Public Utility District No. 1 of Franklin County, Washington
Regular Commission Meeting Agenda

July 23, 2024| Tuesday | 8:30 A.M.
1411 W. Clark Street & via remote technology | Pasco, WA | www.franklinpud.com

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Meetings of the Board of Commissioners are also available to the public via remote technology. Members of the public may participate by dialing: (888) 475-4499 US Toll-free or 1 (253) 215-8782

Join Zoom Meeting

https://franklinpud.zoom.us/j/84974239458?pwd=SmSXaYJqK5a4b6ZB0z7oXaq7trbGgM.1

Meeting ID: **849 7423 9458** Passcode: **787382**

1) Pledge of Allegiance

2) Public Comment –
Individuals wishing to provide public comment during the meeting (in-person or remotely) will be recognized by the Commission President and be provided opportunity to speak. Written comments can be sent ahead of the meeting and must be received at least two days prior to the meeting to ensure proper distribution to the District's Board of Commissioners. Comments can be emailed to clerkoftheboard@franklinpud.com or mailed to Attention: Clerk of the Board, PO BOX 2407, Pasco, WA, 99302.

3) Employee Minute – **Leticia Monroy-Iglesias, Distribution Clerk - Engineering**

4) District Internship Program – **Victor Fuentes, Engineering & Operations Senior Director**

5) Commissioner Reports

6) Consent Agenda

7) Columbia-Snake River Irrigators Association **– Guest Presenter: Darryll Olsen, Ph.D., Board Representative**

8) Opening the Integrated Resource Plan Public Hearing, Presenting the Integrated Resource Plan, and Recessing the Public Hearing. **Presenter: Katrina Fulton, Finance & Customer Service Director**

9) Providing an Update on the 2024-2025 Operating Plan (Quarter 1 and Quarter 2 Year 2024).
Presenter: Scott Rhees, General Manager/CEO

10) Management Reports:
    a. General Manager/CEO – Scott Rhees
    b. Assistant General Manager– Steve Ferraro
    c. Other members of management

11) Executive Session, *If Needed*

12) Schedule for Next Commission Meetings
    a. July 23, 2024 Special Meeting – 1 pm
    b. August 27, 2024

13) Close Meeting – Adjournment

CONSENT AGENDA
Public Utility District No. 1 of Franklin County, Washington
Regular Commission Meeting

1411 W. Clark Street, Pasco, WA
July 23, 2024 | Tuesday | 8:30 A.M.

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1) To approve the minutes of the June 25, 2024 Regular Commission Meeting.

2) To approve payment of expenditures for June 2024 amounting to $9,346,339.19 as audited and certified by the auditing officer as required by RCW 42.24.080, and as reviewed/certified by the General Manager/CEO as required by RCW 54.16.100, and expense reimbursement claims certified as required by RCW 42.24.090 and as listed in the attached registers and made available to the Commission for inspection prior to this action as follows:

Expenditure Type:	**Amounts:**
Direct Deposit Payroll – Umpqua Bank	$ 538,662.10
Wire Transfers	5,441,478.71
Automated and Refund Vouchers (Checks)	2,380,476.68
Direct Deposits (EFTs)	985,969.66
Voids	(247.96)
Total:	$ 9,346,339.19

3) To approve the Write Offs in substantially the amount listed on the July 2024 Write Off Report totaling $6,878.84.

4) To declare final acceptance of the work completed as inspected by the District; to authorize release of available retainage; and to approve final payment in the amount of $113,357.14 for work completed by DJ's Electrical Inc. under Contract 10115, Miscellaneous Dock Crew Projects.

THE BOARD OF COMMISSIONERS
OF
PUBLIC UTILITY DISTRICT NO. 1 OF FRANKLIN COUNTY, WASHINGTON

MINUTES OF THE JUNE 25, 2024
REGULAR COMMISSION MEETING

The Board of Commissioners of Public Utility District No. 1 of Franklin County, Washington held a regular meeting at 1411 W. Clark St., Pasco, WA, on June 25 2024, at 8:30 a.m. Remote technology options were provided for the public to participate.

Those who participated from the District via remote technology or in person for all or part of the meeting were Commissioner Stu Nelson, President; Commissioner Roger Wright, Vice President; Commissioner Bill Gordon, Secretary; Scott Rhees, General Manager/CEO; Steve Ferraro, Assistant General Manager; Victor Fuentes, Engineering and Operations Senior Director; Katrina Fulton, Finance and Customer Service Director; Rosario Viera, Public Information Officer and Tyler Whitney, General Counsel.

There was no additional staff that participated in person or via remote technology for all or part of the meeting.

Public participating in person or via remote technology for all or part of the meeting was Mr. Pedro Torres, District customer.

OPENING

Commissioner Nelson called the meeting to order at 8:30 a.m. and Commissioner Wright led the Pledge of Allegiance.

PUBLIC COMMENT

Commissioner Nelson called for public comment and called on Mr. Torres for public comment. Mr. Torres noted he did not have public comment to provide.

EMPLOYEE MINUTE

Commissioner Nelson reported that Mr. Kostoff was not present, and he moved to Commissioner Reports.

COMMISSIONER REPORTS

Commissioner Wright reported that:

- He attended the monthly NoaNet meeting. He reported that NoaNet has completed its first bond proceeds draw which will be utilized for equipment needed for projects. He noted that NoaNet continues to perform well.

- He attended the monthly PPC Members Forum and reiterated how beneficial these meetings are. He noted he was concerned with BPA's outlook. Discussion ensued on BPA's outlook, staff and other matters related to BPA.
- He will participate in the July Commission meetings remotely.

Commissioner Gordon circled back to the BPA discussion and reported that he was disappointed the District's BPA Account Executive did not attend the Commission meetings regularly. He noted that attendance at the District's Commission meetings should be prioritized, and he reported that this was a poor example of BPA's commitment to its customers. Mr. Rhees reported that Mr. Rimmer was the District's Power Account Executive, however, transmission matters were assigned to Ms. Jennifer Miller. Commissioner Wright noted that the ability to attend virtually was available to the BPA representatives but was not utilized. There was general disappointment expressed in BPA staff's participation in the District's Commission meetings.

Commissioner Gordon reported that:

- He attended the American Public Power Association's (APPA) National Conference in San Diego and noted it was nice to see other District staff attending the conference. He reported that he was able to have a discussion on hydrogen power and noted it was critical to maintain the water rights associated with the Railroad Avenue Substation site. He requested staff ensure the water rights are in place and Commissioner Wright concurred with the request.

Commissioner Nelson reported that:

- He also attended the APPA National Conference and noted that there were speakers on artificial intelligence (AI). He noted that the matter was very complex, and it was important to ensure we had the proper policies in place before utilizing AI.

CONSENT AGENDA

The Commission reviewed the Consent Agenda. Commissioner Wright reported he had questions on items on the write-offs and that staff had provided the information.

Commissioner Wright moved and Commissioner Gordon seconded to approve the Consent Agenda as follows. The motion passed unanimously.

1) To approve the minutes of the May 28, 2024 Regular Commission meeting and June 14, 2024 Special Commission Meeting.

2) To approve payment of expenditures for May 2024 amounting to $11,207,940.16 as audited and certified by the auditing officer as required by RCW 42.24.080, and as reviewed/certified by the General Manager/CEO as required by RCW 54.16.100, and expense reimbursement claims certified as required by RCW 42.24.090 and as listed in the

attached registers and made available to the Commission for inspection prior to this action as follows:

Expenditure Type:	**Amounts:**
Direct Deposit Payroll – Umpqua Bank	$ 781,396.87
Wire Transfers	5,490,330.32
Automated and Refund Vouchers (Checks)	1,944,676.19
Direct Deposits (EFTs)	2,991,536.78
Voids	(00.00)
Total:	$ 11,207,940.16

3) To approve the Write Offs in substantially the amount listed on the June 2024 Write Off Report totaling $6,622.39.

AGENDA ITEM 6, ADOPTING A RESOLUTION AUTHORIZING THE USE OF THE STATEWIDE SMALL WORKS ROSTER AND THE ABILITY TO UTILIZE DIRECT CONTRACTING.

Ms. Fulton introduced the agenda item and reviewed the background information as reported on the Agenda Item Summary included in the meeting packet. She reported that in 2023, the Washington State Legislature passed Second Substitute House Bill 5268, modifying public works procurement and purchasing requirements for most state agencies and local governments. The modifications will be effective July 1, 2024 and were reviewed with the Commission at the May 28, 2024 meeting. She noted that staff was seeking authorization to utilize two changes that require authorization from the Commission:

1. A statewide Small Works Roster (SWR) which will be administered through the Municipal Research and Services Center (MRSC), and
2. direct contracting for small public works projects with an estimated cost under $150,000, exclusive of Washington State Sales Tax.

She reported that adopting Resolution 1412 would authorize the use of the Statewide Small Works Roster and the ability to use direct contracting. Staff reviewed their recommendation.

Commissioner Wright moved and Commissioner Gordon seconded to adopt Resolution 1412 as presented. The motion passed unanimously.

AGENDA ITEM 7, AUTHORIZING THE GENERAL MANAGER/CEO OR HIS DESIGNEE TO EXECUTE A CONTRACT FOR LABOR, EQUIPMENT, AND MATERIAL NEEDED TO REMODEL THE CUSTOMER SERVICE LOBBY.

Mr. Ferraro introduced the agenda item and reviewed the background information as reported on the Agenda Item Summary included in the meeting packet. There were questions on the drivers for the changes. Mr. Ferraro reported that the changes will improve the handicap entrance ensuring compliance with the American Disabilities Act and add safety features to the customer service lobby area. Staff showed schematics of the how the customer service area would look after the changes are done and there was discussion on the changes and the number of bids received. Staff reviewed their recommendation.

Commissioner Wright moved and Commissioner Gordon seconded to authorize the General Manager/CEO or his designee to execute a contract with Siefken & Sons Construction Inc., the lowest responsive bidder, for the labor, equipment, and material needed to remodel the customer service lobby area in an amount not to exceed $203,987. The motion passed unanimously.

AGENDA ITEM 8, AUTHORIZING THE GENERAL MANAGER/CEO OR HIS DESIGNEE TO EXECUTE A GRANT AGREEMENT WITH THE WASHINGTON STATE DEPARTMENT OF COMMERCE TO ADMINISTER THE WASHINGTON FAMILIES CLEAN ENERGY CREDITS GRANT PROGRAM.
Ms. Fulton introduced the agenda item and reviewed the background information as reported on the Agenda Item Summary included in the meeting packet. She noted that staff has provided updates on this matter during staff reports and that in order to begin the process of administering the grant, the District must execute a grant agreement with the Department of Commerce to receive the allocated funding of approximately $1.185 million.

She noted that staff has reviewed the proposed contract language and provided comments to the Department of Commerce for clarification. Ms. Fulton reported that staff has not received feedback on the comments provided however, given the timeline to distribute the grant funding staff is seeking authorization to execute the contract once the terms are agreed upon. She noted that having the authorization will allow staff to begin administering the program as soon as the contract is executed to allow for disbursement of as much of the grant funding as possible before the September 15, 2024 deadline. Staff reviewed their recommendation.

Commissioner Wright inquired about the involvement of Promise and Ms. Fulton reported that the District will self-administer the program. Mr. Rhees reported that District staff had been highly effective with the other funding received and noted that he was confident that funds would be disbursed effectively and efficiently.

Commissioner Wright requested staff keep the Commission informed on the communications related to the fund disbursements that will be provided to customers.

Commissioner Gordon moved and Commissioner Wright seconded to authorize the General Manager/CEO or his designee to execute a grant agreement with the Washington State Department of Commerce to administer the Washington Families Clean Energy Credits Grant Program. The motion passed unanimously.

GENERAL MANAGER/CEO REPORT

Mr. Rhees reported that:

- The Department of Interiors "Historic and Ongoing Impacts of Federal Dams on the Columbia River Basin Tribes" report was highly concerning. He noted that PPC has begun to draft a letter in response to the many concerns of the report. Discussion ensued on the report. Mr. Rhees reported that staff will continue to monitor this matter closely.
- The Request for Proposal for the capacity / load study will be going out soon. He noted that the study will focus on the impacts of what electrification will have in our service area. He reported that the Port of Pasco, City of Pasco, and other entities will assist with the funding of the study.
- He and Mr. John Francisco from Big Bend Electric Cooperative met with State Representative Stephanie Barnard. He noted that Representative Barnard was very receptive to helping resolve the transmission capacity issues in Franklin County. He noted that it was important to look at this matter not just as a Tri-Cities issue but look at Franklin County on its own.
- Darigold continues to move forward, and he reported that staff had provided a letter to Darigold representatives as was directed by the Commission. He noted that as of today there has not been any response from Darigold.
- The Safety BBQ event will be this Thursday, June 27 and he extended an invitation to the Commission. Commissioner Gordon reported he would not be able to attend.

FINANCE & CUSTOMER SERVICE DIRECTOR REPORT

Ms. Fulton reported that:

- The May 2024 Key Performance Indicators (KPIs) monthly report was included in the meeting packet, and she briefly reviewed slides within the report.
  Commissioner Gordon asked about the processing plant being offline and the Powerex deliveries. Ms. Fulton reported she would report on both matters at the next Commission meeting.
- Staff continues to participate in the Post 2028 BPA meetings and track the matter closely.
- In follow up to last month's change in the Rules and Regulations for Electric Service, she provided information on what reasonable attempts means outside of normal process. She reported that the normal process includes two months of attempting to read the meter which results in bill estimation, after which an additional attempt to contact is made.
- She also attended the APPA National Conference and noted that she found it very valuable to be able to network and have sidebar conversations to learn what other utilities are doing to solve issues and challenges.
- WPUDA submitted the work group's proposal regarding the Statewide Low-Income program to Commerce. She noted that Commerce should have comments on the design of program out by June 30. She noted that none have been received to date.

- District staff has been preparing for the Integrated Resource Plan (IRP) update. She noted that the District is required to conduct an update to the IRP every two years and refresh the full IRP every four years, which is the current project. She reported that the last update was in July 2022. She noted Resource Adequacy, District needs, available resources and other influencing factors have driven the process and that staff has practiced due diligence in driving the process. She reported that the IRP public hearing will be opened at the July regular meeting.

ASSITANT GENERAL MANAGER REPORT
Mr. Ferraro reported that:
- The District currently has three positions open, and he reviewed them.
- In follow up to Commissioner Gordon's question regarding the $13k line entry on the Capital Budget Status report, he reported that the expense was due to various claims that were paid out by the District.
- In follow up to Commissioner Wright's question regarding the communications being done for the fiber to the home project in Connell and Basin City, he reported that communication will be done via multiple avenues. He noted that there will be meetings with town officials, articles in the Franklin County Graphic newspaper, and possibly a bill insert, however the main advertising will be done by the Retail Service Providers.
- As Mr. Rhees reported the Safety BBQ is Thursday, June 27 from 11 a.m. to 1:30 p.m. in the downtown garage area.
- He noted that Mr. Kostoff was not able to attend the Commission meeting for the Employee Minute and that staff would reschedule him for another future meeting.

ENGINEERING & OPERATIONS SENIOR DIRECTOR REPORT
Mr. Fuentes reported that:
- There was a claim against the District, and he reported that a concrete padding had been damaged while a District vehicle entered a property. He noted that the claim was forwarded to Federated for review.
- He attended the BPA Tri-Cities Customer meeting held at Benton PUD on June 14. He noted that he stressed the importance of looking at Franklin County independent of the Tri-Cities and noted that all of the improvements being discussed are being implemented on the Benton County side. Discussion ensued.
- The Railroad Avenue Substation continues to make progress and he shared photos taken recently that showed the progress of the substation. He noted that the substation is nearing completion and should be completed by mid to late July.
- He attended the PPC Residential Exchange meeting and provided an update on the discussions from the meeting.
- He also attended the APPA National Conference and reported that there were several presentations on renewable energy, artificial intelligence, and electric vehicle charging stations.

PUBLIC INFORMATION OFFICER REPORT
Ms. Viera reported that:
- Staff participated in the Kidz Dig Rigz and City of Pasco's Urban Revitalization Days and she provided an update on the events.
- Staff will be at the STEM academy this Thursday, and she reported on the activities the students will be participating in.

GENERAL COUNSEL REPORT
Mr. Whitney did have matters to report on and he requested an executive session as permitted by RCW 42.30.110(i) for the purpose of discussing with legal counsel current or potential litigation as allowed by RCW 42.30.110(i).

At 9:33 a.m., Commissioner Nelson called for a five-minute break and noted it will be followed immediately by a five-minute executive session that would end at 9:43 a.m. for the purpose of discussing with legal counsel current or potential litigation as allowed by RCW 42.30.110(i).

At 9:38 a.m., Commissioner Nelson ended the break and reconvened the regular meeting and immediately went into an executive session for the purpose of discussing with legal counsel current or potential litigation as allowed by RCW 42.30.110(i).

At 9:43 a.m., Commissioner Nelson ended the executive session and reconvened the regular meeting.

CLOSING OF MEETING – ADJOURNMENT
With no further business to come before the Commission, Commissioner Nelson adjourned the regular meeting at 9:43 a.m. The next regular meeting will be July 23, 2024, and begin at 8:30 a.m. at the District's Auditorium located at 1411 W. Clark Street, Pasco, WA. Remote technology options will be provided for members of the public to participate.

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Stuart Nelson, President

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Roger Wright, Vice President

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William Gordon, Secretary

Accounts Payable

Check Register Wires

06/01/2024 To 06/30/2024

Bank Account: 3 - FPUD REVENUE ACCOUNT

#	Check / Tran	Date	Pmt Type	Vendor	Vendor Name	Reference	Amount
1	2552	06/12/2024	WIRE	100464	WA STATE DEPT OF RETIREMENT SYSTEMS	PERS PLAN 3 WSIB A	60,447.96
2	2545	06/13/2024	WIRE	112714	MACQUARIE ENERGY NORTH AMERICA TRADING	POWER SWAP	19,368.40
3	2546	06/13/2024	WIRE	112793	CITIGROUP ENERGY INC	POWER SWAP	389,772.20
4	2549	06/13/2024	WIRE	112776	MORGAN STANLEY CAPITAL GROUP	POWER SWAP	317,259.20
5	2550	06/13/2024	WIRE	112902	EDF TRADING NORTH AMERICA	POWER SWAP	13,345.69
6	2551	06/13/2024	WIRE	112712	BP CORPORATION NA INC	POWER SWAP	56,418.40
7	2559	06/13/2024	WIRE	100285	WA STATE SUPPORT REGISTRY	SUPPORT PAYMENT	503.67
8	2560	06/13/2024	WIRE	113257	EFTPS - PAYROLL TAXES	FEDERAL INCOME TAX	100,861.69
9	2561	06/13/2024	WIRE	114437	OREGON DEPARTMENT OF REVENUE	OREGON WORKERS BENEFIT FUND ASSESS - ER	938.86
10	2555	06/17/2024	WIRE	112707	THE ENERGY AUTHORITY	TEA SCHEDULING & CONSULTING	118,780.54
11	2543	06/18/2024	WIRE	112689	BONNEVILLE POWER ADMINISTRATION	EIM SERVICES BILL	94,149.02
12	2548	06/20/2024	WIRE	112715	POWEREX CORP	POWER SUPPLY CONTRACT	522,200.03
13	2563	06/25/2024	WIRE	109978	WA STATE DEPT OF REVENUE	MAY 2024 EXCISE TAX	312,568.07
14	2556	06/27/2024	WIRE	112709	LL&P WIND ENERGY INC	WHITE CREEK WIND	240,274.92
15	2557	06/27/2024	WIRE	112689	BONNEVILLE POWER ADMINISTRATION	POWER BILL	3,076,353.00
16	2567	06/27/2024	WIRE	100285	WA STATE SUPPORT REGISTRY	SUPPORT PAYMENT	503.67
17	2568	06/27/2024	WIRE	113257	EFTPS - PAYROLL TAXES	FEDERAL INCOME TAX	116,795.29
18	2569	06/27/2024	WIRE	114437	OREGON DEPARTMENT OF REVENUE	OREGON WORKERS BENEFIT FUND ASSESS - ER	938.10
						Total for Bank Account - 3 :	5,441,478.71
						Grand Total :	5,441,478.71

Accounts Payable

Checks and Customer Refunds

06/01/2024 To 06/30/2024

Bank Account: 1 - ZBA - WARRANT ACCOUNT

#	Check / Tran	Date	Pmt Type	Vendor	Vendor Name	Reference	Amount
1	46848	06/06/2024	CHK	100028	ABADAN	PRINTER MAINTENANCE	136.59
2	46849	06/06/2024	CHK	112734	ARNETT INDUSTRIES LLC	OPERATING TOOLS	3,557.63
3	46850	06/06/2024	CHK	104565	BIG BEND ELECTRIC COOPERATIVE INC	UTILITY SERVICES	108.84
4	46851	06/06/2024	CHK	113216	BOYD'S TREE SERVICE	TREE TRIMMING	9,467.98
5	46852	06/06/2024	CHK	100515	CED	WAREHOUSE MATERIALS & SUPPLIES	55,604.35
6	46853	06/06/2024	CHK	100354	CITY OF CONNELL	UTILITY SERVICES	79.54
7	46854	06/06/2024	CHK	100354	CITY OF CONNELL	PROFESSIONAL SERVICES	400.00
8	46855	06/06/2024	CHK	113363	COLEMAN OIL COMPANY	GAS & OTHER FUELS	10,138.45
9	46856	06/06/2024	CHK	100346	CONNELL OIL INC	FUEL & OTHER GASES	1,938.85
10	46857	06/06/2024	CHK	105071	DIRECT AUTOMOTIVE	OPERATING SUPPLIES	134.18
11	46858	06/06/2024	CHK	114007	GRIGG ENTERPRISES INC	BUILDING MAINTENANCE & SUPPLIES	92.72
12	46859	06/06/2024	CHK	114420	HEARTSMART	SAFETY EQUIPMENT & SUPPLIES	13,453.51
13	46860	06/06/2024	CHK	112980	IRRIGATION SPECIALISTS INC	GROUNDS MAINTENANCE & SUPPLIES	36.91
14	46861	06/06/2024	CHK	107277	JUB ENGINEERS INC	PROFESSIONAL SERVICES	798.00
15	46862	06/06/2024	CHK	114080	LOOMIS ARMORED US LLC	ARMORED CAR SERVICE	796.93
16	46863	06/06/2024	CHK	114307	MILSOFT UTILITY SOLUTIONS INC	SOFTWARE MAINTENANCE	882.09
17	46864	06/06/2024	CHK	114186	ONEBRIDGE BENEFITS INC	FLEX PLAN	50.00
18	46865	06/06/2024	CHK	112987	PACIFIC STEEL & RECYCLING	OPERATING SUPPLIES	1,311.75
19	46866	06/06/2024	CHK	100505	SIERRA ELECTRIC INC	PROJECT WORK	1,887.84
20	46867	06/06/2024	CHK	112127	US BANK - P CARDS & TRAVEL	PURCHASE CARD	14,269.16
21	46868	06/06/2024	CHK	100280	US POSTMASTER	PO BOX ANNUAL RENTAL FEE	436.00
22	46869	06/06/2024	CHK	111471	VERIZON WIRELESS SERVICES LLC	PHONE SERVICES	7,195.10
23	46870	06/06/2024	CHK	109927	VESTIS SERVICES LLC	MATS AND COVERALLS	165.40
24	46871	06/06/2024	CHK	113281	WESTERN STATES EQUIPMENT	LOAD TEST BANK	1,707.01
25	46872	06/06/2024	CHK	113359	WINTHROP CONSTRUCTION	RETAINAGE RELEASE CONTRACT 8651	4,331.90
26	46873	06/06/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	116.82
27	46874	06/13/2024	CHK	114357	ALASKA RUBBER GROUP INC	OPERATING SUPPLIES	77.43
28	46875	06/13/2024	CHK	114084	ALLIED POTATO NORTHWEST INC	ENERGY SERVICES	4,275.00
29	46876	06/13/2024	CHK	100087	ALTEC INDUSTRIES INC	OPERATING SUPPLIES	100.72
30	46877	06/13/2024	CHK	113437	ARCHIBALD & COMPANY ARCHITECTS P.S.	PROFESSIONAL SERVICES	1,840.75
31	46878	06/13/2024	CHK	100171	BASIN DISPOSAL INC	UTILITY SERVICES	2,622.40
32	46879	06/13/2024	CHK	100179	BENTON FRANKLIN CAC	HELPING HANDS	948.38
33	46880	06/13/2024	CHK	113216	BOYD'S TREE SERVICE	TREE TRIMMING	6,586.06
34	46881	06/13/2024	CHK	100515	CED	BUILDING MAINTENANCE & SUPPLIES	201.77
35	46882	06/13/2024	CHK	112936	CENTURY LINK	PHONE SERVICES	355.14
36	46883	06/13/2024	CHK	112936	CENTURY LINK	PHONE SERVICES	2.13
37	46884	06/13/2024	CHK	100360	CITY OF PASCO	UTILITY SERVICES	421.29
38	46885	06/13/2024	CHK	112903	CITY OF RICHLAND	UTILITY SERVICES	29.14
39	46886	06/13/2024	CHK	113369	CORWIN OF PASCO LLC	AUTO PARTS	427.81
40	46887	06/13/2024	CHK	114077	EMPIRE INNOVATION GROUP LLC	FLEX PLAN	1,002.89
41	46888	06/13/2024	CHK	114383	EXO GROUP LLC	POLE INSPECTION	23,185.00
42	46889	06/13/2024	CHK	103521	GRAYBAR ELECTRIC INC	BROADBAND MATERIALS & SUPPLIES	3,597.27

Accounts Payable

Checks and Customer Refunds

06/01/2024 To 06/30/2024

Bank Account: 1 - ZBA - WARRANT ACCOUNT

#	Check / Tran	Date	Pmt Type	Vendor	Vendor Name	Reference	Amount
43	46890	06/13/2024	CHK	114007	GRIGG ENTERPRISES INC	BUILDING MAINTENANCE & SUPPLIES	19.59
44	46891	06/13/2024	CHK	114007	GRIGG ENTERPRISES INC	BUILDING MAINTENANCE & SUPPLIES	94.57
45	46892	06/13/2024	CHK	112980	IRRIGATION SPECIALISTS INC	BUILDING MAINTENANCE & SUPPLIES	103.37
46	46893	06/13/2024	CHK	100452	ORKIN EXTERMINATING INC	PEST CONTROL	2,490.87
47	46894	06/13/2024	CHK	104915	PEND OREILLE PUD	CWPU EXPENSE	1,428.49
48	46895	06/13/2024	CHK	114409	POSITIVE PROMOTIONS	ADVERTISING MATERIALS & SUPPLIES	220.65
49	46896	06/13/2024	CHK	100426	POWER CITY ELECTRIC INC	PROJECT WORK	1,435,814.54
50	46897	06/13/2024	CHK	109927	VESTIS SERVICES LLC	MATS AND COVERALLS	117.32
51	46898	06/13/2024	CHK	100290	WA PUBLIC UTILITY DISTRICT ASSOC	DUES & MEMBERSHIP	9,507.00
52	46899	06/13/2024	CHK	113999	WESMAR AUTOMOTIVE	OPERATING SUPPLIES	274.43
53	46900	06/20/2024	CHK	100087	ALTEC INDUSTRIES INC	OPERATING SUPPLIES	589.07
54	46901	06/20/2024	CHK	100129	APOLLO SHEET METAL INC	HVAC MAINTENANCE	678.20
55	46902	06/20/2024	CHK	113887	ASSOCIATION OF CERTIFIED FRAUD EXAMINERS	DUES & MEMBERSHIP	245.00
56	46903	06/20/2024	CHK	100171	BASIN DISPOSAL INC	UTILITY SERVICES	98.80
57	46904	06/20/2024	CHK	113216	BOYD'S TREE SERVICE	TREE TRIMMING	7,463.20
58	46905	06/20/2024	CHK	114378	CABLE HUSTON LLP	PROFESSIONAL SERVICES	4,376.50
59	46906	06/20/2024	CHK	114342	CAMPBELL & COMPANY SERVICE CORPORATION	ELECTRIC GATE DIAGNOSTIC	392.04
60	46907	06/20/2024	CHK	101285	CITY OF PASCO	ROW PERMIT FEE	10.00
61	46908	06/20/2024	CHK	100362	CITY OF PASCO	OCCUPATION/UTILITY	368,798.93
62	46909	06/20/2024	CHK	100360	CITY OF PASCO	UTILITY SERVICES	858.52
63	46910	06/20/2024	CHK	112961	CITY OF RICHLAND	FIBER LEASE	733.73
64	46911	06/20/2024	CHK	113421	COLUMBIA PUMPING & CONSTRUCTION	CONCRETE REPAIRS	33,248.93
65	46912	06/20/2024	CHK	113583	COLUMBIA RIGGING CORP	OPERATING TOOLS	218.76
66	46913	06/20/2024	CHK	110413	COMPUNET INC	SOFTWARE MAINTENANCE	391.06
67	46914	06/20/2024	CHK	100206	FRANKLIN COUNTY GRAPHIC	ADVERTISING	562.50
68	46915	06/20/2024	CHK	100697	FRONTIER FENCE INC	BUILDING MAINTENANCE & SUPPLIES	11.98
69	46916	06/20/2024	CHK	103521	GRAYBAR ELECTRIC INC	BROADBAND MATERIALS & SUPPLIES	291.63
70	46917	06/20/2024	CHK	114007	GRIGG ENTERPRISES INC	BUILDING MAINTENANCE & SUPPLIES	46.07
71	46918	06/20/2024	CHK	114477	H&L AUTO GLASS LLC	WINDSHIELD REPAIR	381.06
72	46919	06/20/2024	CHK	114420	HEARTSMART	SAFETY EQUIPMENT & SUPPLIES	2,469.85
73	46920	06/20/2024	CHK	114110	HOLZER LAND COMPANY LLC	ENERGY SERVICES	2,070.00
74	46921	06/20/2024	CHK	113720	IDSC HOLDINGS LLC	OPERATING TOOLS	11.02
75	46922	06/20/2024	CHK	114184	M&M BOLT CO	BUILDING MAINTENANCE & SUPPLIES	10.75
76	46923	06/20/2024	CHK	113908	MILNE ENTERPRISES INC	OPERATING TOOLS	775.26
77	46924	06/20/2024	CHK	113339	NORTH COAST ELECTRIC COMPANY	OPERATING SUPPLIES	329.00
78	46925	06/20/2024	CHK	100394	OXARC INC	NITROGEN & OTHER GASES	93.36
79	46926	06/20/2024	CHK	113438	PITNEY BOWES INC	MAIL MACHINE POSTAGE	2,000.00
80	46927	06/20/2024	CHK	100411	RANCH & HOME INC	OPERATING SUPPLIES	79.55
81	46928	06/20/2024	CHK	114211	RELATION INSURANCE SERVICES	INSURANCE RENEWAL POLICY	2,455.00
82	46929	06/20/2024	CHK	101679	STELLA-JONES CORPORATION	WAREHOUSE MATERIALS & SUPPLIES	60,996.85
83	46930	06/20/2024	CHK	114071	STUART C IRBY CO.	WAREHOUSE MATERIALS & SUPPLIES	2,454.42
84	46931	06/20/2024	CHK	100143	TRI CITIES BATTERY INC	OPERATING SUPPLIES	294.92

Accounts Payable

Checks and Customer Refunds

06/01/2024 To 06/30/2024

Bank Account: 1 - ZBA - WARRANT ACCOUNT

#	Check / Tran	Date	Pmt Type	Vendor	Vendor Name	Reference	Amount
85	46932	06/20/2024	CHK	114099	U.S. PAYMENTS LLC	KIOSK TRANSACTIONS AND FEES	966.06
86	46933	06/20/2024	CHK	100283	UTILITIES UNDERGROUND LOCATION CENTER	LOCATE SERVICES	435.60
87	46934	06/20/2024	CHK	113360	VALLEY TRANSFORMER INC	TRANSFORMER MAINTENANCE & REPAIRS	19,847.43
88	46935	06/20/2024	CHK	114108	VERIZON CONNECT FLEET USA LLC	FLEET MANAGEMENT SERVICES	1,273.09
89	46936	06/20/2024	CHK	111471	VERIZON WIRELESS SERVICES LLC	PHONE SERVICES	465.18
90	46937	06/20/2024	CHK	109927	VESTIS SERVICES LLC	MATS AND COVERALLS	165.40
91	46938	06/20/2024	CHK	113626	WATER STREET PUBLIC AFFAIRS LLC	CONSULTING SERVICES	3,500.00
92	46939	06/20/2024	CHK	114162	ZAYO GROUP HOLDINGS INC	BROADBAND SERVICES	2,662.11
93	46940	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	174.89
94	46941	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	74.86
95	46942	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	164.84
96	46943	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	85.01
97	46944	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	393.20
98	46945	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	154.85
99	46946	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	181.16
100	46947	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	108.00
101	46948	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	100.82
102	46949	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	200.00
103	46950	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	74.01
104	46951	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	23.98
105	46952	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	107.08
106	46953	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	64.57
107	46954	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	232.95
108	46955	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	41.98
109	46956	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	187.06
110	46957	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	54.62
111	46958	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	194.50
112	46959	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	93.32
113	46960	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	11.09
114	46961	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	26.71
115	46962	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	159.18
116	46963	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	131.74
117	46964	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	122.84
118	46965	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	7.59
119	46966	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	249.20
120	46967	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	10.88
121	46968	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	102.47
122	46969	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	372.92
123	46970	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	141.57
124	46971	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	180.13
125	46972	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	45.94
126	46973	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	17.01

Accounts Payable

Checks and Customer Refunds

06/01/2024 To 06/30/2024

Bank Account: 1 - ZBA - WARRANT ACCOUNT

#	Check / Tran	Date	Pmt Type	Vendor	Vendor Name	Reference	Amount
127	46974	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	107.93
128	46975	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	40.02
129	46976	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	152.02
130	46977	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	177.32
131	46978	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	132.61
132	46979	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	189.38
133	46980	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	42.21
134	46981	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	59.23
135	46982	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	157.23
136	46983	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	81.24
137	46984	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	62.15
138	46985	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	234.02
139	46986	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	5.90
140	46987	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	206.73
141	46988	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	145.64
142	46989	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	53.69
143	46990	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	10.91
144	46991	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	88.91
145	46992	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	155.07
146	46993	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	56.00
147	46994	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	91.64
148	46995	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	274.97
149	46996	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	112.32
150	46997	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	779.03
151	46998	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	210.58
152	46999	06/20/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	87.96
153	47000	06/27/2024	CHK	100028	ABADAN	PRINTER MAINTENANCE	277.68
154	47001	06/27/2024	CHK	113216	BOYD'S TREE SERVICE	TREE TRIMMING	7,507.18
155	47002	06/27/2024	CHK	113631	CENTRAL MACHINERY SALES, INC	2023 EXCAVATOR	101,156.94
156	47003	06/27/2024	CHK	100360	CITY OF PASCO	UTILITY SERVICES	540.91
157	47004	06/27/2024	CHK	113784	COFFMAN ENGINEERS INC	PROFESSIONAL SERVICES	26,150.00
158	47005	06/27/2024	CHK	113662	COLUMBIA BASIN LLC	DISPOSAL SERVICES	1,080.76
159	47006	06/27/2024	CHK	110413	COMPUNET INC	SOFTWARE MAINTENANCE	38,708.69
160	47007	06/27/2024	CHK	114077	EMPIRE INNOVATION GROUP LLC	FLEX PLAN	1,002.89
161	47008	06/27/2024	CHK	100197	FEDEX	FEDEX	2,400.42
162	47009	06/27/2024	CHK	114334	HOWARD INDUSTRIES INC	WAREHOUSE MATERIALS & SUPPLIES	18,912.66
163	47010	06/27/2024	CHK	113706	INTERMOUNTAIN CLEANING SERVICE INC	JANITORIAL SERVICES	4,251.25
164	47011	06/27/2024	CHK	114249	IRONSIDES CUSTOM GRINDING INC	WOOD GRINDING SERVICES	73.51
165	47012	06/27/2024	CHK	100006	LOURDES OCCUPATIONAL HEALTH CENTER	MEDICAL SERVICES	270.00
166	47013	06/27/2024	CHK	113908	MILNE ENTERPRISES INC	OPERATING SUPPLIES	30.31
167	47014	06/27/2024	CHK	100394	OXARC INC	NITROGEN & OTHER GASES	181.23
168	47015	06/27/2024	CHK	112987	PACIFIC STEEL & RECYCLING	OPERATING SUPPLIES	82.05

Accounts Payable

Checks and Customer Refunds

06/01/2024 To 06/30/2024

Bank Account: 1 - ZBA - WARRANT ACCOUNT

#	Check / Tran	Date	Pmt Type	Vendor	Vendor Name	Reference	Amount
169	47016	06/27/2024	CHK	114447	PLUTO ACQUISITION OPCO LLC	NEW HIRE BACKGROUND CHECK	291.40
170	47017	06/27/2024	CHK	114485	PROVIDENCE HEALTH & SERVICES-WASHINGTON	MEDICAL SERVICES	50.00
171	47018	06/27/2024	CHK	114022	PURE WATER PARTNERS LLC	WATER COOLER RENTAL	419.30
172	47019	06/27/2024	CHK	100826	SMITH INSULATION INC	ENERGY SERVICES	3,343.12
173	47020	06/27/2024	CHK	114071	STUART C IRBY CO.	WAREHOUSE MATERIALS & SUPPLIES	6,354.32
174	47021	06/27/2024	CHK	112920	TACOMA SCREW PRODUCTS INC	OPERATING SUPPLIIES	61.76
175	47022	06/27/2024	CHK	114277	THE PRINT GUYS INC	OFFICE FORMS	161.07
176	47023	06/27/2024	CHK	114231	THE TIP PIT INCORPORATED	2024 SAFETY EVENT LUNCHEON	1,355.09
177	47024	06/27/2024	CHK	113870	TOTH AND ASSOCIATES INC	PROFESSIONAL SERVICES	7,588.75
178	47025	06/27/2024	CHK	113100	VERSALIFT NORTHWEST LLC	OPERATING SUPPLIES	511.73
179	47026	06/27/2024	CHK	109927	VESTIS SERVICES LLC	MATS AND COVERALLS	166.43
180	47027	06/27/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	625.04
181	47028	06/27/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	131.67
182	47029	06/27/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	131.14
183	47030	06/27/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	523.03
184	47031	06/27/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	111.22
185	47032	06/27/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	178.32
186	47033	06/27/2024	CHK	90002	CUSTOMER REFUND	CUSTOMER REFUND	248.74
						Total for Bank Account - 1 :	2,380,476.68
						Grand Total :	2,380,476.68

Accounts Payable

Check Register - Direct Deposit

06/01/2024 To 06/30/2024

Bank Account: 3 - FPUD REVENUE ACCOUNT

#	Check / Tran	Date	Pmt Type	Vendor	Vendor Name	Reference	Amount
1	28480	06/06/2024	DD	114180	2001 SIXTH LLC	BROADBAND SERVICES	150.00
2	28481	06/06/2024	DD	113886	AMAZON CAPITAL SERVICES INC	OPERATING SUPPLIES	147.71
3	28482	06/06/2024	DD	100178	BENTON COUNTY PUD	TREE TRIMMING	2,305.88
4	28483	06/06/2024	DD	101625	CARLSON SALES INC	METER SHOP MATERIALS & SUPPLIES	2,705.08
5	28484	06/06/2024	DD	107217	FINANCIAL CONSULTING SOLUTIONS GROUP INC	PROFESSIONAL SERVICES	350.00
6	28485	06/06/2024	DD	100229	GRAINGER INC	BUILDING MAINTENANCE & SUPPLIES	216.64
7	28486	06/06/2024	DD	114438	GRASHER CONSULTING LLC	PROFESSIONAL SERVICES	120.00
8	28487	06/06/2024	DD	112981	GREEN ENERGY TODAY LLC	ESQUATZEL DAM PROJECT	25,189.30
9	28488	06/06/2024	DD	101501	JIM'S PACIFIC GARAGES INC	OPERATING SUPPLIES	174.22
10	28489	06/06/2024	DD	1191	BRIAN C JOHNSON	TRAVEL REIMBURSEMENT	221.58
11	28490	06/06/2024	DD	113652	LEAF CAPITAL FUNDING LLC	PRINTER LEASE	1,146.75
12	28491	06/06/2024	DD	114170	MPOWER TECHNOLOGIES INC	SOFTWARE MAINTENANCE	17,000.00
13	28492	06/06/2024	DD	100300	PRINCIPAL BANK PCS	INSURANCE PREMIUM	135,040.20
14	28493	06/06/2024	DD	113980	SANCHEZ BROS CONSTRUCTION LLC	ENERGY SERVICES	27,054.68
15	28494	06/06/2024	DD	102263	TYNDALE COMPANY INC	FIRE SAFETY CLOTHING	667.02
16	28581	06/13/2024	DD	113886	AMAZON CAPITAL SERVICES INC	HARDWARE PURCHASE	24.79
17	28582	06/13/2024	DD	113861	BMC SOFTWARE INC	SOFTWARE MAINTENANCE	2,407.94
18	28583	06/13/2024	DD	114144	COGENT COMMUNICATIONS INC	BROADBAND SERVICES	2,035.64
19	28584	06/13/2024	DD	102842	ENERGY NORTHWEST	NINE CANYON	177,414.53
20	28585	06/13/2024	DD	1076	KATRINA B FULTON	TRAVEL REIMBURSEMENT	279.67
21	28586	06/13/2024	DD	100216	GENERAL PACIFIC INC	WAREHOUSE MATERIALS & SUPPLIES	81,500.76
22	28587	06/13/2024	DD	113299	HRA VEBA TRUST	VEBA	17,204.30
23	28588	06/13/2024	DD	100245	IBEW LOCAL 77	UNION DUES	5,960.14
24	28589	06/13/2024	DD	101501	JIM'S PACIFIC GARAGES INC	OPERATING SUPPLIES	632.88
25	28590	06/13/2024	DD	100448	LAWSON PRODUCTS INC	WAREHOUSE MATERIALS & SUPPLIES	1,910.87
26	28591	06/13/2024	DD	114319	MISSIONSQUARE 106134	DEFERRED COMPENSATION	1,076.92
27	28592	06/13/2024	DD	114295	MISSIONSQUARE 107514	DEFERRED COMPENSATION	13,837.14
28	28593	06/13/2024	DD	114294	MISSIONSQUARE 301671	DEFERRED COMPENSATION	16,970.24
29	28594	06/13/2024	DD	113201	NAPA	AUTO PARTS	165.67
30	28595	06/13/2024	DD	111368	ONLINE INFORMATION SERVICES INC	UTILITY EXCHANGE REPORT	812.12
31	28596	06/13/2024	DD	113294	PARAMOUNT COMMUNICATIONS, INC	FIBER DOCK CREW	20,302.62
32	28597	06/13/2024	DD	114312	RELIANCE STANDARD LIFE INSURANCE CO	INSURANCE PREMIUM	5,455.28
33	28598	06/13/2024	DD	1200	SCOTT RHEES	TRAVEL REIMBURSEMENT	601.85
34	28599	06/13/2024	DD	113980	SANCHEZ BROS CONSTRUCTION LLC	ENERGY SERVICES	13,035.33
35	28600	06/13/2024	DD	100195	STAPLES ADVANTAGE	OFFICE SUPPLIES	240.12
36	28601	06/13/2024	DD	113684	SUSTAINABLE LIVING CENTER	LOW INCOME CERTIFICATIONS	625.00
37	28602	06/13/2024	DD	100120	TIMBER PRODUCTS INSPECTION INC	POLE INSPECTION	76.92
38	28603	06/13/2024	DD	102263	TYNDALE COMPANY INC	FIRE SAFETY CLOTHING	80.04
39	28604	06/13/2024	DD	100277	UNITED WAY	UNITED WAY	100.00
40	28605	06/20/2024	DD	112724	A W REHN & ASSOCIATES	COBRA NOTIFICATION/FLEX FEE	44.00
41	28606	06/20/2024	DD	113886	AMAZON CAPITAL SERVICES INC	HARDWARE PURCHASE	469.96
42	28607	06/20/2024	DD	113380	ANIXTER INC	WAREHOUSE MATERIALS & SUPPLIES	32,964.03

Accounts Payable

Check Register - Direct Deposit

06/01/2024 To 06/30/2024

Bank Account: 3 - FPUD REVENUE ACCOUNT

#	Check / Tran	Date	Pmt Type	Vendor	Vendor Name	Reference	Amount
43	28608	06/20/2024	DD	101890	COLUMBIA INDUSTRIES	SHREDDING SERVICES	218.02
44	28609	06/20/2024	DD	1232	ENOCH DAHL	TRAVEL REIMBURSEMENT	32.00
45	28610	06/20/2024	DD	113663	DATA HARDWARE DEPOT LP	OPERATING SUPPLIES	540.55
46	28611	06/20/2024	DD	100644	DELL MARKETING L.P.	HARDWARE PURCHASE	5,316.18
47	28612	06/20/2024	DD	112739	DLT SOLUTIONS LLC	AUTOCAD SOFTWARE MAINTENANCE	7,728.85
48	28613	06/20/2024	DD	102842	ENERGY NORTHWEST	PACKWOOD	30,036.00
49	28614	06/20/2024	DD	1076	KATRINA B FULTON	TRAVEL REIMBURSEMENT	1,301.65
50	28615	06/20/2024	DD	1092	WILLIAM M GORDON	TRAVEL REIMBURSEMENT	2,669.80
51	28616	06/20/2024	DD	100229	GRAINGER INC	BUILDING MAINTENANCE & SUPPLIES	767.38
52	28617	06/20/2024	DD	113442	ICE TRADE VAULT, LLC	COUNTERPARTY TRADE FEE	36.00
53	28618	06/20/2024	DD	101501	JIM'S PACIFIC GARAGES INC	OPERATING SUPPLIES	1,064.29
54	28619	06/20/2024	DD	1191	BRIAN C JOHNSON	TRAVEL REIMBURSEMENT	739.24
55	28620	06/20/2024	DD	100448	LAWSON PRODUCTS INC	OPERATING SUPPLIES	1,407.77
56	28621	06/20/2024	DD	113652	LEAF CAPITAL FUNDING LLC	PRINTER LEASE	65.66
57	28622	06/20/2024	DD	112949	LUMEN	PHONE SERVICES	50.64
58	28623	06/20/2024	DD	113201	NAPA	AUTO PARTS	662.45
59	28624	06/20/2024	DD	1093	STUART J NELSON	TRAVEL REIMBURSEMENT	1,599.12
60	28625	06/20/2024	DD	113269	NISC	MAILING SERVICES AND INSERT BILLING	51,281.26
61	28626	06/20/2024	DD	101318	NORTHWEST OPEN ACCESS NETWORK	BUILDING MAINTENANCE	9,884.98
62	28627	06/20/2024	DD	113294	PARAMOUNT COMMUNICATIONS, INC	FIBER DOCK CREW	31,220.87
63	28628	06/20/2024	DD	103410	POTELCO INC	PROFESSIONAL SERVICES	29,354.52
64	28629	06/20/2024	DD	113445	RELIABLE EQUIPMENT & SERVICE COMPANY, IN	OPERATING TOOLS	225.62
65	28630	06/20/2024	DD	113980	SANCHEZ BROS CONSTRUCTION LLC	ENERGY SERVICES	31,481.62
66	28631	06/20/2024	DD	102263	TYNDALE COMPANY INC	FIRE SAFETY CLOTHING	861.41
67	28632	06/20/2024	DD	1221	VICTOR FUENTES	TRAVEL REIMBURSEMENT	1,698.49
68	28633	06/20/2024	DD	114204	VITAL RECORDS HOLDINGS LLC	RECORDS STORAGE SERVICES	519.95
69	28721	06/27/2024	DD	113886	AMAZON CAPITAL SERVICES INC	HARDWARE PURCHASE	655.08
70	28722	06/27/2024	DD	113380	ANIXTER INC	WAREHOUSE MATERIALS & SUPPLIES	5,199.98
71	28723	06/27/2024	DD	112936	CENTURY LINK	PHONE SERVICES	250.34
72	28724	06/27/2024	DD	1232	ENOCH DAHL	TRAVEL REIMBURSEMENT	58.88
73	28725	06/27/2024	DD	113663	DATA HARDWARE DEPOT LP	BROADBAND MATERIALS & SUPPLIES	916.25
74	28726	06/27/2024	DD	100216	GENERAL PACIFIC INC	WAREHOUSE MATERIALS & SUPPLIES	4,075.04
75	28727	06/27/2024	DD	1055	BENJAMIN A HOOPER	TRAVEL REIMBURSEMENT	306.10
76	28728	06/27/2024	DD	113299	HRA VEBA TRUST	VEBA EMPLOYER PAID	22,258.08
77	28729	06/27/2024	DD	113442	ICE TRADE VAULT, LLC	COUNTERPARTY TRADE FEE	375.00
78	28730	06/27/2024	DD	1133	LANCE KOSTOFF	TRAVEL REIMBURSEMENT	267.95
79	28731	06/27/2024	DD	113652	LEAF CAPITAL FUNDING LLC	PRINTER LEASE	1,021.66
80	28732	06/27/2024	DD	114319	MISSIONSQUARE 106134	DEFERRED COMPENSATION	1,076.92
81	28733	06/27/2024	DD	114295	MISSIONSQUARE 107514	DEFERRED COMPENSATION	13,735.50
82	28734	06/27/2024	DD	114294	MISSIONSQUARE 301671	DEFERRED COMPENSATION	16,782.15
83	28735	06/27/2024	DD	100572	MONARCH MACHINE & TOOL INC	TRANSFORMER TRANSPORT	871.20
84	28736	06/27/2024	DD	100130	MOON SECURITY SERVICES INC	SECURITY MAINTENANCE	358.58

Accounts Payable

Check Register - Direct Deposit

06/01/2024 To 06/30/2024

Bank Account: 3 - FPUD REVENUE ACCOUNT

#	Check / Tran	Date	Pmt Type	Vendor	Vendor Name	Reference	Amount
85	28737	06/27/2024	DD	113201	NAPA	AUTO PARTS	463.35
86	28738	06/27/2024	DD	113294	PARAMOUNT COMMUNICATIONS, INC	FIBER DOCK CREW	54,963.68
87	28739	06/27/2024	DD	113168	PORTLAND GENERAL ELECTRIC COMPANY	COB INTERTIE	12,044.16
88	28740	06/27/2024	DD	114326	RELIANCE STANDARD LIFE INSURANCE CO /ASO	INSURANCE PREMIUM	102.50
89	28741	06/27/2024	DD	111776	ROHLINGER ENTERPRISES INC	SAFETY EQUIPMENT & SUPPLIES	1,727.89
90	28742	06/27/2024	DD	113980	SANCHEZ BROS CONSTRUCTION LLC	ENERGY SERVICES	27,078.20
91	28743	06/27/2024	DD	102263	TYNDALE COMPANY INC	FIRE SAFETY CLOTHING	252.65
92	28744	06/27/2024	DD	113904	ULINE INC	SAFETY EQUIPMENT & SUPPLIES	1,580.38
93	28745	06/27/2024	DD	113245	WESTERN UNION FINANCIAL SERVICES INC	WESTERN UNION FEES	66.00
						Total for Bank Account - 3 :	985,969.66
						Grand Total :	985,969.66

Franklin PUD - Write Off Report		
	Write Off Report for the Month of:	**Jul-24**
	Collection Agency:	**Armada Corporation**
#	**Name**	**Amount**
1	SPEEDY TIRES	$ 4,493.04
2	TIARA SEDGWICK	$ 546.86
3	PATRICK STEVENSON	$ 301.81
4	MARIA D URIBE LOPEZ	$ 264.65
5	LAURA DE ALBA NIEVES	$ 182.06
6	TIMOTHY GONZALEZ	$ 105.57
7	ELSA M CUEVAS	$ 102.82
8	JASON BARTHOLOW	$ 97.06
9	LAWRENCE W FRAZER	$ 96.33
10	CHRISTINA PEEL	$ 89.20
11	STEVEN B LAMBERSON	$ 83.64
12	STEPHANIE AVILA	$ 82.58
13	LUIS D OLIVERA MEDRANO	$ 76.71
14	ZACH COUEY	$ 49.63
15	GIAN A RUSSO	$ 47.53
16	KARLA CONTRERAS	$ 47.18
17	CINDY AGUILAR	$ 45.06
18	JOSHUA O DIXON	$ 45.00
19	SHANA ALDERETE	$ 41.40
20	CHARLES CARLSON	$ 40.00
21	DECONTEE KANNAH	$ 28.80
22	FRANKLIN PARADA	$ 11.91
	Total	**$ 6,878.84**
	Average amount per account:	$ 312.67
	Gross bad debts as a percentage to	
	March 2024 monthly sales:	0.10%

AGENDA ITEM 8

Franklin PUD Commission Meeting Packet
Agenda Item Summary

Presenter:	**Katrina Fulton**	☐	REPORT
	Finance and Customer Service Director	☐	DISCUSSION
Date:	**July 23, 2024**	☑	**ACTION REQUIRED**

1. OBJECTIVE:
Opening the Integrated Resource Plan Public Hearing, Presenting the Integrated Resource Plan, and Recessing the Public Hearing.

