referred to in this Letter of Intent, please sign and date the enclosed copy of this Letter of Intent where indicated below and return such copy, as so signed and dated, to the undersigned on or before _____, 2024. If this Letter of Intent is not executed by EN and delivered to [Utility] on or prior to _____, 2024, it shall be null and void.

Very truly yours,

ENERGY NORTHWEST, INC.

By: _____
Name: Brian Cunnington
Title: Professional Services Manager

[UTILITY]

By: _____

Name:
Title:

Effective Date: _____, 2024

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 11/12/2024 Agenda Category: Items of Business

Prepared By: Clint Whitney, Energy Services Director

Subject:
Next Steps for Utilizing AMI Data (10 minutes)

Department:
Energy Services

Recommended Motion:
This item is informational only.

Summary:
The City's Advanced Metering Infrastructure (AMI) project is quickly nearing full implementation. Through October, there are 332 remaining electrical meters to be installed with 30,942 already installed for a 98.9% completion. There are 240 remaining water meters with 21,861 already installed water meters for a 98.9% completion. Approximately 275 of the remaining electrical meters are scheduled to be delivered to the City in December. Once received, they will be installed before the end of the year. The majority of the remaining water meters are being scheduled with customers as the existing water meters are installed in residential basement areas.

AMI features being used internally include: circuit tracing of a meter to the first upstream protective device, remote disconnects, customer move in and move out readings, troubleshooting, leak detection, and consistent billing intervals.

Next steps include:

- November 2024 - Harris Advance Customer Information System (CIS), used for billing purposes, is in the process of being upgraded from version 3 to 4. This is a significant modernizing that will enable other systems to be integrated and workflow improvements.
- November 2024 - MyMeter is being implemented with the CIS version 4 upgrade. MyMeter will provide a customer access portal for utility bills, AMI load profile data, and a pre-pay feature.
- December 2024 - Futura Outage Management System (OMS).
- Itron Gen5 Riva meter option for short haul power line carrier (PLC) communications instead of radio frequency (RF) communications. Riva adds the latest hardware processing capabilities with Itron's Gen5 system implemented in the City.

Fiscal Impact:
There is no fiscal impact.

Attachments:

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 11/12/2024 Agenda Category: Items of Business

Prepared By: Clint Whitney, Energy Services Director

Subject:
Energy Northwest Agreement with Amazon for Partial Small Modular Reactor Funding (10 minutes)

Department:
Energy Services

Recommended Motion:
This item is informational only.

Summary:
On October 16, 2024, Amazon announced an agreement with Energy Northwest (ENW), X-Energy, and Dominion Energy for funding for a Small Modular Reactor (SMR) at previous ENW Site 1. The $500M investment by Amazon will provide two years of engineering, permitting, licensing and the construction permit to the Nuclear Regulatory Commission (NRC) for four X-Energy's Xe-100 SMR units. The funding should be enough to cover the 20% self-funding required of Department of Energy's (DOE) Loan Program Office (LPO) application to access DOE's remaining 80% loan funding. The licensing will be for the entire twelve reactor units. Amazon will receive 320MW of generation from the four 80MW units. ENW will build, own and operate the SMR units. The 640MW generation from the remaining eight 80MW units, if built, would be available to Public Power, Puget Sound Energy (PSE) and/or Amazon. The Xe-100 design is a fourth generation SMR.

Dominion Energy was included in the announcement as they are also looking at an X-Energy project to be constructed in Virginia.

Cost of power from the X-Energy project at Site 1 could be $150/MW with more accurate costs as project estimates are refined. Attached is a project summary pathway for major milestones and events.

A few media links for additional information are:
Apple Valley News: http://my.tvey.es/Nr49X
Northwest News Radio: http://my.tvey.es/Ro6g2

The announcement was very exciting for the nuclear industry and ENW. However, it's the SMR project next steps that will provide many opportunities for the communities, local work force, and manufacturing industries. The City is well positioned to be supportive of the project's success with a supportive community, industrial land, and proximity to the advanced nuclear renaissance.

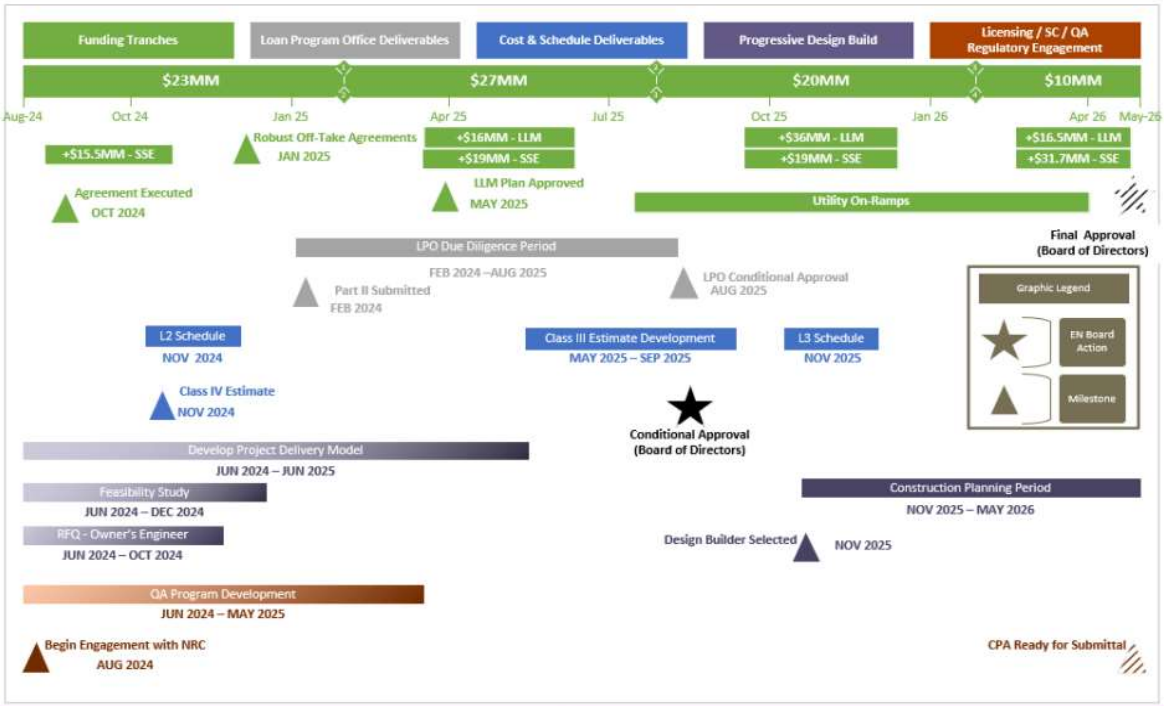
Other nuclear news includes an announcement in September that Microsoft would be funding a $1.5B restart of Three Mile Island Unit #1 through Constellation Energy. In October, Google announced a partnership with Kairos for a 500MW SMR project using TRISO fuel similar to X-energy but with liquid sodium heat transfer instead of helium.

Fiscal Impact:
There is no fiscal impact.

Attachments:
1. SMR Pathway

ENERGY NORTHWEST

Pathway to Project Approval



UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 11/12/2024 Agenda Category: Other Informational Items

Prepared By: Clint Whitney, Energy Services Director

Subject:
Bonneville Power Administration Provider of Choice - Post 2028 Contract Schedule and Comparison

Department:
Energy Services

Recommended Motion:
This item is informational only.

Summary:
Bonneville Power Administration (BPA) continues to make progress with the post 2028 power contract development for public power utilities. The City's existing Regional Dialog (RD) power contract with BPA expires September 30, 2027. The post 2028 replacement power contract is referred to as the Provider of Choice (PoC) with a similar structure to the existing Regional Dialog contract.

Attached is a PoC timeline with key upcoming dates including:

- November 2024 - Draft contract templates are available to the public and utilities
- April 2025 - End of draft comment contract templates
- June 2025 - Final contract templates released
- September 2025 - Final contracts offered to utilities
- December 31, 2025 - Executed Contract Deadline

Also attached is a comparison document between the existing Regional Dialog and the proposed Provider of Choice key contract areas. The proposed PoC will have Load Following, Block and Slice options. With limited non-federal generation options, many utilities have recently switched to Load Following. Staff's recommendation is to continue being a Load Following BPA customer. Tier 1 and Tier 2 will continue being part of the PoC with the Contract High Water Mark (CHWM) that establishes Tier 1 allotment calculated in the FY2026 process. The election period for Tier 2 served by BPA, non-federal or a combination, will need to be made at the contract load election and will be for the duration of the nineteen-year contract. With the City not having significant specified generation resources and limited non-federal generation resources meeting climate regulations, City Staff recommends relying on BPA for Tier 2 needs. New Large Single Loads (NLSL) are separate from Tier 1 and Tier 2 federal resource decisions.

Resource adequacy will have a different significance during PoC with BPA having a binding obligation after joining the Western Resource Adequacy Program (WRAP) compared to Regional Dialog.

City Staff will continue to input on the draft template process through energy trade organizations and BPA's public process. Additional information on more refined contract templates will be presented to UAC at the 1Q25 and 2Q25 meetings.

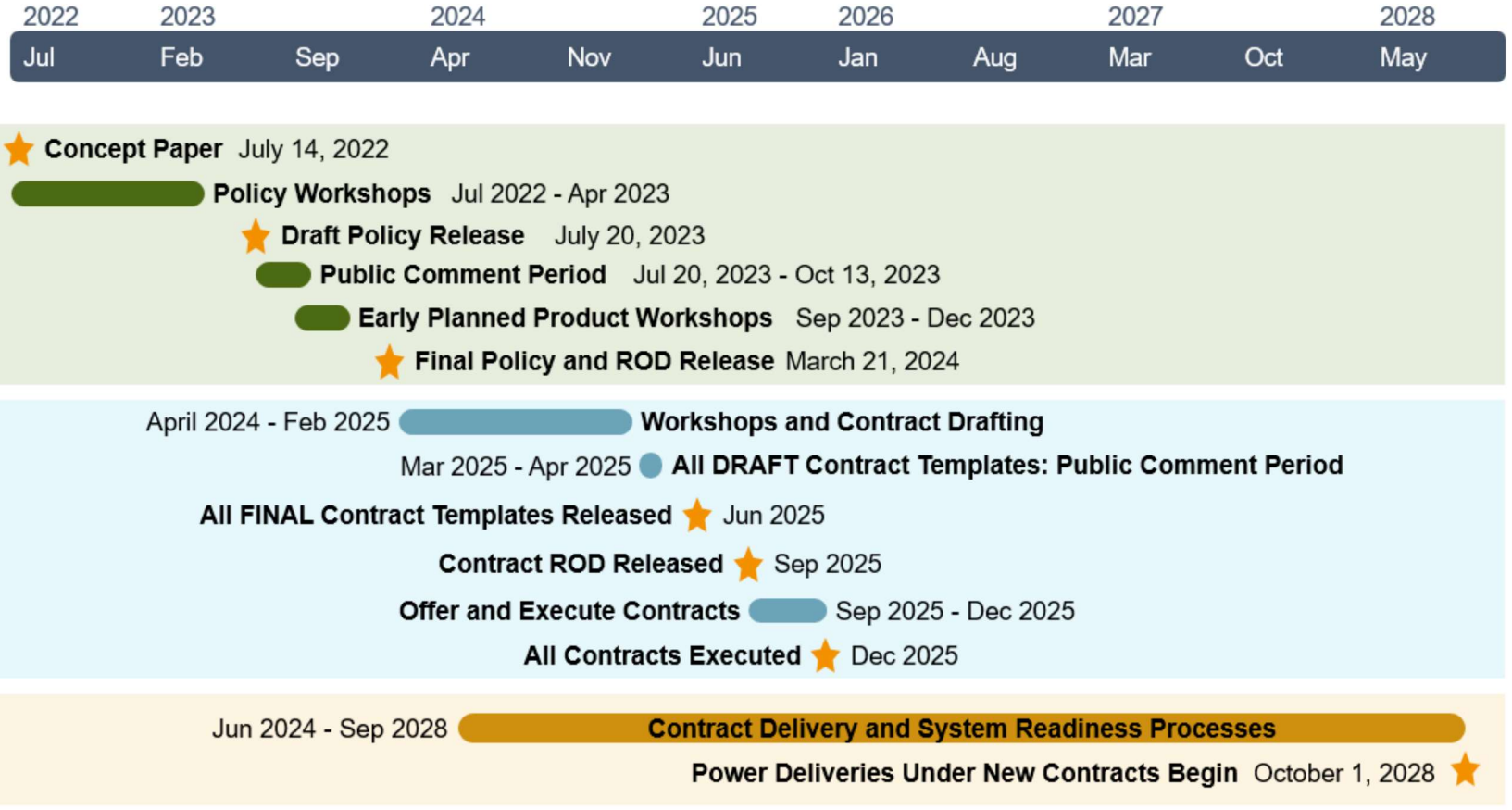
Fiscal Impact:
There is no fiscal impact.

Attachments:
1. provider-of-choice-timeline-graphic
2. poc-comparison-to-regional-dialogue-20241031

BONNEVILLE POWER ADMINISTRATION

Provider of Choice Timeline

Last Updated 12/12/2023



B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

Detailed Contract Phase Timeline

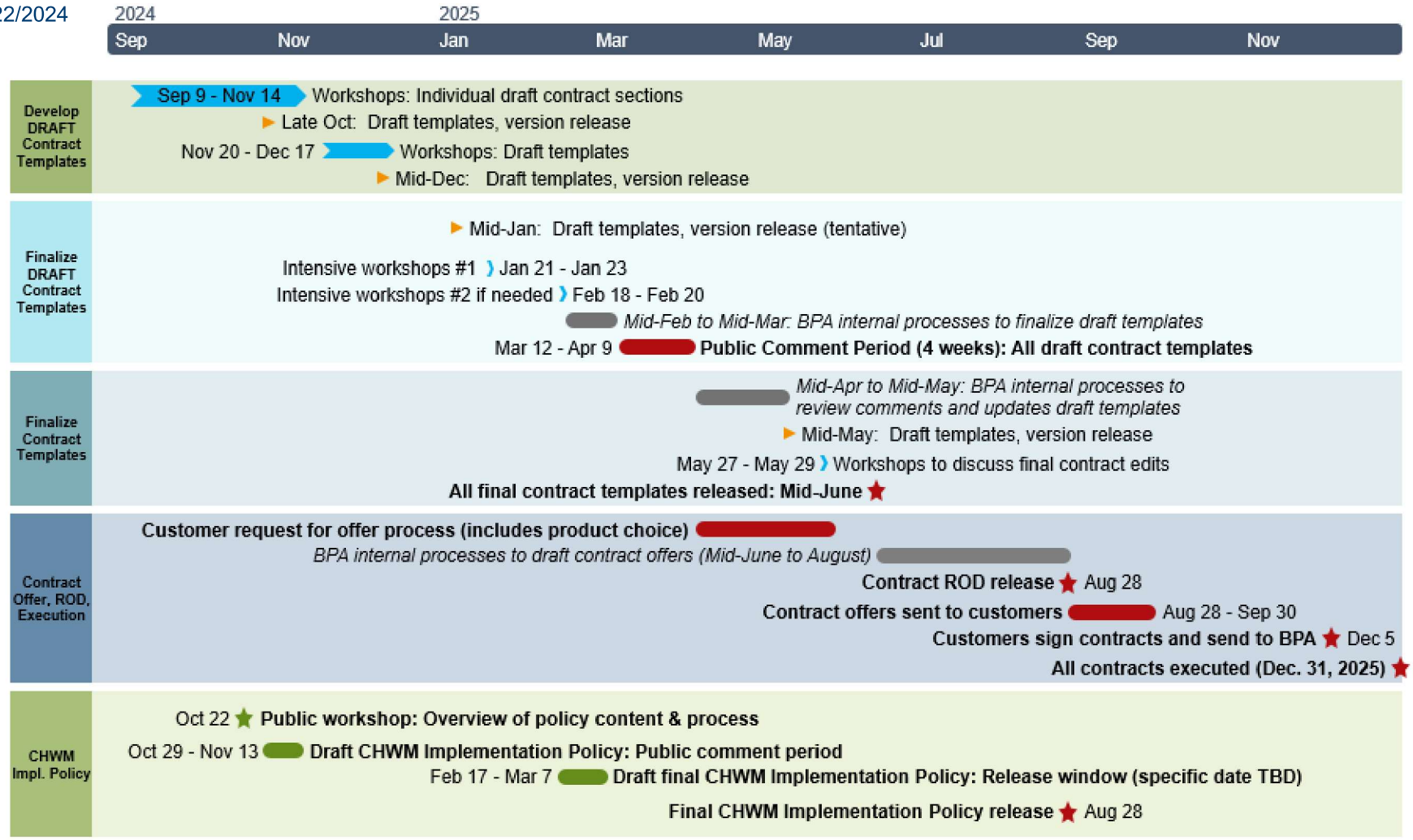
Last Updated 4/9/2024

	2024 Mar	May	Jul	Sep	Nov	2025 Jan	Mar	May	Jul	Sep	Nov
Policy Implement. & Contract Dev.	Apr 2024 - Jun 2024 **Phase 1 Workshops: Discuss and finalize policy implementation details**										
	Apr 2024 - Oct 2024 **Phase 2 Workshops: Draft and negotiate contract provisions for LF, Block, Slice, NR Block contract templates**										
	Nov 2024 - Feb 2025 **Phase 3 Workshops: Finalize all full DRAFT contract templates**										
Contract Templates Finalization & ROD	**All DRAFT contract templates: Release** ★ Mar 2025										
	All DRAFT contract templates: Public comment period Mar 2025 - Apr 2025										
	All DRAFT contract templates: Release updates ★ May 2025										
	Intensive workshops to finalize all draft contract templates May 2025 - Jun 2025										
	All FINAL contract templates: Release ★ Jun 2025										
	Contract ROD: Release ★ Sep 2025										
Contract Offer and Execution	**BPA prepare individual contract offers** Jun 2025 - Sep 2025										
	BPA send all contract offers Sep 2025 - Sep 2025										
	All contracts executed Dec 31, 2025 ★										

B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

Updated Detailed Timeline Through Dec. 31, 2025

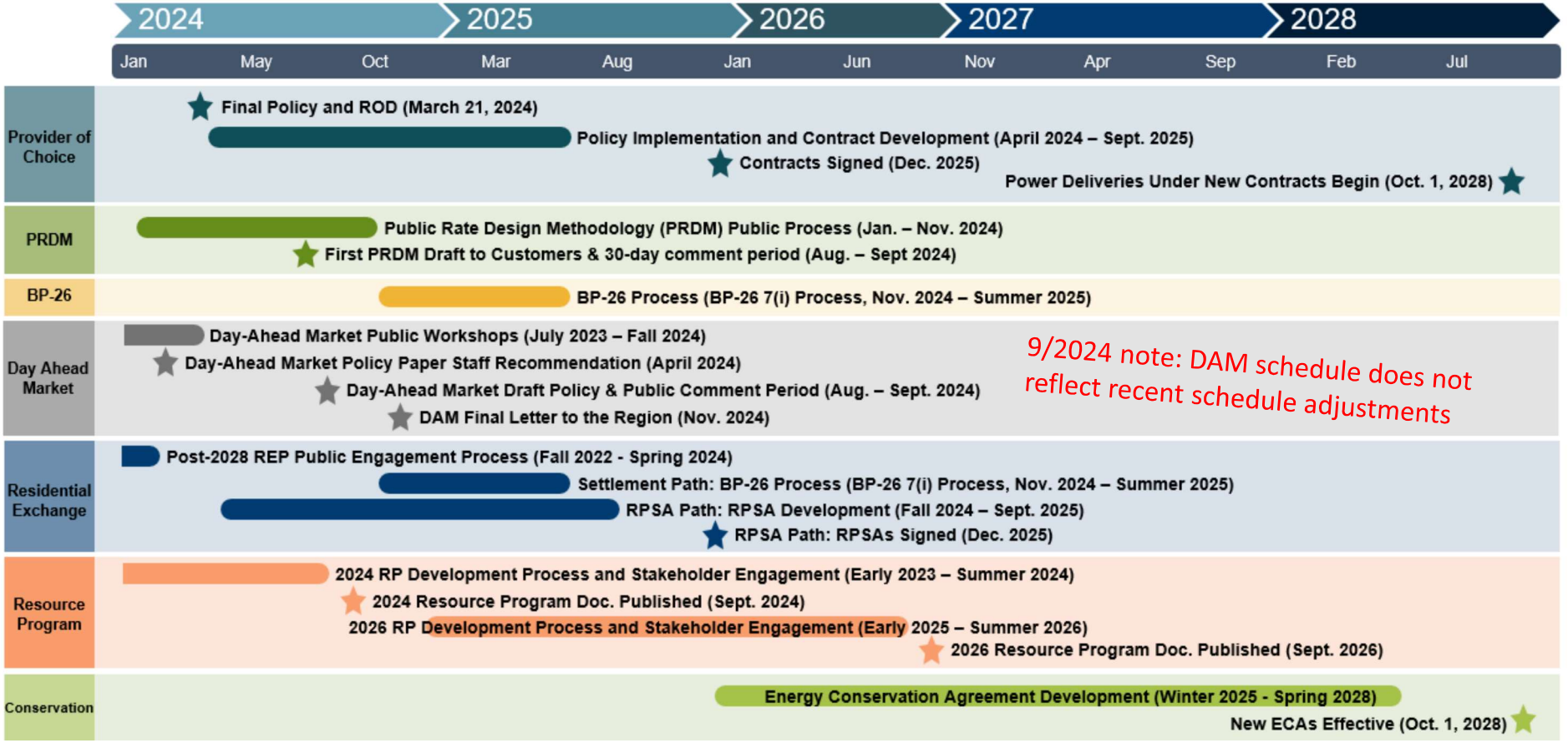
Last Updated 10/22/2024



BONNEVILLE POWER ADMINISTRATION

Post-2028 and Other Related Processes

Last Updated 6/7/2024



Provider of Choice Comparison to Regional Dialogue

Companion to Draft Contract Templates Release, October 31, 2024 Version

Purpose: This document is intended to support review of the October 31, 2024 Provider of Choice draft contract language and draft contract templates. All draft Provider of Choice (POC) contract language is subject to ongoing review and revision given ongoing negotiations between the parties (BPA and its customers). Prior to finalizing the POC contract templates, BPA will publish complete contract templates for public review and comment. The descriptions in this document are for informational purposes only, are not intended to be comprehensive, and do not reflect every change made between the RD and POC contracts. This comparison is neither an interpretation of, nor a substitute for executed contract language. Parties are responsible for reviewing all contract language prior to executing a POC contract.

Regional Dialogue Section	Provider of Choice Section	Regional Dialogue (RD)	Provider of Choice (POC)
1. Term	1. Term	Twenty-year contracts with 17 years of power deliveries. Expires September 30, 2028.	Nineteen-year contracts with 16 years of power deliveries. Expires September 30, 2044.
2. Definitions	2. Definitions	Definitions reflect tiered rate construct with CHWMs. Certain definitions bolded that were aligned with, and updated pursuant to, the TRM.	Definitions updated to reflect POC product design and rates. Definitions are being developed in concert with PRDM development. See separate POC Contract Definitions Edit Tracker for detail.
3. Product Purchase Obligation	3. Product Purchase Obligation	Established Load Following, Block and Slice/Block offerings. Regional Dialogue is a "Take Or Pay" contract, obligating customers to pay for the amount of Firm Requirements Power it is committed to purchase, whether or not customers took actual delivery of such power. Much of section 3 discussed the application, shaping of, and rules applied to Dedicated Resources.	Remains Take or Pay; change from Unspecified Resources to Committed Power Purchase Amounts; increases the power threshold from 200 kW under RD to 1 MW of resources that need to be listed in the contract; addition of Tier 1 Allowance Amount.
4. Block Product (or "Intentionally Left Blank" in LF and Block)	4. Block Product (or "Intentionally Left Blank" in LF and Block)	Described the Block Product for Slice/Block customers, including Tier 1 and, if applicable, Tier 2 Block Amounts. Described allowable Block amount shapes.	Describes the Block Product for Slice/Block customers, including Tier 1 and, if applicable, Tier 2 Block Amounts. Describes allowable Block amount shapes. Includes a draft rewrite to section 4.5 to simplify language regarding Diurnal Flattening Service for Specified Renewable Resources.
5. Slice Product (or "Intentionally Left Blank" in LF and Block)	5. Slice Product (or "Intentionally Left Blank" in LF and Block)	Described the Slice Product for Slice/Block Customers. Initial Slice Percentage fixed for duration of Regional Dialogue with annual adjustment for changes to Tier 1 System Capability. Customer submitted Customer Inputs and scheduled Slice Output Energy for upcoming hour in real time using the Slice Computer Application (SCA).	Describes the Slice Product for Slice/Block Customers. BPA calculates Slice Percentage each Fiscal Year at fifty percent of Tier 1 Net Requirement. Annual CHWM System fixed at 7,250 aMW, eliminates annual adjustment to system capability. Customer submits Customer Inputs for each hour in the following day

Regional Dialogue Section	Provider of Choice Section	Regional Dialogue (RD)	Provider of Choice (POC)
		BPA performed Requirements Slice Output (RSO) test each month to measure Slice Output Energy a customer scheduled to serve TRL. Customer elected to participate in CGS Displacement or receive Replacement Energy. Established Slice Implementation Group (SIG) to ensure SCA accurately represented the capabilities and constraints on the Tier 1 System Resources.	using the SCA in the day ahead timeframe. Customer participates in CGS Displacement, eliminates election option for Replacement Energy. Further discussions on the RSO test and associated contract language will be scheduled for upcoming workshops.
6. Tiered Rate Methodology	6. Public Rate Design Methodology	Established the relationship between the contract and the TRM. The contract included recitations of TRM terms (including definitions of CHWM and RHWM and the formula for calculating RHWMs).	Establishes the relationship between the contract and the PRDM. The language has been updated to reflect that BPA will not be seeking FERC approval on the PRDM.
7. High Water Marks and Contract Demand Quantities	7. High Water Marks	CHWMs were calculated in accordance with the TRM. Stated how the CHWMs, RHWMs, and Contract Demand Quantities (CDQs) are calculated and where the numbers are reflected in the exhibits.	CHWMs will be calculated in the FY 2026 CHWM Calculation Process, reflected in Exhibit B, and can only be adjusted pursuant to the terms and conditions in Exhibit B.
8. Applicable Rates	8. Applicable Rates	Stated the rate schedules that apply to sales, including PF, NR, FPS and mentioned certain additional charges. Pointed to the GRSPs for specific billing determinants.	No longer specifically listing rates and applicable charges and instead points to the 7(i) Processes, the PRDM and GSRPs to capture *all* associated and listed rates in the relevant documents.
9. Elections to Purchase Power Priced at Tier 2 Rates	9. Elections to Purchase Power Priced at Tier 2 Rates	Customer elections for serving their Above-RHWM Load: 1) power purchased from BPA at Tier 2 rates; 2) non-federal resources (i.e. Dedicated Resources); or 3) a combination of both. Established notice deadlines and purchase periods.	Customer elections for serving their Above-CHWM Load: 1) power purchased from BPA at Tier 2 rates; 2) non-federal resources (i.e. Dedicated Resources); or 3) a combination of both. Customer will make its Above-CHWM Load election for the term of the Agreement (and eliminates the RD concept of notice deadlines and purchase periods).
10. Tier 2 Remarketing and Resource Removal	10. Tier 2 Remarketing and Resource Removal	Stated the rights and obligations relating to non-federal resource removal and Tier 2 remarketing.	Changes include: 1) requires that New Resources serving Above-CHWM Load be removed prior to Tier 2 purchase amounts; 2) if a temporary New Resource removal by a customer would impact its obligation to comply with a state or federal law, then customer may reduce its Tier 2 purchase obligation in addition to existing resource removal.
11. Right to Change Purchase Obligation	11. Right to Change Purchase Obligation	Customers had a one-time right to change their purchase obligation, or product. Per the terms of the Agreement, a customer could notify BPA by May 31, 2016, requesting to change its purchase obligation, which would be effective October 1, 2019. There were limitations, and the customer might be subject to charges for switching products.	Customers have a one-time right to request a change to their purchase obligation, or product. No single deadline will be set by which a customer has to request a product change; customer can submit a request to change products any time between October 1, 2028 and September 30, 2037, in accordance with

Regional Dialogue Section	Provider of Choice Section	Regional Dialogue (RD)	Provider of Choice (POC)
			limitations and charges outlined in the contract. BPA will consider the impact of a customer's product change request on the overall impact of BPA's WRAP QCC obligations.
12. Billing Credits and Residential Exchange	12. Billing Credits and Residential Exchange	This section provides for a total waiver for Billing Credits and a partial waiver of participation in the Residential Exchange Program to protect customers from cost shifts associated with non-federal resources of other customers.	Continues the total waiver of Billing Credits and expands the waiver for the REP to a complete waiver.
13. Scheduling	13. Scheduling	Depending on each customer's circumstances, scheduling requirements can vary dramatically. The bulk of the scheduling terms and conditions reside in Exhibit F.	Few changes are proposed for this section. The scheduling provisions in the body of the contract primarily direct the reader to Exhibit F for the applicable scheduling terms and conditions.
14. Delivery	14. Delivery	Addresses transmission, transfer service, losses, and other issues related to the delivery of power. Establishes the points for the delivery of power. Addresses delivery issues specific to customers either served by Transfer Service or are both directly connected and have PODs served by Transfer Service; such issues include ancillary services and direct assignment of costs.	Some changes: 1) adding a section to address terms and conditions if firm transmission is unavailable; 2) revises "Proportional Scheduling" as it relates to the process and costs associated with a Transfer customer served over multiple transmission systems adding a non-federal resource to serve their load; 3) directly assigns to the customer any transfer service costs incurred for power sold at the NR rate; and 4) revises BPA's commitment to acquire and pay for Transfer Service to all Dedicated Resources serving transfer load and Consumer-Owned Resources serving transfer On-Site Consumer Load.
15. Metering	15. Metering	This section primarily addresses a customer's metering equipment requirements. The meter data requirements are primarily found in section 17 and Exhibit E. Exhibit E establishes the parties' rights and obligations for meters including, but not limited to, operating, maintaining, replacing, testing, providing access to, and paying for meters.	Updates to this section reflect current practices, eliminate redundancy with requirements in section17, and provide more consistency in language between the Load Following version and Slice/Block and Block versions. Since the start of RD, BPA's Transmission Services (BPAT) executed Network Operating Agreements (NOA) with its NT customers, which include language regarding the ownership, operation, maintenance and financial responsibilities for meters. The POC contract is adding language referring to the NOA, BPA's Metering Application Requirements, other BPAT agreements, and BPA's metering website.
16. Billing and Payment	16. Billing and Payment	All electricity, products, and services sold and purchased under the contract is billed in accordance with this section. This section addresses payment options, late payments and the process for disputed bills.	Updates and adds payment language specifically for federal agencies, and clarifies the timing and process for failure to pay.

