CANBY UTILITY
REGULAR BOARD MEETING
MAY 13, 2025
7:00 P.M.

AGENDA

I. CALL TO ORDER

II. AGENDA
- Additions, Deletions or Corrections to the Meeting Agenda

III. CONSENT AGENDA
- Approval of Agenda
- Approval of Special Meeting Minutes of March 3, 2025, Work Session Minutes of April 2, 2025, and Regular Board Meeting Minutes of April 8, 2025 (pp. 1-9)
- Approval of Payment of Water and Electric Bills

IV. CITIZEN INPUT ON NON-AGENDA ITEMS *Citizen's wanting to speak virtually, please email or call the Board Secretary-Clerk by 4:30 p.m. on May 13, 2025 with your name, the topic you would like to speak on, and contact information: bbenson@canbyutility.org or 503-263-4312.*

V. PGE FEASIBILITY STUDY RESULTS (*INFORMATION ONLY*) – Carol Sullivan, General Manager and Jason Berning, Operations Manager (pp. 10-28)

VI. RECOMMENDATION Authorize General Manager to reimburse the Bonneville Power Administration in accordance with the reimbursement agreement for a System Impact Study (pp. 29-30)

VII. RECOMMENDATION Award contract with Moss Adams LLP for Audit Services – Mike Schelske, Finance Manager (pg. 31)

VIII. BOARD REPORT
- Chair Comments
- Board Member Comments

IX. STAFF REPORTS

Finance Manager:
- Third Quarter Financials (pp. 32-44)
- Collections and Recoveries (pg. 45)

General Manager Updates

X. ADJOURN

CANBY UTILITY
SPECIAL BOARD MEETING MINUTES
MARCH 3, 2025

Board Present: Chair Thompson; Members Molamphy, Pendleton, and Hill

Staff Present: Carol Sullivan, General Manager; Barbara Benson, Board Secretary; Jason Berning, Operations Manager; Mike Schelske, Finance Manager; Cindy Dittmar, Customer Service Supervisor; and Jason Peterson, Operations Field Supervisor

Others Present: Mark Knudson, Special Districts Association of Oregon; Bob Westcott; Brian Hutchins, Veolia Water North America; and Ken Miller

Chair Thompson called the Special Board Meeting to order at 6:00 p.m. The meeting was convened to hear a presentation from Mark Knudson of the Special Districts Association of Oregon (SDAO) regarding their consulting services approach to recruitment and the scope of services available to assist Canby Utility in the search for a new General Manager.

Mr. Knudson began by outlining his extensive background in public utility management. He previously served as Chief Executive Officer of the Tualatin Valley Water District and as a board member for Oak Lodge Water Services. His recruitment approach is shaped by his experience in both executive and board leadership roles.

Knudson then provided an overview of SDAO's Consulting Services Program, which includes management recruitment facilitation. He emphasized that SDAO is a not-for-profit organization, and its consulting services operate as a subsidiary solely for the benefit of SDAO members. During the presentation, he outlined their recruitment methodology, provided examples of deliverables, reviewed a typical recruitment timeline, and discussed service fees. The facilitation services are billed at $66 per hour, with total costs typically ranging between $5,000 and $10,000. A copy of his presentation is attached for reference.

Knudson also presented several options for the candidate selection process. He recommended that the Board consider forming a subcommittee to prescreen applications and develop a list of finalists for full Board review. The Board discussed the merits of this approach versus having the full Board review all applications.

Candidates' travel costs were also addressed. Knudson recommended using the Government Services Administration per diem rates for meals, lodging, and mileage. He noted that this method eliminates the need to collect receipts and is a standard approach. Canby Utility would reimburse candidates traveling from long distances for their lodging and coach airfare.

Further discussion covered SDAO's role in reviewing the job description and application materials, developing interview questions, how SDAO's services differ from those provided by a traditional executive search firm, applicant scoring, and employment agreement negotiations.

The next steps for engaging Knudson to facilitate the recruitment are to prepare a Professional Services Agreement and establish the scope of work. The Board agreed to set the contract amount at $10,000.

Member Molamphy made the *MOTION to adjourn the meeting. Member Hill seconded, and the motion passed 4-0.

The meeting adjourned at 7:15 p.m.

Melody Thompson, Chair	John Molamphy, Member
Jake Hill, Member	Jack Pendleton, Member
Vacant	Barbara Benson, Board Secretary

CANBY UTILITY
BOARD WORK SESSION MINUTES
APRIL 2, 2025

Board Present: Chair Thompson; Members Molamphy, Pendleton, Hill, and Westcott

Staff Present: Carol Sullivan, General Manager; and Barbara Benson, Board Secretary

Others Present: Mark Knudson, Special Districts Association of Oregon

Chair Thompson called the Board Work Session to order at 6:01 p.m. The session was convened to define key features and requirements of the General Manager position and to review the proposed hiring process.

Mark Knudson of the Special Districts Association of Oregon (SDAO) presented the Board with seven draft documents for the Board's review and discussion.

The Board first reviewed the Position Description. The updated version includes additional job duties; more detailed knowledge, skills, and abilities; updated qualification requirements; and updated working conditions. The Board discussed minimum qualifications and agreed to include experience managing large, complex construction projects. Additionally, they identified a desired qualification: experience within the electric and/or water utility industries in the Pacific Northwest.

Knudson presented a proposed Hiring Procedure and Timeline, which will be updated as needed. The process complies with statutory requirements and includes an opportunity for public comment during the April 8, regular Board meeting, when the Board adopts the procedure. Knudson proposes that the position be open on April 14 and close on June 2, with a target start date of September 15. The Board had consensus to establish a two-member subcommittee, consisting of Members Molamphy and Hill, to conduct initial candidate screenings. They also decided that two interview panels will be used for the finalist interviews: one composed of board members and another of staff representatives.

Knudson reviewed the Job Announcement, which summarizes the position's key features, organizational background, compensation, and application procedures. The Board added a sentence to include leadership experience in the water and/or electric utility industries in the Pacific Northwest.

The Advertising and Outreach Plan summarizes how Canby Utility and SDAO will publicize and increase awareness of the position. Knudson reviewed strategies to promote the position, including outreach through various trade associations. The Board also wanted to include national trade organizations such as the American Public Power Association and the American Water Works Association.

SDAO updated the Application form for candidates to apply for the position. Candidates will also be required to provide a cover letter and resume. The application also includes the Veterans' Preference form. Knudson explained how the veterans' preference is applied during the selection process.

The evaluators will use Candidate Evaluation Criteria to screen the applicants, identify the finalists, and evaluate the finalist candidates. Knudson outlined the virtual evaluation process and reviewed scoring methodologies for the initial screening and finalist interviews. The Board discussed point weightings for the various evaluation components.

The Candidate Travel Expense Reimbursement Guidelines will be used to plan the finalist interviews and approve allowable travel expenses for those candidates. Knudson reviewed the proposed travel, food, and lodging reimbursements. The Internal Revenue Service mileage rates would apply for those traveling by car, and the General Services Administration per diem rates would apply to meals and lodging. Airfare would be reimbursed at coach/economy class.

Knudson will revise the draft documents based on the Board's feedback and present them for adoption at the April 8, 2025, regular Board meeting.

Member Molamphy made the <u>*MOTION</u> to adjourn the meeting. Member Pendleton seconded, and the motion passed 5-0.

The meeting adjourned at 8:02 p.m.

______________________	______________________
Melody Thompson, Chair	John Molamphy, Member
______________________	______________________
Jake Hill, Member	Jack Pendleton, Member
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Bob Westcott, Member	Barbara Benson, Board Secretary

CANBY UTILITY
REGULAR BOARD MEETING MINUTES
APRIL 8, 2025

Board Present:	Chair Thompson; Members Molamphy, Pendleton, Hill, and Westcott
Staff Present:	Carol Sullivan, General Manager; Barbara Benson, Board Secretary; Jason Berning, Operations Manager; Mike Schelske, Finance Manager; Cindy Dittmar, Customer Service Supervisor; and Jason Peterson, Operations Field Supervisor
Others Present:	Mark Knudson, Special Districts Association of Oregon; Dick Talley, Stantec; Brian Hutchins, Veolia Water North America; David Horrax; Bill and Karyn Fenton; My Do-Kruse and Christian Kruse; Chad Holtry; Patty Travis, and Joe Brennan

Chair Thompson called the Regular Board Meeting to order at 7:00 p.m.

Chair Thompson presented the meeting agenda for consideration and asked for any additions, deletions, or corrections. Board Secretary Barbara Benson requested the addition of a "Stantec Owner's Representative Announcement" to the agenda.

Chair Thompson presented the consent agenda for approval. Member Hill made the *MOTION to approve the consent agenda, consisting of the meeting agenda, regular meeting minutes of March 11, 2025, and payment of the electric and water department bills in the amount of $350,408.08. Member Molamphy seconded, and the motion passed 5-0.

Chair Thompson presented former board member David Horrax with a commemorative meter lamp for his six years of dedicated service to the Canby Utility Board.

Chair Thompson invited citizen input on non-agenda items. No public comments were received.

Chair Thompson opened the public rate hearing at 7:05 p.m. She reviewed the hearing process and applicable legal standards. Finance Manager Mike Schelske then presented the proposal to increase water rates by 14.24% on both the base and consumption charges for all customer classifications. This increase is based upon the 2023 Water Rate Study conducted by Steve Donovan of Donovan Enterprises, Inc., and is necessary to fund the construction of a new water treatment facility.

Schelske explained that the previous rate adjustment was implemented on May 1, 2024, as the first in a series of five recommended increases. The new water treatment plant project, estimated to cost $82 million, is critical to replacing aging infrastructure, improving water quality, and providing additional system capacity. According to the 2023 Water Master Plan, the existing plant will reach capacity by 2035. The funding strategy for the new facility includes $72 million in loans or revenue bonds and $10 million from reserves. Those reserves will be sourced through current reserve funds, projected revenue from the rate increases, and anticipated water system development charges (SDCs) from 2025 through 2029.

Schelske explained that the rate study's primary purpose was to determine water rates necessary to generate sufficient cash flow to service the $72 million of loans. The rate consultant recommended a series of equal, smaller rate adjustments. The current forecast anticipates annual increases of approximately 14.3% over the five-year period. An annual inflationary adjustment of 3% per year for operating expenses has also been factored into the calculations. During the estimated five-year planning and construction period, 85% of revenues from the rate increases will go towards construction costs and debt service, and 15% toward estimated increases in operating expenses.

Schelske noted that the forecast may change as the project progresses and more accurate cost estimates are obtained, potentially altering the projected rate increases.

Chair Thompson asked for further explanation of the SDC. Staff gave a brief overview and said the SDCs are based on the 2023 Water Master Plan.

Chair Thompson then invited public testimony. Karyn Fenton addressed the Board, requesting clarification on the annual 14.3% increase and expressed concern about affordability for retirees. She asked whether the new treatment plant could be built more economically. Chair Thompson explained the reasons for incremental increases, and Schelske added that delaying them would require steeper rate hikes later. The average residential customer using 1,000 cubic feet of water would see a monthly increase of $6.69.

Christian Kruse inquired about the timeline for the existing plant reaching capacity and asked about the implications of not constructing a new facility. Brian Hutchins of Veolia Water responded, explaining that beyond the capacity concerns, the existing plant lacks seismic resilience and cannot treat for taste and odor. Kruse also asked about the aggressive rate increase schedule. Schelske explained the reasons relating to the construction timeline.

Chad Holtry shared feedback from senior citizens in the community, many of whom are on fixed incomes and struggling with rising costs. He expressed concern that the proposed increases would place an additional financial strain on them.

Keith Galitz submitted written testimony opposing the proposed 14.24% rate increase, stating that it is both unjust and unfair, and much higher than required to meet the need for the planned new facility. New housing will drive higher demand for water and more revenue to help offset the need for such a significant rate increase. Galitz noted the current Tier 3 rates create a financial hardship in the summer months and listed his utility bills for July through October. Galitz noted that he had already reduced his water usage in 2023 and would likely have to let his lawn die under the new rates. Galitz said he is retired and cannot afford the significant cost increases.

Debora Gustin also submitted written testimony, acknowledging her concern over the proposed hike but expressing her understanding of its rationale. Gustin shared that her Social Security cost-of-living adjustment had been offset by a rise in her insurance premiums. Gustin concluded with a kind note and a banana bread recipe for the Board.