2. BACKGROUND:
In 2006, the Washington State legislature passed RCW 19.280, which requires that utilities with over 25,000 customers, who are not a load-following customer of the Bonneville Power Administration, develop comprehensive resource plans every four years. The District adopted the first full Integrated Resource Plan (IRP) in 2020 and an IRP Progress Report in 2022.

The goal of the IRP is to provide a framework for evaluating a wide array of supply resources, conservation, and renewable energy credits. The IRP provides guidance towards strategies to meet growing loads, capacity requirements, and regulatory requirements in the most reliable and cost-effective manner.

Staff will present the draft IRP (Attachment A) for Commission review and public comment. Two public hearings have been scheduled the first beginning today and the second one on August 27, 2024 during the regular Commission meeting.

When the Commission closes the final hearing in August, staff will recommend that the Commission approve the IRP for submittal to the Department of Commerce.

Staff recommends that after hearing any public comment and after review and discussion, the Commission recess the public hearing to the August 27, 2024 regular Commission meeting.

3. SUGGESTED MOTION:
I move to recess the Integrated Resource Plan public hearing to the August 27, 2024 regular Commission meeting.

FRANKLIN PUD

THE POWER IS YOURS

2024 INTEGRATED RESOURCE PLAN

PREPARED IN COLLABORATION WITH:

TEA

THE EnergyAuthority

JULY 2024

CONFIDENTIAL & PROPRIETARY

Section 1 Executive Summary

1.1 Background

Public Utility District No. 1 of Franklin County (FPUD) is required by Washington State law, Chapter 19.280 of the Revised Code of Washington (RCW), to develop "a comprehensive resource plan that explains the mix of generation and demand-side resources it plans to use to meet its customers' electricity needs in both the long term and the short term." The law stipulates that FPUD produce a comprehensive plan every four years and provide an update to that plan every two years. The Integrated Resource Plan (IRP) analysis must include a range of load forecasts over a ten-year time horizon; an assessment of feasible conservation and efficiency resources; an assessment of supply-side generation resources; an economic appraisal of renewable and nonrenewable resources; a preferred plan for meeting the utility's requirements; and a formal action plan.

The goal of this 2024 IRP is to forecast the future electric demand of our customers and to identify the optimal mix of resources that is affordable and reliable while meeting regulatory requirements and social expectations of our community. FPUD's previous IRP was adopted by the Board in August 2020. The 2020 IRP analysis showed that FPUD's existing long-term Bonneville Power Administration (BPA) power supply contract and its other owned and contracted resources can provide enough energy to meet its forecast need on an average annual basis through 2030. The 2020 IRP also identified a strategy to meet the short- and long-term electricity needs of FPUD customers and Washington State renewable portfolio standard (RPS) obligations for the 2020 through 2030 study period. The preferred portfolio included relying on market purchases for any short-term capacity deficits and procuring renewable energy credits (RECs) to address a projected shortfall in renewable portfolio standard compliant generation beginning in 2025.

FPUD developed a Progress Report in 2022 that reviewed the changing conditions in the wholesale energy market and planning environments as well as its progress in carrying out the strategy and formal action plan of the 2020 IRP. The Progress Report is consistent with the State of Washington's regulatory requirements (RCW 19.280.030).

FPUD contracts with The Energy Authority Inc. (TEA) for a suite of services including Portfolio Management, load forecasting, bilateral power trading, regulatory reporting, and integrated resource plans (IRPs). TEA's clients are located throughout the United States, operating in both bilateral and organized markets, including MISO, CAISO, ERCOT, SPP, and PJM. Founded by three public power owners to address changes in the electric utility industry, enhance the use of its clients' electric generating assets in the wholesale electric energy market, and optimize power sales and purchases for their systems, TEA's commitment to public power utilities has fueled its growth. Since 1997, TEA has expanded to seven owners and now serves over 60 total clients across the nation with generating assets and contract rights exceeding 25,000 megawatts. TEA has over 270 employees operating from its offices in Jacksonville, FL, and Bellevue, WA.

1.2 Franklin Public Utility District

Franklin Public Utility District (FPUD) provides electric service to approximately 33,500 residential, commercial, industrial, and street lighting customers countywide. FPUD purchases most of its wholesale power from the Bonneville Power Administration (BPA) at cost, through the long-term Slice and Block Power Sales Agreement.

Most of the BPA power supply comes from the Federal Columbia River Power System (FCRPS) hydroelectric projects. BPA also markets the output of the Columbia Generating System (nuclear plant) near Richland, WA, and makes miscellaneous energy purchases on the open market. FPUD augments its remaining energy and capacity requirements primarily through contracts for portions of the Nine Canyon and White Creek wind projects and the PowerEx, Packwood Lake, and Esquatzel Canal hydroelectric generating facilities.

1.3 Future Load and Resource Balance

FPUD's load was forecast for this IRP using linear and non-linear regression models developed by TEA and trained on historical weather, customer demand, and econometric data for the period from 2004 – 2024. The load forecast provides hourly granularity for the full study period from 2025 – 2044 based on econometric forecasts for Franklin County from Woods and Poole. In addition, the load forecast used in this study incorporates additional load growth due to building and vehicle electrification in excess of what has been seen historically. This growth was forecast separately using regression models trained on data from S&P Global Commodity Insights (S&P Global) and the National Renewable Energy Laboratory (NREL).

In aggregate, these models forecast average energy and peak demand growth of 1.6% per year over the 2025 to 2044 time period. In addition to the reference case scenario that is based on this base case load forecast, FPUD considered high and low load scenarios. The high load was developed by increasing the base load growth rate by 0.5% per year. The low load reduced the base load by 0.5% per year.

FPUD is currently forecast to have sufficient resources available to meet average energy demand through 2028. However, on a capacity basis, FPUD is currently at a deficit and is projected to grow that deficit to 231 MW of summer capacity and 131 MW of winter capacity by the end of the study period absent additional resource procurement. That deficit is partially exacerbated by the additional capacity required to comply with the Western Resource Adequacy Program (WRAP), which is modeled to take effect in November 2027.

1.4 Resources to Meet Future Growth and CETA Requirements

New resources are needed to address this substantial capacity deficit. Due to significant lead times required for construction and interconnecting a resource to the electric system, timely planning for each new resource is critical to ensure capacity requirements are met. To ensure compliance with the requirements of the Clean Energy Transformation Act (CETA), FPUD evaluated only carbon-free supply-side resource options including solar, wind, lithium-ion battery storage, geothermal, small-modular nuclear reactors, BPA Tier 2 power, market-based PPAs, and extensions of existing PPA contracts.

1.5 Conclusions

FPUD is currently meeting the energy demand of its customers with 90% carbon-free electric power and is projected to maintain balance between its load and resources in spite of a roughly 1.6% year-over-year projected load growth through the study period. However, on a capacity basis, FPUD has a considerable deficit and, without the implementation of a comprehensive and well-planned strategy, would likely see that deficit increase to as much as 231 MW by 2044.

FPUD will leverage all the tools available to meet this need reliably, affordably, and sustainably. First, FPUD will maximize use of Bonneville Power Administration (BPA) Tier 1 power, which is the cheapest low-carbon capacity resource available to the utility. FPUD will also acquire all cost-effective conservation measures and monitor opportunities for demand response and distributed generation investments. FPUD will continue to explore opportunities for adding both utility-scale renewables and behind-the-meter renewable resources, such as community solar projects, to its resource portfolio. FPUD will consider the possible extension of current renewable PPA contracts that are set to expire during the study period. In addition, FPUD is in the process of potentially adding approximately 60 MW of nameplate solar capacity in 2026 through participation in the Ruby Flats and Palouse Junction projects. FPUD will also consider BPA Tier 2 opportunities and market-based purchases. FPUD continues to monitor the emerging technologies, including geothermal, hydrogen, and small-modular nuclear reactors (SMR) for possible future procurement.

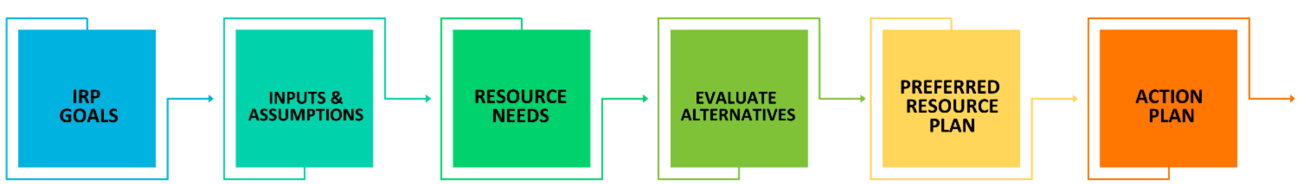
Section 2 IRP Methodology

Integrated Resource Planning (IRP) is a comprehensive and strategic planning process that FPUD performs on a regular basis to ensure the utility is utilizing an optimal mix of resources that minimize future costs while meeting the goals of FPUD and its community. Key outputs of the process are Net Present Value of Revenue Requirements (NPVRR), Levelized Cost of Energy (LCoE), and the amount of carbon emissions. Energy Exemplar's PLEXOS capacity planning model was utilized in the development of this 2024 IRP study.

The following are the steps taken by FPUD to develop this resource planning study:

1. IRP goals: IRP methodology begins with identification and establishment of the objectives of the IRP process. FPUD's goals include delivery of safe, reliable and cost-effective service while maintaining environmental responsibilities and regulatory compliance.
2. Inputs and Assumptions: This step involves identifying potential future resource options, developing assumptions for costs and operating characteristics of current and potential resources, and estimating future electric demand.
3. Resource Needs: The third step compares capacity contributions from existing resources with load forecast estimates to identify expected timing and magnitude of future capacity shortfalls.
4. Alternatives Evaluation: The capacity planning model is used to identify resource plans that meet utility objectives. To identify operational risks, resource plans are developed under multiple scenarios and sensitivities. This comprehensive evaluation helps FPUD to develop strategies that mitigate risk and ensures resilience in the face of unforeseen circumstances.
5. Preferred Resource Plan: A preferred resource plan is selected based on its performance across multiple scenarios and sensitivities. A resource plan is considered effective if it is capable of meeting FPUD's goals listed in the first step of the process.
6. Action Plan – A series of steps is developed to carry out the preferred resource plan. These steps may include developing additional studies, issuing requests for proposals (RFPs), and procuring and contracting for additional resources.

IRP 6-Step Process



Section 3 Policy And Regulation

3.1 Integrated Resource Planning

Franklin Public Utility District (FPUD) is required by Washington State law, Chapter 19.280 of the Revised Code of Washington (RCW), to develop "a comprehensive resource plan that explains the mix of generation and demand-side resources it plans to use to meet its customers' electricity needs in both the long term and the short term." The law stipulates that FPUD produce a comprehensive plan every four years and provide an update to that plan every two years. The Integrated Resource Plan (IRP) analysis must include a range of load forecasts over a ten-year time horizon; an assessment of feasible conservation and efficiency resources; an assessment of supply-side generation resources; an economic appraisal of renewable and nonrenewable resources; a preferred plan for meeting the utility's requirements; and a formal action plan.

The goal of this 2024 IRP is to forecast the future electric demand of our customers and to identify the optimal mix of resources that is affordable and reliable while meeting regulatory requirements and social expectations of our community. FPUD's previous IRP was adopted by the Board in August 2020. The 2020 IRP analysis showed that FPUD's existing long-term Bonneville Power Administration (BPA) power supply contract and its other owned and contracted resources can provide enough energy to meet its forecast need on an average annual basis through 2030. The 2020 IRP also identified a strategy to meet the short- and long-term electricity needs of FPUD customers and Washington State renewable portfolio standard (RPS) obligations for the 2020 through 2030 study period. The preferred portfolio included relying on market purchases for any short-term capacity deficits and procuring renewable energy credits (RECs) to address a projected shortfall in renewable portfolio standard compliant generation beginning in 2025.

FPUD developed a Progress Report in 2022 that reviewed the changing conditions in the wholesale energy market and planning environments as well as its progress in carrying out the strategy and formal action plan of the 2020 IRP. The Progress Report is consistent with the State of Washington's regulatory requirements (RCW 19.280.030).

3.2 Energy Independence Act

In 2006, Washington State voters approved the Energy Independence Act (EIA), RCW 19.285 (I-937). The act stipulates that any utility servicing over 25,000 customers must serve load with an increasing proportion of renewable energy. In 2012, 3% of retail load was required to be sourced from renewable generation, 9% in 2016, and finally 15% in 2020. The goal is that eventually renewable energy will become the sole energy provider within a utility's portfolio. Furthermore, the EIA requires that the District outlines its achievable cost-effective conservation potential every two years, as well as a focus on the ten-year energy efficiency potential. The EIA defines the following as eligible resources: water, wind, solar energy, geothermal energy, landfill gas, wave, ocean or tidal power, gas for sewage treatment plants and biodiesel fuel and biomass energy.

FPUD was initially exempt from the EIA and only came into compliance in 2016 when The District surpassed 25,000 customers. As a result, Franklin's compliance mandate is on a different timeline compared to those affected by the EIA when it first came into law. The first compliance mandate is 3% starting in 2021, then 9% in 2025, and 15% in 2029. If the District fails to meet the requirement, it will be assessed a penalty of $50/MWh, in 2007 dollars, equating to approximately $76/MWh in 2024 dollars.

3.3 Washington Climate Commitment Act

The Climate Commitment Act (CCA) was passed by the Washington State Legislature in 2021 and went live on January 1st, 2023. The act establishes a Cap-and-Invest program which places a declining cap on statewide emissions to help reach the State's 2050 goal of eliminating 95% of emissions. Business types covered under this program include fuel suppliers, natural gas and electric utilities, waste-to-energy facilities (starting in 2027), and railroads (starting in 2031). Additionally, electric utilities, natural gas utilities, and EITEs (emissions intensive trade exposed) receive "no cost" allowances. Entities that emit over 25,000 metric tons of CO_2e are required to retire allowances for compliance. Further, entities emitting more than 10,000 metric tons of CO_2e are required to report emissions annually. These reports are due June 1st of the following year for electric power entities, and March 31st of the following year for any other entities. As noted in Table 1, 63.2M allowances were distributed in 2023 across all sectors, and the no cost allowance budget decreases by 7% annually for the first compliance period. In 2023, 17.5M allowances were distributed to the electric sector at no cost.

Table 1. Total program allowance budget for the first compliance period (CP1) where 1 allowance equals 1 MT CO2e

Emissions Year	Total Covered Emissions ($MT\ CO_2e$)
2023	63, 288, 565
2024	58, 524, 909
2025	53, 761, 254
2026	48, 997, 598

FPUD and other electric utilities who are subject to CETA were allocated allowances for the first compliance period based on the cost burden effect. The cost burden effect calculations emissions from load served by coal, natural gas, Asset-Controlling Supplier resources (such as BPA), non-emitting resources, and unspecified generation. Franklin's allowance allocation, in Table 2 is assumed to provide sufficient allowances for compliance over the first compliance period. These allowances may be sold at auction or retired for compliance.

Table 2. Franklin Public Utilities allowance allocation for the first compliance period of the Cap-And-Invest program.

	2023	2024	2025	2026
FPUD Allowances	140,118	140,609	141,274	TBD

The most recent cap and invest auction at the time of the IRP took place in June 2024. At the June 2024 Auction, 7.8M vintage 2023 and 2024 allowances were offered, and all allowances sold at a price of $29.92/MTCO2s. Additionally, 1,317,000 2027 vintage allowances were sold at advanced auction at the floor price of $24.02 leaving 883,000 vintage 2027 allowances unsold. Any allowances that go unsold are offered again at the following auction. Notably, the settlement price for current vintage allowances decreased from its peak of $63.03 in Auction 2 to $29.92 in Auction 6.

Initiative 2117 (I-2117) will be voted on in Washington State in the November 2024 election. If passed, I-2117 would eliminate the Climate Commitment Act and prohibit the existence of any cap-and-trade programs within the state of Washington. Given that at the time of the IRP the outcome of this initiative is unknown, the IRP assumes that the Cap-and-Invest program will continue as planned, and thus includes the cost of carbon as an input to the market simulation. If the CCA is repealed, FPUD would no longer be subject to any compliance obligation, and the no cost allowances distributed to FPUD would lose all value. FPUD contracts with TEA to actively manage risks associated with the Cap and Invest program.

3.4 Clean Energy Transformation Act (CETA)

The Clean Energy Transformation Act (CETA) (SB 5116, 2019) was signed into Washington law by Governor Jay Inslee in May 2019, and requires utilities to be 80% clean and GHG neutral by 2030 and prohibits the use of fossil fuel electricity production by the year 2045. Alongside this requirement, there are objectives that need to be achieved on time. The first one, completed in 2022, required utilities to create a clean energy implementation plan (CEIP) outlining actions regarding energy efficiency and renewable energy. CEIPs must be submitted every four years, and accompanying progress reports will be required starting in 2026. Further, all utilities must remove coal-fired electricity by 2025. As a result of this requirement, the Centralia Steam Plant, in Centralia, Washington, is on schedule to be retired by the end of 2025. Units 1 and 2 of the Colstrip Plant, in Colstrip, Montana, were retired in January 2020, and Units 3 and 4 will likely retire in the early 2030s. These retirements are included in the IRP market simulation. The "no coal" restriction also excludes coal that may be acquired through unspecified forward market purchases for terms greater than 1 month. As a result, utilities will be less able to rely on unspecified physical forward market purchases as a mechanism for hedging market exposure and may therefore face reduced hedging liquidity or higher prices in the forward market.

3.5 Western Resource Adequacy Program (WRAP)

As a result of increasing concern across the region about capacity sufficiency, the Western Resource Adequacy Program (WRAP) was created. This program is designed to leverage load and resource diversity and deliver resource adequacy efficiencies to participants. The WRAP has a forward showing program and an operational program. The forward showing program requires that 7 months prior to each season (Winter or Summer), participants in WRAP need to demonstrate that they have obtained sufficient capacity to meet their P50 Peak Load plus an additional Planning Reserve Margin (PRM). The operational program occurs each day of the season with 7 days of consideration before said operating day and calculates if WRAP participants have a shortage or surplus of their resources. Additionally, the program looks at the larger forward showing forecast and compares it to a forecast consisting of a few days ahead. Based on these forecasts and if a participant is at a deficit or surplus there will be allocations of energy to ensure all participants meet their energy needs.

Franklin is currently participating in the WRAP non-binding program through the TEA Load Serving Entity (LSE) group. Participating as a single LSE allows Franklin to take advantage of the diversity benefit that is provided by aggregating obligations and resources with three other utilities who have load in different locations. While in a planned product contract such as Slice/Block Franklin is considered the Load Responsible Entity, under a Load Following contract, BPA would be WRAP LRE on Franklin's behalf. BPA made the decision to participate in the WRAP binding program in 2022.

3.5.1 Qualifying Capacity Contribution

Qualifying Capacity Contribution (QCC) is a vital metric in capacity planning, used to evaluate and quantify the reliable contribution of energy resources to the overall capacity mix. It specifically refers to the capacity of a resource that meets defined criteria to contribute to the energy supply or capacity needs of a system or grid. QCC considers factors such as resource availability, variability, and the capability to dispatch power as required. However, QCC assessments focus solely on evaluating the resource type and do not address associated transmission deliverability requirements. Table 3 shows the percentage of installed capacity by resource type for QCC requirements.

Table 3. WRAP QCC Capabilities by Resource Type

Month	Season	BPA Product	Wind (VER1)	Solar (VER1)	ESR / Hybrid (Mid-C)	Thermal / Geothermal (Mid-C)	RoR (Mid-C)
January	Winter	100%	6%	3%	86%	90%	15%
February	Winter	100%	9%	3%	82%	90%	22%
March	Winter	100%	14%	5%	100%	90%	36%
April	Spring						
May	Spring						
June	Summer	100%	23%	29%	100%	90%	60%
July	Summer	100%	16%	17%	77%	90%	59%
August	Summer	100%	14%	12%	88%	90%	50%
September	Summer	100%	11%	6%	88%	90%	45%
October	Fall						
November	Winter	100%	8%	1%	100%	90%	22%
December	Winter	100%	7%	3%	100%	90%	19%

The WRAP QCC is not fixed; it can be adjusted as the WRAP initiative develops. The WRAP specifically targets two seasons—winter and summer—to fulfill capacity requirements.

3.6 Federal Policies & Regulations

3.6.1 PURPA

The Public Utility Regulatory Policies Act of 1978 (PURPA) directs state regulatory authorities and non-FERC jurisdictional utilities (including FPUD) to consider certain standards for rate design and other utility procedures. FPUD is operating in compliance with these PURPA ratemaking requirements. The FERC could potentially assert jurisdiction over rates of licensees of hydroelectric projects and customers of such licensees under the Federal Power Act. The FERC has adopted maximum prices that may be charged for certain wholesale power. FPUD may be subject to certain provisions of the Energy Policy Act of 2005, relating to transmission reliability and non-discrimination. Under the Enabling Act, FPUD is required to establish, maintain, and collect rates or charges that shall be fair and nondiscriminatory and adequate to provide revenues sufficient for the payment of the principal of the interest on revenue obligations for which the payment has not otherwise been provided and for other purposes set forth in the Enabling Act.

PURPA established a new class of generating facilities known as qualifying facilities (QFs) which would receive special rate and regulatory treatment, including qualifying small power production facilities "of 80 MW or less whose primary energy source is renewable (hydro, wind or solar), biomass, waste, or geothermal resources."

The FERC defers to the states to determine the implementation of PURPA-based contracts, and this has had a significant impact on how many QFs have been built in each state. Idaho had a short-lived solar surge until the state PUC shortened the length of negotiated QF contracts from 20 years to 2 years. In June 2016, the Montana Public Service Commission (PSC) issued an emergency order suspending guaranteed PURPA contracts to small solar farms in response to a large number of applications from solar developers (as many as 130 solar projects). Oregon, however, has many PURPA facilities in the pipeline. In March 2016, the Oregon PUC decided to keep its 20-year guaranteed contracts in place with 15 years of fixed prices, which pleased renewable developers. Washington, on the other hand, doesn't have a required standard contract length for QFs. In addition, the depressed wholesale market prices (when compared to other markets) due to low-cost hydro makes the avoided cost of power too low for PURPA projects in Washington to be economically viable to developers. FPUD is currently a purchaser of RECs from Idaho PURPA solar generation facilities, which contribute to satisfying CPU's EIA renewable requirements.

The FERC announced its intention to review PURPA citing reports from utilities that developers may be unfairly applying PURPA rules to maximize economic returns. The FERC applies a test, known as the "one-mile rule," to determine whether adjacent facilities should be counted as one or multiple facilities. PURPA limits each facility's generation capacity to 80MW; thus, breaking a single large facility into multiple, smaller facilities increases the generation capacity allowance. The one-mile rule states that facilities located within one mile of each other are considered a single facility, whereas those greater than one mile apart are separate facilities. With wind plants stretched out over an extremely wide geographic footprint relative to other generation technologies, the FERC decided to review and clarify its one-mile rule. The rule is still under review as of the publication of this IRP.

3.6.2 Inflation Reduction Act (IRA)

On August 16th, 2022, President Biden signed the Inflation Reduction Act into law. The Act includes provisions for healthcare reform and clean energy investment, with a specific focus on the reduction of greenhouse gas emissions. The IRA allocates $370 billion for clean energy investments, supporting the development of carbon-free electricity generation through tax incentives, grants, and loan guarantees. The Act impacts numerous sectors including energy, manufacturing, environmental, transportation, agriculture, and water, with a primary focus on the electric industry.

The IRA extends investment tax credits (ITC) and production tax credits (PTC) to incentivize the creation of carbon-free resources and enable tax-exempt entities to maintain project ownership. The ITC is awarded based on the total investment upon project completion, while the PTC is paid over a decade based on the project's energy output. Both Sections 48E ITC and 45Y PTC offer technology-neutral credits for facilities with zero or negative greenhouse gas emissions. Facilities for new solar, wind, geothermal, and nuclear energy qualify for these tax credits, as do battery storage facilities for ITC.

Section 48E ITC: Section 48E of the U.S. tax code outlines a technology-neutral ITC for qualifying facilities constructed and operational after December 2024. The base ITC value for eligible energy projects is 6% of the capital investment upon project completion. This can be increased to 30% if the project meets certain prevailing wage and apprenticeship criteria. Additional bonus credits of 10% are available if the project complies with domestic content requirements and is located in an energy community area such as a brownfield or fossil fuel community.

Section 45Y PTC: Section 45Y of the U.S. tax code details a clean energy PTC paid over ten years for qualifying facilities constructed after December 31, 2024. The base PTC amount is 2.75 cents per kilowatt-hour (kWh) of electricity produced and sold, adjusted for inflation. If the project meets certain prevailing wage and registered apprenticeship criteria. Additional 10% bonus credits are available for projects meeting domestic content requirements and for those located in a designated energy community area.

A significant provision of the IRA allows direct payments to nonprofit organizations like municipal electric utilities instead of tax credits. This shift from the previous system, where municipal utilities had to sign a Power Purchase Agreement (PPA) with a renewable developer to receive the tax credit, allows entities like FPUD to develop a self-build renewable project and receive PTC or ITC credits. However, for this study, TEA modeled FPUD renewable participation as PPA agreements.

3.6.3 Renewable Electricity Production Tax Credit (PTC)

The federal renewable electricity production tax credit (PTC) is an inflation-adjusted per-kilowatt-hour (kWh) tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year. The duration of the credit is 10 years after the date the facility is placed in service for all facilities placed in service after August 8, 2005. The PTC for generators with a construction commencement vintage of 2017 was $19/MWh. That rate will be reduced to approximately $14.25/MWh for generators with a 2018 vintage and $9.50/MWh for those with a 2019 vintage. The PTC for new wind construction was sunset entirely by the end of 2019 before being extended until the end of 2020 and restored to $9.50/MWh for facilities that start construction during the 2020 calendar year.

Originally enacted in 1992, the PTC has been renewed and expanded numerous times, most recently by the Inflation Reduction Act of 2022 as described in section 3.6.2. Previously it had been extended by the American Recovery and Reinvestment Act of 2009 (H.R. 1 Div. B, Section 1101 & 1102) in February 2009 (often referred to as "ARRA"), the American Taxpayer Relief Act of 2012 (H.R. 8, Sec. 407) in January 2013, the Tax Increase Prevention Act of 2014 (H.R. 5771, Sec. 155) in December 2014, and the Consolidated Appropriations Act, 2016 (H.R. 2029, Sec. 301) in December 2015, and the Taxpayer Certainty and Disaster Tax Relief Act of 2019.

3.6.4 Renewable Energy Investment Tax Credit (ITC)

The Renewable Energy Investment Tax Credit (ITC) allows taxpayers to claim a credit for expenditure on renewable generation assets installed on homes owned and lived in by the taxpayer. The taxpayer can elect whether to use the ITC or the PTC to best fit their needs. The ITC may be preferable in locations with lower expected generation as the ITC is not dependent on the unit's generation.

Expenditures with respect to the equipment are treated as made when the installation is completed. If the installation is at a new home, the "placed in service" date is the date of occupancy by the homeowner. Qualified expenditures include labor costs for on-site preparation, assembly, original system installation, and for piping or wiring to interconnect a system to the home. If the federal ITC exceeds tax liability, the excess amount may be carried forward to the succeeding taxable year.

Most recently, the ITC has been expanded by the 2022 Inflation Reduction Act as described in section 3.6.4.

Section 4 Load Forecast

4.1 Load Forecast Summary

Projected system load is the amount of electric energy FPUD's customers require for heating, lighting, motors, and other end-uses prior to accounting for conservation, demand response, rooftop solar, and other distribution system resources. The load forecasts for FPUD used in this study were developed using historical load, weather, and econometric data for Franklin County for the period from 1970 to 2024. Unlike previous IRP analyses, this IRP developed a load forecast down to the hourly level to better capture the challenges presented by integrating a high volume of renewables in a capacity-short market environment.

A linear regression model was trained to forecast annual load growth at monthly granularity through 2044 based on econometric forecasts by Woods and Poole. A non-linear regression machine learning model was then trained to resolve the forecast down to hourly demand over the study time horizon. Forecasts for the rate of building and vehicle electrification were then added. Low and high load scenarios were then developed at matching hourly granularity based on the range of historical growth rates. These scenarios are used to understand FPUD's power resource needs under different futures.

4.2 Monthly Forecast

The monthly load forecast incorporates the long-term impacts of economic demographics according to the steps below:

1. 20 years of historical monthly system total and peak load data (2003-2022) was collected from data provided by Franklin.
2. 20 years of historical weather data for the KPSC weather station (Jan. 2004 – Jan. 2024) was collected from DTN weather. A normalized weather pattern based on temperature was determined using the rank and median method and applied to historical years and forecast horizon years. For both the historical and normalized weather data, heating and cooling degree days were then calculated using the formula below for each day. For hours with temperatures above 65˚ F, heating degree days were set to zero. This same methodology was used for cooling degree days in hours with temperatures below 65˚ F. These heating and cooling degree days were then summed to the monthly level.

$$Cooling\ Degree\ Day = \sum \frac{(Hourly\ Temperature - 65^{\circ}\ F)}{24}$$
$$Heating\ Degree\ Day = \sum \frac{(65^{\circ}\ F - Hourly\ Temperature)}{24}$$

3. Econometric data for Franklin County was obtained from Woods & Poole's 2022 Complete Economic and Demographic Data Source[1]. This dataset included both historical data from 1970 to 2022 and forecasted data extending from 2023 to 2060. Eight different economic metrics for Franklin County were obtained and total number of households was determined to have the best fit to the historical load data when weather normalized. **Error! Reference source not found.** below shows the total number of households in F ranklin County.

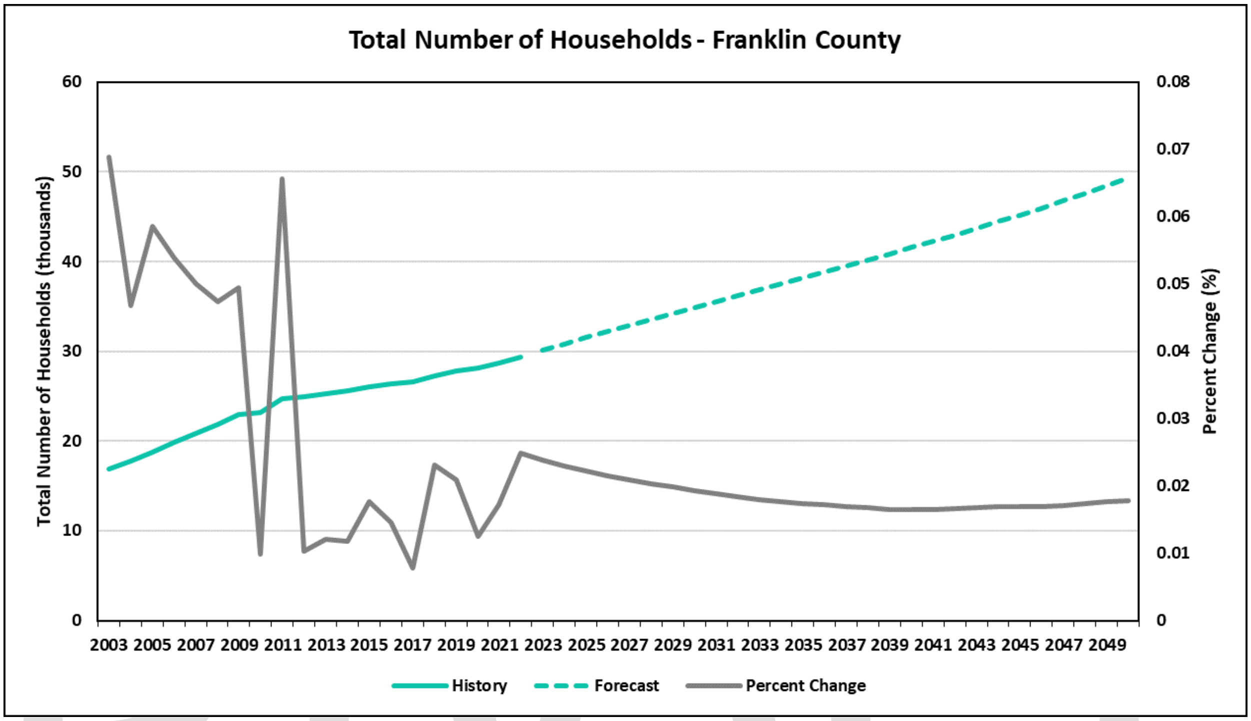


Figure 1. History and Forecast of Total Number of Households in Franklin County 2003 – 2050

4. Linear regression models were trained for predicting total and peak monthly load using the month of the year, historical heating/cooling degree days, and historical number of households.
5. These regression models were then used to project total and peak monthly load using the month of year, normalized weather, and economic projections for number of households in Franklin County. Figure 2 below is a visual of annual total and peak load calculated from the monthly history and regression model projections.

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[1] **Woods & Poole Economics, Inc.** "2022 Complete Economic and Demographic Data Source (CEDDS)®." 2022. Woods & Poole Economics, Inc. Accessed, 2023. https://www.woodsandpoole.com/our-databases/united-states/cedds/.

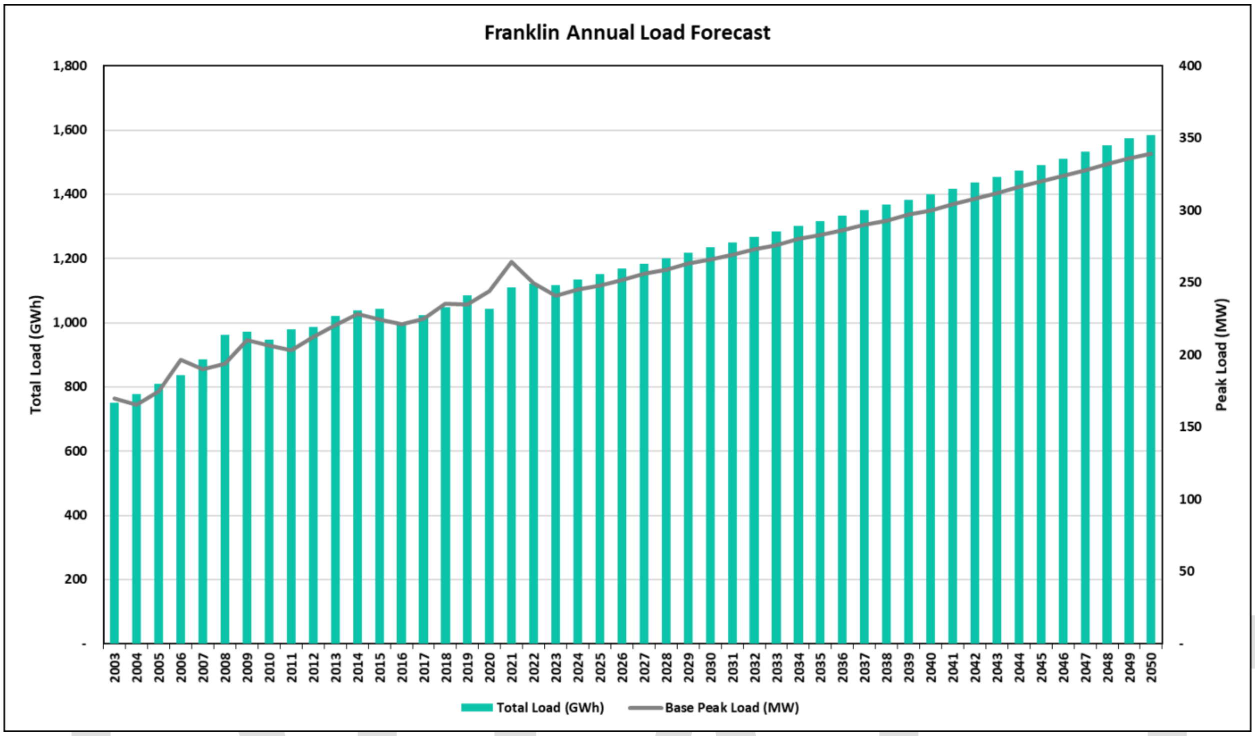


Figure 2. FPUD annual load history and forecast from 2003 – 2050

4.3 Hourly Forecast

The hourly load forecast was developed with the following steps:

1. Hourly historical meter-level load data was obtained for the last 5 years of load history. This CPOD level data was aggregated to calculate hourly system historical load for 2018-2022.
2. Hourly historical weather data for the KPSC weather station was collected from DTN weather. 10 years of historical weather data was then used to calculate hourly normalized weather using the rank and median method for the forecast horizon.
3. A non-linear machine learning model (GBM) was trained to predict load values given the historical weather data, actual system load, and time series features including hour of the day, month, and day of the week.
4. The trained model was then used to predict future load using the normalized weather forecast.
5. The hourly forecasted load was then fitted to the monthly total and peak load projections shown in the previous section. This was done to ensure congruency between the two predictions, since this hourly model has no feature which incorporates long-term load growth.

4.4 New Load Additions

Several large new customers are expected to begin service with Franklin PUD over the next few years. These expected new loads were added into the load forecast after the base forecast was developed. For simplicity, these new customers are assumed to have a flat load shape, consuming the same amount of energy every hour after beginning service. The impact of these new load additions on the projected peak and total load is shown in Figure 3 below.

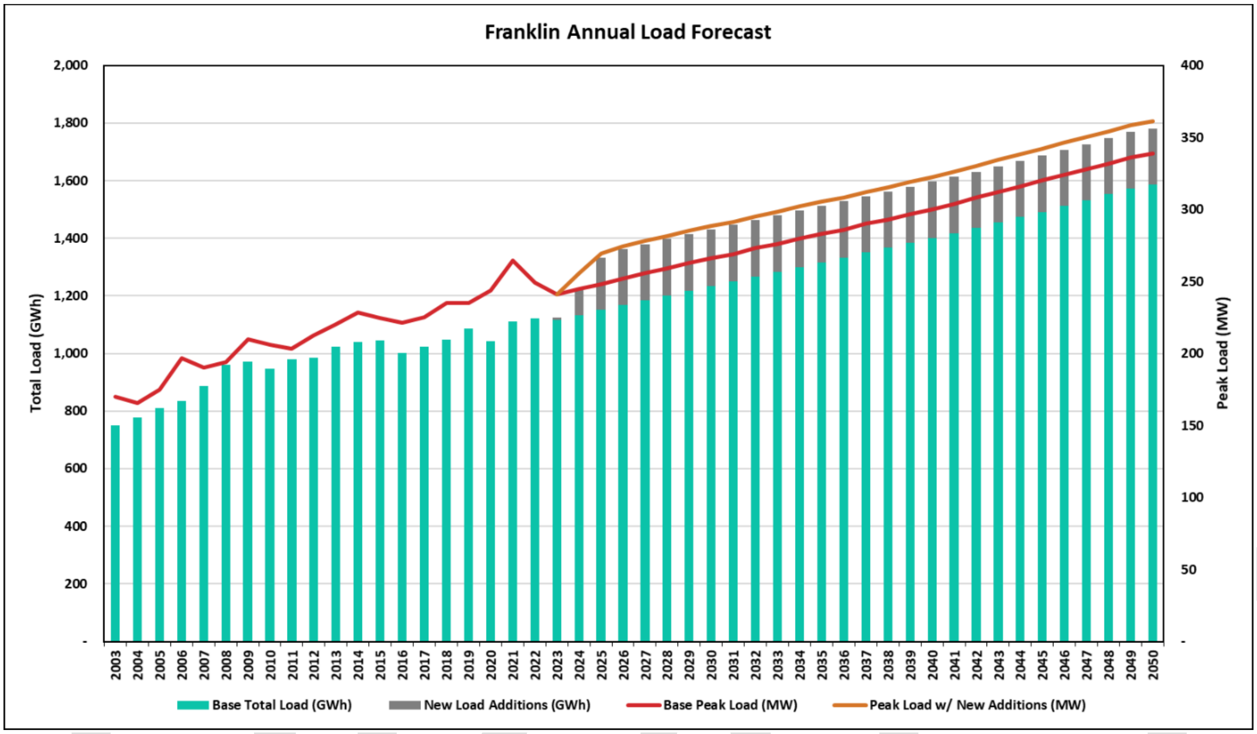


Figure 3. FPUD annual load history and forecast from 2003 - 2050 with new load additions

4.5 EV Forecast Methodology

The electric vehicle (EV) charging load forecast was developed separately and added on top of the base load forecast using the steps below.

1) A regression model was trained to project EVs as a percentage of total vehicles on the road by year. State-level data on the percentage of EVs on the road for 5 different years was sourced from S&P Global[2]. Additionally, economic projections of income per capita by state were obtained from Woods & Poole. The economic projections were assumed to be the primary driver in EV growth, particularly in the near-term. After model training using this state-level data, annual per-capita income projections for Franklin County, Washington were then input into the regression model to project the percentage of vehicles on the road that are EVs. These percentages were multiplied by the total number of vehicles on the road, obtained for Franklin County from Washington Department of Transportation data[3].