Regional Dialogue Section	Provider of Choice Section	Regional Dialogue (RD)	Provider of Choice (POC)
17. Information Exchange and Confidentiality	17. Information Exchange and Confidentiality	Performance of the contract requires the parties to share a lot of information with each other. While detailed requirements of data provision are included throughout the contact, this section describes general requirements of information exchange and addresses the customer's right to, and process required for, confidentiality for information provided to BPA.	Includes language that customers will provide meter data, historic load data, load and resource data related to NLSLs, resource information, battery and storage facility information (energy storage devices), information necessary for QCC calculation, and other information necessary to administer the contracts. Also, see sections 18 and 19 below for elements pulled from those sections under RD and included in section 17 for POC.
18. Conservation and Renewables	See 17.2.4 under Information Exchange and Confidentiality	Customers agree to cooperate with BPA in any evaluation of conservation programs; provide a 10-year conservation plan to BPA; and report any non-BPA funded conservation measures. The renewables section requires the customer to provide information regarding their renewable resource and REC acquisition plans and provide BPA with copies of any integrated resource plans or forecasts. BPA has routinely waived the customers' reporting requirements under section 18.	Section 18 was removed in Provider of Choice. However, BPA is retaining its ability to request customers' long-term integrated resource plans; BPA is including that element into a new section 17.2.4 in Information Exchange and Confidentiality.
19. Resource Adequacy	See 17.2.3 under Information Exchange and Confidentiality	Requires certain customers to send forecasted loads and resources data to Pacific Northwest Utilities Conference Committee (PNUCC) annually, and potentially to the Northwest Power and Conservation Council (Council) in order to facilitate PNUCC's region-wide assessment of loads and resources.	Since joining WRAP, resource adequacy will have different significance during POC than it did during RD. BPA is moving RD section 19 Resource Adequacy provisions into the POC Information Exchange and Confidentiality as a new section 17.2.3. The POC contract will additionally include language stating that a customer may require PNUCC or Council to execute a non-disclosure prior to providing those third parties with the requested load and resource data.
20. Notices and Contact Information	Exhibit I, Notices and Contact Information	Most information that is sent between BPA and the customer does not need proof that the information was received. This provision provides for the few circumstances where obtaining proof of receipt is a requirement of the contract. The section also includes the contact information for each party's primary point of contact.	See POC Exhibit I description below.
21. Uncontrollable Forces	18. Uncontrollable Forces	Includes a definition of uncontrollable force and includes examples of events that would and would not constitute an uncontrollable force. Establishes the obligations on both Parties if they experience an uncontrollable force.	Epidemics, pandemics and terrorist acts are being added to the list of examples of an uncontrollable force. The requirement to notify the other party "immediately" of an uncontrollable force was adjusted to a requirement that one party "promptly" notify the other party of an uncontrollable force.

Regional Dialogue Section	Provider of Choice Section	Regional Dialogue (RD)	Provider of Choice (POC)
22. Governing Law and Dispute Resolution	19. Governing Law and Dispute Resolution	Establishes the mechanisms for resolving disputes that arise under the contract and states that the contract is governed by federal law. If a dispute arises, parties are required to make a good faith effort to resolve the dispute informally before initiating litigation or arbitration. Parties must continue operation of the contract while a dispute is pending.	No changes.
23. Statutory Provisions	20. Statutory Provisions	Section 23.1, Retail Rate Schedules: The Bonneville Project Act requires that customers who purchase requirements power from BPA provide a copy of their retail rate schedules. This provision allows customers to notify BPA if the information is already available on their website.	No changes.
		Section 23.2, Insufficiency and Allocations: If, after a reasonable period of experience, the Administrator determines he cannot acquire sufficient resources to meet his load obligations he may restrict his obligations during a period of insufficiency. The provision references BPA's insufficiency and allocations methodology.	Section 20.2, Insufficiency and Allocations: One edit compared to RD: a change from the term "federal power" to "electric power" which aligns with the NW Power Act.
		Section 23.3, New Large Single Loads and CF/CTs: This provision establishes the service to NLSLs and CF/CTs and points to Exhibit D where such types of load and their amounts are identified. It requires that the customer provide notice of loads that are likely to become NLSLs (Potential or Planned NLSLs).	Section 20.3, New Large Single Loads and CF/CTs: BPA is taking some language from Exhibit D and including it into section 20.3. Some of the language is being reorganized to improve flow and readability and add clarity to the language. Should a Load Following customer request BPA to supply firm power to serve a Planned NLSL or an NLSL, terms and conditions are included to allow BPA to perform a service study to assess its ability to meet such a request. The section also expands flexibilities for Consumer-Owned Resources serving an NLSL.
		Section 23.4, Priority of Pacific Northwest Customers: This provision incorporates by reference the 1964 Regional Preference Act and sections 9(c) and 9(d) of the Northwest Power Act affirming regional and public preference to Federal power generated in the Northwest consistent with BPA statutes.	Section 20.4, Priority of Northwest Customers: edit to change the term "federal power" to "electric power" which aligns with the NW Power Act.
		Section 23.5, Prohibition on Resale: This provision precludes the resale of Firm Requirements Power, which is defined as power provided under section 5(b) of the Northwest Power Act.	Section 20.5, Prohibition on Resale: No changes.

Regional Dialogue Section	Provider of Choice Section	Regional Dialogue (RD)	Provider of Choice (POC)
		Section 23.6, Use of Regional Resources: This provision helps ensure BPA's 9(c) Policy is enforceable. It requires a customer to notify BPA before they export power from a Generating Resource or Contract Resource that has been used to serve firm consumer load, and allows BPA to decrement the customer's power purchases from BPA if they do not report an export out of region.	Section 20.6, Use of Regional Resources: This section includes edits to update terminology (i.e., Purchase Period changed to Rate Period), reflect current circumstances (PNCA expiring), and delete the definition of firm power. Additionally, BPA is adding a new subsection that states participation in a day ahead market will not be considered an "export outside the Region" if specific criteria are met.
		Section 23.7, BPA Appropriations Refinancing: The 1996 BPA Refinancing Act requires that BPA offer to include section 3201(i) of the Act in its contracts. By incorporating this provision, customers are held harmless from any congressional legislation to refinance BPA's debt during the term of the contract.	Section 20.7 adds the US Code reference in the citation of the BPA Refinancing Act.
24. Standard Provisions	21. Standard Provisions	Section 24.1, Amendments: Ensures that any amendment of the Agreement will be in writing (no verbal amendments) and agreed to by both parties, unless the contract specifically allows for a provision to be unilaterally amended.	Section 21.1, Amendments: No changes.
		Section 24.2, Entire Agreement and Order of Precedence: The Agreement, including documents incorporated by reference (such as the Northwest Power Act and the BPA Refinancing Act), constitute the entire agreement. If there is a conflict between something stated in the body of the Agreement and an exhibit, what is stated in the body prevails over the exhibit.	Section 21.2, Entire Agreement and Order of Precedence: No changes.
		Section 24.3, Assignment: Allows for the assignment of the contract and ensures that the contractual obligations would still be met after assignment. Outlines limitations under which BPA could reasonably withhold its consent to an assignment. There were two versions of this clause because cooperative customers who obtained financing through the Rural Utility Service must have also obtained RUS approval before they could assign the contract to another entity.	Section 21.3, Assignment: Deleted a repetitive sentence.
		Section 24.4, No Third-Party Beneficiaries: The only legal beneficiaries under the RD contract are BPA and the customer. End-users do not have standing under the Agreement and are not beneficiaries.	Section 21.4, No Third-Party Beneficiaries: No changes.

Regional Dialogue Section	Provider of Choice Section	Regional Dialogue (RD)	Provider of Choice (POC)
		Section 24.5, Waivers: Waivers must be in writing and signed by the waiving party. Waivers are non-precedential and do not imply or cause a waiver of any other provision of the agreement than the one being waived.	Section 21.5, Waivers: No changes.
		Section 24.6, BPA Policies: References in the RD contract to BPA policies do not mean that the customer either agreed with those policies or waived its rights to challenge the legality of those policies.	Section 21.6, BPA Policies: No changes.
		Section 24,7, Rate Covenant and Payment Assurance: Requires the customer to set its rates high enough to make the payments required under the RD contract. The provision allows BPA to require payment assurance, such as a letter of credit, if it determines the customer may not be able to pay its bills.	Section 21.7, Rate Covenant and Payment Assurance: One section reference change from RD section 20, Notices and Contact Information to POC Exhibit I, Notices and Contact Information.
		Section 24.8, Bond Assurances: This provision was only included in RD contracts of cooperatives and tribal utilities. Under RD, BPA retained the right to adjust an impacted customer's CHWM if it annexed load resulted in exceeding the established 2.8% threshold.	Section 21.8, Bond Assurances: While this provision will still only be included in POC contracts of cooperatives and tribal utilities, BPA is developing a Load Following/Block version and a Slice/Block version. For POC, BPA is adding changes that would limit an applicable cooperative's Slice Percentage so that the Slice amount is equal to the threshold amount. This limit would be on top of the 50% Slice percentage limit in the Slice/Block product and would be an additional check done annually when Slice Percentages are calculated. With this approach, BPA's sale of the Slice/Block product should avoid a direct use of CGS above the de minimis threshold; however, BPA is including language that states BPA would pass through any remediation costs should unforeseeable circumstances occur that would cause remedial action.
N/A	22. Future Amendment for Day-Ahead Market	This provision was not in Regional Dialogue.	If BPA joins a day ahead market, BPA commits, with this new provision, to 1) conduct a public process to negotiate amendments to the POC contract necessary to facilitate participation in such market and 2) conduct a separate and subsequent public process on settlements for the Slice Product in a day ahead market.
25. Termination	23. Termination	For BPA's right to terminate, section 23 points to other sections of the contract that allow BPA the right to terminate if a customer fails to pay its bills or provide	Because BPA will not seek FERC approval of the PRDM, the section on the customer's right to terminate has not been included in POC.

Regional Dialogue Section	Provider of Choice Section	Regional Dialogue (RD)	Provider of Choice (POC)
		payment assurance. The customers' right to terminate was tied to FERC's approval of the Tiered Rate Methodology.	
26. Signatures	24. Signatures	During the term of Regional Dialogue, BPA adopted (optional) electronic signatures on its offered contract actions and changed its Signature clause. The provision states that the contract action is executed as of the last date that the bilateral contract action was signed.	No changes.
Exhibit A, Net Requirements and Resources	Exhibit A, Net Requirements and Resources	At a high level, a customer's Net Requirement, as the amount of power it may purchase from BPA, is its Total Retail Load minus its Dedicated Resources. The RD Exhibit A differs depending on a customer's purchase obligation (product), but it captures the elements of the customer's Net Requirement including non-federal resources. For planned product customers, Exhibit A includes forecast TRL and forecast Net Requirements.	BPA has added updates to this exhibit that would both increase efficiencies and reflect resource changes in other sections of the contract: 1) Unspecified Resources are being updated to reflect the change to "Committed Power Purchase Amounts"; 2) BPA is adding language on Tier 1 Allowance Amount (consistent with section 3.5.2); and 3) BPA is removing Small Non-Dispatchable Resources and Super Peak. A "Delivery Plan" (associated with section 14, Delivery) and "Applied Tier 1 Allowance Amount" data elements are being added to the Resource Profile sections within Exhibit A. BPA is also considering a more streamlined set of resource shaping options.
Exhibit B, High Water Marks and Contract Demand Quantities	Exhibit B, Contract High Water Marks	The RD Exhibit B states a customer's CHWM, the conditions under which a customer's CHWM could change, the customer's Contract Demand Quantity (CDQ) Amounts, and the conditions under which a customer's CDQ would be changed.	This exhibit will state a customer's CHWM and the conditions under which a customer's CHWM could change. Consistent with the POC Final Policy and ROD, BPA is updating the language specific to NLSL corrections and annexations. New sections are being added specific to the CF/CT adjustment and small utility adjustment, and updates are being made to the tribal utility section and US DOE Richland section. BPA is removing all mention of CDQs from the exhibit.
Exhibit C, Purchase Obligations	Exhibit C, Purchase Obligations	Establishes customer's Firm Requirements Power at Tier 1 Rates and Tier 2 Rates. The RD Exhibit C was different depending on a customer's purchase obligation (product).	This exhibit establishes a customer's Firm Requirements Power purchase amounts at Tier 1 Rates and Tier 2 Rates, and includes four Provider of Choice Above-CHWM Load election options along with a Tier 2 Vintage offering. A customer makes its Above-CHWM Load service election once for the term of the Agreement, though options for a one-time election change are provided. This exhibit also establishes Tier 1 Block options for the six Block product offerings that BPA has proposed and will include the calculation

Regional Dialogue Section	Provider of Choice Section	Regional Dialogue (RD)	Provider of Choice (POC)
			details of the Block portion of the Slice/ Block product, as applicable.
Exhibit D, Additional Products and Special Provisions	Exhibit D, Additional Products and Special Provisions	Commonly referred to as "unique and special issues", Exhibit D is home for unique or non-standard provisions that do not logically fit in other sections of the contract to address a customer's unique and/or special circumstances. Information on a customer's CF/CTs and NLSLs, if any, are contained in section 1 of Exhibit D. Over the term of RD, BPA added new options to section 1, including the option for Planned NLSLs. Section 2 of Exhibit D contains the Resources Support Services terms and conditions, if a customer purchased such. Section 3 covers Irrigation Rate Mitigation, again, if the customer receives the irrigation discount. Other provisions commonly found in Exhibit D, as applicable, include Grandfathered GMS, Limitations on Exchange of Existing Resources (related to Residential Exchange Program), WREGIS Subaccount language, and Baseline Delivery Percentages and Amounts (or Proportional Scheduling).	BPA will continue to utilize Exhibit D as the home for unique and non-standard provisions that do not logically fit in other sections of the contract. However, BPA has proposed to move the RSS provisions to the new Exhibit J. The 'Limitations on Exchange' provision does not apply under POC and will not be included. BPA has restructured 'Proportional Scheduling' in section 14, Delivery such that the Baseline Delivery Percentages language is no longer needed in Exhibit D. Also, BPA includes the WREGIS Subaccount provisions in Exhibit H, so those will no longer be contained in Exhibit D. Edits to section 1 of Exhibit D, NLSLs and CF/CTs, are intended to improve the flow, understandability and clarity of the NLSL language. Language is being added that will apply to Load Following customers requesting firm power from BPA to serve NLSLs.
Exhibit E, Metering	Exhibit E, Metering	Exhibit E, Metering, is found in all RD contracts, though there are two versions. One version is for Load Following customers and any Block or Slice/Block customer that does not operate their own balancing authority areas (BAA); this version includes considerable detail about customers' meters. The second version is for Block or Slice/Block customers that operate their own BAAs, with limited meter information captured in Exhibit E. Over the term of RD, BPA, for administrative efficiency purposes, introduced a table format for some customers' Exhibit E revisions.	BPA is including a table format for all customers' Exhibit Es. BPA is proposing that after the Parties have the opportunity to agree to proposed changes in a revision, BPA would have the unilateral right to revise the exhibit if the customer unreasonably delays or withholds their review and approval.
Exhibit F, Scheduling or Transmission Scheduling Service	Exhibit F, Scheduling or Transmission Scheduling Service	At a high level, Exhibit F is an operational exhibit outlining the parties' respective obligations regarding scheduling of BPA provided power and customers' non-federal resources. Certain customers are required and some customers could elect to purchase Transmission Scheduling Service; these customers received Exhibit F, Transmission Scheduling Service. This exhibit has been revised numerous times to provide additional services and options to customers, including Transmission Curtailment Management Service and TSS-Partial. Consequently, several versions exist.	BPA has not yet brought proposed Exhibit F language for POC to workshop. However, at a high level, BPA anticipates again having numerous versions of Exhibit F based on a customer's characteristics. Exhibit F will contain the parties' respective obligations regarding scheduling of BPA-provided power and customers' non-federal resources. BPA is seeking administrative efficiencies as it drafts Exhibit F language for POC.

Regional Dialogue Section	Provider of Choice Section	Regional Dialogue (RD)	Provider of Choice (POC)
Exhibit G, Principles of Non-Federal Transfer Service (or "Intentionally Left Blank")	Exhibit G, Terms Related to Transfer Service	Exhibit G was only included in transfer customers' contracts and was left blank for all directly connected customers. Section 14.6.7 of the RD contract states that BPA would offer a separate contract after the RD contracts were signed under which BPA would obtain transfer service for delivery of non-Federal resources to the customer. Exhibit G listed the principles which formed the basis for that stand-alone Agreement, which would become the Transfer Service Support for Non-Federal Resources Agreement (TSSA).	BPA is proposing to fold the terms and conditions of the TSSA and the related Reimbursement Agreement into Exhibit G of the POC contract for administrative efficiency.
Exhibit H, Renewable Energy Certificates and Carbon Attributes	Exhibit H, Renewable Energy Certificates and Environmental Attributes	Exhibit H provides the procedures for BPA's transfer of RECs to customers and established the principles for distributing (any future) Carbon Credits. Exhibit H was renegotiated and amended as part of the REP Settlement.	Governs BPA's transfer of RECs and Environmental Attributes consistent with the POC final Policy and commensurate with the physical amount of power purchased. Other changes include: BPA is proposing to not lock its Environmental Attribute allocation methodology down in the contract and, instead, would engage customers through a public process after the conclusion of each Rate Case and prior to a new Rate Period during POC to determine the details of the allocation for the upcoming Rate Period. BPA is also adding new language regarding a transfer of Emissions Allowances from customers to BPA, when BPA needs such Allowances to cover the customer's state compliance obligations. BPA is no longer offering to remarket RECs for customers.
Exhibit I, Critical Slice Amounts	N/A	Exhibit I section 1 states the Adjusted Annual RHWM Tier 1 System. Section 2 describe how BPA calculated Critical Slice amounts AART1SC * Slice % and stated the Customer's monthly Critical Slice Amount in aMW and MWH.	RD Exhibit I section 1 (AART1SC) has been deleted. RD Exhibit I, section 2 (Firm Slice Amount) has been moved to Exhibit K, section 3.
20. Notices and Contact Information	Exhibit I, Notices and Contact Information	See RD section 20 description above.	For administrative efficiencies, BPA moved the Notices and Contact information into an exhibit. One change, other than location, is that BPA will have the unilateral right to update the contact information upon notice of a change to a party's contact information. Additionally, POC will allow for a party, upon request, to have more than one contact person listed in Exhibit I.
Exhibit J, Preliminary	N/A	Preliminary Slice Percentage was the Slice percentage request by customer before adjustment for Unsold Slice	RD Exhibit J, Preliminary Slice Percentage and Initial Slice Percentage has been deleted.

Regional Dialogue Section	Provider of Choice Section	Regional Dialogue (RD)	Provider of Choice (POC)
Slice Percentage and Initial Slice Percentage		Amount and Maximum Additional Slice. Initial Slice Percentage is Preliminary Slice Percentage with Unsold Slice Amount and Maximum Additional Slice.	
N/A	Exhibit J, Additional Resource and Energy Storage Device Requirements	This provision was not in Regional Dialogue.	This new exhibit will be used to identify a customer's resource and energy storage device-related elections and requirements. There have been several new resource related elections/requirements developed during Regional Dialogue (Resource Support Services (RSS) and Transmission Curtailment Management Service (TCMS)) and being introduced under Provider of Choice (resource adequacy requirements and energy storage devices). Exhibit J will capture specific elections/ requirements, by resource, to better organize the resource related exhibit information for clarity, ease and administrative efficiency.
Exhibit K, Annual Determination of Slice Percentage	Exhibit K, Annual Slice Percentage and Firm Slice Amounts	Exhibit K includes the following items: Section 1.1 Definitions Section 1.2 Slice Percentage Adjustment Ratio: Adjusted Slice Customers' Initial Slice Percentage for changes in annual Tier 1 System Capability Section 1.3 Adjustments for Annual Net requirement less than AART1SC*ISP*SPAR Section 2: annual Slice Percentage	Exhibit K provides the following items, consolidates amounts that were in multiple Regional Dialogue exhibits: Section 1: Annual Slice Percentage: inputs and Slice Percentage calculated pursuant to section 5.3. Section 2: Annual CHWM: monthly amounts Section 3: Firm Slice Amount: monthly amount stated in aMW and MWH, calculated pursuant to section 5.4.
Exhibit L, RHWM Augmentation	N/A	Exhibit L states the RHWM Augmentation amounts established in each Rate Period. RHWM Augmentation was a component of the BOS Base Amount and provided to customers in the Flat Annual Shape.	Exhibit has been deleted. See below for description of Provider of Choice Exhibit L.
Exhibit M, Slice Computer Application	Exhibit L, Slice Computer Application	Established the Slice Computer Application that consisted of the Slice Water Routing Simulator, the Balance of System Module, the Default User Interface, and other related processes used for scheduling, tagging, and accounting of Slice Output and communication of information between BPA and Slice Customers.	Use of the SCA and its components to request Slice Output Energy will continue. BPA Simulator Parameters and Customer Inputs adjusted to align with the day-ahead submission deadline. Customer will submit a preliminary Simulated Operating Scenario ahead of Customer Inputs submission deadline. Adds provisions for constraints that cannot be modeled accurately in SCA. Adds procedures to request shielding of Simulated Operating Scenario constraint violations.
Exhibit N, Slice Implementation Procedures	Exhibit M,	Described Storage Offset Adjustment and Deviation Accounting in SCA. Provided procedures for Operating	Preserves procedures used in Regional Dialogue. Aligns SOA and Deviation Returns with day-ahead

Regional Dialogue Section	Provider of Choice Section	Regional Dialogue (RD)	Provider of Choice (POC)
	Slice Implementation Procedures	Constraint Violations and BOS Flex Validations. Described Grand Coulee Project Storage Bounds.	Slice Output Energy Request. Customer Input submission deadline included.
Exhibit O, Interim Slice Implementation Procedures	N/A	Exhibit O described the interim procedures that BPA and Slice Customers would use if the Slice Computer Application Implementation Date was established after 10/1/2011.	Exhibit has been deleted.
Exhibit P, Slice Computer Application Development Schedule	N/A	Exhibit P described the milestones and dates for development of the Slice Computer Application. Exhibit P dates were not binding. The binding SCA Implementation Date was provided in Section 5 in the body of the Agreement.	Exhibit has been deleted.
Exhibit Q, Determination of Initial Slice Percentage	N/A	Exhibit Q described the process that BPA used to establish Initial Slice Percentages. Regional Dialogue included a mechanism to increase a customer's Slice Percentage if the total Slice Percentage requested by all customers was less than the limit established by BPA.	Exhibit has been deleted.

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 11/12/2024 Agenda Category: Other Informational Items

Prepared By: Clint Whitney, Energy Services Director

Subject:
Bonneville Power Administration Quarterly Report - September 2024

Department:
Energy Services

Recommended Motion:
This item is informational only.

Summary:
Bonneville Power Administration (BPA) provides Tri-City electric utilities a quarterly update on significant transmission line projects BPA has planned in the region. Attached is the 3Q24 update of the BPA projects including:

- South Tri-Cities Reinforcement - New 500/115kV interconnection to the Tri-Cities 115kV transmission network.
- Richland-Stevens 115kV Line - Rebuild an existing 115kV line and add another 115kV line from Richland Sub to Stevens Sub.
- McNary Paterson Tap - A new 115kV line in the Paterson/Plymouth, WA area.
- Red Mountain-Horn Rapids 115kV Line - Rebuilding an existing 115kV line in West Richland, WA area

Completion of the four projects will relieve transmission constraints and add additional transmission capacity to the Tri-Cities 115kV network. The most significant project is the South Tri-Cities Reinforcement, followed by the Richland-Stevens 115kV line. The last of the projects is planned to be completed by winter 2027. However, BPA notes there are continued risks to the projects in the supply chain and labor markets.

The only changes from 1Q24 to the latest 3Q24 update are changes to the McNary-Patterson Tap completion, shifting from 4Q24 to 1Q25. There is no impact to the City of Richland with the McNary-Paterson tap project.

Fiscal Impact:
There is no fiscal impact.

Attachments:
1. BPA_STriCities Report Q3 2024

BONNEVILLE POWER ADMINISTRATION

PROJECT STATUS UPDATE | September 2024 Q3 (FY2024)

TRI-CITIES AREA REINFORCEMENT

BACKGROUND| Tri-Cities Area Reinforcement is a key part of Bonneville's greater strategic goal of delivering projects on-schedule and on-budget while minimizing planned outages. Bonneville is accomplishing this by improving project scoping, planning, contracting and project management processes to ensure efficient execution of our capital programs and maintenance activities.

THE PROJECTS | BPA is proceeding with four large projects in the Tri-Cities region. The primary goal of this work is to improve reliability and system flexibility. These projects have the added benefits of increasing BPA transmission capacity into the area, improving security, and modernizing BPA's substations and lines.

The ***South of Tri-Cities Reinforcement*** adds a new 500 kV substation, Webber Canyon, and a 115kV line to our existing Badger Canyon substation. This ties the Tri-Cities region into the 500kV Grid. This project provides both short term operational and maintenance needs, long term reliability and additional load growth capacity to the Tri-Cities region.

The ***McNary-Paterson Tap*** is a new 115 kV line from McNary Substation to south Benton County. This project resolves low-voltage issues in Paterson Load area and provides some through flow relief.

Both the ***Red Mountain-Horn Rapids*** and ***Richland-Stevens Drive 115 kV lines projects*** will provide reinforcement. Under peak conditions, one line out could cause the other to overload. All four projects together will allow for additional load and mitigate bottlenecks in the Richland area.

BPA is committed to the continued outreach to our customers, constituents, and the public. We are working with local electric utilities in coordinating efforts and public outreach specific to these projects.

Please note: *Next quarter bulleted items & project schedules are estimates. They are subject to change due to potential issues such as site conditions, supply chain issues, or staffing resources.*

Project Name	Estimated Project Cost	Proposed Energization
South Tri-Cities Reinforcement	$107M	Winter 2027
McNary-Paterson Tap	$15M	Spring 2025
Red Mountain-Horn Rapids 115 kV Line	$3.6M	Summer 2025
Richland-Stevens Drive 115 kV Line	$12.5M	Spring 2027

BONNEVILLE POWER ADMINISTRATION

PROJECT STATUS UPDATE | September 2024 Q3 (FY2024)

TRI-CITIES AREA REINFORCEMENT

ACTIONS IN THE LAST QUARTER & NEXT QUARTER

South of Tri-Cities Reinforcement

- Last Quarter
  - ✓ Continued design with our consultant.
  - ✓ Ongoing outreach with landowners on existing Right-Of-Way
  - ✓ Real Property service contract is in place.
  - ✓ Transformer manufacturer drawings received.
  - ✓ NEPA field surveys in progress.
  - ✓ Draft EA undergoing internal review.

- Next Quarter
  - ✓ Ongoing coordination substation land acquisition with DNR.
  - ✓ Continuing design
  - ✓ Continuing Environmental and Cultural surveys.
  - ✓ Yakama Nation is conducting the Traditional Cultural Property Study of the project area.
  - ✓ Continuing community outreach
  - ✓ Continue route alternative evaluation.
  - ✓ Review & finalize project construction sequencing plan.
  - ✓ Send draft EA for BLM review.

McNary-Paterson Tap

- Last Quarter
  - ✓ Kicked off Transmission line construction phase

- Next Quarter
  - ✓ Transmission line construction in progress.
  - ✓ Substantial completion set for March 2025.

Red Mountain-Horn Rapids 115kV line

- Last Quarter
  - ✓ Design resubmittal complete.
  - ✓ Continue to work on Land Acquisitions

- Next Quarter
  - ✓ PM is working on construction planning.
  - ✓ Construction brought back in house.

Richland-Stevens Drive 115kV line

- Last Quarter
  - ✓ Ongoing design with consultant.
  - ✓ Continued coordination with the City of Richland and the Richland School District.

- Next Quarter
  - ✓ Finalize the Transportation Plan.
  - ✓ Finalize the construction agreement with the City of Richland
  - ✓ Finalize project construction sequencing plan with City of Richland.
  - ✓ Finalize the construction plans and package.

Risks:

- ✓ Outage restrictions: outages needed for the program will be challenging to plan, the team is coordinating to produce an overall plan to highlight and mitigate issues.
- ✓ Due to unforeseen issues an alternative design for South TriCities fiber may be required. Team is working on minimizing impacts to schedule.
- ✓ Land acquisition: potential legal, regulatory, and environmental risks might impact the timing for obtaining the land and the right of way for the projects.
- ✓ Supply chain: continuous disruption in the flow of services and supplies represents a big challenge to the delivery of this program.