After closing public testimony, members of the Board offered comments. Member Hill acknowledged the financial challenges with this rate proposal. He underscored the importance of the project and the Board's long-standing consideration since the adoption of the Water Master Plan. Member Molamphy highlighted the necessity of the new water treatment plant being vital to Canby's future. Member Westcott stressed the limitations of the Molalla River and the need to establish a secondary water source from the Willamette River, which contributes significantly to the project's cost. Chair Thompson encouraged the public to tour the existing water treatment facility to understand its constraints, including the lack of space for expansion. She also referenced a presentation made to the Canby City Council, available on the utility's website, that offers a helpful overview of the project. She thanked the public for attending and sharing their input.

Member Molamphy made the <u>*MOTION</u> to close the public hearing and continue with the rate adjustment. Member Hill seconded, and the motion passed 5-0. The public hearing closed at 7:32 p.m.

Member Hill made the <u>*MOTION</u> to Adopt Resolution No. 329, adjusting Canby Utility's water rates effective May 1, 2025, with a rate increase of 14.24% on the base and volume charges for all customer classifications. Member Molamphy seconded, and the motion passed 5-0.

Mark Knudson, Senior Consultant with the Special Districts Association of Oregon (SDAO), presented the proposed documents and guidelines for the recruitment of a new General Manager. These documents included the Position Description, Hiring Procedure and Schedule, Position Announcement, Advertising and Outreach Plan, Application Form, Candidate Screening Criteria, Finalist Evaluation Criteria, and Travel Expense Reimbursement Guidelines. Knudson noted that the Board had reviewed and contributed to these documents during its April 2, 2025, work session. Chair Thompson opened the floor for public comment on these materials in accordance with ORS 192.660(7)(d)(D), but no comments were received.

Member Westcott made the <u>*MOTION</u> move to approve the proposed documents for recruitment of the Canby Utility General Manager, including the proposed Position Description, Hiring Procedure and Schedule, Position Announcement, Advertising and Outreach Plan, Application Form, Candidate Screening Criteria, Finalist Evaluation Criteria, and Travel Expense Reimbursement Guidelines. Member Pendleton seconded, and the motion passed 5.0.

Member Westcott made the *MOTION move to appoint Board Members Molamphy and Hill to serve on a Candidate Screening Committee to work with SDAO as outlined in the approved Hiring Procedure and Schedule, with this committee and these appointments to be terminated at the conclusion of the hiring process. Member Pendleton seconded, and the motion passed 5-0.

Dick Talley from Stantec who is serving as the owner's agent for Canby Utility's water treatment plant project gave the Board an update on the progress. He explained that two teams have been established—one focused on engineering and the other on operations—and both include Canby Utility's leadership team. Talley described the work performed by each team. Talley also discussed pending legislation that could affect water rights and point of diversion transfers, noting that Canby Utility intends to add a point of diversion on the Willamette River. The proposed legislation may introduce clauses allowing such transfers to be contested, prompting quick action to submit the request to the Water Resources Department.

Member Pendleton asked if storage is being considered a project component. Talley explained that the clearwell may be enlarged to provide additional storage capacity. Pendleton also asked about interest rate oversight for the project's funding. Talley clarified that Canby Utility is leading this effort, supported by Stantec's finance team. Talley also announced his retirement effective May 1.

Chair Thompson raised the subject of the NW 4th and Fir St. water reservoir site, referencing a recent inquiry from City Councilor Stearns. She noted that the 2023 Water Master Plan recommends continued evaluation of the property's long-term value. Chair Thompson stated that the utility should conduct appropriate due diligence to assess the potential uses of the site, its market value, and whether the property could be sold or exchanged for another site. A brief discussion followed.

Operations Manager Jason Berning presented the quarterly reliability report for January through March, noting there were no power outages during this period. He attributed the reliability to extensive tree trimming efforts conducted by the electric crew last fall and winter.

Berning also reported on the Public Utility Commission's inspection of 45 power poles in March and anticipated that approximately 20 corrections may be required once the report is finalized.

Finance Manager Schelske reviewed the fiscal year 2026 budget timeline, stating that proposed budgets will be distributed to Board members on June 5 and considered for approval at the June 10 meeting.

General Manager Carol Sullivan gave an update on the Portland General Electric (PGE) feasibility study. While studying the load addition at the Westcott substation, PGE identified that the plan of service they were initially studying was likely infeasible and unnecessarily costly to the customer. PGE has identified an alternative plan of service, but needed more time to study the alternative. They expect to deliver the final study on April 14. Member Pendleton asked whether Trammel Crow and City of Canby staff were informed, and Berning confirmed that they were. Pendleton voiced concern about how the study's outcome could affect growth in Canby. Sullivan explained that the challenges related to transmission affect the region, not just Canby. The Bonneville Power Administration (BPA) has paused all future studies due to an influx of requests. Chair Thompson inquired about other projects being impacted by the study, and Berning said there are two projects: the Oregon Liquor and Cannabis Commission and the Clackamas County Fairgrounds. Member Westcott asked about PGE's reference to "customer" in their response, and discussion ensued. Chair Thompson asked if Canby Utility could connect directly to BPA. Berning responded that the concept will be explored in the upcoming five-year electric system study.

Sullivan reported on the Canby Drinking Water Supply System project meetings. Stantec met with staff on March 20 for the Owners Representative Workshop (WP) #1. During this meeting, Stantec introduced staff to the SharePoint collaboration portal. On March 26, Stantec met with staff for the Conceptual Engineering WS#1. In this meeting, alternative water treatment plant and river intake siting options were explored. On April 7, Stantec met with staff for the Owners Representative WS#2. In this meeting, the program management plan overview, position descriptions, and responsibilities were discussed. Then on April 8, Stantec met with staff for the Owners Representative WS#3. In this meeting, the program authority matrix was reviewed.

Member Molamphy made the <u>*MOTION</u> to adjourn the meeting at 8:47 p.m. Member Hill seconded, and the motion passed 5-0.

The meeting was adjourned at 8:47 p.m.

Melody Thompson, Chair	John Molamphy, Member
Jake Hill, Member	Jack Pendleton, Member
Robert Westcott, Member	Barbara Benson, Board Secretary

Portland General Electric Company

Feasibility Study

Line and Load Interconnection Request

(CUB Westcott Substation)

April 14, 2025

Table of Contents

Introduction

This interconnection feasibility study[1] (IFS) examines the Bonneville Power Administration's (BPA or Customer) line and load interconnection request (LLIR) 24-116 for 7.5 MW (Westcott Load) of load service at the Canby Utility Board (CUB) Westcott substation in Canby, Oregon. The CUB Westcott substation is connected to the Portland General Electric (PGE) Twilight 57 kV substation. The Twilight 57 kV substation is configured as a sectionalizing station on the North Marion-Sullivan 57 kV line.[2]

Study Scope

This IFS is an evaluation of the impact and cost to the PGE system that is associated with the Westcott Load. This IFS identifies any facility additions, and if applicable, any affected system, necessary to facilitate the Westcott Load addition. This IFS consists of a power flow analysis. The following objectives are met in this IFS:

- Documentation of the assumptions used in the analyses;
- Documentation of any system impacts observed that are adverse to the safety and reliability of the broader electric system as a result of the Westcott Load;
- Documentation of other transmission providers' transmission systems that are impacted and identification of such transmission providers as Affected Systems;
- A non-binding estimate of the cost for constructing the facility additions necessary to facilitate the Westcott Load; and,
- A non-binding estimate of the time to construct the required facility additions.

This IFS considers all transmission facilities and generation facilities that, on the date the study was commenced:

- Were directly interconnected to the PGE Transmission System;
- Were interconnected to other transmission providers' transmission systems and may have an impact on the requested load interconnection;
- Have a pending generator Interconnection Request or line and load interconnection request to interconnect to the PGE Transmission System;
- Have a pending Transmission Service Request (TSR) for the PGE Transmission System (unless related to serving the Westcott Load); and,

[1] With the exception of those terms that are defined herein, capitalized terms used throughout this document have the same meanings as such terms are defined in PGE's Open Access Transmission Tariff (OATT).
[2] On March 19, 2025, in Docket EL25-11, PGE filed a Petition for Declaratory Order with the Federal Energy Regulatory Commission to reclassify as transmission assets certain 57kV facilities currently classified as distribution assets.

- Have no generator interconnection queue position but have executed a Large Generator Interconnection Agreement (LGIA) or requested that an unexecuted LGIA be filed with the Federal Energy Regulatory Commission (FERC).

Study Assumptions

This IFS includes the following assumptions for all system conditions and seasons:

- The requested load service is 7.5 MW, per Customer's application;
- The requested load will be served from the existing CUB Westcott substation;
- Generating facilities that have no queue position but have an executed LGIA or have requested an unexecuted LGIA be filed with FERC, are modeled at the maximum generation level documented in their respective LGIAs. The specific generating facilities with executed or contested LGIAs, which are included in this IFS, are:
    - There are no generating facilities that have no queue position included in this IFS;
- Pending generator Interconnection Requests are modeled at their requested maximum generation levels. The specific generation Interconnection Requests included in this IFS are:
    - There are no pending generator Interconnection Requests that are included in this IFS;
- The specific pending TSRs included in this IFS are:
    - There are no pending TSRs that are expected to have an impact on this IFS.
- The Customer will provide reactive compensation devices necessary to remain within a 0.95 leading/lagging power factor at the POI;
- No generator interconnection requests on other transmission providers' transmission systems were included in this IFS;
- PGE's committed projects[3] for which construction is scheduled to overlap with the Customer's requested in-service date:
    - There are no PGE committed projects that are expected to have an impact on this IFS;
- BPA will install metering infrastructure so as to account for line/transformer losses back to the POI;
- BPA will grant PGE access to data for accounting purposes; and,
- BPA will contact PGE when the revenue meters are placed in-service, and for biennially meter testing.

Study Case Development

This IFS utilizes Western Electricity Coordinating Council (WECC) base cases as the starting point for studying the impact of the Westcott Load interconnecting to the PGE transmission system. WECC base

[3] PGE's Willamette Valley Resiliency Project is not expected to overlap with the Customer's requested in-service date and it is not expected to be an effective mitigation for transmission system impacts due to this load addition.

cases include models for the entire western interconnection[4] including facility representation of voltage levels at the sub-transmission level. WECC collects the data for the western interconnection through its members who provide the representations and equivalent data for elements in their systems, including: the initial conditions for the study case, up-to-date line parameters, load information, generation unit parameters, and equivalent representations consistent with the time period being studied. The WECC base cases used in this IFS were modified for use in the North American Electric Reliability Corporation (NERC) TPL-001-5.1 Transmission Planning Assessment (TPL) for PGE, as follows:

- The TPL 2026 summer peak case is based on the WECC 2024 Heavy Summer 3 Ops case;
- The TPL 2026-27 winter peak case is based on the WECC 2023-24 Heavy Winter 3 Ops case; and,
- The TPL 2026 spring off-peak case is based on the WECC 2025 Light Spring 1S case.

The TPL cases include higher customer loads to reflect the summer peak and peak winter forecasted for the PGE service territory and BPA loads. The TPL cases were further modified to include any pending TSRs, Interconnection Requests, or LLIRs listed in the Study Assumptions section of this IFS; as well as Interconnection Requests that have executed an LGIA or requested that an unexecuted LGIA be filled with FERC. Forecasted load growth for CUB loads in the study area were removed from the TPL cases to prevent double counting expected Customer load growth. The Customer confirmed that the load in the study area is expected to grow at approximately 1% year over year. The resulting cases are referred to in this IFS as the "Benchmark Cases".

Moving forward from the Benchmark Cases, a model of the Westcott Load was inserted, and the resulting cases are hereafter referred to as the "Project Cases". The differences between the Benchmark Cases and the Project Cases form the basis for comparisons of the transmission system's performance before and after introducing the Westcott Load.

IFS Methodology

This IFS consists of power flow analyses. Power flow analyses may reveal unacceptable system performance that must be mitigated in order to safely and reliably interconnect the Westcott Load to the PGE transmission system. The Benchmark Cases and the Project Cases are analyzed to determine if facility upgrades are necessary to ensure that the transmission system, with the addition of the Westcott Load, demonstrates acceptable system performance. A power flow analysis is performed on a version of the Project Cases that includes all Network upgrades, Direct Assignment Facilities, Transmission Provider's Interconnection Facilities, and Interconnection Customer's Interconnection Facilities required for any TSR, Interconnection Request, or LLIR pending in PGE's queue as well as any that are required for Interconnection Requests that have executed an LGIA or have requested an unexecuted LGIA to be filed with FERC.