[2] **S&P Global Mobility.** "State Electric Vehicle Forecast." S&P Global Mobility. Accessed Apr., 2023. https://www.spglobal.com/mobility/en/index.html.

[3] **Washington State Department of Transportation.** "Registration Activity by Fiscal Year and Primary Use." data.wa.gov. Accessed Jan, 2024. https://data.wa.gov/Transportation/Registration-Activity-by-Fiscal-Year-and-Primary-U/f8kb-pm6f.

2) The EVI-Pro Lite tool from the National Renewable Energy Laboratory (NREL) provides an hourly charging load shape[4]. This tool requires several inputs, listed below.
    a) EV count projections by year, obtained from the previous step.
    b) Average temperature, which is varied by month depending on the average monthly temperature from the last 10 years at the Pasco/Tri Cities Airport (KPSC).
    c) Average miles traveled per day for an EV owner – assumed to be 35 miles.
    d) Full EV vs. plug-in hybrid – assumed to be an even split between the two.
    e) EV Sedans vs SUVs – assumed to favor sedans.
    f) Assumed EV owners who have access to a home charger and prefer to charge at home, both assumed to be 100%.
    g) Charger type, assumed to be an even split between level 1 and level 2 for home chargers and favor level 2 for public chargers.
    h) Charging strategy – assume customer charging behavior pattern follows immediate strategy, where customers charge their vehicles as quickly as possible once plugged in.
3) The EVI-Pro Lite tool provided the output of the hourly EV charging shape given the assumptions above. This hourly forecast was then added on top of the base load forecast, enabling the load forecast to be available with and without forecast EV charging impacts. The below figure shows the annual energy and peak load resulted by EVs for Franklin County. Figure 4**Error! Reference source not found.** below shows FPUD's annual load from 2003 through 2050 after including new load additions and EV charging load.

[4] **National Renewable Energy Laboratory (NREL).** "EVI-Pro Lite Tool." NREL. Accessed May 2023. https://www.nrel.gov/transportation/evi-pro.html.

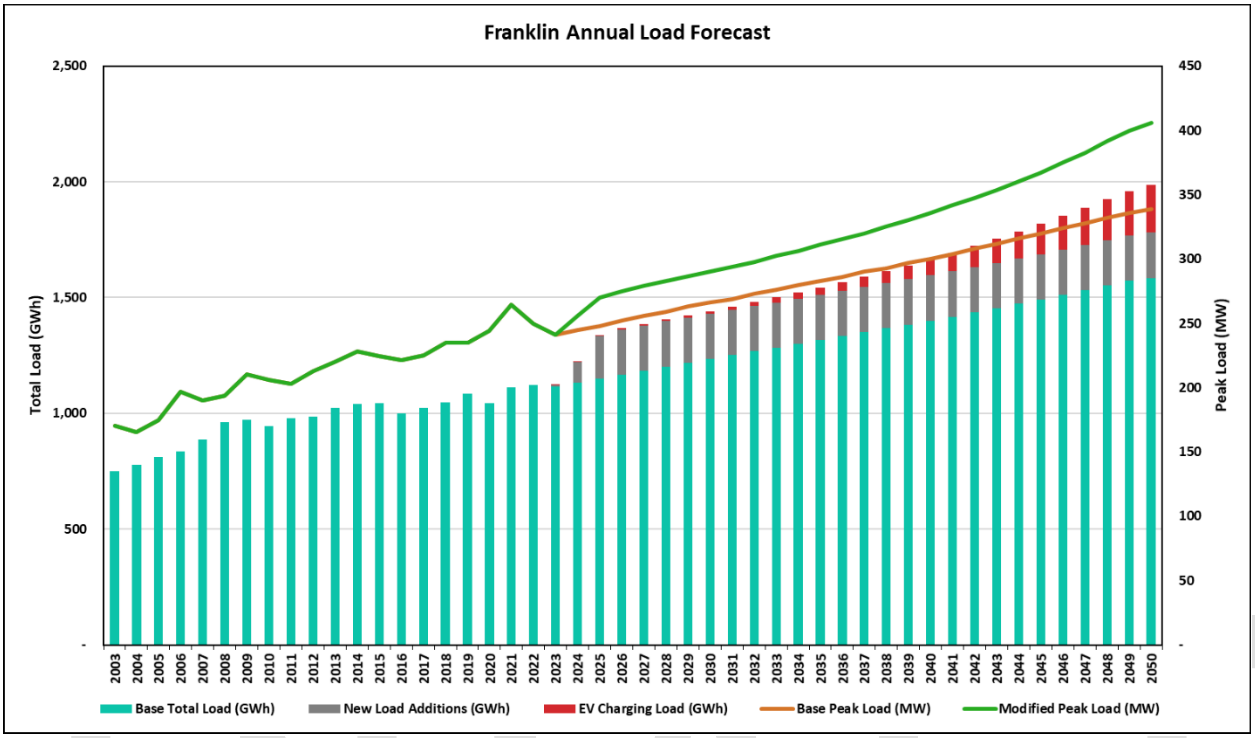


Figure 4. FPUD Load from 2003 - 2050 with New Load Additions and EV Charging Load

4.6 High and Low Load Scenarios

In addition to the base load scenario (the expected case), high and low scenarios are provided to account for uncertainties and multiple possible futures in the forecast model. Figure 5 below shows the base, high, and low energy forecasts. Figure 6 shows the base, high, and low peak demand forecasts.

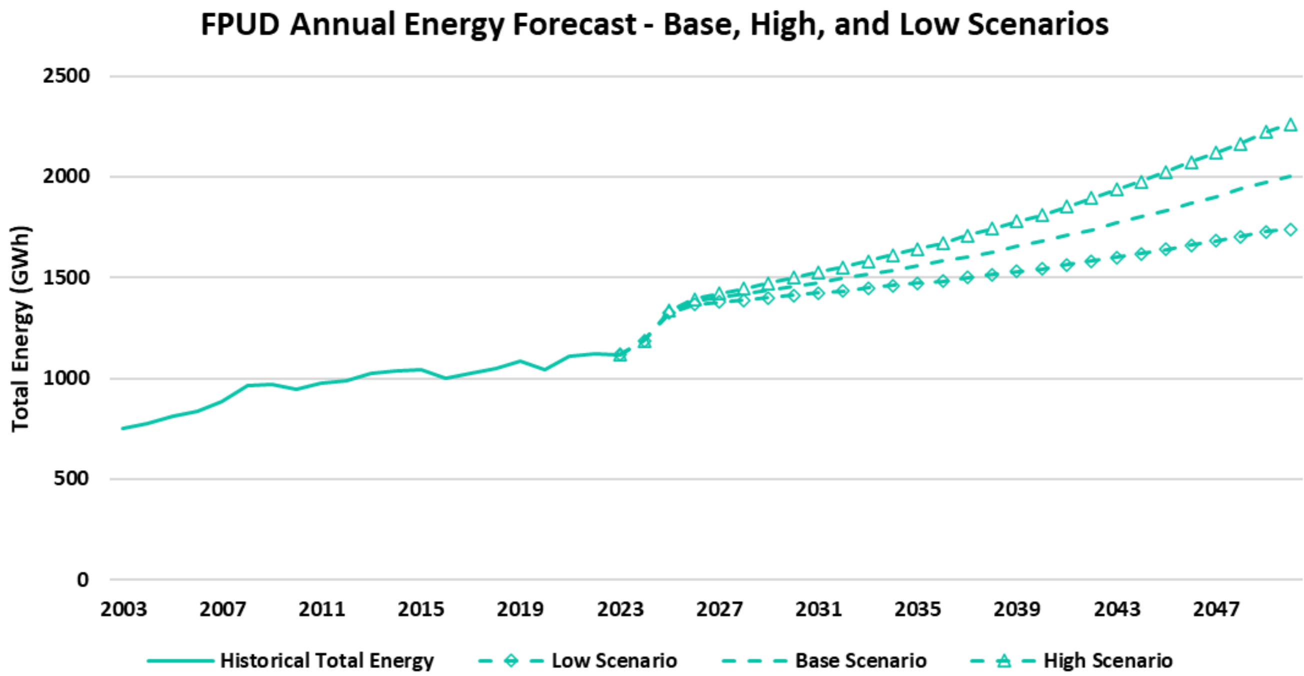


Figure 5. FPUD Annual Load Forecast Scenarios

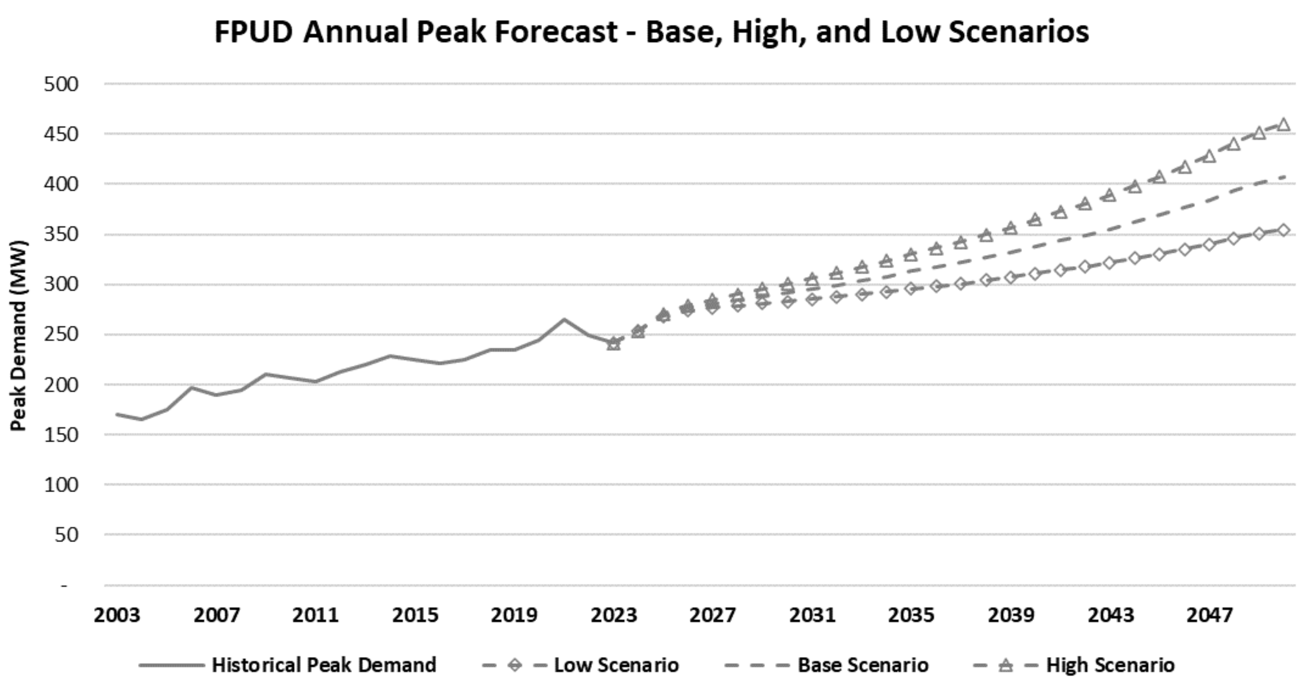


Figure 6. FPUD Annual Peak Demand Forecast Scenarios

Additionally, Table 4 below provides the annual projected growth rates and year-over-year change for different scenarios.

Table 4. FPUD Annual Load Forecast Scenarios

	Low Scenario				Base Scenario				High Scenario			
	Total Energy (GWh)		Peak Demand (MW)		Total Energy (GWh)		Peak Demand (MW)		Total Energy (GWh)		Peak Demand (MW)	
Year	Forecast	YoY Change	Forecast	YoY Change	Forecast	YoY Change	Forecast	YoY Change	Forecast	YoY Change	Forecast	YoY Change
2025	1,323		268		1,329		270		1,336		271	
2026	1,367	3.4%	274	2.1%	1,381	3.9%	277	2.6%	1,395	4.4%	279	3.1%
2027	1,379	0.9%	277	1.0%	1,400	1.4%	281	1.5%	1,421	1.9%	285	2.0%
2028	1,387	0.6%	279	0.7%	1,419	1.4%	284	1.3%	1,444	1.6%	290	1.7%
2029	1,401	1.0%	281	0.9%	1,437	1.2%	288	1.4%	1,473	2.0%	296	1.9%
2030	1,412	0.8%	283	0.7%	1,455	1.3%	292	1.2%	1,499	1.8%	300	1.7%
2031	1,423	0.8%	285	0.8%	1,474	1.3%	296	1.4%	1,526	1.8%	306	1.9%
2032	1,432	0.6%	288	0.8%	1,495	1.4%	300	1.3%	1,551	1.6%	312	1.8%
2033	1,447	1.0%	290	1.0%	1,515	1.3%	304	1.5%	1,583	2.1%	318	2.0%
2034	1,459	0.9%	293	0.8%	1,536	1.4%	308	1.3%	1,613	1.9%	323	1.8%
2035	1,472	0.9%	296	1.1%	1,557	1.4%	313	1.6%	1,643	1.9%	330	2.1%
2036	1,482	0.7%	298	0.8%	1,581	1.5%	317	1.3%	1,671	1.7%	336	1.8%
2037	1,499	1.2%	301	0.8%	1,604	1.4%	322	1.4%	1,708	2.2%	342	1.8%
2038	1,514	1.0%	304	1.2%	1,628	1.5%	327	1.7%	1,742	2.0%	350	2.2%
2039	1,530	1.0%	307	0.9%	1,654	1.6%	332	1.4%	1,778	2.0%	357	1.9%
2040	1,543	0.8%	311	1.2%	1,681	1.7%	338	1.8%	1,811	1.9%	365	2.3%
2041	1,563	1.3%	314	1.2%	1,708	1.6%	344	1.8%	1,853	2.3%	373	2.2%
2042	1,581	1.2%	318	1.0%	1,738	1.7%	349	1.5%	1,894	2.2%	380	2.0%
2043	1,600	1.2%	322	1.3%	1,768	1.8%	355	1.8%	1,937	2.2%	389	2.3%
2044	1,617	1.0%	326	1.3%	1,801	1.9%	362	1.9%	1,976	2.1%	398	2.3%
2045	1,641	1.5%	330	1.3%	1,833	1.8%	369	1.9%	2,025	2.5%	408	2.4%
2046	1,662	1.3%	335	1.5%	1,867	1.8%	377	2.1%	2,072	2.3%	418	2.5%
2047	1,683	1.3%	340	1.5%	1,902	1.9%	384	2.1%	2,121	2.3%	429	2.6%
2048	1,702	1.1%	346	1.7%	1,939	2.0%	393	2.3%	2,166	2.1%	441	2.8%
2049	1,727	1.5%	351	1.5%	1,974	1.8%	401	2.0%	2,221	2.5%	452	2.5%
2050	1,741	0.8%	354	0.9%	2,001	1.4%	407	1.5%	2,261	1.8%	460	1.9%

Section 5 Current Resources

5.1 Overview of Existing BPA Resources

About 75% of FPUD's power is currently supplied through its Slice/Block agreement with the Bonneville Power Administration (BPA), the federal agency that markets the Federal Columbia River Power System (FCRPS). The FCRPS is managed and operated by a collaboration of three federal agencies: BPA, the U.S. Army Corps of Engineers (Corps of Engineers), and the Bureau of Reclamation. It consists of 31 multipurpose hydroelectric dams, the Columbia Generating Station, and a small amount of generation from contracts with wind farms. The dams provide the region with power generation, flood control, protection of migrating fish, irrigation, navigation, and recreation. Inside the dams are hundreds of turbines, the largest of which can generate 800 MW. The FCRPS has an aggregate generation capacity of 22,060 MW (Bonneville Power Administration, n.d.). Due to the size of the system, up to 10,000 MW of generation capacity can be offline for maintenance at any given time. Hydroelectric generation is variable by nature and fluctuates with overall water supply conditions. Electricity production is highly correlated to overall hydrological conditions, i.e. higher precipitation years generally equate to higher power generation years and vice versa. Hydrological conditions are catalogued by measuring the quantity of water runoff at a specific point for a specific period. BPA water years, which begin in October and end in September, are categorized by total water runoff in million acre-feet (MAF) at The Dalles between January and July. Hydrological conditions at The Dalles have been recorded since 1929. In that period, total runoff has varied between 53.3 MAF in 1977 and 158.9 MAF in 1997. The variability that can be seen from year to year (1949-2023) is illustrated in Figure 7.

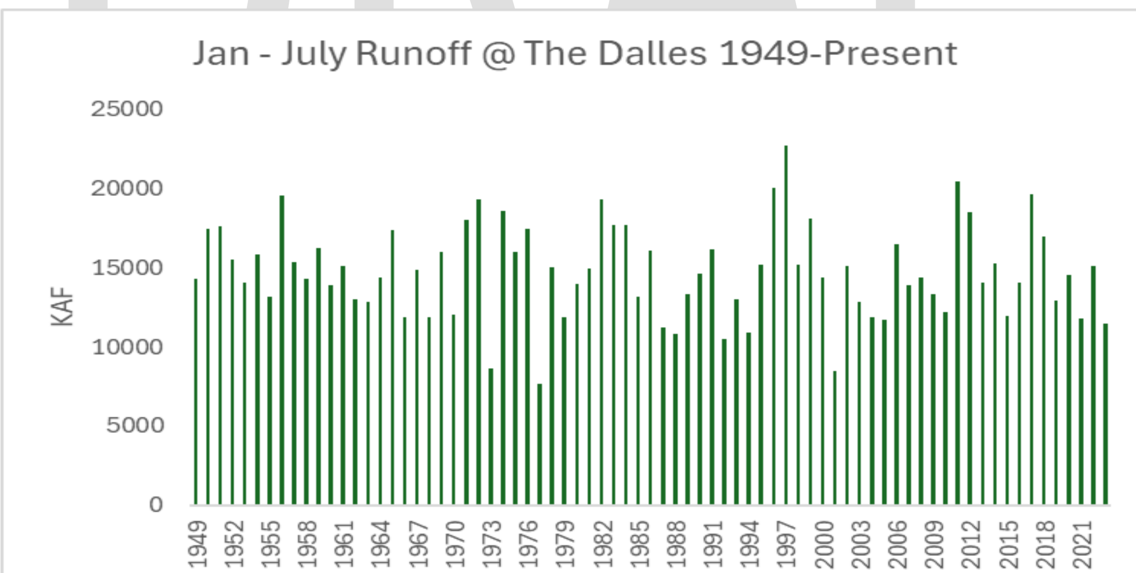


Figure 7. Historical Water Years (1949-2023)

The 1937 water year streamflows represented the worst (lowest) on record and was chosen as the benchmark "critical water" year to represents baseline system capability. Until 2022, BPA conservatively measured the system capability by determining its average annual energy output in critical water conditions. In October 2022, BPA shifted from using the 1937 water year to using a "P10" approach for determining the firm generation for the federal system. In this approach, the monthly 10th percentile of the most recent 30 years of streamflows are used to set the firm generation expectation. This change in methodology is intended to capture the impact of climate change on system generation, and it resulted in an 87 average megawatt decrease in annual generation.

As a BPA Slice/Block customer, FPUD receives a fixed monthly block of guaranteed generation and a variable allotment (Slice) of the Federal Columbia River Power System (FCRPS) output. The Slice portion is an allocated share of the total FCRPS for FPUD to operate and manage to serve FPUD's load while observing constraints for with water conditions, fish migration and spawning, migratory bird considerations, and flood control. BPA Tier 1 customers' FCRPS power allocation is referred to as the Contract High Water Mark (CHWM). CHWMs under the current contract were calculated to achieve load-resource balance between Tier 1 energy and a utility's 2010 adjusted loads less the utility's resources used to serve load (dedicated resources). The amount of power a Tier 1 customer is entitled to purchase in each rate period is then adjusted from the CHWM for any changes in FCRPS capability and is referred to as the Rate Period High Water Mark (RHWM). FPUD's share of annual Slice output is roughly 72 aMW in an average water year but can vary substantially depending on hydrological conditions. This source of power is assumed to be 94% clean and CETA compliant based on BPA's fuel mix report from 2021-2023.

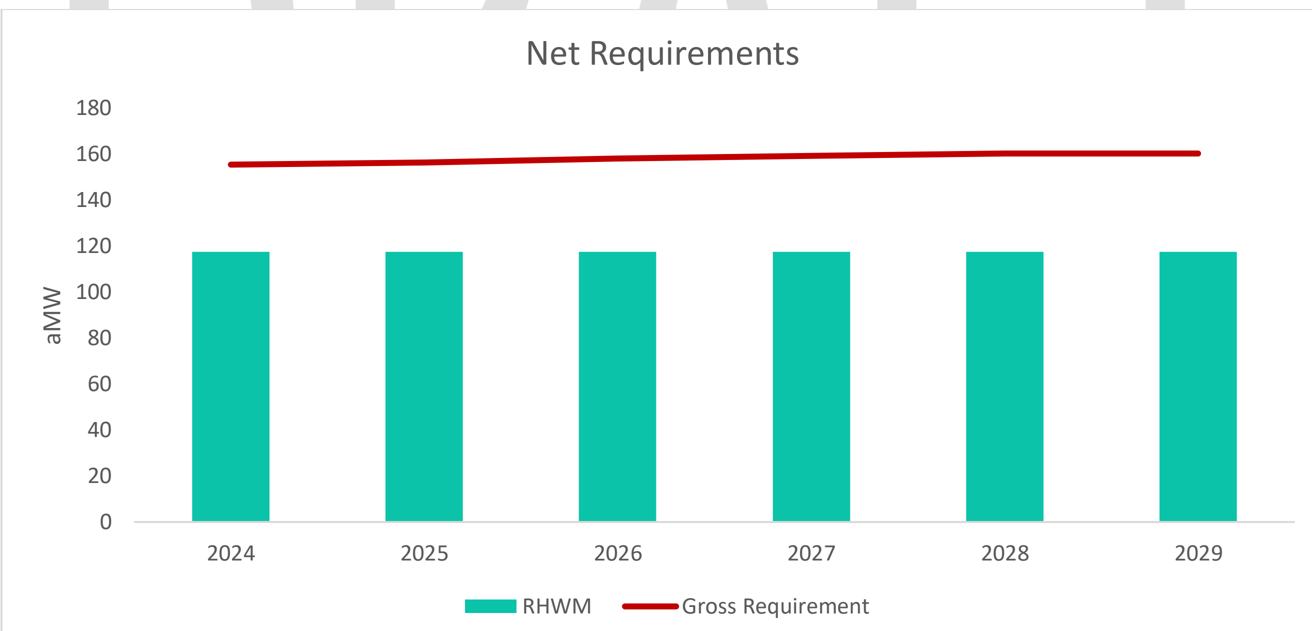


Figure 8. Retail Load vs. BPA Contract High Water Mark

The system allocation is calculated by dividing a utility's RHWM (or net requirements, whichever is lower) by the sum of all utilities RHWM (which is approximately equal to the Tier 1 system capability under critical hydrological conditions) resulting in a Tier One Cost Allocator (TOCA).

The Tier 1 rate is based on the cost of the existing federal system with very little augmentation. If preference customers choose to buy more power from BPA beyond their RHWM, this power is sold at a Tier 2 rate, which fully recovers BPA's incremental costs of securing additional resources to serve this load. Major components of the Tiered Rate Methodology include:

- ✓ Tier 1 priced at cost of existing system
- ✓ Tier 2 priced at marginal cost of new BPA purchases and/or acquisitions (i.e., equal to the cost of market or new resource)
- ✓ Public utilities can buy from BPA at Tier 2 rates, or acquire their own resources, to serve loads in excess of their HWM

The Slice/Block product is divided into two components: fixed and variable. The fixed component, or "Block," is a known and guaranteed quantity of power that FPUD receives from BPA, irrespective of the hydro conditions. Whether it is a critical water year or the highest on record, the quantity of Block power that BPA delivers to FPUD does not change. The power is shaped in advance into monthly blocks, which follows FPUD's monthly load profile. In other words, more Block power is delivered in higher load months; the converse is also true. The average energy output from the Slice system is expected to average 8,100 MW for the current two-year rate period, but daily generation will fluctuate from between 4,000 MW to greater than 15,000 MW. The FCRPS is a multipurpose system and power generation achieves only one of the system's goals. The need to fulfill other system obligations, such as fish migration, navigation, and flood control may at times compete with the power generation aspect of the river system. It may require the dams to hold back water when additional power generation may be beneficial or release additional water through the dams when there is already too much power available. FPUD accepts these operational risks as a Slice customer. It accepts fluctuations in actual federal system output and takes responsibility for managing its percentage share of the federal system output to serve its load. There is no guarantee that the amount of Slice output made available, combined with the firm Block power, will be sufficient to meet load obligations, be it hourly, daily, weekly, monthly, or annually. Being a Slice customer requires FPUD to, at times, fulfill its load obligations with resources other than what is provided by BPA and FPUD's contracted non-federal resources.

5.1.1 BPA POST-2028 PRODUCT OPTIONS

Figure 9 shows BPA's Provider of Choice (POC) Timeline updated June 2024. Source: BPA Provider of Choice

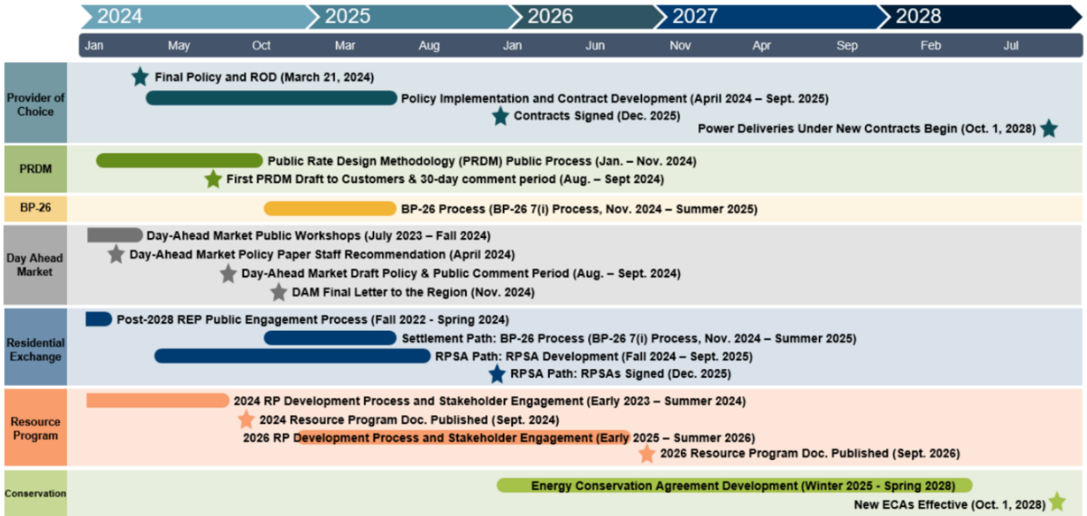


Figure 9. BPA's Provider of Choice (POC) Timeline

BPA's goal is that preference customers execute new power contracts by the end of 2025. As of the time the IRP, BPA has three main product options which include Load Following, Block Products, and Slice/Block.

Bonneville will continue offer the Load Following product in Provider of Choice (POC), which will serve a utilities' hourly energy and peak net requirements load. The Load Following product is not expected to change materially under POC. Load Following customers will continue to have load service certainty, and BPA will continue to require resource shaping services to integrate non-federal resources that have been declared to serve load.

BPA will continue to offer the Block Product which provides a planned amount of firm power to meet a utilities' Net Requirements. The Block Product will be offered in a flat annual amount, a monthly shaped amount, and a Block with Shaping Capacity option. BPA has made significant changes to the Block with Shaping Capacity product which was not selected by any utility under the Regional Dialogue (RD) contract. As proposed at the time of the IRP, the Block with Shaping Product provides a monthly volume that is shaped to the customer's load. These MWhs may be shaped by the utility prior to the Day-Ahead Market based on a fixed set of criteria including a maximum hourly volume, and minimum hourly volume, and a half-month usage constraint. Additionally, BPA has proposed offering a Peak Load Variance Service which will provide capacity up to a customer's P10 Load. BPA has not yet indicated how P10 load will be defined.

The Block with Shaping Capacity product as proposed appears to be a viable option for consideration given a similar risk profile to Load Following but better flexibility to integrate non-federal resources than Load Following. However, the viability of this product is contingent on how BPA chooses to define specific elements of the product, particularly the Peak Load Variance Service offering.

BPA has stated that they intend to continue to offer the Slice/Block product. However, Bonneville has suggested that they require that a sufficient group of customers indicate interest in Slice/Block to continue developing the product. At the time of the IRP, BPA's proposed POC Slice/Block Product is similarly structured to the RD Slice product, and differences between the two contracts largely stem from changes that BPA view as necessary to apply the product in an organized market. As with the current contract, the block portion of the contract provides a fixed amount of power, and the slice portion of the contract is based on a percentage share of BPA's generation resources. This share fluctuates based on the generation output of BPA's generation assets which predominately consist of the hydroelectric projects that make up the Federal Columbia River Power System (FCRPS) and the Columbia Generating Station nuclear facility. Unlike the RD Slice product, BPA proposes that in POC Slice, the schedule be locked down on a day-ahead basis and may not be changed in real-time.

At the time of the IRP, BPA has floated the concept of adding "Federal Surplus" to a Block with Shaping Capacity Product. This concept is in its infancy, and there is not certainty whether Bonneville will offer this option. However, a Block with Shaping Capacity Product with Federal Surplus may prove to be a viable option for consideration given its potential for a similar risk profile to Load Following and similar flexibility to Slice.

5.2 Product Comparison

This section provides a summary of the products that BPA is considering offering to its customer utilities at the time of the IRP.

Proposed Product Attributes

Product	Fit to Load Shape	Anticipated Capacity Specific Charges	Capacity Provided above P50	Non-Fed Resource Flexibility	PNR Check
Slice/Block	Least	No Embedded	System Dependent	Yes	No @ 50/50
Block: Stand-Alone	Partial	No Embedded	No	Yes	No
Block: w/Shaping Capacity	Partial	Yes Embedded +	No	Yes	≤XX% No >XX% Yes
NEW! Block: w/ Shaping Capacity + Peak Load Variance Service	Partial	Yes Embedded ++	Yes	Yes	Yes
Load Following	Most	Yes Embedded ++	Yes	Limited	No

5.2.1 Cost Comparison

At the time of the IRP, the Public Rate Design Methodology (PRDM) for the Provider of Choice contracts has yet to be finalized, so there will not be certainty regarding how the products compare from a rate standpoint until mid-2025. In general, all products will have similar costs in the long-term, given that BPA's rate design is intended to provide mechanisms for adjustments based on actual costs. While the costs are expected to be similar overall, there are some key differences in rate structure between the three products including capacity or demand charges and resource integration or Resource Support Services (RSS) charges. Slice/Block and Standalone Block, as proposed at the time of the IRP, have no anticipated charges for capacity or demand. This means that a utility would be responsible for meeting their net requirements load and capacity requirements in excess of the capability of the selected BPA Tier 1 product with non-federal resources or market mechanisms.

5.2.2 WRAP Comparison

Under a Load Following contract, BPA would be the Load Responsible Entity (LRE) under WRAP. Alternatively, for planned product options such as Slice/Block and Block with Shaping, FPUD would be the LRE. Peak Load Variance Service (PLVS) has been proposed as an add on to the Block with Shaping Capacity product to provide capacity up to a P10 load. At the time of writing, it is unclear exactly how much capacity PLVS would provide to FPUD. The Slice/Block product is anticipated to provide capacity based on the WRAP QCC of the FCRPS. FPUD is anticipated to need to purchase additional capacity providing resources to serve above-HWM load regardless of product choice. The Slice product is anticipated to provide the least amount of capacity out of all three products, so to be WRAP compliant with this product, FPUD would need to add significant capacity resources (see Figure 10).

5.3 Columbia Generating Station

The largest non-hydro generation asset is the Columbia Generating Station (CGS) located in Richland, WA, with a generation capacity of 1,190MW. It is owned and operated by Energy Northwest (ENW), a joint operating agency that consists of 28 public utilities in Washington State. FPUD's share of output from CGS is equivalent to its Slice system allocation.

5.4 Nine Canyon Wind Project

The Nine Canyon Wind Project is an Energy Northwest-owned wind generation resource situated on dryland wheat farms approximately eight miles southeast of Kennewick in the Horse Heaven Hills. Phase I of the project consists of 37 wind turbines, with a total capacity of 48 MW. Phase II consists of an additional 12 wind turbines, totaling 15.6 MW of capacity. Phase III consists of 14 wind turbines with a total capacity of 32 MW. The aggregate capacity of the Project is 95.6 MW.

Franklin PUD entered into a power purchase agreement with Energy Northwest for 10.5 percent of the generation capacity of the project, including the environmental attributes it produces, that extends through June 2030, and the IRP assumes this contract will extend through the study period. These attributes will help Franklin PUD fulfill its EIA renewable requirements. Nine Canyon has an expected capacity factor of 30 percent, also equating to an average energy output of 3 aMW.

5.5 White Creek Wind Project

Located just northwest of Roosevelt, WA in Klickitat County, the White Creek Wind Project consists of 89 turbines, each with 2.3 MW of capacity, with a combined capacity of 205 MW. It came online and began generating electricity in November 2007. White Creek provides renewable energy and environmental attributes that will help Franklin PUD meet its Energy independence Act (EIA) renewable requirements. Franklin PUD has contractual rights to a portion of the project's output, including all associated environmental attributes, through 2027.

With a capacity factor of around 30 percent, Franklin PUD receives an average energy output of 3 aMW from the project.

5.6 Packwood Lake Hydroelectric Project

The Packwood Lake Hydroelectric Project has a generation capacity of 27.5 MW, a firm output of 7 aMW, and an average output of approximately 10 aMW. It is owned and operated by Energy Northwest, but 12 Washington PUDs are participants in the project with "ownership-like" rights. It is located 5 miles east of Packwood, Washington in Gifford Pinchot National Forest. Franklin PUD receives a 10.5% share of the output from the project, .7 aMW under critical water conditions, and approximately 1.3 aMW under average water. The project does not qualify as a renewable resource and does not help Franklin PUD meet its obligations under the EIA.

5.7 Esquatzel Canal Hydro Project

The Esquatzel Canal, which discharges into the Columbia River, is located about 5 miles north of Pasco, in Franklin County. In 2011, Green Energy Today, LLC installed a hydroelectric generation turbine at the confluence of the canal and the Columbia River to capture the kinetic energy of the flowing water and convert it into electricity. Franklin PUD purchased all of the rights to the power and environmental attributes generated by the .9 MW Esquatzel Canal Hydroelectric Project through 2031, and has an option to extend the contract. The IRP therefore assumes that Esquatzel will remain as a resource through the study period. The project produces roughly 6,000 MWh of power annually.

Esquatzel is a run of the river project. Its generation cannot be turned on and off since neither Green Energy Today nor Franklin PUD controls the timing or quantity of water flows through the canal. Esquatzel is an EIA eligible renewable resource, and because its generating capacity is less than 5 megawatts, it is also classified as "distributed generation," which allows its environmental attributes (RECs) to count double.

5.8 PowerEx Hydro PPA

In 2020, the District signed a PPA with PowerEx Corporation, the marketing arm of BC Hydro, for a hydro energy purchase of 40 MW around-the-clock for the 3rd Quarter period (July through September) and 25 MW around-the-clock for all other months of the year. The PPA began in July 2023 and continues through the end of 2028, with an option to extend the contract upon mutual approval.

5.9 Solar PPAs

FPUD is in the process of potentially adding approximately 60 MW of nameplate solar capacity (approximately 13 aMW of annual generation) through participation in the Ruby Flats and Palouse Junction projects. Both solar projects are expected to begin producing power in 2026, are 100 percent carbon-free, and qualify as renewable energy under the EIA and CETA.

5.10 Conservation

Franklin PUD has been actively engaged in conservation/energy efficiency resources for 30 years. Since 2002, the District's programs have resulted in the acquisition of over 10 aMW of conservation resources. More emphasis will be focused on conservation planning and acquisition in the future. Along with a renewable portfolio requirement, the EIA requires that qualifying utilities pursue all cost-effective conservation. For the sake of this IRP, cost effective conservation is assumed to be implicit in the load forecast and is therefore not treated separately as a resource to avoid double counting.

5.11 Existing Transmission

BPA Transmission Services (BPAT) as the Balancing Authority (BA) is the entity obligated to meet FPUD's peak load. Each BPA Slice customer sets aside and cannot access its share of Slice capacity to allow BPAT to meet all its within hour requirements. This includes regulation, imbalance, and contingency reserves (spinning and supplemental). BPAT reimburses BPA Power (BPAP) for any revenues it receives from use of this capacity. These revenues include regulation, imbalance charges, Contingency Reserves, and both Variable and Dispatchable Energy Resources Balancing Service charges (VERBS and DERBS). Slice customers receive their share of these revenues as an offset to the Composite Charge. BPAT uses this capacity to meet changes in both load and resources that occur within the hour. These changes can be an increase in net load (requiring these resources to increase output (INC)), or a decrease in net load (requiring these resources to decrease (DEC)). By virtue of purchasing these services from BPAT (Regulation, Imbalance, and Contingency Reserves) and contractually giving up its share of capacity for within hour services, FPUD has handed over its obligation for these services to the BA and does not need to include capacity for these services in its capacity planning for the IRP. Since BPAT has the responsibility for meeting this load, it will not be addressed in the IRP.

5.12 Load/Resource Balance with Existing Resources

Figure 10 illustrates FPUD's current resource qualifying capacity in relation to average energy consumption, peak demand load, and WRAP reserve margin requirements. FPUD's existing resources fulfill average energy consumption needs until late 2028. However, comparing resource capacity to peak load and WRAP requirements shows a shortfall ranging from 46 MW to 231 MW. Presently, peak demand is met through market purchases. Therefore, additional peaking or immediate capacity will be necessary to satisfy capacity requirements and energy needs effectively.

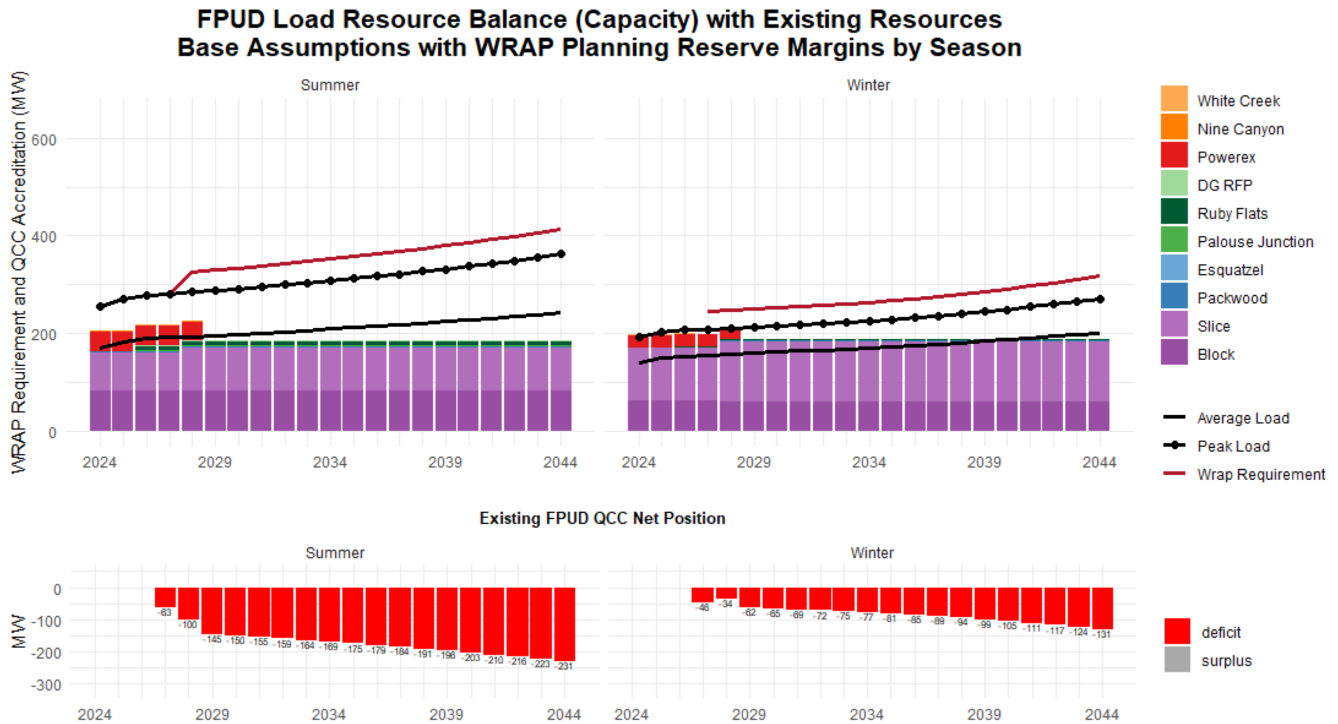


Figure 10. Existing Load Resource Balance

Section 6 New Resource Alternatives

New resources are needed to accommodate load growth and the retirement of aging generation units. Due to significant lead times required for construction and interconnecting a resource to the electric system, timely planning for each new resource is critical to ensure capacity requirements are met.

The requirements of the Clean Energy Transformation Act (CETA), which became effective on January 1, 2020, were major factors in determining the viability of potential resource alternatives. CETA requires that all utilities in Washington must supply carbon-neutral electricity by 2030. Although FPUD retains the flexibility to include carbon-emitting resources in its portfolio equal to up to 20 percent of its retail load until 2045, any carbon emissions generated from these resources must be offset by the procurement of renewable energy credits or the investment in renewable energy projects. In addition, when contemplating such resources, the societal cost of carbon must be included in the evaluation. CETA stipulates that by 2045, utilities must eliminate all carbon emissions by producing power exclusively with renewable and other non-emitting sources. For these reasons, FPUD evaluated only carbon-free supply-side resource options. The following supply options are considered currently or potentially viable within the study period and were included in this IRP analysis:

6.1 Solar PPA

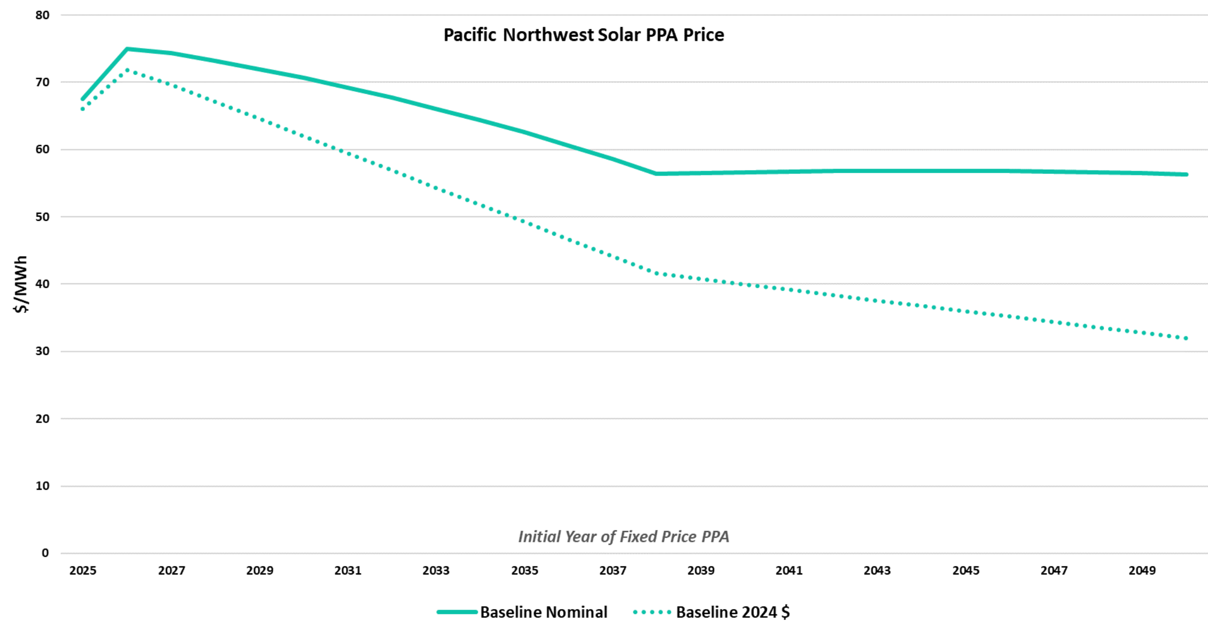
Solar resources were modeled as 20 MW PPAs based on large-scale solar photovoltaic projects. This option satisfies the long-term requirements of CETA. The rapid growth in electric generation from solar resources across the U.S. has been driven by declining costs, supportive governmental policies, and the increasing demand for carbon-free renewable energy. Installed utility-scale solar capacity in the U.S. has risen from less than 1 GW in 2010 to approximately 100 GW[5] by the end of 2023 and provided approximately 4%[6] of the total electric generation in the U.S. in 2023.

FPUD is in the process of potentially adding approximately 60 MW of nameplate solar capacity in 2026 through participation in the Ruby Flats and Palouse Junction projects. Additional solar resources considered by FPUD are assumed to have a 3-year construction period and to be located in southeastern Washington within the BPA balancing authority. Based on market data, the cost of energy from a solar PPA, fixed for the duration of a 15-year term, is assumed to be $75/MWh for a project with a 2026 commercial date. Prices in subsequent years were based on expected changes in construction costs and subsidies available through the Inflation Reduction Act. Future overnight capital cost assumptions were provided by The National Renewable Energy Laboratory's (NREL) 2023 Annual Technology Baseline. NREL projects utility-scale solar capital costs to decline by an average of

[5] **Buttel, Lindsey**. America's Electricity Generation Capacity 2024 Update, American Public Power Association. America's Electricity Generation Capacity Report, 2024 Update (publicpower.org), accessed on 7/1/2024.

[6] **Fitzgerald Weaver, John**. "Solar generated 5.5% of U.S. electricity in 2023, a 17.5% increase." PV Magazine USA. https://pv-magazine-usa.com/2024/02/29/solar-generated-5-5-of-u-s-electricity-in-2023-a-17-5-increase/, accessed on 7/1/2024.

2.9%/year in constant dollars between 2024 and 2045 due to additional technological advancements and efficiency improvements. The following exhibit shows the projected solar PPA prices assumed in the study.



6.2 Wind PPA

Wind resources were modeled as 25 MW PPAs based on utility-scale on-shore wind projects. Wind resources also satisfy the long-term requirements of the EIA and CETA. As with solar, the strong growth of wind generation has also benefitted from declining costs, supportive governmental policies, and the increasing demand for carbon-free renewable energy. Installed utility-scale wind capacity in the U.S. has grown from 46 GW in 2010 to over 150 GW[7] today. In 2023 wind generation provided over 10% of the total electric generation[8,9] in the US.