BONNEVILLE POWER ADMINISTRATION

PROJECT STATUS UPDATE | September 2024 Q3 (FY2024)

TRI-CITIES AREA REINFORCEMENT

CONTACT

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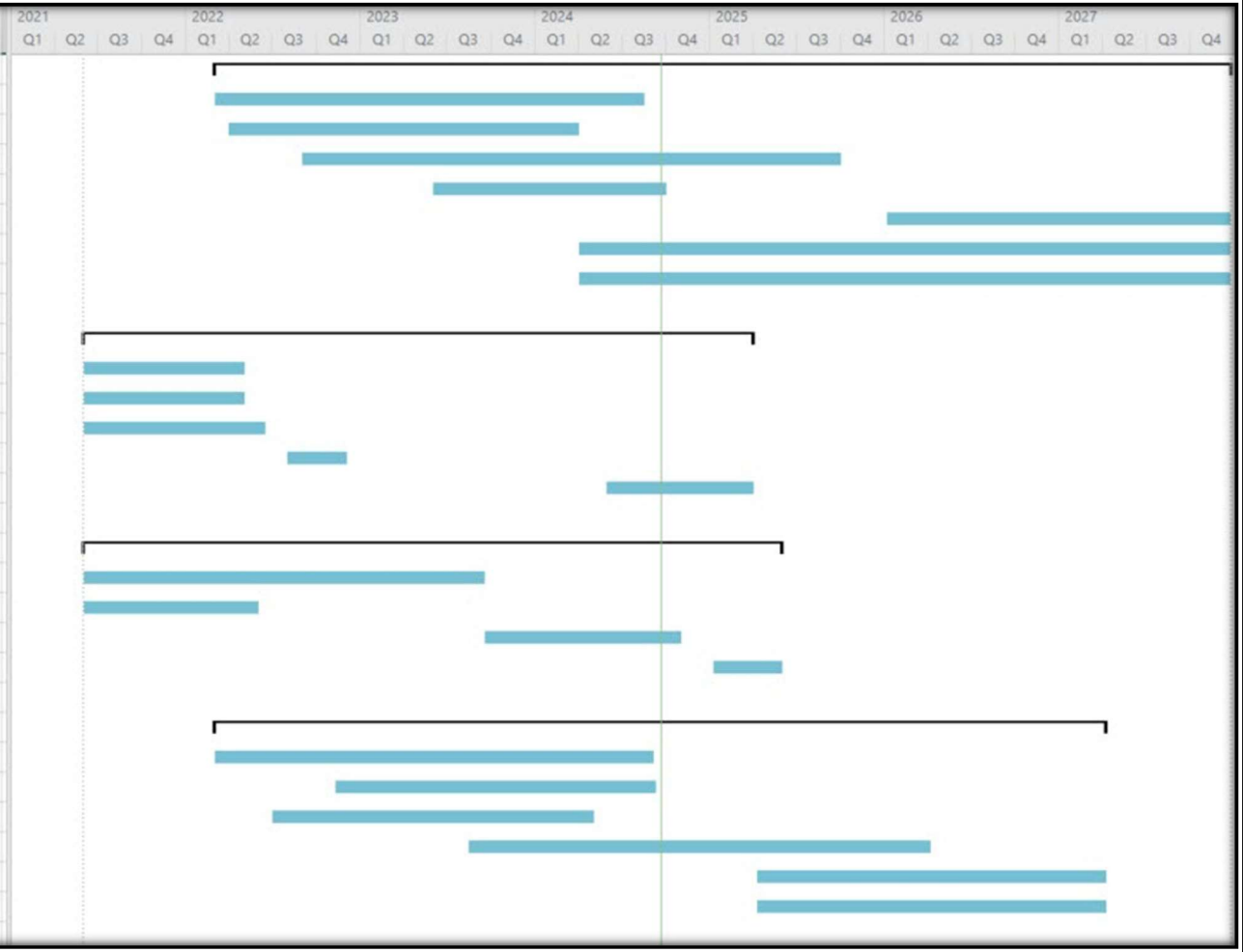
BONNEVILLE POWER ADMINISTRATION

PROJECT STATUS UPDATE | September 2024 Q3 (FY2024)

TRI-CITIES AREA REINFORCEMENT

Task Name	Start	Finish
South of Tri-Cities Reinforcement	**Tue 3/1/22**	**Fri 12/24/27**
EPC Design	Tue 3/1/22	Thu 8/15/24
Environmental Review	Thu 3/31/22	Mon 4/1/24
Material Production and Delivery	Thu 9/1/22	Tue 9/30/25
Land Acquisition (Fee and ROW)	Thu 6/1/23	Mon 9/30/24
Substation Construction	Mon 1/5/26	Fri 12/24/27
New Transmission Line Construction	Mon 4/1/24	Fri 12/24/27
Fiber Construction	Mon 4/1/24	Fri 12/24/27
McNary-Patterson Tap	**Tue 6/1/21**	**Mon 3/31/25**
EPC Design	Tue 6/1/21	Mon 5/2/22
Environmental Review	Tue 6/1/21	Mon 5/2/22
ROW Acquisition	Tue 6/1/21	Wed 6/15/22
Material Acquisition	Mon 8/1/22	Thu 12/1/22
Construction	Tue 5/28/24	Mon 3/31/25
Red Mountain-Horn Rapids 115kV Line	**Tue 6/1/21**	**Fri 5/30/25**
Design	Tue 6/1/21	Fri 9/15/23
Environmental Review	Tue 6/1/21	Mon 5/30/22
Material Acquisition	Mon 9/18/23	Wed 10/30/24
Line Construction	Mon 1/6/25	Fri 5/30/25
Richland-Stevens Drive 115kV Line	**Tue 3/1/22**	**Wed 4/7/27**
EPC Design	Tue 3/1/22	Mon 9/2/24
Environmental Review	Wed 11/9/22	Mon 9/9/24
ROW Acquisition	Fri 7/1/22	Thu 5/2/24
Material Acquisition	Tue 8/15/23	Mon 4/6/26
Substation Construction	Wed 4/9/25	Wed 4/7/27
Line Construction	Wed 4/9/25	Wed 4/7/27

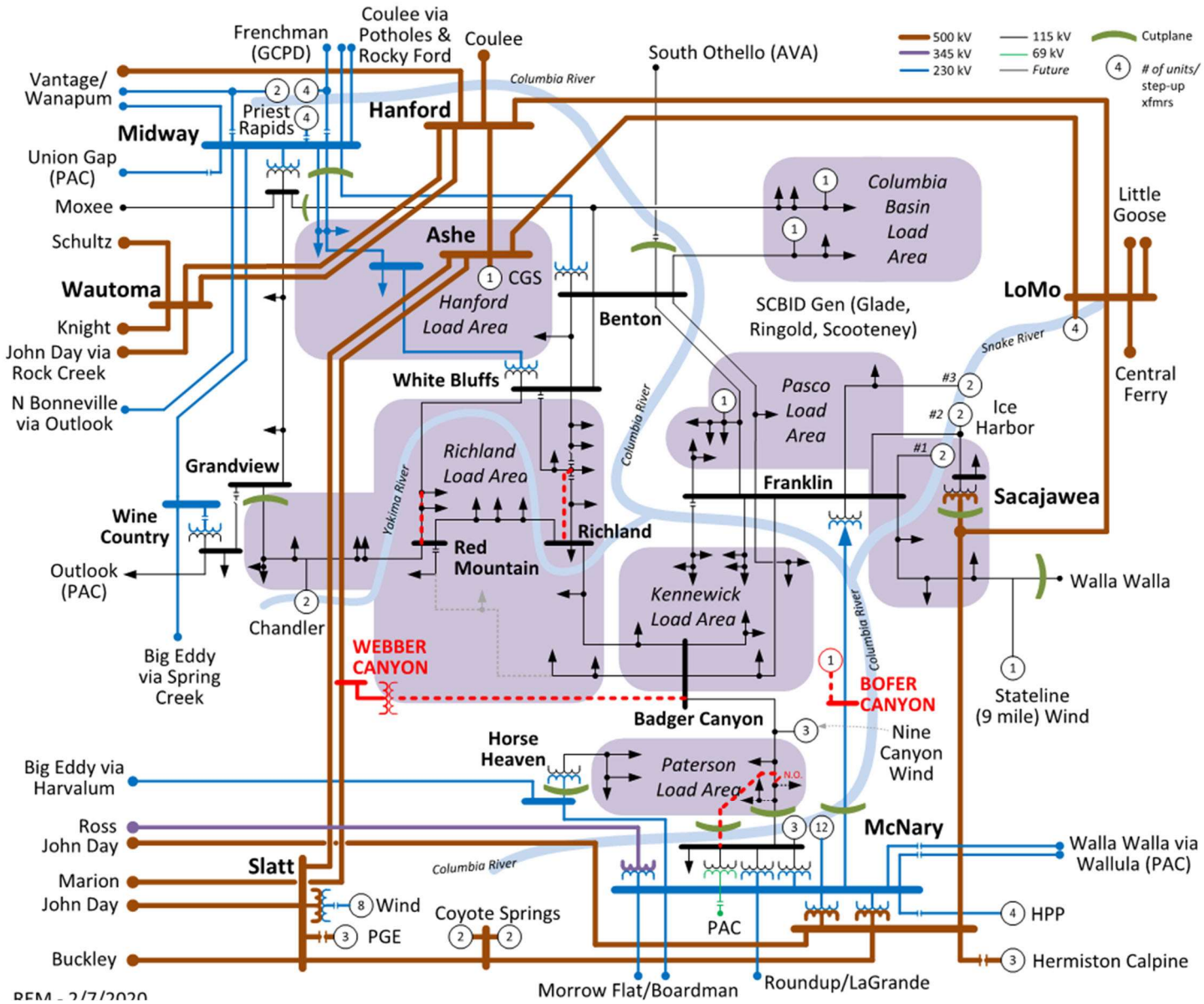


Pre-Decisional

BONNEVILLE POWER ADMINISTRATION

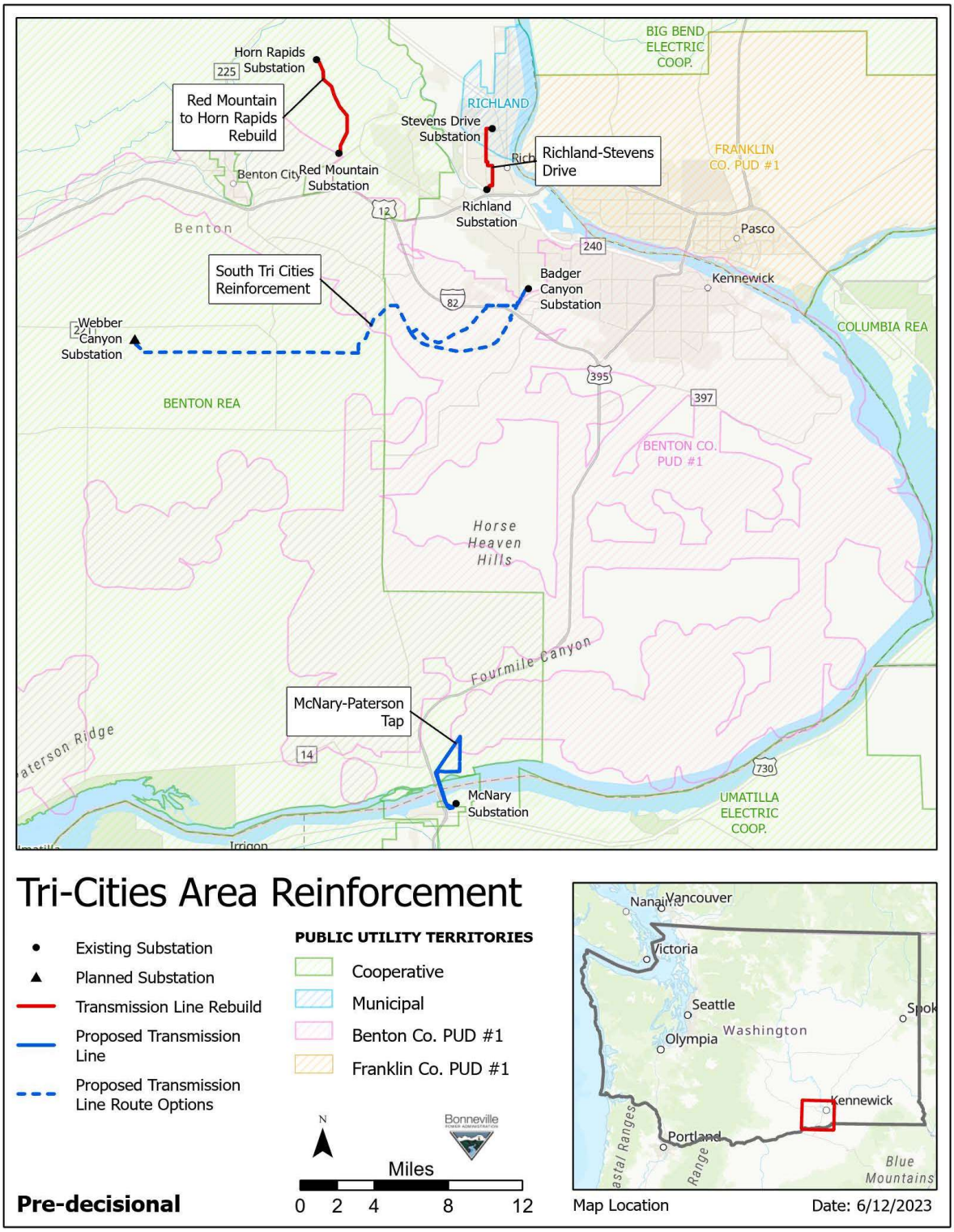
PROJECT STATUS UPDATE | September 2024 Q3 (FY2024)

TRI-CITIES AREA REINFORCEMENT



PROJECT STATUS UPDATE | September 2024 Q3 (FY2024)

TRI-CITIES AREA REINFORCEMENT



UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 11/12/2024 Agenda Category: Other Informational Items

Prepared By: Clint Whitney, Energy Services Director

Subject:
3Q24 Electric Utility Financial Statements

Department:
Energy Services

Recommended Motion:
This item is informational only.

Summary:
Attached are the 3Q24 Electric Utility Financial Statements. The financial for the City's Energy Services (RES) continues to be strong despite lower operating revenues and higher purchased power expenses in 2024 compared to 2023. The Days Cash on Hand is just over 165 days in 2024 compared to 2023. The increase in unrestricted and general purpose operating cash is attributed to Reserve Distribution Clause (RDC) credits from Bonneville Power Administration (BPA) that ended October 1, 2024 and revenues received from WA Department of Ecology's carbon allocation auction in September 2024. Low income electric utility customers also received a $200 billing account credit in August 2024 from a WA Department of Commerce Climate Commitment Act (CCA) grant. The CCA grant could lower the RES Accounts Receivable (A/R) balances compared to previous years.

In summary, the financial position of RES continues to look strong with no recommendations for a rate increase in 2024. BPA is forecasting an approximate 9% wholesale power increase and 20% wholesale transmission increase beginning October 1, 2025. It is possible, RES may recommend a bond issuance for continued capital work and/or a retail rate increase in 2025. RES has not had a retail rate increase since June 2019.

Fiscal Impact:
There is no fiscal impact.

Attachments:
1. 3Q24 RES - Electric Utility Financial Statements

CITY OF RICHLAND, WASHINGTON

Electric Utility Financial Statements

For the Quarter Ended
September 30, 2024

(Unaudited)

Prepared by:
Finance Department

Issued on:
October 31, 2024

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY FINANCIAL STATEMENTS
September 30, 2024

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CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY

Current Financial Developments

The following comments address events impacting the Electric utility's financial position. These comments clarify certain financial activity, including the environment in which the financial transactions occur.

1st Quarter

- BPA made its decision on the application of $285.4M excess revenues in the FFY2023 period resulting from secondary power sales. BPA's Administrator announced December 22, 2023 that Reserve Distribution Clause (RDC) credits will be credited on the City's wholesale power bills from December 2023-September 2024 for an estimated total credit of $3,358,204.
- The 2024 capital work plan for Energy Services is budgeted for $10.7M with major work including:
    - $1.6M – Renewal & Replacement of underground cable in the Duportail - bypass highway area
    - $1.9M – Renewal & replacement of underground cable in the Willow Brook area.
    - $5.0M – Stevens and Thayer Substation rebuilds.
    - $1.6M – Development line extensions and pole replacements.
    - $1.1M – Fusion Substation engineering and new residential services.

2nd Quarter

- RES worked with The Energy Authority (TEA) for a recommendation to auction 50% of excess carbon emission allowances to be auctioned through the WA Department of Ecology's 7th auction scheduled for September 2024. No-cost carbon allowances are received from Ecology as part of the State's Climate Commitment Act (CCA) and can be used to offset electric utility carbon emissions for generated energy. RES has a low carbon emission fuel mix with nearly 90% being carbon free generated from hydro and nuclear resources. The auction could generate revenues of $815k from 33,938 carbon allowances at an auction floor of $24.02 per allowance. If WA voter initiative I-2117 passes in November, it is expected to unwind the Clean Energy Transformation Act (CETA) and CCA requirements causing the value of carbon allowances to be worthless.

3rd Quarter

- The WA Department of Ecology's 7th carbon allocation auction, as a part of the State's CCA, settled on September 30, 2024. The auction settlement price was $29.88 per allowance with 33,938 allowances auctioned for $1,014,067. Ecology's 8th carbon allocation auction will take place in December after State voter initiative I-2117 is decided in November.
- The State Department of Commerce administered a Washington Families Clean Energy Credits grant for the City as part of funding from the CCA. The grant allowed electric utility bill credits of up to $200 per eligible residential household customer having less than 80% of the Benton County area mean income. The total grant award was $1,010,693 with the funds applied to customer's electric account before the initiative ended September 15, 2024.
- City staff and the Utility Advisory Committee (UAC) recommended the City's utility discount for low-income electric customers align with the State's definition of low income being less than 200% of the Federal poverty level (FPL) or less than 80% of the area mean income. The State low-income definition is codified in RCW 19.405.120 and WAC 194-40-030. Electric utilities are required to demonstrate progress in providing energy assistance and reducing

energy burden for low-income households. Staff's recommendation is for the electric utility discount program to be tiered with a 25% discount for 0-50% of FPL, 15% discount for 50-100% FPL, 10% discount for 100-150 FPL and 5% for 150-200% FPL or less than 80% area mean income.

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY

Current Business Developments

The following comments address events influencing the operations of the Electric utility. These comments provide additional information not specifically addressed or identified in the financial statement presentation.

1st Quarter

- The Federal government signed an agreement, on December 14, 2023, related to Columbia River System Operations (CRSO) litigation that stays further litigation. The agreement is expected to commit the Federal government to providing tribal developed generation resources as replacement resources for the Lower Snake River Dams (LSRD).
- The AMI project is 93.8% complete with the 30,900 total electric meter installations and 95.1% complete with the 21,900 total water meter installations. A new customer portal will be included in the MyMeter project replacing CIS eCare portal and is expected to be complete by the end of 2024. An internal and external customer facing outage map solution is still being evaluated.
- Washington State carbon regulations and electrification efforts continue to cause higher demand and lower availability of energy generation resource options. The 2024-2028 non-Federal forward power costs are approximately $80-$90/MWh. The current BPA Tier 2 costs are approximately $40-$60/MWh. Beginning October 2023 and through 2028, Energy Services has selected BPA to provide the energy above Tier 1 allocations at the Tier 2 rate.
- BPA completed the feasibility study for the L0534 Atlas Agro interconnection. The study identified the transmission interconnection would cost approximately $180M and include 500kV/230kV and 115kV infrastructure improvements. A $6.2M reimbursable agreement was signed between the City and BPA for preliminary engineering activities with the L0534 Facility Study required before an interconnection construction agreement can be considered.
- An MOU between the City and Atlas Agro was signed that identified additional definitive agreements are to be developed and approved.

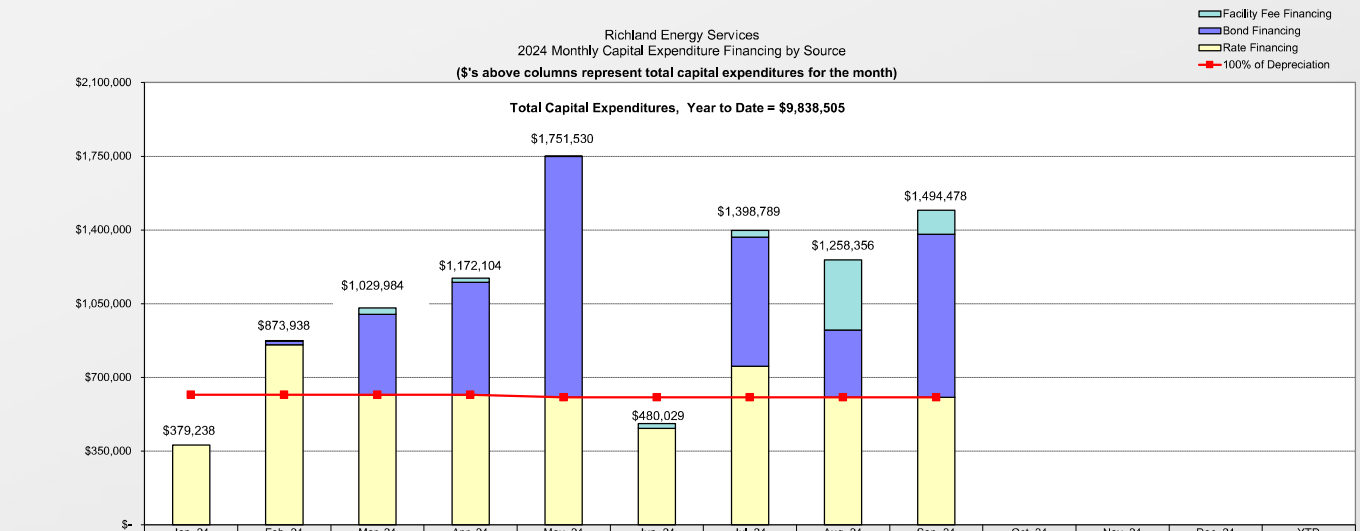
2nd Quarter

- Lighthouse Energy Consulting prepared a 2024 Resource Plan that was presented to the Utility Advisory Committee. A Resource Plan (RP) or Integrated Resource Plan (IRP) is required, through RCW 19.280, to be developed and submitted to the WA State Department of Commerce every two years. The 2024 RP identifies BPA as the projected 10-year energy resource except for the renewable power purchase agreement (PPA) with Tucci Energy for power from the Horn Rapids Solar, Storage and Training (HRSST) site. City Council approved the 2024 RP through Resolution 2024-93 on August 7, 2024. The 2024 RP was submitted to Commerce on August 13, 2024.
- The Capital Work Plan (CWP) expenses through May were $2.1M. The largest CWP item was $1.0M towards development request line extension work. This is significant increase in line extension work through mid-year compared to $1.2M expended in all of 2023.
  The AMI project is 98.1% complete with the 30,900 total electric meter installations and 97.2% complete with the 21,900 total water meter installations.

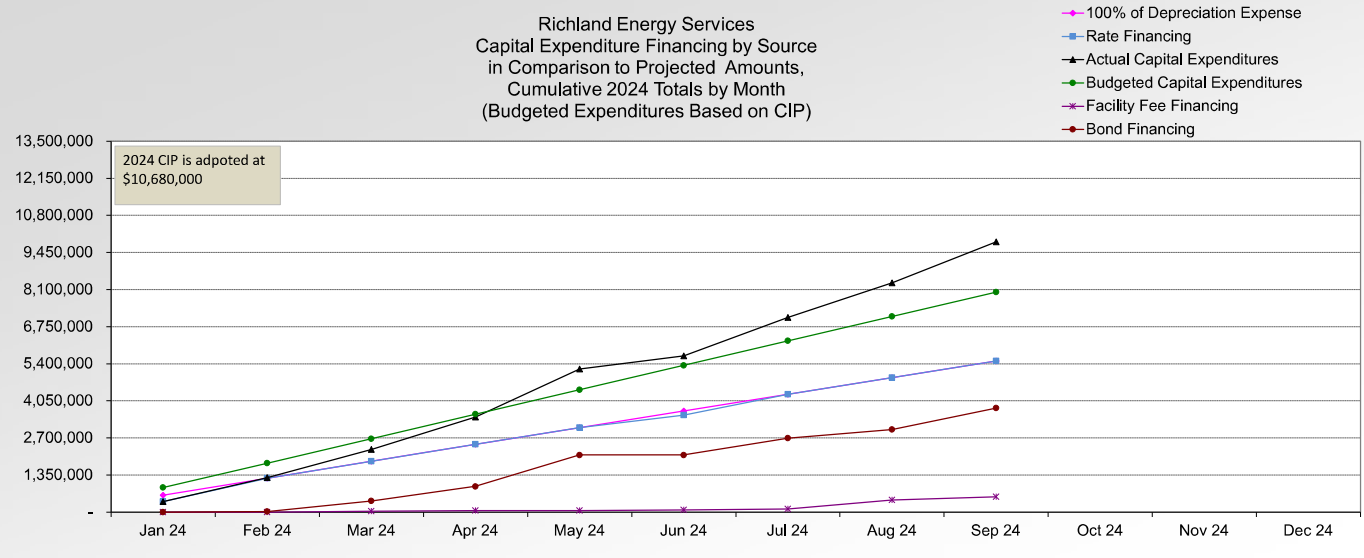
3rd Quarter

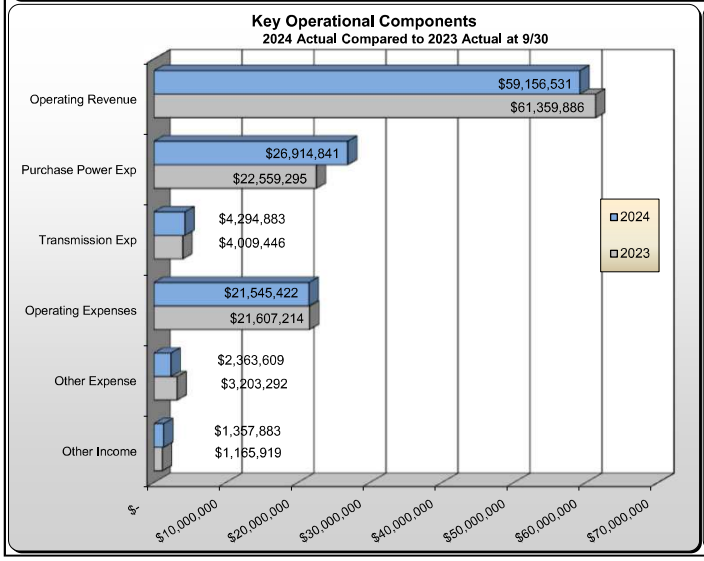
- BPA revised its capital work schedule for the Stevens & Thayer Drive transmission line which caused RES to delay coordinated CWP at Stevens & Thayer Substations. The 2024 CWP projected capital expenditures were reduced to $7.2M of the total $11.4M originally planned. CWP expenditures through July were $2.9M.
- RES presented an Electric Utility Wildfire Mitigation Plan to the UAC on September 10, 2024. The mitigation plan is a requirement codified in RCW 19.29A.170 using a template created by Department of Natural Resources (DNR) and Department of Commerce with plan elements based upon best practices to reduce the risk of wildfire and the resulting damage and losses. UAC supported staff's recommendation and City Council approved the mitigation plan through Resolution No. 2024-132 on October 1, 2024. The wildfire mitigation plan was submitted to DNR on October 24, 2024.
- RES prepared a 2023 fuel mix report summarizing the percentage mix of power purchased from various fuel sources. The annual fuel mix summary is an RCW 19.29A.060 requirement to be submitted to WA State Department of Commerce. The 2023 fuel mix is approximately 90% from clean carbon free power sources and like the 2020-2022 reported fuel mix.
- Through October, the AMI project is 98.9% complete with the 30,923 total electric meter installations and 98.9% complete with the 21,900 total water meter installations.

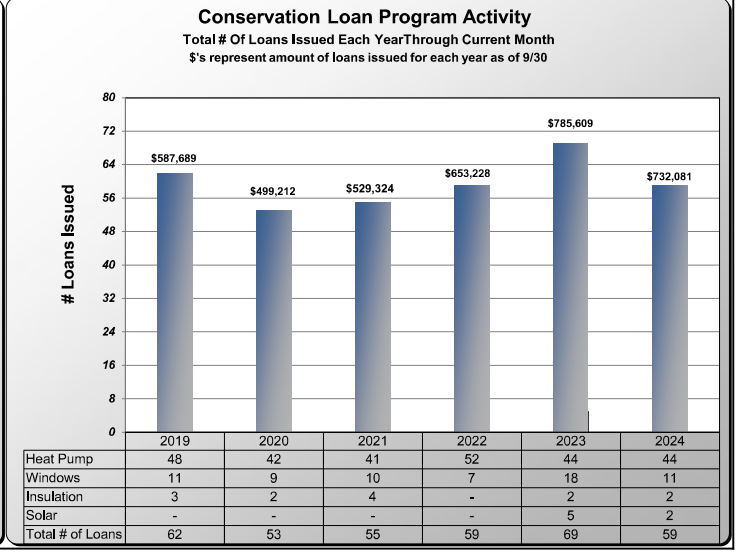
CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY FINANCIAL TREND INFORMATION
September 30, 2024



	Jan 24	Feb 24	Mar 24	Apr 24	May 24	Jun 24	Jul 24	Aug 24	Sep 24	Oct 24	Nov 24	Dec 24	YTD
Facility Fee Financing	-	1,220	30,152	20,852	2,798	21,630	32,507	333,842	115,157				558,158
Bond Financing	-	18,007	382,858	534,277	1,142,793	-	612,803	318,635	773,854				3,783,227
Rate Financing	379,238	854,711	616,974	616,975	605,939	458,399	753,479	605,938	605,467				5,497,120
100% of Depreciation	616,974	616,975	616,974	616,975	605,939	605,939	605,939	605,938	605,467				5,497,120

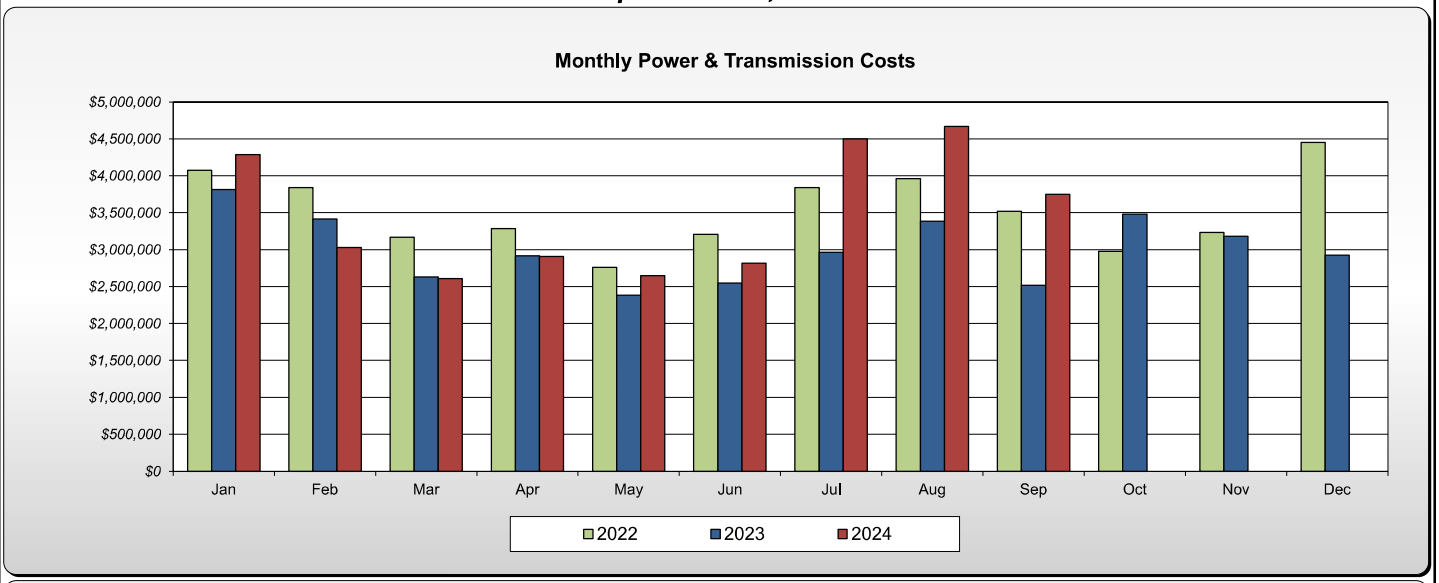


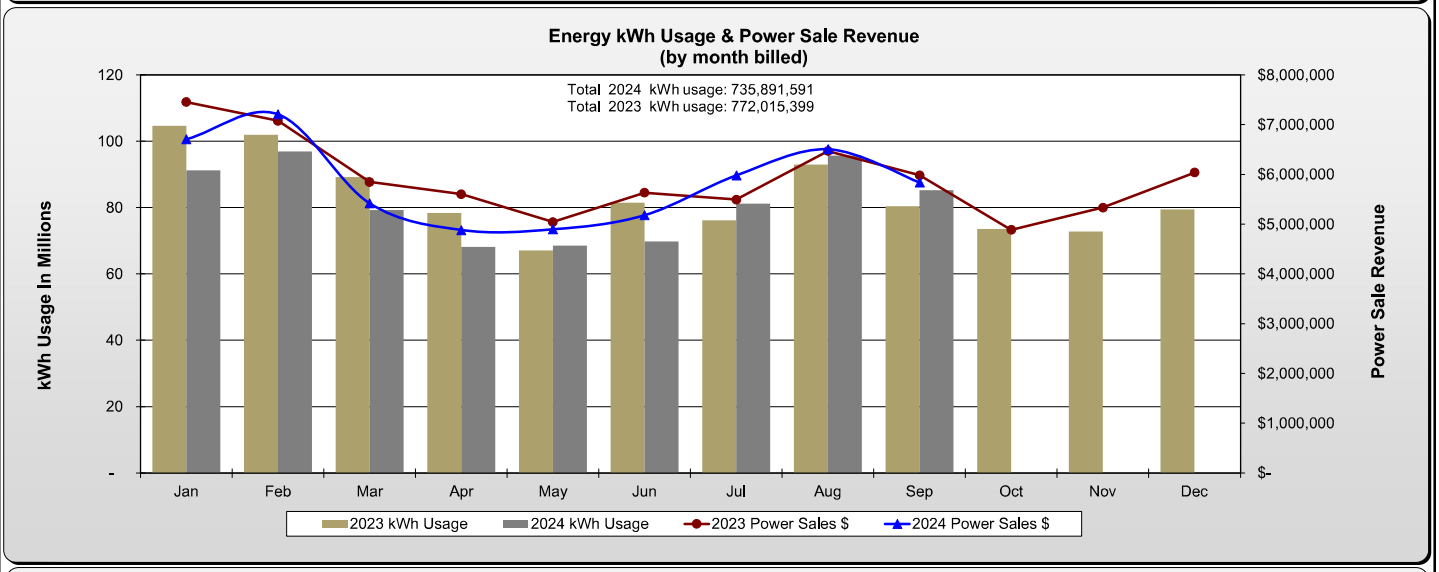


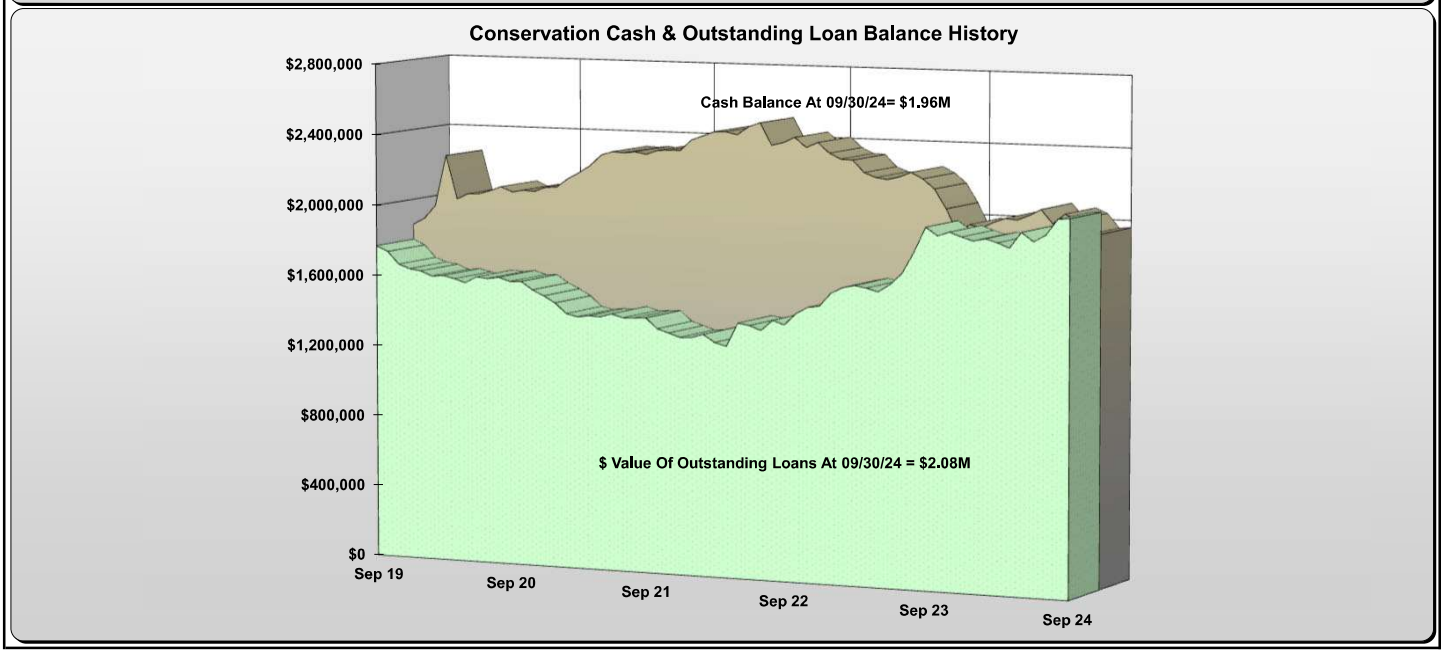


	2019	2020	2021	2022	2023	2024
Heat Pump	48	42	41	52	44	44
Windows	11	9	10	7	18	11
Insulation	3	2	4	-	2	2
Solar	-	-	-	-	5	2
Total # of Loans	62	53	55	59	69	59