[4] The Western Interconnection spans 1.8 million square miles in all or part of 14 states, the Canadian provinces of British Columbia and Alberta, and the northern part of Baja California in Mexico.

Power Flow Analysis

The NERC TPL-001-5.1 reliability standard requires that all transmission system elements comprising the bulk electric system (BES) remain within their established thermal and voltage limits following the loss of a single BES element (N-1) or the loss of two or more BES elements (N-2 or N-1-1). This IFS includes the N-1, N-2, and N-1-1 contingencies for all BES elements in the PGE transmission system and neighboring areas. In addition, the WECC System Performance Criteria[5] require that the change in bus voltage percentage not exceed 8% for N-1 contingencies. Thermal line loading increases, due to the Westcott Load, that are less than 2% over the Benchmark Case loadings are not considered significant impacts that need to be addressed.

The analysis results for each contingency are assessed for compliance with the following NERC and WECC system performance Requirements:

Pre-Contingency:

- All BES elements shall be within their normal thermal limits
- All BES elements shall be within their normal voltage limits

Post-Contingency:

- All BES elements shall be within their emergency thermal limits
- All BES elements shall be within their emergency voltage limits
- Bus Voltage Change Limits:
  - The difference between pre- and post-contingency load-serving bus voltages must be less than:
    - 8% for N-1 contingencies
    - 10% for N-2 and N-1-1 contingencies[6]
- Cascading or uncontrolled separation shall not occur

[5] WECC Criterion – TPL-001-WECC-CRT-3.2
[6] Load-serving bus voltages must be less than 10% for category P2-2 through category P7 contingencies; this is a PGE performance requirement and is not documented in NERC and WECC standards.

Study Analyses and Results

Preliminary Plan of Service

The Preliminary Plan of Service discussed in this section of the report was developed to meet the requirements for the Customer's load request.

The PGE-owned system relevant to the study area is shown below in **Figure 1**. The CUB Westcott substation is served from the PGE Twilight 57 kV substation. Twilight 57 kV is operated as a sectionalizing station in the North Marion-Sullivan 57 kV line. The Westcott Load will be served out of the existing CUB Westcott substation. There are no new facility upgrades necessary to implement the Preliminary Plan of Service.

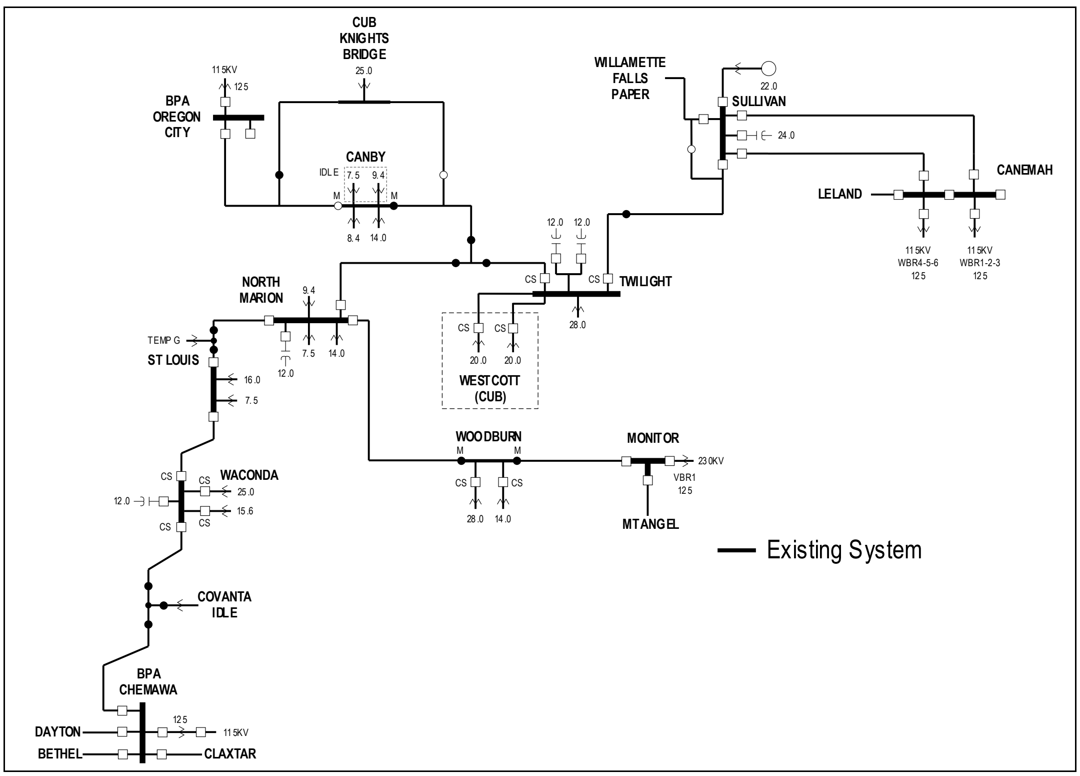

Figure 1: Preliminary Plan of Service

Results of Power Flow Analyses – Preliminary Plan of Service

2026 Peak Summer

The power flow results for the 2026 peak summer season identified that five PGE system elements will exceed their seasonal thermal ratings for three N-1, six N-2, and 37 N-1-1 contingencies. No thermal overloads or voltage violations were observed on Affected Systems in any season. The 2026 peak summer power flow results are shown in **Table 1**.

Peak Summer Power Flow Results – Preliminary Plan of Service					
#	**Contingency Name**	**Limiting Element**	**Project Case**	**Benchmark Case**	**Difference**
1	Chemawa BPA-Waconda 57kV	Monitor-North Marion 57 kV	101.3	97.8	3.5
2	Monitor-Woodburn 57kV	Chemawa BPA-St Louis 57 kV	100.1	96.6	3.4
3	Sullivan-Twilight 57kV	Monitor-North Marion 57 kV	98.6	92.3	6.3
4	Canemah B52 57kV	Canemah-Sullivan #1 57 kV	101.9	94.7	7.2
5	Monitor 57kV	Chemawa BPA-St Louis 57 kV	100.5	97.2	3.4
6	Canemah Bus Sectionalizing Breaker 57kV	Monitor-North Marion 57 kV	107.8	97.8	10.0
7	Bethel V218 230kV (Fault on McLoughlin line)	North Marion-Sullivan 57 kV	102.8	96.5	6.3
8	Bethel V218 230kV (Fault on McLoughlin line)	North Marion-Sullivan 57 kV	102.8	96.5	6.3
9	Chemawa L55 BPA 57kV (Fault on St Louis line)	Monitor-North Marion 57 kV	101.3	97.8	3.5
10	Canemah-Sullivan #2 57kV St Louis-Waconda 57kV	Canemah-Sullivan #1 57 kV	108.2	99.8	8.4
11	Canemah-Sullivan #1 57kV St Louis-Waconda 57kV	Canemah-Sullivan #2 57 kV	108.2	99.8	8.4
12	Canemah-Sullivan #2 57kV Chemawa BPA-St Louis 57kV	Canemah-Sullivan #1 57 kV	107.9	99.5	8.4
13	Canemah-Sullivan #1 57kV Chemawa BPA-St Louis 57kV	Canemah-Sullivan #2 57 kV	107.9	99.5	8.4
14	Canemah-Leland 57kV Canemah-Sullivan #2 57kV	Canemah-Sullivan #1 57 kV	106.2	98.7	7.5
15	Canemah-Leland 57kV Canemah-Sullivan #1 57kV	Canemah-Sullivan #2 57 kV	106.2	98.7	7.5
16	Bethel-McLoughlin 230kV Chemawa BPA-Waconda 57kV	Canemah-Sullivan #1 57 kV	106.2	99.1	7.1
17	Chemawa BPA-Santiam BPA 230kV Sullivan-Twilight 57kV	Monitor-North Marion 57 kV	105.8	99.4	6.4
18	Chemawa BPA-Waconda 57kV Monitor VBR1 230/57kV	Canemah-Sullivan #1 57 kV	104.4	97.3	7.0
19	Bethel-McLoughlin 230kV Chemawa BPA-Waconda 57kV	Canemah-Sullivan #2 57 kV	104.2	97.1	7.1

Peak Summer Power Flow Results – Preliminary Plan of Service					
#	Contingency Name	Limiting Element	Project Case	Benchmark Case	Difference
20	Monitor-Mt Angel 57kV Sullivan-Twilight 57kV	Monitor-North Marion 57 kV	103.9	98.1	5.9
21	Bethel-McLoughlin 230kV Chemawa BPA Transformer #1 115/57kV	North Marion-Sullivan 57 kV	102.8	96.3	6.5
22	Bethel-McLoughlin 230kV Canemah-Leland 57kV	North Marion-Sullivan 57 kV	102.4	96.3	6.2
23	Chemawa BPA-Waconda 57kV Monitor VBR1 230/57kV	Canemah-Sullivan #2 57 kV	102.4	95.4	7.0
24	Dayton-McMinnville BPA-Newberg 115kV Sullivan-Twilight 57kV	Monitor-North Marion 57 kV	102.2	95.9	6.4
25	Sullivan-Twilight 57kV Dayton WBR2 115/57kV	Monitor-North Marion 57 kV	102.2	95.8	6.4
26	Bethel-Salem 57kV Sullivan-Twilight 57kV	Monitor-North Marion 57 kV	101.6	95.2	6.4
27	Bethel-Silverton 57kV Monitor VBR1 230/57kV	Chemawa BPA-St Louis 57 kV	101.6	98.8	2.8
28	Bethel-Market 115kV Sullivan-Twilight 57kV	Monitor-North Marion 57 kV	101.2	95.0	6.3
29	Canemah-Sullivan #2 57kV Bethel WBR3 115/57kV	Canemah-Sullivan #1 57 kV	100.9	93.4	7.5
30	Canemah-Sullivan #1 57kV Bethel WBR3 115/57kV	Canemah-Sullivan #2 57 kV	100.9	93.3	7.6
31	Sullivan-Twilight 57kV Twilight Cap Bank #1 57kV	Monitor-North Marion 57 kV	100.8	94.0	6.8
32	Sullivan-Twilight 57kV Twilight Cap Bank #2 57kV	Monitor-North Marion 57 kV	100.8	94.0	6.8
33	Sullivan-Twilight 57kV North Marion Cap Bank 57kV	Monitor-North Marion 57 kV	100.8	94.0	6.8
34	Sullivan-Twilight 57kV Bethel VWR2 230/115kV	Monitor-North Marion 57 kV	100.7	94.4	6.3
35	Sullivan-Twilight 57kV Bethel VWR4 230/115kV	Monitor-North Marion 57 kV	100.7	94.3	6.4
36	Canemah-Rosemont 115kV Canemah-Sullivan #2 57kV	Canemah-Sullivan #1 57 kV	100.6	93.3	7.3
37	Monitor-Mt Angel 57kV Monitor VBR1 230/57kV	Chemawa BPA-St Louis 57 kV	100.6	97.1	3.4
38	Canemah-Rosemont 115kV Canemah-Sullivan #1 57kV	Canemah-Sullivan #2 57 kV	100.6	93.3	7.3
39	Canemah-Sullivan #2 57kV Chemawa BPA Transformer #2 230/115kV	Canemah-Sullivan #1 57 kV	100.5	93.0	7.5
40	Canemah-Sullivan #2 57kV Canemah-Sullivan 115kV	Canemah-Sullivan #1 57 kV	100.5	93.2	7.3
41	Canemah-Sullivan #1 57kV Chemawa BPA Transformer #2 230/115kV	Canemah-Sullivan #2 57 kV	100.5	93.0	7.5
42	Canemah-Sullivan #1 57kV Canemah-Sullivan 115kV	Canemah-Sullivan #2 57 kV	100.5	93.2	7.3

Peak Summer Power Flow Results – Preliminary Plan of Service					
#	Contingency Name	Limiting Element	Project Case	Benchmark Case	Difference
43	Monitor-Woodburn 57kV Chemawa BPA Transformer #2 230/115kV	North Marion-Sullivan 57 kV	100.4	93.2	7.2
44	Canemah-Sullivan #2 57kV Chemawa BPA-Santiam BPA 230kV	Canemah-Sullivan #1 57 kV	100.2	92.7	7.5
45	Canemah-Sullivan #1 57kV Chemawa BPA-Santiam BPA 230kV	Canemah-Sullivan #2 57 kV	100.2	92.7	7.5
46	Chemawa BPA Transformer #1 115/57kV Monitor VBR1 230/57kV	North Marion-Sullivan 57 kV	100.1	93.6	6.5
47	Bethel-Santiam BPA 230kV Canemah-Sullivan #1 57kV	Canemah-Sullivan #2 57 kV	100.0	92.5	7.5

Table 1: 2026 Peak Summer Power Flow Results – Preliminary Plan of Service

2026-2027 Peak Winter

The power flow results for the 2026-2027 peak winter season identified that five PGE system elements will exceed their seasonal thermal ratings for six N-1-1 contingencies. The power flow results also identify one N-1-1 contingency that is unsolved. Unsolved contingencies indicate potential system instability. No thermal overloads or voltage violations were observed on Affected Systems in any season. The 2026 peak winter power flow results are shown in **Table 2**.