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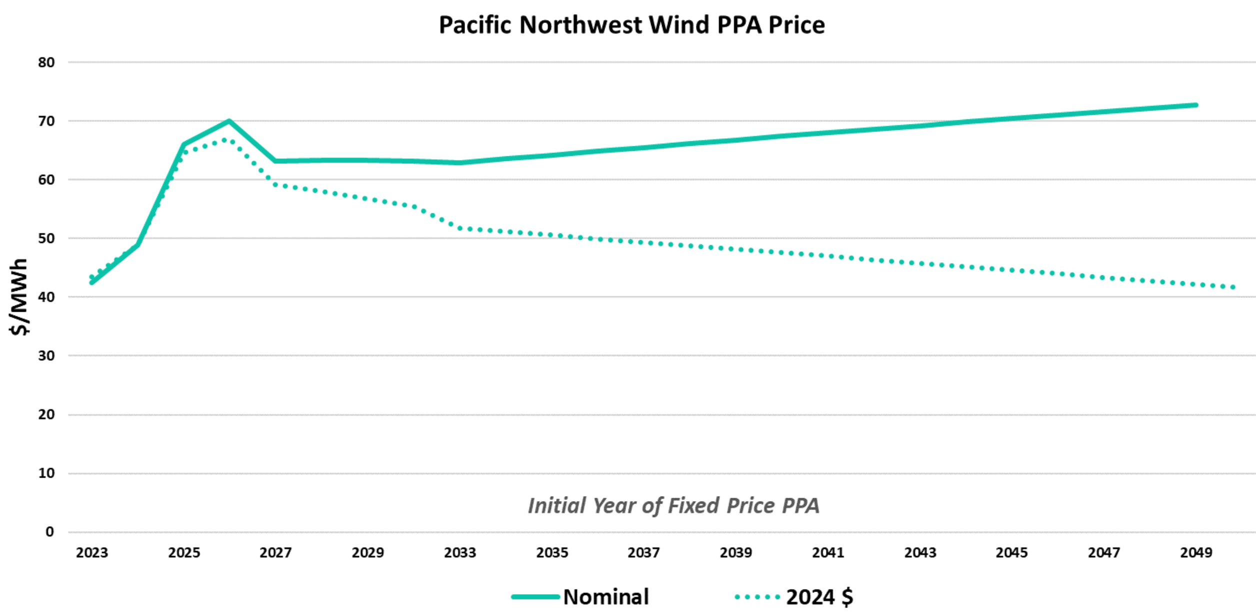
[7] Buttel, Lindsey. America's Electricity Generation Capacity 2024 Update, American Public Power Association. URL: America's Electricity Generation Capacity Report, 2024 Update (publicpower.org), accessed on 7/1/2024.

[8] Morey, Mark, and Jell, Scott. "Wind generation declined in 2023 for the first time since the 1990s." U.S. Energy Information Administration (EIA), April 30, 2024. URL: https://www.eia.gov/todayinenergy/detail.php?id=61943, accessed on 7/1/2024.

[9] Form EIA-923 detailed data with previous form data (EIA-906/920). U.S. Energy Information Administration (EIA). URL: https://www.eia.gov/electricity/data/eia923/, accessed on 7/1/2024.

Wind resources considered by FPUD are assumed to have a three-year construction period and to be located within the BPA balancing authority. Based on market data, the cost of energy from a wind PPA, fixed for the duration of a 15-year term, is assumed to be $70/MWh for a project with a 2026 commercial date. Prices in subsequent years were based on expected changes in construction costs and subsidies available through the Inflation Reduction Act. Future overnight capital cost assumptions were provided by The National Renewable Energy Laboratory's (NREL) 2023 Annual Technology Baseline. NREL projects utility-scale wind capital costs to decline by an average of 1.3%/year in constant dollars between 2024 and 2045 due to additional technological advancements and efficiency improvements. The following exhibit shows the projected wind PPA prices assumed in the study.



6.3 Battery Storage PPA

Battery storage allows energy from the power grid or renewable resources such as wind or solar to be stored for later use. Enabling the storage and dispatch of power from renewable resources is vital in the transition towards cleaner, more sustainable energy and achieving full reliance on renewable and carbon-free generation by 2045.

Currently, most utility-scale battery storage installations rely on lithium-based battery chemistry. Advantages include high energy density, long cycle life, and a history of declining costs. For utility peak shaving or load shifting applications, a Li-ion battery can discharge at its rated capacity level for up to a 4-hour duration.

Battery storage is modeled as a Li-ion battery PPA with 4-hour discharge capability. Storage projects are assumed to have a 3-year construction period and to be located within the BPA balancing authority. The first year of availability is assumed to be 2027. Based on market data, the cost of battery storage, fixed for a 15-year term, is assumed to be $144/kW-yr in 2027. Prices in subsequent years are based on expected changes in construction costs and investment tax credits available through the Inflation Reduction Act. Future overnight capital cost assumptions are from the National Renewable Energy Laboratory's (NREL) 2023 Annual Technology Baseline. NREL projects utility-scale battery storage capital costs to decline by an average of 2.7%/year in constant dollars between 2024 and 2045 due to additional technological advancements and efficiency improvements. The following exhibit shows the projected battery storage PPA prices assumed in the study.

6.4 Geothermal PPA

Geothermal power is a renewable energy source that uses the natural heat stored beneath the earth's surface to generate carbon-free electricity. The U.S. is the world leader in geothermal electric generation with approximately 4 GW of installed capacity.

Conventional geothermal resources naturally contain the presence of hot rocks, fluid, and underground permeability. In these locations, wells are drilled to harness the naturally occurring reservoirs of steam or hot water to drive turbines and generate electricity. These reservoirs are typically found in limited regions with high geothermal activity.

New or Advanced Geothermal resources refer to emerging techniques that can be used to harness geothermal energy in areas without naturally occurring reservoirs. One such technique is Enhanced Geothermal Systems (EGS). EGS involves drilling deep into the earth's crust, injecting water into the rock to create fractures, and then circulating the water through the fractures to create steam and generate electricity. This method can theoretically be used anywhere, as heat is always present deep in the earth's crust, making it more versatile than traditional geothermal energy. These emerging geothermal technologies also include methods to improve efficiency and reduce environmental impact. For example, some systems are designed to reinject used geothermal fluids back into the ground to sustain the pressure of the geothermal reservoir and to prevent surface disposal of these fluids.

Given the limited options to supply the carbon-free generation required by CETA, FPUD considers electric generation using geothermal energy as a potential option in the future. In this IRP's Reference Portfolio Scenario, a 25 MW block of traditional Geothermal generation was assumed to be available to FPUD beginning in 2035 as well as 75 MW of new geothermal. New geothermal refers to Enhanced Geothermal Systems (EGS) which involves drilling into the earth's crust and injecting high pressure water to create artificial geothermal reservoirs. The heated water is then brought back to the surface and used to generate power. New geothermal is more expensive than traditional geothermal but may be able to expand the use of geothermal generation which is now currently limited to geologically active sites. The cost of energy from a 25-year PPA based on traditional geothermal is assumed to be $90/MWh in 2024 dollars while the cost of energy from a 25-year PPA based on new geothermal is assumed to be $105/MWh. These costs are escalated at the inflation rate of 2.2%/year.

6.5 Small Modular Reactor (SMR) PPA

SMR is an emerging technology that could play a significant role in decarbonizing the electric generation industry in the future. If brought successfully to market, the technology will provide flexible nuclear power generation in a smaller size than the current base load nuclear plants that typically exceed 1,000 MW. The compact designs can be factory-fabricated and transported by truck or rail to a designated site.

The modular design of SMRs allows for less on-site construction, increased containment efficiency, and enhanced safety due to passive nuclear safety features. Co-location of multiple modules of approximately 60 MW each would provide precise amounts of generating capacity in locations where power is specifically needed. SMRs are part of a new generation of nuclear technology and have the potential to reduce the financial burden and risk associated with nuclear power. SMR technology may prove to be a source of significant carbon-free electric generation in the future.

Given the requirements of CETA and the inability to utilize natural gas-fired generation beyond 2045, FPUD has been open to considering the inclusion of SMRs in its future resource portfolio and would prefer to purchase SMR generation through a PPA. In this IRP's Reference Portfolio Scenario, the first year of SMR availability is assumed to be 2035. Based on The Energy Information Administration's January 2024 report, "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies," developed by Sargent & Lundy, the cost of energy from SMRs is assumed to be approximately 45% higher than that of traditional geothermal; therefore, energy from a 25-year SMR PPA is assumed to cost $130/MWh in 2024 dollars and is escalated at the inflation rate of 2.2%/year.

6.6 Other Resource Options

Several additional opportunities are modeled in the study.

- Extension of existing PPA contracts
    - White Creek wind – a 10-year extension is assumed to be available from 2027 through 2036 at a cost of approximately $75/MWh in 2024 dollars escalated at the 2.2%/ annual inflation rate.
    - PowerEx hydro – two 5-year extensions are assumed to be available in 2029 and 2034 with a market-based variable charge and a fixed charge of approximately $110 to $120/kW-year
    - Nine Canyon wind – a 10-year extension is assumed to be available from 2030 through 2039 at a cost of approximately $83/MWh in 2024 dollars and escalated at the 2.2% annual inflation rate.
- BPA Tier 2

    From 2026 through 2028, up to 10 MW is assumed to be available in 5 MW blocks at a cost of $80 per MWh.

    From 2029 through 2035, up to 20 MW is assumed to be available in 5 MW blocks at a cost of $85 per MWh.

- Short-Term Contract

    Short-term (1-year) contracts of up to 125 MW in 25 MW block sizes are assumed to be available during the 2026-2034 period prior to the availability of geothermal and SMR PPAs. The energy price is assumed to be $90/MWh in 2024 dollars with no escalation.

Options considered in this study are summarized in Table 5.

Table 5. Supply Resource Options

Supply Options	Max Build (MW)	First Available (Date)	Economic Life (Years)	Unit Size (Net MW)	Contract Price (2024$/MWh)	FOM (2024$/kW-yr)	Escalation rate (%)
4-Hr Storage PPA	200	2027	15	25	0.00	144.00	Note[10]
BPA Tier 2 (2026-2028)	10	2026	1	5	80.00	0.00	0.00%
BPA Tier 2 (2029-2035)	20	2029	1	5	85.00	0.00	0.00%
Geothermal PPA (New)	75	2035	25	25	105.00	0.00	2.20%
Geothermal PPA (Traditional)	25	2035	25	25	90.00	0.00	2.20%
Nine Canyon (2030-2039)	10	2030	10	10	82.83	0.00	2.20%
PowerEx (2029-2033)	25/40	2029	5	25/40	Index	111.28[11]	0.00%
PowerEx (2034-2038)	25/40	2029	5	25/40	Index	116.85[11]	0.00%
SMR	100	2035	25	25	130.00	0.00	2.20%
Solar PPA	Note[12]	2027	15	20	75.00	0.00	Note[10]
ST Contract (2026-34)	125	2026	1	25	90.00	0.00	0.00%
White Creek (2027-2036)	10	2027	10	10	74.95	0.00	2.20%
Wind PPA	40	2027	15	5	75.00	0.00	Note[10]

Distributed Energy Resources (DER)

Instead of traditional, one-way delivery of electricity from large, central station power plants located far from demand, technologies are now available that allow customers to generate their own electricity. Due to a combination of maturing technology and financial incentives, many of these technologies, such as rooftop solar, are currently affordable to many customers. Costs are expected to continue to trend down, and more technologies are expected to become available in the near future as research progresses, allowing more customers to adopt DERs. Understanding how DERs impact the grid itself, including reliability, is an important factor to be considered. Alternatively, understanding where, when, and how DER can benefit the grid is of equal value. While the economic signals may not yet be fully developed, technology has advanced to the point where consumers can respond to price changes, reduce (or increase) demand when useful to the system, or store electricity for later use.

DER are typically defined as small grid-connected power sources that can be aggregated to meet electric demand. Some technologies and services easily fit into any definition, such as residential rooftop wind or solar, but others have yet to be definitively placed inside or outside of this definition. DER are being adopted at increasing rates due to favorable policies from both state and federal governments, improvements in technology, reduction in

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[10]Emerging technologies like solar and storage follow a unique growth curve to accommodate for advancements in technology and government incentives.

[11]Powerex FOM is projected based on existing rates, with a 5% increase for each extension.

[12]The solar installed capacity will gradually be permitted, allowing up to 200MW by 2029, then up to 400MW by 2033, and after 2040, there will be no limits.

costs, and identifiable customer benefits, both at the individual and grid levels. Once DER adoption passes certain levels, DER can begin to cause significant issues for traditional rate making, utility models, and the delivery of electricity which can result in a cost shift among classes of ratepayers. It is important for electric utilities to identify potential economic and grid issues and benefits from DER. DER are becoming more widespread with increasing commercial availability, decreasing costs, and evolving consumer preferences. FPUD is proactively investigating and exploring programs and strategies that will lead to greater benefits for the public, customers, developers, and utilities alike. The DER space is evolving at a pace as rapid as any industry – it is imperative to develop a plan flexible enough to adapt to increased levels of DER.

Section 7 Market Simulation

7.1 Methodology Overview

Long-term resource planning requires a fundamental price forecast used to value existing and future capacity resource options. Operators, participants, and other market entities utilize a production cost model to simulate future market conditions to forecast prices. This following section details the methodologies used to create a market environment outlook that can generate prospective power prices.

7.1.1 Modeling Approach

Electric price simulation is generated using a fundamental production cost model. Figure 11 provides an overview of the process used to create the price simulation. The progression can be broken down into three principal phases. In the first phase, fundamental and legislative factors were modeled and integrated, including load forecasts, regional generation portfolio changes, carbon penalty assumptions, and regional renewable portfolio standards. The second phase of the study uses the inputs from the first step to run a capacity expansion analysis. The capacity expansion model optimally adds hypothetical resources to the existing supply stack over a 20-year time horizon. In the third and final phase, the long-term production cost model performs a 20-year dispatch of the entire Western Interconnect using the modified supply stack to simulate market prices. The following sections will describe how the model assumptions and inputs were derived, and the price simulation in further detail.

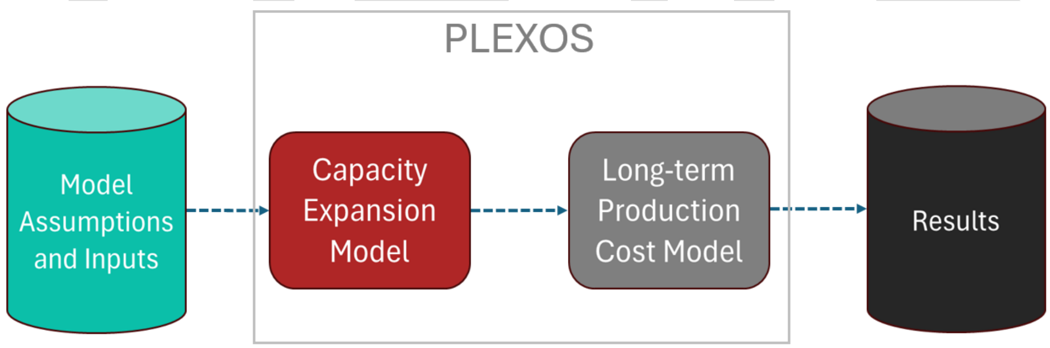


Figure 11. Modeling Approach

7.1.2 Model Structure

The primary tool used to determine the long-term market environment is PLEXOS. PLEXOS is a production cost software, licensed through Energy Exemplar LLC, that simulates the supply and demand fundamentals of the physical power market and ultimately produces a long-term power price forecast. Using factors such as economic and performance characteristics of supply resources, regional demand profiles, and zonal transmission constraints, PLEXOS then simulates a Western Electricity Coordinating Council (WECC) system expansion to produce a generation portfolio capable of satisfying future electricity demand. The model simulates resource dispatch which is then used to create long-term price and capacity expansion forecasts.

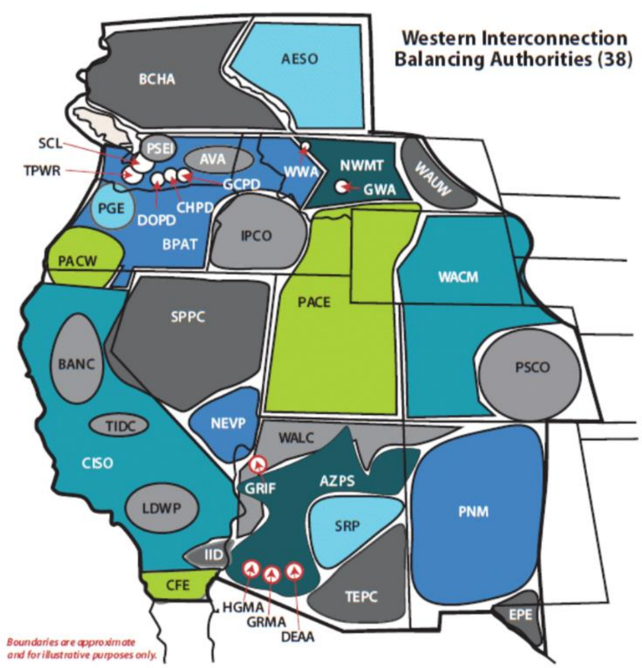
PLEXOS is utilized for three main purposes:

1. To determine a long-term deterministic view of resource additions and retirements.
2. Establish an expected long-term forecast price.
3. Perform scenario analysis on the expected price forecast by changing key inputs and assumptions.

Forecast drivers were either created or leveraged from reputable third-party vendors for such key variables as regional load growth rates, planning reserve margins, natural gas prices, hydro generation, and carbon prices. Renewable resource additions were set to correspond to the regional load growth and renewable portfolio standard set by each state. Upon the completion of a WECC footprint capacity expansion study, a set of scenario analyses was conducted using various combinations of natural gas and carbon prices. These scenarios were used to generate a long-term price forecast for the Mid-Columbia (Mid-C) trading hub.

7.1.3 WECC-Wide Forecast

The WECC is responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection, which encompasses the 14 western-most states in the U.S., parts of Northern Mexico and Baja California, as well as Alberta and British Columbia.



The WECC region is the most geographically diverse of the eight Regional Entities that have delegation agreements with the North American Electric Reliability Corporation (NERC). PLEXOS was used to model numerous zones within the Western Interconnect based on geographic, load and transmission constraints. The analysis focuses mainly on the Northwest region, specifically Oregon, Washington, and Idaho. Although the study forecast focuses on the Mid-C electricity market, it is important to model the entire region due to how fundamentals in other parts of the WECC can exert a strong influence on the Pacific Northwest market. The ability to import electricity from or export to other regions, the generation and load profiles of another region can have a significant impact on Mid-C power prices. As such, to create a credible Mid-C forecast, it is imperative that the economics of the entire Western Interconnect are captured.

7.1.4 Long-Term Fundamental Simulation

A vital part of the long-term market simulation is the capacity expansion analysis. The study utilized PLEXOS to determine what types of generation resources will likely be added in the WECC over the next 20 years, given our current expectations of future load growth, natural gas prices, and regulatory environment. PLEXOS' WECC dataset includes known or projected retirement dates for existing resources as well as online dates for proposed resources. PLEXOS then conducts a capacity expansion simulation in which load increases, resources are retired or derated due to regulatory requirements, and new generating resources are added to serve load requirements and meet planning reserve margins and renewable portfolio standards. The resources that are chosen are the best economic performers – i.e. the resources which provide the most regional benefit for the lowest price based on the constraints previously detailed.

7.2 Principal Assumptions

Market conditions change regularly, driven by a multitude of factors. Energy demand, regulations, fuel and capital costs, and environmental goals all influence the future economic viability of generating resource options. As regional resource portfolios transform, power price values and shapes will shift. The intent of this section is to detail the methodologies used to model the expected changes across the WECC footprint during the 2020's through the 2040's that will best capture the impact to future power prices that will be used in the portfolio analysis.

7.2.1 WECC Load

PLEXOS's default annual demand forecasts for zones in the WECC region are based on WECC's Data Archives and FERC-714 filings. The data available in the PLEXOS WECC database includes load for 34 regions through 2054. FERC only published forecast data for ten years and to account for the additional years the final three-year average of the FERC growth is applied to generate load, by region, for the subsequent years. For example, on average annual peak load is expected to increase at a 0.86% rate.

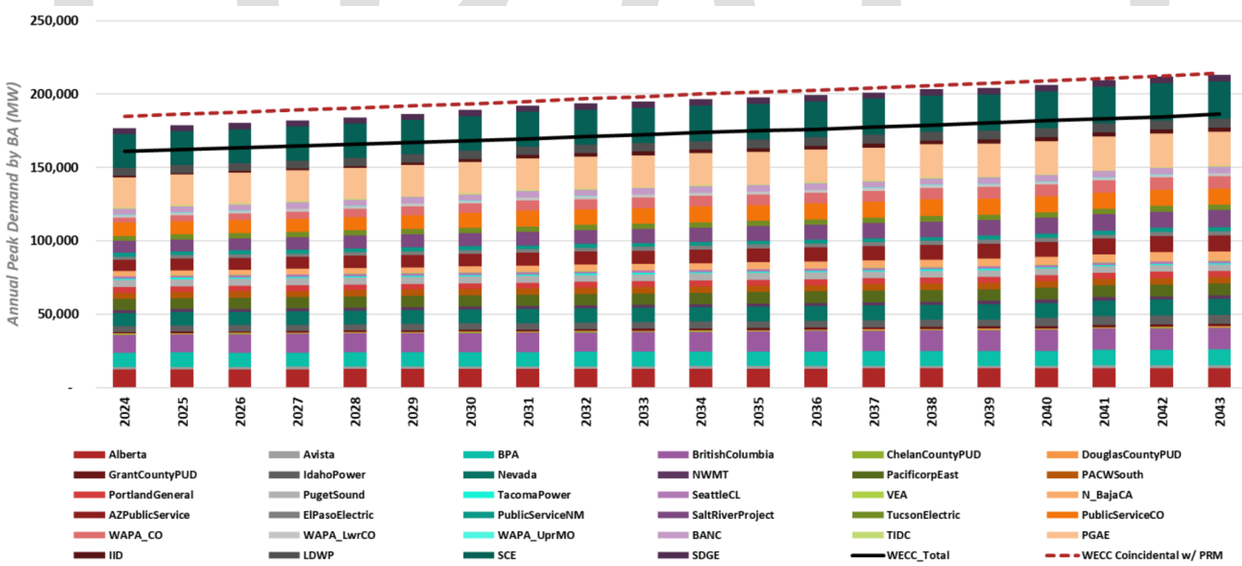


Figure 12. WECC Annual Peak Load Projections

Annual load projections are then shaped at the hourly level using three-year historical hourly load data and Energy Exemplar's "Smooth-Ranked" methodology, which removes volatility and creates a typical hourly load profile. The typical load profile, in conjunction with the total and peak energy inputs and PLEXOS build function, are used to develop the hourly load forecast in PLEXOS through 2054 for each region.

7.2.2 Regional Planning Reserve Margins (PRM)

To ensure there will be sufficient generating capacity to meet demand, a defined amount of generating reserve capacity is built into the market. These operating reserves are often extra generating capacity at existing operating plants, or fast-start generators, which can start-up and reach maximum capacity within a short amount of time. Historically these fast-start resources have been natural gas-fired generators, but the shift to batteries or other energy storage resources is on the rise.

Planning reserve margins (PRM) are a long-term measurement of the operating reserve capacity within a region, used to ensure there will be sufficient capacity to meet operating reserve requirements. The PRM is an important metric used to determine the amount of new generation capacity that will need to be built in the future. A 15% planning reserve margin on each zone was modeled during the capacity expansion simulation, consistent with WECC reliability assumptions in the 2021 WECC Western Assessment of Resource Adequacy.

7.2.3 WECC Renewable Portfolio Standards (RPS)

Renewable portfolio standards (RPS) are state-level requirements that require electric utilities to serve a certain percentage of their load with eligible renewable electricity sources by a certain date. The goal of these requirements is to increase the amount of renewable energy being produced, in the most cost-effective way possible. Currently, there are not federally mandated RPS requirements, instead states have set their own based on their environmental, economic, and political needs.

Among states in the WECC, California has the highest RPS requirement at 60% by 2030, with Oregon following shortly behind it with a 50% requirement for its IOUs by 2040. In Washington, there is a 15% RPS requirement, but with the 2019 enactment of the Clean Energy Transformation Act (CETA), there is now also an 80% carbon-free requirement by 2030. A wide variability in the requirements exists between states in the region, which could have a sizeable effect on electricity pricing within the region. Figure 13 details the RPS goals for each state or province included in the PLEXOS WECC database.

State/Province	Program Type	Description
Alberta	RPS	30% renewable energy by 2030
Arizona	RPS	15% renewable energy by 2025
California	RPS	60% renewable energy by 2030
Colorado	RPS	30% renewable energy by 2020
Neveda	RPS	50% renewable energy by 2030
Neveda	PRS_Solar	6% solar energy by 2030
New Mexico	RPS	80% renewable energy by 2040
New Mexico	PRS_Solar	4% solar energy by 2040
Oregon	RPS	50% renewable energy by 2040
Utah	RPS	20% renewable energy by 2025
Washington	RPS	15% renewable energy by 2020

Figure 13. PLEXOS WECC RPS Assumptions

7.2.4 Carbon Goals and Pricing

Initiative 2117 (I-2117) is to be voted on in the November 2024 election. If passed, I-2117 would eliminate the Climate Commitment Act and prohibit the existence of any cap-and-trade programs within the state of Washington. Given at the time of the IRP the outcome of this initiative is unknown, the IRP assumes that the Cap-and-Invest program will continue as planned, and thus includes the cost of carbon as an input to the market simulation. Figure 14 details the Carbon Reduction goals for each state or province included in the PLEXOS WECC database.

State/Province	Program Type	Description
British Columbia	Carbon	93% renewable of zero-carbon by 2020
California	Carbon	100 zero-carbon by 2045
Neveda	Carbon	100 zero-carbon by 2050
New Mexico	Carbon	100 zero-carbon by 2045
Oregon	Carbon	100 zero-carbon by 2040
Washington	Carbon	100 zero-carbon by 2045

Figure 14. PLEXOS WECC Carbon Goal Assumptions

For carbon pricing the IRP uses recent auction settlements and bilateral Washinton Carbon Allowance (WCA) and California Carbon Allowance (CCA) trades on ICE as inputs to the expected case in Figure 15. The WCA 2024 expected price of $52/MT CO2e was based on an average of the most recent 100 days of WCA '24 settlements on ICE as of February 2024. Similarly, the CCA 2024 expected price of $42/MT CO2e was based on an average of the most recent 100 days of WCA '24 settlements on ICE as of February 2024. From 2027 onward, one carbon price was assumed for both Washington and California given the expectation that Washington and California will link markets after Washington's first compliance period ends. The WCA floor price and ceiling prices were set to Ecology's 2024 floor and ceiling prices of $24/MT CO2e and $88/MT CO2e respectively. All prices were escalated by 5% annually based on the WAC 173-446-335 rule that states floor and ceiling prices will be escalated by 5% plus inflation annually.

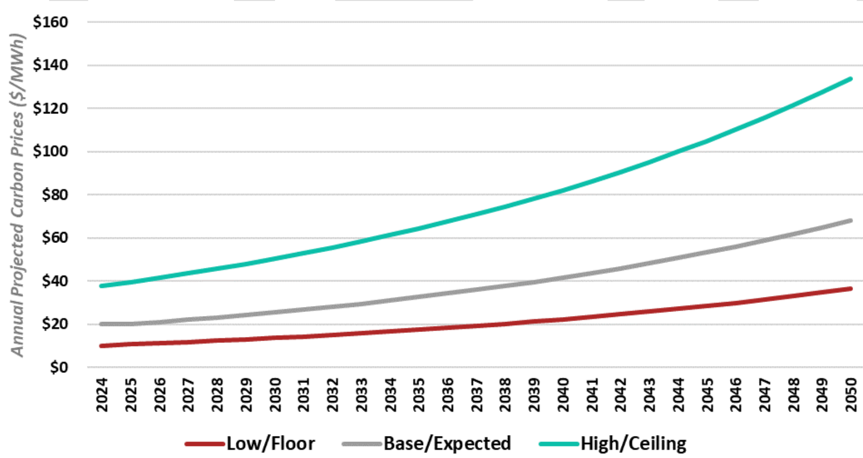


Figure 15. Washington Carbon Allowance Price Assumption in $/MWh in nominal dollars. Uses the $/MT CO2e price assumption multiplied by the unspecified per MWh emissions.

7.2.5 Natural Gas Price

TEA developed a base case forecast of Pacific Northwest natural gas prices that was used in all scenarios. The forecast was based on February 7, 2024 NYMEX prices through 2027 and Henry Hub price forecasts developed by S&P Global for the remainder of the study period. S&P Global price forecasts are based on a detailed analysis of natural gas supply and demand fundamentals. The forecasts referenced were from the January 2024 short-term and September 2023 long-term outlooks.

In addition to the base case forecast, TEA has high and low natural gas price forecasts. The high forecast is based on the Low Gas and Oil Supply Availability forecast from the 2023 Annual Energy Outlook (AEO23) produced by the Energy Information Administration (EIA). The low forecast is based on the AEO23 High Gas and Oil Supply Availability forecast. These forecasts are shown below in Figure 16.

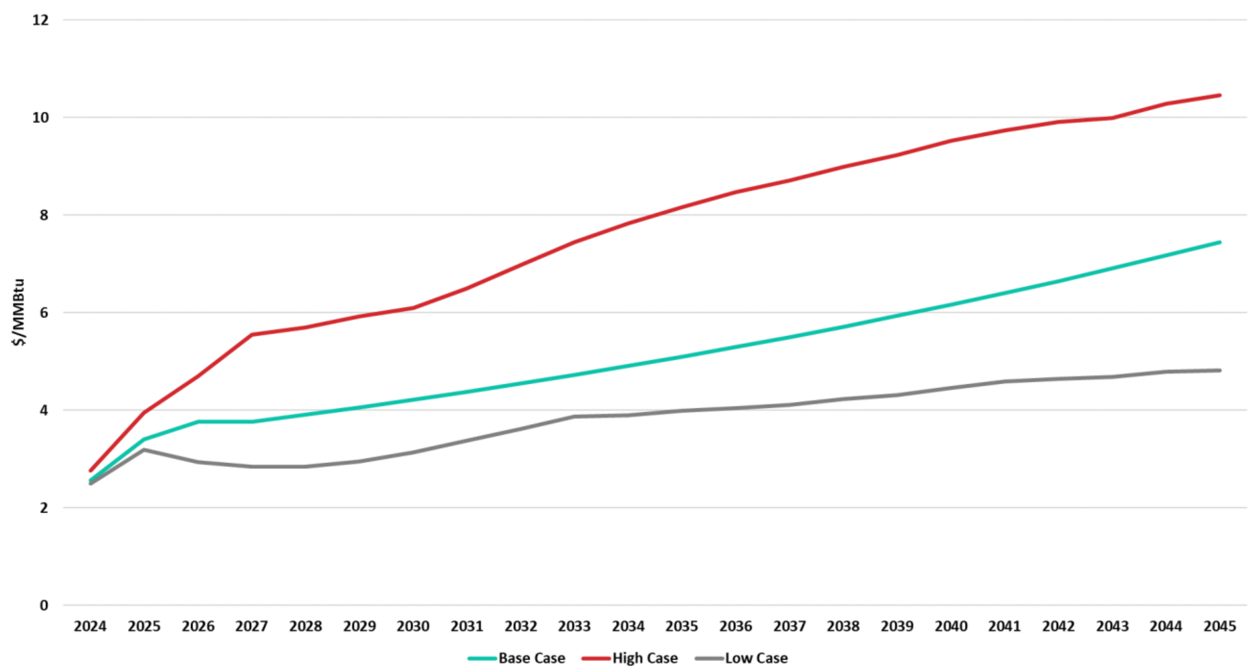


Figure 16. Annual average natural gas price, by price scenario

In the base case, Henry Hub prices in nominal dollars grow from an average of \$2.56/mmBtu in 2024 to \$7.45/mmBtu in 2045. See Figure 17 below. The average annual growth rate during this period is 5.2%. Future U.S. LNG exports and an eventual shift to higher cost natural gas basins are the major factors driving this price increase.

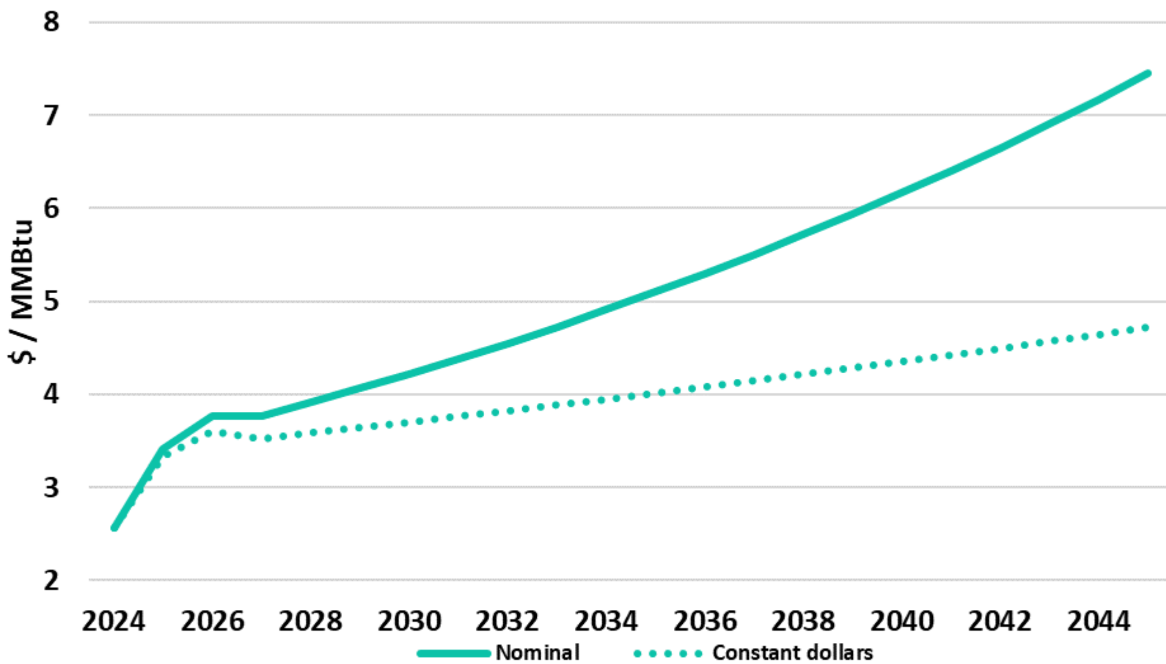


Figure 17. Natural gas prices at Henry Hub in nominal and constant 2024 dollars per mmBtu.

FPUD receives natural gas for its River Road combined cycle facility from Canada through the Sumas Hub in northwest Washington and from the south through the Stanfield Hub in north central Oregon. TEA added a basis estimate to the Henry Hub price forecast to estimate future prices delivered to Washington and specifically to the River Road facility. Projected basis was derived by comparing forward price curves from April 8, 2024 for Sumas and Stanfield to NYMEX. Based on historical data, TEA assumed that 58% of deliveries would come through Sumas and 42% through Stanfield. The price of natural gas delivered to the Pacific northwest and the natural gas price at Henry Hub are shown in Figure 18 below.

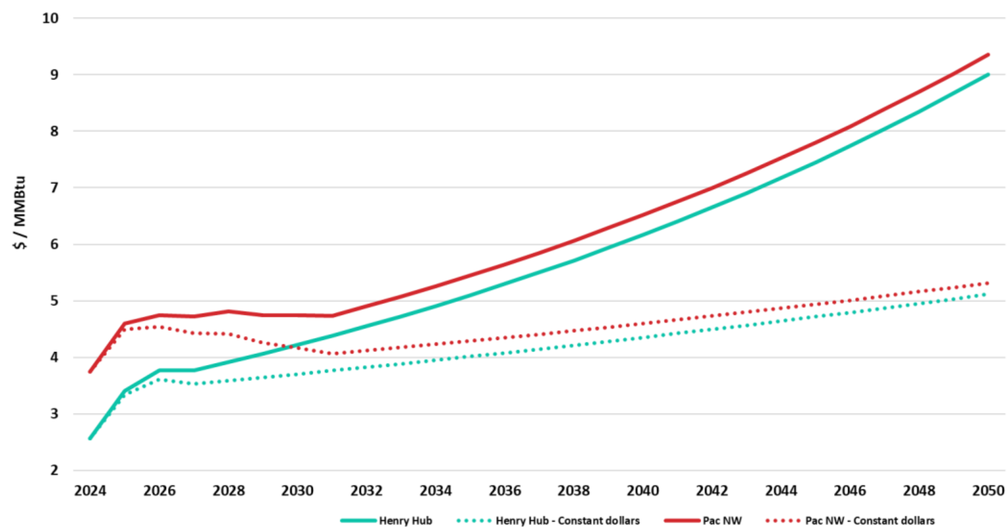


Figure 18. Annual natural gas prices delivered to the Pacific northwest for the 2024 through 2045 period.

Figure 19 below compares the Pacific Northwest pricing to that of Henry Hub. Note that the basis differential between Henry Hub and the Pacific Northwest is typically negative for April through October and positive for the winter months of November through March.

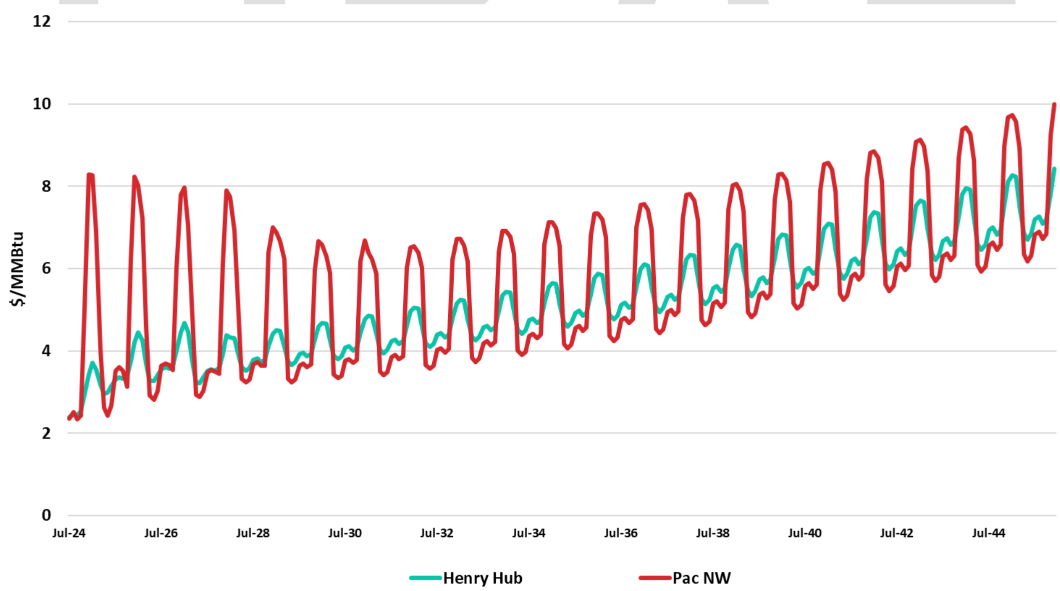


Figure 19. Henry Hub versus Delivered Pacific Northwest Natural Gas Prices

7.3 Simulations

After the development of the market model and assumptions, the model itself can be used for various purposes. First, a capacity expansion simulation was conducted where resources are removed and added to the market footprint based on constraints and market drivers. Second, the resulting portfolio was in a market dispatch simulation that produced forward power prices. These forward power prices are a fundamental input to the portfolio analysis that determines the least cost solution to meet future capacity needs. The following sections detail the process.

7.3.1 Capacity Expansion & Retirements

The generation options considered when modeling new resource additions in the region included nuclear, simple and combined cycle natural gas, solar, wind, storage, hydro, geothermal, and biomass. The PLEXOS WECC dataset contained economic assumptions for each resource options' such capital cost, variable operation and maintenance, fixed operation and maintenance, heat rate (thermal efficiency), performance standards such as forced and scheduled maintenance rates, and generation shapes for variable energy resources. The update to existing resources resulted in significant changes in the pattern and volume of new natural gas, wind, and solar capacity built as WECC continues to divest its interest in conventional energy resources for more sustainable/renewable sources.

Figure 20 details the base line year-by-year capacity retirements and additions across the WECC system from 2023-2040 prior to the capacity expansion simulation. Announced retirements for existing resources are input into the model with their scheduled retirement dates, which include many coal resources set to retire throughout the decade. In addition to coal resources, the Diablo Canyon Nuclear facility, the last nuclear plant in California, will retire by 2029. Just under 28 GW of capacity is expected to be retired with 90% of that being either coal or natural gas. Over 33 GW of known capacity is estimated to be installed in the system by 2032; of which 45% is expected from solar generators, followed by natural gas at 27%, 24% wind, and 2% hydro.

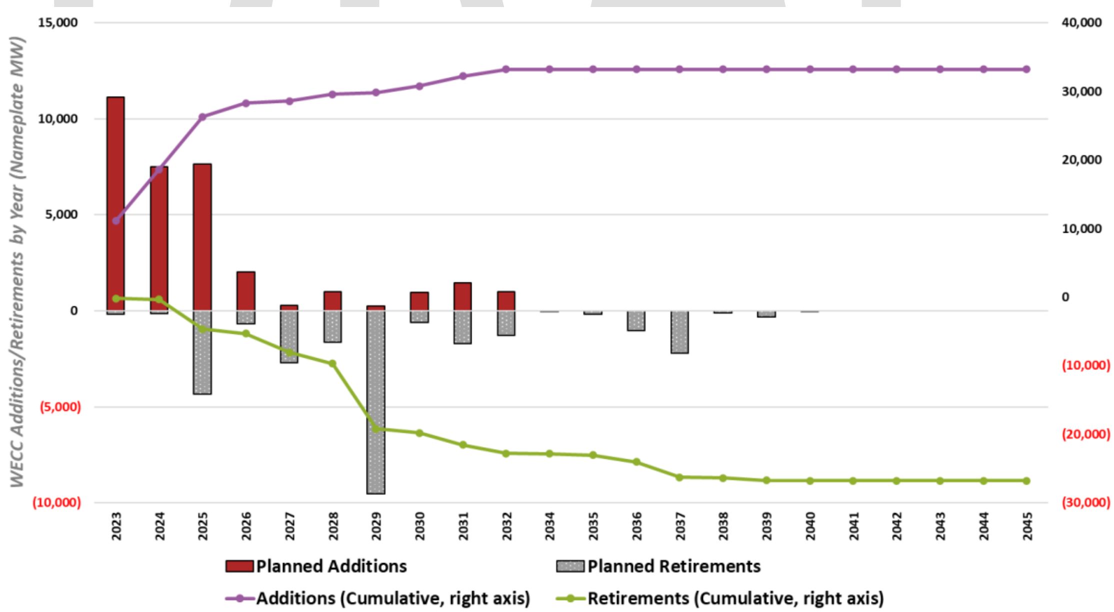


Figure 20. WECC Generation Additions and Retirements (pre-Capacity Expansion)

Based on the parameters outlined above, PLEXOS then determines the ideal mixture of new resource additions and further retirements to meet the inputs constraints in the most economical way. In conjunction with the expected retirements and additions noted above and the PLEXOS baseline capacity expansion simulation the 2023 Western Assessment of Resource Adequacy was used to supplement the resource additions. A summary of the near-term, mid-term, and long-term period additions can be seen in Figure 21.

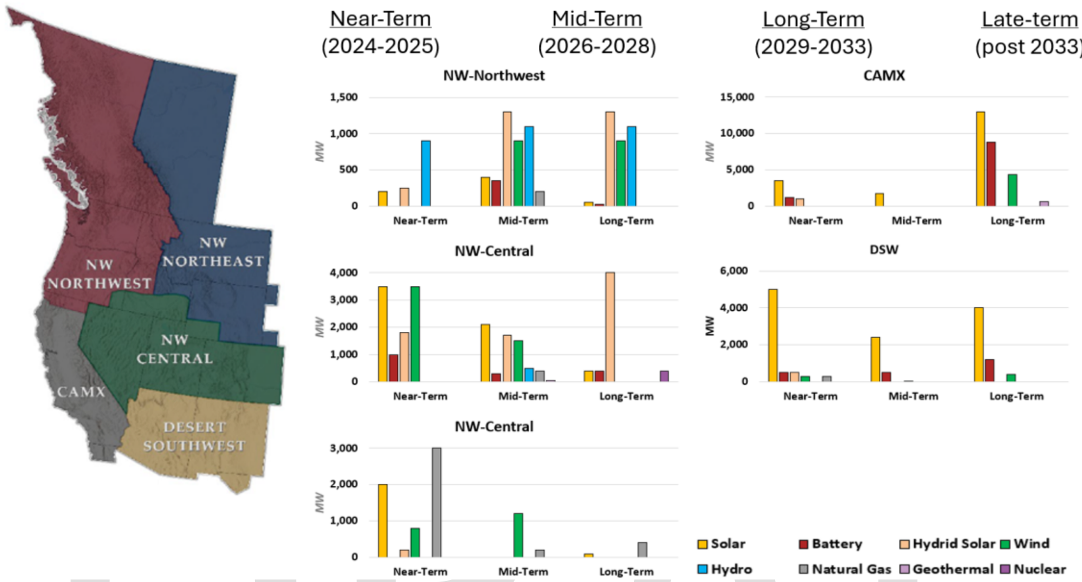


Figure 21. WECC Generation Additions and Retirements (post-Capacity Expansion)

Resources added post-2033 were done so exclusively by PLEXOS for meeting either demand needs or RPS goals. Figure 22 illustrates the total additions, year by year, across the entire WECC capacity expansion simulation.

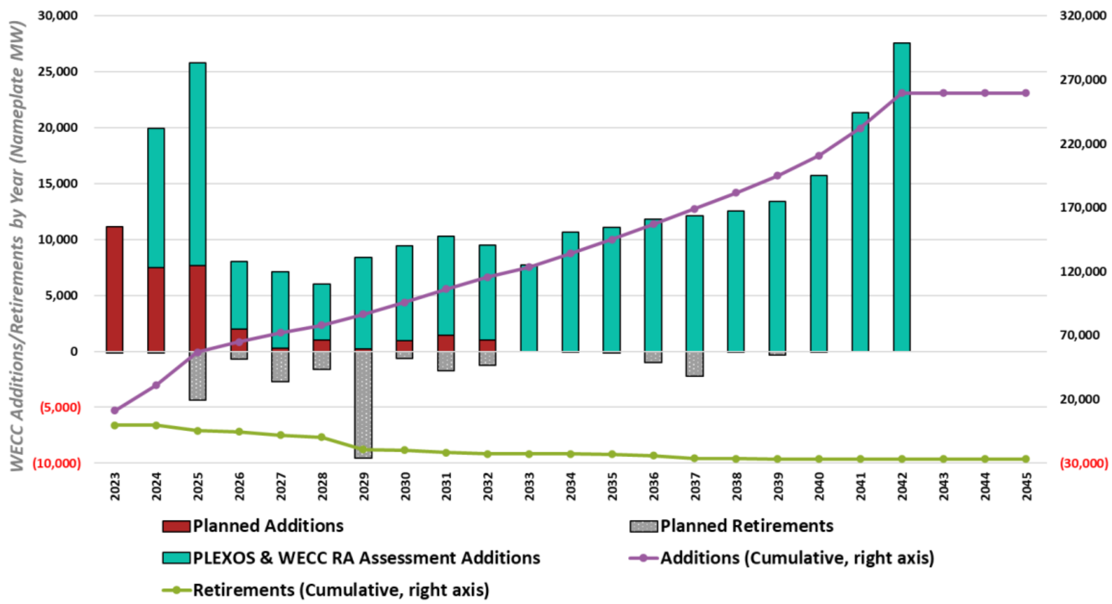


Figure 22. Annual nameplate capacity retirements and additions

Over 90 GW of new generation is added to the WECC footprint by 2033 with Wind or Solar making up 53 GW and Batteries or Hybrid making up 28 GW. By 2042, the final year of the capacity expansion simulation, nearly 260 GW of new generation is available to WECC. The notable drivers for adding this volume of new generation is due to the reduction in capacity accreditation for standalone wind and solar project, but the added need for these resources in order to meet the carbon reduction goals, most of which hit their 100% adoption in the 2040's. A breakdown in percentage of fuel type is represented in Figure 23.