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY FINANCIAL TREND INFORMATION, CONTINUED
September 30, 2024

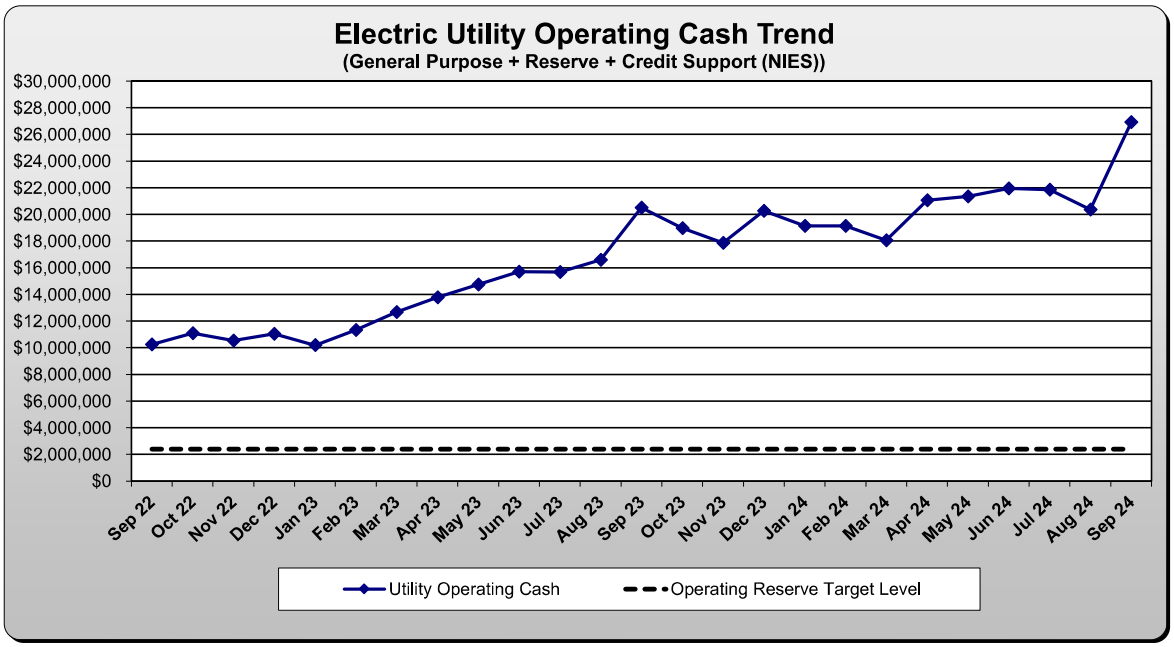


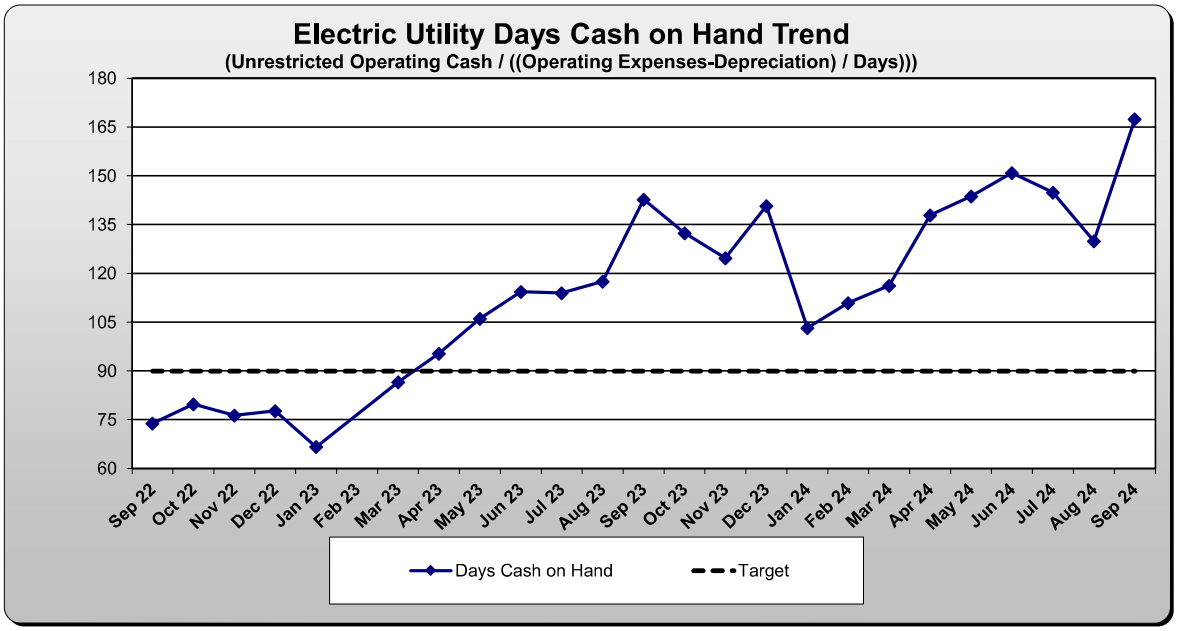




CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
CASH POSITION
September 30, 2024

Unrestricted Cash and Investments:	September 30, 2024	September 30, 2023
Operating Cash, General Purpose	$ 24,524,384	$ 17,464,053
Operating Cash, Reserve	2,400,000	2,400,000
Conservation Loan Cash	1,960,125	1,931,374
Credit Support Reserve Cash (NIES)	-	639,000
Total Unrestricted Cash and Investments:	28,884,509	22,434,426
Restricted Cash and Investments:		
Revenue Bond Proceeds	3,596,270	10,252,066
Facility Development Fees (Line Extension)	3,417,588	1,281,017
Construction Allowances Subject To Refund (Note 1)	452,788	357,832
Bond Redemption Set-Aside	3,931,234	3,674,731
Bond Reserve (Note 11)	3,708,351	3,665,656
Total Restricted Cash and Investments:	15,106,232	19,231,302
Total Cash	$ 43,990,741	$ 41,665,728





CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
COMPARATIVE BALANCE SHEET
September 30, 2024 and 2023

	2024	2023	2024 - 2023 (+/-)
ASSETS:			
Current Assets			
Cash & Cash Equivalents	$ 28,884,509	$ 22,398,753	$ 6,485,756
Deposits With Third Parties	1,900	1,900	-
Investments	-	-	-
Receivables:			
Customer Utility Accounts, (net) (Note 8)	3,063,498	3,276,603	(213,105)
Customer Conservation Loans	2,920,368	2,625,406	294,962
Miscellaneous	123,291	87,082	36,210
Prepaid Expenses	80,816	60,555	20,261
Inventory	8,258,168	8,136,732	121,436
Total Current Assets	**43,332,550**	**36,587,032**	**6,745,518**
Noncurrent			
Restricted Cash	15,106,232	19,231,302	(4,125,070)
Restricted Investments (Note 12)	-	-	-
Net Pension Asset	1,854,814	1,866,386	(11,572)
Lease Receivable	388,133	528,760	(140,628)
Capital:			
Land	837,461	837,428	33
Depreciable Assets (net)	5,614,485	5,804,129	(189,644)
Infrastructure	124,511,731	117,996,996	6,514,735
Construction in Progress	4,521,314	2,176,837	2,344,477
Total Capital Assets (net)	135,484,992	126,815,390	8,669,602
Total Noncurrent Assets	**152,834,170**	**148,441,838**	**4,532,960**
TOTAL ASSETS	**196,166,720**	**185,028,870**	**11,278,478**
DEFERRED OUTFLOWS OF RESOURCES			
Unamortized Loss - Reacquired Debt (Note 2)	71,762	76,493	(4,732)
Other Deferred Debits (Note 2)	2,578,022	2,686,506	(108,484)
Total Deferred Outflows of Resources	**2,649,784**	**2,763,000**	**(113,216)**
LIABILITIES:			
Current Liabilities			
Accounts Payable & Accrued Expenses	11,384,539	7,675,882	3,708,657
Due to Other Funds	-	-	-
Current Portion of Compensated Absences	397,592	397,994	(402)
Current Portion of Bond Principal Payable	2,435,000	2,295,000	140,000
Total Current Liabilities	**14,217,131**	**10,368,876**	**3,848,254**
Noncurrent Liabilities			
Noncurrent Portion of Compensated Absences	397,592	397,994	(402)
Revenue Bonds Payable	75,173,087	77,937,226	(2,764,139)
Unearned Revenue	568,563	478,641	89,923
Net OPEB Liability (Note 14)	681,997	642,892	39,106
Net Pension Liability	801,160	1,076,136	(274,976)
Total Noncurrent Liabilities	**77,622,400**	**80,532,889**	**(2,910,489)**
TOTAL LIABILITIES	**91,839,531**	**90,901,765**	**937,766**
DEFERRED INFLOWS OF RESOURCES			
Unamortized Gain - Reacquired Debt (Note 2)	1,103,204	1,163,772	(60,568)
Other Deferred Credits (Note 2)	1,778,607	2,923,285	(1,144,678)
Total Deferred Outflows of Resources	**2,881,811**	**4,087,057**	**(1,205,247)**
NET POSITION:			
Net Investment in Capital Assets	60,441,733	47,559,214	12,882,519
Restricted For:			
Debt Service	7,639,585	7,340,387	299,199
Capital Improvements	3,870,376	1,638,849	2,231,527
Pension	2,363,118	1,752,752	610,366
Unrestricted (Note 14)	29,780,350	34,511,845	(4,731,495)
TOTAL NET POSITION	**$ 104,095,163**	**$ 92,803,047**	**$ 11,292,116**

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
COMPARATIVE STATEMENT OF OPERATIONS
THIRD QUARTER 2024

	Quarter Ended 9/30/2024 Actual	Quarter Ended 9/30/2023 Actual	% Variance From 2023 Actual
OPERATING REVENUES:			
Power Sales Revenue	$ 18,329,271	$ 17,946,674	2%
Utility Occupation Tax	1,701,028	1,669,171	2%
Other Operating Revenues (Note 3)	496,465	765,028	-35%
Total Operating Revenues	20,526,763	20,380,873	1%
OPERATING EXPENSES:			
Power	11,320,220	7,441,498	52%
Transmission	1,597,134	1,424,891	12%
Total Purchased Power	12,917,354	8,866,389	46%
Distribution Operations and Maintenance (O&M)			
Distribution - Operations	882,278	1,121,825	-21%
Distribution - Maintenance	365,766	498,682	-27%
Total Distribution O&M	1,248,044	1,620,507	-23%
Customer Accounting			
Meter Reading Expense	43,185	51,032	-15%
Customer Records & Collections	210,103	242,899	-14%
Bad Debt Expense (Note 9)	33,930	40,590	-16%
Total Customer Accounting	287,219	334,520	-14%
Conservation & Customer Service (Note 10)	445,565	600,613	-26%
Administration & General	700,167	711,512	-2%
Depreciation	1,817,345	1,753,754	4%
Taxes	2,481,811	2,204,810	13%
Operating Transfer to Equipment Replacement Fund	208,216	189,287	0%
Other Operating Expenses (Note 4)	627	661	-5%
Total Non-Power Operating Expenses	7,188,993	7,415,664	-3%
Total Operating Expenses	20,106,347	16,282,053	23%
OPERATING INCOME (LOSS):	**420,416**	**4,098,820**	**-90%**
OTHER INCOME:			
Interest Income	349,228	384,397	-9%
Gain / (Loss) on Fair Market Value (FMV) Adjustment	-	-	NA
Other Income (Note 5)	71,309	211,266	-66%
City Shops Rental	-	-	NA
Total Other Income:	420,537	595,663	**-29%**
OTHER EXPENSE:			
Interest on Long-Term Debt	789,637	1,015,171	-22%
Debt Issuance Expense	-	117,873	-100%
Amortization of Bond Discount / Premium	(82,285)	(82,285)	0%
Amortization of Loss on Reacquired Debt	(13,959)	(13,959)	0%
Other Expenses (Note 6)	88,173	172,298	-49%
Total Other Expense:	781,566	1,209,098	-35%
NET INCOME (LOSS) BEFORE CAPITAL CONTRIBUTIONS AND TRANSFERS	**59,388**	**3,485,386**	**-98%**
Capital Contributions - Facility Development Fees (Note 7)	1,249,359	621,433	101%
Transfers From General Fund	-	-	NA
Transfers To Broadband Fund (Note 12)	(7,500)	(7,500)	0%
Total of Capital Contributions and Transfers to Other Funds	1,241,859	613,933	102%
CHANGE IN NET POSITION BEFORE PRIOR PERIOD ADJUSTMENTS	**1,301,247**	**4,099,319**	**-68%**
Prior Period Adjustments	-	-	
CHANGE IN NET POSITION	**$ 1,301,247**	**$ 4,099,319**	**-68%**

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
COMPARATIVE STATEMENT OF OPERATIONS
September 30, 2024

	9/30/2024 Actual	9/30/2023 Actual	% Variance From 2023 Actual
OPERATING REVENUES:			
Power Sales Revenue	$ 52,630,220	$ 54,600,547	-4%
Utility Occupation Tax	4,883,104	5,071,310	-4%
Other Operating Revenues (Note 3)	1,643,207	1,688,029	-3%
Total Operating Revenues	59,156,531	61,359,886	-4%
OPERATING EXPENSES:			
Power	26,914,841	22,559,295	19%
Transmission	4,294,883	4,009,446	7%
Total Purchased Power	31,209,724	26,568,741	17%
Distribution Operations and Maintenance (O&M)			
Distribution - Operations	3,004,070	3,262,326	-8%
Distribution - Maintenance	952,872	1,295,571	-26%
Total Distribution O&M	3,956,942	4,557,897	-13%
Customer Accounting			
Meter Reading Expense	123,117	167,620	-27%
Customer Records & Collections	630,789	742,060	-15%
Bad Debt Expense (Note 9)	101,790	121,770	-16%
Total Customer Accounting	855,696	1,031,451	-17%
Conservation & Customer Service (Note 10)	1,336,445	938,442	42%
Administration & General	2,145,054	2,099,517	2%
Depreciation	5,497,120	5,261,262	4%
Taxes	7,126,350	7,147,962	0%
Operating Transfer to Equipment Replacement Fund	624,647	567,861	10%
Other Operating Expenses (Note 4)	3,167	2,822	12%
Total Non-Power Operating Expenses	21,545,422	21,607,214	0%
Total Operating Expenses	52,755,146	48,175,955	10%
OPERATING INCOME (LOSS):	**6,401,386**	**13,183,931**	**-51%**
OTHER INCOME:			
Interest Income	1,067,540	826,342	29%
Gain / (Loss) on Fair Market Value (FMV) Adjustment	-	-	NA
Other Income (Note 5)	290,344	339,577	-14%
City Shops Rental	-	-	NA
Total Other Income:	1,357,883	1,165,919	**16%**
OTHER EXPENSE:			
Interest on Long-Term Debt	2,368,910	2,459,018	-4%
Debt Issuance Expense	-	480,847	-100%
Amortization of Bond Discount / Premium	(246,854)	(243,523)	-1%
Amortization of Loss on Reacquired Debt	(41,878)	(8,534)	-391%
Other Expenses (Note 6)	283,431	515,484	-45%
Total Other Expense:	2,363,609	3,203,292	-26%
NET INCOME (LOSS) BEFORE CAPITAL CONTRIBUTIONS AND TRANSFERS	**5,395,659**	**11,146,558**	**-52%**
Capital Contributions - Facility Development Fees (Note 7)	3,014,078	1,204,317	150%
Transfers From General Fund	-	-	NA
Transfers To Broadband Fund (Note 12)	(22,500)	(22,500)	0%
Total of Capital Contributions and Transfers to Other Funds	2,991,578	1,181,817	153%
CHANGE IN NET POSITION BEFORE PRIOR PERIOD ADJUSTMENTS	**8,387,238**	**12,328,375**	**-32%**
Prior Period Adjustments	-	-	
CHANGE IN NET POSITION	**$ 8,387,238**	**$ 12,328,375**	**-32%**

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
MONTHLY STATEMENT OF OPERATIONS
CY 2024 ACTUAL

	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Total
OPERATING REVENUES:													
Power Sales Revenue	$ 6,708,366	$ 7,207,822	$ 5,421,900	$ 4,883,572	$ 4,898,219	$ 5,181,071	$ 5,982,809	$ 6,506,054	$ 5,840,408	$ -	$ -	$ -	$ 52,630,220
Utility Occupation Tax	622,773	669,139	503,157	451,713	454,527	480,766	555,230	603,795	542,002	-	-	-	4,883,104
Other Operating Revenues (Note 3)	80,655	338,749	254,101	223,975	120,800	128,462	143,215	197,676	155,574	-	-	-	1,643,207
Total Operating Revenues	**7,411,794**	**8,215,711**	**6,179,158**	**5,559,260**	**5,473,547**	**5,790,299**	**6,681,254**	**7,307,526**	**6,537,984**	**-**	**-**	**-**	**59,156,531**
OPERATING EXPENSES:													
Power	3,595,002	2,528,526	2,210,828	2,548,303	2,307,594	2,404,369	3,922,289	4,109,870	3,288,061	-	-	-	26,914,841
Transmission	691,934	501,672	396,040	356,687	340,820	410,596	577,458	558,140	461,536	-	-	-	4,294,883
Total Purchased Power	4,286,936	3,030,198	2,606,868	2,904,990	2,648,414	2,814,965	4,499,747	4,668,010	3,749,597	-	-	-	31,209,724
Distribution Operations and Maintenance (O&M)													
Distribution - Operations	305,234	384,159	312,637	457,221	399,309	263,231	296,097	340,376	245,805	-	-	-	3,004,070
Distribution - Maintenance	88,430	114,238	110,651	93,086	113,086	67,614	81,131	160,648	123,987	-	-	-	952,872
Total Distribution O&M	393,665	498,397	423,289	550,307	512,395	330,845	377,227	501,025	369,792	-	-	-	3,956,942
Customer Accounting													
Meter Reading Expense	16,860	18,797	7,356	10,074	12,815	14,031	25,264	11,224	6,697	-	-	-	123,117
Customer Records & Collections	69,360	72,228	69,820	69,650	70,025	69,602	69,985	69,990	70,129	-	-	-	630,789
Bad Debt Expense (Note 9)	11,310	11,310	11,310	11,310	11,310	11,310	11,310	11,310	11,310	-	-	-	101,790
Total Customer Accounting	97,529	102,335	88,487	91,034	94,151	94,942	106,558	92,524	88,136	-	-	-	855,696
Conservation & Customer Service (Note 10)	185,219	191,131	148,510	87,335	219,732	58,954	62,828	329,431	53,306	-	-	-	1,336,445
Administration & General	417,182	221,136	221,212	208,807	183,483	193,067	206,325	286,730	207,112	-	-	-	2,145,054
Depreciation	616,974	616,974	616,974	616,974	605,939	605,939	605,939	605,939	605,467	-	-	-	5,497,120
Taxes	903,777	977,926	735,045	670,705	660,160	696,926	805,765	890,329	785,718	-	-	-	7,126,350
Operating Transfer to Equipment Replacement Fund	69,405	69,405	69,405	69,405	69,405	69,405	69,405	69,405	69,405	-	-	-	624,647
Other Operating Expenses (Note 4)	459	553	465	387	361	317	274	-	353	-	-	-	3,167
Total Non-Power Operating Expenses	2,684,210	2,677,857	2,303,386	2,294,954	2,345,626	2,050,395	2,234,321	2,775,383	2,179,290	-	-	-	21,545,422
Total Operating Expenses	**6,971,146**	**5,708,055**	**4,910,254**	**5,199,944**	**4,994,040**	**4,865,360**	**6,734,068**	**7,443,393**	**5,928,886**	**-**	**-**	**-**	**52,755,146**
OPERATING INCOME (LOSS):	**440,648**	**2,507,656**	**1,268,904**	**359,316**	**479,507**	**924,939**	**(52,814)**	**(135,867)**	**609,098**	**-**	**-**	**-**	**6,401,386**
OTHER INCOME :													
Interest Income	138,316	118,099	118,325	120,703	112,685	110,183	125,671	106,644	116,912	-	-	-	1,067,540
Gain / (Loss) on Fair Market Value (FMV) Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Income (Note 5)	11,110	9,276	11,658	13,143	11,825	162,022	58,016	5,648	7,645	-	-	-	290,344
City Shops Rental	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Income	**149,426**	**127,376**	**129,984**	**133,845**	**124,510**	**272,205**	**183,687**	**112,293**	**124,557**	**-**	**-**	**-**	**1,357,883**
OTHER EXPENSE :													
Interest on Long-Term Debt	263,212	263,212	263,212	263,212	263,212	263,212	263,212	263,212	263,212	-	-	-	2,368,910
Debt Issuance Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of Bond Discount / Premium	(27,428)	(27,428)	(27,428)	(27,428)	(27,428)	(27,428)	(27,428)	(27,428)	(27,428)	-	-	-	(246,854)
Amortization of Loss on Reacquired Debt	(4,653)	(4,653)	(4,653)	(4,653)	(4,653)	(4,653)	(4,653)	(4,653)	(4,653)	-	-	-	(41,878)
Other Expenses (Note 6)	27,693	41,905	36,016	29,813	32,274	27,557	30,153	39,539	18,481	-	-	-	283,431
Total Other Expense:	**258,824**	**273,036**	**267,146**	**260,944**	**263,405**	**258,688**	**261,284**	**270,669**	**249,612**	**-**	**-**	**-**	**2,363,609**
NET INCOME (LOSS) BEFORE CAPITAL CONTRIBUTIONS AND TRANSFERS	**331,250**	**2,361,996**	**1,131,741**	**232,217**	**340,612**	**938,456**	**(130,411)**	**(294,244)**	**484,043**	**-**	**-**	**-**	**5,395,659**
Capital Contributions - Facility Development Fees (Note 7)	-	109,545	392,728	831,615	251,733	179,098	272,399	888,320	88,640	-	-	-	3,014,078
Transfers To Broadband Fund (Note 12)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	-	-	-	(22,500)
Total of Capital Contributions and Transfers to Other Funds	(2,500)	107,045	390,228	829,115	249,233	176,598	269,899	885,820	86,140	-	-	-	**2,991,578**
CHANGE IN NET POSITION BEFORE PRIOR PERIOD ADJUSTMENTS	**328,750**	**2,469,040**	**1,521,969**	**1,061,332**	**589,845**	**1,115,055**	**139,488**	**591,575**	**570,183**	**-**	**-**	**-**	**8,387,238**
Prior Period Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
CHANGE IN NET POSITION	**$ 328,750**	**$ 2,469,040**	**$ 1,521,969**	**$ 1,061,332**	**$ 589,845**	**$ 1,115,055**	**$ 139,488**	**$ 591,575**	**$ 570,183**	**$ -**	**$ -**	**$ -**	**$ 8,387,238**

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
STATEMENT OF CASH FLOWS
September 30, 2024

	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Year To Date
Cash Flows From Operating Activities													
Receipts from power sales to customers	$ 7,112,885	$ 7,119,568	$ 7,199,007	$ 6,332,550	$ 5,062,767	$ 5,657,282	$ 5,835,348	$ 7,081,433	$ 7,352,121	$ -	$ -	$ -	$ 58,752,961
Other operating cash receipts	312,188	238,943	356,394	1,735,856	135,060	327,942	202,511	190,492	1,670,201	-	-	-	5,169,588
Receipts from interfund rents and services	-	-	-	-	-	-	-	-	-	-	-	-	-
Other cash payments	-	-	-	-	-	-	-	-	-	-	-	-	-
Payments for power	(2,431,346)	(3,599,596)	(2,540,789)	(2,211,972)	(2,551,883)	(2,306,499)	(2,405,134)	(3,920,577)	(22,818)	-	-	-	(21,990,613)
Payment for transmission	(427,844)	(691,934)	(501,672)	(396,040)	(356,687)	(340,820)	(410,596)	(577,458)	(558,140)	-	-	-	(4,261,191)
Payments to suppliers	(4,101,656)	(1,520,144)	(3,758,382)	(590,068)	(310,618)	(1,051,050)	(1,339,293)	(2,286,340)	(173,227)	-	-	-	(15,130,776)
Payments for utility tax	(623,147)	(669,542)	(502,794)	(454,335)	(454,983)	(481,256)	(555,733)	(604,337)	(542,505)	-	-	-	(4,888,633)
Payments to employees	(30,693)	(87,454)	35,779	31,670	52,973	36,930	(8,304)	(28,150)	131,300	-	-	-	134,052
Payments for interfund services	(436,847)	(306,341)	(318,796)	(378,219)	(358,277)	(324,776)	(314,374)	(333,413)	(318,070)	-	-	-	(3,089,114)
Net Cash Provided (Used) by Operating Activities	**(626,460)**	**483,502**	**(31,253)**	**4,069,442**	**1,218,353**	**1,517,754**	**1,004,425**	**(478,349)**	**7,538,863**	**-**	**-**	**-**	**14,696,275**
Cash Flows From Noncapital Financing Activities													
Interfund Loan Repayments Received	-	-	-	-	-	-	-	-	-	-	-	-	-
Transfer (to) / from Broadband Fund (Note 13)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	(2,500)	-	-	-	(22,500)
Transfer (to) / from General Fund (Note 13)	-	-	-	-	-	-	-	-	-	-	-	-	-
Transfer (to) / from Industrial Development (Note 13)	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Cash Used by Noncapital Financing Activities	**(2,500)**	**(2,500)**	**(2,500)**	**(2,500)**	**(2,500)**	**(2,500)**	**(2,500)**	**(2,500)**	**(2,500)**	**-**	**-**	**-**	**(22,500)**
Cash Flows From Capital and Related Financing Activities													
Proceeds from Issuance of Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
Bond Issuance costs (Paid) Refunded	-	-	-	-	-	-	-	-	-	-	-	-	-
Principal Paid on Long-Term Debt	-	-	-	-	-	-	-	-	-	-	-	-	-
Interest Paid on Long-Term Debt	-	-	-	-	(1,579,273)	-	-	-	-	-	-	-	(1,579,273)
Capital Contributions	-	109,545	392,728	831,615	251,733	179,098	272,399	888,320	88,640	-	-	-	3,014,078
Deferred Capital Contributions	-	-	-	-	-	-	-	67,200	-	-	-	-	67,200
Capital Contributions Refunded	-	-	-	-	-	-	-	-	(67,800)	-	-	-	(67,800)
Sale of Land	-	-	-	2,032	1,994	-	-	-	-	-	-	-	4,025
Acquisition and Construction of Capital Assets	(379,238)	(873,938)	(1,029,984)	(1,172,104)	(1,751,531)	(480,029)	(1,398,789)	(1,258,414)	(1,494,478)	-	-	-	(9,838,505)
Net Cash Provided (Used) by Capital and Related Financing Activities	**(379,238)**	**(764,394)**	**(637,256)**	**(338,457)**	**(3,077,077)**	**(300,931)**	**(1,126,389)**	**(302,895)**	**(1,473,638)**	**-**	**-**	**-**	**(8,400,274)**
Cash Flows From Investing Activities													
Interest Received on Investments	138,316	118,099	118,325	120,703	112,685	110,183	125,671	106,644	116,912	-	-	-	1,067,540
Premium Received on Investments	-	-	-	-	-	-	-	-	-	-	-	-	-
Investments Sold *	20,141,269	-	-	-	-	-	-	-	-	-	-	-	20,141,269
Investments Purchased *	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Cash Provided (Used) by Investing Activities	**20,279,585**	**118,099**	**118,325**	**120,703**	**112,685**	**110,183**	**125,671**	**106,644**	**116,912**	**-**	**-**	**-**	**21,208,809**
Net Change in Cash and Cash Equivalents	**19,271,388**	**(165,293)**	**(552,684)**	**3,849,187**	**(1,748,539)**	**1,324,506**	**1,206**	**(677,099)**	**6,179,637**	**-**	**-**	**-**	**27,482,310**
Cash and Cash Equivalents at Beginning of Period	**16,508,431**	**35,779,819**	**35,614,526**	**35,061,842**	**38,911,030**	**37,162,491**	**38,486,997**	**38,488,203**	**37,811,104**	**43,990,741**	**43,990,741**	**43,990,741**	**16,508,431**
Cash and Cash Equivalents at End of Period	**$ 35,779,819**	**$ 35,614,526**	**$ 35,061,842**	**$ 38,911,030**	**$ 37,162,491**	**$ 38,486,997**	**$ 38,488,203**	**37,811,104**	**43,990,741**	**43,990,741**	**43,990,741**	**43,990,741**	**$ 43,990,741**
Reconciliation of Operating Income to Net Cash Provided (Used) by Operating Activities													
Net Operating Income	$ 440,648	$ 2,507,656	$ 1,268,904	$ 359,316	$ 479,507	$ 924,939	$ (52,814)	$ (135,867)	$ 609,098	$ -	$ -	$ -	$ 6,401,386
Adjustments to reconcile net operating income to net cash provided by operating activities:													
Depreciation & Amortization	616,974	616,974	616,974	616,974	605,939	605,939	605,939	605,939	605,467	-	-	-	5,497,120
Accrued Pension Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Income, Net	(16,583)	(32,629)	(24,357)	(18,702)	(22,443)	134,465	27,863	(33,890)	(10,836)	-	-	-	2,887
Changes in operating assets and liabilities:													
(Increase) / Decrease in Receivables	(482)	(956,865)	(145,271)	2,429,165	(429,916)	(19,942)	(781,082)	(1,681,114)	2,479,396	-	-	-	893,890
(Increase) / Decrease in Inventory	(4,523)	(869,343)	(695,697)	506,983	724,409	(322,081)	(288,679)	180,729	229,530	-	-	-	(538,672)
(Increase) / Decrease in Prepaid Expenses	(274,189)	76,939	26,939	26,939	26,939	26,939	26,939	26,939	26,939	-	-	-	(8,680)
Increase / (Decrease) in Power & Transmission AP	1,432,045	(1,255,198)	(445,766)	320,558	(256,576)	168,388	1,682,945	168,263	3,164,566	-	-	-	4,979,226
Increase / (Decrease) in Accounts Payable	(2,656,156)	542,032	(547,971)	(80,776)	201,771	42,392	(143,486)	534,832	548,809	-	-	-	(1,558,553)
Increase / (Decrease) in Accrued Wages	(30,679)	-	-	-	-	-	-	-	-	-	-	-	(30,679)
Increase / (Decrease) in Unearned Facility Fees	-	-	-	-	-	-	-	-	-	-	-	-	-
Increase / (Decrease) in Prepaid Leases	-	-	-	-	-	-	-	-	-	-	-	-	-
(Increase) in Expired Construction Allowances (Note 1)	-	-	-	-	-	-	-	-	-	-	-	-	-
(Increase) / Decrease in Deferred Charges	(133,516)	(146,064)	(85,007)	(91,014)	(111,277)	(43,284)	(73,200)	(144,179)	(114,107)	-	-	-	(941,648)
Prior Period Adjustments	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Cash Provided (Used) by Operating Activities	**$ (626,460)**	**$ 483,502**	**$ (31,253)**	**$ 4,069,442**	**$ 1,218,353**	**$ 1,517,754**	**$ 1,004,425**	**$ (478,349)**	**$ 7,538,863**				**$ 14,696,275**
Contribution of Capital Assets	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

* The Electric Utility's cash is invested along with the City's cash in pooled investments. Pooled cash and investments are maintained in a separate fund for investment and are shown in individual funds as purchased on December 31 and sold on January 1. The rest of the year pooled cash and investments are shown as a component of cash and cash equivalents on interim cash flow statements.