Peak Winter Power Flow Results – Preliminary Plan of Service					
#	Contingency Name	Limiting Element	Project Case	Benchmark Case	Difference
1	Canemah-Sullivan #1 57kV Canemah-Sullivan #2 57kV	Unsolved	--	100.4	N/A
2	Chemawa BPA-St Louis 57kV Monitor-Woodburn 57kV	Canemah-Sullivan #1 57 kV	123.4	99.8	23.6
3	Chemawa BPA-St Louis 57kV Monitor-Woodburn 57kV	Canemah-Sullivan #2 57 kV	122.9	99.2	23.7
4	Monitor-North Marion 57kV Sullivan-Twilight 57kV	Chemawa BPA-St Louis 57 kV	113.4	99.5	13.8
5	Monitor-Woodburn 57kV North Marion-St Louis 57kV	North Marion-Sullivan 57 kV	106.9	97.7	9.3
6	Chemawa BPA-St Louis 57kV Sullivan-Twilight 57kV	Monitor-North Marion 57 kV	102.3	95.3	7.0
7	St Louis-Waconda 57kV Sullivan-Twilight 57kV	Monitor-North Marion 57 kV	102.3	95.3	7.0
8	North Marion-Woodburn 57kV St Louis-Waconda 57kV	North Marion-Sullivan 57 kV	100.6	92.6	8.0

Table 2: 2026-2027 Peak Winter Power Flow Results – Preliminary Plan of Service

2028 Off-Peak Spring

The power flow results for the 2026 off-peak spring season did not identify any PGE system elements that will exceed their seasonal thermal ratings. No thermal overloads or voltage violations were observed on Affected Systems in any season.

The power flow results identify that extensive reconductors of 57 kV lines in the study area must be completed prior to the Westcott Load coming on-line. Additionally, the Westcott Load creates a new unsolved contingency which potentially indicates system instability. Consequently, the Preliminary Plan of Service is considered to be infeasible to serve the Westcott Load.

Alternate Plan of Service

The Alternate Plan of Service will extend the Oregon City BPA-Knights Bridge CUB 57 kV line to Twilight by re-using an idle section of line, adding a new normally open switch outside of CUB Knights Bridge, and rebuilding 2.6 miles of the Sullivan-Twilight 57 kV line section of North Marion-Sullivan 57 kV to a double circuit configuration, creating the Oregon City BPA-Twilight 57 kV line.

The new Oregon City BPA-Twilight 57 kV line will be terminated at the Twilight 57 kV substation in the existing North Marion position. The existing circuit switcher will be replaced with a circuit breaker. The North Marion-Twilight 57 kV line will be rerouted and terminated at a new line position at Twilight 57 kV with a circuit breaker. The circuit switcher on the Sullivan position at the Twilight 57 kV substation will be replaced with a circuit breaker. The addition of the new circuit breakers requires the installation of a new control enclosure. CUB must provide CT output from the high side of the CUB Westcott transformers to be included in the 57 kV bus differential. Drawing and relay settings changes will be required at North Marion and Sullivan.

The addition of circuit breakers at the Twilight 57 kV substation will bifurcate the North Marion-Sullivan 57 kV line into the North Marion-Twilight 57 kV and Sullivan-Twilight 57 kV lines. The Canby substation and the Knights Bridge CUB substations will remain as transfer stations between the Oregon City BPA-Twilight 57 kV and the North Marion-Twilight 57 kV lines.

The Alternate Plan of Service is shown below in **Figure 2**.

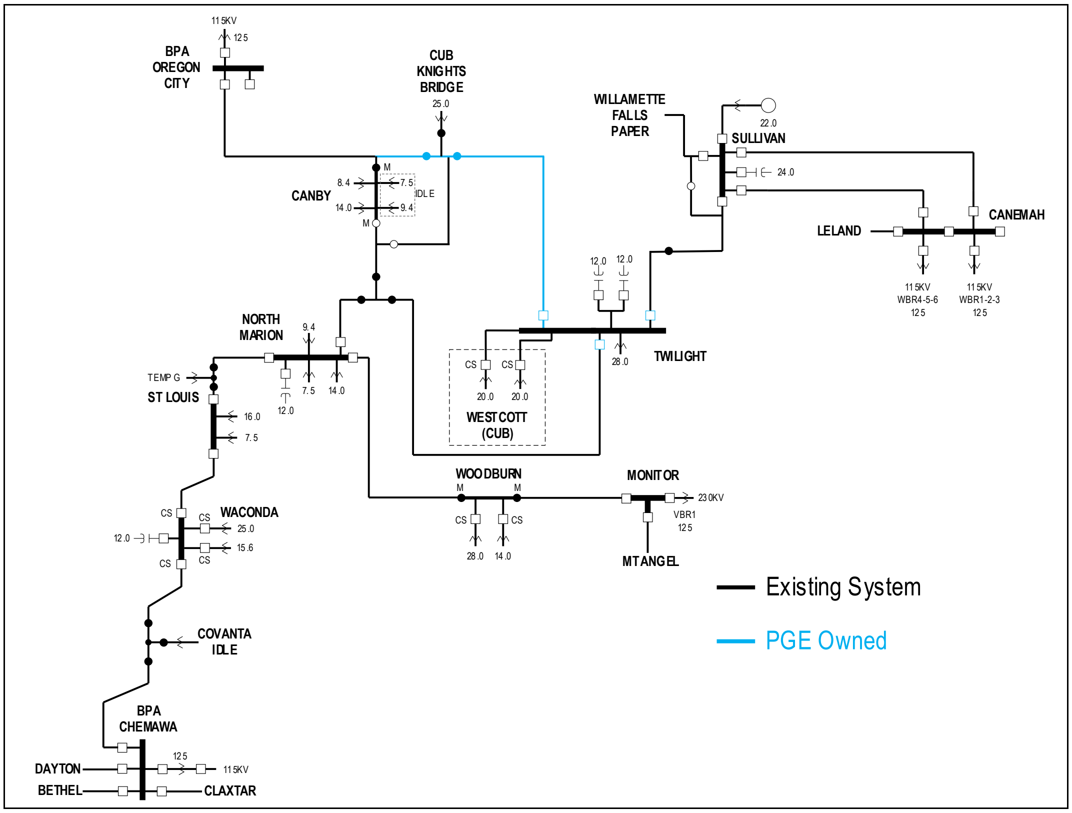

Figure 2: Alternative Plan of Service

Results of Power Flow Analyses – Alternative Plan of Service

2026 Peak Summer

The power flow results for the 2026 peak summer season identified that three PGE system elements will exceed their seasonal thermal ratings for four N-1-1 contingencies. The power flow results also identify five PGE system elements that will exceed their low voltage limit for seven N-1-1 contingencies. The BPA owned section of the new Oregon City BPA-Twilight 57 kV line exceeded its seasonal thermal rating for N-1, N-2, and N-1-1 contingencies. BPA is identified as an Affected System and will be provided with a copy of this report. The 2026 peak summer power flow results are shown in **Table 3** and **Table 4**.

Peak Summer Power Flow Results – Alternative Plan of Service					
#	Contingency Name	Limiting Element	Project Case	Benchmark Case	Difference
1	Oregon City BPA-Twilight 57kV Sullivan-Twilight 57kV	Monitor-North Marion 57 kV	110.9	100.6	10.3
2	Monitor-Woodburn 57kV Oregon City BPA-Twilight 57kV	Sullivan-Twilight 57 kV	106.3	94.6	11.7
		Chemawa BPA-St Louis 57 kV	103.6	95.9	7.7
3	Chemawa BPA-Waconda 57kV Oregon City BPA-Twilight 57kV	Monitor-North Marion 57 kV	103.4	95.8	7.6

Table 3: 2026 Peak Summer Power Flow Results – Alternative Plan of Service

Peak Summer Voltage Results – Alternative Plan of Service				
#	Contingency Name	Limiting Element	Project Case Voltage (p.u.)	Low Voltage Limit (p.u.)
1	Oregon City BPA-Twilight 57kV Sullivan-Twilight 57kV	Canby 57 kV	0.882	0.913
		Twilight 57 kV	0.891	0.913
2	Sullivan-Twilight 57kV Twilight Cap Bank #1 57kV	Twilight 57 kV	0.900	0.913
3	Sullivan-Twilight 57kV Twilight Cap Bank #2 57kV	Twilight 57 kV	0.900	0.913
4	Monitor-Woodburn 57kV Oregon City BPA-Twilight 57kV	Woodburn 57 kV	0.902	0.913
		North Marion 57 kV	0.910	0.913
5	Chemawa BPA-Waconda 57kV Oregon City BPA-Twilight 57kV	Waconda 57 kV	0.905	0.913
6	Chemawa BPA-Waconda 57kV North Marion-Twilight 57kV	North Marion 57 kV	0.912	0.913
7	Sullivan-Twilight 57kV North Marion-Woodburn 57kV	North Marion 57 kV	0.912	0.913

Table 4: 2026 Peak Summer Voltage Results – Alternative Plan of Service

The Chemawa BPA-St Louis 57 kV, Monitor-North Marion 57 kV, Sullivan-Twilight 57 kV lines exceed their summer seasonal rating for N-1-1 contingencies that include the new Oregon City BPA-Twilight 57 kV line. These lines must be reconductored. In order to facilitate the Westcott Load coming on-line before these lines can be reconductored, a bus sectionalizing circuit breaker (BSB) will be added to the Twilight 57 kV substation as shown below in **Figure 3**. The BSB will be used as the Oregon City BPA-Twilight 57 kV line terminal breaker until the line reconductors are complete. Utilizing the BSB as the Oregon City BPA-Twilight 57 kV line terminal breaker will result in the entire CUB Westcott substation being dropped as consequential load loss for a fault on the Oregon City BPA-Twilight 57 kV line. The consequential load loss will mitigate all of the N-1-1 contingencies shown in **Table 3**. The CUB Westcott load can then be restored by operator action dependent on system conditions. The consequential load loss also mitigates three of the voltage violations identified in **Table 4**. Reconductoring the BPA owned section of the Oregon City BPA-Twilight 57 kV line is expected to mitigate the remaining four voltage violations identified in **Table 4**. Once the reconductors of the Chemawa BPA-St Louis 57 kV, Monitor-North Marion 57 kV, and Sullivan-Twilight 57 kV lines is complete, the CUB Westcott substation will be removed from the Oregon City BPA-Twilight 57 kV line zone of protection so that a fault on the Oregon City BPA-Twilight 57 kV line does not result in an outage to the CUB Westcott substation.

The alternative to the loss of the CUB Westcott load as consequential load loss will be to reduce CUB Westcott load following any single contingency outage to Chemawa BPA-Waconda 57 kV, Monitor-Woodburn 57 kV, North Marion-Twilight 57 kV, North Marion-Woodburn 57 kV, Sullivan-Twilight 57 kV, or Oregon City BPA-Twilight 57 kV lines or either of the Twilight shunt capacitors. The load must be reduced before the next worst-case contingency occurs. This pre-contingency load reduction may result in extended outages depending on the nature of the outage.

Proposed Plan of Service

The Proposed Plan of Service considers the results of the power flow analyses and revises the Alternative Plan of Service, as necessary, to include any required upgrades necessary to facilitate the Customer's load request.

The Proposed Plan of Service includes:

- Rebuilding 2.6 miles of the Sullivan-Twilight 57 kV line section of North Marion-Sullivan 57 kV to a double circuit configuration;
- Installing a new line circuit breaker and BSB at the Twilight 57 kV substation;
- Replacing the existing Twilight 57 kV circuit switchers with circuit breakers;
- Installing a new control enclosure at Twilight 57 kV
- Reconductoring the Chemawa BPA-Waconda 57 kV section of the Chemawa BPA-St Louis 57 kV line;
- Reconductoring the Monitor-Woodburn 57 kV section of the Monitor-North Marion 57 kV line; and,
- Reconductoring a 2.6 mile line section of the Sullivan-Twilight 57 kV line.