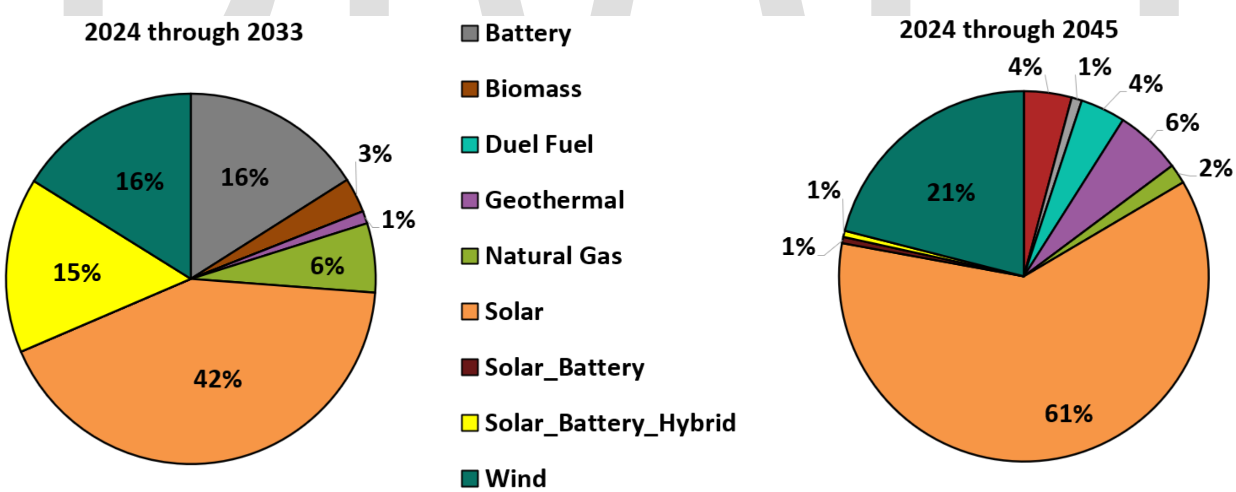


Figure 23. WECC Capacity Additions Percentages (Nameplate), by Fuel Type

Figure 24 and Figure 25 illustrate the expected new resource expansion and retirements through 2042 in the Pacific Northwest and California/Mexico regions.

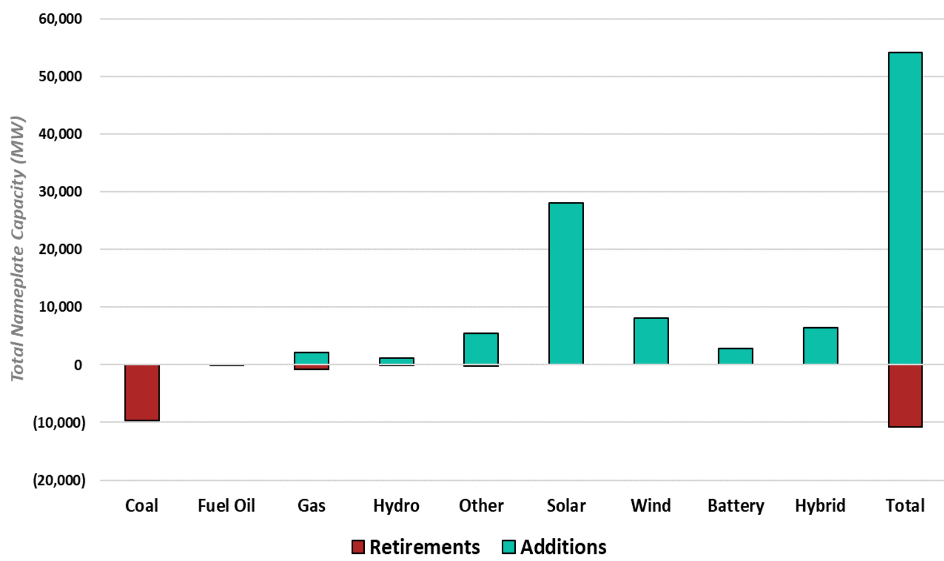


Figure 24. Forecasted Pacific Northwest Generation Capacity Retirements and Additions through 2042, by Fuel Source

Within the Northwest Power Pool region, which includes the Canadian providences of British Columbia and Alberta, and the states of Washington, Oregon, Idaho, Wyoming, Montana, Nevada, Utah, and a small portion of northern California, hydro will remain the largest single generating resource through the study period. All coal plants in the region are projected to retire (or be converted into natural gas units) by the end of 2030.

Solar is the renewable fuel type of choice for fulfilling RPS requirements across the simulation. A shift to batteries or hybrid resources does occurs in the mid-term and long-term periods. The cumulative expansion in the Pacific Northwest over the study period is over 54 GW, of which 8 GW comes from wind, 28 GW from solar, and 9 GW from batteries or hybrid resources.

In addition to a significant build out of solar in the region, just 2,100 MW of Combined Cycle (CCGT) or Combustion Turbine (CT) Gas generation is added. This addition largely offsets some of the lost capacity from retiring coal generation. Due to the assumption of increasing loads across the WECC, more capacity will be required to serve load, and this build-out of natural gas resources, coupled with the addition of storage, supports the growing need for capacity in the region. The additional cost of carbon and future carbon reduction goals, however, puts thermal resources at a disadvantage for meeting overall energy needs, preventing a higher buildout of this resource type.

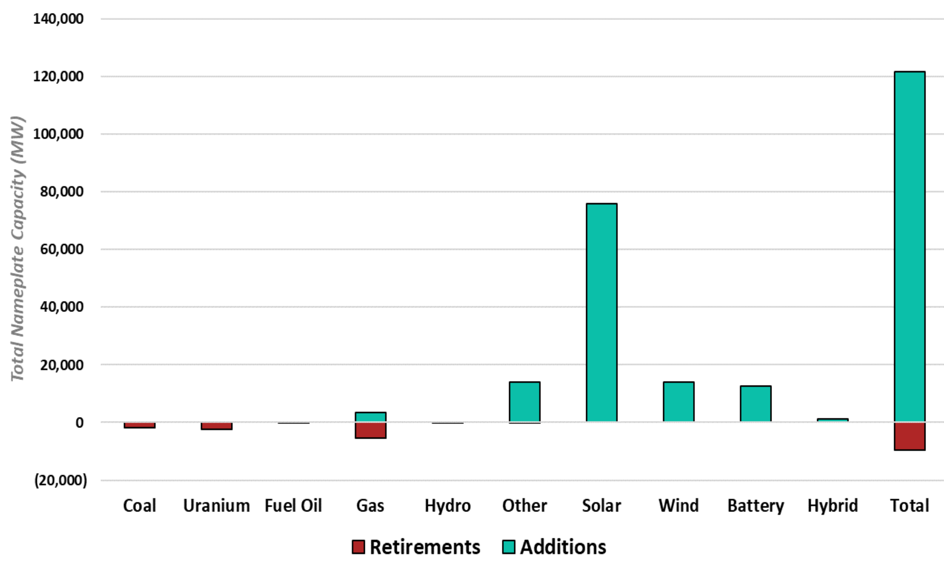


Figure 25. Forecasted California Generation Capacity Requirements and Additions through 2042, by Fuel Source

In California, there are substantial natural gas and coal resource retirements, and the retirement by 2030 of Diablo Canyon, the final nuclear facility in CAISO. Like in the Northwest, most of the generation expansion is from solar (76 GW), wind (14 GW) and batteries/hybrid (14 GW), but there is also over 14 GW of geothermal expected to be added. By 2042 over 121 GW of new generation is projected to be added to meet California/Baja demand, RPS, and carbon reduction goals.

7.3.2 Power Price Simulation

Using the hourly dispatch logic and assumptions outlined previously, hourly Mid-Columbia electricity prices were obtained for various future scenarios. **Error! Reference source not found.**Figure 26 shows the average monthly nominal heavy load hourly (HLH) and light load hourly (LLH) Mid-C power prices from the long-term WECC dispatch simulation.

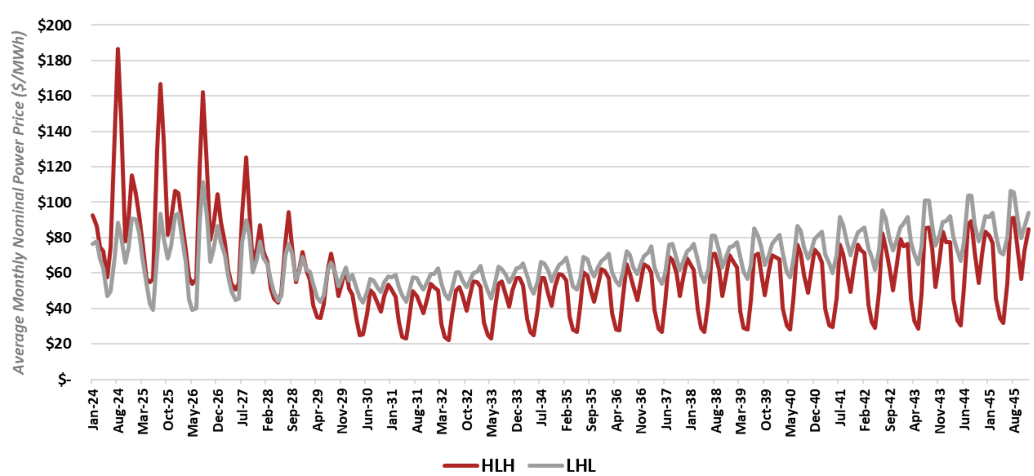


Figure 26. Mid-C Prices

Within the past couple of years, a paradigm shift has started in some US-based markets and regions. Where traditional HLH prices have been at a premium to LLH, some months of the year have begun to post pricing for LLH above HLH. This is a dramatic shift in the power market and correlated to the implementation of large volumes of Solar generation. During the spring hydro runoff period, low loads, and low natural gas prices, when combined with an increase in renewable generation, lead to the collapse of the HLH premium. Results from the WECC market simulation project an annual switch from HLH to LLH being the premium time-of-use product to occur in the late-2020's as seen in Figure 27.

Figure 27. Projected Annual Mid-C Prices

Figure 28 below shows the average 24-hour profile of Mid-Columbia power prices, by season, across various years in the simulation. This view is intended to show the expected change in the shape of Mid-C prices as volumes of renewable generation is added to the system. The "Duck Curve" traditionally seen in California prices begin to take shape in the northwest power markets by the late 2020's. As mentioned earlier, the spring hydro runoff, low load, and now high renewable generation are expected to push power prices down to the $0/MWh level for extended hours of the during the Spring season.

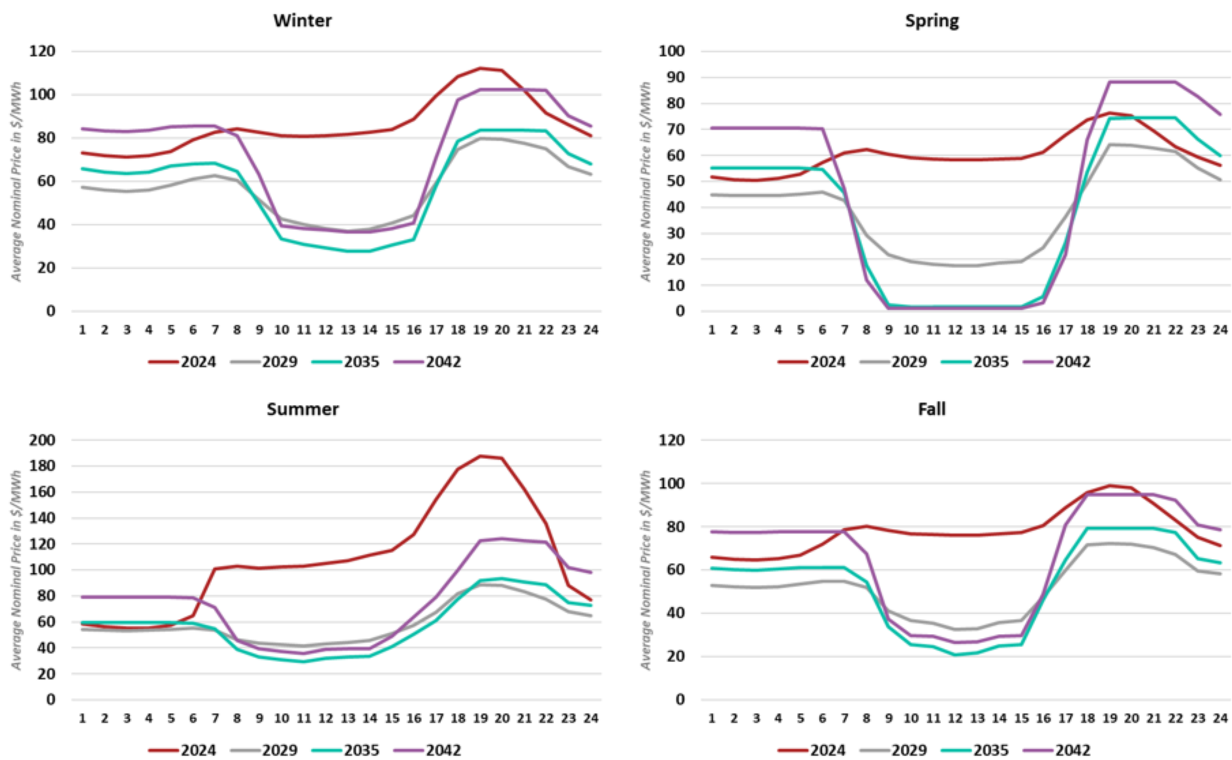


Figure 28. Projected Mid-C Average Hourly Price Profile, by Season, for 2024, 2029, 2035, and 2042

7.4 WECC Simulation Scenario Analysis

In addition to the above Base Case scenario, three alternative scenarios were considered. Although not used in the IRP analysis itself, these scenarios are intended to stress two of the key assumptions, natural gas and carbon prices, that went into the market simulation, and based on the IRP team's judgment, could potentially change in the future. The goal of the scenario analysis is to project a range of outcomes contingent upon changes in key underlying assumptions that are included in the market simulation. These three alternative scenarios include:

1) Base Natural Gas and No Carbon Prices: Although this scenario did not consider a change in the natural gas prices it did remove the additional cost on the WECC system associated with carbon pricing in the Northwest. This scenario was intended to simulate a future where I-2117 is passed and the Washington Cap-and-Invest program is eliminated.

2) High Natural Gas and Ceiling Carbon Prices: Carbon reduction goals across the US become more progressive. A future where added pressure on natural gas production and usage is very plausible. In this future it is also believed that in order to curtail natural gas usage and further development in the generation technology added costs to carbon production would be needed as well. This scenario is meant to simulate this type of future.

3) Low Natural Gas and Floor Carbon Prices: In the case of higher than anticipated renewable and low carbon buildout, both Natural Gas and WCA prices would see a commensurate reduction compared to the base case.

In Figure 29 the annual average nominal Mid-C price for all four scenarios is presented. In all four scenarios the years 2024 and 2025 are held to be the same. Starting in 2026, prices begin to diverge as the impact of having different natural gas and carbon prices in the simulations take hold.

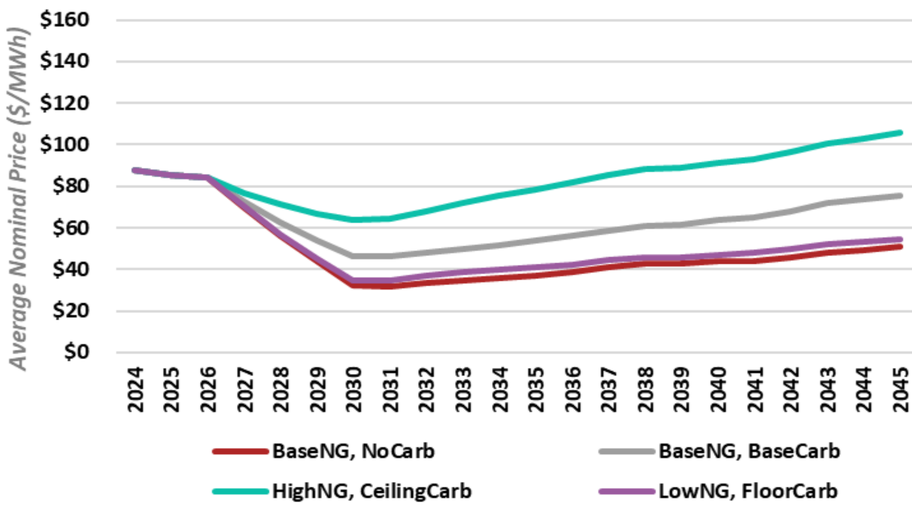


Figure 29. Projected Mid-C Average Nominal Price, by Scenario

As expected, removing the carbon price, and reducing the natural gas and carbon prices produces a market environment details the change in price for the alternative scenarios as compared the Base Case across the 2024-to-2045-time horizon.

	BaseNG, NoCarb	BaseNG, BaseCarb	HighNG, CeilingCarb	LowNG, FloorCarb
Average Price	$49.03	$63.53	$83.14	$51.68
Price Difference ($/MWh)	-23%		31%	-19%
Price Difference (%)	($14.50)		$19.61	($11.85)

Figure 30. Variance from Base Natural Gas and Base Carbon Scenario

Section 8 Risk Analysis and Portfolio Selection

FPUD's objectives are to develop an optimal resource plan capable of managing uncertainties in projected monthly peak demands and to meet the WRAP requirements. The IRP process is a strategic approach used to achieve these objectives. It evaluates and plans for future capacity and energy requirements while considering various objectives and constraints. It involves a comprehensive analysis integrating technical, economic, environmental, and regulatory factors to develop a balanced and optimal resource plan. The IRP process also uses scenario and sensitivity analysis to detect gaps, communicate insights, and identify risks and opportunities.

Scenarios typically involve key business decisions or pathways based on varying one or more assumptions. The assumptions can encompass changes in an organization's portfolio, the timing of decisions, or regulatory factors impacting the organization. These scenarios allow the organization to explore a range of possibilities and assess how different factors might influence the outcomes of the IRP.

Sensitivity analysis is used to evaluate how sensitive the outcomes of the IRP are to varying input variables. Its use is important in assessing reliability, understanding uncertainty, and enhancing the robustness of resource plans. It quantifies the impact of changes in each input variable on the outputs by varying one input at a time while holding all others constant. This analytical approach supports developing plans that are resilient and adaptable to changing conditions, thereby mitigating risks effectively.

The IRP incorporates several key assumptions guiding FPUD's decisions on future energy and capacity resources:

- **20-year demand forecast:** A prediction of electricity consumption over two decades guiding capacity planning and infrastructure investment decisions.
- **Existing and planned resource dispatchable variable cost:** The operational costs associated with current and future dispatchable resources, influencing operational decisions and cost projections.
- **Supply-side generation resource options:** Estimation of factors such as availability, capital expenditures, fixed costs, and variable costs for the development and procurement of various generating technologies.
- **Fuel, economic and market product costs:** Projections of fuel prices, economic indicators such as inflation and discount rates, and market prices for electricity and related products.

These assumptions, among others, provide a comprehensive framework for FPUD to make informed decisions regarding existing capacity resources and strategically plan for future requirements. They form the basis for developing a resilient and cost-efficient plan that aligns with regulatory requirements and market dynamics.

This study uses a long-term generation expansion model to determine the least cost replacement and expansion resource mix. The PLEXOS electricity production cost model is used to simulate FPUD's production cost and interactions within the electric market. PLEXOS integrates the system and resource assumptions to optimize and select the least cost resource mix.

The primary goal of PLEXOS is to minimize the incremental Net Present Value of Revenue Requirements (NPVRR) while complying with system and regulatory requirements. NPVRR represents the net cost that must be recovered for all resources in FPUD's portfolio, adjusted for the time value of money. This includes capital costs for new resources, variable costs, and fixed costs incurred during the study period. It excludes existing debt service costs, sunk costs prior to the study period, and costs incurred 5 years beyond the study period.

The model provides a mathematically optimal selection of future resources based on defined input assumptions, diverse resource types and capacities, and specific constraints such as import limits and minimum reserve margins.

8.1 Scenario Cases and Results

FPUD has considered two scenarios to help meet their objectives: the Reference Portfolio and a Renewable portfolio. The Reference Portfolio is used as a baseline to compare against other scenarios and sensitivities. For the Reference Portfolio the following assumptions were provided:

- Inflation rate of 2.2% and a discount rate of 4.75%.
- WRAP reserve requirements, as detailed in Section 3.5, include additional constraints aimed at ensuring seasonal adequacy rather than focusing solely on peak month demands.
- Base Load as described in Section 4.2.
- Operating information and variable costs for existing owned and contracted resources.
- Supply-side generation resource options in accordance with 0.
- Base natural gas price and market price forecast as discussed in Sections 7.2.5 and 7.3.2 respectively.

In the Reference Portfolio, FPUD assumes that the WRAP implementation starts in November 2027 and continues through the entire planning horizon.

Acknowledging the cost competitiveness and environmental benefits of renewable energy initiative, FPUD also assumes a scenario to explore more aggressive implementation of wind and solar energy sources. Restrictions on the adoption have been removed from both wind and solar energy sources, but limits remain on battery storage adoption. Table 6 outlines how the scenarios are incorporated into the IRP.

Table 6. Scenario Analysis Assumptions

Scenario	Load	NG Price	Carbon	WRAP Implementation	Technology
Reference Portfolio	Base	Base	Base	11/2027	Base
Renewable Portfolio	Base	Base	Base	11/2027	Unlimited wind & solar

8.1.1 Reference Portfolio Results

The PLEXOS modeling software optimized a cost-effective portfolio, illustrated in Figure 31, to fulfill FPUD's seasonal WRAP requirements throughout the study horizon. The figure depicts existing resources and proposed additions optimized to meet the WRAP requirements. Resources identified by PLEXOS are labeled as "New" with their respective source type, ST Contract or Tier 2. Existing resources are projected to satisfy average energy consumption through 2028, highlighting a need for intermediate to peak resources to bridge the gap thereafter. Powerex 10-year extension has been selected to meet average energy, complemented by the integration of battery storage and short-term energy solutions. Battery storage selection incorporates capacity and operational advantages. Initially, Short-term energy and capacity needs are fulfilled by Teir 2 and ST contracts later transitioning on to battery storage. Solar additions are progressively expanded to meet the remaining capacity and energy needs.

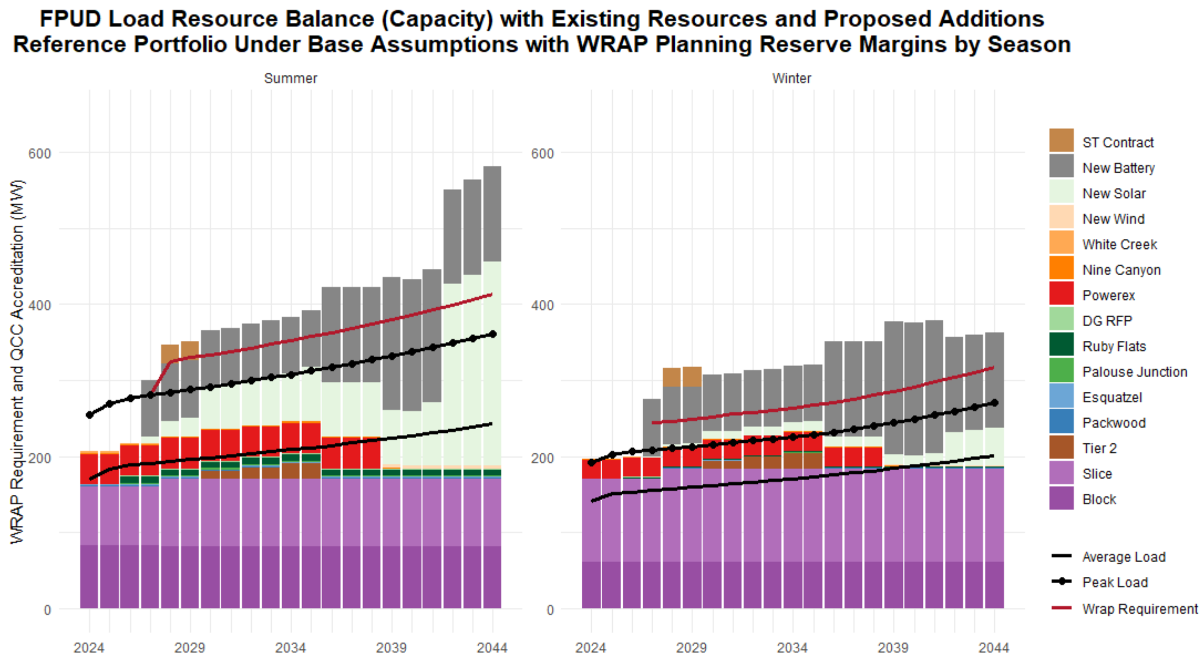


Figure 31. Demand and Resource Load Balance for Reference Portfolio

Figure 32 displays the seasonal energy generated by the existing and proposed resource additions in average megawatts (aMW) per year. This measure is derived by dividing the resource's seasonal energy production by the total number of hours in a season. FPUD's current resources, including the Powerex extensions, meet average energy consumption through 2038. Beyond 2039, when the Powerex contract expires, solar and wind energy sources will be utilized to fill the energy gap. The intermittent nature of these sources reduces the system flexibility; however, integrating battery storage and leveraging the market can enable economic sales and enhance energy management capabilities.

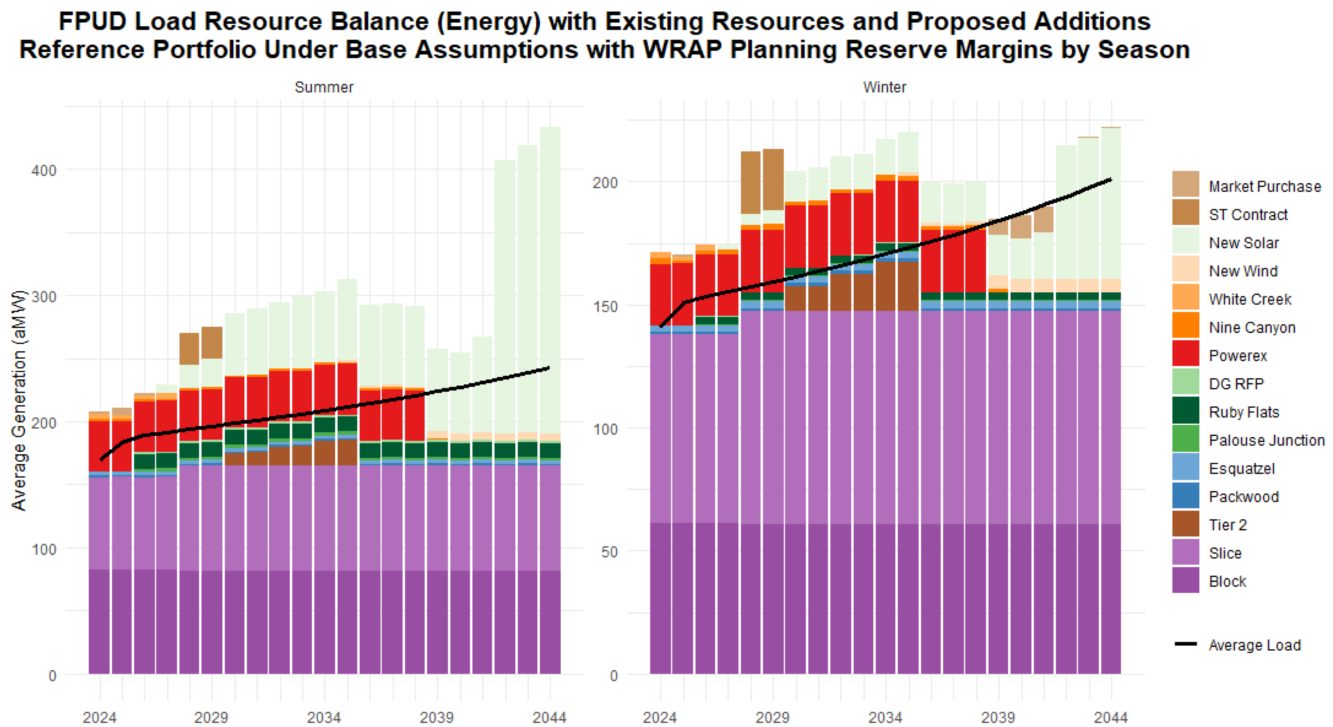


Figure 32. Energy Resource Load Balance for Reference Portfolio

Figure 33 shows the annual variable and incremental revenue requirements with qualifying capacity changes for the Reference Portfolio. This analysis excludes existing debt servicing costs and sunk costs prior to the study period.

The Variable Operations and Maintenance (VOM) cost is tied to current resources. When Powerex goes offline in 2039, the VOM cost decreases. The Fixed Operations and Maintenance (FOM) cost correlates with batteries, which increases gradually as battery storage is integrated into the portfolio. The Construction (Build) cost is linked to the installation of wind and solar additions. The cumulative incremental NPVRR for the Reference Portfolio totals to $947 million over the study period. This amount serves as the benchmark for scenario comparisons and sensitivity analyses.

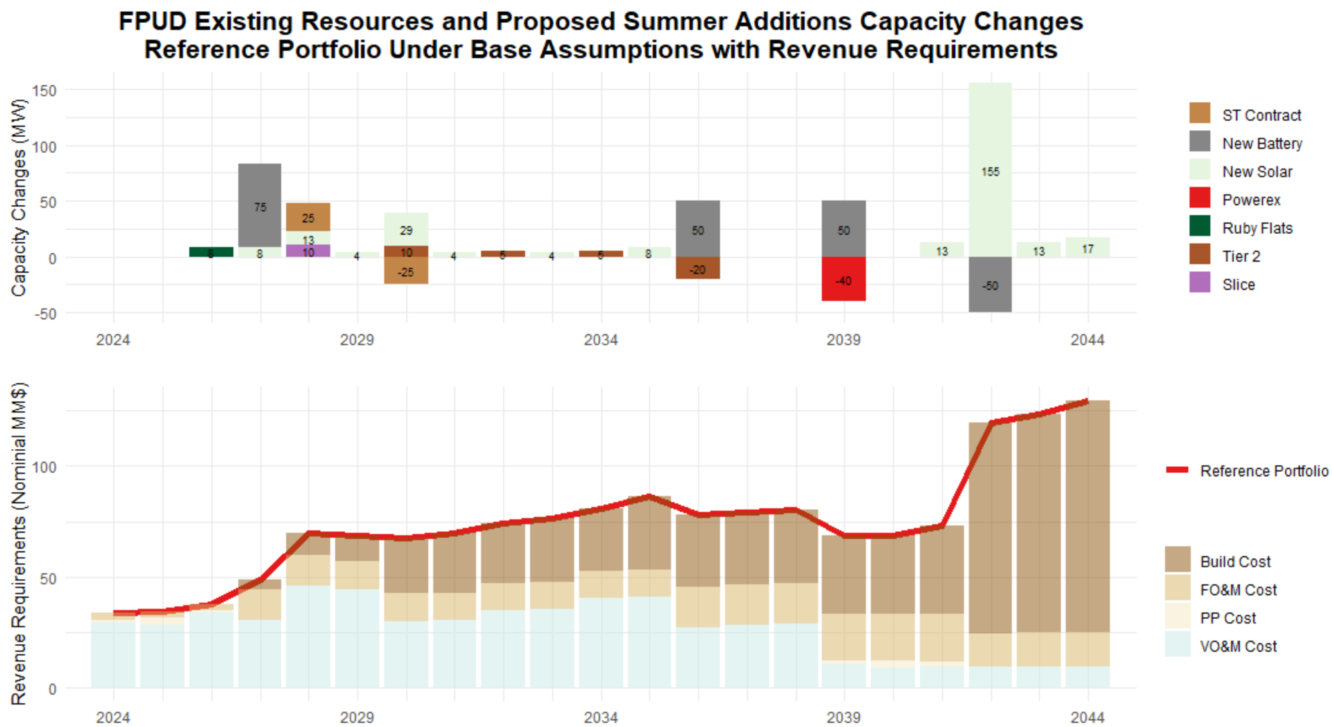


Figure 33. Nominal Revenue Requirements for Reference Portfolio

Battery storage, with its distinctive characteristics unlike traditional thermal sources, functions both as a load and a capacity resource. It can store significant amounts of energy and shift it to periods when the system faces shortages in energy supply. This capability is advantageous for a portfolio of this scale, especially in later years when numerous intermittent resources are installed. Figure 34Figure 34 provides a simulated view of how this is accomplished within FPUD's portfolio after the adoption of significant amounts of renewable energy.

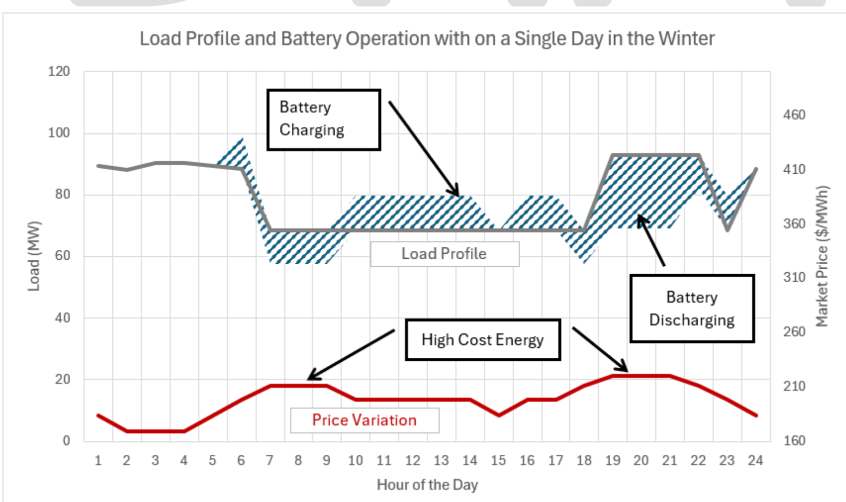


Figure 34. PLEXOS Simulated Output of Energy Shifting Within FPUD Reference Portfolio

The Reference Portfolio includes resources that enhance system resiliency while renewable energy capacity is increasing significantly. Battery storage plays a crucial role in bridging short-term capacity gaps due to changing WRAP requirements. Battery operation will allow flexibility for effectively integrating over 1,200 MW of renewable energy into the portfolio, ensuring adaptive and sustainable energy management strategies.

8.1.2 Renewable Portfolio Results

The renewable portfolio was introduced to understand the economic opportunities and cost associated with transitioning to a low carbon and sustainable energy system. This analysis provides insights into the resources required using current technology options and help provide strategic pathways necessary to achieve a sustainable energy future.

Figure 35 shows FPUD's current energy portfolio is well-balanced and capable of meeting average energy consumption with minimal exposure to market price fluctuations. Before 2027, there are no economic opportunities for resource selection. In the renewable portfolio, restricting the portfolio to renewable resources preserves the reliance on battery storage. While wind plays a smaller role in meeting energy and capacity needs, solar capacity expands within the portfolio. These dynamics highlight the evolving mix of renewable sources and emphasize strategic adjustments to enhance reliability and sustainability in energy supply.

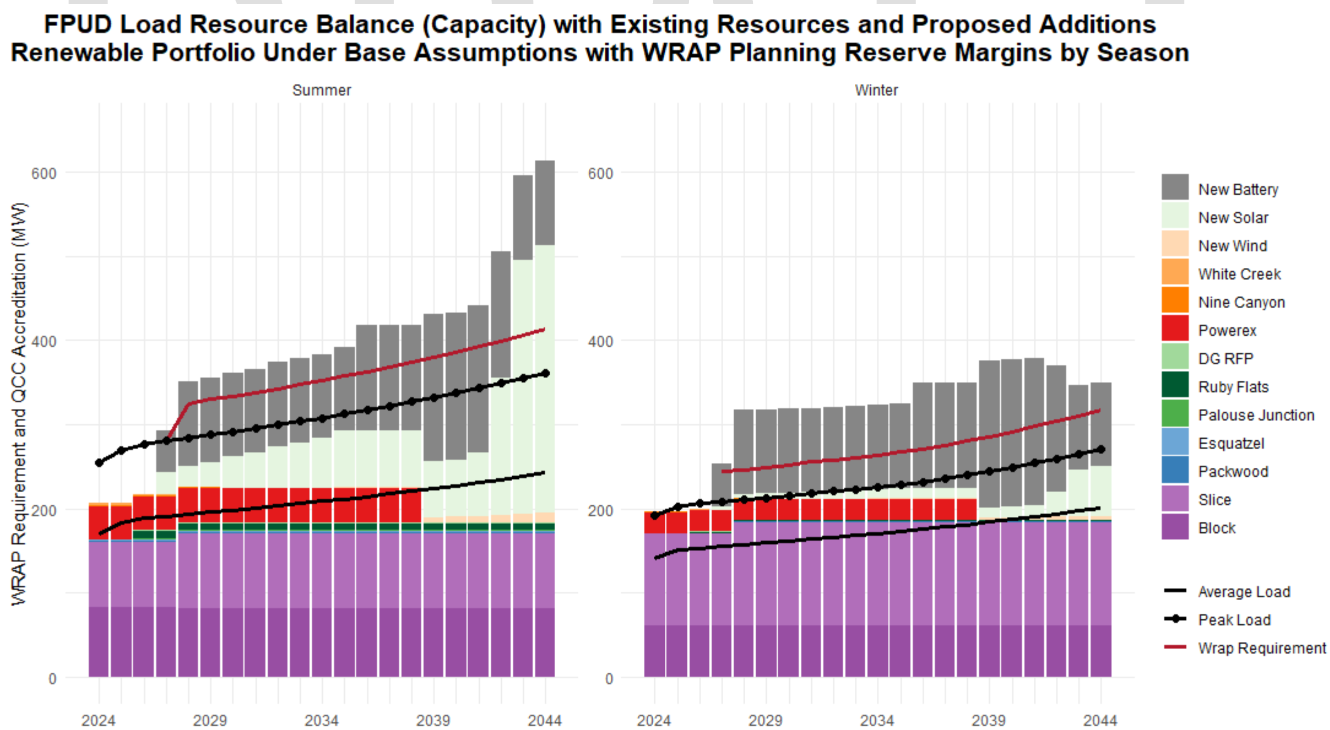


Figure 35. Demand and Resource Load Balance for Renewable Portfolio

Figure 36 displays the seasonal energy generated by the existing resources and proposed additions in average megawatts (aMW) per year for the Renewable Portfolio. The renewable portfolio reflects similar characteristics as the reference cases solution, including an overbuild of intermittent energy to ensure capacity requirements are met. Existing resources remain the primary source of energy for the portfolio.

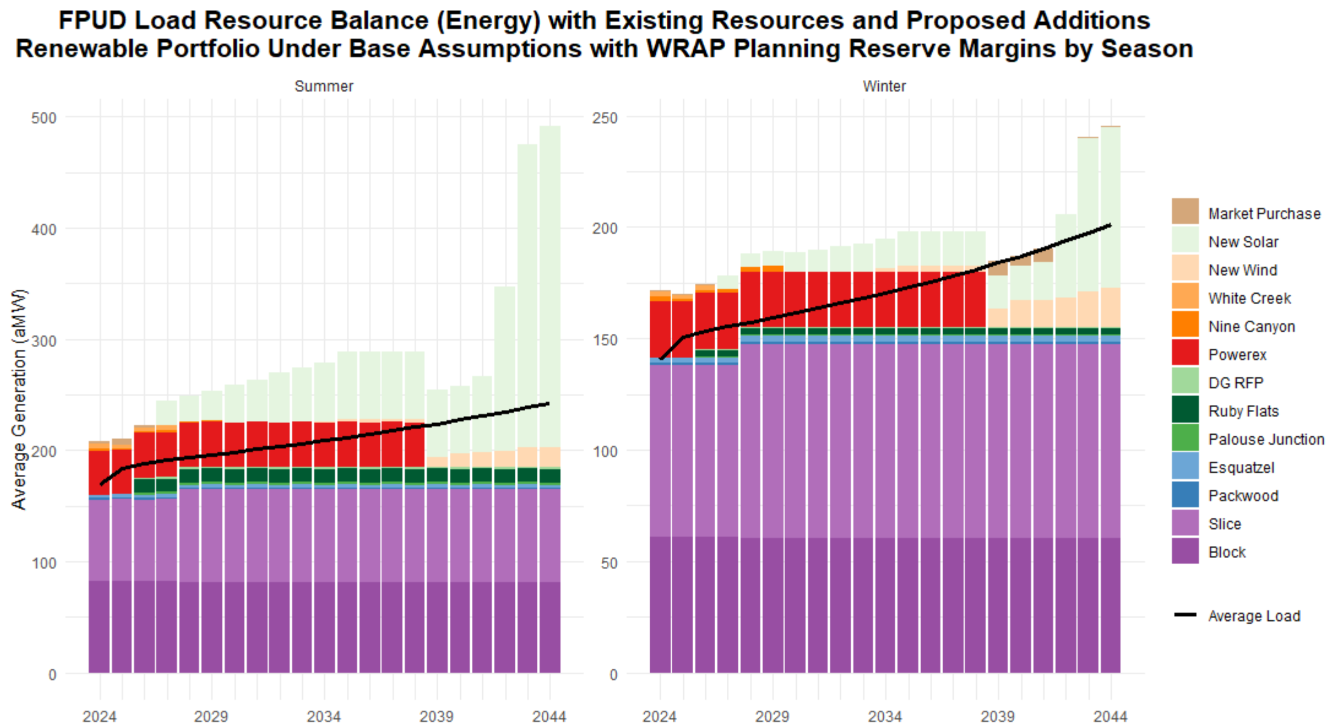


Figure 36. Energy Resource Load Balance for Renewable Portfolio

Figure 37 illustrates that the NPVRR of the renewable portfolio is lower than that of the reference portfolio. The renewable analysis enables the model to strategically choose renewable resources for the portfolio. Unrestricted solar additions provide further benefits by optimizing resource allocation, including larger solar installations in 2027. Moreover, this approach mitigates the need for costly short-term solutions like ST Contracts and Tier 2 option.

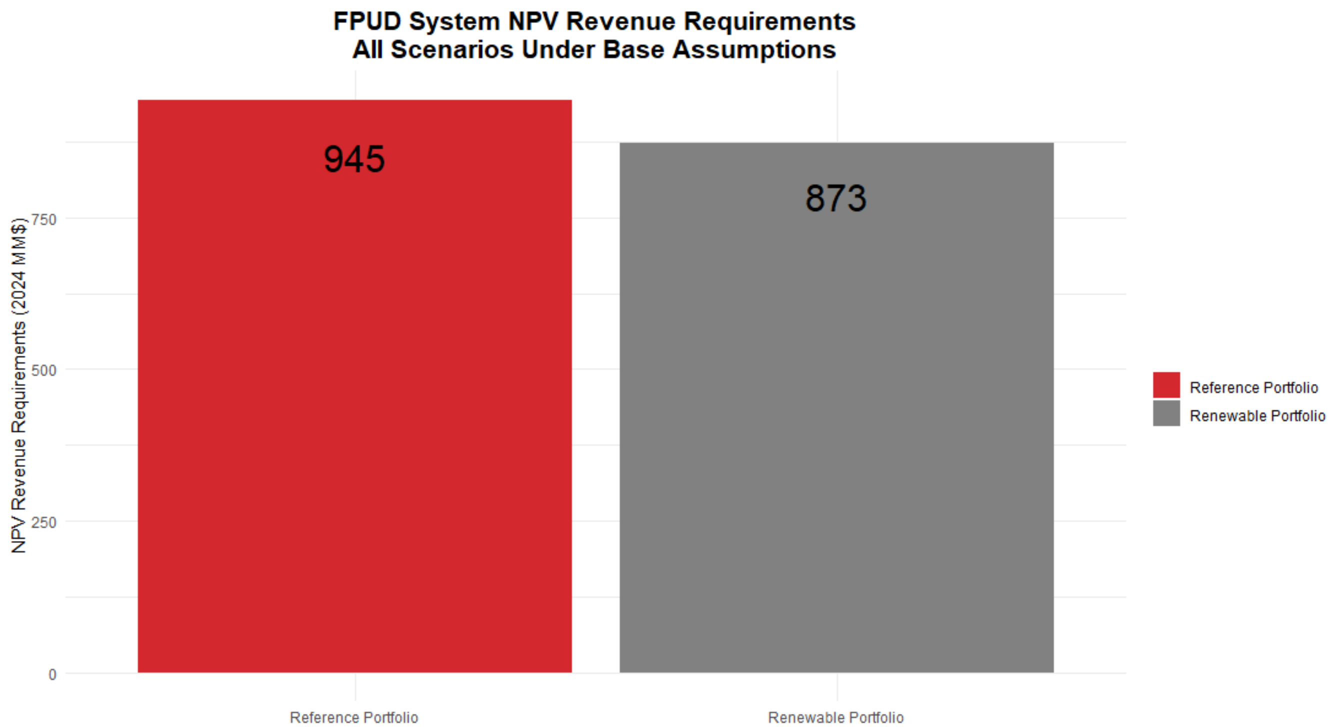


Figure 37. 20-year NPVRR for All Scenarios

FPUD performed a comparison between two portfolios: the reference portfolio, which imposes restrictions on the integration of solar and wind resources, and the renewable portfolio, removing these constraints. Both portfolios were limited to 200MW battery storage in which both used optimally 175 MW. The remaining capacity requirements are fulfilled through increased solar adoption, requiring an overbuild of solar energy to meet these obligations.

In the reference portfolio, which utilizes short-term contracts for capacity needs, these options proved costly and offered no additional flexibility compared to the renewable portfolio. The availability of renewable energy technologies played a crucial role in effectively meeting FPUD's capacity requirements.