City of Richland, Washington
Electric Utility
Notes to the Financial Statements
September 30, 2024

1. The construction allowance is the portion of line extension costs paid for by the Utility, assuming the expected number of permanent connections to the system result. The developer bears the full cost of the line extension up front, and the Utility pays its portion by refunding the developer based on the number of permanent connections to the line extension over a five-year period.

   The refundable portion of fees collected is a deposit to guarantee connections to the line extension. Deposits are not characterized as revenue. Instead, a Deferred Revenue: Facility Fee Deposits account is included in the liability section of the balance sheet to offset the cash balance of these potentially refundable amounts. Five years from the date the line extension is energized, unused deposits expire and are recognized as revenue.

   Reported separately from these traditional line extension projects are large, customer requested projects, facilitating customer specific needs as opposed to improvements to the utility system. Customer payments are received in advance and are recorded as Facility Development Fees - Large Projects with an offset to Unearned Facility Fee Revenue. Cash is depleted and fees are reclassified as revenue when expenses are incurred by the Utility.

   Year-to-date facility fees collected from customers totaled $3,081,278 of which $3,014,078 was recognized as revenue and $67,200 represents refundable construction allowances recorded as unearned revenue.

2. Deferred outflows of resources represent expenses of the Utility that apply to future periods. The primary purpose of the deferred outflow of resources accounts is to accumulate expenditures that are to be recognized in future periods or allocated to more than one account number. Deferred outflow of resources includes unamortized loss on reacquired bond debt. Other Deferred Debits includes clearing accounts that are used to hold warehousing, overhead, and equipment costs pending final allocation.

   GASB Statement 68, *Accounting and Financial Reporting for Pensions*, requires reporting the fund's proportionate share the State's retirement plan net pension assets and liabilities. Other Deferred Debits also includes contributions after the State retirement plan measurement date and Other Deferred Credits include the net difference between projected and actual investments earnings on pension plan investments.

3. Other Operating Revenue includes the items listed below, with year-to-date comparisons to the prior year.

Other Operating Revenue YTD Through:	September 2024	September 2023	Difference
Permanent Service Fees	$ 128,001	$ 121,155	$ 6,847
New Account Fees	58,020	61,230	(3,210)
Rewire / Charges to Repair Damage	18,850	42,758	(23,908)
Delinquent Account Fees	248,118	269,066	(20,948)
Disconnect Fees	108,050	207,650	(99,600)
Pole Contracts	101,733	101,733	-
BPA - Conservation Program (EEI)	937,692	845,783	91,909
Other	42,743	38,655	4,088
Total Other Operating Revenue	$ 1,643,207	$ 1,688,029	$ (44,822)

4. Other Operating Expenses as reported on the Comparative Statement of Operations consist of power costs paid to Benton PUD for one customer account provided power through the Benton PUD system.

5. Other Income as reported on the Comparative Statement of Operations includes the following revenue sources:

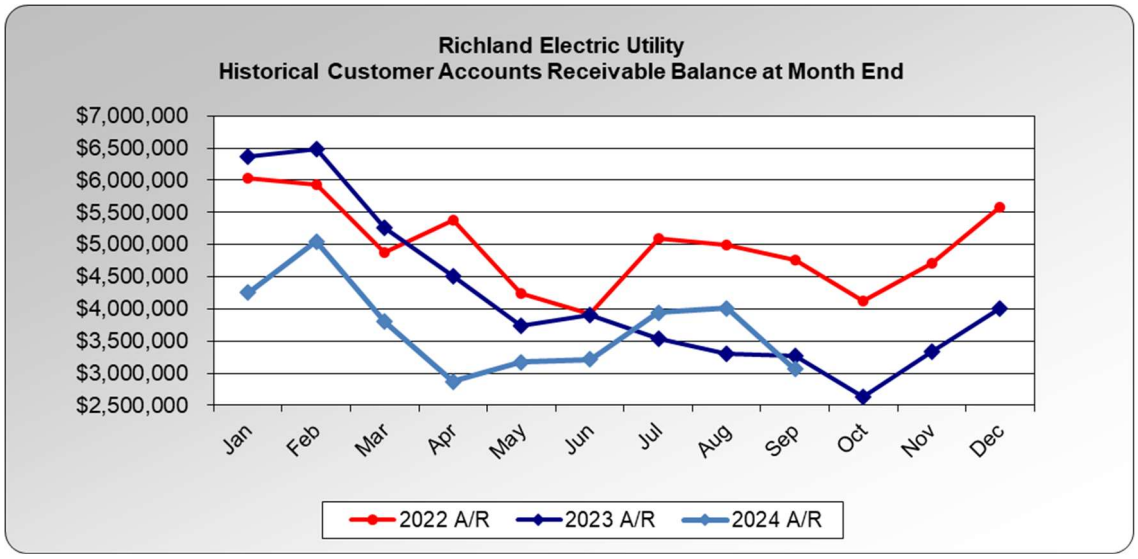
Other Income YTD Through:	September 2024	September 2023	Difference
Interest Collected on Conservation Loan Payments	$ 47,244	$ 39,961	$ 7,283
BPA - Conservation Admin Fee	-	90,000	(90,000)
Meter Reading Revenue	26,423	87,425	(61,002)
Work Performed for City Departments	208,779	114,105	94,674
Gain / (Loss) on Land sales and Disposition of Assets	7,898	8,085	(188)
Other	-	-	-
Total Other Income	$ 290,344	$ 339,577	$ (49,233)

Other Income also includes revenues allocated to the Electric Utility for its share of Horn Rapids Industrial Park sale proceeds. In 1982, work was undertaken by the City to develop the Horn Rapids Industrial Park, Phase One. Proceeds from the sale of land at Horn Rapids Industrial Park are allocated to City Utility Funds from the Industrial Development Fund based on each utility's proportionate share of total improvement costs. The remaining maximum reimbursement due to the Electric Utility, contingent upon sale of Horn Rapids Industrial Park Phase One property as of September 2024 is $131,769.

6. The Other Expenses reported on the Comparative Statement of Operations includes the cost of Non-Electric Utility Operations work. Some of the non-utility Operations costs are those charged to other City departments through the Interdepartmental Billing (IDB) process.

7. The Electric Utility recognized $1,249,359 in facility development fee revenue (capital contributions) in the third quarter of 2024. According to Governmental Accounting Standard Board (GASB) Statement No. 33, capital contributions from external sources are to be recognized as revenue in the current year rather than as a direct increase to contributed capital. Year-to-date facility development fee revenue of $3,014,078 is comprised of $2,993,078 in fees paid during the year and $21,000 of expired refundable construction allowances.

8. The outstanding utility accounts receivable balance, net of allowance for doubtful accounts on September 30, 2024, is $3,063,498. This represents a $153,364 decrease from the previous quarter. The following graph presents month-end customer accounts receivable balances during the last three calendar years.



Write-offs, recoveries, and accounts receivable balances for the year-to-date, with prior year comparisons are as follows:

Accounts Receivable YTD Through:	September 2024	September 2023	Difference
Write-Offs	$ 13,738	$ (106)	$ 13,844
Recoveries	5,036	13,670	(8,634)
Balance	$ 3,063,498	$ 3,276,603	$ (213,105)

9. Customer Accounting Expense includes bad debt expense. Customer accounts receivable is written off using the allowance method as prescribed by generally accepted accounting principles. Under this method, the projected uncollectible portion of customer accounts receivable is presented on the balance sheet based on a study of prior years' actual write-offs. Uncollectible accounts are written off against this estimated allowance rather than to bad debt expense. The monthly expense is 1/12 of the estimated annual allowance. Periodically, actual write-offs as a percentage of billings are analyzed, and the allowance is adjusted with an offset to bad debts expense, or the monthly entry may be suspended if the allowance becomes too high.

10. Conservation expenses may vary greatly from month-to-month and from budgeted amounts, as expenses for conservation supplies, educational materials, and payment of incentives to customers do not follow a regular schedule. In the third quarter of 2024, a total of $661,000 was spent on ductless heat pumps, windows, insulation and conservation programs. Year-to-date expenses on conservation measures total $1,901,583.

11. Bond ordinances require either maintenance of a cash Bond Reserve or purchase of bond insurance with an AAA rated provider to ensure debt is serviced in the event of financial hardship. The utility has historically purchased bond sureties to fulfill this requirement. However, due to the current economic climate, none of the surety companies currently enjoy an AAA rating. As a result, the utility funded a Bond Reserve, in 2008, to stay in compliance until the bond surety companies' ratings recover. The bond reserve was initially funded using $993,000 in Facility Fee cash and $2,111,575 in unrestricted cash. The amount of the bond reserve is adjusted annually and when additional debt is issued.

12. Monthly transfers to the Broadband Fund are presented in the financial statements as non-operating transfers to other funds.

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
COMPARATIVE MONTHLY ENERGY ACTIVITY
FOR THE PERIOD ENDED
September 2024

REVENUES: (Net of Utility Tax)	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Total To Date	Budget	Variance	% Budget Variance
Residential	$ 4,007,992	$ 4,081,184	$ 2,717,779	$ 2,279,508	$ 2,215,463	$ 2,344,265	$ 2,979,553	$ 3,166,453	$ 2,642,584				$ 26,434,782	$ 25,476,532	$ 958,250	4%
Small General Service	663,545	754,336	611,351	549,315	513,986	528,379	572,322	659,237	628,761				5,481,233	4,994,430	486,803	10%
Medium General Service	761,695	915,998	774,305	746,234	707,014	754,242	807,504	940,618	867,437				7,275,045	6,432,141	842,904	13%
Large General Service	620,244	656,646	607,205	621,004	652,242	711,565	735,908	796,504	760,965				6,162,283	6,347,985	(185,702)	-3%
Small Industrial	248,514	287,483	278,919	241,394	348,958	342,051	354,908	485,903	516,932				3,105,062	2,606,451	498,612	19%
Large Industrial	378,826	480,351	402,272	354,779	326,277	313,625	311,408	203,912	209,385				2,980,834	4,123,978	(1,143,144)	-28%
Small Irrigation	1,091	1,555	1,427	20,743	11,494	16,405	18,851	21,518	18,743				111,829	92,003	19,826	22%
Large Irrigation	1,314	1,464	1,419	44,054	95,752	143,807	175,197	205,504	168,474				836,986	1,018,998	(182,012)	-18%
Cable TV Amp	5,620	5,620	5,620	5,620	5,620	5,620	5,620	5,620	5,620				50,584	50,601	(17)	0%
Street Lighting	8,997	8,416	8,997	8,707	8,997	8,707	8,997	8,997	8,707				79,520	272,310	(192,790)	-71%
Rental Lighting	9,314	10,250	9,887	9,517	9,809	9,776	9,955	9,101	10,174				87,784	93,407	(5,623)	-6%
Traffic Lights	1,215	4,517	2,717	2,696	2,607	2,627	2,585	2,687	2,625				24,277	29,358	(5,082)	-17%
TOTAL REVENUES	$ 6,708,366	$ 7,207,822	$ 5,421,900	$ 4,883,572	$ 4,898,219	$ 5,181,071	$ 5,982,809	$ 6,506,054	$ 5,840,408				$ 52,630,220	$ 51,538,194	$ 1,092,026	2%

CONSUMPTION (kWh):													Total To Date	Budget	Variance	% Budget Variance
Residential	46,474,963	46,449,407	31,101,840	24,280,697	23,603,684	25,063,440	33,761,939	36,081,367	30,954,667				297,772,004	276,679,390	21,092,614	8%
Small General Service	8,970,098	9,971,001	8,067,210	7,036,012	6,633,792	6,610,922	7,112,108	8,831,426	8,163,624				71,396,193	64,259,147	7,137,046	11%
Medium General Service	13,955,681	15,792,464	13,060,912	12,356,206	12,295,106	12,551,570	13,533,371	15,933,028	15,586,314				125,064,652	109,331,826	15,732,826	14%
Large General Service	11,305,220	11,582,060	11,745,360	12,245,960	11,842,240	12,500,860	12,925,480	15,390,200	13,940,600				113,477,980	114,469,072	(991,092)	-1%
Small Industrial	3,136,400	4,029,200	7,409,600	5,286,400	6,281,200	4,584,400	4,758,800	12,034,400	9,529,600				57,050,000	47,737,431	9,312,569	20%
Large Industrial	7,002,600	8,644,320	7,515,840	6,361,920	6,054,840	5,785,680	5,796,600	3,679,320	3,822,600				54,663,720	76,941,462	(22,277,742)	-29%
Small Irrigation	28,896	23,929	35,846	34,420	171,481	252,379	290,018	331,046	288,357				1,456,372	1,103,115	353,257	32%
Large Irrigation	33,231	23,520	18,520	262,347	1,331,486	2,188,454	2,721,882	3,142,480	2,600,089				12,322,009	15,601,177	(3,279,168)	-21%
Cable TV Amp	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092				963,828	963,828	-	0%
Street Lighting	180,707	147,345	143,374	117,161	102,467	102,467	96,906	113,587	129,870				1,133,884	1,265,549	(131,665)	-10%
Rental Lighting	61,614	50,239	48,885	39,948	34,937	34,937	33,042	38,729	44,281				386,612	391,027	(4,415)	-1%
Traffic Lights	-	50,574	23,010	22,252	21,035	21,363	20,976	22,353	22,774				204,337	283,785	(79,448)	-28%
TOTAL CONSUMPTION (kWh):	91,256,502	96,871,151	79,277,489	68,150,415	68,479,360	69,803,564	81,158,214	95,705,028	85,189,868				735,891,591	709,026,810	26,864,781	4%

METERS: (Active meters at month end)													Monthly Avg	Budget	Variance	% Budget Variance
Residential	25,443	25,452	25,541	25,461	25,464	25,467	25,461	25,475	25,480				25,472	26,323	(852)	-3%
Small General Service	2,492	2,495	2,485	2,557	2,556	2,552	2,552	2,554	2,557				2,533	2,595	(62)	-2%
Medium General Service	318	319	322	322	321	321	324	324	324				322	314	8	2%
Large General Service	45	45	46	47	47	47	47	47	47				46	57	(10)	-18%
Small Industrial	9	9	8	8	8	8	9	9	9				9	8	0	5%
Large Industrial	5	5	5	4	5	5	4	4	4				5	3	1	48%
Small Irrigation	80	79	80	79	79	79	79	79	79				79	86	(7)	-8%
Large Irrigation	18	18	19	19	19	19	19	19	19				19	21	(2)	-10%
Cable TV Amp	1	1	1	1	1	1	1	1	1				1	1	-	0%
Street Lighting (unmetered)	1	1	1	1	1	1	1	1	1				1	1	-	0%
Rental Lighting (Accounts)	400	400	400	400	400	400	400	400	400				400	400	-	0%
Traffic Lights	56	56	56	56	56	56	56	56	56				56	57	(1)	-2%
TOTAL ACTIVE METERS:	28,868	28,880	28,964	28,955	28,957	28,956	28,953	28,969	28,977				28,942	29,867	(925)	-3%

METERED DEMAND (kW):													Total To Date	Budget	Variance	% Budget Variance
Residential	412	398	300	335	340	300	331	332	324				3,072	-	3,072	
Small General Service	22,287	27,006	19,995	19,774	18,772	18,360	40,684	46,091	80,852				293,821	-	293,821	
Medium General Service	34,173	40,465	34,707	35,069	34,769	35,885	37,484	41,655	39,553				333,760	311,588	22,172	7%
Large General Service	20,985	21,640	22,978	25,815	24,535	25,494	26,652	31,056	27,363				226,518	254,041	(27,523)	-11%
Small Industrial	7,560	7,818	15,206	12,815	12,278	9,848	10,212	21,043	16,760				113,540	92,021	21,519	23%
Large Industrial	14,624	20,326	14,861	15,074	12,321	12,014	11,502	8,498	8,353				117,573	156,215	(38,642)	-25%
Small Irrigation	160	101	153	238	693	675	711	732	700				4,163	-	4,163	
Large Irrigation	49	50	75	2,382	5,067	6,655	7,841	9,540	7,673				39,332	47,417	(8,085)	-17%
TOTAL METERED DEMAND (kW):	100,250	117,804	108,275	111,502	108,775	109,231	135,417	158,947	181,578				1,131,779	861,282	270,497	31%

ELECTRIC UTILITY CUSTOMERS:	27,440	27,477	27,688	27,071	27,663	27,802	27,935	27,862	27,884

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
COMPARATIVE REVENUE AND CONSUMPTION
FOR THE PERIOD ENDED
September 2024

POWER SALE REVENUE (Net of City Utility Tax):	CURRENT QUARTER	BUDGET	VARIANCE FROM BUDGET	% VARIANCE FROM BUDGET	2024 - 2023 CURRENT QTR. (+/-)	2024 YEAR TO DATE	2024 - 2023 YTD (+/-)
Residential	$ 8,788,591	$ 8,354,799	$ 433,792	5%	79,550	$ 26,434,782	$ (1,353,835)
Small General Service	1,860,321	1,742,754	117,566	7%	124,593	5,481,233	45,313
Medium General Service	2,615,558	2,307,604	307,954	13%	130,715	7,275,045	89,748
Large General Service	2,293,377	2,123,794	169,583	8%	172,491	6,162,283	318,059
Small Industrial	1,357,743	935,542	422,200	45%	264,514	3,105,062	57,719
Large Industrial	724,705	1,331,527	(606,822)	-46%	(285,810)	2,980,834	(930,695)
Small Irrigation	59,113	48,144	10,968	23%	(278)	111,829	1,849
Large Irrigation	549,175	661,048	(111,873)	-17%	(86,477)	836,986	(47,419)
Cable TV Amp	16,861	16,867	(6)	0%	-	50,584	-
Street Lighting	26,700	91,433	(64,732)	-71%	(17,052)	79,520	(148,561)
Rental Lighting	29,230	31,936	(2,706)	-8%	246	87,784	(1,816)
Traffic Lights	7,897	9,211	(1,314)	-14%	107	24,277	(689)
TOTAL POWER SALE REVENUE:	$ 18,329,271	$ 17,654,660	$ 674,611	4%	$ 382,597	$ 52,630,220	$ (1,970,327)
CONSUMPTION (kWh):							
Residential	100,797,973	90,320,559	10,477,414	12%	3,098,736	297,772,004	(18,539,541)
Small General Service	24,107,158	22,574,732	1,532,426	7%	1,130,934	71,396,193	(2,622,072)
Medium General Service	45,052,713	39,318,012	5,734,701	15%	(286,662)	125,064,652	(1,457,651)
Large General Service	42,256,280	38,222,186	4,034,094	11%	4,955,300	113,477,980	4,871,740
Small Industrial	26,322,800	17,038,525	9,284,275	54%	11,160,800	57,050,000	3,025,400
Large Industrial	13,298,520	25,115,232	(11,816,712)	-47%	(5,279,160)	54,663,720	(18,667,560)
Small Irrigation	909,421	740,685	168,736	23%	428	1,456,372	1,735
Large Irrigation	8,464,451	10,892,640	(2,428,189)	-22%	(2,042,197)	12,322,009	(1,588,899)
Cable TV Amp	321,276	321,276	-	0%	-	963,828	-
Street Lighting	340,363	378,849	(38,486)	-10%	(134,623)	1,133,884	(1,144,922)
Rental Lighting	116,052	114,694	1,358	1%	904	386,612	8,506
Traffic Lights	66,103	85,791	(19,688)	-23%	2,614	204,337	(10,544)
TOTAL CONSUMPTION (kWh):	262,053,110	245,123,181	16,929,929	7%	12,607,074	735,891,591	(36,123,808)
METERED DEMAND (kW):							
Residential	987	-	987		(160)	3,072	(2,213)
Small General Service	167,627	-	167,627		114,183	293,821	(158,851)
Medium General Service	118,692	111,654	7,038		10,749	333,760	2,067
Large General Service	85,071	85,623	(552)		6,952	226,518	3,838
Small Industrial	48,015	33,657	14,358		17,701	113,540	4,323
Large Industrial	28,353	48,334	(19,981)		(10,398)	117,573	(31,331)
Small Irrigation	2,143	-	2,143		299	4,163	338
Large Irrigation	25,054	26,691	(1,637)		129	39,332	1,240
TOTAL METERED DEMAND (kW):	475,942	305,959	169,983		139,455	1,131,779	(180,589)

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
COMPARATIVE REVENUE AND CONSUMPTION
FOR THE PERIOD ENDED
September 2024

	CURRENT QUARTER	QUARTERLY BUDGET	% VARIANCE FROM BUDGET	MONTHLY AVERAGE Y-T-D ACTUAL	MONTHLY AVERAGE Y-T-D BUDGET	% VARIANCE FROM BUDGET
POWER SALE REVENUE PER METER:						
(Net of Utility Tax)						
Residential	$ 345	$ 317	8%	$ 115	$ 106	8%
Small General Service	728	669	8%	240	214	11%
Medium General Service	8,073	7,306	9%	2,513	2,335	7%
Large General Service	48,795	38,571	21%	14,742	12,729	14%
Small Industrial	150,860	101,056	33%	40,325	37,182	8%
Large Industrial	181,176	431,488	-138%	72,703	155,599	-114%
Small Irrigation	748	564	25%	157	120	23%
Large Irrigation	28,904	31,735	-10%	4,953	5,155	-4%
Cable TV Amp	16,861	16,867	0%	5,620	5,622	0%
Street Lighting	26,700	91,433	-242%	8,836	30,312	-243%
Rental Lighting	73	80	-9%	24	26	-8%
Traffic Lights	141	162	-15%	48	58	-20%
System Average Per Meter	$ 633	590	7%	$ 202	$ 192	5%
POWER SALE REVENUE PER KILOWATT HOUR:	($/kWh)	($/kWh)		($/kWh)	($/kWh)	
(Net of Utility Tax)						
Residential	$ 0.2614	$ 0.2792	-7%	$ 0.0888	$ 0.0925	-4%
Small General Service	0.2321	0.2318	0%	0.0768	0.0777	-1%
Medium General Service	0.1744	0.1761	-1%	0.0582	0.0589	-1%
Large General Service	0.1633	0.1667	-2%	0.0543	0.0556	-2%
Small Industrial	0.1692	0.1646	3%	0.0544	0.0545	0%
Large Industrial	0.1639	0.1591	3%	0.0545	0.0536	2%
Small Irrigation	0.1950	0.1950	0%	0.0768	0.0777	-1%
Large Irrigation	0.1946	0.1824	6%	0.0679	0.0662	3%
Cable TV Amp	0.1574	0.1575	0%	0.0525	0.0525	0%
Street Lighting	0.2391	0.7358	-208%	0.0701	0.1976	-182%
Rental Lighting	0.7660	0.8468	-11%	0.2271	0.2243	1%
Traffic Lights	0.3587	0.3227	10%	0.1188	0.1030	13%
System Average Per Meter	$ 0.0699	$ 0.0720	-3%	$ 0.0715	$ 0.0727	-2%
KILOWATT HOURS PER METER:	(kWh)	(kWh)		(kWh)	(kWh)	
Residential	3,957	3,423	13%	1,299	1,144	12%
Small General Service	9,437	8,664	8%	3,131	2,754	12%
Medium General Service	139,052	124,488	10%	43,200	39,646	8%
Large General Service	899,070	694,159	23%	271,478	229,030	16%
Small Industrial	2,924,756	1,840,474	37%	740,909	681,894	8%
Large Industrial	3,324,630	8,138,722	-145%	1,333,261	2,904,155	-118%
Small Irrigation	11,512	8,673	25%	2,043	1,547	24%
Large Irrigation	445,497	522,916	-17%	72,911	77,845	-7%
Cable TV Amp	321,276	321,276	0%	107,092	107,092	0%
Street Lighting	340,363	378,849	-11%	125,987	153,376	-22%
Rental Lighting	290	287	1%	107	117	-9%
Traffic Lights	1,180	1,508	-28%	405	561	-38%
System Average Per Meter	3,016	2,785	8%	2,825	2,638	7%

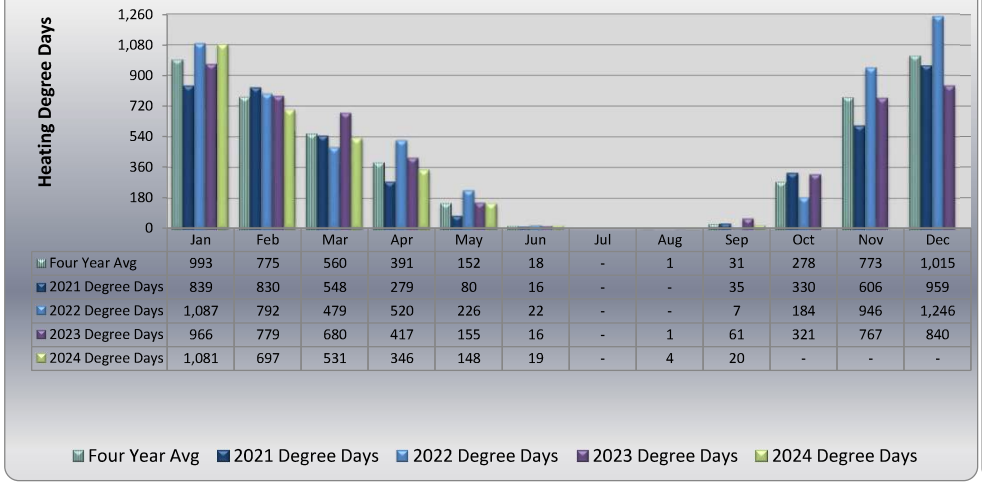
CITY OF RICHLAND, WASHINGTON
KWH SALES
MONTHLY ACTIVITY
September 30, 2024

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	**2020**	38,935,267	33,391,001	32,026,840	30,053,283	19,718,645	19,423,100	26,873,074	34,593,924	28,873,241	23,502,098	24,628,883	36,059,784	348,079,140
	2021	42,961,552	32,653,469	37,341,171	24,940,097	21,125,515	25,314,073	36,208,801	36,373,806	29,298,314	22,255,864	20,848,763	30,691,029	360,012,454
	2022	49,039,611	41,279,574	36,354,431	27,133,139	23,367,853	21,489,861	32,671,389	35,444,762	31,219,771	22,625,124	25,506,629	42,997,932	389,130,076
	2023	51,240,007	49,159,844	36,100,316	29,254,817	24,584,090	28,273,234	33,696,594	34,995,841	29,006,802	20,689,801	27,575,612	38,090,278	402,667,236
	2024	46,474,963	46,449,407	31,101,840	24,280,697	23,603,684	25,063,440	33,761,939	36,081,367	30,954,667	-	-	-	297,772,004
Small	**2020**	7,922,069	7,873,541	6,785,986	6,098,899	4,868,686	5,097,523	5,986,353	7,517,741	7,006,880	6,158,758	6,446,476	6,724,282	78,487,194
General	**2021**	7,779,373	7,469,306	6,905,812	6,476,957	6,064,756	6,428,885	8,108,563	8,955,264	8,498,312	6,416,984	6,039,814	6,549,444	85,693,470
Service	**2022**	8,672,513	8,557,533	7,645,107	6,313,778	6,396,075	6,200,458	7,404,873	8,841,295	8,643,402	6,807,432	5,955,973	6,223,346	87,661,785
	2023	9,355,656	9,378,275	10,702,353	7,753,484	6,606,235	7,246,038	4,135,463	10,226,661	8,614,100	6,612,713	6,584,222	7,625,562	94,840,762
	2024	8,970,098	9,971,001	8,067,210	7,036,012	6,633,792	6,610,922	7,112,108	8,831,426	8,163,624	-	-	-	71,396,193
Medium	**2020**	11,981,289	14,945,342	12,184,535	11,649,312	10,181,464	10,224,047	11,570,896	13,356,128	13,627,983	11,466,564	11,744,235	11,826,692	144,758,487
General	**2021**	12,162,982	11,921,031	11,465,540	11,256,256	10,488,859	11,759,542	13,301,710	16,054,935	15,258,787	12,549,015	11,830,679	12,021,842	150,071,178
Service	**2022**	13,698,251	13,782,777	12,114,825	11,418,118	11,629,718	11,284,763	12,786,332	15,317,547	16,166,234	13,770,398	13,759,046	11,427,267	157,155,276
	2023	14,985,418	15,109,377	13,107,117	12,484,419	11,972,542	13,524,055	11,323,304	18,633,333	15,382,738	13,458,975	12,553,373	12,140,431	164,675,082
	2024	13,955,681	15,792,464	13,060,912	12,356,206	12,295,106	12,551,570	13,533,371	15,933,028	15,586,314	-	-	-	125,064,652
Large	**2020**	11,477,460	13,461,220	11,357,660	12,005,980	11,191,560	11,811,640	12,659,220	14,427,140	16,242,360	13,425,600	13,387,580	12,653,440	154,100,860
General	**2021**	13,056,640	12,933,980	11,423,420	12,765,020	12,289,580	12,879,680	14,141,600	15,151,200	14,000,340	12,381,300	11,663,940	11,404,860	154,091,560
Service	**2022**	11,598,180	12,041,400	10,807,040	12,275,920	10,485,140	11,312,580	12,189,280	13,585,040	13,728,440	12,780,740	9,460,100	9,411,980	139,675,840
	2023	12,640,040	10,396,460	13,906,960	11,498,200	10,771,760	12,091,840	10,940,080	12,818,120	13,542,780	12,722,340	11,713,060	11,274,880	144,316,520
	2024	11,305,220	11,582,060	11,745,360	12,245,960	11,842,240	12,500,860	12,925,480	15,390,200	13,940,600	-	-	-	113,477,980
Small	**2020**	3,868,600	4,583,600	4,541,600	5,963,200	4,181,600	3,903,200	4,886,400	3,735,400	5,810,000	5,149,600	4,522,400	4,705,600	55,851,200
Industrial	**2021**	4,685,200	4,653,600	4,830,200	4,607,200	5,672,400	5,836,400	6,182,600	6,703,400	6,444,400	6,807,400	6,072,000	5,853,400	68,348,200
	2022	5,610,800	5,307,800	5,434,000	5,758,000	5,915,200	6,257,600	6,147,600	6,628,200	6,437,000	5,585,000	5,815,800	7,175,200	72,072,200
	2023	5,889,400	5,881,600	9,455,400	5,693,400	5,209,600	6,733,200	5,600,000	5,042,800	4,519,200	10,400,000	5,411,200	3,142,000	72,977,800
	2024	3,136,400	4,029,200	7,409,600	5,286,400	6,281,200	4,584,400	4,758,800	12,034,400	9,529,600	-	-	-	57,050,000
Large	**2020**	9,568,800	10,219,200	8,959,200	9,716,400	7,278,000	8,372,400	7,125,600	7,981,200	7,704,000	7,100,400	8,516,400	7,970,400	100,512,000
Industrial	**2021**	8,343,600	8,580,000	7,447,200	8,732,400	8,337,600	8,667,600	9,037,200	9,279,600	9,560,400	8,481,600	9,216,000	8,749,200	104,432,400
	2022	8,991,600	9,993,600	8,713,200	9,255,600	7,690,800	8,941,200	9,226,800	9,133,200	10,334,400	8,713,200	8,968,800	8,552,400	108,514,800
	2023	9,807,600	11,328,000	5,374,800	11,052,000	6,448,440	10,742,760	6,657,000	6,733,080	5,187,600	6,903,960	7,612,800	6,702,840	94,550,880
	2024	7,002,600	8,644,320	7,515,840	6,361,920	6,054,840	5,785,680	5,796,600	3,679,320	3,822,600	-	-	-	54,663,720
Small	**2020**	25,840	14,998	10,035	20,824	110,048	188,869	251,090	274,364	288,970	290,624	140,492	46,807	1,662,961
Irrigation	**2021**	17,719	10,685	14,422	22,364	88,955	196,765	252,630	293,120	297,801	242,759	180,958	45,373	1,663,551
	2022	28,124	19,883	21,581	26,973	54,735	175,679	227,307	245,067	353,832	240,112	129,185	44,584	1,567,062
	2023	65,717	40,210	21,382	29,830	137,081	251,424	285,545	322,718	300,730	224,573	102,724	32,260	1,814,194
	2024	28,896	23,929	35,846	34,420	171,481	252,379	290,018	331,046	288,357	-	-	-	1,456,372
Large	**2020**	18,246	20,251	108,912	163,069	1,370,968	2,098,460	2,758,538	3,323,710	3,299,247	2,347,097	981,071	56,975	16,546,544
Irrigation	**2021**	22,252	19,252	17,673	278,619	1,570,589	2,622,592	3,852,844	4,716,033	3,762,517	2,507,068	1,212,151	82,111	20,663,701
	2022	23,849	14,030	22,991	241,635	880,123	1,368,193	2,591,007	3,779,317	4,034,037	2,856,070	878,835	103,131	16,793,218
	2023	20,437	126,130	24,647	119,860	828,125	2,285,061	3,112,964	3,892,077	3,501,607	2,158,889	847,010	31,193	16,948,000
	2024	33,231	23,520	18,520	262,347	1,331,486	2,188,454	2,721,882	3,142,480	2,600,089	-	-	-	12,322,009
Cable	**2020**	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	74,613	107,092	74,613	107,092	960,314
	2021	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	1,285,104
	2022	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	1,285,104
	2023	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	1,285,104
	2024	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	107,092	-	-	-	963,828
Street	**2020**	303,597	303,597	303,597	303,597	303,597	303,597	303,597	303,597	303,597	387,102	422,742	466,167	4,008,384
Lighting	**2021**	451,268	332,116	323,068	264,321	231,601	201,080	219,033	257,236	294,270	354,826	388,245	426,343	3,743,407
	2022	413,449	337,120	329,071	268,909	235,181	204,188	222,548	260,855	298,819	358,217	391,115	429,495	3,748,967
	2023	418,105	340,917	331,822	270,872	237,757	204,347	221,373	118,325	135,288	162,180	177,074	194,450	2,812,510
	2024	180,707	147,345	143,374	117,161	102,467	102,467	96,906	113,587	129,870	-	-	-	1,133,884
Rental	**2020**	89,311	72,822	65,550	48,568	42,476	42,090	42,090	46,658	53,479	64,109	69,997	76,866	714,016
Lighting	**2021**	74,381	49,652	48,313	39,480	34,529	29,978	32,655	38,276	43,763	52,462	57,280	62,901	563,670
	2022	60,894	49,652	48,313	39,480	34,529	29,978	32,655	38,276	43,763	52,462	57,280	62,901	550,183
	2023	60,894	49,652	48,313	39,480	34,529	30,090	32,784	38,428	43,936	52,670	57,958	63,646	552,380
	2024	61,614	50,239	48,885	39,948	34,937	34,937	33,042	38,729	44,281	-	-	-	386,612
Traffic	**2020**	34,040	39,820	35,212	31,086	31,698	26,067	25,910	26,001	27,452	30,845	33,623	39,461	381,215
Lights	**2021**	35,436	38,640	35,325	29,882	29,952	28,759	27,778	26,685	31,328	31,347	32,788	34,689	382,609
	2022	32,878	41,145	34,449	30,058	31,402	26,989	26,512	33,764	28,696	28,950	30,867	29,271	374,981
	2023	28,875	28,220	24,005	25,510	22,839	21,943	-	41,376	22,113	22,745	23,523	23,981	285,130
	2024	-	50,574	23,010	22,252	21,035	21,363	20,976	22,353	22,774	-	-	-	204,337
Total	**2020**	84,299,132	85,000,005	76,453,740	76,128,831	59,353,355	61,565,606	72,557,381	85,660,476	83,311,822	70,029,889	70,968,512	80,733,566	906,062,315
System	**2021**	89,697,495	78,768,823	79,959,236	69,519,688	66,041,428	74,072,446	91,472,506	97,956,647	87,597,324	72,187,717	67,649,710	76,028,284	950,951,304
	2022	98,277,241	91,531,606	81,632,100	72,868,702	66,827,848	67,398,581	83,633,395	93,414,415	91,395,486	73,924,797	71,060,722	86,564,599	978,529,492
	2023	104,619,241	101,945,777	89,204,207	78,328,964	66,960,090	81,511,084	76,112,199	92,969,851	80,363,986	73,515,938	72,765,648	79,428,613	997,725,598
	2024	91,256,502	96,871,151	79,277,489	68,150,415	68,479,360	69,803,564	81,158,214	95,705,028	85,189,868	-	-	-	735,891,591