The Proposed Plan of Service is shown below in **Figure 3**.

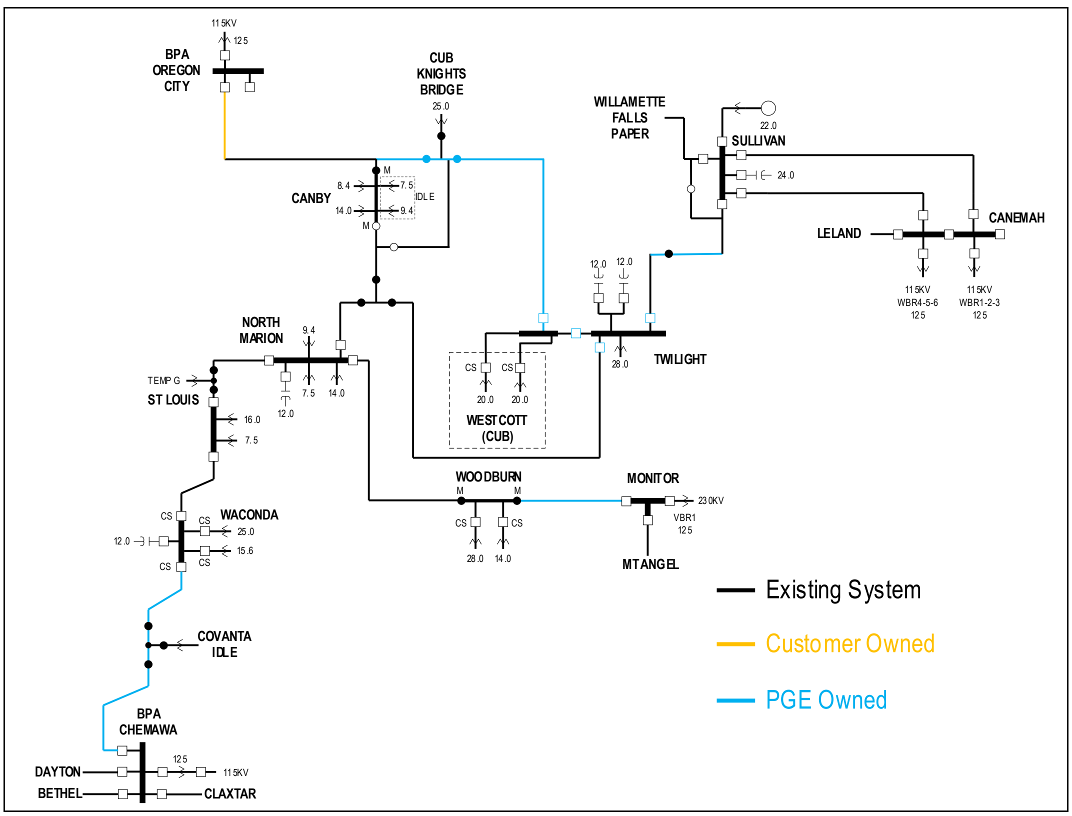

Figure 3: Proposed Plan of Service

A non-binding good-faith cost estimate of PGE's system upgrades required for the Proposed Plan of Service is shown below in **Table 5**. The good-faith construction schedule is discussed after the estimate. The cost of the BPA line upgrades is not included in the estimate for the proposed plan of service. The target accuracy of this cost estimate is +100/-50%.

Proposed Plan of Service Cost Estimate			
Twilight 57 kV			
Labor Cost		$	407,900.00
Material Cost		$	2,829,500.00
Engineering		$	887,500.00
Other Services		$	2,209,200.00
	Sub Total	$	6,334,100.00
Labor Cost		$	457,500.00
Material Cost		$	4,049,000.00
Engineering		$	2,043,900.00
Other Services		$	6,615,600.00
	Sub Total	$	13,166,000.00
Chemawa BPA-Waconda 57 kV			
Labor Cost		$	559,600.00
Material Cost		$	1,482,400.00
Engineering		$	1,807,000.00
Other Services		$	7,708,500.00
	Sub Total	$	11,557,500.00
Monitor-Woodburn 57 kV			
Labor Cost		$	410,400.00
Material Cost		$	1,511,700.00
Engineering		$	1,192,800.00
Other Services		$	4,721,800.00
	Sub Total	$	7,836,700.00
Sullivan-Twilight 57 kV			
Labor Cost		$	286,100.00
Material Cost		$	1,466,400.00
Engineering		$	946,500.00
Other Services		$	3,492,900.00
	Sub Total	$	6,191,900.00
	Total	$	45,086,200.00

Table 5: Plan of Service Cost Estimate

The schedule to implement the Proposed Plan of Service will require approximately 5-7 years to complete.

There are many factors outside of PGE’s control that could increase the costs and/or extend the time required for completing the Proposed Plan of Service outlined above. These factors include but are not limited to: Unexpected delays in the permitting process, long lead times for obtaining electrical equipment, shortages of qualified workers, contractual negotiations with third parties including vendors, inclement weather conditions, seasonal system load and outage restrictions, unforeseen permitting and environmental issues, and import tariffs.

Conclusion

The study results demonstrate that the Proposed Plan of Service for this load interconnection meets all NERC and WECC requirements. The Proposed Plan of Service to connect the Customer's load to the PGE transmission system includes:

- Rebuilding 2.6 miles of the Sullivan-Twilight 57 kV line section of North Marion-Sullivan 57 kV to double circuit;
- Installing a new line circuit breaker and BSB at the Twilight 57 kV substation;
- Replacing the existing Twilight 57 kV circuit switchers with circuit breakers;
- Installing a new control enclosure at Twilight 57 kV
- Reconductoring the Chemawa BPA-Waconda 57 kV section of the Chemawa BPA-St Louis 57 kV line;
- Reconductoring the Monitor-Woodburn 57 kV section of the Monitor-North Marion 57 kV line; and,
- Reconductoring a 2.6 mile line section of the Sullivan-Twilight 57 kV line.

The contingency analysis identified that BPA elements are expected to overload. BPA has therefore been identified as an Affected System and will be provided with a copy of this report.

The proposed plan of service is dependent on:

- BPA rebuilding the BPA-owned sections of the new Oregon City BPA-Twilight 57 kV line

The current estimated cost of the Proposed Plan of Service is approximately $45,086,200. The schedule to implement the Proposed Plan of Service will require 5-7 years for design, material procurement, and construction.

There are many factors outside PGE's control that could increase the costs and/or extend the time required for completing the Proposed Plan of Service outlined above. These factors include but are not limited to: Unexpected delays in the permitting process, long lead times for obtaining electrical equipment, shortages of qualified workers, contractual negotiations with third parties including vendors, inclement weather conditions, seasonal system load and outage restrictions, unforeseen permitting and environmental issues, and import tariffs.

PGE cannot guarantee that future analysis (i.e., Requests for Transmission Service or operational studies) will not identify additional problems or system constraints that require mitigation or reduced operation. An LLIR does not convey or imply any type of transmission service; a separate Transmission Service Request must be made for Transmission Service. If there is a material change in any aspect of this load interconnection, an SIS restudy may be required.

MEMORANDUM
May 10, 2025

TO: Chair Thompson, Member Molamphy, Member Pendleton, Member Hill, and Member Westcott

FROM: Carol Sullivan, General Manager & Jason Berning, Operations Manager

SUBJECT: Portland General Electric Transmission Impact Study

Suggested Motion: Motion to authorize the General Manager to reimburse the Bonneville Power Administration in accordance with the reimbursement agreement for a System Impact Study.

Background: At Canby Utility's (CU) August 2024 board meeting, Operations Manager Jason Berning reported on the feasibility studies required by the Bonneville Power Administration (BPA) and Portland General Electric (PGE) to assess the transmission system's ability to accommodate new loads of 1 MW or greater that are on the horizon.

A total of 7.5 megawatts (MW) of new industrial load—each individual load exceeding one MW—was projected. Due to potential constraints on PGE's 57kV transmission line that feeds CU's Westcott Substation, a Feasibility Study was initiated to determine the viability of integrating these new loads. The study concluded that the system, in its current configuration, could not accommodate the additional 7.5 MW. BPA paid PGE the initial $50,000 deposit on CU's behalf, and CU is now required to reimburse BPA under the terms of the reimbursement agreement. Although the actual cost may be less than the deposit, the final amount is currently unknown.

A virtual meeting was held with representatives from BPA, PGE, CU, and other stakeholders to review the study's findings. The results indicated that the new load could not be supported during severe weather events unless significant system upgrades were implemented. PGE proposed a preliminary plan of service that includes system upgrades estimated at $45 million. While BPA would initially fund the upgrades, the costs would ultimately be allocated among the beneficiaries—CU being one of them. Notably, the proposed upgrades do not include converting the transmission line from 57kV to 115kV and are estimated to take 5 to 7 years to construct.

A second meeting, held primarily in person, included representatives from BPA, PGE, CU, and CU's engineering consultants to discuss options. PGE acknowledged that their existing 57kV transmission system is relatively weak, and portions are slated for future improvement under the Willamette Valley Resilience Project that is estimated to be 10–15 years out. It remains unclear how much additional CU load PGE can support without a more detailed System Impact Study, which would require an additional $50,000 deposit.

PGE will also evaluate the feasibility of CU integrating non-firm loads—loads that are not guaranteed and may be curtailed or interrupted during extreme conditions, such as severe weather.

An additional study, the System Impact Study, is now necessary, since the Feasibility Study results determined that the current system configuration cannot support the additional 7.5 MW of load. The upcoming study will assess how much new load—beyond normal growth—CU can accommodate moving forward.

Below is the list of applicable studies and the associated deposit amounts for each:

- **Feasibility Study Deposit - $50k:** A preliminary evaluation of the proposed interconnection to PGE's Transmission System, along with the preliminary estimated cost to CU.
- **System Impact Study Deposit - $50k:** This study includes power flow, short circuit, transient stability, and voltage stability analyses. Each analysis may reveal unacceptable system performance that must be mitigated to safely and reliably interconnect to the PGE Transmission System.
- **Facilities Study Deposit - $75k:** Specifies and estimates the cost and schedule for engineering, permitting, equipment procurement, and construction work needed to implement the conclusions of the System Impact Study in accordance with Good Utility Practice. A plan of service and project scoping document is developed.

Jason and I will be available to answer any questions the Board may have.

MEMORANDUM

May 7, 2025

TO: Chair Thompson; Member Molamphy, Member Pendleton, Member Hill, and Member Westcott

FROM: Mike Schelske, Finance Manager

SUBJECT: Recommendation to Award Professional Services Contract for Audit Services

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Suggested Motion:

I move to authorize the General Manager to sign a contract with Moss Adams LLP for a three-year period of annual audit services starting with fiscal year 2025.

Summary of RPF Process:

Requests for proposals were submitted to eight qualified accounting firms. In addition, notice was published in the Daily Journal of Commerce and posted on the Canby website.

Proposals Received:

Moss Adams was the only firm that submitted a proposal. The proposed not-to-exceed amounts for FY 2025, FY 2026, and FY 2027 are $50,250, $54,600, and $56,700 respectively. These amounts include a 5% administrative and technology fee.

Management Recommendation:

Management recommends this proposal be accepted. Moss Adams has performed audits for Canby Utility since 2015. Their extensive knowledge of our processes and financials will enable them to provide efficient audits.

Procurement Approval:

The cost for this service falls within the intermediate procurement policy and does not require a formal Request for Proposal. However, an RFP was issued for these services. The General Manager has the authority to enter into personal service contracts not exceeding $25,000. In this case Board approval is required because the cost exceeds the $25,000 threshold set by policy.

If this recommendation is approved, a Professional Services Contract will be issued and signed by the General Manager, or her designee, according to Canby Utility's Public Contracting Rules, Resolution No. 320, for signature authority, Section 1.10.020.

Staff will be available to answer any questions you may have.