Overall, the study highlights the advantages of a flexible approach to renewable energy integration, demonstrating how removing constraints on solar and wind installations can lead to cost savings, increased flexibility (compared to fixed contract energy), and more efficient capacity management within FPUD's portfolio.

8.2 Sensitivity Analysis and Results

FPUD has incorporated sensitivity analysis to address the uncertainty surrounding its load forecast. The load forecast is a key driver for future infrastructure investments required to maintain system reliability. Understanding the potential impact load can have on these investments is crucial to this IRP process. The IRP includes three load sensitivity analyses: low (annual demand growth of 1.1%), base (annual demand growth of 1.6%), and high (annual demand growth of 2.1%). Table 7 outlines how sensitivity analyses are incorporated into the IRP.

Table 7. Sensitivity Analysis Assumptions

Sensitivity	Load	NG Price	Carbon	WRAP	Technology
Low Load	Low	Base	Base	Base	Base
Base Assumptions	Base	Base	Base	Base	Base
High Load	High	Base	Base	Base	Base

These analyses offer understanding of how FPUD's current and future resource needs would change under different possible load growth scenarios.

Figure 38 presents the load resource balance using existing and proposed resources across various scenarios and sensitivity combinations. Instead of depicting changes over 20 years, specific years are highlighted. The year 2028 marks a full year of WRAP implementation in the Reference Portfolio scenario. Years 2033 and 2036 represent periods before and after resources such as SMR and geothermal become available under the same scenario. Finally, 2044 marks the conclusion of the IRP study.

At a high level, resource selection remains uniform across all scenario and sensitivity variations. Battery storage remains the primary resource for meeting capacity requirements, with solar adoption progressively increasing to fulfill both capacity and energy demands. Capacity levels adjust accordingly across different studies, showing increased adoption in response to higher load levels.

Resource selection remains consistent across most scenario and sensitivity combinations:

- In sensitivities with incremental restrictions on solar additions, short-term products are added in the reference cases.
- High load sensitivity introduces additional resources such as wind and geothermal into the mix.
- Throughout all studies, battery storage and solar remain primary resources.

After the completion of the load forecast used for this IRP, Franklin PUD received a new population growth forecast from the City of Pasco that likely implies a higher load growth than the high scenario used in this study. A portion of the City of Pasco’s load falls outside of the service territory of FPUD, so it is unclear how much of the projected new load will impact FPUD. However, if FPUD’s load growth exceeds that forecasted in the high scenario in this study, this analysis indicates that the portfolio of resources would be unlikely to change. Instead, the same resources would likely remain cost-effective and simply be needed in larger quantities.

Figure 38. Sensitivity Load Resource Balance

Figure 39 compares the NPVRR of each of the sensitivities. The NPVRR graph reveals insights into the financial dynamics of renewable adoption within the portfolio. It demonstrates increasing the deployment of renewables results in cost savings, ranging from $7 to $59 million, with the most significant savings observed under conditions of high load sensitivity. Moreover, there is a clear correlation between load levels and costs: as load decreases, costs also decrease, whereas higher loads correspond to increased costs. The reference case exhibits greater cost variability due to fluctuations in load, highlighting the critical role of load management in optimizing financial outcomes. These findings give emphasis to the economic advantages of scaling renewable integration while emphasizing the strategic importance of load-sensitive planning in achieving cost efficiency.

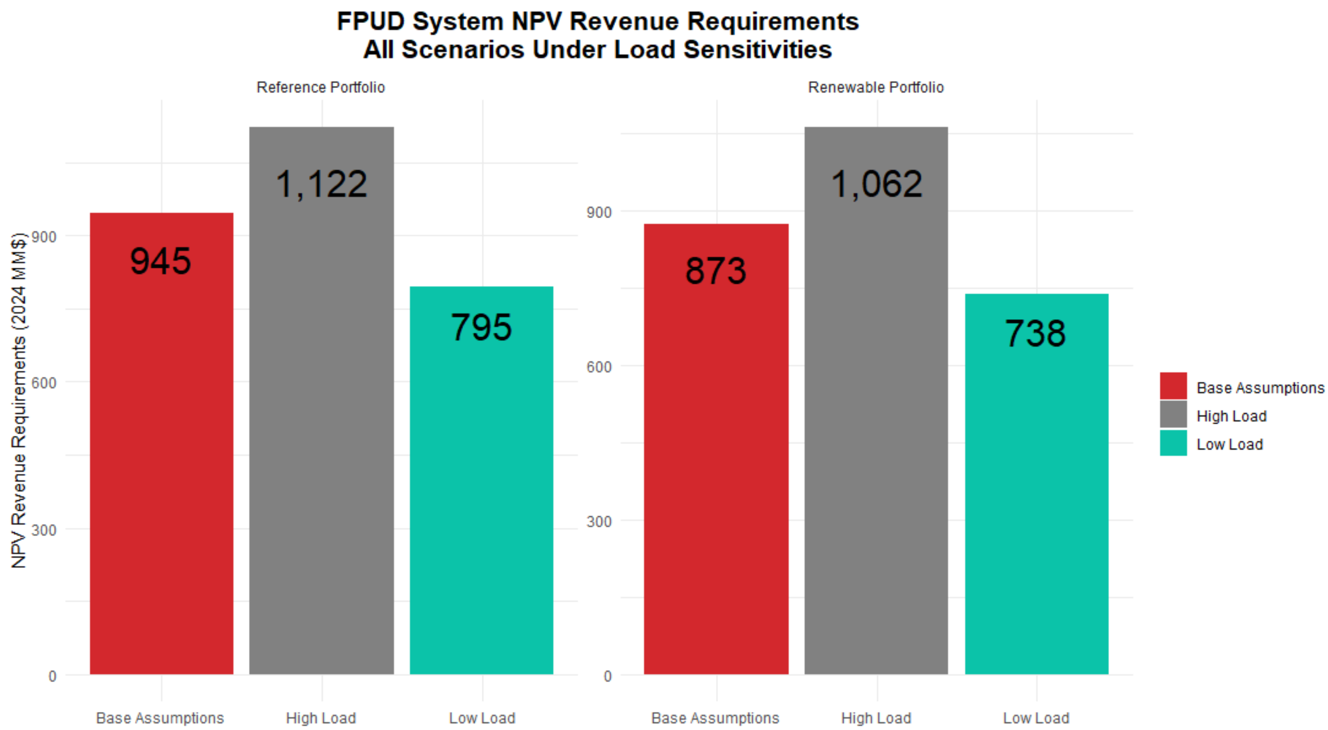


Figure 39. Sensitivity NPVRR

Battery storage and solar power play pivotal roles in meeting both capacity and energy requirements for FPUD. Effectively scaling renewable integration is crucial to mitigating potential cost escalations. Planning for future load growth is key to managing costs effectively. By strategically managing these resources, FPUD not only optimizes energy allocation but also enhances overall infrastructure efficiency, ensuring sustainable and reliable energy solutions for future demands.

8.3 BPA Load Following

FPUD will have the option of changing products with Bonneville Power Administration (BPA) under the next BPA power contract, known as the Provider of Choice (POC) contract. Neither the design of the products nor the rates for those products under the POC have yet been finalized. FPUD will review all BPA product offerings carefully once these products have been defined and select the option the best fits the needs of FPUD's customers.

Section 9 Conclusions

FPUD is currently meeting the energy demand of its customers with 90% carbon-free electric power and is projected to maintain balance between its load and resources in spite of a roughly 1.6% year-over-year projected load growth through the study period. However, on a capacity basis, FPUD has a considerable deficit that could grow to as much as 231 MW by 2044 if not addressed through additional conservation and power procurement. In addition, the introduction of the Western Resource Adequacy Program (WRAP) in 2027 would significantly increase the effective capacity need of Franklin Public Utility District.

The menu of options available to FPUD to meet this growing deficit is constrained but several environmental policies in the State of Washington. These include Washington's Renewable Portfolio Standard (RPS), the Clean Energy Transformation Act (CETA), as well as the Climate Commitment Act (CCA). In combination, these policies make it either economically infeasible or illegal to procure additional greenhouse-gas emitting resources. As such, Franklin will pursue all options available to meet its capacity needs using carbon-neutral resources.

First among these options, FPUD will maximize use of Bonneville Power Administration (BPA) Tier 1 power, which is the cheapest low-carbon capacity resource available to the utility. Notably, 2028 marks the start of a new 20-year contract with BPA in which FPUD will have the opportunity to re-evaluate it's BPA product choice. At this time, the BPA products and rates that will be offered in 2028 have not yet been defined. FPUD will remain fully engaged with the BPA process crafting these products and will carefully evaluate the product options once they are defined to select the product that offers the best fit for FPUD's needs over the next 20-year contract period.

In addition to maximizing BPA Tier 1 power, FPUD will continue to evaluate both opportunities for procuring additional resources and consider the extending current PPA contracts that are otherwise set to expire during the study period. The findings in this study indicate that a new resource portfolio dominated by solar and utility-scale batteries would be the most cost-effective way to meet its needs while complying with state environmental policies. FPUD is already in the process of potentially adding approximately 60 MW of nameplate solar capacity in 2026 through participation in the Ruby Flats and Palouse Junction projects. FPUD will also consider BPA Tier 2 opportunities and market-based purchases wherever competitive.

FPUD continues to monitor several emerging technologies, most notably geothermal, hydrogen, and small-modular nuclear reactors (SMR) for possible future procurement. At this time, these resources do not appear to be cost-competitive with solar and batteries, but technological innovations may change that dynamic within the timeframe of the study.

Finally, FPUD will acquire all cost-effective conservation measures and monitor opportunities for demand response and distributed generation investments that could cost-effectively reduce it's need for new capacity resources.

AGENDA ITEM 9

Franklin PUD Commission Meeting Packet
Agenda Item Summary

Presenter:	**Scott Rhees**	☑	**REPORTING ONLY**
	General Manager/CEO	☐	FOR DISCUSSION
Date:	**July 23, 2024**	☐	ACTION REQUIRED

1. **OBJECTIVE:**
Providing an Update on the 2024-2025 Operating Plan (Quarter 1 and Quarter 2 Year 2024).

2. **BACKGROUND:**
The 2024-2025 Operating Plan was approved at the May 27, 2024 regular meeting and contains goals centered around the four Strategic Priorities which are:

   - Preserve and Continue to Grow the Safety Culture
   - Optimize Systems to Provide Reliability for Our Customers
   - Effectively Mitigate Factors Impacting Rates
   - Develop Strong and Supportive Internal and External Relationships

   Through discussions with staff the General Manager/CEO has identified the progress made on Operating Plan Goals through Quarters 1 and 2 of 2024 and will provide an update to the Commission.

3. **SUGGESTED MOTION:**
No action required, reporting only.

June 2024

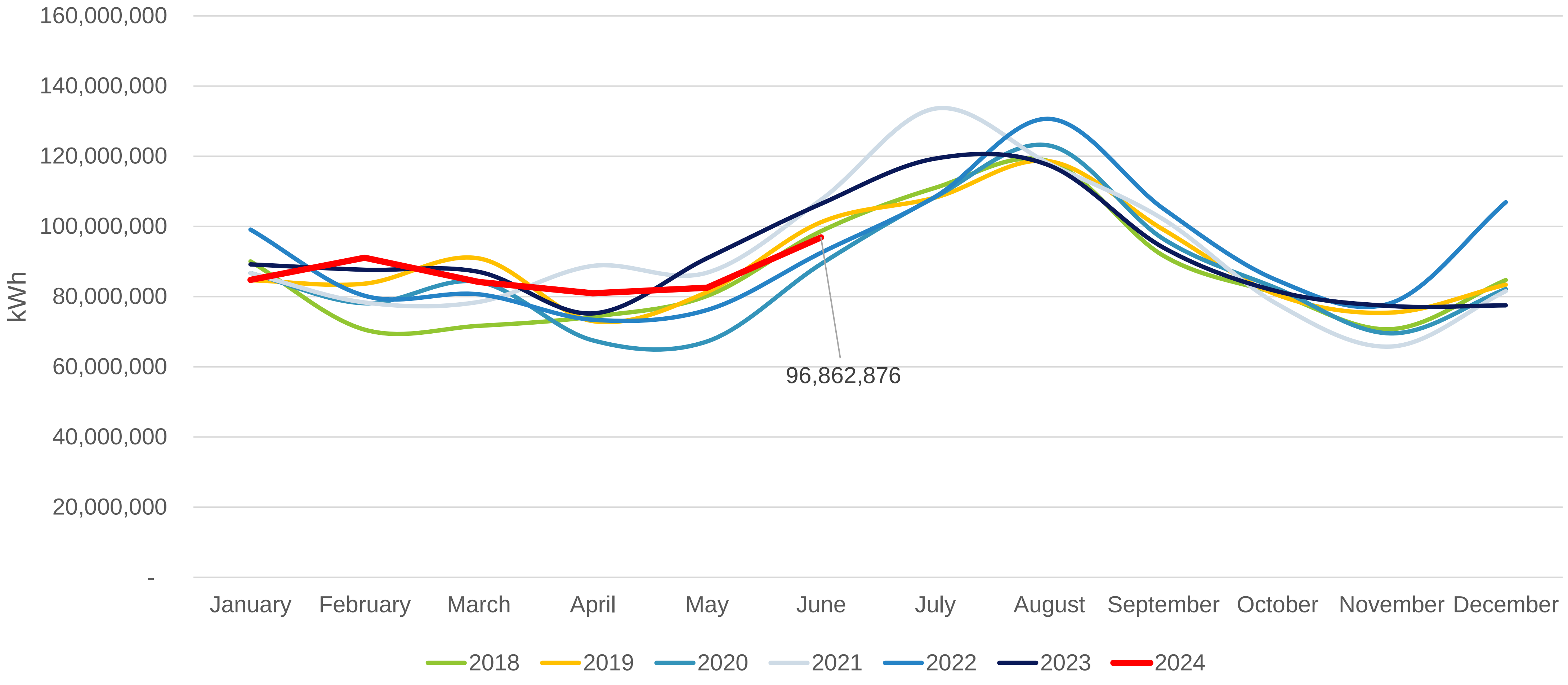
Monthly Key Performance Indicators

EXECUTIVE SUMMARY

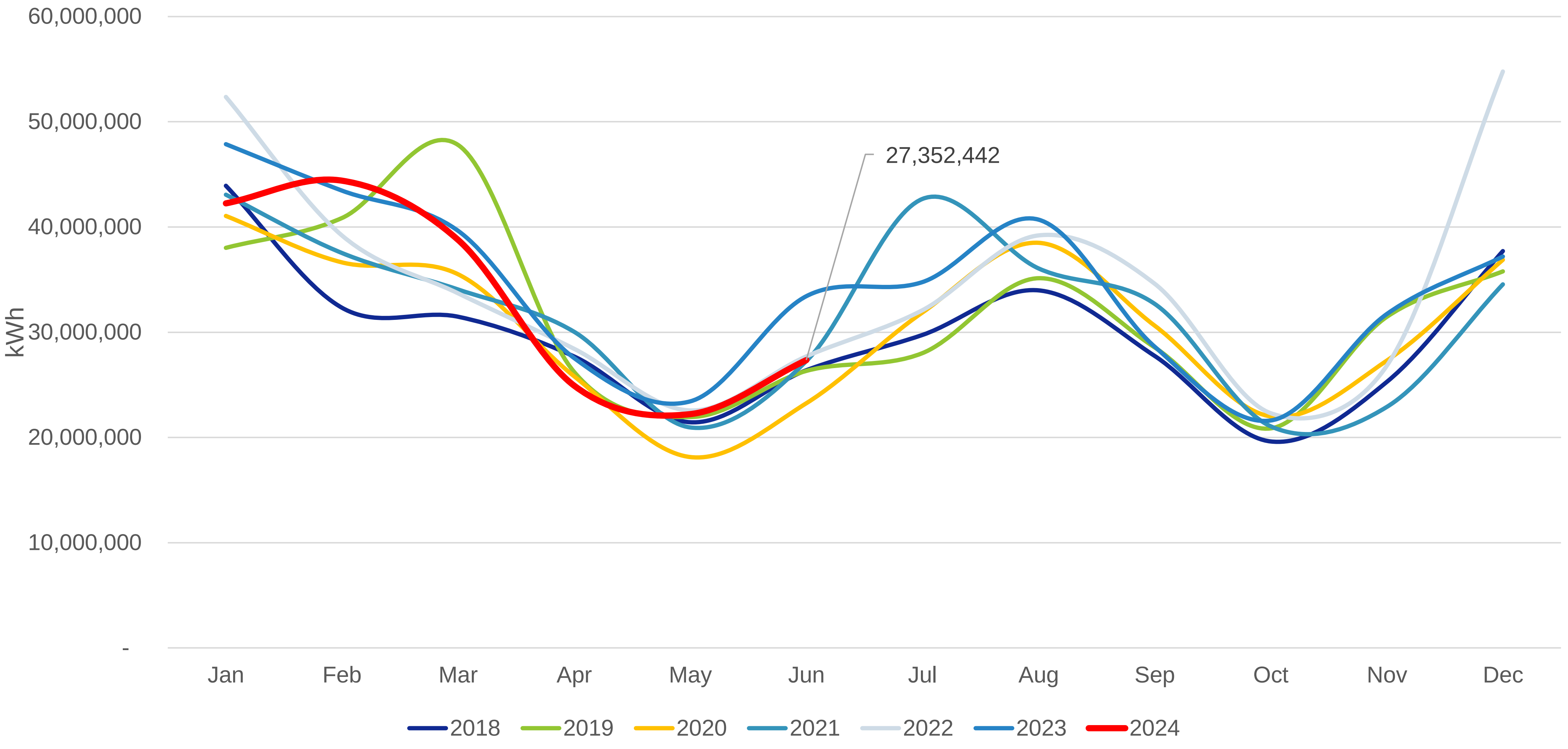
June retail loads were close to average and below June 2023, even with the heat late in the month. Overall, retail is running very close to budget on a YTD basis.

While June operating results were positive, they fell short of budget close to $1 million. This was due largely to slower federal grant revenue and capital contributions than expected, and net power costs exceeding budget.

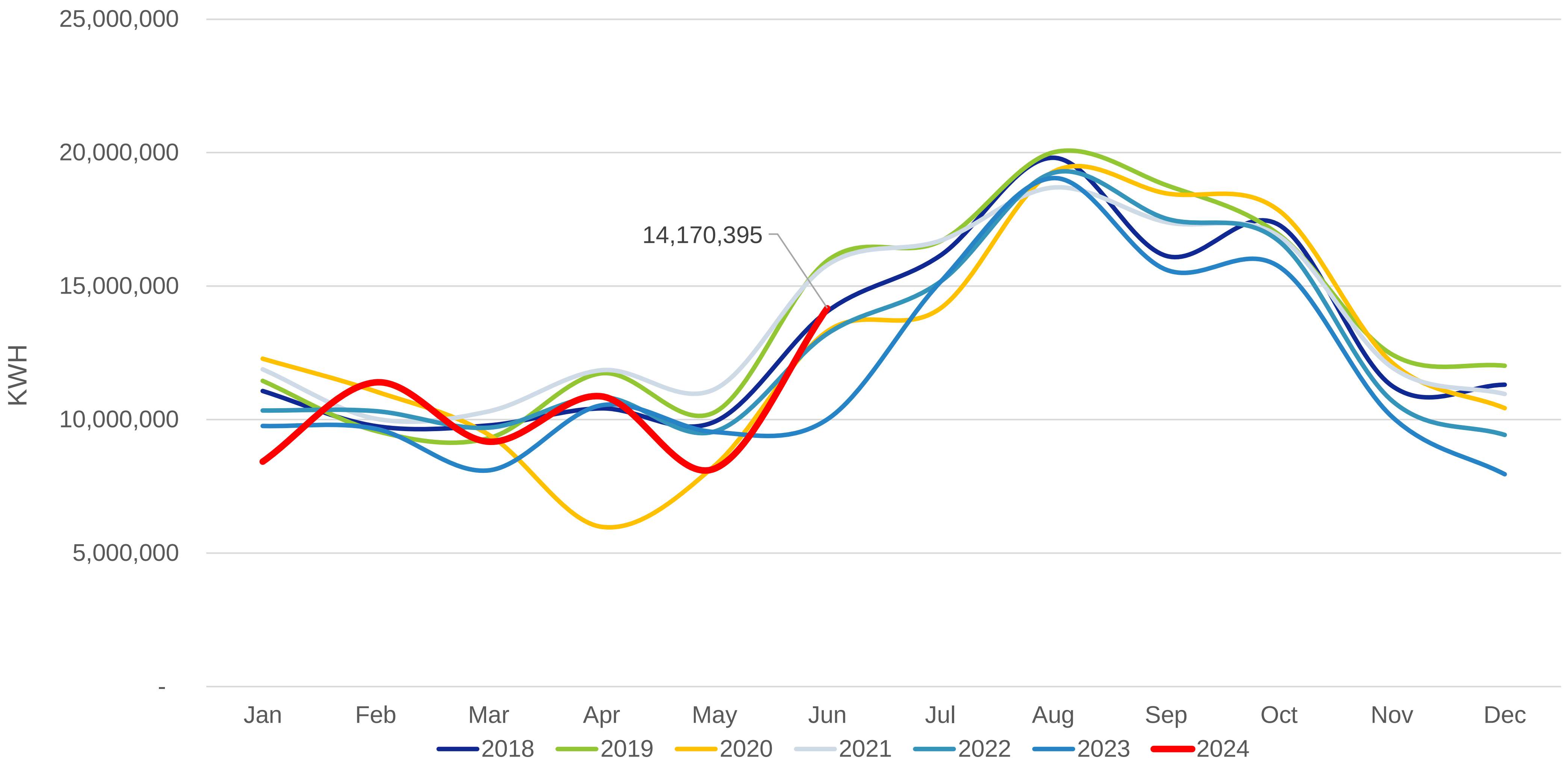
RETAIL LOAD COMPARISON



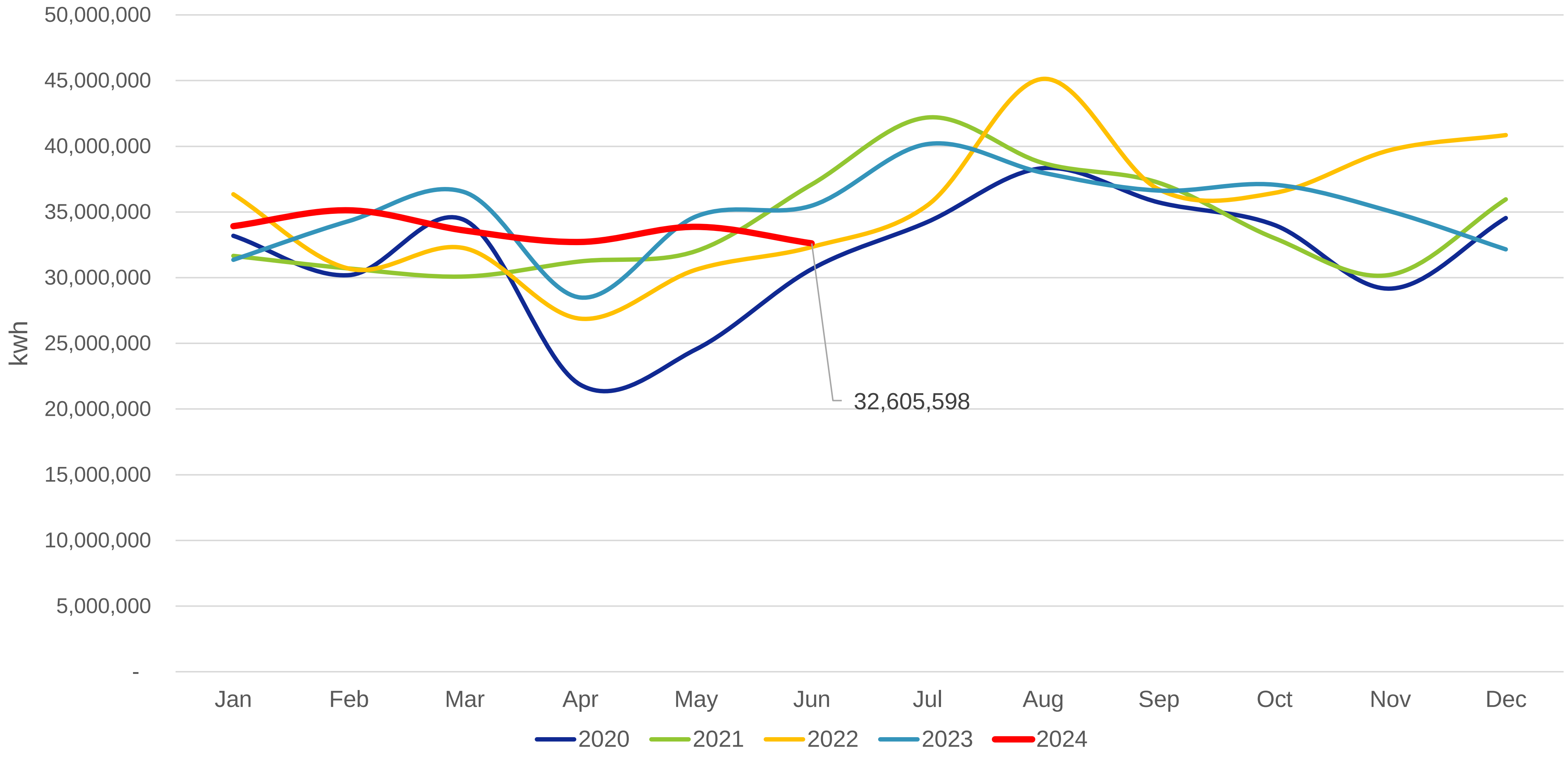
RESIDENTIAL LOADS



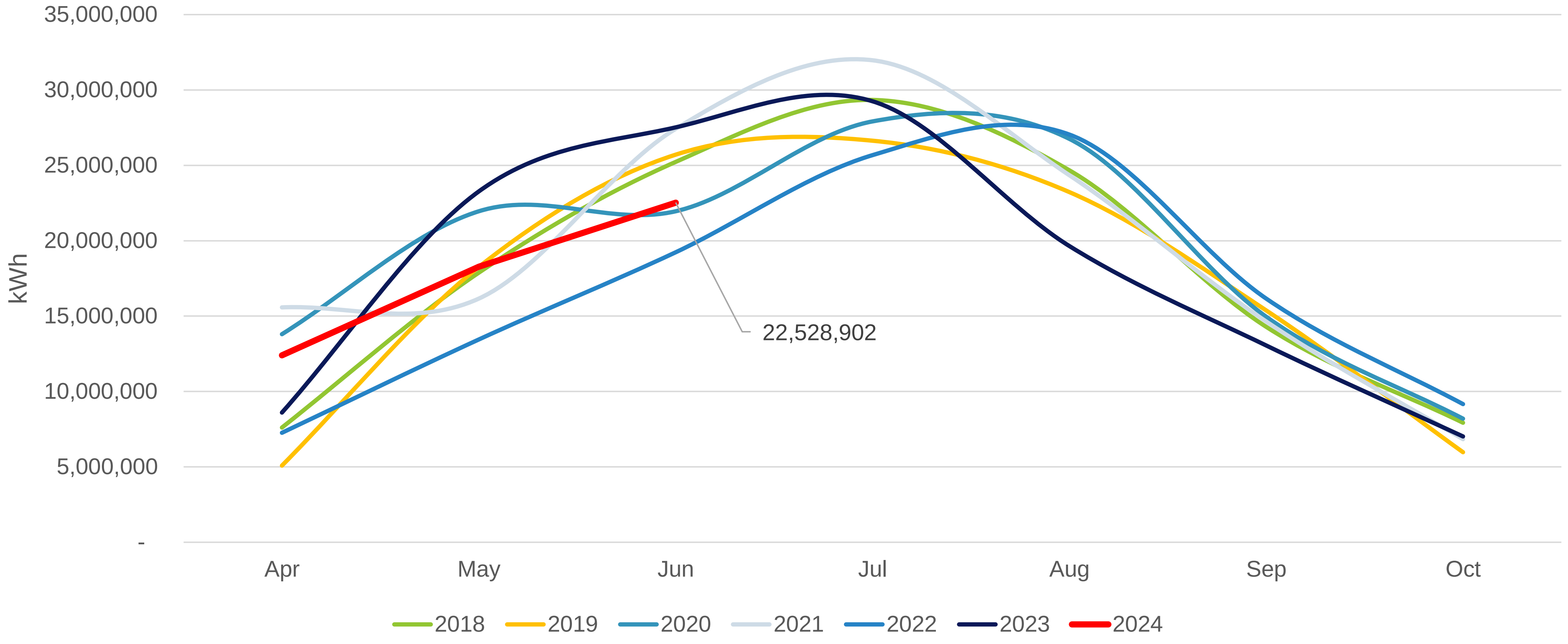
INDUSTRIAL LOADS



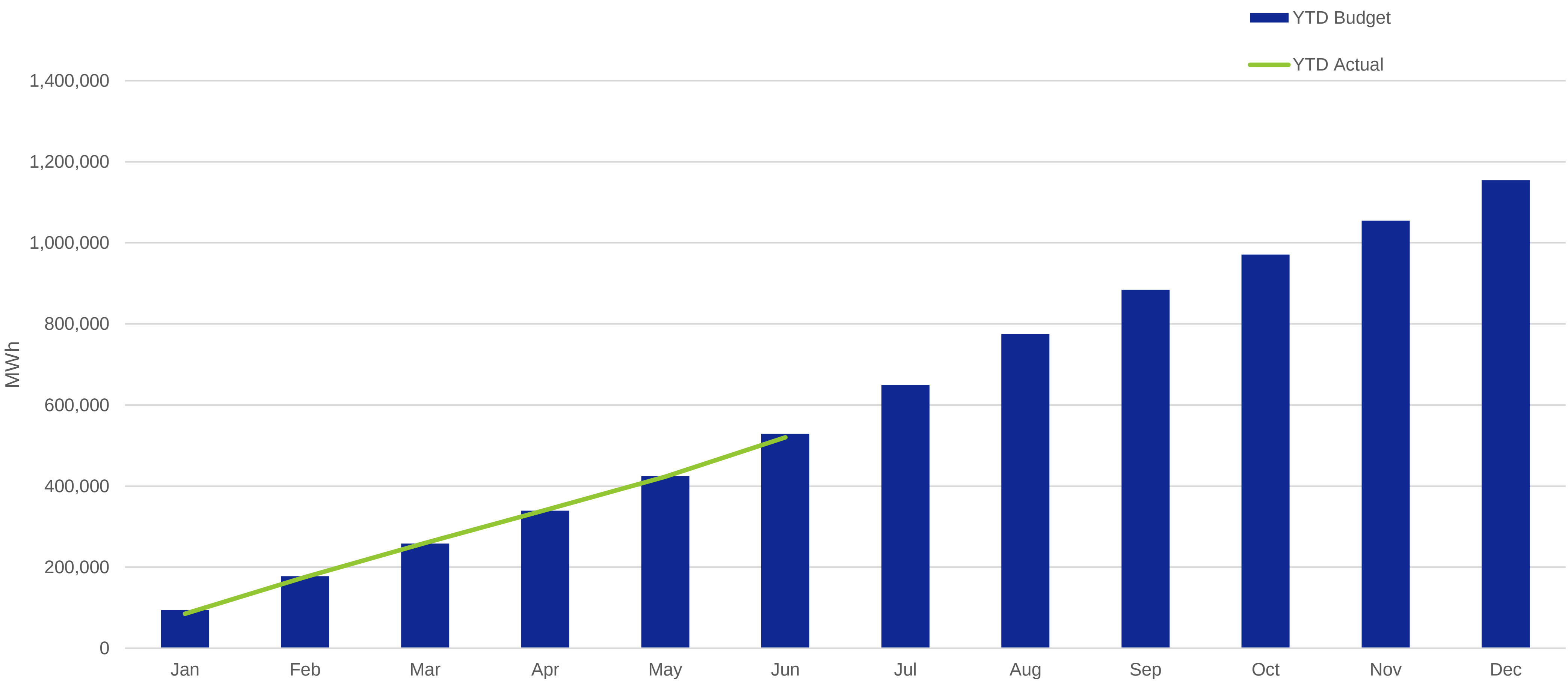
GENERAL LOADS



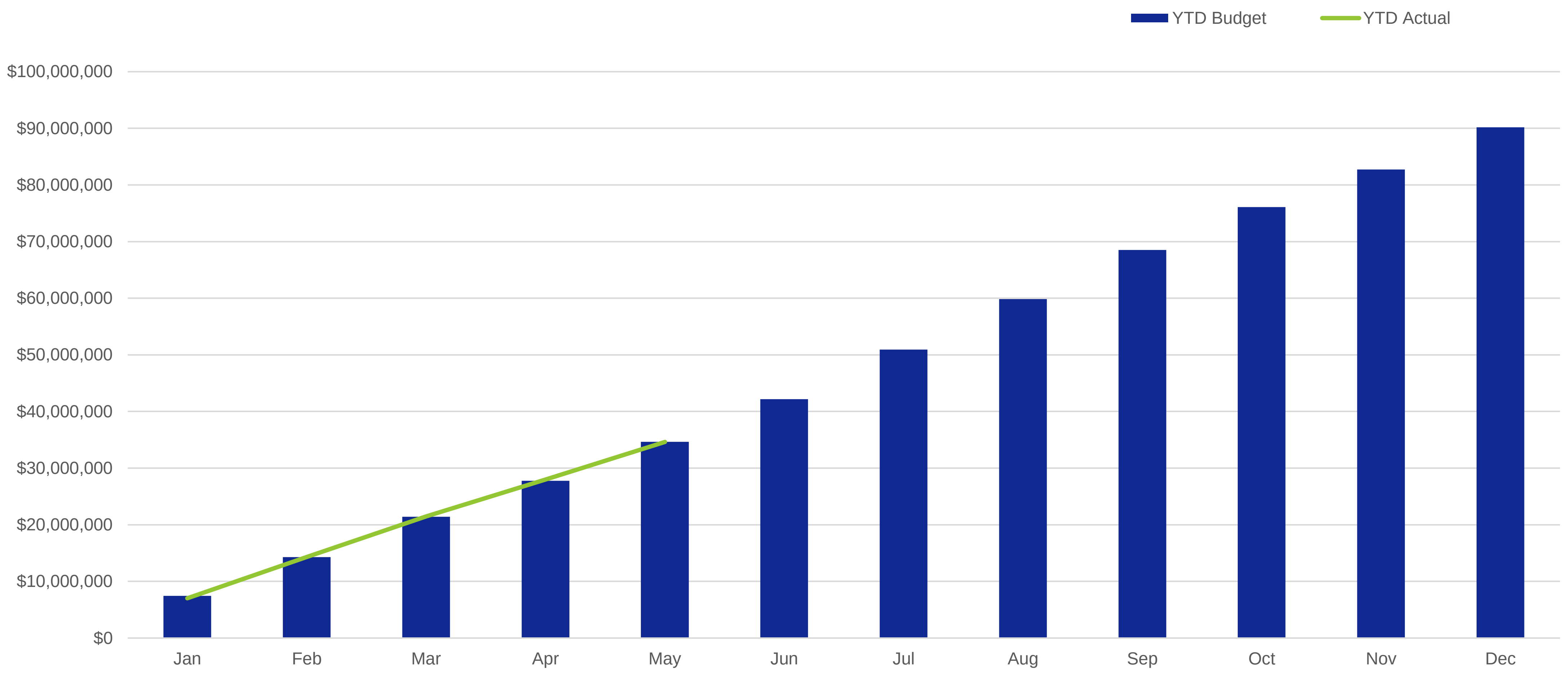
IRRIGATION LOADS



YTD LOADS: BUDGET VS. ACTUAL



YTD RETAIL ENERGY SALES $: BUDGET VS. ACTUAL



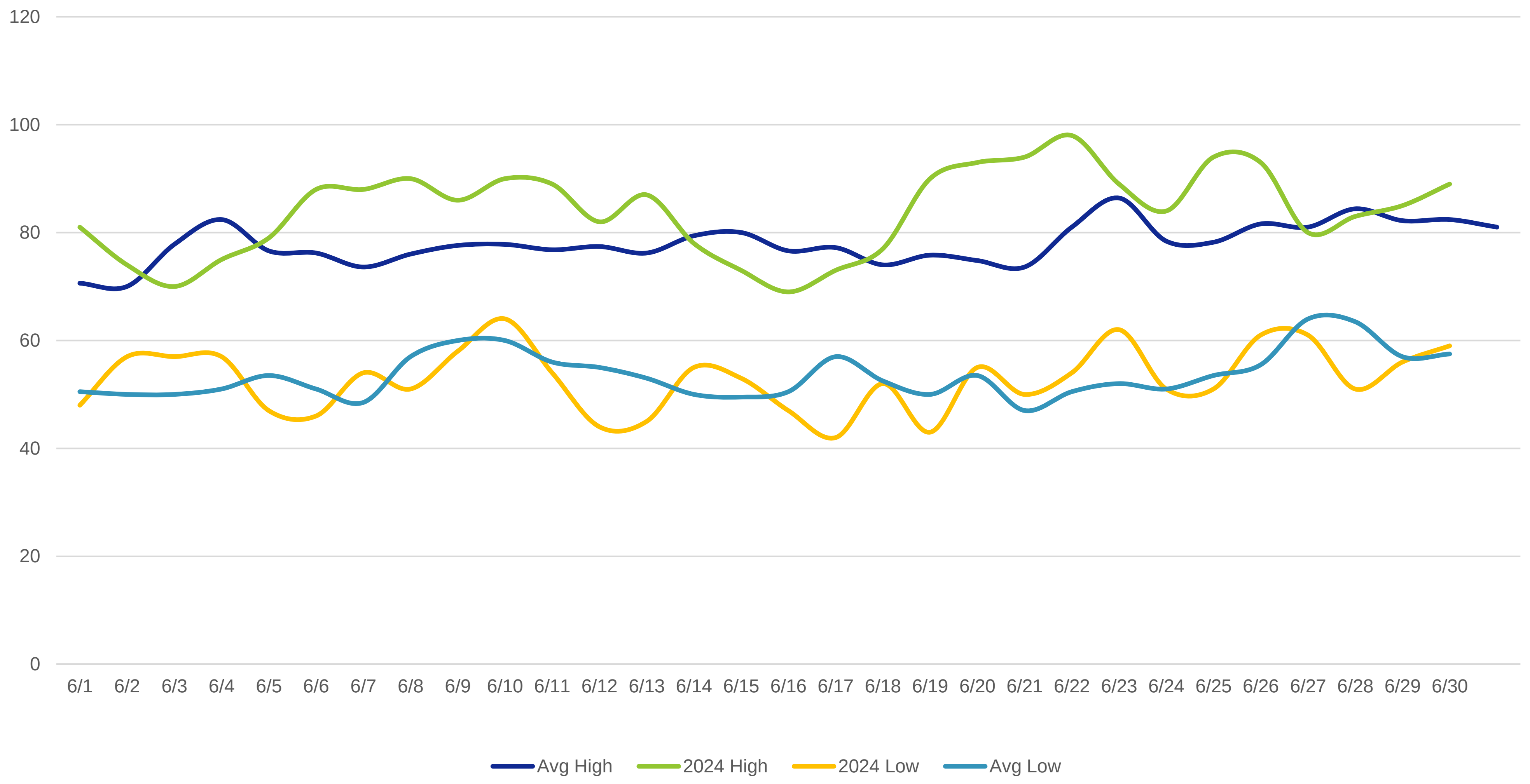

POWER


JUNE OVERVIEW

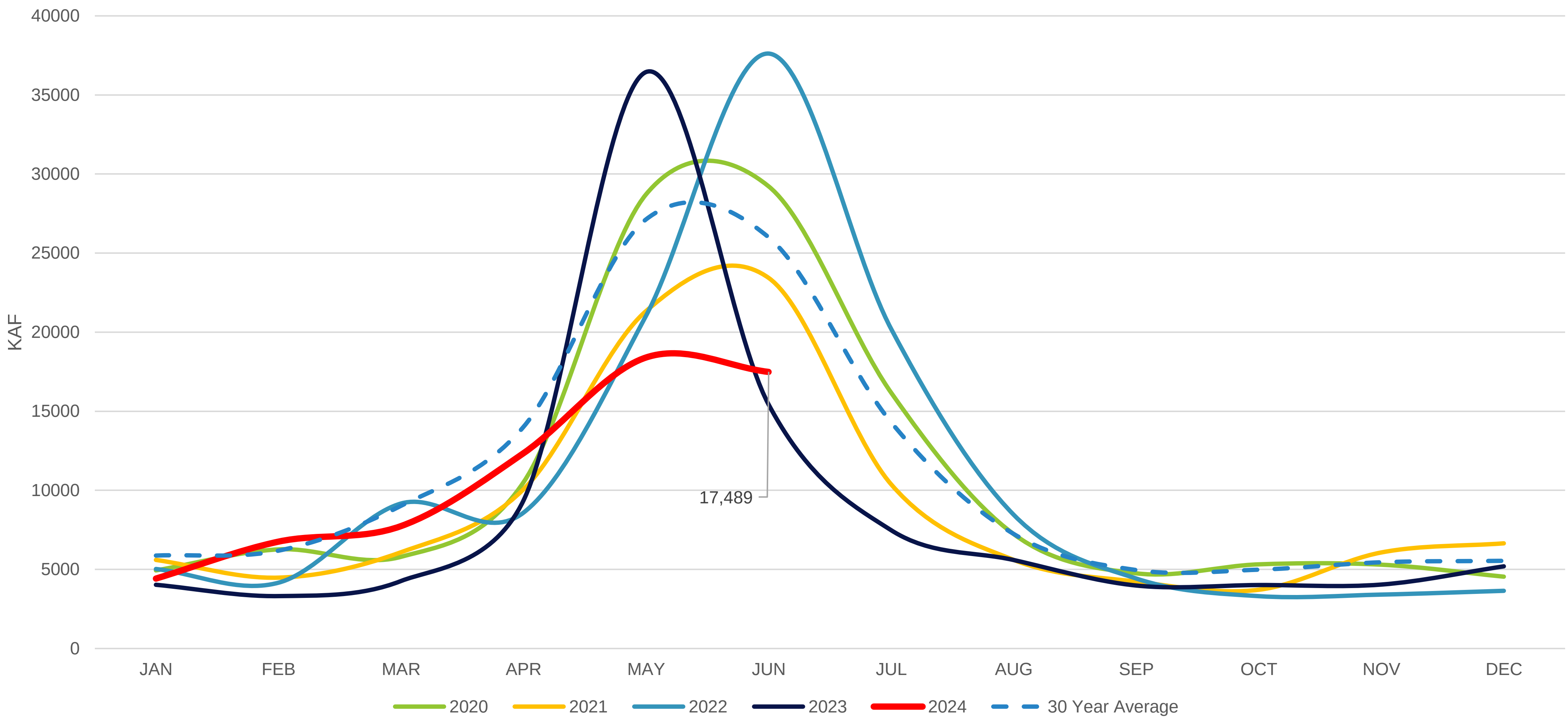
Average June weather led to stable and moderate pricing throughout the month. Due to stable market and delay in energization of some planned new loads, the District's swaps settled out of the money.

Water conditions in June continued as expected for the 2024 water year, coming in well below the 30-year average. We expect water to continue in this pattern and conditions remain tight.