City of Richland, Washington
Electric Utility
September 30, 2024

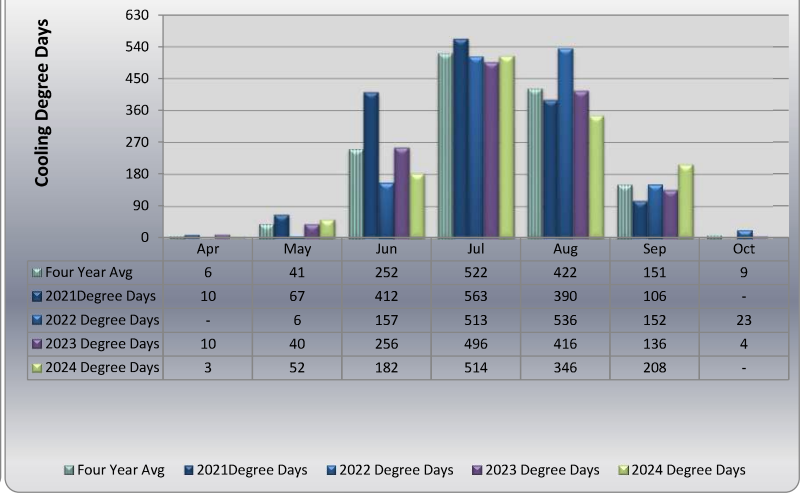
Climatological Data From Hanford Meteorology Station Located 25 Miles N.W. of Richland, WA

Heating Degree Days By Month



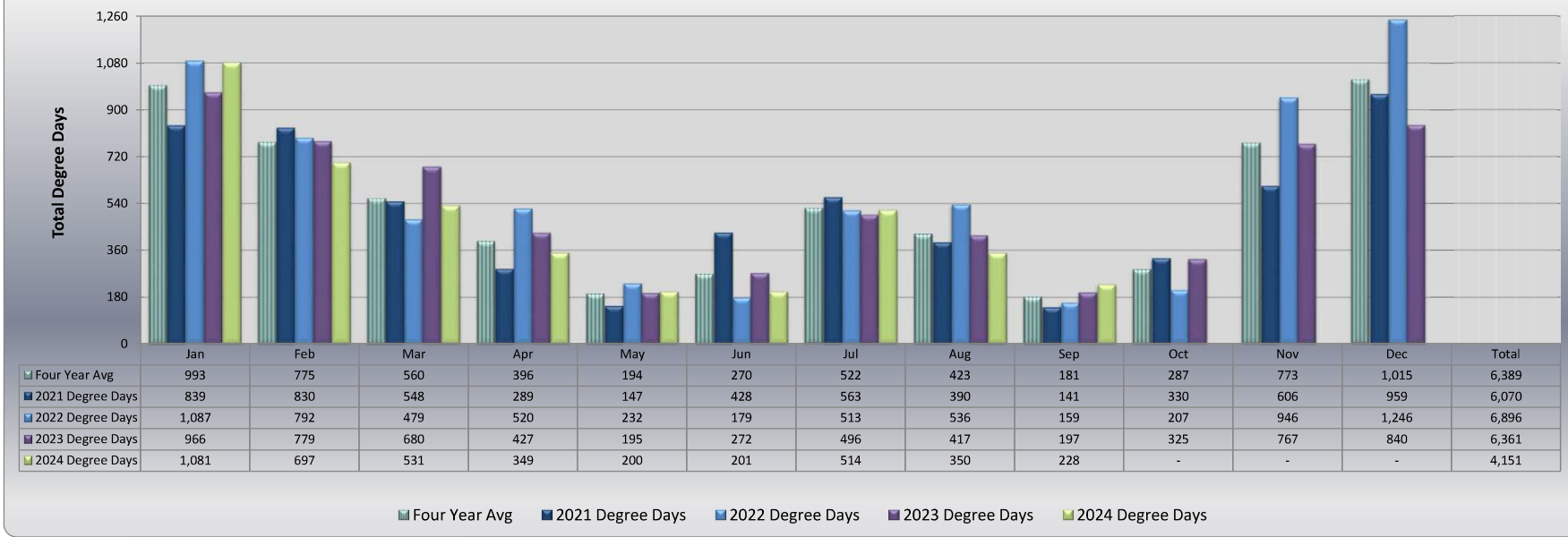
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Four Year Avg	993	775	560	391	152	18	-	1	31	278	773	1,015
2021 Degree Days	839	830	548	279	80	16	-	-	35	330	606	959
2022 Degree Days	1,087	792	479	520	226	22	-	-	7	184	946	1,246
2023 Degree Days	966	779	680	417	155	16	-	1	61	321	767	840
2024 Degree Days	1,081	697	531	346	148	19	-	4	20	-	-	-

Cooling Degree Days By Month



	Apr	May	Jun	Jul	Aug	Sep	Oct
Four Year Avg	6	41	252	522	422	151	9
2021Degree Days	10	67	412	563	390	106	-
2022 Degree Days	-	6	157	513	536	152	23
2023 Degree Days	10	40	256	496	416	136	4
2024 Degree Days	3	52	182	514	346	208	-

Total Degree Days By Month



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Four Year Avg	993	775	560	396	194	270	522	423	181	287	773	1,015	6,389
2021 Degree Days	839	830	548	289	147	428	563	390	141	330	606	959	6,070
2022 Degree Days	1,087	792	479	520	232	179	513	536	159	207	946	1,246	6,896
2023 Degree Days	966	779	680	427	195	272	496	417	197	325	767	840	6,361
2024 Degree Days	1,081	697	531	349	200	201	514	350	228	-	-	-	4,151

Degree days are indicators of how much energy a typical household will use for heating or cooling. Degree days are based on the assumption that when the outside temperature is 65° F, a household would not need heating or cooling to be comfortable. An increase in heating or cooling degrees days correlates with increased energy consumption. Degree days are the difference between the average daily temperature and 65° F. Cooling degree days result when the daily temperature average is above 65°F. Heating degree days result when the daily temperature average is below 65°F.

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
DETAILED BALANCE SHEET
As of September 30, 2024

Acct. No.	Account Title	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
ASSETS													
12810	Cash - Bond Redemption	1,781,476.40	2,247,605.26	2,713,734.12	3,179,862.98	2,066,718.71	2,532,847.57	2,998,976.43	3,465,105.29	3,931,234.15			
12810	Cash - Adjustment for Investments	-											
12811	Cash - Rate Financed Capital Reserve	-											
12812	Cash - 2015 Bond (LGIP)	-											
12813	Cash - Conservation Loan (LGIP)	330,965.68	332,389.12	333,915.41	335,396.76	336,934.59	338,431.19	339,986.50	341,544.48	343,012.03			
12814	Cash - Bond Reserve (LGIP)	3,532,342.08	3,553,139.94	3,575,440.64	3,597,084.58	3,619,553.85	3,641,420.64	3,664,145.26	3,686,908.90	3,708,351.22			
12840	Cash - Operating Reserve	2,400,000.00	2,400,000.00	2,400,000.00	2,400,000.00	2,400,000.00	2,400,000.00	2,400,000.00	2,400,000.00	2,400,000.00			
12845	Cash - 2018 Bonds (LGIP)	-	-	-	-	-	-	-	-	-			
12847	Cash - 2019 Bonds (LGIP)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
12850	Cash - 2021 Bonds (LGIP)	-	-	-	-	-	-	-	-	-			
12851	Cash - 2023 Bonds (LGIP)	7,142,848.08	7,169,741.48	6,825,320.17	6,322,128.60	5,211,368.25	5,238,053.12	4,648,315.59	4,351,303.27	3,596,270.17			
12856	Investments - Unrestricted	-	-	-	-	-	-	-	-	-			
12857	Investments - Bond Reserve	-	-	-	-	-	-	-	-	-			
12860	Investments - Conservation Loan	-	-	-	-	-	-	-	-	-			
12861	Investments - Bond Proceeds	-	-	-	-	-	-	-	-	-			
12870	Cash - Facility Fees	926,728.55	1,033,599.12	1,394,050.51	2,203,867.93	2,452,802.51	2,606,797.00	2,844,600.11	3,465,958.96	3,417,587.77			
12870	Cash - Facility Fees - Large Projects	-	-	-	-	-	-	-	-	-			
12870	Cash - Facility Fees Subject To Refund	453,388.19	453,388.19	453,388.19	453,388.19	453,388.19	453,388.19	453,388.19	520,588.19	452,788.19			
13100	Cash - Unrestricted	17,516,915.88	16,737,973.11	15,652,784.09	18,672,212.46	18,953,102.91	19,552,917.62	19,444,912.22	17,965,790.12	24,524,384.39			
13100	Cash - Credit Support Reserve (NIES)	-	-	-	-	-	-	-	-	-			
13130	Cash - Conservation Loan	1,695,153.82	1,686,689.71	1,713,209.22	1,747,088.07	1,668,621.86	1,723,141.33	1,693,878.84	1,613,904.46	1,617,112.76			
14100	Energy Conservation Loans	1,781,224.33	1,793,224.29	1,773,457.11	1,749,781.30	1,831,790.81	1,784,198.35	1,821,352.38	1,910,397.87	1,913,741.93			
14101	Energy Conservation Loans Billed Monthly	156,682.78	159,596.95	160,016.08	158,075.61	163,683.41	163,274.98	163,457.90	164,241.24	167,253.55			
14200	A/R - Customer Billings	4,499,861.45	5,299,714.75	4,071,290.39	3,148,143.62	3,462,995.60	3,509,099.18	4,249,802.83	4,323,109.68	3,388,637.89			
14300	A/R - Misc.	79,709.56	220,307.13	1,587,177.26	116,350.11	116,350.11	123,314.17	117,265.59	1,637,931.93	123,291.46			
14310	A/R - Pole Contracts	-	-	-	-	-	-	-	-	-			
14320	Due from Other Funds	-	-	-	-	-	-	-	-	-			
14400	Provision for Uncollectible	(246,306.00)	(254,187.61)	(266,004.14)	(277,415.69)	(288,532.46)	(292,237.10)	(301,950.00)	(313,840.50)	(325,140.06)			
15400	Materials and Supplies	7,717,615.51	8,586,958.84	9,282,656.32	8,775,673.45	8,051,264.33	8,373,345.72	8,662,024.61	8,481,295.30	8,251,765.07			
15410	Exempt Materials and Supplies	6,402.69	6,402.69	6,402.69	6,402.69	6,402.69	6,402.69	6,402.69	6,402.69	6,402.69			
16300	Stores Expense - Clearing	46,749.90	93,022.47	163,728.45	215,158.24	276,414.81	267,847.35	313,820.53	385,015.72	437,919.08			
16500	Prepaid Expenses	346,324.38	269,385.80	242,447.22	215,508.64	188,570.06	161,631.48	134,692.90	107,754.32	80,815.74			
16512	WCIA Insurance Deposit	1,900.00	1,900.00	1,900.00	1,900.00	1,900.00	1,900.00	1,900.00	1,900.00	1,900.00			
17200	Net Pension Asset	1,854,814.00	1,854,814.00	1,854,814.00	1,854,814.00	1,854,814.00	1,854,814.00	1,854,814.00	1,854,814.00	1,854,814.00			
17210	Lease Receivable	388,132.60	388,132.60	388,132.60	388,132.60	388,132.60	388,132.60	388,132.60	388,132.60	388,132.60			
18171	Unamortized Prem - 2013 Rev Ref Bonds	-	-	-	-	-	-	-	-	-			
18172	Unamortized Prem - 2015 Bonds	(1,473,507.37)	(1,467,861.75)	(1,462,216.13)	(1,456,570.51)	(1,450,924.89)	(1,445,279.27)	(1,439,633.65)	(1,433,988.03)	(1,428,342.41)			
18173	Unamortized Prem - 2018 Bonds	(880,331.20)	(877,242.32)	(874,153.44)	(871,064.56)	(867,975.68)	(864,886.80)	(861,797.92)	(858,709.04)	(855,620.16)			
18174	Unamortized Prem - 2019 Bonds	(2,177,575.35)	(2,168,865.05)	(2,160,154.75)	(2,151,444.45)	(2,142,734.15)	(2,134,023.85)	(2,125,313.55)	(2,116,603.25)	(2,107,892.95)			
18175	Unamortized Prem - 2021 Bonds	(1,051,322.95)	(1,047,486.00)	(1,043,649.05)	(1,039,812.10)	(1,035,975.15)	(1,032,138.20)	(1,028,301.25)	(1,024,464.30)	(1,020,627.35)			
18176	Unamortized Prem - 2023 Bonds	(1,794,776.52)	(1,788,630.03)	(1,782,483.54)	(1,776,337.05)	(1,770,190.56)	(1,764,044.07)	(1,757,897.58)	(1,751,751.09)	(1,745,604.60)			
18400	Clearing Account - Overhead	55,165.78	140,064.46	118,243.15	112,798.25	97,002.03	120,624.62	126,442.71	166,547.97	204,930.43			
18410	Clearing Account - Equipment	32,924.06	50,846.24	82,702.31	132,006.69	200,994.66	234,624.00	255,195.10	295,273.91	321,662.83			
18500	Deferred Debits - Temp. Facilities	(4,950.00)	(9,225.00)	(14,625.00)	(18,900.00)	(22,071.42)	(27,471.42)	(31,521.42)	(38,721.42)	(45,021.42)			
18610	Deferred Debits - Damages & Claims	3,626.01	4,871.62	14,537.71	14,537.71	14,537.71	14,537.71	19,425.01	19,425.01	22,156.98			
18620	Deferred Debits - Pension	1,585,624.00	1,585,624.00	1,585,624.00	1,585,624.00	1,585,624.00	1,585,624.00	1,585,624.00	1,585,624.00	1,585,624.00			
18630	Deferred Debits - OPEB	50,750.34	50,750.34	50,750.34	50,750.34	50,750.34	50,750.34	50,750.34	50,750.34	50,750.34			
18640	Conservation Programs	730,356.49	739,737.82	777,727.59	779,564.12	818,127.49	836,707.45	855,510.49	864,713.16	839,372.56			
18916	Unamortized Loss on 2001 Refunded	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
18925	Unamort Loss 2003 Rev & Rev Ref Bonds	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)			
18926	Unamort Loss 2009 Rev & Rev Ref Bonds	74,916.07	74,521.77	74,127.47	73,733.17	73,338.87	72,944.57	72,550.27	72,155.97	71,761.67			
	SUBTOTAL ASSETS	47,563,829.24	49,320,903.94	49,694,290.99	50,698,439.75	48,766,780.08	50,476,689.16	51,620,951.72	52,588,511.75	56,173,424.55			
CWIP													
10200	Electric Plant Purchased	-	-	-	346,147.93	346,147.93	346,147.93	346,147.93	346,147.93	346,147.93			
10700	Utility Plant Work in Progress	-	-	-	-	-	-	-	-	-			
10710	Utility Plant Work in Progress	2,352,030.18	2,609,210.54	2,826,440.93	3,025,005.41	3,246,580.60	3,472,043.08	3,653,318.26	3,967,338.50	4,175,166.45			
10720	Construction W I P Ret	-	-	-	-	-	-	-	-	-			
	TOTAL CWIP	2,352,030.18	2,609,210.54	2,826,440.93	3,371,153.34	3,592,728.53	3,818,191.01	3,999,466.19	4,313,486.43	4,521,314.38			
FIXED ASSETS													
34100	Leasehold Structures & Improve - Solar	8,092.88	8,092.88	8,092.88	8,092.88	8,092.88	8,092.88	8,092.88	8,092.88	8,092.88			
35000	Land and Land Rights	586,985.87	586,985.87	586,985.87	586,985.87	587,018.92	587,018.92	587,018.92	587,018.92	587,018.92			
35300	Station Equipment	16,928.56	16,928.56	16,928.56	16,928.56	16,928.56	16,994.65	17,358.16	17,358.16	17,358.16			
35400	Towers & Fixtures	16,360.40	16,360.40	16,360.40	16,360.40	16,360.40	16,459.54	16,459.54	16,459.54	16,459.54			

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
DETAILED BALANCE SHEET
As of September 30, 2024

Acct. No.	Account Title	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
35500	Poles & Fixtures	5,844,912.92	5,848,987.58	5,849,170.69	5,855,880.33	5,859,284.71	5,859,648.22	5,859,648.22	5,860,837.90	5,860,837.90			
35600	Conductor - Overhead	1,566,942.58	1,568,396.64	1,568,482.36	1,569,209.38	1,574,629.04	1,576,365.39	1,577,690.05	1,579,871.14	1,580,625.61			
35700	U/G Conduit	123,104.26	124,139.47	125,527.43	126,254.46	126,617.97	127,741.56	130,220.07	134,036.97	137,969.54			
35800	Conductor - Underground	1,729,311.01	1,744,827.73	1,766,869.85	1,796,658.83	1,820,089.52	1,838,439.56	1,866,270.26	1,895,732.78	1,918,948.14			
36000	Land and Land Rights	222,252.42	222,252.42	222,252.42	222,252.42	222,252.42	222,252.42	222,252.42	222,252.42	222,252.42			
36100	Structures & Improvements	1,465,481.15	1,465,481.15	1,465,481.15	1,465,481.15	1,465,481.15	1,465,481.15	1,465,481.15	1,465,481.15	1,465,481.15			
36200	Station Equipment	6,423,221.34	6,448,276.05	6,641,360.45	6,664,627.97	6,665,355.91	6,665,566.15	7,659,129.38	7,675,261.74	7,678,167.95			
36210	1st Street Substation	2,131,401.59	2,131,401.59	2,131,401.59	2,131,401.59	2,131,401.59	2,131,401.59	2,131,401.59	2,131,401.59	2,135,397.51			
36211	1st Street Substation - SCADA	50,821.15	50,821.15	50,821.15	50,821.15	50,821.15	50,821.15	50,821.15	50,821.15	50,821.15			
36212	SCADA System - Wide	642,772.57	642,772.57	642,772.57	642,772.57	642,772.57	642,772.57	643,534.64	643,534.64	643,534.64			
36220	Tapteal Substation	818,597.99	818,597.99	819,395.52	864,795.70	864,795.70	864,795.70	864,795.70	864,795.70	867,214.57			
36221	Tapteal Substation - SCADA	66,140.03	66,140.03	66,140.03	66,140.03	66,140.03	66,140.03	66,140.03	66,140.03	66,140.03			
36230	Richland SW Sub-Stn Expa	1,509,675.81	1,509,675.81	1,509,725.66	1,509,725.66	1,551,497.07	1,551,497.07	1,551,497.07	1,592,154.00	1,595,039.33			
36231	Richland SW Sub-Stn SCADA	76,309.86	76,309.86	76,309.86	76,309.86	76,309.86	76,309.86	76,309.86	76,309.86	76,309.86			
36250	Sub Stn Equip - Snyder St	3,659,237.04	3,659,669.04	3,659,669.04	3,659,669.04	3,659,669.04	3,659,669.04	3,659,669.04	3,659,669.04	3,662,259.03			
36251	Snyder - SCADA	125,836.45	125,836.45	125,836.45	125,836.45	125,836.45	125,836.45	125,836.45	125,836.45	125,836.45			
36260	Stevens Sub	2,304,257.99	2,319,016.29	2,322,247.53	2,324,395.77	2,334,429.12	2,347,037.22	2,360,534.97	2,364,629.09	2,394,057.67			
36261	Stevens Sub - SCADA	178,159.50	178,159.50	178,159.50	178,159.50	178,159.50	178,159.50	178,159.50	178,159.50	178,159.50			
36265	Leslie Sub	4,363,563.84	4,363,563.84	4,363,563.84	4,363,563.84	4,363,563.84	4,363,563.84	4,363,563.84	4,363,563.84	4,363,563.84			
36266	Leslie Sub - SCADA	3,577.64	3,577.64	3,577.64	3,577.64	3,577.64	3,577.64	3,577.64	3,577.64	5,131.96			
36270	Thayer Sub	3,989,896.62	3,996,111.03	3,998,408.30	3,998,618.54	4,000,462.49	4,006,929.69	4,009,789.69	4,012,929.52	4,024,801.83			
36271	Thayer Sub - SCADA	124,852.73	124,852.73	124,852.73	124,852.73	124,852.73	124,852.73	124,852.73	124,852.73	124,852.73			
36275	Sandhill Crane Substation	2,955,518.26	2,959,609.80	2,959,749.96	2,960,100.35	2,960,170.43	2,960,170.43	2,960,170.43	2,960,170.43	2,961,670.68			
36276	Sandhill Crane - SCADA	69,132.08	69,132.08	69,132.08	69,132.08	69,132.08	69,132.08	69,132.08	69,132.08	69,132.08			
36281	SCADA Master - Shop	51,135.51	51,135.51	51,135.51	51,135.51	51,135.51	51,135.51	51,135.51	51,135.51	51,135.51			
36285	City View Substation	5,831,989.24	6,243,363.51	6,661,316.71	6,664,197.21	6,826,266.01	6,832,967.34	6,836,989.74	6,837,294.74	6,837,846.99			
36290	SE Richland Substation	6,231,942.75	6,231,942.75	6,233,193.67	6,233,193.67	6,233,193.67	6,233,193.67	6,233,193.67	6,233,193.67	6,233,193.67			
36291	SE Richland Substation - SCADA	36,715.92	36,715.92	36,715.92	36,715.92	36,715.92	36,715.92	36,715.92	36,715.92	36,715.92			
36292	Dallas Substation	80,790.40	80,790.40	80,790.40	80,790.40	80,790.40	80,790.40	80,790.40	80,790.40	80,790.40			
36300	Storage Battery Equipment	11,323.64	11,323.64	11,323.64	11,323.64	11,323.64	11,323.64	11,323.64	11,323.64	11,323.64			
36400	Poles, Towers, Fixtures	9,376,812.70	9,393,724.28	9,424,777.69	9,446,597.59	9,504,442.63	9,558,404.35	9,585,201.28	9,627,110.98	9,644,780.04			
36500	Conductor - Overhead	9,148,544.78	9,148,544.78	9,149,982.00	9,151,108.84	9,154,550.72	9,162,117.17	9,163,075.53	9,163,268.20	9,163,763.90			
36600	Conduit - Underground	46,471,503.94	46,476,141.25	46,483,385.11	46,487,965.67	46,512,446.51	46,515,817.28	46,518,655.78	46,814,812.00	47,563,815.67			
36700	Conductor - Underground	49,318,758.98	49,346,113.74	49,437,789.11	49,669,333.31	50,155,213.89	50,119,060.68	50,158,208.37	50,362,797.24	50,576,674.54			
36710	Underground Cond and Dev	17,924,442.97	17,929,147.85	17,922,157.34	18,040,450.22	18,049,228.62	18,051,019.97	18,071,708.39	18,107,054.26	18,171,623.50			
36800	Line Transformers	9,816,519.78	9,816,719.16	9,818,466.54	9,818,466.54	10,024,673.69	10,026,317.80	10,026,540.87	10,026,540.87	10,026,540.87			
36810	Line Transformers - Overhead	2,139,536.17	2,160,152.54	2,175,268.98	2,182,302.39	2,190,068.39	2,198,078.64	2,198,276.92	2,205,051.22	2,206,132.45			
36820	Line Transformers - Underground	14,499,163.75	14,520,072.85	14,516,469.11	14,597,299.46	14,699,516.49	14,809,228.29	14,856,486.44	15,043,277.68	15,153,353.71			
36840	Dist Plant Line Transform	50,051.35	50,051.35	50,051.35	50,051.35	50,051.35	50,051.35	50,051.35	50,051.35	50,051.35			
36900	Services	6,958,334.27	6,964,329.93	6,968,233.79	6,990,595.36	6,998,155.88	7,007,196.88	7,015,259.50	7,021,911.15	7,032,840.05			
36910	Services - Overhead	755,676.40	755,872.52	755,905.57	755,942.75	756,240.17	756,438.44	756,669.77	758,886.70	761,513.19			
36920	Services - Underground	5,012,980.99	5,020,177.70	5,026,646.74	5,035,726.51	5,040,359.34	5,045,297.00	5,052,592.22	5,057,871.55	5,063,380.55			
37000	Meters	5,574,470.06	5,589,206.61	5,611,371.33	5,629,546.43	5,946,632.63	5,989,093.82	6,005,905.83	6,056,016.76	6,070,913.07			
37100	Installation Cust. Premises	119,716.08	119,716.08	119,716.08	119,716.08	119,716.08	119,716.08	119,716.08	119,716.08	119,716.08			
37200	Leased Pr. Cust. Premises	1,039,967.82	1,039,967.82	1,039,967.82	1,039,967.82	1,039,967.82	1,039,967.82	1,039,967.82	1,039,967.82	1,039,967.82			
37300	Lighting and Signal System	3,616,801.76	3,616,801.76	3,616,801.76	3,616,801.76	3,616,801.76	3,616,801.76	3,616,801.76	3,616,801.76	3,616,801.76			
37320	Traffic Signals	805,746.09	805,746.09	805,746.09	805,746.09	805,746.09	805,746.09	805,746.09	805,986.55	805,986.55			
37330	Distr Plant Tone Control	144.60	144.60	144.60	144.60	144.60	144.60	144.60	144.60	144.60			
38900	Land and Land Rights	20,097.17	20,097.17	20,097.17	20,097.17	20,097.17	20,097.17	20,097.17	20,097.17	20,097.17			
39000	Structures & Improvements	300,991.49	300,991.49	300,991.49	300,991.49	300,991.49	300,991.49	300,991.49	300,991.49	305,768.99			
39010	S & I - City Shops Elec	8,052,810.18	8,052,810.18	8,052,810.18	8,052,810.18	8,052,810.18	8,052,810.18	8,052,810.18	8,052,810.18	8,052,810.18			
39020	S & I - City Shops Non-Elec	4,032,582.00	4,032,582.00	4,032,582.00	4,032,582.00	4,032,582.00	4,032,582.00	4,032,582.00	4,032,582.00	4,032,582.00			
39100	Office Furniture & Fixtures	564,657.11	564,657.11	564,657.11	564,657.11	564,657.11	564,657.11	564,657.11	564,657.11	564,657.11			
39200	Transportation Equipment	66,100.05	66,100.05	66,100.05	66,100.05	66,100.05	66,100.05	66,100.05	66,100.05	66,100.05			
39300	Stores Equipment	33,274.99	33,274.99	33,274.99	33,274.99	33,274.99	33,274.99	33,274.99	33,274.99	33,274.99			
39400	Tools, Shop & Garage Equip	242,174.68	242,174.68	242,174.68	242,174.68	242,174.68	242,174.68	242,174.68	242,174.68	243,290.05			
39500	Laboratory Equip	707,912.23	707,912.23	707,912.23	707,912.23	707,912.23	707,912.23	707,912.23	707,912.23	707,912.23			
39600	Power Operated Equip	542,417.44	542,417.44	542,417.44	542,417.44	542,417.44	542,417.44	542,417.44	542,417.44	542,417.44			
39700	Communication Equip	6,265,960.51	6,266,560.51	6,266,560.51	6,266,860.51	6,276,746.22	6,277,046.22	6,277,346.22	6,277,646.22	6,277,946.22			
39710	Communication Equip - Shops	231,102.33	231,102.33	231,102.33	231,102.33	231,102.33	231,102.33	231,102.33	231,102.33	231,102.33			
39712	Communication Equip - GEMS Software	-	-	-	-	-	-	-	-	-			
39713	Work Order System	-	-	-	-	-	-	-	-	-			
39800	Miscellaneous Equipment	2,712,236.21	2,720,930.04	2,720,930.04	2,720,930.04	2,765,638.96	2,765,638.96	2,765,638.96	2,772,437.64	2,774,555.43			
	TOTAL FIXED ASSETS	259,718,730.88	260,335,489.01	261,148,242.59	261,775,634.09	263,305,589.43	263,560,156.38	264,777,669.79	265,722,005.07	267,008,655.09			
ACCUMULATED DEPRECIATION													
10810	Accum Depr - Transmission	(1,557,458.84)	(1,578,586.49)	(1,599,714.16)	(1,620,841.81)	(1,641,969.48)	(1,663,097.12)	(1,684,224.79)	(1,705,352.43)	(1,726,480.10)			
10812	Accum Depr - Distribution	(111,881,268.53)	(112,451,494.67)	(113,021,721.01)	(113,591,947.16)	(114,151,138.01)	(114,710,328.67)	(115,269,519.52)	(115,828,710.17)	(116,387,429.40)			
10814	Accum Depr - General Plant	(5,927,576.20)	(5,953,196.68)	(5,978,817.15)	(6,004,437.62)	(6,030,058.09)	(6,055,678.56)	(6,081,299.03)	(6,106,919.50)	(6,132,539.97)			