MEMORANDUM

To: Chair Thompson, Member Molamphy, Member Pendleton, and Member Hill, Member Westcott

Copy to: Carol Sullivan, Jason Berning, Jason Peterson, Cindy Dittmar

From: Mike Schelske, Finance Manager

Date: May 8, 2025

Subject: Financial Results for Nine Months Ending March 31, 2025

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*Please refer to the attached **Charts**, **Financial Highlights, Summary Income Statement,** and **Balance Sheet** for supporting details and additional information.*

YTD Electrical Highlights

- Operating revenue of $11.9 million exceeded the budget by 2.1%.
- Total expenses – purchased power and operating expenses - are slightly over budget with 78% of the budget expended after 75% of the year has been completed.
- Purchased power of $7.4 million was 8.5% higher than budget due to higher sales and an error in the Q1 purchased power budget calculation.
- Operating expenses of $4.4 million were 6.5% lower than budget, mainly due to one open position, lower BPA energy incentive payments, and lower costs for supplies and contractors.
- The operating loss of $161,000 was 16.5% higher than budget.
- Net income of $1.2 million was 35.0% lower than budget due to lower contributed capital.

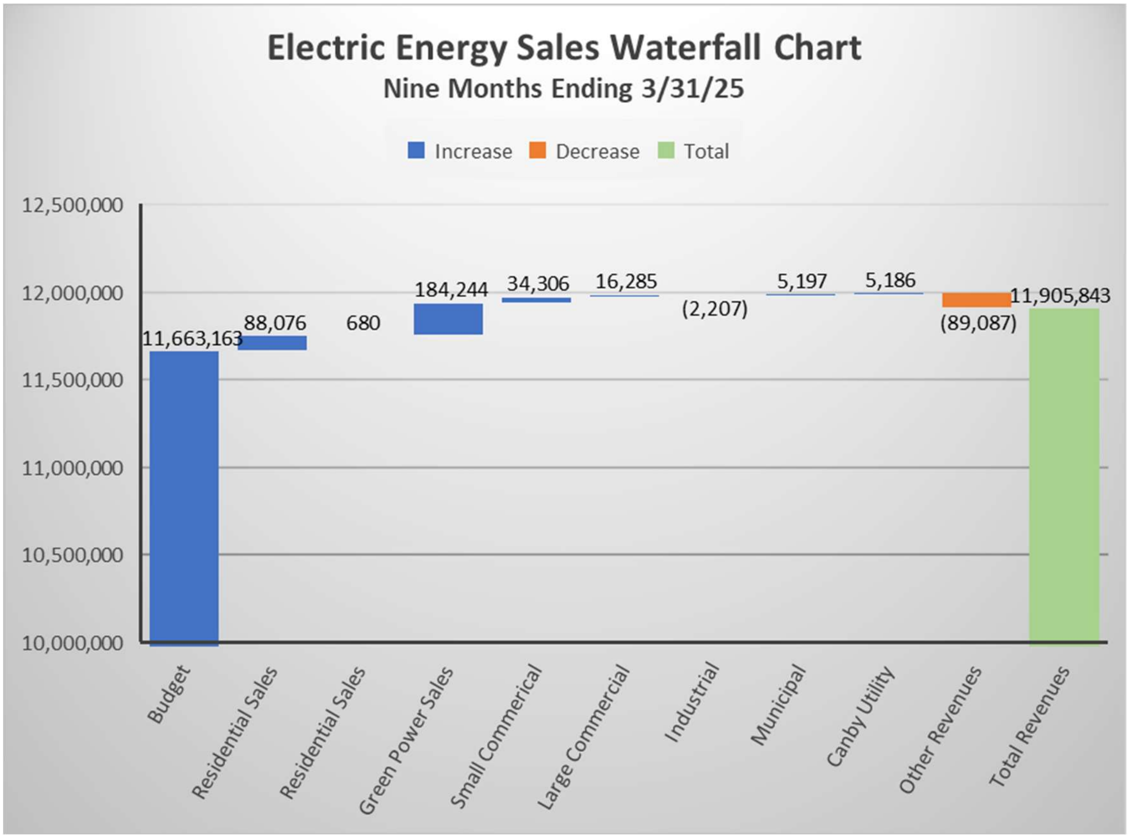
Water Highlights

- Operating revenue of $3.7 million was 3.3% higher than budget.
- Operating expenses are under budget with 67% of the budget expended after 75% of the year has been completed.
- Operating income of $769,000 was 161.9% higher than budget.
- Net income of $2.4 million was 1.9% lower than budget due to lower contributed capital.

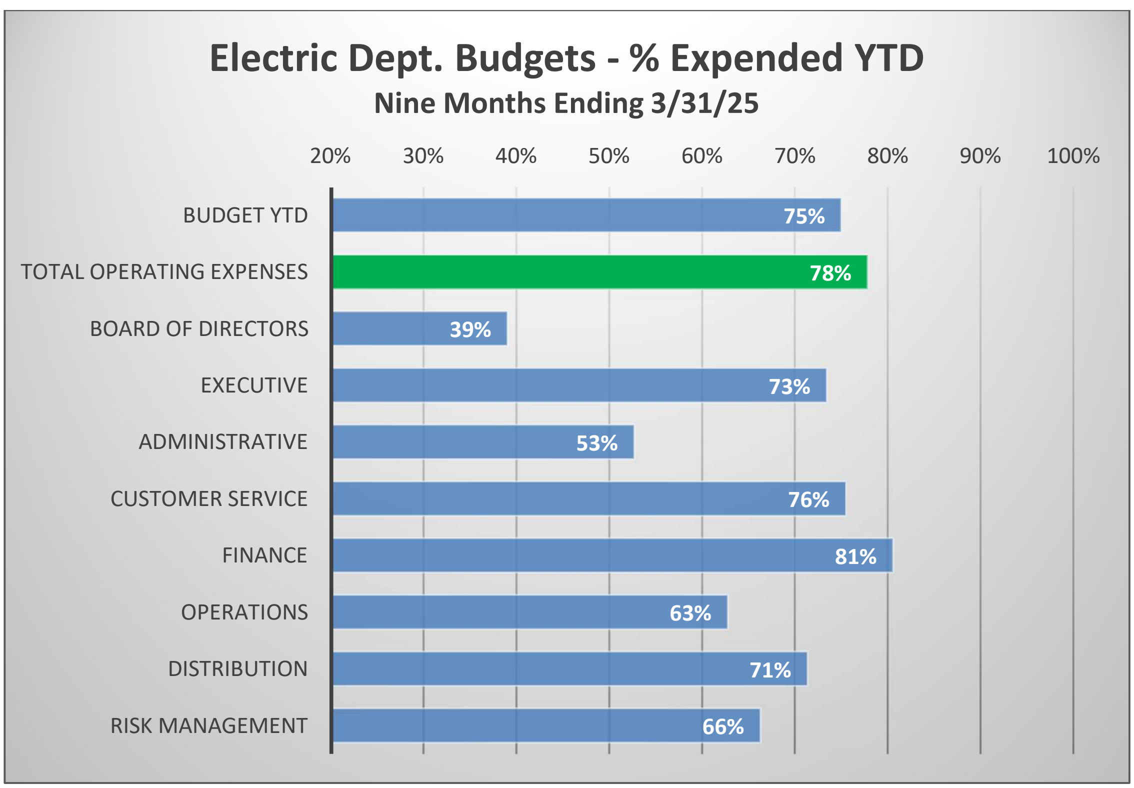
Please feel free to contact me if you have any questions or comments.

Charts on following pages:

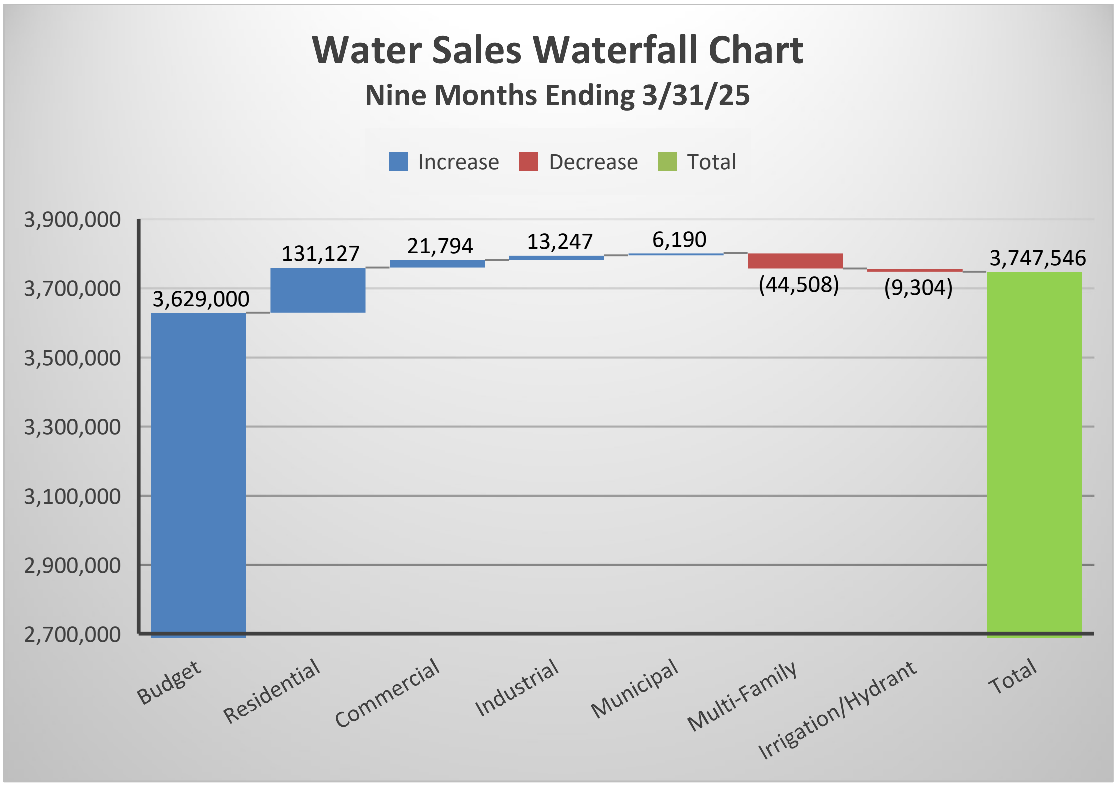
- Electric Revenue Waterfall Chart
- Electric Department Budgets – Percentage Expended YTD
- Water Revenue Waterfall Chart
- Water Department Budgets – Percentage Expended YTD

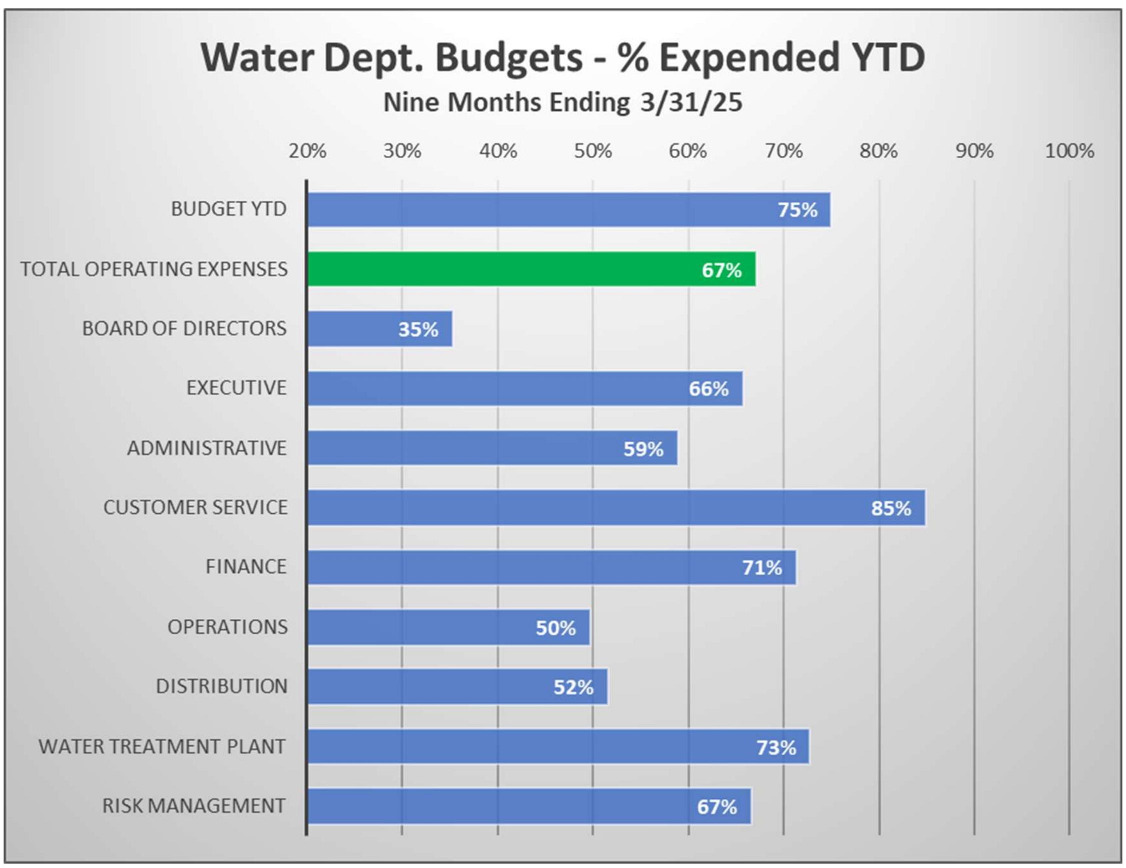


Electric Energy Sales Waterfall Chart
Nine Months Ending 3/31/25
Increase
Decrease
Total
12,500,000
12,000,000
11,500,000
11,000,000
10,500,000
10,000,000
11,663,163
88,076
680
184,244
34,306
16,285
(2,207)
5,197
5,186
(89,087)
11,905,843
Budget
Residential Sales
Residential Sales
Green Power Sales
Small Commerical
Large Commercial
Industrial
Municipal
Canby Utility
Other Revenues
Total Revenues



Electric Dept. Budgets - % Expended YTD
Nine Months Ending 3/31/25
20%
30%
40%
50%
60%
70%
80%
90%
100%
BUDGET YTD
75%
TOTAL OPERATING EXPENSES
78%
BOARD OF DIRECTORS
39%
EXECUTIVE
73%
ADMINISTRATIVE
53%
CUSTOMER SERVICE
76%
FINANCE
81%
OPERATIONS
63%
DISTRIBUTION
71%
RISK MANAGEMENT
66%


Water Sales Waterfall Chart
Nine Months Ending 3/31/25
Increase
Decrease
Total
3,900,000
3,700,000
3,500,000
3,300,000
3,100,000
2,900,000
2,700,000
3,629,000
131,127
21,794
13,247
6,190
(44,508)
(9,304)
3,747,546
Budget
Residential
Commercial
Industrial
Municipal
Multi-Family
Irrigation/Hydrant
Total


Water Dept. Budgets - % Expended YTD
Nine Months Ending 3/31/25
20%
30%
40%
50%
60%
70%
80%
90%
100%
BUDGET YTD
75%
TOTAL OPERATING EXPENSES
67%
BOARD OF DIRECTORS
35%
EXECUTIVE
66%
ADMINISTRATIVE
59%
CUSTOMER SERVICE
85%
FINANCE
71%
OPERATIONS
50%
DISTRIBUTION
52%
WATER TREATMENT PLANT
73%
RISK MANAGEMENT
67%

Canby Utility
Financial Highlights
Quarter and YTD Ending March 31, 2025

Electric Operations	Quarter Actual	Quarter Budget	YTD Actual	YTD Budget	YTD Over (Under) Budget	YTD Budget Status
Balance Sheet						
Cash & Investments			$ 15,495,533	$ 15,244,743	$ 250,790	Favorable
Income Statement						
Operating Revenue	$ 4,203,903	$ 4,295,721	**$ 11,905,843**	$ 11,663,163	$ 242,680	Favorable
Purchased Power	2,310,509	2,341,788	**7,385,025**	6,808,559	576,466	Unfavorable
Operating Expenses	1,465,637	1,545,723	4,359,156	4,660,964	(301,808)	Favorable
Operating Profit (Loss)	427,757	408,210	**161,661**	193,640	(31,979)	Unfavorable
Operating Margin	10.2%	9.5%	1.4%	1.7%		
Other Rev. (Exp.)	197,446	207,306	799,432	801,765	(2,333)	Variance < 1%
Capital Contributions	152,475	297,921	266,020	893,763	(627,743)	Unfavorable
Net Income (Loss)	$ 777,678	$ 913,437	**$ 1,227,114**	$ 1,889,168	$ (662,054)	Unfavorable
Sales Data						
kWh Sold	54,046,783		152,758,568			
kWh Purchased	54,308,122		157,367,579			

Water Operations	Quarter Actual	Quarter Budget	YTD Actual	YTD Budget	YTD Over (Under) Budget	YTD Budget Status
Balance Sheet						
Cash & Investments			$ 11,548,855	$ 8,747,890	$ 2,800,966	Favorable
Income Statement						
Operating Revenue	$ 868,524	$ 858,000	**$ 3,747,546**	$ 3,629,000	$ 118,546	Favorable
Operating Expenses	1,006,026	1,058,928	**2,978,533**	3,335,412	(356,879)	Favorable
Operating Profit (Loss)	(137,503)	(200,928)	**769,013**	293,588	475,425	Favorable
Operating Margin	-15.8%	-23.4%	20.5%	8.1%		
Other Rev. (Exp.)	(1,583)	105,138	470,586	319,421	151,165	Favorable
Capital Contributions	759,524	$ 627,669	1,209,178	1,883,007	(673,829)	Unfavorable
Net Income (Loss)	$ 620,438	$ 531,879	**$ 2,448,778**	$ 2,496,016	$ (47,239)	Variance <2%
Sales Data						
Cu. Ft. Sold	14,784,615		80,877,237			

Canby Utility
Summary Income Statement
Profit (Loss) from Operations, Captial Contributions, and Net Income
Month, Quarter & YTD Ending March 31, 2025

Electric

	Month			Quarter			Year-to-Date		
	Actual	Budget	Prior Year	Actual	Budget	Prior Year	Actual	Budget	Over (Under)
Operating Revenue	$ 1,263,153	$ 1,430,907	$ 1,372,808	$4,203,903	$4,295,721	$4,120,492	$ 11,905,843	$ 11,663,163	$ 242,680
Less: Purchased Power	(686,244)	(855,942)	(722,485)	(2,310,509)	(2,341,788)	(2,184,903)	(7,385,025)	(6,808,559)	(576,466)
Margin on Sales	576,909	574,965	650,323	1,893,394	1,953,933	1,935,589	4,520,818	4,854,604	(333,787)
	45.7%	40.2%	47.4%	45.0%	45.5%	47.0%	38.0%	41.6%	
Operating Expenses									
Operations & Maintenance	258,970	338,176	267,009	930,314	1,005,318	837,591	2,789,582	3,107,358	(317,776)
Depreciation	108,991	109,885	107,383	326,994	329,655	321,309	980,679	982,556	(1,877)
Taxes	62,595	70,200	68,254	208,329	210,750	204,941	588,895	571,050	17,845
Total Operating Expenses	430,556	518,261	442,646	1,465,637	1,545,723	1,363,841	4,359,156	4,660,964	(301,808)
Operating Profit (Loss)	146,352	56,704	207,677	427,757	408,210	571,748	161,661	193,640	(31,979)
	11.6%	4.0%	15.1%	10.2%	9.5%	13.9%	1.4%	1.7%	
Other Revenue (Expense)									
Interest Income	58,438	60,837	60,418	168,004	178,056	166,333	541,756	513,587	28,169
Interest Expense	(1,562)	(767)	(1,591)	(4,807)	(2,301)	(5,076)	(15,699)	(6,903)	(8,796)
Other (Net)	14,333	10,517	77,987	34,250	31,551	289,729	273,375	295,081	(21,706)
Total Other Revenue (Expense	71,210	70,587	136,814	197,446	207,306	450,987	799,432	801,765	(2,333)
Change in Net Position Before Capital Contributions	217,562	127,291	344,491	625,204	615,516	1,022,735	961,093	995,405	(34,312)
Capital Contributions									
Hook-up Fees	11,849	15,903	21,748	38,080	47,709	44,680	151,626	143,127	8,499
Contributed by Others	111,894	-	-	114,394	-	54,794	114,394	-	114,394
Line Extension Fees	-	83,404	-	-	250,212	202,983	-	750,636	(750,636)
Total Capital Contributions	123,744	99,307	21,748	152,475	297,921	302,458	266,020	893,763	(627,743)
Net Income (Loss)	$ 341,306	$ 226,598	$ 366,239	$ 777,678	$ 913,437	$ 1,325,193	$ 1,227,114	$ 1,889,168	$ (662,054)

Canby Utility
Summary Income Statement
Profit (Loss) from Operations, Captial Contributions, and Net Income
Month, Quarter & YTD Ending March 31, 2025

Summary of Purchased Power and Operating Expenses

	Month			Quarter			Year-to-Date		
	Actual	Budget	Over (Under)	Actual	Budget	Over (Under)	Actual	Budget	Over (Under)
Purchased Power	$ 686,244	$ 855,942	$ (169,698)	$ 2,310,509	$ 2,341,788	$ (31,279)	$ 7,385,025	$ 6,808,559	$ 576,466
Operating Expenses									
Payroll & Employer Paid Expenses	203,471	241,610	(38,139)	671,971	724,830	(52,859)	2,005,000	2,174,490	(169,490)
Depreciation	108,991	109,885	(894)	326,994	329,655	(2,661)	980,679	982,556	(1,877)
Taxes	62,595	70,200	(7,605)	208,329	210,750	(2,421)	588,895	571,050	17,845
Other Costs	55,499	96,566	(41,067)	258,343	280,488	(22,145)	784,583	932,868	(148,285)
Total Operating Expenses	430,556	518,261	(87,705)	1,465,637	1,545,723	(80,086)	4,359,156	4,660,964	(301,808)
Total Purchased Power & Operating Expenses	$ 1,116,800	$ 1,374,203	$ (257,403)	$ 3,776,146	$ 3,887,511	$ (111,365)	$ 11,744,181	$ 11,469,523	$ 274,659

Canby Utility
Summary Income Statement
Profit (Loss) from Operations, Captial Contributions, and Net Income
Month, Quarter & YTD Ending March 31, 2025

Water

	Month			Quarter			Year-to-Date		
	Actual	Budget	Prior Year	Actual	Budget	Prior Year	Actual	Budget	Over (Under)
Operating Revenue	$ 276,792	$ 292,000	$ 269,654	$ 868,524	$ 858,000	$ 772,093	$ 3,747,546	$ 3,629,000	$ 118,546
Operating Expenses									
Operations & Maintenance	245,815	263,141	212,288	741,206	783,153	626,985	2,126,696	2,457,079	(330,383)
Depreciation	73,193	77,625	72,810	221,394	232,875	218,166	664,460	696,883	(32,423)
Taxes	13,840	14,600	13,483	43,426	42,900	38,605	187,377	181,450	5,927
Total Operating Expenses	332,848	355,366	298,581	1,006,026	1,058,928	883,756	2,978,533	3,335,412	(356,879)
Operating Profit (Loss)	(56,056)	(63,366)	(28,928)	(137,503)	(200,928)	(111,664)	769,013	293,588	475,425
	-20.3%	-21.7%	-10.7%	-15.8%	-23.4%	-14.5%	20.5%	8.1%	
Other Revenue (Expense)									
Interest Income	44,431	35,374	40,228	127,142	107,433	115,674	392,665	333,262	59,403
Interest Expense	(1,122)	(1,122)	(1,774)	(3,365)	(3,366)	(5,323)	(12,053)	(12,054)	1
Other (Net)	372	357	25	(125,361)	1,071	1,580	89,974	(1,787)	91,761
Total Other Revenue (Expense	43,682	34,609	38,479	(1,583)	105,138	111,931	470,586	319,421	151,165
Change in Net Position Before Capital Contributions	(12,374)	(28,757)	9,551	(139,086)	(95,790)	267	1,239,599	613,009	626,590
Capital Contributions									
Hook-up Fees	2,520	6,318	1,440	8,280	18,954	5,280	23,170	56,862	(33,692)
Contributed by Others	480,836	107,780	-	492,954	323,340	137,322	505,372	970,020	(464,648)
SDC Fees	78,610	95,125	32,937	258,290	285,375	89,644	680,636	856,125	(175,489)
Total Capital Contributions	561,966	209,223	34,377	759,524	627,669	232,246	1,209,178	1,883,007	(673,829)
Net Income (Loss)	$ 549,593	$ 180,466	$ 43,928	$ 620,438	$ 531,879	$ 232,513	$ 2,448,778	$ 2,496,016	$ (47,238)

Canby Utility
Summary Income Statement
Profit (Loss) from Operations, Captial Contributions, and Net Income
Month, Quarter & YTD Ending March 31, 2025

Summary of Operating Expenses

	Month			Quarter			Year-to-Date		
	Actual	Budget	Over (Under)	Actual	Budget	Over (Under)	Actual	Budget	Over (Under)
Operating Expenses									
Payroll & Employer Paid Expenses	$ 90,385	$ 105,750	$ (15,365)	$ 272,032	$ 317,250	$ (45,218)	$ 717,465	$ 951,750	$ (234,285)
Depreciation	73,193	77,625	(4,432)	221,394	232,875	(11,481)	664,460	696,883	(32,423)
Taxes	13,840	14,600	(760)	43,426	42,900	526	187,377	181,450	5,927
Other Costs	155,430	157,391	(1,961)	469,174	465,903	3,271	1,409,231	1,505,329	(96,098)
Total Operating Expenses	$ 332,848	$ 355,366	$ (22,518)	$ 1,006,026	$ 1,058,928	$ (52,902)	$ 2,978,533	$ 3,335,412	$ (356,879)

Balance Sheet - Electric

March 31, 2025

	This Year YTD	Last Year YTD	Variance Dollar	Variance Percent
Assets				
Current Assets				
Cash	470,560.33	632,916.35	(162,356.02)	-25.65%
Allocate Cash to Reserves	(15,275,876.53)	(12,827,618.53)	(2,448,258.00)	19.09%
Local Government Investment Pool	15,024,972.71	13,380,869.66	1,644,103.05	12.29%
Current Accounts Receivable	1,466,455.01	1,605,881.40	(139,426.39)	-8.68%
Plant Materials & Operating Supplies	2,491,324.45	2,542,107.93	(50,783.48)	-2.00%
Prepayments	95,544.71	81,694.64	13,850.07	16.95%
Total Current Assets	**4,272,980.68**	**5,415,851.45**	**(1,142,870.77)**	**-21.10%**
Noncurrent Assets				
Other Deferred Charges	1,182,989.76	1,269,481.87	(86,492.11)	-6.81%
Total Noncurrent Assets	**1,182,989.76**	**1,269,481.87**	**(86,492.11)**	**-6.81%**
Property Plant and Equipment				
Property Plant & Equipment in Service	51,327,835.16	49,909,872.23	1,417,962.93	2.84%
Accumulated Depreciation	(19,312,198.16)	(18,077,689.88)	(1,234,508.28)	6.83%
Construction Work in Progress	702,635.28	685,088.83	17,546.45	2.56%
Total Property Plant and Equipment	**32,718,272.28**	**32,517,271.18**	**201,001.10**	**0.62%**
Cash Designated for Future Use				
Reserve-Emergency	0.00	0.00	0.00	na
Reserve-Capital Improvement	0.00	0.00	0.00	na
Reserve-Capital Replacement	0.00	0.00	0.00	na
Rate Stabilization	0.00	0.00	0.00	na
Future Improvement/Replacement	15,275,876.53	12,827,618.53	2,448,258.00	19.09%
Total Cash Designated for Future Use	**15,275,876.53**	**12,827,618.53**	**2,448,258.00**	**19.09%**
Total Assets	**53,450,119.25**	**52,030,223.03**	**1,419,896.22**	**2.73%**
Liabilities and Net Assets				
Current Liabilities				
Accounts Payable	895,571.75	1,660,455.49	(764,883.74)	-46.06%
Customer Deposits	433,510.63	416,300.51	17,210.12	4.13%
Accrued Payroll Taxes Payable	(24,572.94)	(22,046.53)	(2,526.41)	11.46%
Accrued Payroll	86,810.09	80,922.04	5,888.05	7.28%
Accrued Employee Leave	131,138.84	139,234.90	(8,096.06)	-5.81%
Other Current & Accrued Liabilities	22,731.00	12,219.18	10,511.82	86.03%
Total Current Liabilities	**1,545,189.37**	**2,287,085.59**	**(741,896.22)**	**-32.44%**
Noncurrent Liabilities				
Noncurrent Liabilities	3,344,746.77	3,448,228.24	(103,481.47)	-3.00%
Total Noncurrent Liabilities	**3,344,746.77**	**3,448,228.24**	**(103,481.47)**	**-3.00%**
Total Liabilities	**4,889,936.14**	**5,735,313.83**	**(845,377.69)**	**-14.74%**
Net Assets - Unrestricted				
Reserves	0.00	0.00	0.00	na

Balance Sheet - Electric

March 31, 2025

	This Year YTD	Last Year YTD	Variance Dollar	Variance Percent
Liabilities and Net Assets				
Unappropriated Retained Earnings	48,814,624.51	45,204,862.20	3,609,762.31	7.99%
YTD Net Income(Loss)	1,227,113.60	2,571,602.00	(1,344,488.40)	-52.28%
Other Equities	(1,481,555.00)	(1,481,555.00)	0.00	0.00%
Less PP&E, Net	(32,718,272.28)	(32,517,271.18)	201,001.10	0.62%
Total Net Assets - Unrestricted	**15,841,910.83**	**13,777,638.02**	**2,064,272.81**	**14.98%**
Investment in Capital Assets	**32,718,272.28**	**32,517,271.18**	**201,001.10**	**0.62%**
Total Net Assets	**48,560,183.11**	**46,294,909.20**	**2,265,273.91**	**4.89%**
Total Liabilities and Net Assets	**53,450,119.25**	**52,030,223.03**	**1,419,896.22**	**2.73%**

Balance Sheet - Water

March 31, 2025

	This Year YTD	Last Year YTD	Variance Dollar	Variance Percent
Assets				
Current Assets				
Cash	125,340.36	33,056.23	92,284.13	279.17%
Allocate Cash to Reserves	(9,348,255.47)	(5,396,028.92)	(3,952,226.55)	73.24%
Local Government Investment Pool	11,423,515.05	8,909,440.86	2,514,074.19	28.22%
Current Accounts Receivable	546,422.04	514,713.38	31,708.66	6.16%
Plant Materials & Operating Supplies	313,520.42	353,489.60	(39,969.18)	-11.31%
Prepayments	41,698.78	36,731.26	4,967.52	13.52%
Total Current Assets	**3,102,241.18**	**4,451,402.41**	**(1,349,161.23)**	**-30.31%**
Noncurrent Assets				
Other Deferred Charges	392,661.32	468,833.22	(76,171.90)	-16.25%
Total Noncurrent Assets	**392,661.32**	**468,833.22**	**(76,171.90)**	**-16.25%**
Property Plant and Equipment				
Property Plant & Equipment in Service	43,495,727.35	42,078,336.50	1,417,390.85	3.37%
Accumulated Depreciation	(15,867,546.82)	(14,966,848.96)	(900,697.86)	6.02%
Construction Work in Progress	212,278.62	283,057.50	(70,778.88)	-25.01%
Total Property Plant and Equipment	**27,840,459.15**	**27,394,545.04**	**445,914.11**	**1.63%**
Cash Designated for Future Use				
Bond Reserve Requirement	0.00	0.00	0.00	na
Reserve-SDC	687,825.47	191,841.92	495,983.55	258.54%
Reserve-Capital Improvement	0.00	0.00	0.00	na
Reserve-Capital Replacement	0.00	0.00	0.00	na
Future Improvement/Replacement	8,660,430.00	5,204,187.00	3,456,243.00	66.41%
Total Cash Designated for Future Use	**9,348,255.47**	**5,396,028.92**	**3,952,226.55**	**73.24%**
Total Assets	**40,683,617.12**	**37,710,809.59**	**2,972,807.53**	**7.88%**
Liabilities and Net Assets				
Current Liabilities				
Accounts Payable	163,336.73	190,441.25	(27,104.52)	-14.23%
Sewer Collections Payable	0.00	0.00	0.00	na
Accrued Interest	6,729.78	10,646.69	(3,916.91)	-36.79%
Accrued Payroll Taxes Payable	(4,463.45)	(2,805.43)	(1,658.02)	59.10%
Accrued Payroll	32,820.38	22,676.62	10,143.76	44.73%
Accrued Employee Leave	14,352.82	9,031.94	5,320.88	58.91%
Other Current & Accrued Liabilities	(5,290.69)	(5,854.63)	563.94	-9.63%
Total Current Liabilities	**207,485.57**	**224,136.44**	**(16,650.87)**	**-7.43%**
Noncurrent Liabilities				
Noncurrent Liabilities	1,876,359.37	2,353,449.84	(477,090.47)	-20.27%
Total Noncurrent Liabilities	**1,876,359.37**	**2,353,449.84**	**(477,090.47)**	**-20.27%**
Total Liabilities	**2,083,844.94**	**2,577,586.28**	**(493,741.34)**	**-19.16%**

Net Assets - Unrestricted

Balance Sheet - Water

March 31, 2025

	This Year YTD	Last Year YTD	Variance Dollar	Variance Percent
Liabilities and Net Assets				
Reserves	61,004.36	49,531.16	11,473.20	23.16%
Unappropriated Retained Earnings	34,665,421.61	32,568,625.29	2,096,796.32	6.44%
YTD Net Income(Loss)	2,448,777.50	1,079,024.95	1,369,752.55	126.94%
Other Equities	1,424,568.71	1,436,041.91	(11,473.20)	-0.80%
Less PP&E, Net	(27,840,459.15)	(27,394,545.04)	445,914.11	1.63%
Total Net Assets - Unrestricted	**10,759,313.03**	**7,738,678.27**	**3,020,634.76**	**39.03%**
Investment in Capital Assets	**27,840,459.15**	**27,394,545.04**	**445,914.11**	**1.63%**
Total Net Assets	**38,599,772.18**	**35,133,223.31**	**3,466,548.87**	**9.87%**
Total Liabilities and Net Assets	**40,683,617.12**	**37,710,809.59**	**2,972,807.53**	**7.88%**

MEMORANDUM

To: Chair Thompson, Member Molamphy, Member Pendleton, Member Hill, and Member Westcott

Copy to: Carol Sullivan, Jason Berning, Jason Peterson, Cindy Dittmar

From: Mike Schelske, Finance Manager

Date: May 8, 2025

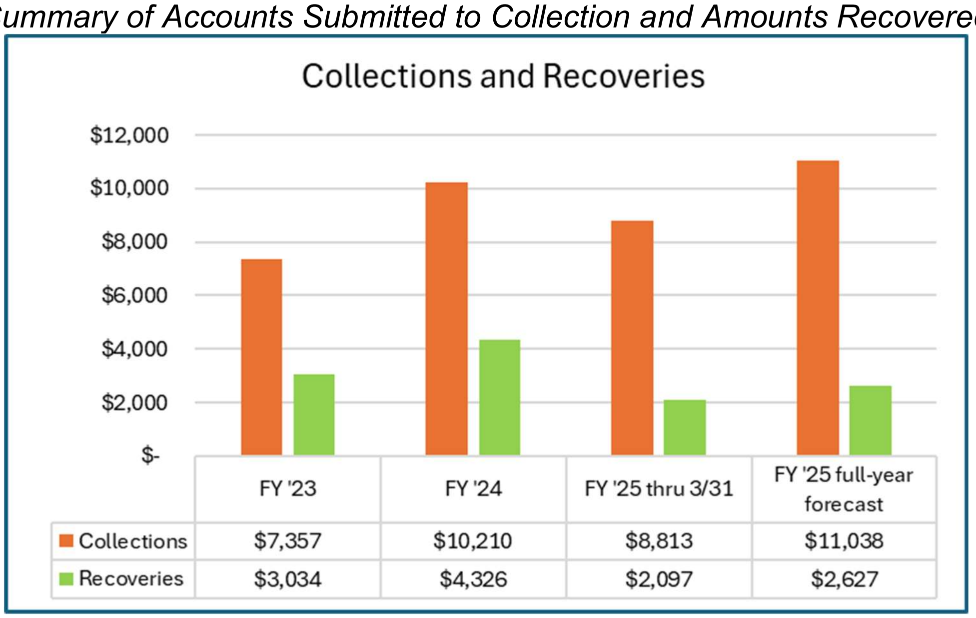
Subject: Report on Collections and Recoveries

This is a summary of accounts submitted to collection and the amounts recovered.

The main highlights here are:

- There was a slight increase in accounts submitted to collection from FY2023 to FY2024. Projections for FY 2025 also indicate a modest increase.
- The amount of uncollectable amounts remains extremely low compared to total revenue.
- CU's uses a highly proactive account management process, effectively minimizing past due and uncollectable accounts.

Summary of Accounts Submitted to Collection and Amounts Recovered



Staff will be available to answer any questions.