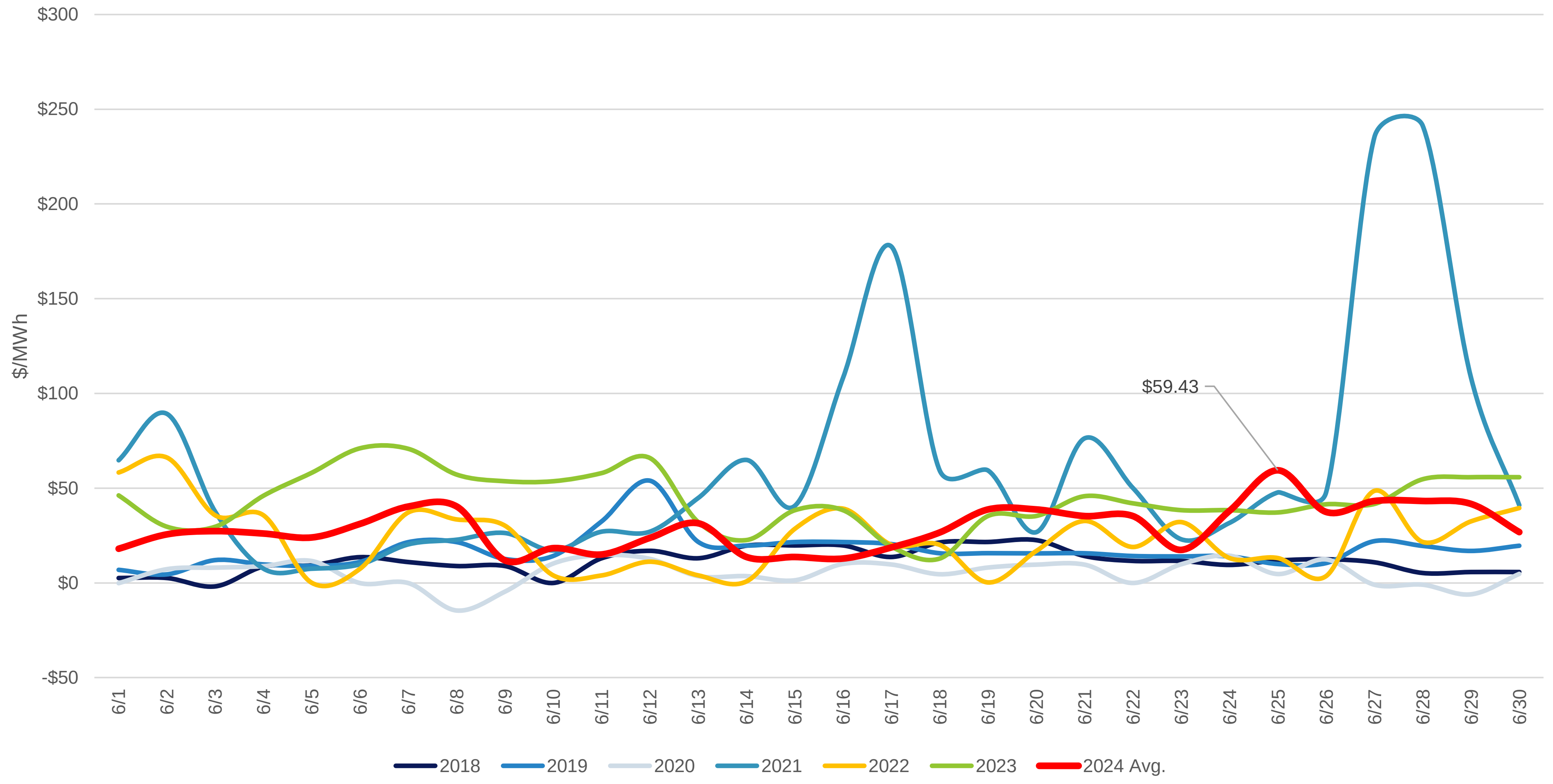
TEMPERATURES



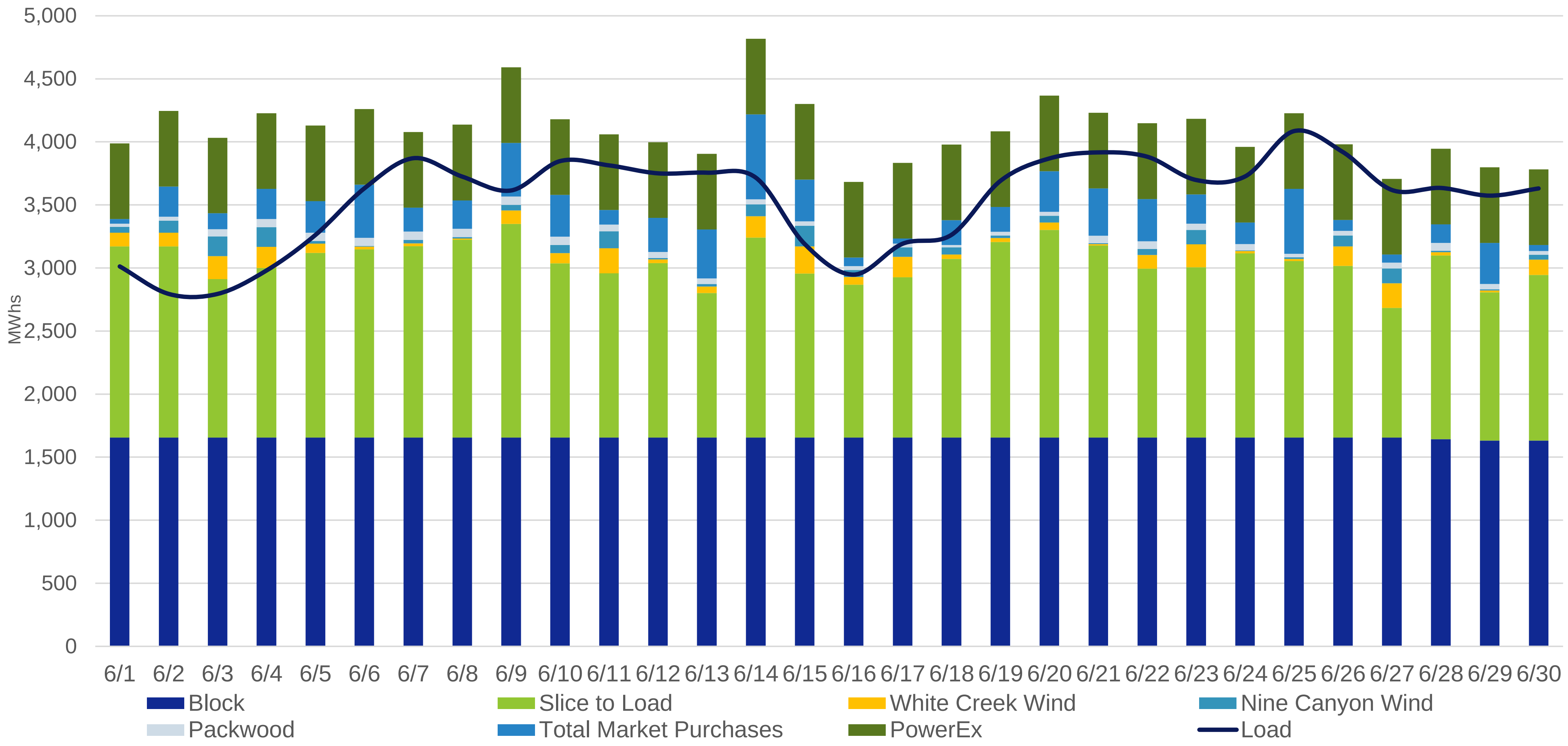
COLUMBIA RIVER RUNOFF



AVERAGE DAILY PRICES (MID-COLUMBIA)

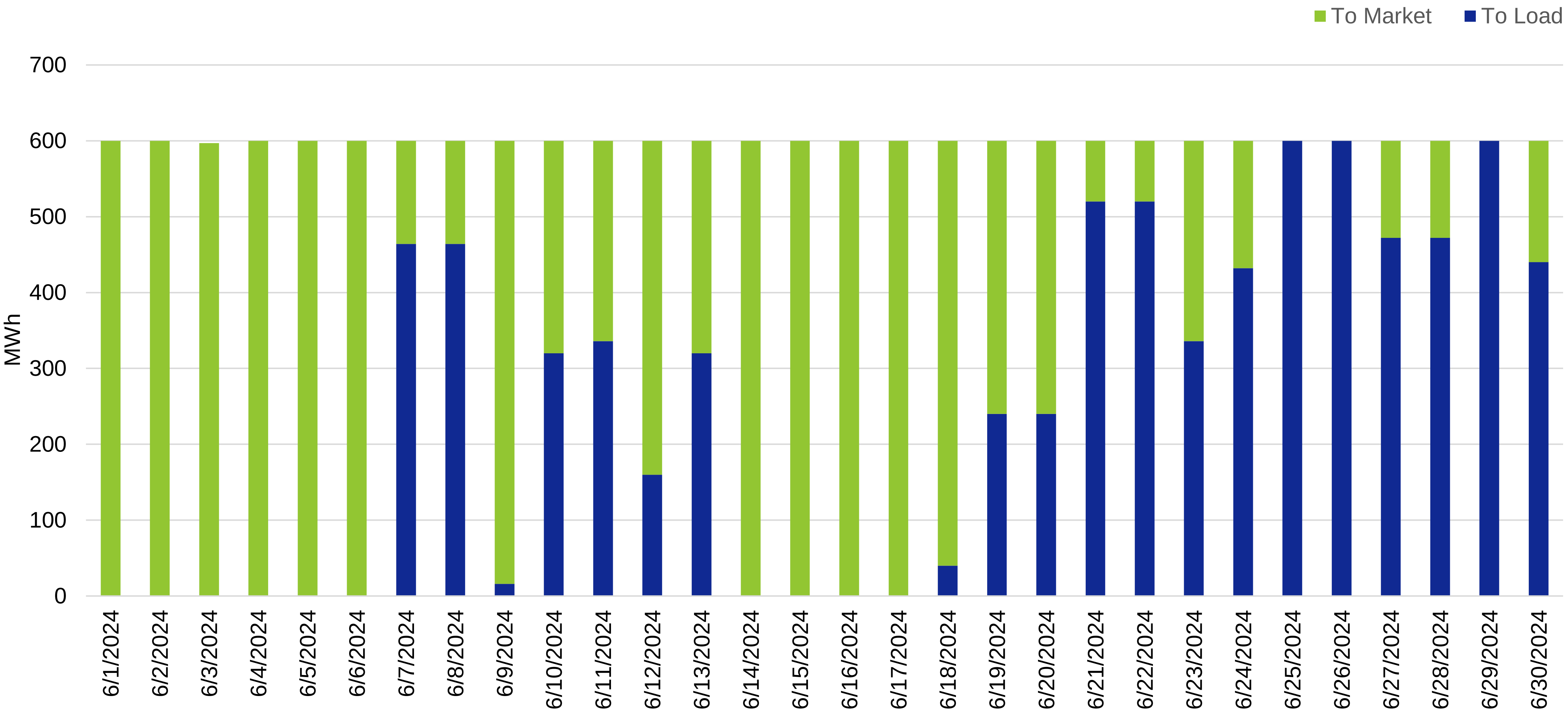


LOAD/RESOURCE BALANCE



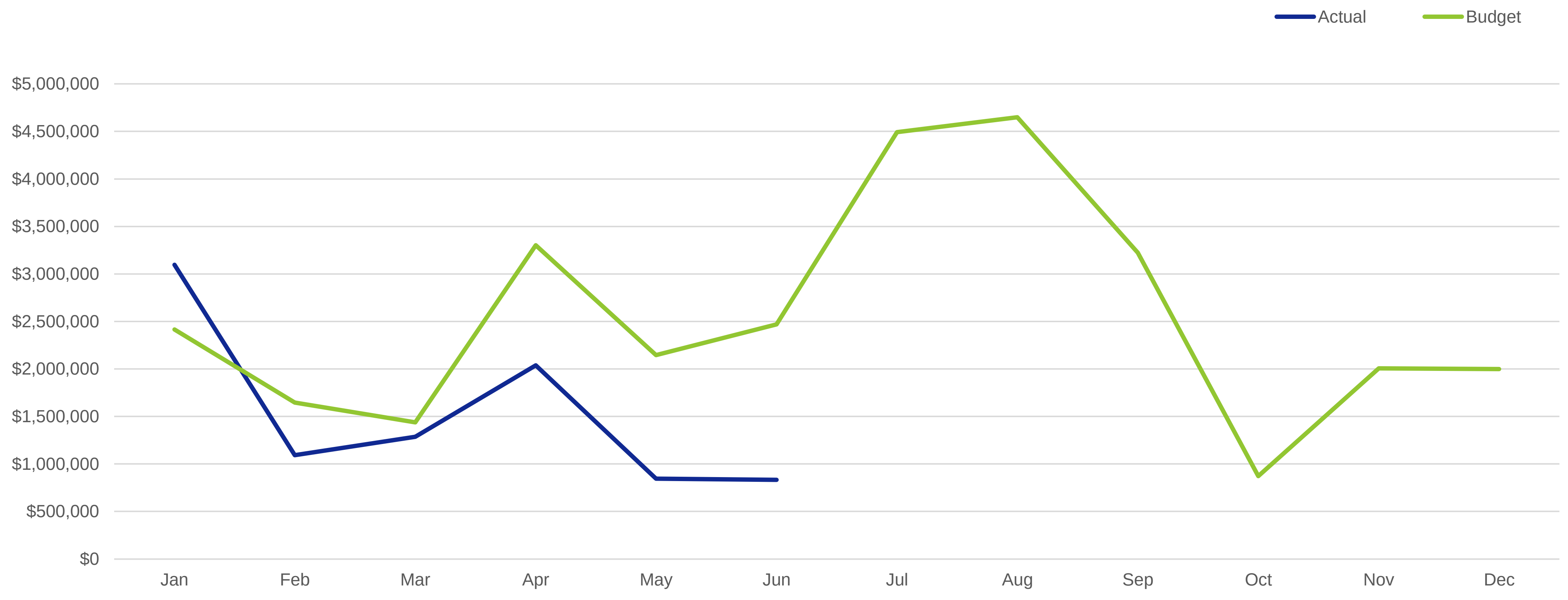
June 2024 Key Performance Indicators

POWEREX DELIVERIES

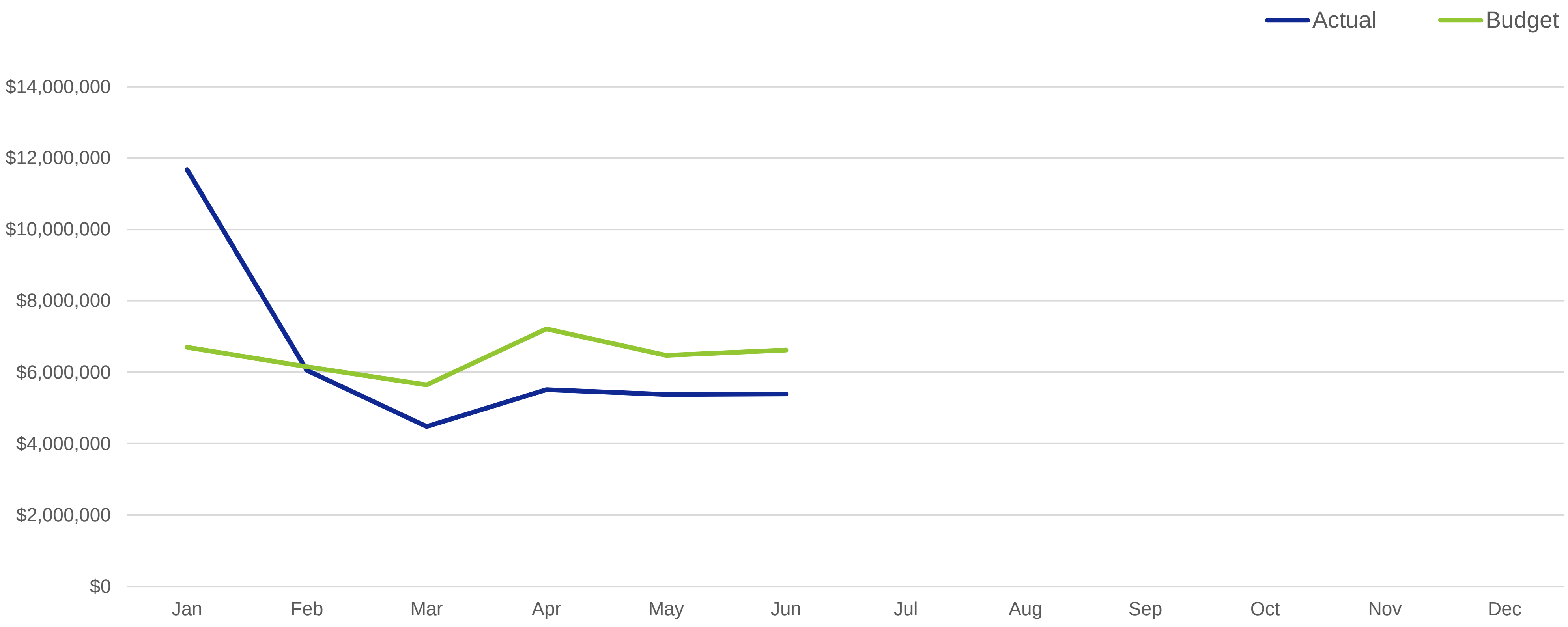


6/3/2024 – Total of 597 MWh delivered due to curtailment

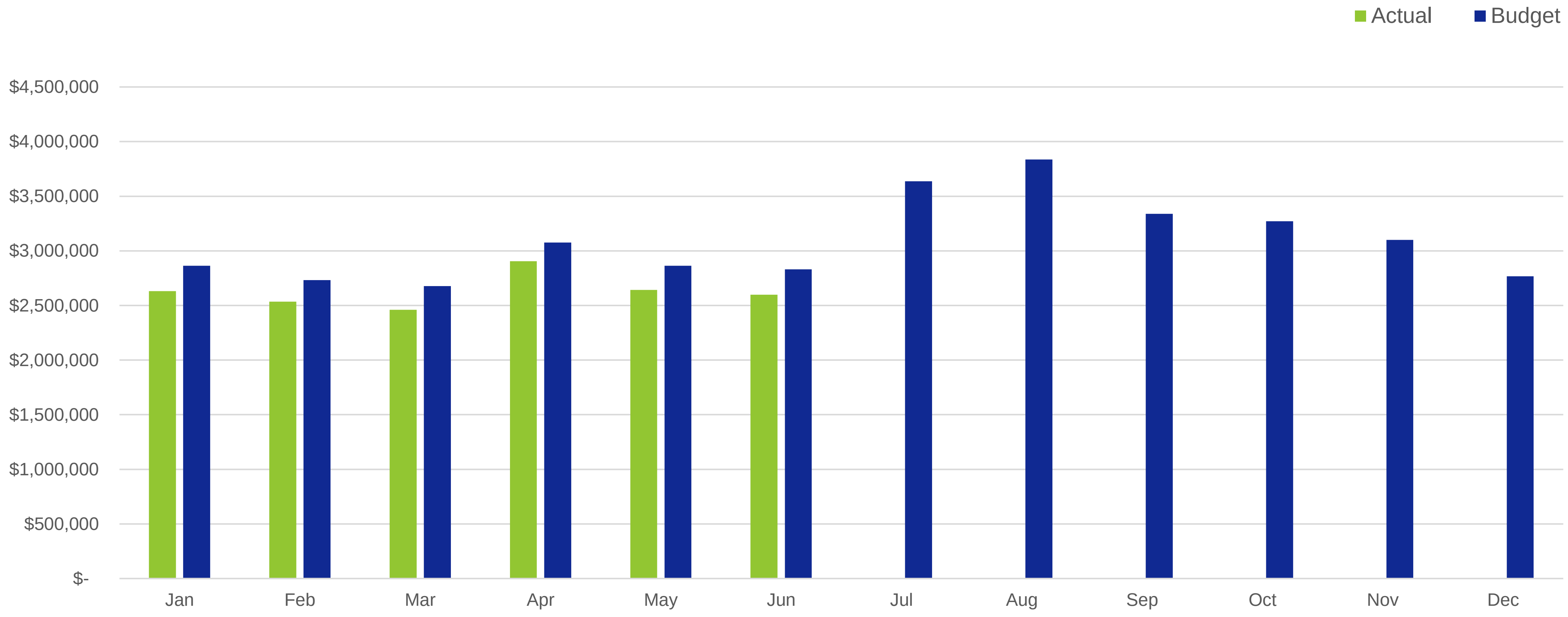
SECONDARY MARKET SALES



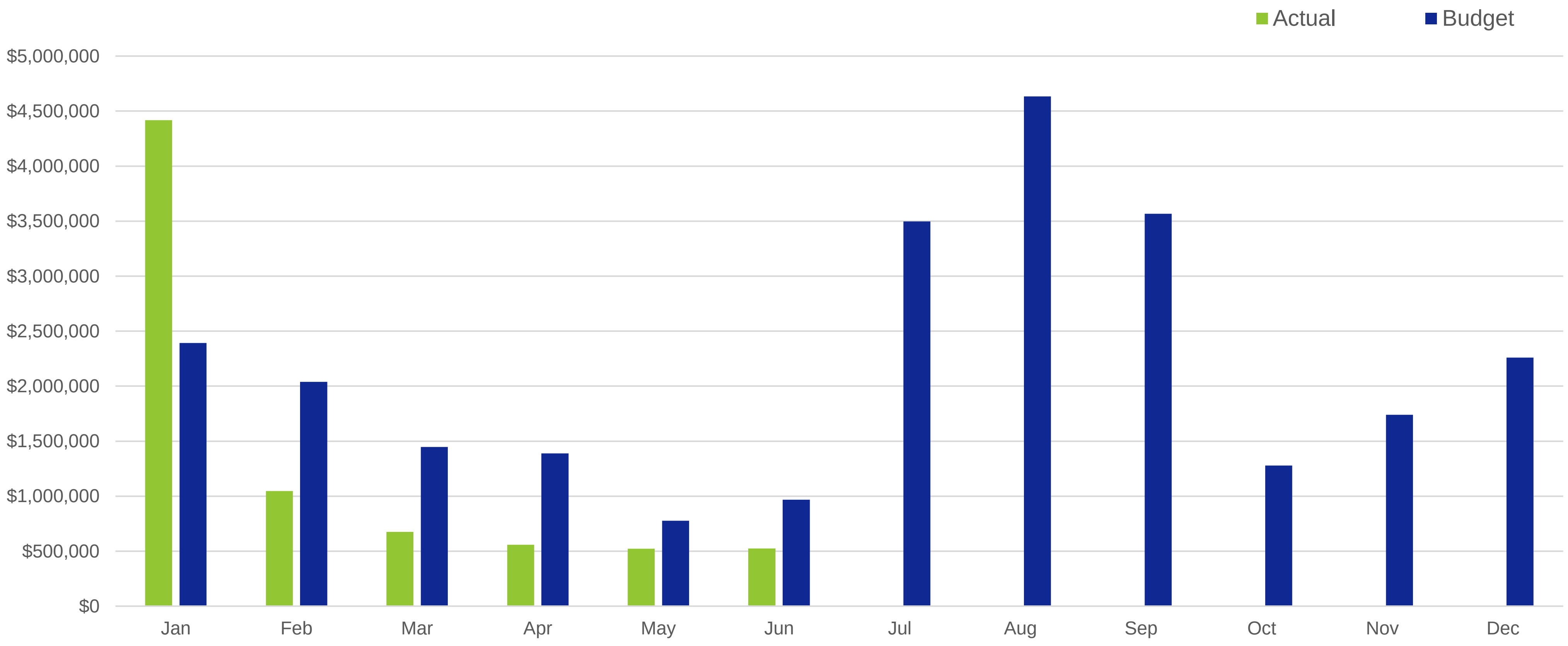
POWER SUPPLY COSTS



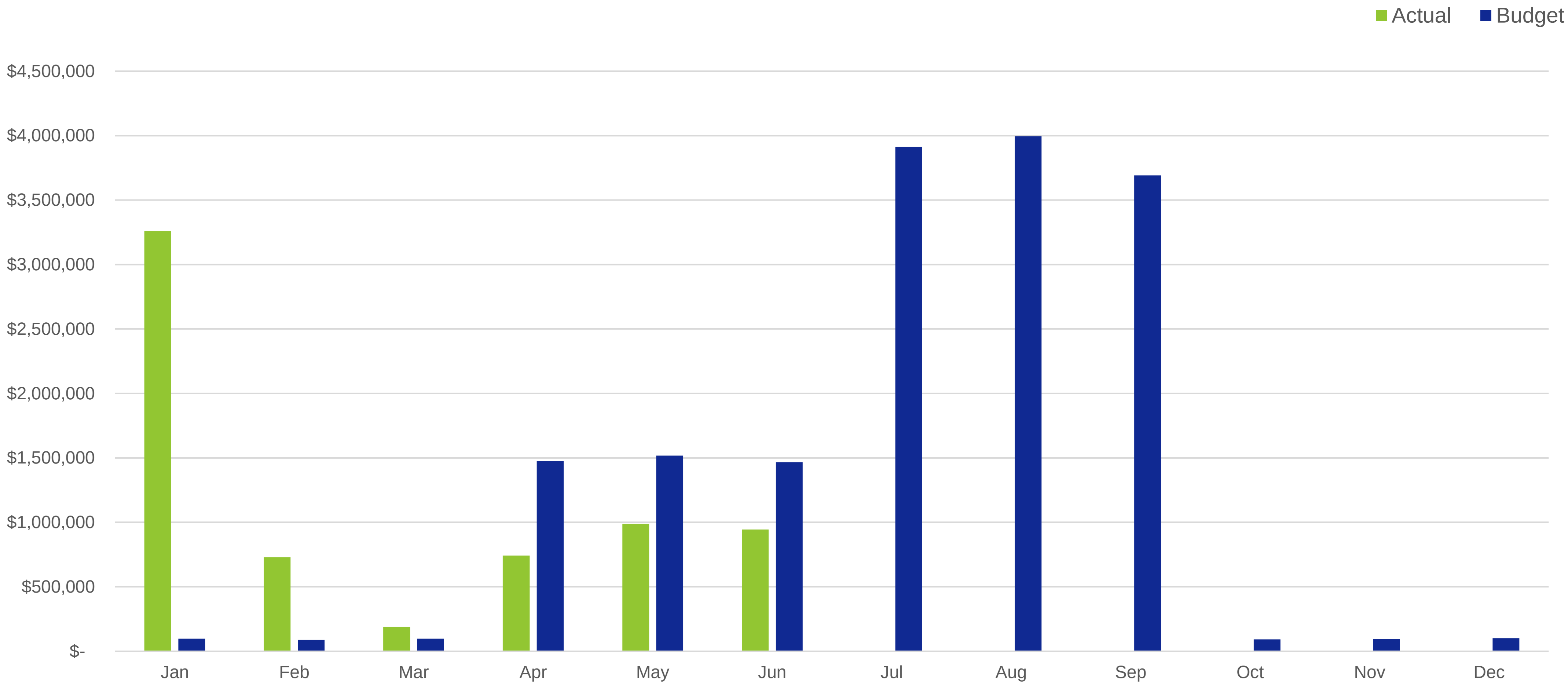
BPA POWER: BUDGET VS. ACTUAL



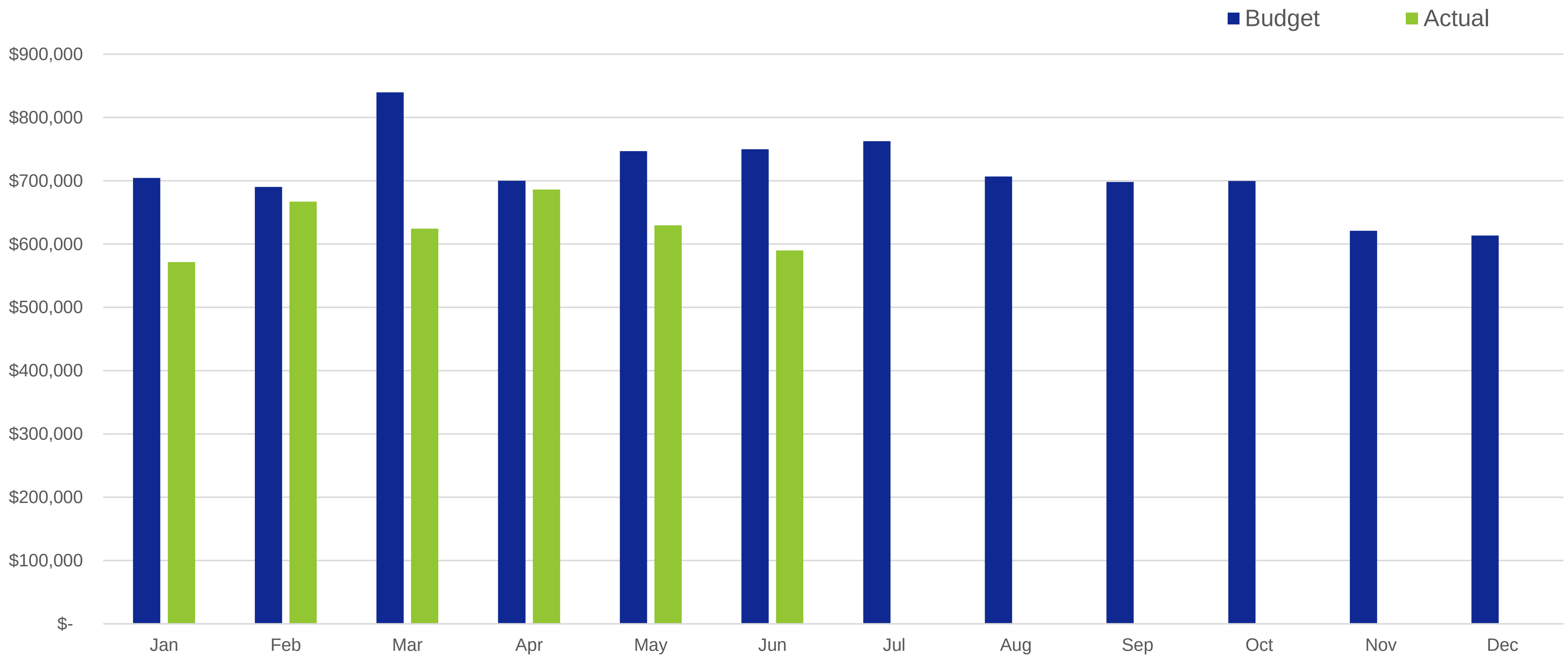
POWEREX: BUDGET VS. ACTUAL



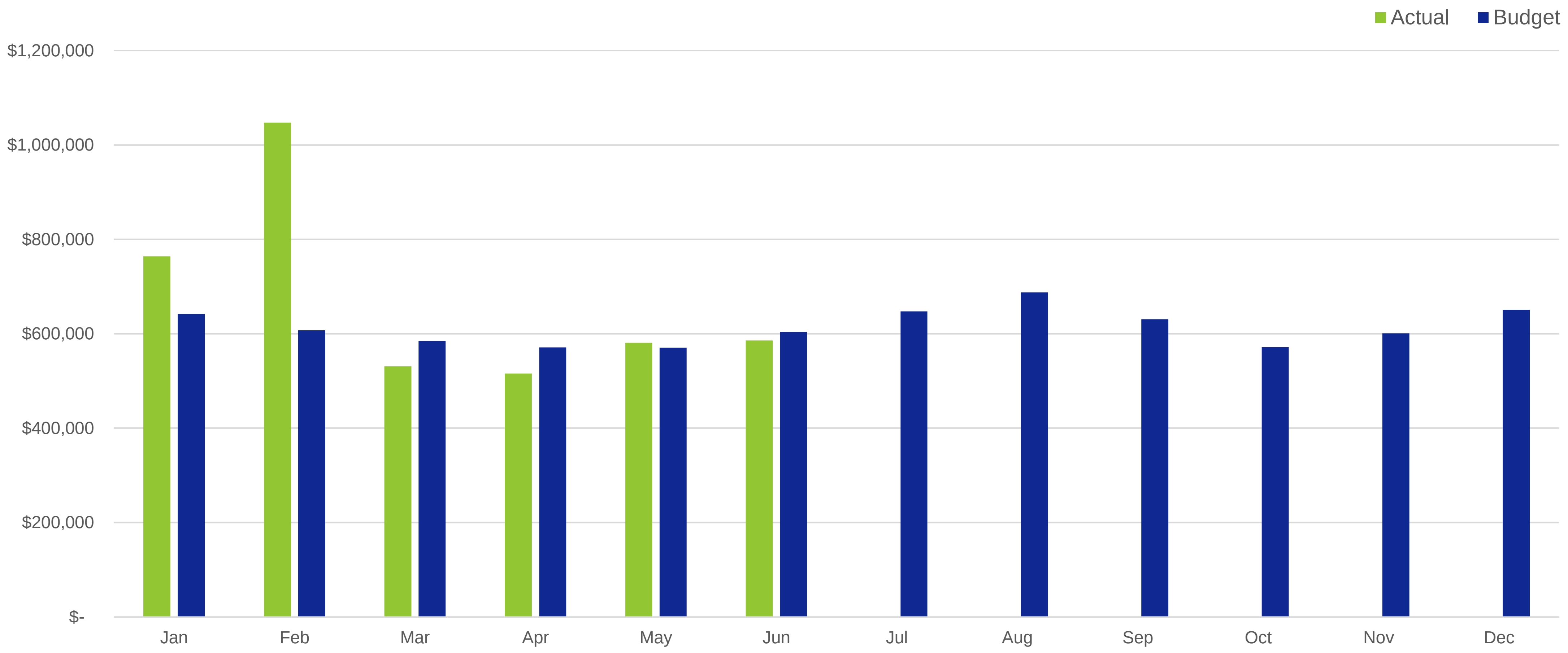
MARKET PURCHASES: BUDGET VS. ACTUAL



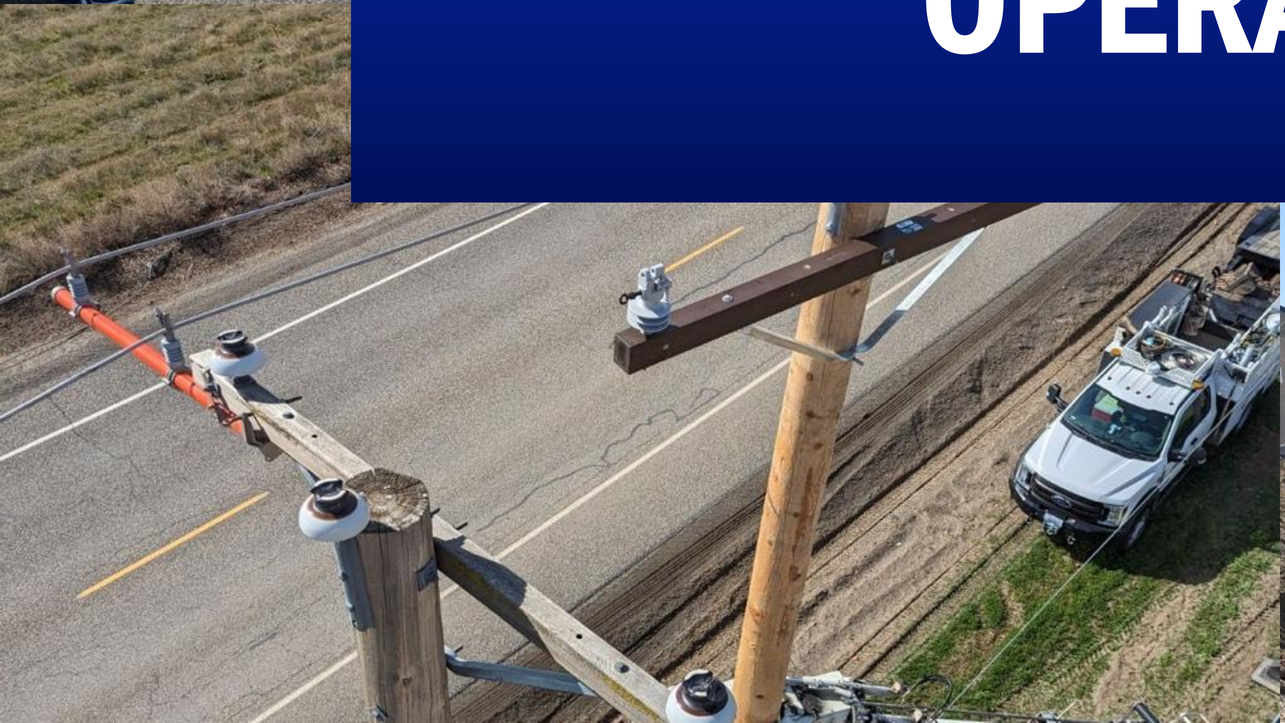
OTHER RESOURCES: BUDGET VS. ACTUAL



TRANSMISSION & ANCILLARY: BUDGET VS. ACTUAL



OPERATIONS

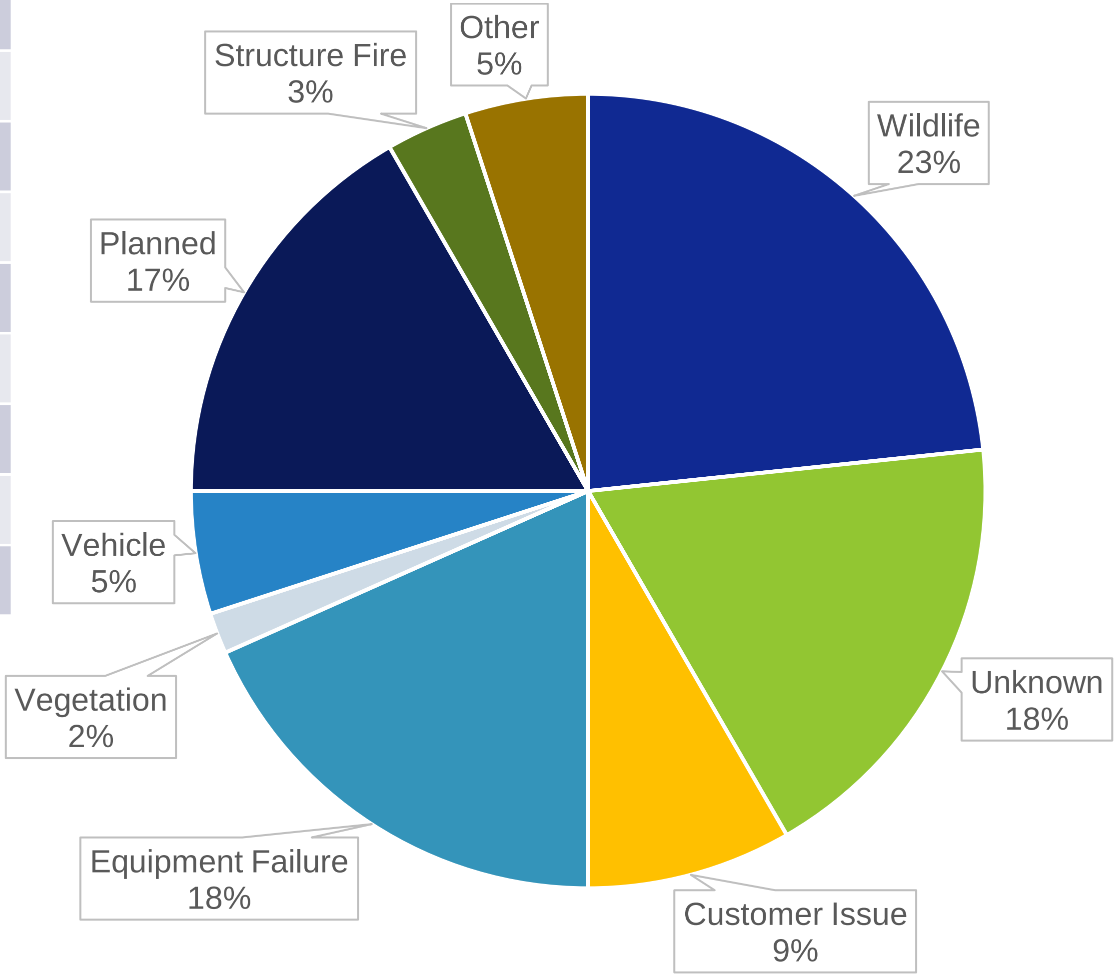


OVERVIEW

There were 60 outages that occurred in June.
10 of the outages were planned. The longest unplanned outage occurred out of Big Pasco Substation on June 2nd and was caused by a structure fire. It lasted 7 hours, 56 minutes and affected 22 customers.

JUNE OUTAGES

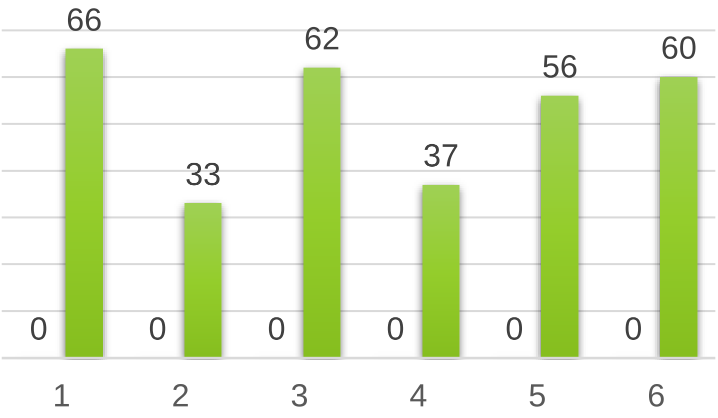
Outage Causes	
Wildlife	14
Unknown	11
Customer Issue	5
Equipment Failure	11
Vegetation	1
Vehicle	3
Planned	10
Structure Fire	2
Other	3



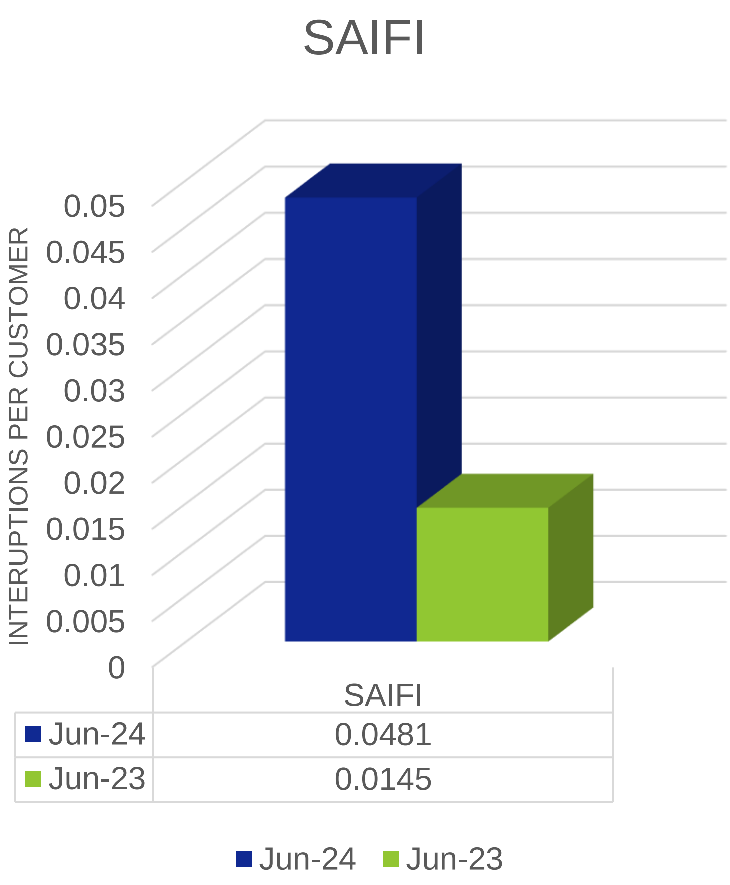
Total Outages

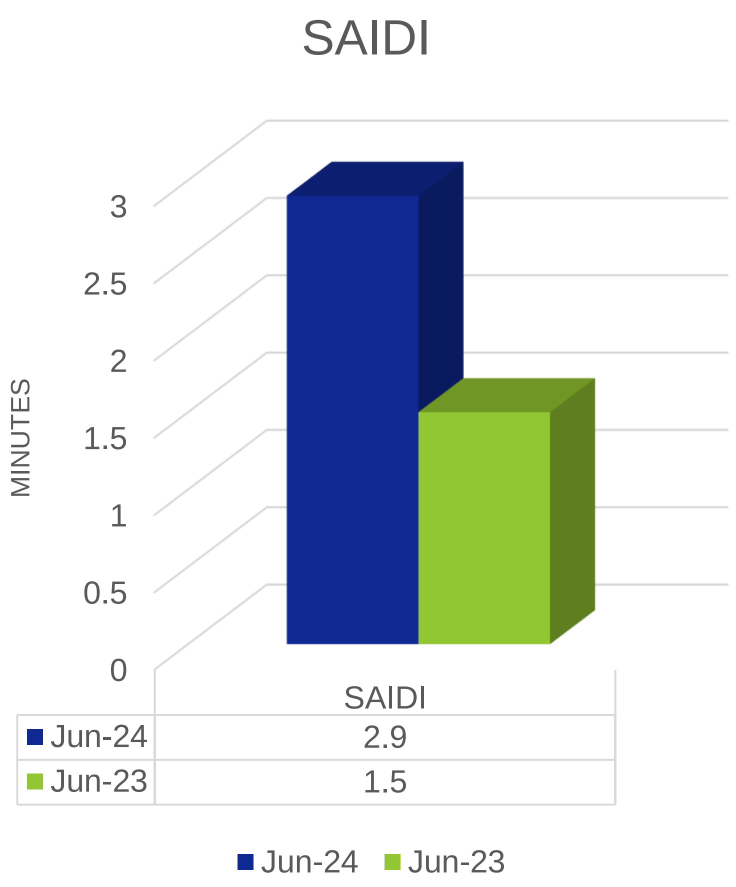
60

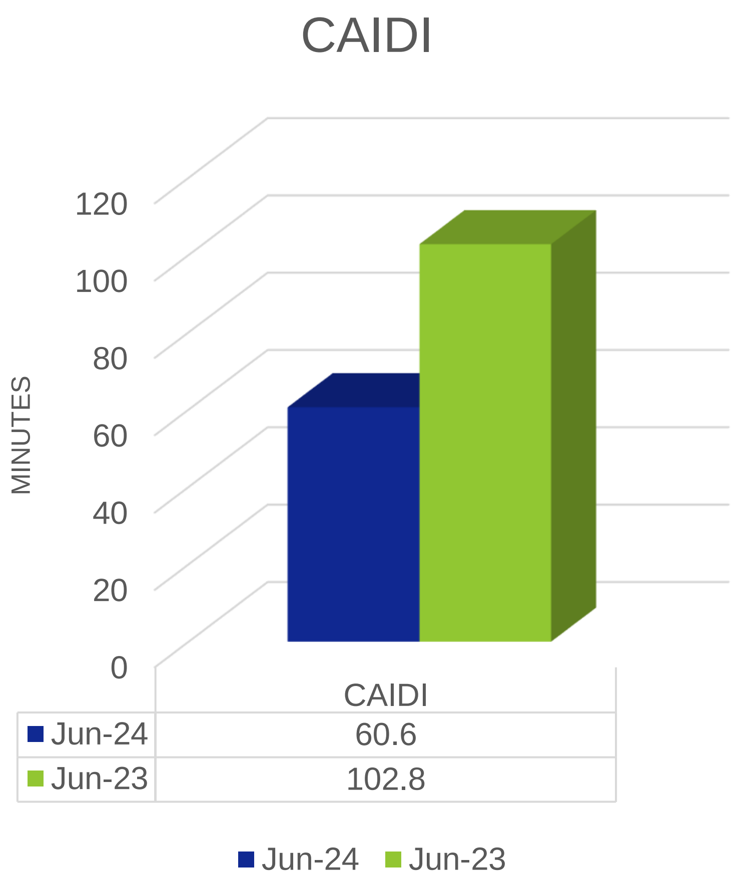
Monthly Outages



JUNE RELIABILITY INDICES







SAIFI (System Average Interruption Frequency Index):

How often the average customer experiences an interruption

SAIDI (System Average Interruption Duration Index):

The total time of interruption the average customer experiences

CAIDI (Customer Average Interruption Duration Index):

The average time required to restore service

*Only outages lasting longer than five minutes are included in the calculations

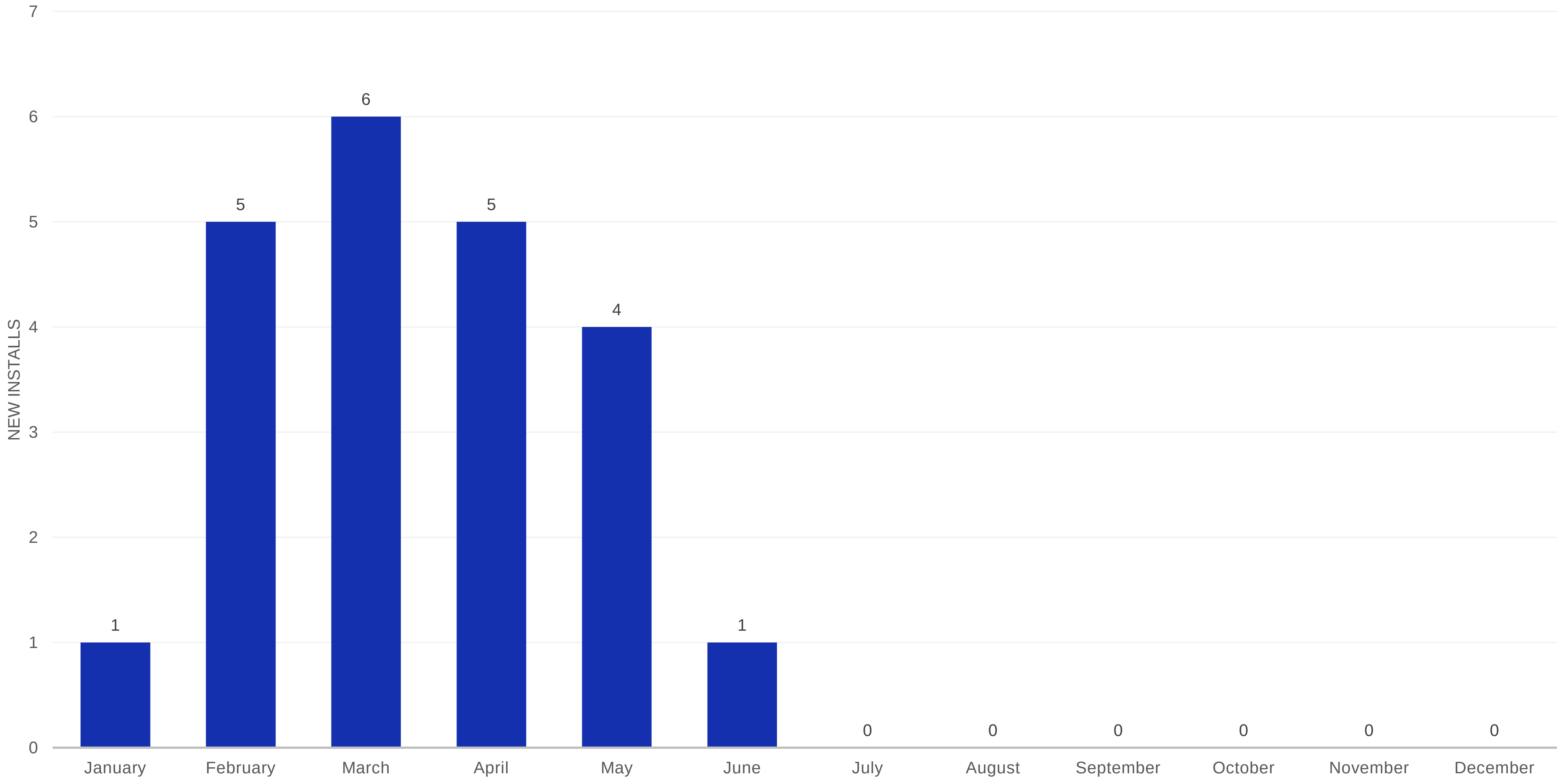
ENGINEERING

OVERVIEW

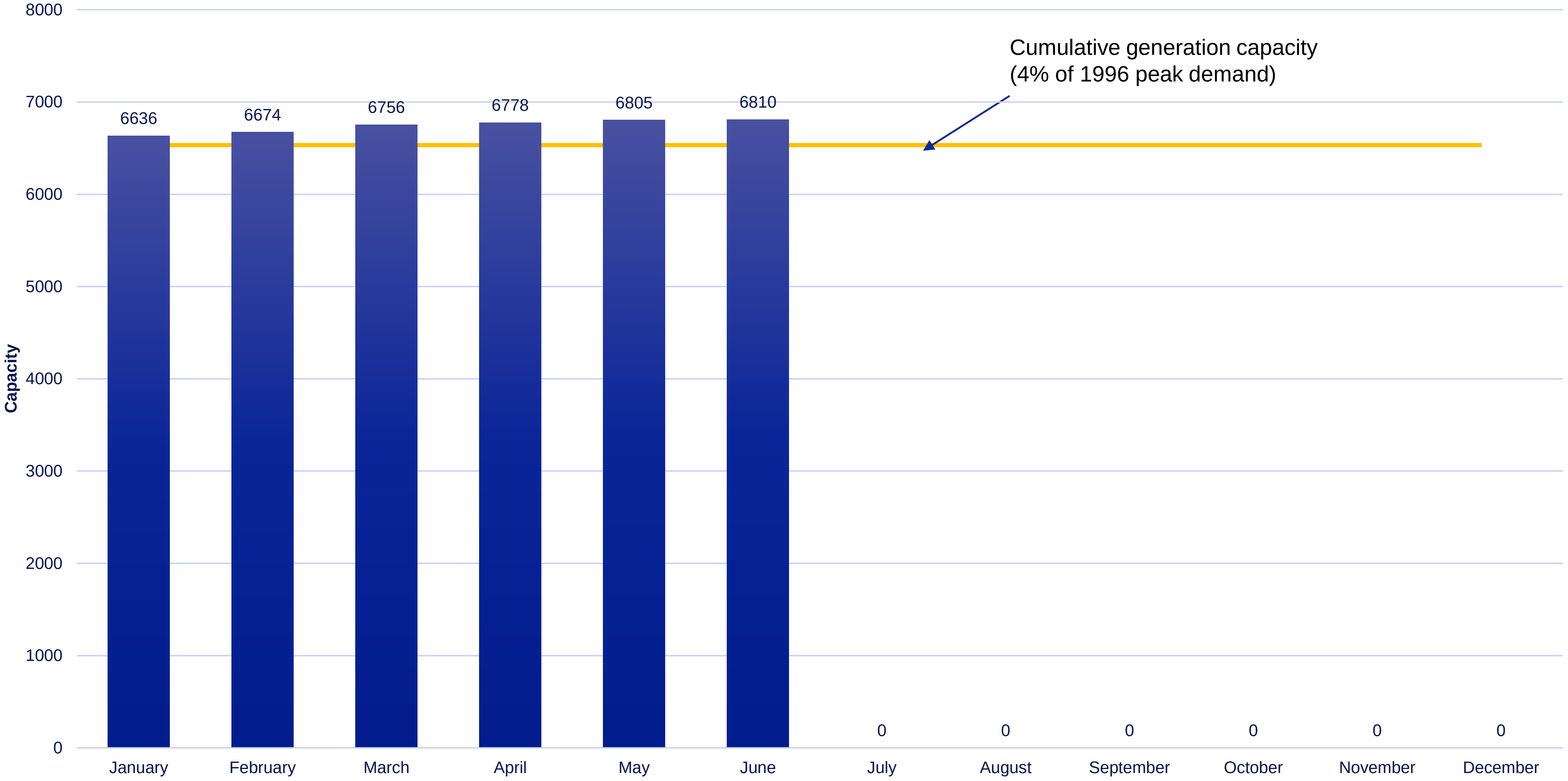
There was 1 new net metering (solar) interconnections added to the system in June. This brings the total capacity of net meter connections on the system up to 6,810 kWac. Total active net meter connections on the system are 837 with the average system size being 8.14 kWac.

A total of 9 work orders were released to Operations in the month of June with a total material and labor cost estimate of $616,521.46, which is an average of $68,502.38 per job. For new services during this time period, there were 16 new residential and 4 commercial services that came online.

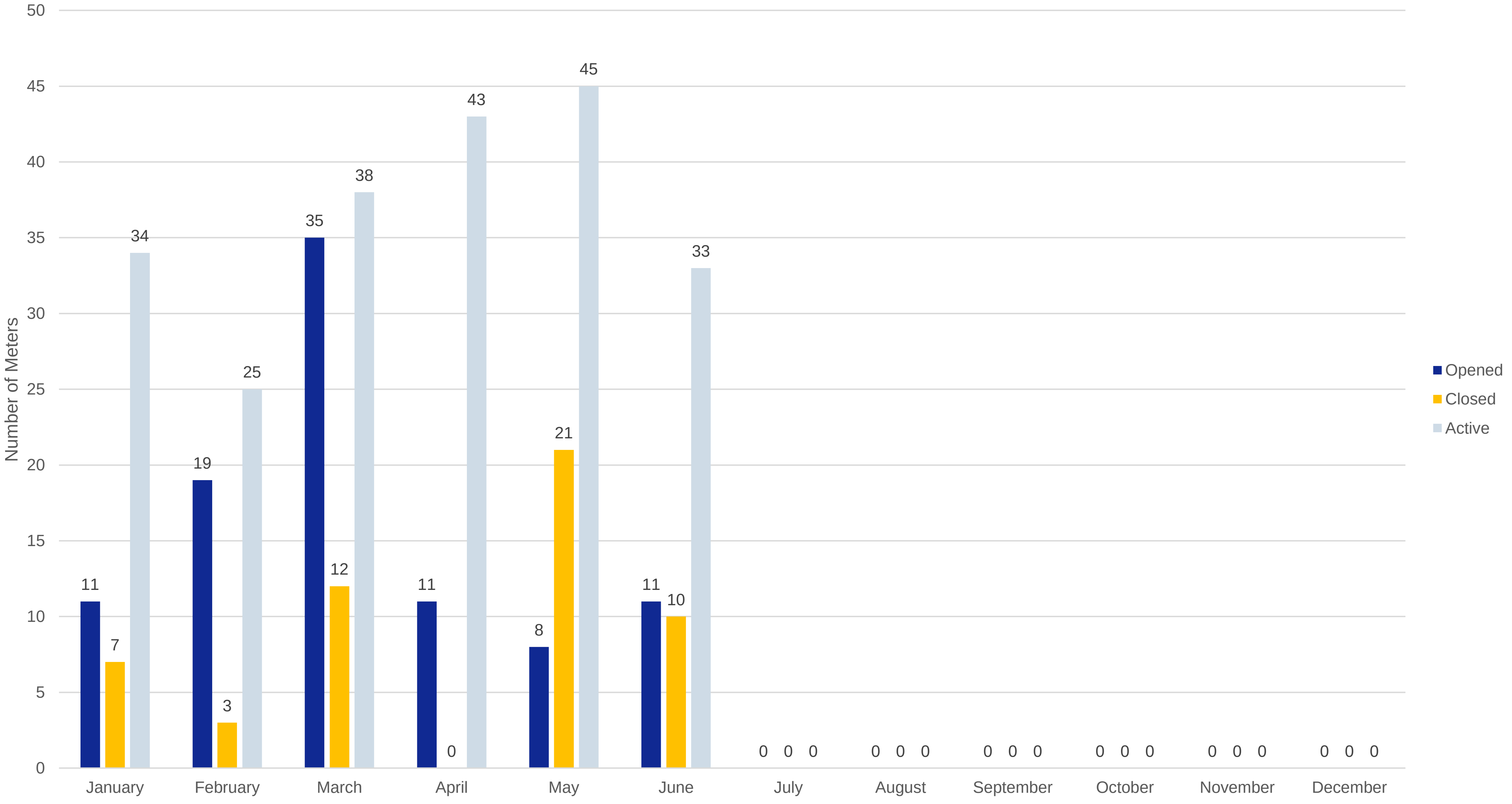
NET METERING INSTALLATIONS



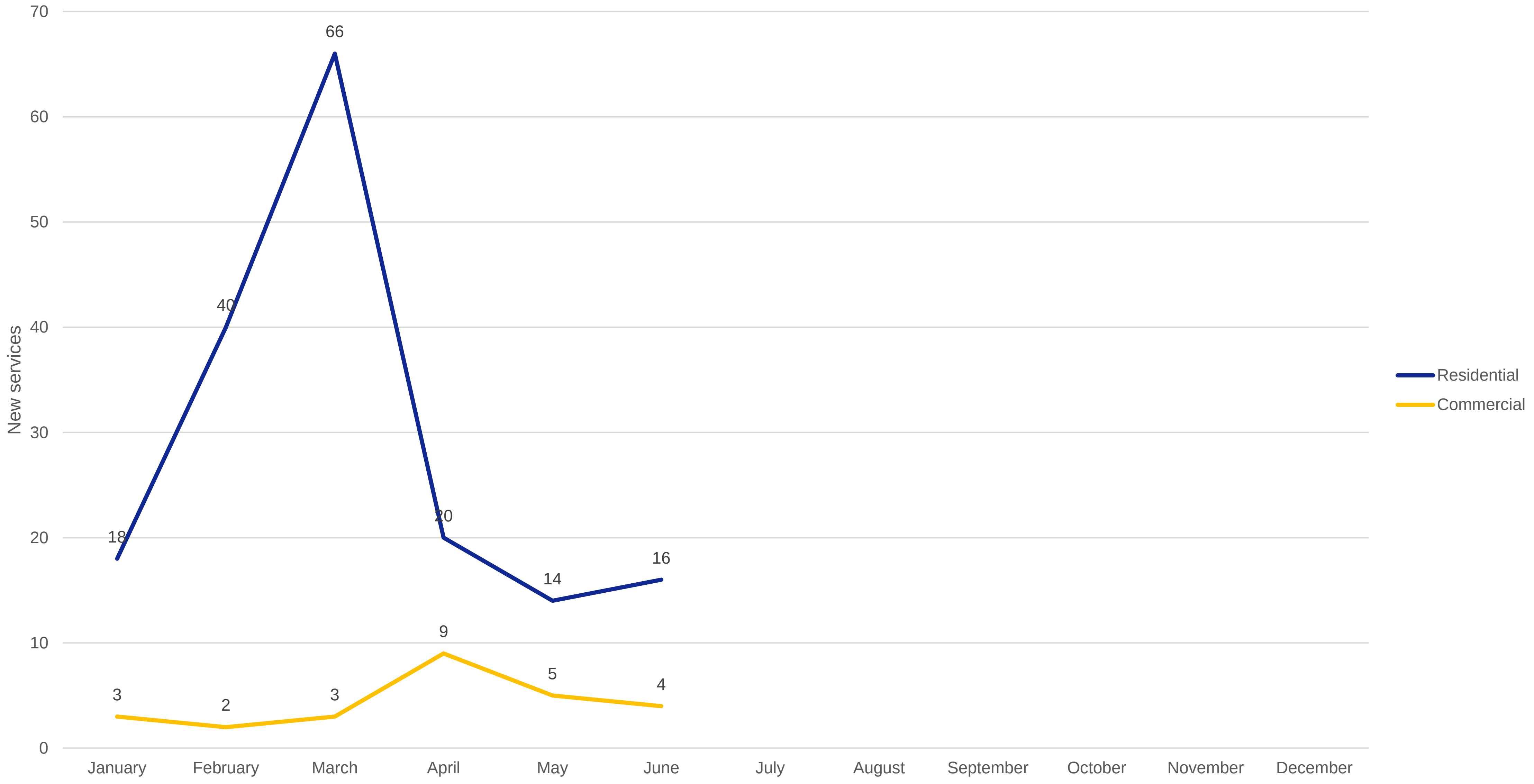
NET METERING CAPACITY INSTALLED



TEMPORARY SERVICE



NEW SERVICES

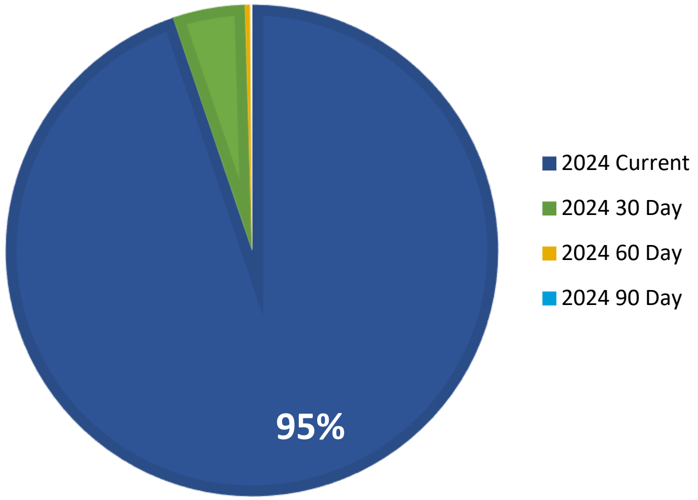


CUSTOMER SERVICE

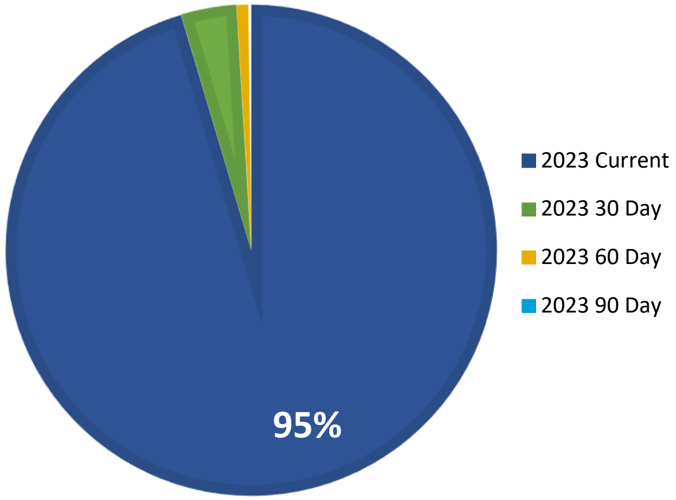
CUSTOMER SERVICE

AGING ACCOUNTS

JUNE 2024



JUNE 2023

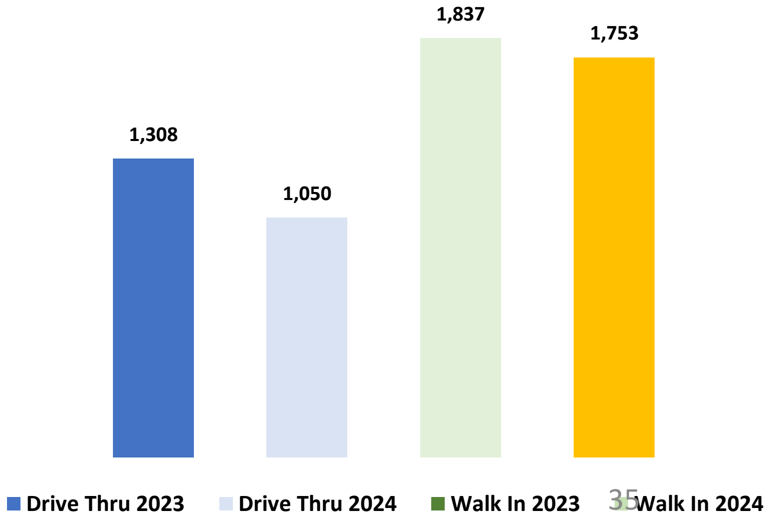


	Current	30-60	60-90	90+
2024	$6,422,570	$322,215	$21,947	$8,212
2023	$6,391,929	$245,451	$49,608	$14,359

Move in/Move Out Service Orders Processed in June 2024

610

June In Person Payments




DELL
PowerEdge 2950

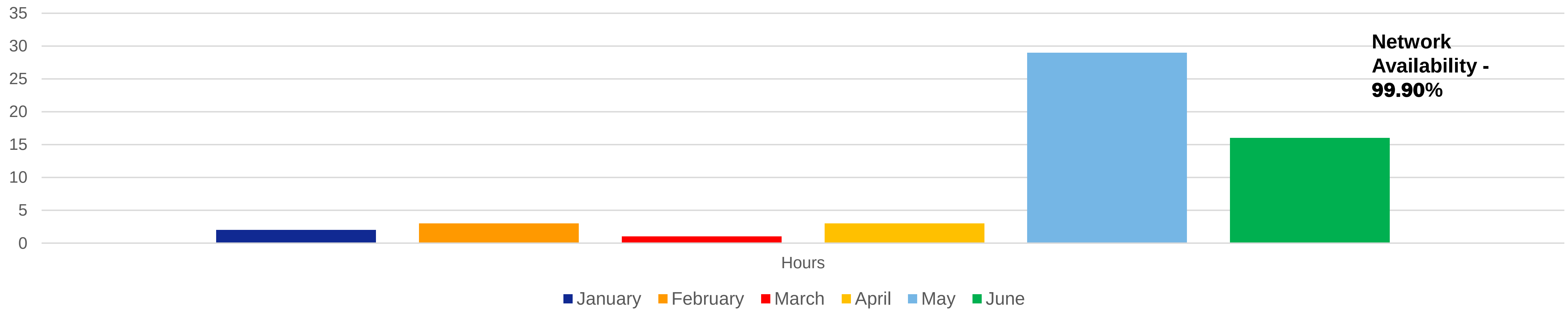
Altec

BROADBAND

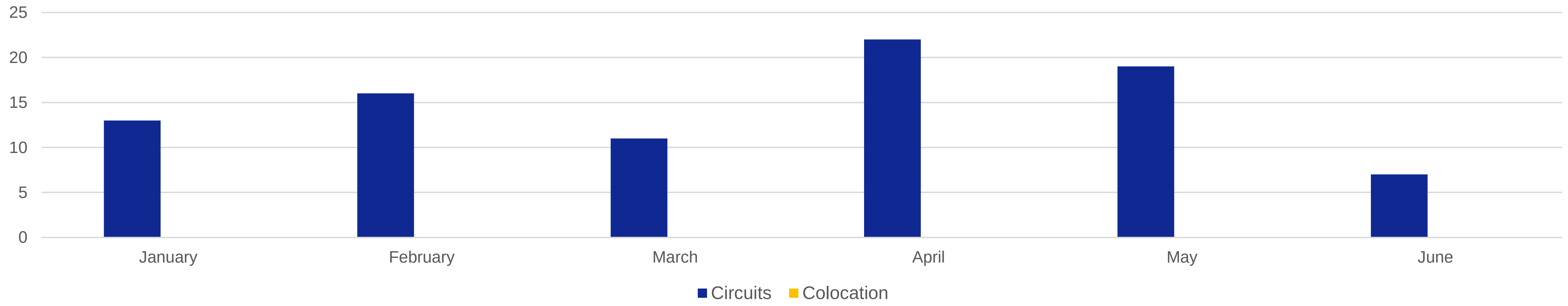


CONSOLE
UTILIZATION
STATUS
LINK
ACTIVE

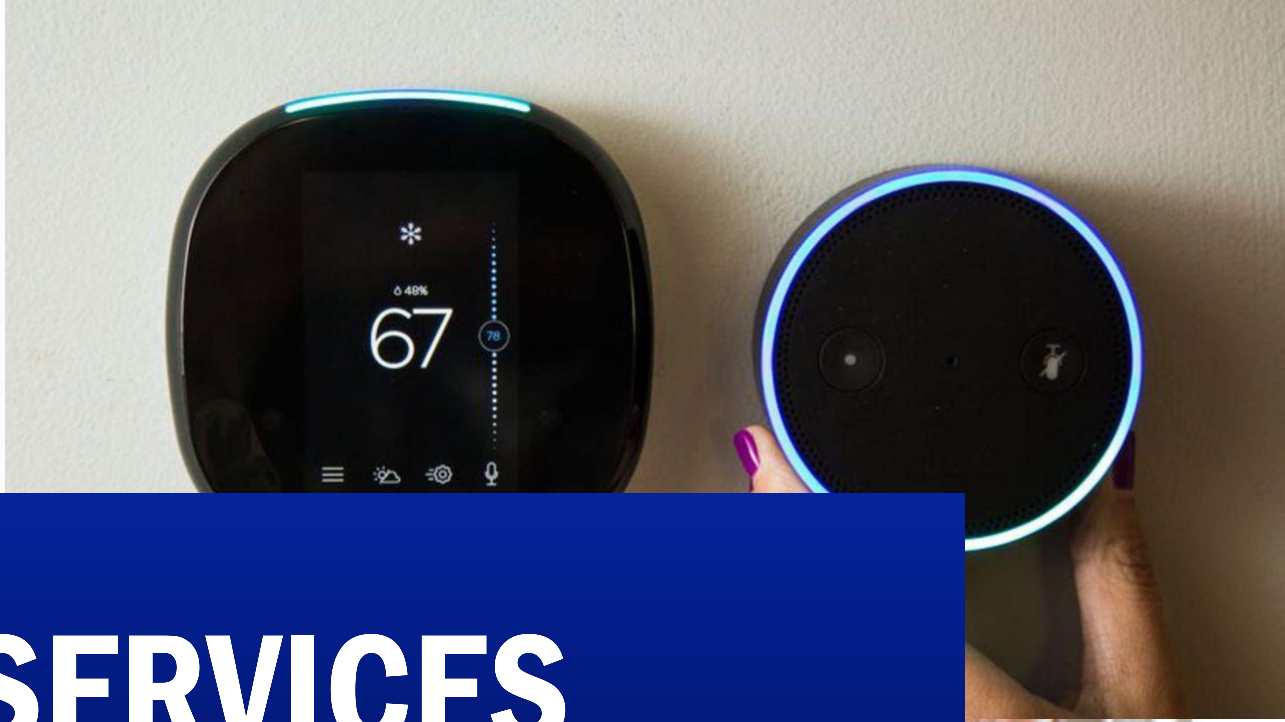
Broadband Unplanned Outage Time



Broadband New Services



ENERGY SERVICES



ENERGY SERVICES

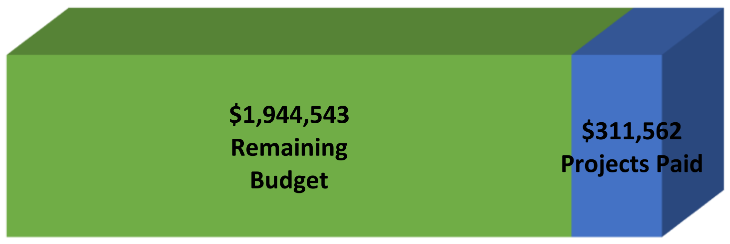
UTILITY FUNDED

Self-Funding 2024 Total Budget $300,000

Type	Qty	Total Paid YTD
Residential Low Income	36	$168,280
Residential Non-Low Income	3	$10,021
Thermostat/Appliance Rebates	13	$925
Agriculture	2	$22,465
Commercial	7	$38,433
Industrial	3	$37,346
SEM	0	$0
Other	0	$0

BPA FUNDED

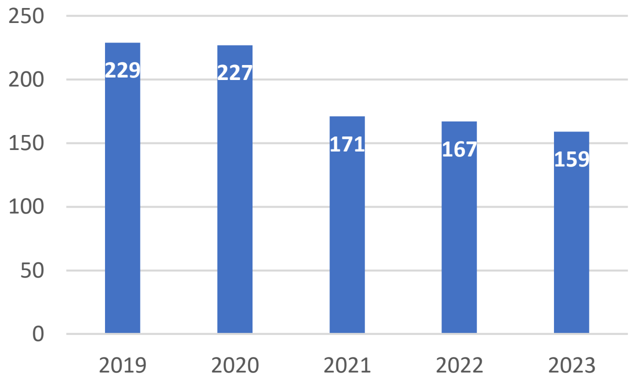
BPA FY24-FY25 Total Budget $2,256,105



Type	Qty	Total Paid YTD
Residential Low Income	43	$246,521
Residential Non-Low Income	0	$0
Thermostat/Appliance Rebates	0	$0
Agriculture	5	$12,180
Commercial	4	$52,861
Industrial	0	$0
SEM	0	$0
Other	0	$0

Pre-Inspections/Final Inspections Completed in 2024

Solar Incentive Participants




METRICS & DASHBOARDS


PUBLIC AFFAIRS

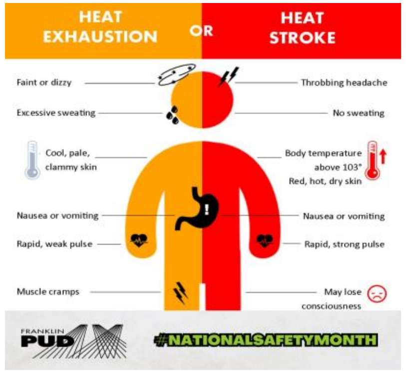
June 2024 – National Safety Month

Total Audience
3,959 ↗ 0.1%

Total Engagement
260 ↗ 2,789%

Total Impressions
6,068 ↗ 270%

Posts That Made The Most Impact (June 2024)



Events We Participated In (June 2024)

- **Kidz Dig Rigz (June 1 – 2) GESA Stadium Parking Lot**

- **STEM Academy – (June 22 – 26) Local 598 Facilities**

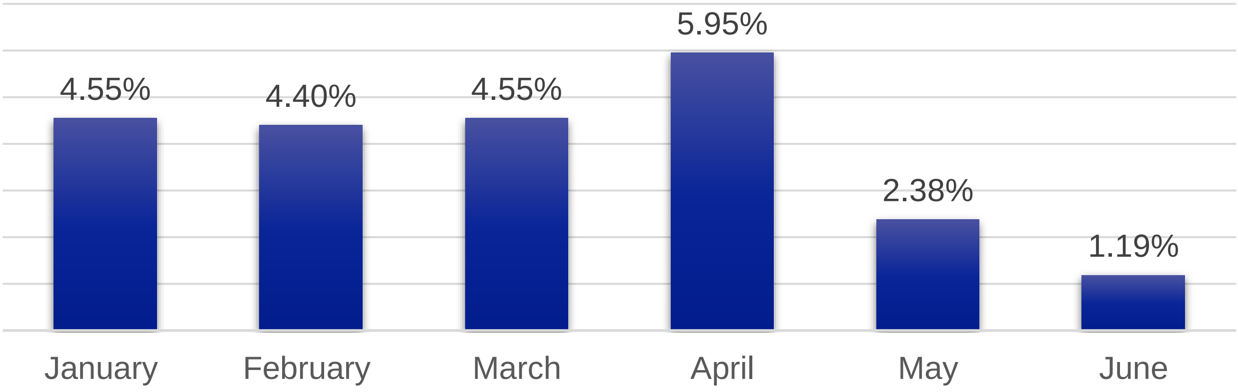
June 2024 Key Performance Indicators

CYBERSECURITY

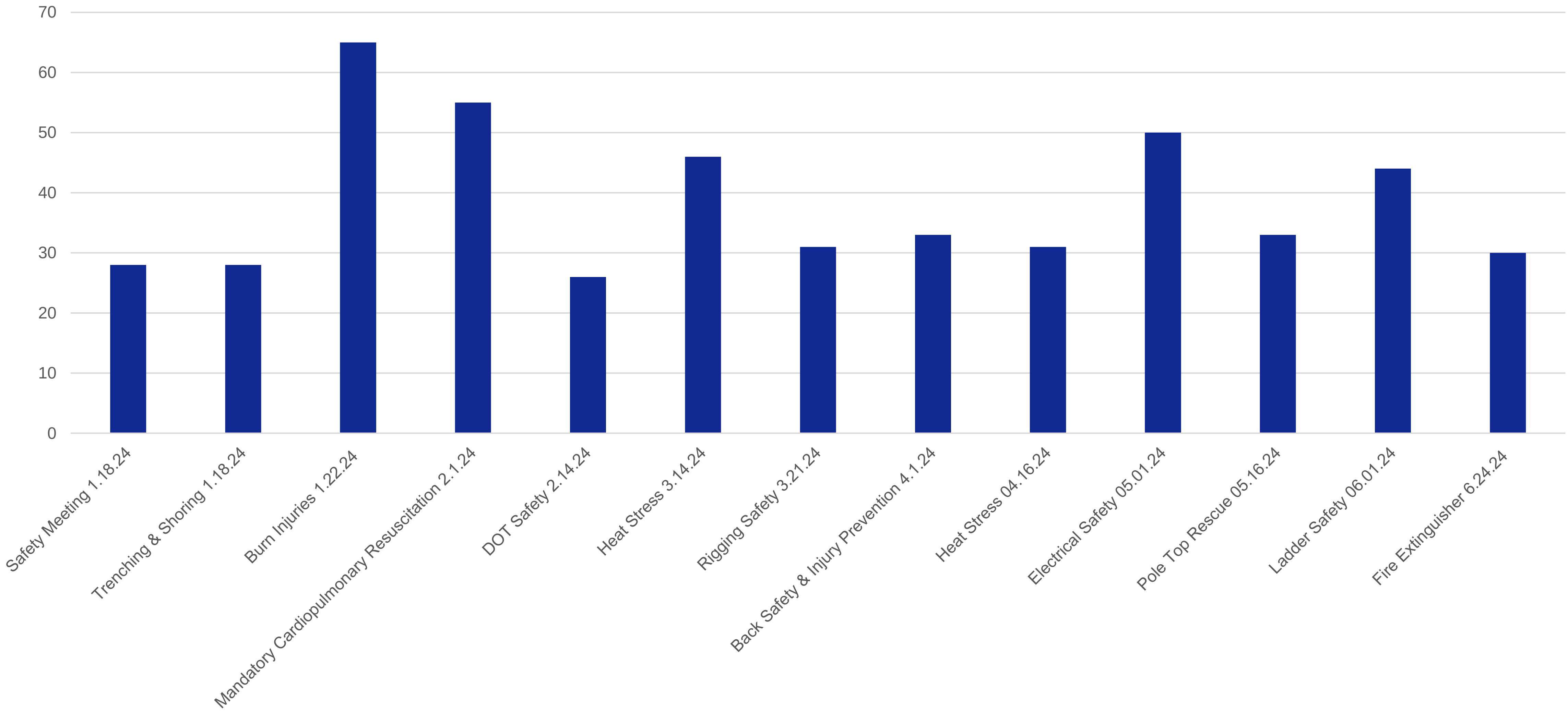
June Phishing Results	
Total Emails Sent	84
Number of users who clicked on links	1
Number of users who reported as "Phishing"	22
Phish-Prone %	1.19

Previous Results		
June	Teams Meeting	1.19%
May	Labor Day	2.38%
April	Job Description	5.95%
March	New Health Portal	4.55%
February	401K Statement Phish	4.4%
January	Payroll Statement Phish	4.55%

Phish-Prone % By Month

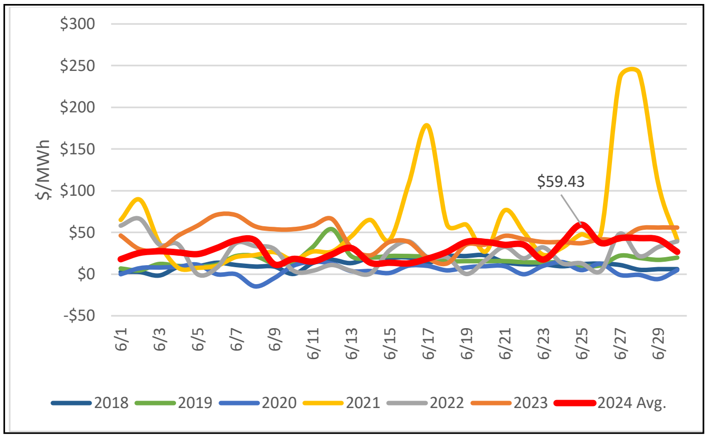


SAFETY TRAINING

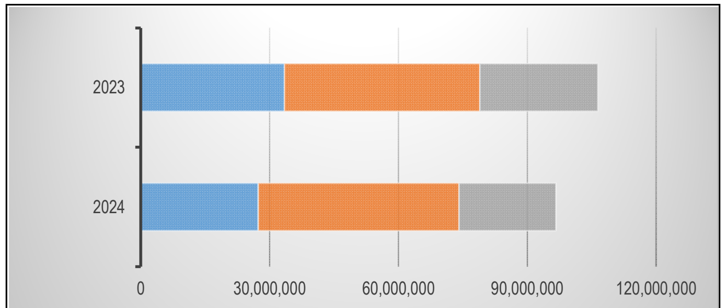


Public Utility District No. 1 of Franklin County
Monthly Financial Highlights
For the Month Ended June 30, 2024

Average Day Ahead Wholesale Power Pricing - Current Month

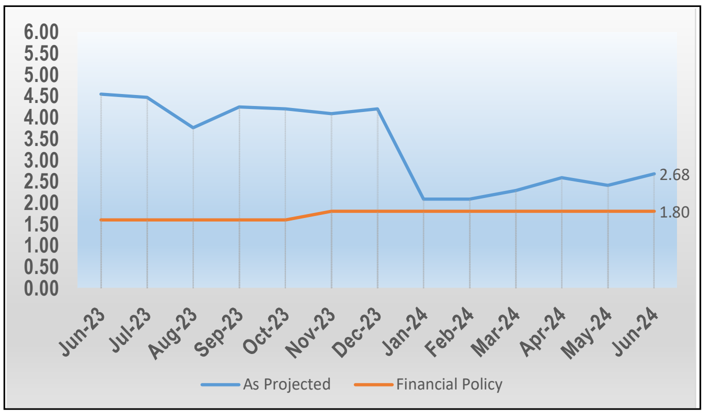


Energy Uses - kWh

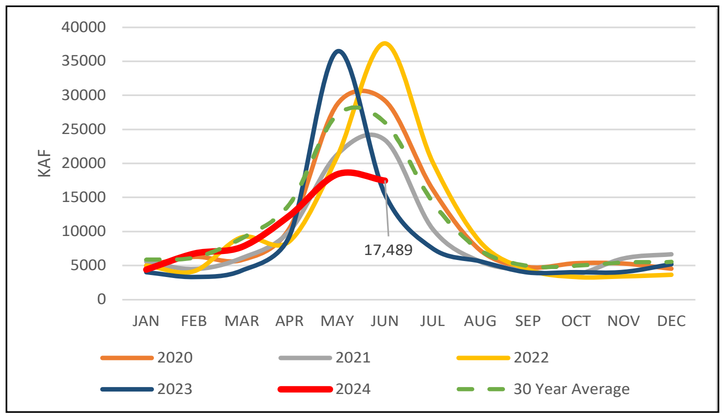


	2024	2023
Residential	27,352,522	33,430,574
Commercial	46,775,341	45,490,873
Irrigation	22,528,902	27,515,652

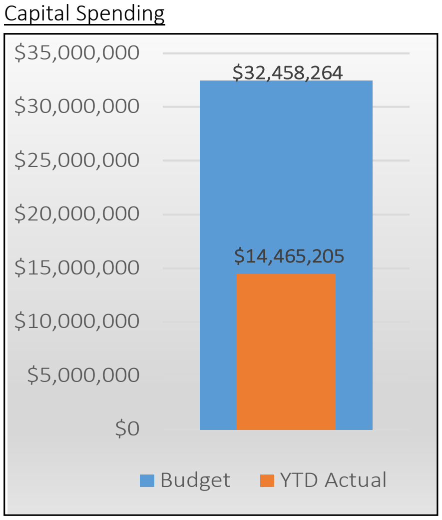
Debt Service Coverage



Runoff at The Dalles



Capital Spending



Labor & Benefits

	Budget	Actual	+/- 10%
Capital	$142,492	$142,799	
Operating	1,099,369	909,421	
Garage & Warehouse	67,050	53,219	
Total	$1,308,912	$1,105,439	

Overtime

YTD June:	Budget*	Actual
Hours	3380	2772
Dollars	$363,648	$310,362

*Budget is submitted for annual period, amount shown is prorated for months elapsed

Electric Customer Statistics

As of June 30:	2024	2023
Electric Residential Meters	29,106	28,630
Electric Commercial Meters	3,853	3,823
Electric Irrigation Meters	905	905

Cash & Investment Balances

	End of Year Forecast Prior Month	End of Year Forecast Current Month
Unrestricted Revenue Fund	$ 26,219,111	$ 30,372,619
Unrestricted Rate Stabilization	$ 5,900,000	$ 5,900,000
Restricted Bond Funds	$ 2,031,821	$ 2,031,821
Restricted Construction Funds	$ 11,000,000	$ 11,000,000
Restricted Debt Service Reserve	$ 2,098,434	$ 2,098,434
Restricted Deposit Fund	$ 1,417,793	$ 1,417,793
Restricted Other	$ 10,000	$ 10,000

Public Utility District No. 1 of Franklin County
Budget Status Report
For the Month Ended June 30, 2024

		Budget	Actual	Variance	FY Forecast	FY Budget	Variance
1	*Operating Revenues*						
2	Retail Energy Sales	$7,546,629	$7,467,133	($79,496)	$90,115,584	$90,184,916	($69,332)
3	Broadband Sales	$198,930	$205,525	6,596	2,491,963	2,403,248	88,715
4	Transmission Sales	$0	$2,522	2,522	141,059	0	141,059
5	Secondary Market Sales	$2,468,528	$833,260	(1,635,268)	18,546,134	30,661,278	(12,115,144)
6	Other Operating Revenue	27,475	28,232	757	622,162	469,700	152,462
7	*Total Operating Revenues*	*$10,241,562*	*$8,536,672*	*($1,704,890)*	*$111,916,902*	*$123,719,142*	*(11,802,240)*
8							
9	*Operating Expenses*						
10	Power Supply	6,620,292	5,391,417	(1,228,875)	83,741,569	95,864,748	(12,123,179)
11	System Operations & Maintenance	684,640	513,844	(170,796)	7,761,342	8,491,826	(730,484)
12	Broadband Operations & Maintenance	79,886	98,612	18,727	1,074,884	995,434	79,450
13	Customer Accounts Expense	156,843	150,272	(6,571)	1,923,882	1,905,280	18,603
14	Administrative & General Expense	619,507	448,009	(171,498)	6,839,834	7,568,307	(728,473)
15	Taxes	492,725	475,905	(16,821)	5,380,750	5,376,125	4,625
16	*Total Operating Expenses*	*8,653,893*	*7,078,059*	*(1,575,834)*	*106,722,262*	*120,201,720*	*(13,479,458)*
17							
18	*Operating Income (Loss)*	*$1,587,668*	*$1,458,612*	*($129,056)*	*$5,194,640*	*$3,517,422*	*$1,677,218*
19							
20	Non Operating Revenue (Expense)						
21	Interest Income	119,036	294,580	175,544	2,099,530	1,640,012	459,518
22	Interest Expense	(155,284)	(215,125)	(59,841)	(2,644,263)	(1,845,812)	(798,451)
23	Federal Grant Revenue	249,999	0	(249,999)	1,837,632	3,000,000	(1,162,368)
24	Federal Grant Expense	0	0	0	0	0	0
23	Other Non Operating Revenue (Expense)	833	63,217	62,383	70,429	10,000	60,429
24	*Total Non Operating Revenue (Expense)*	*214,584*	*142,672*	*(71,912)*	*1,363,328*	*2,804,200*	*(1,440,871)*
25							
26	Capital Contributions	1,100,000	305,404	(794,596)	4,804,213	4,875,000	(70,787)
27							
28	Change in Net Position	$2,902,253	$1,906,688	($995,564)	$11,362,181	$11,196,622	$165,559

	FY Forecast	FY Budget
Debt Service Payment (Annual)	$ 5,226,586	$ 4,866,663
Change in Net Position	11,362,181	11,196,622
Interest Expense	2,644,263	1,845,812
Net Revenue Available for Debt Service	$ 14,006,444	$ 13,042,434
Debt Service Coverage (DSC)	2.68	2.68

Public Utility District No. 1 of Franklin County
2024 Capital Budget by Project
Percent of Year Elapsed: 50%

Category	Project Description	Year to Date June 2024	2024 Budget	$ Remaining in Budget	% Spent
Broadband					
1.24	BROADBAND SYSTEM IMPROVEMENTS & EXPANSION	$ 328,378	$ 696,000	$ 367,622	47.18%
2.24	BROADBAND CUSTOMER CONNECTS	420,029	570,924	150,895	73.57%
142.24	RAILROAD AVE COLLO FACILTY	76,561	50,000	(26,561)	153.12%
197.24	SMALL CELLULAR SITES	-	285,000	285,000	0.00%
188.24	NEW HVAC SERVER ROOM	-	25,000	25,000	0.00%
189.24	NEW HVAC COLO 1	-	25,000	25,000	0.00%
198.24	WSBO CONNELL - BASIN CITY PROJECT*	270,018	3,000,000	2,729,982	9.00%
BBPD.24	BROADBAND PROPERTY DAMAGE	28,406	-	(28,406)	100.00%
	Total for Broadband	1,123,392	4,651,924	3,528,532	24.15%
	* *AMOUNTS FUNDED BY FEDERAL GRANT PROGRAM*				
Building					
92.24	RTU 8 REPLACEMENT- *CARRYOVER*	-	155,000	155,000	0.00%
199.24	AC UNITS FOR OPERATIONS (2)	-	55,000	55,000	0.00%
200.24	SECURE DOORS AT OPERATIONS	-	10,000	10,000	0.00%
201.24	SECURITY SYSTEM UPDATE	-	50,000	50,000	0.00%
202.24	ASPHALT WORK AT OPERATIONS & W. CLARK ST	-	75,000	75,000	0.00%
203.24	1411 W. CLARK POWER REMODEL	53,350	750,000	696,650	7.11%
204.24	ADA COMPLIANCE/ SAFETY ENHANCEMENT	5,522	147,000	141,478	3.76%
212.24	RTU 1 REPLACEMENT	24,290	-	(24,290)	100.00%
215.24	CURBING AT MAIN OFFICE	32,596	-	(32,596)	100.00%
	Total for Building	115,758	1,242,000	1,126,242	9.32%
Information Handling					
205.24	TELECOM USAGE IN SERVICE	-	43,560	43,560	0.00%
206.24	ELECTRONIC CODING SYSTEM WAREHOUSE	-	21,780	21,780	0.00%
213.24	FIBER MANAGEMENT SOFTWARE	18,513	-	(18,513)	100.00%
	Total for Information Handling	18,513	65,340	46,827	28.33%
System Construction - New Customers					
63.24	PURCHASE OF REGULAR METERS	2,121	-	(2,121)	100.00%
121.24	PURCHASE OF METERS	303,792	300,000	(3,792)	101.26%
64.24	CUSTOMER ADDS TO THE DISTRIBUTION SYSTEM	1,435,416	2,700,000	1,264,584	53.16%
65.24	PURCHASE OF TRANSFORMERS	195,313	2,800,000	2,604,687	6.98%
157.24	SUBSTATION TRANSFORMER- *CARRYOVER*	-	1,300,000	1,300,000	0.00%
106.24	ACQUIRE FUTURE SUBSTATION SITES- *CARRYOVER*	-	500,000	500,000	0.00%
	Total for System Construction- New Customers	1,936,642	7,600,000	5,663,358	25.48%
System Construction - Reliability & Overloads					
	TRANSMISSION PROJECTS				
177.24	RAILROAD AVE SUB (REIMANN INDUSTRIAL) TRANSMISSION	752,794	780,000	27,206	96.51%
207.24	COMPLETE BPA B-F #1 TAP TO RAILROAD AVE	-	1,075,000	1,075,000	0.00%
	SUBSTATION PROJECTS				
178.24	RAILROAD AVE SUB (REIMANN INDUSTRIAL) SUBSTATION	9,066,891	10,156,000	1,089,109	89.28%
70.24	SCADA UPGRADES- SUBSTATIONS	-	60,000	60,000	0.00%
148.24	VOLTAGE REGULATORS UPGRADES	-	400,000	400,000	0.00%
73.24	REPLACE OBSOLETE BREAKER RELAYS	10,883	300,000	289,117	3.63%
208.24	FOSTER WELLS/EAST OF HWY 395	-	600,000	600,000	0.00%
	DISTRIBUTION PROJECTS				
179.24	RAILROAD AVE SUB (REIMANN INDUSTRIAL) DISTRIBUTION	3,850	1,798,000	1,794,150	0.21%
67.24	UNDERGROUND CABLE REPLACEMENTS	28,802	600,000	571,198	4.80%
209.24	DISTRIBUTION CIRCUIT RECONDUCTORS- NP, BM, AND KC FEEDERS	-	700,000	700,000	0.00%
72.24	MISCELLANEOUS SYSTEM IMPROVEMENTS	1,080,925	1,000,000	(80,925)	108.09%
103.24	CONVERT OH/UG- CITY OF PASCO	792	675,000	674,208	0.12%
CHP.24	CAR HIT POLES	134,576	90,000	(44,576)	149.53%
	Total for System Construction- Reliability & Overloads	11,079,513	18,234,000	7,154,487	60.76%
Vehicles					
210.24	FOREMAN TRUCK (1)	-	185,000	185,000	0.00%
211.24	LINE TRUCK	-	480,000	480,000	0.00%
170.24	BUCKET TRUCK- CARRYOVER	241	-	(241)	100.00%
184.24	DIGGER DERRICK	74,200	-	(74,200)	100.00%
196.24	VERSALIFT BUCKET TRUCK	2,335	-	(2,335)	100.00%
214.24	AED PURCHASE FOR VEHICLES	13,454	-	(13,454)	100.00%
186.24	MINI EXCAVATOR	101,157	-	(101,157)	100.00%
	Total for Vehicles	191,387	665,000	473,613	28.78%
	Grand Total	$ 14,465,205	$ 32,458,264	$ 17,993,059	44.57%