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
DETAILED BALANCE SHEET
As of September 30, 2024

Acct. No.	Account Title	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
10816	Accum Depr - City Shops	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)	(12,085,392.18)			
10820	Cost of Property Retired	212,055.22	212,055.22	212,055.22	212,055.22	212,055.22	212,055.22	212,055.22	212,055.22	212,055.22			
10830	Ut Plant - Cost of Removal	446,791.74	446,791.74	446,791.74	446,791.74	446,791.74	446,791.74	446,791.74	446,791.74	446,791.74			
10840	Utility Plant - Salvage	(372,041.41)	(372,041.41)	(372,041.41)	(372,041.41)	(372,041.41)	(372,041.41)	(372,041.41)	(371,982.66)	(371,982.66)			
	TOTAL ACCUMULATED DEPR	(131,164,890.20)	(131,781,864.47)	(132,398,838.95)	(133,015,813.22)	(133,621,752.21)	(134,227,690.98)	(134,833,629.97)	(135,439,509.98)	(136,044,977.35)			
LIABILITIES													
22143	Cur Ptn LTD - 2009 Bonds	-	-	-	-	-	-	-	-	-			
22148	Cur Ptn LTD - 2013 Rev Ref Bonds	-	-	-	-	-	-	-	-	-			
22152	Cur Ptn LTD - 2015 Bonds	(475,000.00)	(475,000.00)	(475,000.00)	(475,000.00)	(475,000.00)	(475,000.00)	(475,000.00)	(475,000.00)	(475,000.00)			
22153	Cur Ptn LTD - 2018 Bonds	(455,000.00)	(455,000.00)	(455,000.00)	(455,000.00)	(455,000.00)	(455,000.00)	(455,000.00)	(455,000.00)	(455,000.00)			
22154	Cur Ptn LTD - 2019 Bonds	(555,000.00)	(555,000.00)	(555,000.00)	(555,000.00)	(555,000.00)	(555,000.00)	(555,000.00)	(555,000.00)	(555,000.00)			
22155	Cur Ptn LTD - 2021 Bonds	(180,000.00)	(180,000.00)	(180,000.00)	(180,000.00)	(180,000.00)	(180,000.00)	(180,000.00)	(180,000.00)	(180,000.00)			
22156	Cur Ptn LTD - 2023 Bonds	(770,000.00)	(770,000.00)	(770,000.00)	(770,000.00)	(770,000.00)	(770,000.00)	(770,000.00)	(770,000.00)	(770,000.00)			
22161	2013 Rev Ref Bonds Outstanding	-	-	-	-	-	-	-	-	-			
22162	2015 Rev Bonds Outstanding	(16,980,000.00)	(16,980,000.00)	(16,980,000.00)	(16,980,000.00)	(16,980,000.00)	(16,980,000.00)	(16,980,000.00)	(16,980,000.00)	(16,980,000.00)			
22163	2018 Rev Bonds Outstanding	(12,570,000.00)	(12,570,000.00)	(12,570,000.00)	(12,570,000.00)	(12,570,000.00)	(12,570,000.00)	(12,570,000.00)	(12,570,000.00)	(12,570,000.00)			
22164	2019 Rev Bonds Outstanding	(13,760,000.00)	(13,760,000.00)	(13,760,000.00)	(13,760,000.00)	(13,760,000.00)	(13,760,000.00)	(13,760,000.00)	(13,760,000.00)	(13,760,000.00)			
22165	2021 Rev Bonds Outstanding	(6,060,000.00)	(6,060,000.00)	(6,060,000.00)	(6,060,000.00)	(6,060,000.00)	(6,060,000.00)	(6,060,000.00)	(6,060,000.00)	(6,060,000.00)			
22166	2023 Rev Bonds Outstanding	(18,645,000.00)	(18,645,000.00)	(18,645,000.00)	(18,645,000.00)	(18,645,000.00)	(18,645,000.00)	(18,645,000.00)	(18,645,000.00)	(18,645,000.00)			
22830	Net Pension Liability	(801,160.00)	(801,160.00)	(801,160.00)	(801,160.00)	(801,160.00)	(801,160.00)	(801,160.00)	(801,160.00)	(801,160.00)			
22840	Net OPEB Liability	(681,997.36)	(681,997.36)	(681,997.36)	(681,997.36)	(681,997.36)	(681,997.36)	(681,997.36)	(681,997.36)	(681,997.36)			
23200	A/P - Accrued Power Bills	(4,285,395.89)	(3,030,197.73)	(2,584,432.00)	(2,904,989.57)	(2,648,413.68)	(2,816,801.75)	(4,499,746.97)	(4,668,010.38)	(7,832,576.78)			
23209	Accts Pay - Inventory	(1,616.43)	(1,710.39)	(872.31)	(872.31)	(872.31)	524.49	524.49	524.49	524.49			
23210	Accts Pay - Payroll	(266,871.36)	(266,871.36)	(266,871.36)	(266,871.36)	(266,871.36)	(266,871.36)	(266,871.36)	(266,871.36)	(266,871.36)			
23211	Accts Pay - Excise Tax	(283,037.49)	(314,436.37)	(238,294.68)	(222,945.85)	(206,033.98)	(215,829.99)	(250,164.60)	(286,278.68)	(244,036.64)			
23212	Accounts Payable	(3,914.14)	(514,453.23)	(190,307.65)	(124,880.66)	(357,630.72)	(391,623.68)	(213,802.80)	(712,520.69)	(1,303,571.93)			
23214	Deferred Revenue - Fac Fee Deposit	(453,388.19)	(453,388.19)	(453,388.19)	(453,388.19)	(453,388.19)	(453,388.19)	(453,388.19)	(520,588.19)	(452,788.19)			
23215	Deferred Revenue - Fac Fee Large Projects	-	-	-	-	-	-	-	-	-			
23216	Due to Other Funds	-	-	-	-	-	-	-	-	-			
23217	Retainage Payable	(186,974.30)	(186,974.30)	(40,128.22)	(40,128.22)	(26,060.98)	(26,060.98)	(26,060.98)	(26,060.98)	(26,060.98)			
23750	Accrued Interest - Bonds	(1,185,521.55)	(1,448,733.74)	(1,711,945.93)	(1,975,158.12)	(659,097.18)	(922,309.37)	(1,185,521.56)	(1,448,733.75)	(1,711,945.94)			
24200	Accrued Sick and Vacation	(795,183.52)	(795,183.52)	(795,183.52)	(795,183.52)	(795,183.52)	(795,183.52)	(795,183.52)	(795,183.52)	(795,183.52)			
25300	Deferred Credit - Pension	(1,068,775.00)	(1,068,775.00)	(1,068,775.00)	(1,068,775.00)	(1,068,775.00)	(1,068,775.00)	(1,068,775.00)	(1,068,775.00)	(1,068,775.00)			
25310	Deferred Credit - OPEB	(321,699.39)	(321,699.39)	(321,699.39)	(321,699.39)	(321,699.39)	(321,699.39)	(321,699.39)	(321,699.39)	(321,699.39)			
25320	Deferred Credit - Lease	(388,132.60)	(388,132.60)	(388,132.60)	(388,132.60)	(388,132.60)	(388,132.60)	(388,132.60)	(388,132.60)	(388,132.60)			
25402	Prepaid Lease - BPUD	(115,775.25)	(115,775.25)	(115,775.25)	(115,775.25)	(115,775.25)	(115,775.25)	(115,775.25)	(115,775.25)	(115,775.25)			
25700	Unamortized Gain on 2007 Refunded	(4,483.46)	(4,454.16)	(4,424.86)	(4,395.56)	(4,366.26)	(4,336.96)	(4,307.66)	(4,278.36)	(4,249.06)			
25701	Unamortized Gain on 2013 Refunded	(1,139,099.03)	(1,134,080.97)	(1,129,062.91)	(1,124,044.85)	(1,119,026.79)	(1,114,008.73)	(1,108,990.67)	(1,103,972.61)	(1,098,954.55)			
	TOTAL LIABILITIES	(82,433,024.96)	(81,978,023.56)	(81,242,451.23)	(81,740,397.81)	(80,364,484.57)	(80,833,429.64)	(82,631,053.42)	(83,659,513.63)	(87,563,254.06)			
NET INCOME & FUND EQUITY													
NI	Net Income - Year to Date	(328,750.24)	(2,797,790.56)	(4,319,759.43)	(5,381,091.25)	(5,970,936.36)	(7,085,991.03)	(7,225,479.41)	(7,817,054.74)	(8,387,237.71)			
21500	Ret Earnings - Ins Set Aside	-	-	-	-	-	-	-	-	-			
21600	Unappro Retained Earnings	(84,212,177.91)	(84,212,177.91)	(84,212,177.91)	(84,212,177.91)	(84,212,177.91)	(84,212,177.91)	(84,212,177.91)	(84,212,177.91)	(84,212,177.91)			
27150	Contributed Capital	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)	(16,564,772.63)			
27160	Contributed Capital	-	-	-	-	-	-	-	-	-			
43910	Residual Equity Transfer	-	-	-	-	-	-	-	-	-			
43900	Adjust to Retained Earnings	5,069,025.64	5,069,025.64	5,069,025.64	5,069,025.64	5,069,025.64	5,069,025.64	5,069,025.64	5,069,025.64	5,069,025.64			
	TOTAL NET INCOME & FUND EQUITY	(96,036,675.14)	(98,505,715.46)	(100,027,684.33)	(101,089,016.15)	(101,678,861.26)	(102,793,915.93)	(102,933,404.31)	(103,524,979.64)	(104,095,162.61)			
	TOTAL ASSETS	178,469,700.10	180,483,739.02	181,270,135.56	182,829,413.96	182,043,345.83	183,627,345.57	185,564,457.73	187,184,493.27	191,658,416.67			
	TOTAL LIABILITIES & FUND EQUITY	(178,469,700.10)	(180,483,739.02)	(181,270,135.56)	(182,829,413.96)	(182,043,345.83)	(183,627,345.57)	(185,564,457.73)	(187,184,493.27)	(191,658,416.67)			
		-	-	-	-	-	-	-	-	-			

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
DETAILED REVENUE SHEET
CY 2024 ACTUAL

REVENUES

Acct. No	Account Title	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Year To Date
41900	Interest Income	(136,253.63)	(116,675.90)	(116,681.92)	(119,151.09)	(111,091.94)	(108,686.66)	(124,103.81)	(104,998.22)	(115,444.75)	-	-	-	(1,053,087.92)
41900	(Gain)/Loss on Fair Market Value (FMV) Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
41910	Interest (Consv Loan Int Payments)	(5,092.19)	(5,258.02)	(5,170.46)	(5,115.57)	(5,213.05)	(5,214.58)	(5,162.58)	(5,499.92)	(5,517.67)	-	-	-	(47,244.04)
41911	Interest on Conservation Loan Investment	(1,517.11)	(1,423.44)	(1,526.29)	(1,481.35)	(1,537.83)	(1,496.60)	(1,555.31)	(1,557.98)	(1,467.55)	-	-	-	(13,563.46)
41912	Other Interest Thru Collection Agency	(545.21)	-	(117.17)	(70.36)	(55.36)	-	(12.20)	(88.12)	-	-	-	-	(888.42)
41920	BPA - Conservation Admin Fee	-	-	-	-	-	-	-	-	-	-	-	-	-
41921	BPA - Conservation Program (EEI)	(18,223.05)	(169,390.88)	(175,505.27)	(163,871.67)	(77,068.50)	(49,670.64)	(79,842.85)	(115,312.72)	(88,806.17)	-	-	-	(937,691.75)
41922	LSO Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-
42100	Miscellaneous Revenue	-	-	(3,412.31)	-	(50.00)	(7,114.06)	(10.00)	-	-	-	-	-	(10,586.37)
42100	Other Non-Operating Revenue	-	-	-	-	-	-	-	-	-	-	-	-	-
42100	Transfers From General Fund	-	-	-	-	-	-	-	-	-	-	-	-	-
43400	Insurance Recovery	-	-	-	-	-	-	-	-	-	-	-	-	-
43401	Bonneville Power Admin. REP Agreement	-	-	-	-	-	-	-	-	-	-	-	-	-
43902	Prior Period Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
44000	Electric Utility Tax	(622,773.31)	(669,139.46)	(503,157.24)	(451,713.15)	(454,527.12)	(480,765.95)	(555,230.42)	(603,795.27)	(542,002.23)	-	-	-	(4,883,104.15)
44010	Energy: Residential	(4,007,991.67)	(4,081,183.60)	(2,717,779.43)	(2,279,508.14)	(2,215,462.61)	(2,344,265.30)	(2,979,553.30)	(3,166,453.48)	(2,642,584.38)	-	-	-	(26,434,781.91)
44210	General Service	1,064.71	192.32	-	51.46	338.60	-	-	-	-	-	-	-	1,647.09
44211	Small Gen Service	(664,609.27)	(754,528.47)	(611,351.31)	(549,366.70)	(514,324.56)	(528,379.33)	(572,322.21)	(659,237.17)	(628,761.26)	-	-	-	(5,482,880.28)
44212	Medium Gen Service	(761,694.63)	(915,997.75)	(774,304.62)	(746,233.52)	(707,014.09)	(754,242.26)	(807,503.87)	(940,617.66)	(867,436.53)	-	-	-	(7,275,044.93)
44213	Large Gen Service	(620,243.81)	(656,646.41)	(607,205.18)	(621,004.16)	(652,241.51)	(711,565.07)	(735,907.85)	(796,503.80)	(760,965.28)	-	-	-	(6,162,283.07)
44215	Cable TV Amp	(5,620.47)	(5,620.47)	(5,620.47)	(5,620.47)	(5,620.47)	(5,620.47)	(5,620.47)	(5,620.47)	(5,620.47)	-	-	-	(50,584.23)
44220	Large Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-
44221	Small Industrial	(248,514.36)	(287,483.06)	(278,918.98)	(241,394.19)	(348,958.27)	(342,050.92)	(354,907.75)	(485,902.94)	(516,931.90)	-	-	-	(3,105,062.37)
44222	Large Industrial	(378,825.59)	(480,350.88)	(402,271.68)	(354,778.65)	(326,277.08)	(313,625.30)	(311,407.90)	(203,911.66)	(209,385.39)	-	-	-	(2,980,834.13)
44225	Large Irrigation	(1,313.51)	(1,464.29)	(1,419.23)	(44,053.93)	(95,752.37)	(143,807.36)	(175,196.81)	(205,504.48)	(168,473.71)	-	-	-	(836,985.69)
44230	Small Irrigation	(1,091.12)	(1,555.48)	(1,427.49)	(20,743.36)	(11,494.29)	(16,404.77)	(18,851.35)	(21,518.20)	(18,743.38)	-	-	-	(111,829.44)
44410	Street Lighting	(8,996.82)	(8,416.38)	(8,996.82)	(8,706.60)	(8,996.82)	(8,706.60)	(8,996.82)	(8,996.82)	(8,706.60)	-	-	-	(79,520.28)
44420	Traffic Lighting	(1,214.84)	(4,517.32)	(2,717.39)	(2,696.30)	(2,606.90)	(2,627.01)	(2,585.35)	(2,686.63)	(2,624.99)	-	-	-	(24,276.73)
44700	Sales for Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
45100	Misc Service Revenue	(750.00)	(750.00)	(450.00)	(1,650.00)	(600.00)	(600.00)	(450.00)	(900.00)	(1,050.00)	-	-	-	(7,200.00)
45110	New Accounts	(4,425.00)	(7,200.00)	(7,470.00)	(4,890.00)	(4,410.00)	(9,525.00)	(8,640.00)	(7,470.00)	(3,990.00)	-	-	-	(58,020.00)
45112	Accounts Transfer Fee	-	-	-	-	-	-	-	-	-	-	-	-	-
45120	Reimb Loan Service Fees	-	(1,192.00)	(2,001.00)	(3,147.00)	(3,956.00)	(1,304.00)	(4,948.00)	(4,362.00)	(4,047.00)	-	-	-	(24,957.00)
45121	Temp Service Fees	-	-	-	-	-	-	-	-	-	-	-	-	-
45122	Permanent Service Fees	(15,200.00)	(14,175.00)	(13,500.00)	(12,169.20)	(8,288.62)	(14,998.53)	(11,450.00)	(19,695.00)	(18,525.00)	-	-	-	(128,001.35)
45123	Damages & Claims	-	-	-	-	-	-	-	-	-	-	-	-	-
45124	Rewires & Underground Conversion	(1,545.34)	-	(8,087.10)	-	-	-	-	(6,941.35)	(2,276.15)	-	-	-	(18,849.94)
45125	Facilities Fees	-	(109,544.66)	(392,728.22)	(831,614.92)	(251,733.17)	(179,098.27)	(272,399.16)	(888,319.73)	(88,640.09)	-	-	-	(3,014,078.22)
45126	Contributed Capital (NonCash)	-	-	-	-	-	-	-	-	-	-	-	-	-
45150	Disconnect/Reconnect Fees	(12,975.00)	(17,300.00)	(13,775.00)	(10,050.00)	(9,925.00)	(13,275.00)	(5,925.00)	(11,400.00)	(13,425.00)	-	-	-	(108,050.00)
45152	Operations Disconnect/Rec Fees	-	-	-	-	-	-	-	-	-	-	-	-	-
45154	Delinquent Account Fees	(27,536.60)	(27,008.80)	(29,900.00)	(28,197.00)	(16,502.20)	(31,974.80)	(31,948.80)	(31,595.20)	(23,454.60)	-	-	-	(248,118.00)
45160	Rental Lights Contract	(9,314.19)	(10,250.14)	(9,887.35)	(9,517.12)	(9,808.89)	(9,776.43)	(9,954.88)	(9,100.70)	(10,174.20)	-	-	-	(87,783.90)
45170	Land Sales	-	-	-	(2,031.64)	(1,993.55)	-	-	-	-	-	-	-	(4,025.19)
45440	Pole Contacts-Telecable	-	(101,732.75)	-	-	-	-	-	-	-	-	-	-	(101,732.75)
45601	EECBG/ARRA Grant Funds	-	-	-	-	-	-	-	-	-	-	-	-	-
45602	BAB Federal Interest Subsidy	-	-	-	-	-	-	-	-	-	-	-	-	-
45603	COVID Assistance	-	-	-	-	-	-	-	-	-	-	-	-	-
45610	Gain/Loss on Sale of Scrapped Assets	-	-	-	(2,223.75)	(1,648.75)	-	-	-	-	-	-	-	(3,872.50)
45629	Meter Reading Revenue	(6,018.30)	(4,018.30)	(4,023.38)	(3,771.57)	(2,969.50)	(3,346.30)	-	(148.28)	(2,127.31)	-	-	-	(26,422.94)
45630	Work For City Depts	-	-	(2,464.28)	-	-	(153,461.28)	(52,853.30)	-	-	-	-	-	(208,778.86)
45653	City Shops Rental	-	-	-	-	-	-	-	-	-	-	-	-	-
45654	Land Lease	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL REVENUES	(7,561,220.31)	(8,452,631.14)	(6,701,869.59)	(6,524,719.95)	(5,849,789.85)	(6,241,602.49)	(7,137,339.99)	(8,308,137.80)	(6,751,181.61)	-	-	-	(63,528,492.73)

CITY OF RICHLAND, WASHINGTON
ELECTRIC UTILITY
DETAILED EXPENSE SHEET
CY 2024 ACTUAL

EXPENSES

Acct. No	Account Title	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Year To Date
40300	Depr Exp Transmission	20,306.92	20,306.90	20,306.92	20,306.90	20,306.92	20,306.89	20,306.92	20,306.89	20,306.92	-	-	-	182,762.18
40302	Depr Exp Distribution	571,047.09	571,046.89	571,047.09	571,046.90	560,011.60	560,011.41	560,011.60	560,011.40	559,539.98	-	-	-	5,083,773.96
40304	Depr Exp Misc	25,620.47	25,620.48	25,620.47	25,620.47	25,620.47	25,620.47	25,620.47	25,620.47	25,620.47	-	-	-	230,584.24
40306	Depr Exp City Shops	-	-	-	-	-	-	-	-	-	-	-	-	-
40310	Transfer To Equip Replacement Fund	69,405.25	69,405.25	69,405.25	69,405.25	69,405.25	69,405.25	69,405.25	69,405.25	69,405.25	-	-	-	624,647.25
40311	Transfer To Broadband Fund	2,500.00	2,500.00	2,500.00	2,500.00	2,500.00	2,500.00	2,500.00	2,500.00	2,500.00	-	-	-	22,500.00
40810	Taxes-City Occupation	623,146.81	669,541.72	502,794.09	454,334.98	454,983.44	481,256.13	555,733.31	604,337.19	542,504.87	-	-	-	4,888,632.54
40830	Taxes-Social Security	-	-	-	-	-	-	-	-	-	-	-	-	-
40910	Taxes-State B&O	911.95	3,432.60	7,319.30	15,485.89	5,078.85	4,283.35	5,844.49	17,941.96	1,359.20	-	-	-	61,657.59
40920	Taxes-State Public Utility	279,718.17	304,952.03	224,931.11	200,883.97	200,097.59	211,386.88	244,187.12	268,049.50	241,853.85	-	-	-	2,176,060.22
41600	Contract Work Locator	-	-	-	-	-	-	-	-	-	-	-	-	-
41710	Non-Utility Operations	25,663.06	38,860.66	33,053.83	28,528.68	29,464.76	24,901.89	26,793.11	34,949.34	16,696.77	-	-	-	258,912.10
41711	Non-Billable Work For Other Depts	2,030.34	3,044.40	2,961.75	1,284.70	2,809.42	2,655.02	3,359.78	4,589.25	1,784.65	-	-	-	24,519.31
42750	Accrued Interest Bonds	263,212.19	263,212.19	263,212.19	263,212.19	263,212.19	263,212.19	263,212.19	263,212.19	263,212.19	-	-	-	2,368,909.71
42756	Interest Exp-1999 Bonds	-	-	-	-	-	-	-	-	-	-	-	-	-
42765	Interest Exp-Notes	-	-	-	-	-	-	-	-	-	-	-	-	-
42800	Amort of Debt Discount	-	-	-	-	-	-	-	-	-	-	-	-	-
42800	Debt Issuance Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
42810	Amort of Loss on Reacquired Debt	(4,653.06)	(4,653.06)	(4,653.06)	(4,653.06)	(4,653.06)	(4,653.06)	(4,653.06)	(4,653.06)	(4,653.06)	-	-	-	(41,877.54)
42900	Amort of Debt Premium	(27,428.24)	(27,428.24)	(27,428.24)	(27,428.24)	(27,428.24)	(27,428.24)	(27,428.24)	(27,428.24)	(27,428.24)	-	-	-	(246,854.16)
43901	Prior Period Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
55500	Purchased Power	3,587,651.00	2,516,581.00	2,186,620.00	2,522,951.00	2,278,662.00	2,376,532.00	3,893,687.00	4,082,980.00	3,265,243.00	-	-	-	26,710,907.00
55520	Purchased Power WPPSS	-	-	-	-	-	-	-	-	-	-	-	-	-
55550	Purchased Power For Resale	-	-	-	-	-	-	-	-	-	-	-	-	-
55501	BPUD Energy Charges For City Customers	458.69	552.55	465.05	386.72	361.15	316.52	273.66	-	352.95	-	-	-	3,167.29
55503	Purchased Power - Non Federal	-	-	-	-	-	-	-	-	-	-	-	-	-
55504	Purchased Power - Renewable	7,350.89	11,944.73	24,207.88	25,351.57	28,931.68	27,836.75	28,601.97	26,890.38	22,817.78	-	-	-	203,933.63
56500	Transmission Expense	691,934.00	501,672.00	396,040.00	356,687.00	340,820.00	410,596.00	577,458.00	558,140.00	461,536.00	-	-	-	4,294,883.00
58000	Oper-Supervision & Engineering	181,183.69	185,997.67	125,945.54	287,490.64	275,714.29	130,284.99	165,259.50	176,941.71	124,089.91	-	-	-	1,652,907.94
58100	Oper-Load Dispatching	41,214.73	53,694.61	40,162.97	26,433.69	29,697.71	29,078.99	37,275.19	58,984.91	39,694.10	-	-	-	356,236.90
58200	Oper-Station Expense	-	-	977.08	-	-	-	-	-	-	-	-	-	977.08
58300	Oper-Overhead Line	31,786.44	59,487.38	35,787.27	16,502.00	29,808.92	22,369.65	28,917.10	27,007.53	15,902.00	-	-	-	267,568.29
58350	Oper-PCB Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
58400	Oper-Underground Line	3,037.89	3,683.32	32,567.63	5,826.01	1,539.05	303.92	257.40	21,732.69	269.28	-	-	-	69,217.19
58500	Oper-Street Light & Signal	-	-	-	-	-	-	-	-	-	-	-	-	-
58510	Oper-Street Lights	19,437.64	12,025.32	21,288.72	11,368.62	10,934.28	15,213.37	15,447.87	2,754.92	1,992.21	-	-	-	110,462.95
58520	Oper-Telemeter Systems	377.76	1,265.20	183.32	199.77	319.28	809.29	1,308.97	1,386.76	137.49	-	-	-	5,987.84
58530	Oper-Traffic Signals	1,836.76	2,332.43	2,333.76	3,399.32	4,199.12	3,344.36	401.39	4,045.16	4,843.68	-	-	-	26,735.98
58550	Oper-Rental Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-
58600	Oper-Meter Expense	-	287.15	15,275.03	52,480.69	-	24,153.31	-	-	2,708.94	-	-	-	94,905.12
58700	Oper-Customer Install	-	-	-	-	-	-	-	-	-	-	-	-	-
58800	Oper-Misc Distribution	26,359.44	65,386.18	38,116.03	53,520.43	47,096.30	37,673.28	47,229.31	47,522.52	56,167.59	-	-	-	419,071.08
58900	Oper-Rents	-	-	-	-	-	-	-	-	-	-	-	-	-
59000	Maint-Supervision & Engineering	1,409.89	1,379.99	438.34	824.86	1,911.07	1,105.38	1,027.94	1,721.41	1,131.76	-	-	-	10,950.64
59100	Maint-Structures	249.61	445.73	-	624.37	-	-	-	-	-	-	-	-	1,319.71
59200	Maint-Station Equip	624.37	1,404.84	-	1,271.67	137.48	-	-	-	5,429.46	-	-	-	8,867.82
59300	Maint-Overhead Lines	18,937.39	6,942.92	46,675.84	9,131.61	35,999.39	16,639.68	21,596.02	26,173.24	9,524.73	-	-	-	191,620.82
59400	Maint-Underground Lines	44,070.53	61,736.74	27,498.86	52,104.12	45,387.14	24,149.80	34,916.35	96,296.37	85,637.32	-	-	-	471,797.23
59500	Maint-Line Transformers	6,246.07	19,041.02	16,157.60	9,867.06	12,383.07	5,531.37	8,899.22	18,179.34	7,539.69	-	-	-	103,844.44
59510	Maint-Line Transformers OH	-	358.57	-	-	756.99	-	-	-	-	-	-	-	1,115.56
59520	Maint-Line Transformers Underground	-	-	-	-	595.42	5,353.98	273.20	-	-	-	-	-	6,222.60
59600	Maint-Street Lighting	-	1,717.03	390.23	312.19	-	325.15	547.88	1,012.65	312.19	-	-	-	4,617.32
59620	Other Maintenance	-	-	-	-	-	-	-	-	233.22	-	-	-	233.22
59700	Maint-Meters	471.19	2,858.12	4,926.49	5,320.09	277.71	1,813.40	1,172.53	95.25	-	-	-	-	16,934.78
59800	Maint-Misc Distr Plant	16,421.22	18,353.08	14,563.87	13,630.34	15,638.09	12,694.96	12,697.52	17,170.10	14,178.70	-	-	-	135,347.88
59810	Maint-Vehicles	-	-	-	-	-	-	-	-	-	-	-	-	-
90200	Meter Reading Expense	16,859.55	18,796.81	7,356.48	10,073.62	12,815.33	14,030.50	25,263.74	11,224.21	6,697.21	-	-	-	123,117.45
90300	Customer Records & Collections	69,359.74	72,227.88	69,820.24	69,650.12	70,025.37	69,601.90	69,984.50	69,989.85	70,129.02	-	-	-	630,788.62
90400	Uncollectible Accounts	11,310.00	11,310.00	11,310.00	11,310.00	11,310.00	11,310.00	11,310.00	11,310.00	11,310.00	-	-	-	101,790.00
90840	Customer Assistance Cons Program	185,218.77	191,130.52	148,509.59	87,335.24	219,731.66	58,954.08	62,827.50	329,431.38	53,305.78	-	-	-	1,336,444.52
90841	BPA reimbursement	-	-	-	-	-	-	-	-	-	-	-	-	-
92000	Admin & General Salaries	23,912.86	39,581.95	26,230.16	27,084.45	16,841.78	27,318.49	35,529.63	36,539.47	27,718.23	-	-	-	260,757.02
92100	Office Supplies & Expense	901.35	1,630.57	2,200.87	772.65	1,790.90	2,584.61	3,702.47	1,930.74	4,743.59	-	-	-	20,257.75
92300	Outside Service Employees	67,038.83	53,903.25	58,672.74	66,389.08	51,907.33	52,772.22	52,251.33	129,917.68	55,600.33	-	-	-	588,452.79
92301	Service Territory Relations	-	-	-	-	-	-	-	-	-	-	-	-	-
92400	Insurance	26,938.62	26,938.58	26,938.58	26,938.58	26,938.58	26,938.58	26,938.58	26,938.58	26,938.58	-	-	-	242,447.26
92500	Injuries & Damages	-	-	-	-	-	-	-	-	-	-	-	-	-
92600	Employee Pension & Benefits	14,598.33	17,773.99	15,054.72	14,811.37	14,837.62	14,811.88	14,818.80	17,480.78	14,898.50	-	-	-	139,085.99
93000	Misc General Expenses	39,431.67	7,921.95	3,483.26	6,509.70	4,865.92	2,034.31	739.46	7,621.78	10,911.63	-	-	-	83,519.68
93021	Organizational Dues	178,059.28	7,085.00	22,330.95	-	-	306.00	6,043.72	-	-	-	-	-	213,824.95
93022	Information Systems Services	66,300.92	66,300.92	66,300.92	66,300.92	66,300.92	66,300.92	66,300.92	66,300.92	66,300.92	-	-	-	596,708.28
93100	Rents	-	-	-	-	-	-	-	-	-	-	-	-	-
93200	Maint Of General Plant	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL EXPENSES	7,232,470.07	5,983,590.82	5,179,900.72	5,463,388.13	5,259,944.74	5,126,547.82	6,997,851.61	7,716,562.47	6,180,998.64	-	-	-	55,141,255.02
	Net Income	328,750.24	2,469,040.32	1,521,968.87	1,061,331.82	589,845.11	1,115,054.67	139,488.38	591,575.33	570,182.97	-	-	-	8,387,237.71

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 11/12/2024 Agenda Category: Other Informational Items

Prepared By: Clint Whitney, Energy Services Director

Subject:
2025 Capital Work Plan

Department:
Energy Services

Recommended Motion:
This item is informational only.

Summary:
Attached is a summary Capital Work Plan (CWP) of Energy Services (RES) projects recommended for budget approval and implementation in 2025. The projects are prioritized from electrical outages and reliability data, load forecasts, and economic development areas. The goal of the projects is to provide improvements in safety and reliability while balancing infrastructure costs for the City's electric rate payers.

The recommended CWP for 2025 includes $11.9M of projects associated with small Substation Improvements, System Improvements, Renewal & Replacements, Line Extensions, and major Substation Construction. The CWP is typically one year of work with major substation construction engineering and long lead items in one year, followed by construction in the second year.

Fiscal Impact:

Attachments:
1. 2025 Capital Work Plan

2025 Capital Work Plan

Energy Services

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www.ci.richland.wa.us/EnergyServices

Table of Contents

Executive Summary

Purpose

The purpose of this report is to provide an overview of the 2025 Capital Work Plan (CWP) Projects and how Richland Energy Services (RES) intends to strategically meet its improvement objectives, performance and operational goals while focusing on preserving infrastructure for increased reliability and ensuring the efficient use of rate payer money.

Description

The 2025 CWP includes five categories of capital improvements. These categories include specific projects contributing to RES' overall goals and improvements servicing the community. These projects are strategically evaluated and prioritized based on the City's Strategic Leadership Plan and the RES Long Range Plan (LRP).

2025 CWP Categories and Descriptions:

Substation Improvements:
A variety of major improvement projects within the eleven existing electric utility substation sites

System Improvements:
These are new improvements to the electric utility infrastructure.

Renewal and Replacements (R&R):
Capital improvements extending the life of existing electric utility infrastructure and replacing infrastructure or equipment that has met its useful life expectancy.

Fusion/Triton Substation:
This category includes planning, design and construction of electrical distribution and transmission infrastructure from the new Fusion and Triton Substations serving the Northwest Advanced Clean Energy Park(NACEP) and connecting into the transmission system operated by Bonneville Power Administration (BPA).

Line Extensions-New Developments
Capital improvement projects for the purpose of extending electrical utility infrastructure to new developer requested loads. Line Extensions utilize facility fee contributions for project funding.

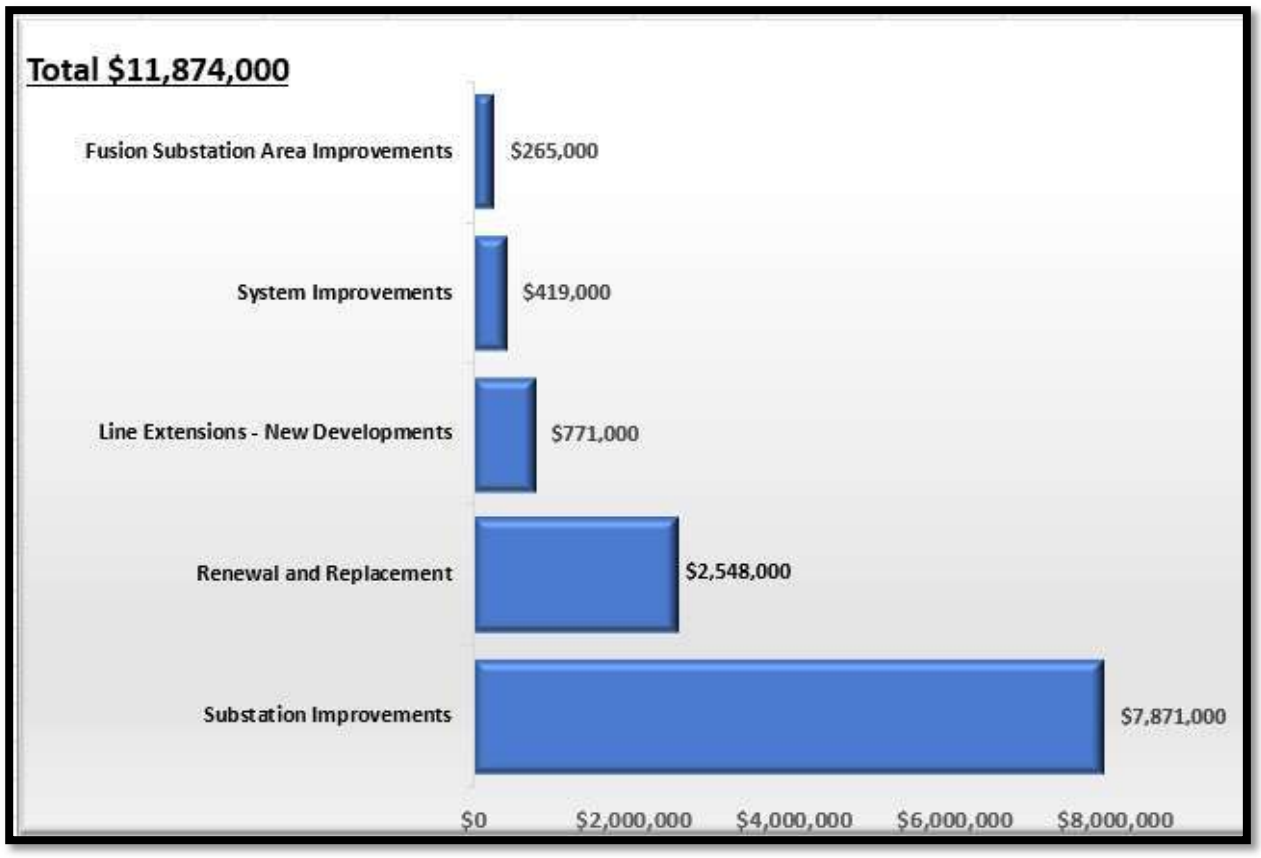
Highlights

The CWP has an estimate to perform approximately $11.9 million of capital work in 2025. This amount was presented to Council in August as part of the City's 2025 Budget and Capital Improvement Plan (CIP), with anticipated final approval in November, 2024.

In addition to the 2025 planned estimate, some CWP projects and funding not expended in 2024 may be continue into 2025 to complete 2024 projects.

Each category of work has an overall project estimate consisting of material, equipment, overhead, engineering, expert services and inside labor costs. These totaled costs for each category of work equal the CWP overall estimate.

Below is a graph representing dollars associated for each work category.



Project Information

Purpose and Project Selection

The driving purpose for developing and implementing a capital work plan is to maintain reliable power at the lowest responsible cost to Richland's electric utility customers. Programmed investment in utility infrastructure avoids unplanned service outages and costly repairs.

The selection of 2025 CWP projects are intended to align with the City's Strategic Leadership Plan and the Electric Utility Long Range Plan (LRP). These projects result from the evaluation of required maintenance, aging infrastructure, system capacity, reliability, and economic development opportunities

2025 Project Summaries

System Improvements:

- **New Services (continuous project)**
  Providing new or additional electrical services to customers.

Renewal and Replacements:

- **Meter Replacement and Upgrade (continuous project)**
  Replacement of existing meters that are aged, damaged or are no longer operable.

- **Pole Replacement Program**
  Replacement of identified aging poles to meet current specifications.

- **Underground Cable Replacement (continuous project)**
  Replacement of aging, underground cables as well as identified boring and drilling projects.

Fusion Substation

- **Fusion Substation**
  Engineering and design services for new substation and transmission line to serve the Northwest Advanced Clean Energy Park (NACEP), formerly DOE land transfer area.

Substation Improvements

- **Thayer Drive Substation: Bank #1 Upgrade**
  Engineering services for upgrades to Thayer Drive Substation providing purchasing support, design guidelines, construction documents, bidding assistance and Project Management. Other substantial costs associated with

this project will include the purchase and delivery of the metal-clad switchgear expected Q2 of 2025.

- **Stevens Substation: Bank #1 Rebuild**
  Engineering and design services, in cooperation with Bonneville Power Administration (BPA), for upgrades to Stevens Substation, Bank #1. Other significant costs related to this project include the purchase of the metal-clad switchgear expected Q2 of 2025.

- **Sandhill Crane Bank #3**
  Continuation of engineering, design services and completion of construction to the addition of Sandhill Substation Bank #3.

Line Extensions:

- **Line Extensions (continuous project)**
  Provide new electrical infrastructure from City of Richland Electrical Distribution System to the development customer.

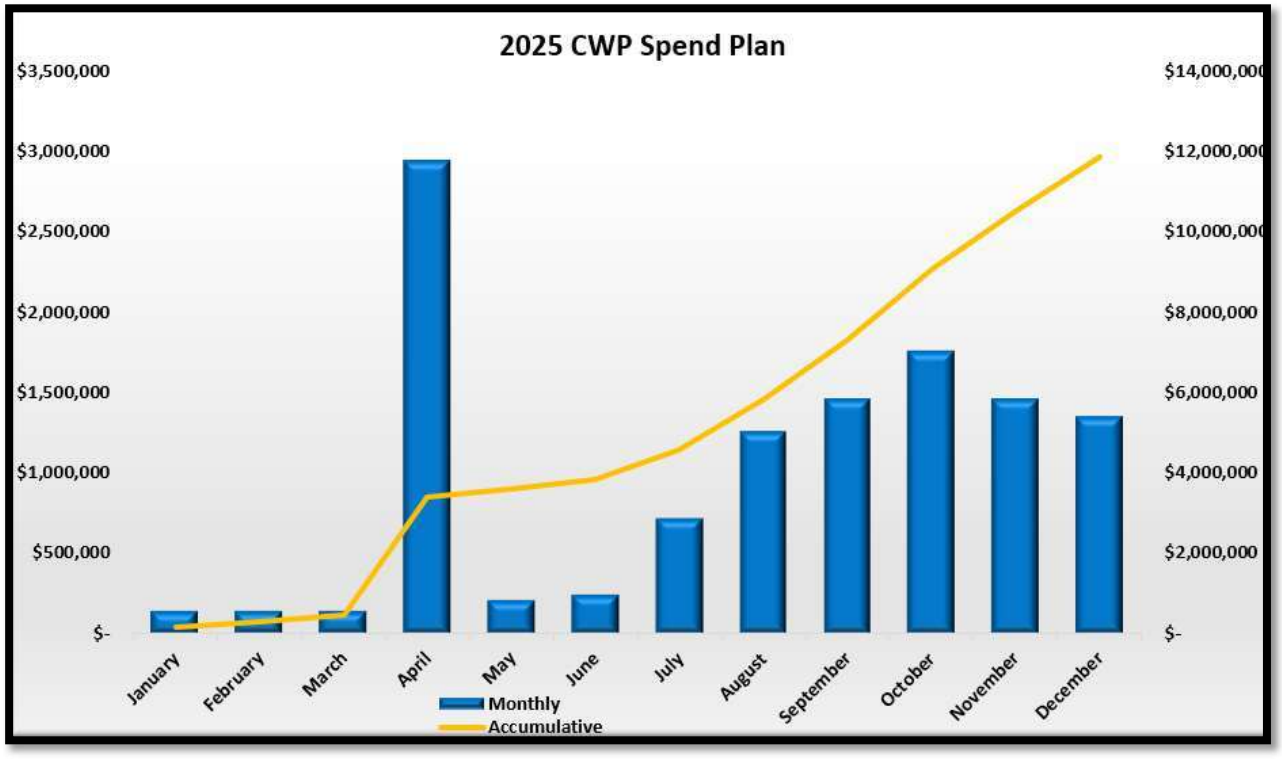
Projects by Category

Project	Total
	Sum of Spend Plan Total
⊟ **Substation Improvements**	**$7,871,000**
Stevens Substation- Bank 1 Rebuild	$3,074,000
Thayer Bank #1	$1,484,000
Sandhill Crane Bank 3	$3,313,000
⊟ **Renewal and Replacement**	**$2,548,000**
Underground Cable Replacement	$1,994,000
Pole Replacement Program	$534,000
Meter Replacement and Upgrade	$20,000
⊞ **Line Extensions - New Developments**	**$771,000**
⊟ **System Improvements**	**$419,000**
New Services	$419,000
⊟ **Fusion Substation Area Improvements**	**$265,000**
Fusion Substation	$265,000
Grand Total	**$11,874,000**

Project Spend Plan

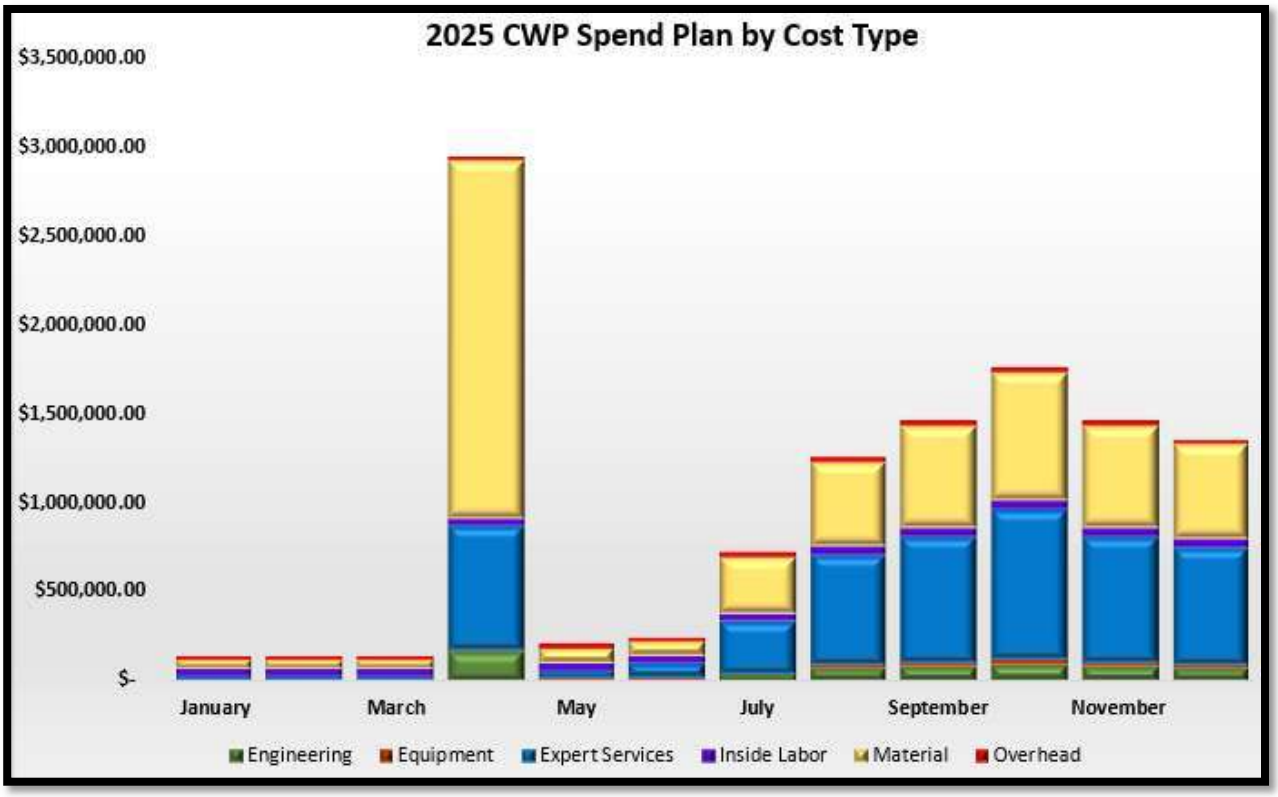
The 2025 Spend Plan is based on monthly projected costs relating to the performance of the CWP Projects. The project schedule and its associated costs drive the values listed on the Spend Plan. RES intends to perform $11.9 million of work by end of December 2025.

Below is a graph to recognize the anticipated monthly costs and overall accumulated costs.



Spend Plan by Cost Type

The following graph shows the type of costs allocated by month.

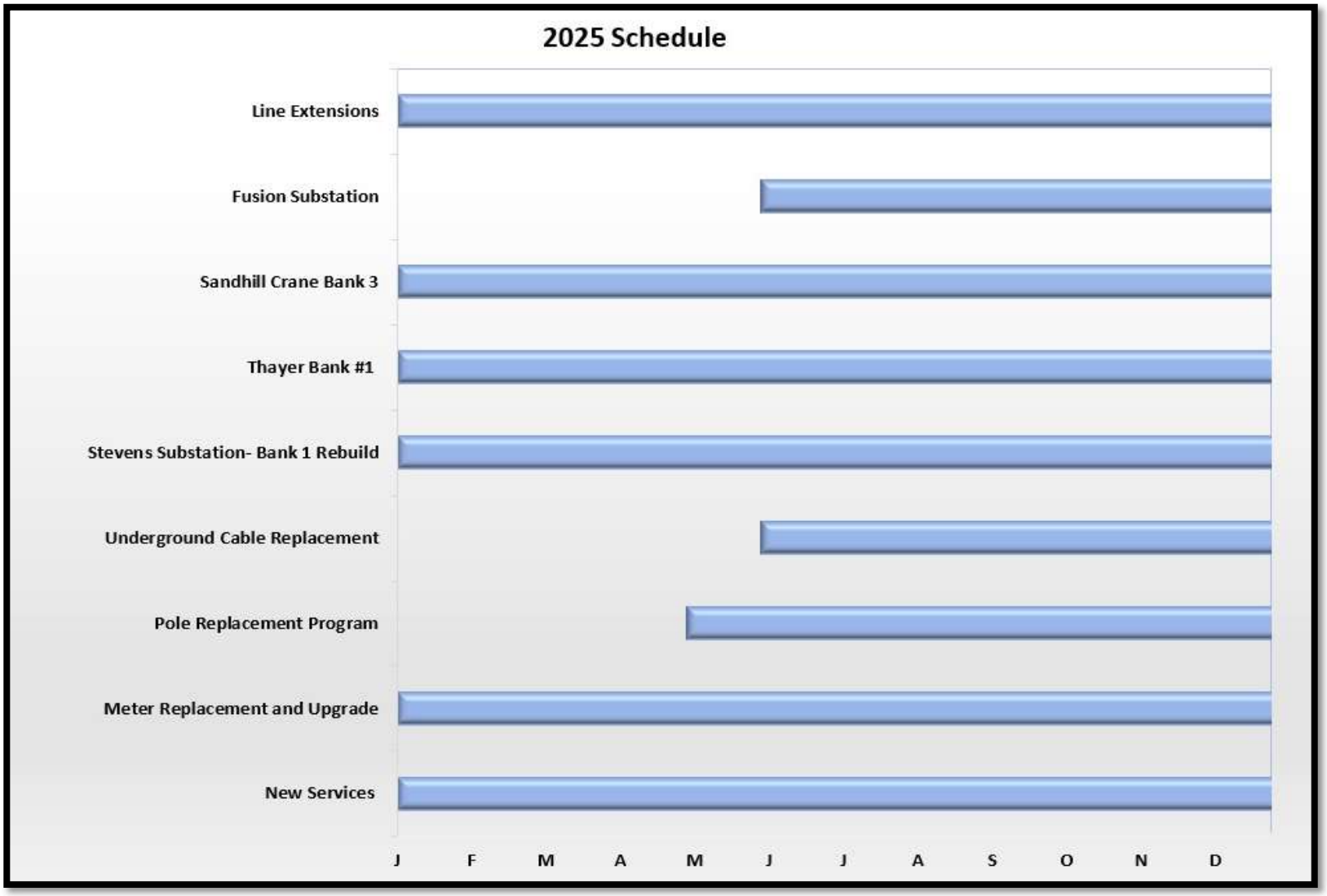


Project Schedule

Schedule

The 2025 CWP Schedule is strategically planned and evaluated by RES based on internal and external factors. Internal factors include availability of staffing resources, materials and equipment. External factors include availability of consultant and contractor support, projects that are developer driven, projects with time restraints and material deliveries, and weather conditions.

Project Schedule



UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 11/12/2024 Agenda Category: Other Informational Items

Prepared By: Clint Whitney, Energy Services Director

Subject:
Capital Work Plan Update - November 2024

Department:
Energy Services

Recommended Motion:
This item is informational only.

Summary:
Attached is a summary of Energy Services capital work through September 2024. The overall projected annual capital expenditures is $7.2M of the $11.4M that was originally planned. The $4.2M capital reduction is a result of Stevens & Thayer Substation rebuild projects that were pushed to 2026/2027 to align with BPA's revised schedule. Capital expenditures through September are $5.8M.

The 2024 capital work budget includes YTD expenses of:

- Line extensions - $1.6M
- System Improvements - $212K
- Renewal and Replacement - $2.1M
- Purchase of Southwest Service Area Infrastructure - $444K
- Substation Improvements - $143K
- Fusion Substation - $0
- Sand Hill Crane Substation Bank 3 (new) and Bank 4 (future) - $1.2k

There are two Carry Over Projects from 2023:

- AMI Project - Due to be completed in December 2024 when a final shipment of electric meters is received. 30,773 electrical AMI meters have been installed with 389 meters remaining for a 98.7% completion rate. 21,461 water AMI meters have been installed with 561 meters remaining for a 97.4% completion rate. Keystone Utility Services is currently installing water AMI meters in the legacy basement locations.
- City View Bank 2 - Completed in March 2024

Fiscal Impact:
There is no fiscal impact.

Attachments:
1. RES CWP REPORT-September 2024

CITY OF RICHLAND
WASHINGTON

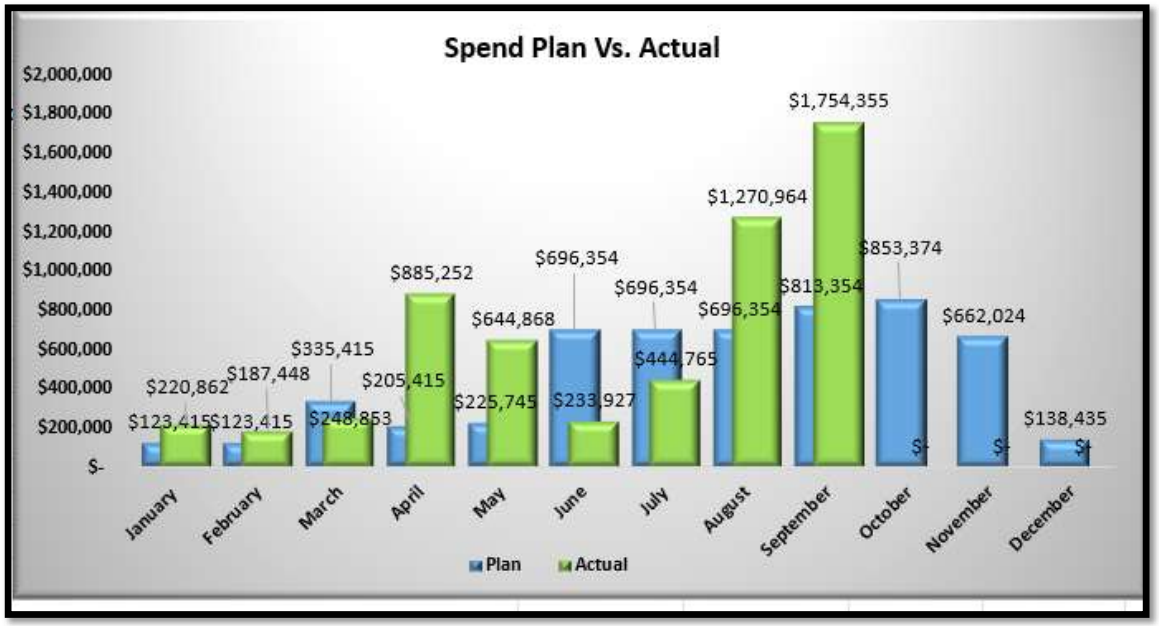
Richland Energy Services
Capital Work Plan
September 2024

CWP Costs through September

	Approved 2024 Budget	2024 Revised Budget	Actual	Remaining	September
Line Extensions	$983,000	$ 983,000	$1,688,400	$ (705,400)	$ 132,331
System Improvements	$473,000	$ 473,000	$ 212,379	$ 260,621	$ 14,089
Renewal and Replacement	$2,627,000	$ 3,589,654	$2,139,329	$ 1,450,325	$ 333,055
Purchase Southwest Service Area Infrastructure	$212,000	$ 212,000	$ 443,718	$ (231,718)	$ -
Substation Improvements	$6,597,000	$ 237,000	$ 143,108	$ 93,892	$ 17,494
Fusion Substation	$530,000	$ -	$ -	$ -	$0.00
Sandhill Substation Area Improvements	$0	$ 1,690,000	$1,264,359	$ 425,641	$1,257,386.07
Grand Total	$11,422,000	$ 7,184,654	$5,891,293	$ 1,293,361	$1,754,355

Cost Performance YTD:	$5,891,293
Cost Performance remaining:	$1,293,361
YTD % Complete	82%

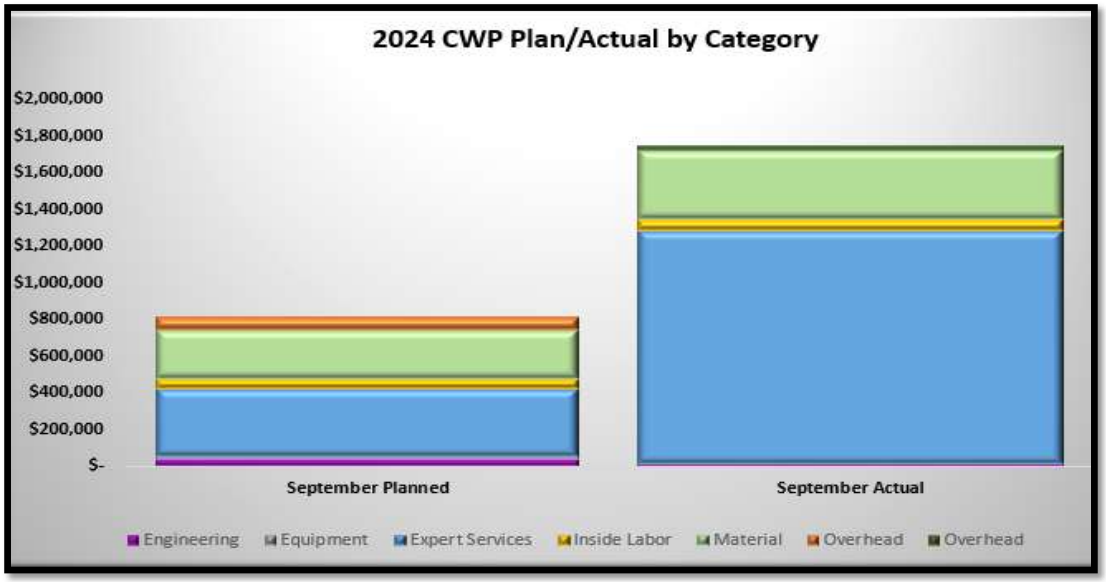
CWP Monthly Spend Vs. Actuals



% Complete of Overall Spend		
To-Date Pro	$	3,915,821
Actual	$	5,891,293
Variance	**$1,975,472**	**150%**

Costs by Category

CWP Cost Types



Cost Type	September Plan	September Actual
Engineering	$ 37,250	$ 13,874
Equipment	$ 21,000	$ -
Expert Services	$ 370,441	$ 1,272,833
Inside Labor	$ 48,333	$ 62,777
Material	$ 268,581	$ 378,323
Overhead	$ 67,749	$ 26,548
Total	**$ 813,354**	**$ 1,754,355**

CWP Project Costs for September

	Approved 2024 Budget	2024 Revised Budget	Actual	Remaining	September
Line Extensions	**$983,000**	**$ 983,000**	**$ 1,688,400**	**$ (705,400)**	**$ 132,331**
System Improvements	**$473,000**	**$ 473,000**	**$ 212,379**	**$ 260,621**	**$ 14,089**
System Improvements					
RES OH UG ENG DESIGN DWGS	$0	$ -	$ 6,651	$ (6,651)	$473.84
TEMPORARY SERVICES	$0	$ -	$ 650	$ (650)	$0.00
SKYLINE DR DEVELOPMENT; NEW PRIMARY AN	$0	$ -	$ 16,017	$ (16,017)	$0.00
Material Specifications	$0	$ -	$ 24,504	$ (24,504)	$947.66
New Services	$473,000	$ 473,000	$ 162,409	$ 310,591	$12,515.50
Renewal and Replacement	**$2,627,000**	**$ 3,589,654**	**$ 2,139,329**	**$ 1,450,325**	**$ 333,055**
UG Cable Replacement	$1,861,000	$ 2,823,654	$ 1,305,677	$ 1,517,977	$255,854.87
Purchase Southwest Service Area Infrastructure	**$212,000**	**$ 212,000**	**$ 443,718**	**$ (231,718)**	**$ -**
Substation Improvements	**$6,597,000**	**$ 237,000**	**$ 143,108**	**$ 93,892**	**$ 17,494**
Substation Improvements					
Demand Response by Voltage Reduction (DR	$0	$ -	$ 3,286	$ (3,286)	$0.00
Gateway Substation 2021 Project	$0	$ -	$ 11,059	$ (11,059)	$0.00
City View Bank 2 Addition	$0	$ -	$ 59,314	$ (59,314)	$3,331.89
Gateway Substation Feeder 151	$0	$ -	$ 840	$ (840)	$0.00
Stevens/Thayer Rebuild Design	$4,770,000	$ -	$ -	$ -	$0.00
City View Extension 131, EXT 3P 750 Aprox 200	$0	$ -	$ 302	$ (302)	$151.87
Substation PLC Replacement (Sandhill Crane,	$0	$ -	$ 4,834	$ (4,834)	$0.00
Thayer Substation - Bank 1 Rebuild and 115kV	$0	$ -	$ 50,404	$ (50,404)	$13,863.09
Design and Install SEL 2414 at SHC b1-2, FIS b1	$0	$ -	$ 9,965	$ (9,965)	$0.00
Substation Spill Prevention Control and Coun	$1,590,000	$ -	$ 3,103	$ (3,103)	$147.51
RES SCADA Radio Upgrade	$38,000	$ 38,000	$ -	$ 38,000	$0.00
Substation Security Improvements	$117,000	$ 117,000	$ -	$ 117,000	$0.00
Relay Replacement	$82,000	$ 82,000	$ -	$ 82,000	$0.00
Fusion Substation	**$530,000**	**$ -**	**$ -**	**$ -**	**$0.00**
Sandhill Substation Area Improvements	**$0**	**$ 1,690,000**	**$ 1,264,359**	**$ 425,641**	**$1,257,386.07**
Sandhill Crane Substation Bank 3 Addition	$0	$ 1,645,000	$ 1,264,359	$ 380,641	$1,257,386.07
Sandhill Bank 4 Addition	$0	$ 45,000	$ -	$ 45,000	$0.00
Sandhill Substation Area Improvements	$0	$ -	$ -	$ -	$0.00
Grand Total	**$11,422,000**	**$ 7,184,654**	**$ 5,891,293**	**$ 1,293,361**	**$1,754,355**

2023 Carry Over Projects

Carry Over Proje	Costs-to-date 2024	Comments
AMI	$ 804,299.92	Due to complete October 2024
City View Bank 2	$ 1,884,815.60	Metalclad delivered 01/04, Construction Completed 03/24
Total	**$ 2,689,115.52**	

UTILITY ADVISORY COMMITTEE AGENDA ITEM COVERSHEET

Meeting Date: 11/12/2024 Agenda Category: Other Informational Items

Prepared By:

Subject:
Forward Agenda

Department:
Energy Services

Recommended Motion:
This item is informational only.

Summary:
Resource Adequacy - January 2025
Bonneville Provider of Choice - Q1.25 and Q2.25
Electric Rates Review with Presentation by FCS – September 2025

Fiscal Impact:
There is no fiscal impact.

Attachments: