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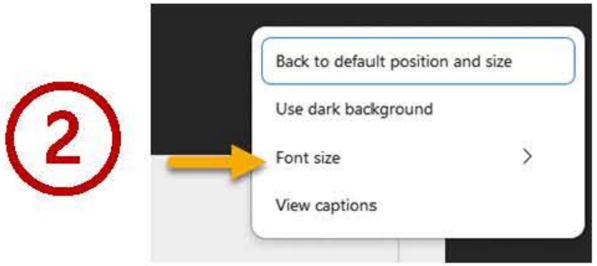

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1. Select the **ellipsis** in the lower right

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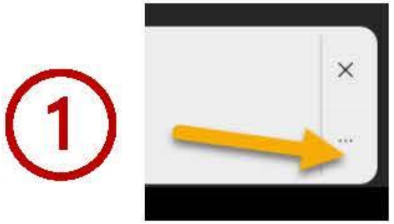
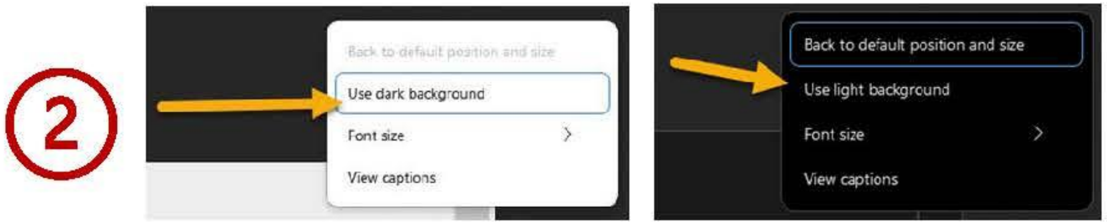




QUARTERLY BUSINESS REVIEW TECHNICAL WORKSHOP

November 13, 2025

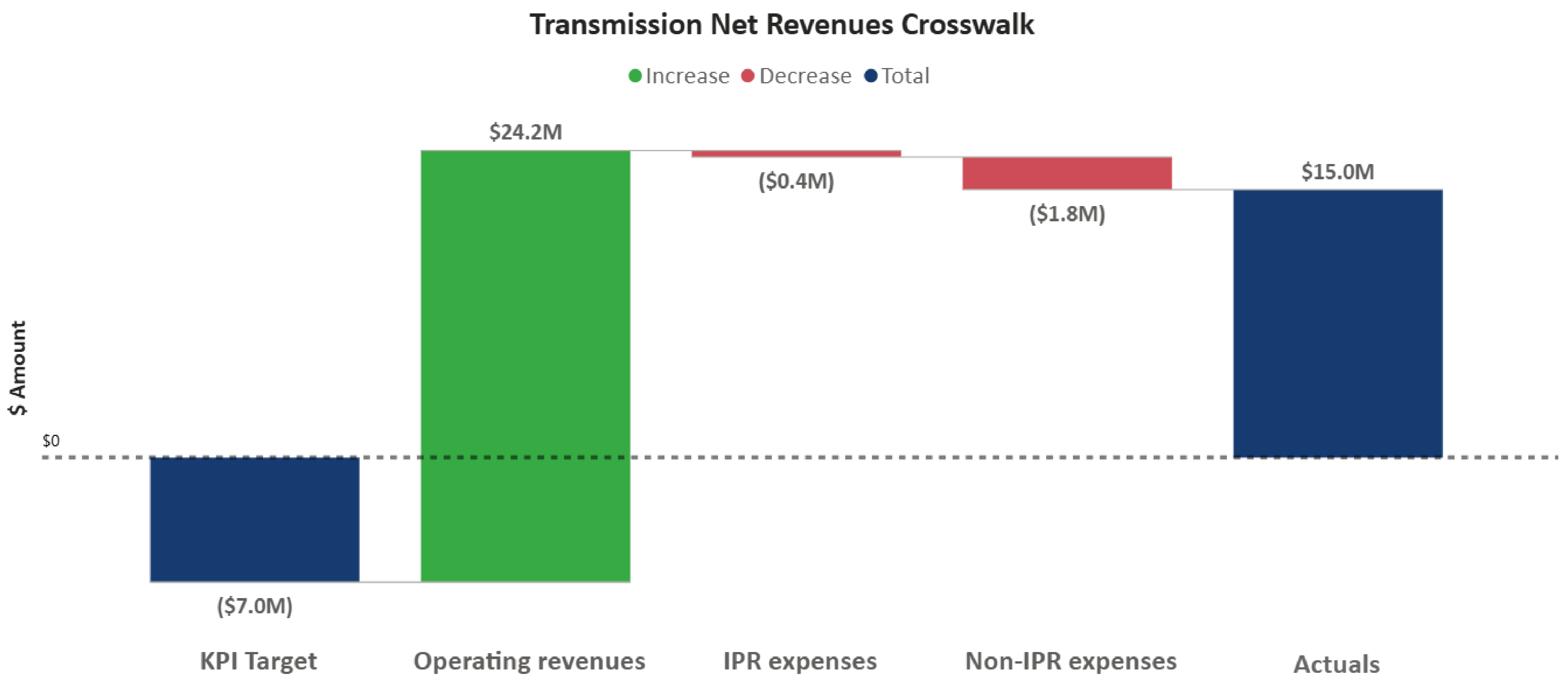
AGENDA

Time	Min.	QBRTW Topic	Presenter
1:00	5	Introduction	Taryn Redinger
1:05	10	FY25 Results: Transmission and Power Net Revenue	Drew Mellon, Pablo Zepeda-Martinez
1:15	10	FY25 Results: Reserves for Risk	Damen Bleiler
1:25	10	FY25 Results: Agency Capital	Heather Seibert
1:35	10	Fed Hydro Capital Metrics	Wayne Todd
1:45	10	Transmission Capital Metrics	Jeff Cook and Jana Jusupovic
1:55	15	Cancelling Reporting on BPA's EIM Metrics	Matt Germer
2:10	10	Western Resource Adequacy Program (WRAP)	Matt Hayes
2:20	20	Regional Cooperation Debt 2 (RCD2) Regional Check-In	Ethan Postrel
2:40	10	Questions & Answers / Closing	Taryn Redinger

FY25 Results: Transmission and Power Net Revenues

Presenter: Drew Mellon and Pablo Zepeda-Martinez

FY25 RESULTS: TRANSMISSION NET REVENUE



The KPI Target is less than Transmission's FY25 Rate Case net revenue forecast due to FY25 budget increases.

QBRTW ANALYSIS: TRANSMISSION NET REVENUE

FY25 results for Operating Revenues : $24M (2%) above target

- $5M increase in sales driven by increased Southern Intertie Short-Term revenues resulting from increased wheeling due to favorable market prices.
- $12M increase in other revenues driven by increased reimbursables and PFIA capital.
- $6M increase in Inter-Business Unit Revenues, driven by increased EIM sub-allocated charges.

FY25 results for Integrated Program Review Operating Expenses: $.4M (.05%) above target

- Driven by the cancellation of a capital IT project which resulted in the transfer of capital expenditures to expense in Q4.

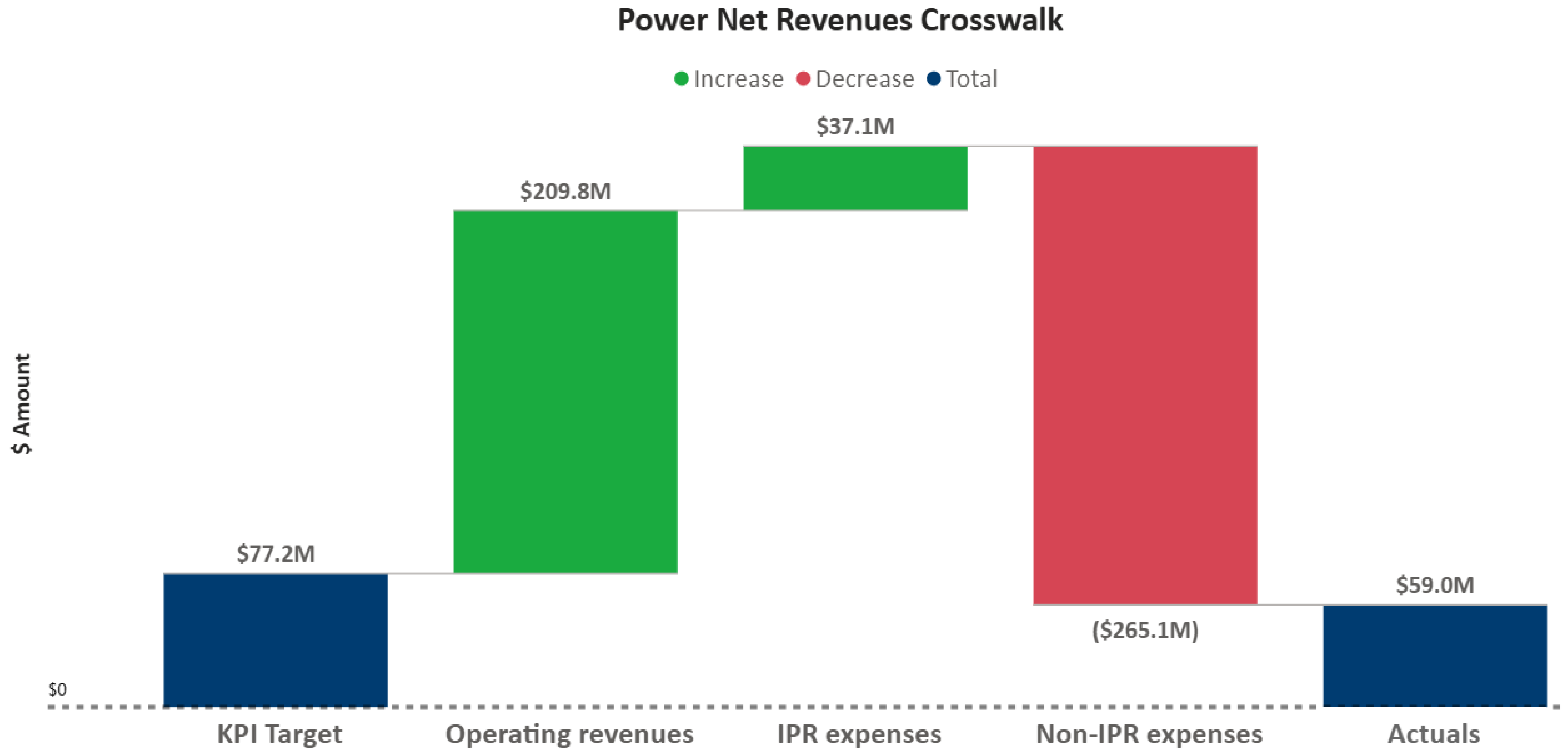
QBRTW ANALYSIS: TRANSMISSION NET REVENUE

FY25 results for Non-IPR Program Expenses: $2M (.3%) above target

- $38M increase in the Commercial Activities Non-IPR Program driven by increased reimbursable projects and increased EIM Entity Scheduling Coordinator Settlement Charges.
- $50M increase in Depreciation expense due to more capital work being placed in service than forecasted in Target and a higher depreciation rate that was implemented in March from the recent depreciation study

  Partially offset by:
  - $25M decrease in Amortization expense driven by the full amortization of the I5 Regulatory Asset.
  - $61M decrease in Interest expense and other income, net primarily driven by debt management actions that resulted in a significant gain from the early call and settlement of federal bonds.

FY25 RESULTS: POWER NET REVENUE



Power's net revenue KPI target is less than the rate case net revenue forecast mainly due to a lower secondary revenue forecast, budget increases, budget carryover from last fiscal year and lower power purchase expense.

QBRTW ANALYSIS: POWER NET REVENUE

FY25 results for Operating Revenues: $210M (7%) above the target

- Gross sales were $309M greater than Target largely due to increases in quantities sold and slightly high prices throughout the fiscal year. The gross sales were entirely offset by higher power purchases that are included in Non-IPR expenses.
- U.S treasury credits (4h10c) were $32M higher than expected due to higher modeled purchases and prices.
- Other revenues were $6M greater due to financial swap revenues particularly in February when prices were high.
- These increases are partially offset by:
    - $102M in bookouts, which are net revenue neutral due to a like amount in the non-IPR expense section.
    - The slice true-up (included in the appendix of this presentation) is a credit to customers of $28M, mainly due a debt management transaction and higher revenue credits (e.g., 4h10c).
    - Generating Inputs revenue decreased by $7M due to penalty charges, largely driven by resource additions moving out to FY26. In addition, lower-than-normal hydro conditions were a factor.

FY25 results for Integrated Program Review Operating Expenses: $37M (-2%) below target

- Asset management expenses decreased $29M primarily due to lower execution on Fish and Wildlife carryover from FY24. Also reduced spending on Lower Snake Hatcheries, as work was delayed from high water events in the spring. The underspending was slightly offset by higher Columbia River Fish Mitigation studies from the Portland district which saw higher project costs.
- Operations expenses decreased $18M primarily due to lower wind output for renewable energy purchases, and budget was shifted from Conservation Infrastructure to the Commercial activities for the Direct Fund Demonstration program within Energy Efficiency.
- Enterprise Services programs increased $5M mainly driven by deferred resignation program employee cost which historically would be included in the various programs.

QBRTW ANALYSIS: POWER NET REVENUE (cont.)

FY25 results for Non-IPR Program expenses: $265M (19%) above target

- Power purchases increased $527M across all months of the fiscal year compared to Target due to dry conditions and low stream flows. The biggest increase in purchases were seen in January and February. In those months, there was significantly higher than expected purchases driven by cold weather which led to additional purchases as well as higher prices which drove up the purchase expense. For water year 2025, the January through July observed volume was 81.4 MAF at the Dalles which is 78.5% of the 30-Year Normal from 1991-2020.
- Fish & Wildlife and Lower Snake Hatcheries program spent $21M of the Reserves Distribution Clause funding they received, which wasn't included in the target. RDC spending since the agreements were implemented are:
  - Of the $25M FY22 F&W RDC Funds, $7M was spent through FY25. The remaining balance is ~$18M.
  - Of the $25M FY22 F&W Lower Snake Hatcheries RDC Funds, $20M was spent through FY25. The remaining balance is $5M.
  - Of the $30M FY23 F&W RDC, $9M has been spent since FY25. The remaining balance is $21M.
- Resilient Columbia Basin Agreement (RCBA) of $20M is the amount owed to the Six Sovereigns for prior year amounts that BPA is responsible to pay to the agreement partners.
- These increases are partially offset by the following:
  - Bookouts reduce Non-IPR expenses by $102M but are net revenue neutral due to a like amount in the revenue section.
  - Lower 3rd Party GTA wheeling expense by $10M due to lower rate increases than expected.
  - The Colville and Spokane Generating Settlements were $8M less than Target because the payment is mainly based upon prior year output at Grand Coulee Dam, Power Services gross sales and the number of megawatts sold. Lower than average flows at Grand Coulee Dam and lower average price per megawatt in fiscal year 2024 led to a decrease in the annual payment made in FY25.
  - Lower Transmission and Ancillary Services by $7M, mainly driven by lower total inventory.

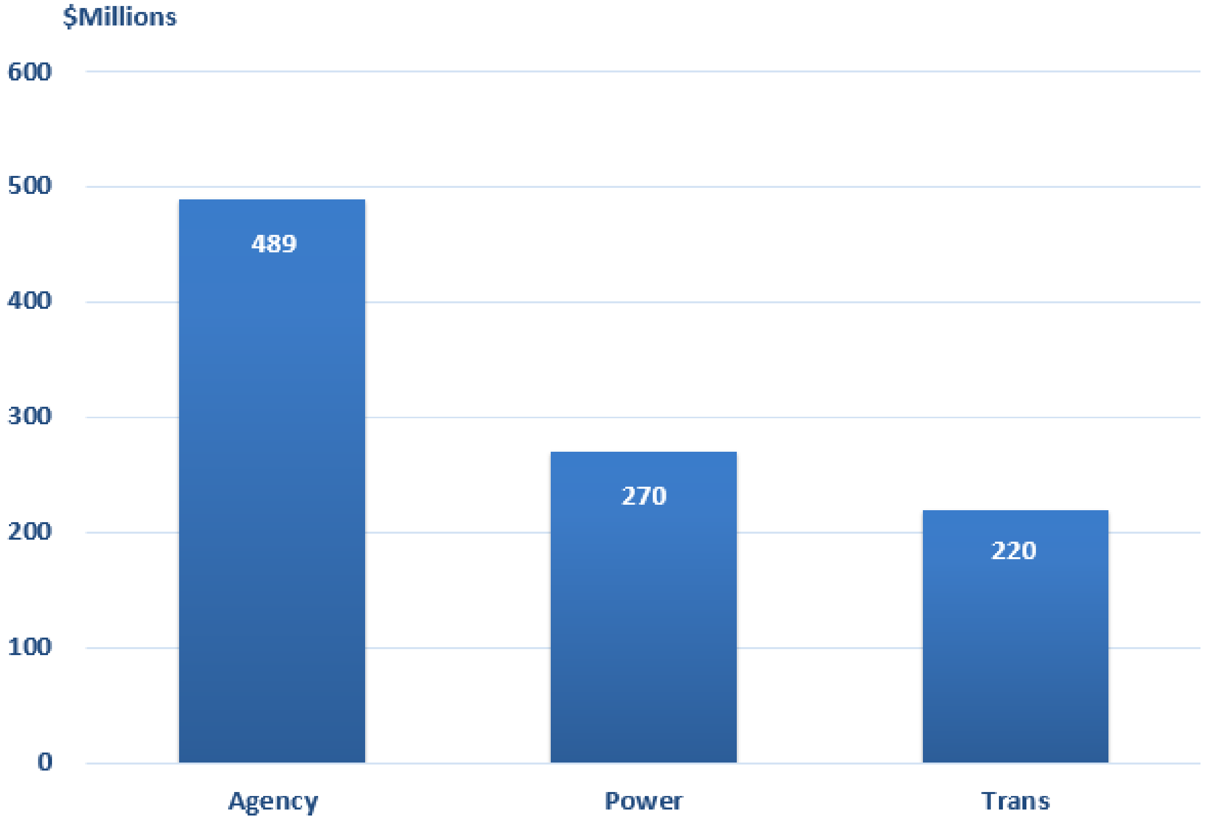
FY25 Results: Reserves for Risk

Presenter: Damen Bleiler

FY25 ACTUALS: RESERVES FOR RISK

- Share FY 2025 EOY Reserves for Risk, RFR, results by business unit
- Financial Reserves Policy Results – Power Surcharge Calculation & Amount
- Preliminary Surcharge Rates
- Refresh on the Surcharge Process per GRSPs
- Timeline

FY25 ACTUALS: Reserves for Risk



	Agency	Power	Trans
DCOH	64	50	94
Thresholds			
RDC	>$768M	>$741M	>$283M
Surcharge		<$370M	<$141M

Power EOY RFR is $452M lower than RC expectations. Drivers:

- RFR @ SOY was $130M lower than assumed in RC.
- Cash from operations is ~$356M lower than assumed in RC.
  - ~$171M from lower NR than RC.
  - ~$147M from higher cash use due to cash timing vs accruals (e.g. F&W prior year invoices & EN fiscal year differences).
  - ~$37M from settlement payments & write offs not included in rates.
- A net cash flow improvement of $34M from unwinding of revenue financing built into rates.

Trans EOY RFR closely aligns to RC expectations, ~$13M higher.

- RFR @ SOY was $107M higher than assumed in RC.
- Cash from operations is ~$60M higher than assumed in RC.
  - NR ~$28M lower than RC.
  - However, this is more than offset by increased non-cash items (e.g. depreciation expense) & timing of cash payments vs accruals.
- Net cash flow use of $154M from additional debt payments for the FY24 RDC & debt management gain proceeds.

FY25: Financial Reserve Policy Results

Transmission: Mechanisms do not trigger since EOY RFR is between the upper and lower FRP thresholds.

- Upper threshold $283M
- **EOY RFR = $220M**
- Lower threshold $141M

Power: Mechanisms trigger because RFR is below the FRP Surcharge Threshold. Per the FRP calculation, the Surcharge amount = $40M.

- Upper threshold $741M
- Lower threshold $370M
- **EOY RFR = $270M**
- Surcharge calculation threshold = lower threshold ($370M) minus FY26 Revenue Financing ($37M) = $333M

	Power Surcharge
FY25 EOY Actual RFR	$269.9
Surcharge RFR Threshold (less FY26 RF)	$333.0
Amount below Threshold	$63.1
Surcharge Amount (Cap = $40M)	$40.0

FY25 ACTUALS: Power Surcharge Preliminary Rates

- Annual Average Effective Rate to recover $40M of FRP Surcharge over the ten-month billing period of Dec – Sept is estimated at 2.2%
- Preliminary annual effective rate change for Power average effective PF Non-Slice Tier 1 Rates is estimated at $0.84 MWh

	A	B	C	D	E	F
1	*(a) Power FRP Surcharge Rate:*					**FY2026**
2		Power FRP Surcharge Amount:				$40,000,000
3		Sum of Dec - Sept Billing Determinants (MWh):				39,529,503
4		Power FRP Surcharge rate ($/MWh):				**$1.01**
5						
6	*(c) Adjusted PF Tier 1 Equivalent Energy Rates:*					
7				HLH ($/MWh)	LLH ($/MWh)	
8			Oct-25	46.04	44.26	
9			Nov-25	34.94	37.05	
10			**Dec-25**	**44.05**	**45.21**	
11			**Jan-26**	**39.98**	**40.22**	
12			**Feb-26**	**41.85**	**45.60**	
13			**Mar-26**	**25.61**	**30.96**	
14			**Apr-26**	**18.75**	**23.51**	
15			**May-26**	**5.02**	**9.15**	
16			**Jun-26**	**11.52**	**12.50**	
17			**Jul-26**	**47.40**	**44.48**	
18			**Aug-26**	**50.22**	**46.74**	
19			**Sep-26**	**56.93**	**55.48**	
20						
21	*(d) Annual Power FRP Surcharge Rate and Other Adjustments:*					
22		Sum of Annual Billing Determinants (MWh):				47,361,290
23		Annual Power FRP Surcharge Rate ($/MWh):				**$0.84**
24						
25		Adjusted Load Shaping Charge True-Up rate:				$3.75
26		Adjusted PF Melded Equivalent Energy Scalar rate:				$1.23
27						
28			Average Effective Non-Slice Tier 1 Rate			$38.40
29			New Average Effective Non-Slice Tier 1 Rate			$39.24
30			**Annual Effective Rate Increase**			**2.2%**

Surcharge Process per GRSPs

- The Financial Reserves Policy establishes actions based on reserves levels. When reserves decline below established thresholds, rates increase through the Financial Reserves Policy, FRP, Surcharge and Cost Recovery Adjustment Clause, or CRAC. When reserves exceed established thresholds, the RDC triggers for the Administrator to consider repurposing them for other high-value business unit-specific purposes.
- The Power and Transmission General Rate Schedule Provisions, GRSPs, outline the Surcharge process and requirements. The language is the same for both business units and states:

  By November 30, 2025, BPA shall complete the calculation of Power/Transmission RFR and BPA RFR as of the end of FY 2025, for use in calculating the Power/Transmission Surcharge applicable to rates for December through September of FY 2026.

  If the Power/Transmission Surcharge triggers, BPA will notify customers of the preliminary Power/Transmission Surcharge Amount and to be recovered by Power FRP Surcharge for the applicable year. Such notice will be provided as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the Power/Transmission Surcharge.

  BPA will hold at least one public meeting to discuss the calculations of Power/Transmission RFR, the Power/Transmission FRP Surcharge Amount, the Power FRP Surcharge Rate, and the Annual Power FRP Surcharge Rate. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Power/Transmission FRP Surcharge, Power FRP Surcharge Rate, and the Annual Power FRP Surcharge Rate as soon as practicable, but in no case later than December 15 of each applicable year.

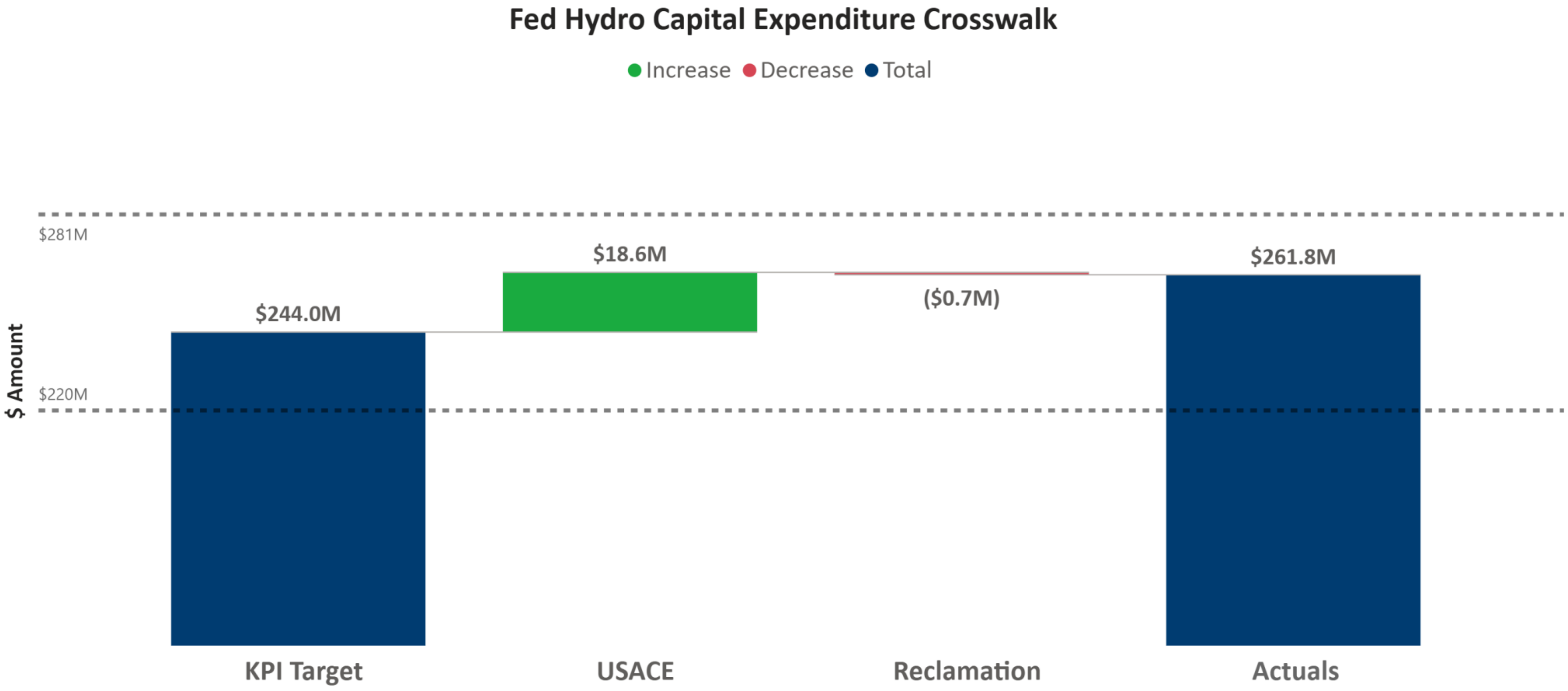
Surcharge Timeline

- 11/10: Post QBRTW Material – starts comment period
- 11/13: Surcharge Calculated Rate Adjustment shared at QBR/QBRTW
- 11/21: Comment period ends
- NLT 12/15: Issue the final Power FRP Surcharge rate

FY25 Results: Agency Capital

Presenter: Heather Seibert

FY25 ACTUALS: FED HYDRO CAPITAL



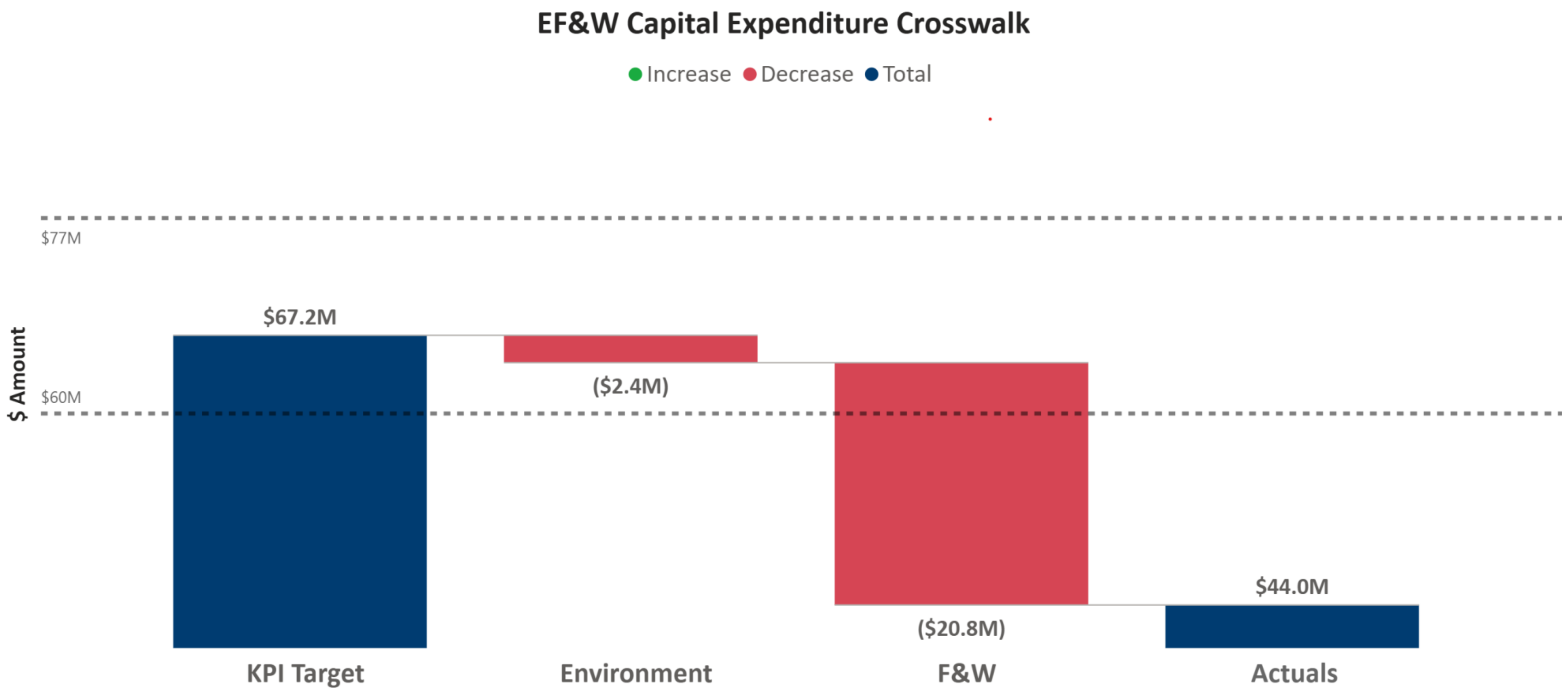
The Fed Hydro capital expenditure KPI target is a range. The range is equal to +15% and -10% of the target midpoint. If the Fed Hydro direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: FED HYDRO

The FY25 actuals for Fed Hydro's direct capital ended $17.8M above or 107% of the Target midpoint due to the following:

- The delta between Q4 actuals and Target is due to multiple factors, including a decrease in USACE expand work and an increase in sustain at both USACE and BOR. With limited personnel and several large projects underway, strategically reducing expand while focusing on sustain enabled the existing projects to continue while reducing strain on the workforce and still exceed the target.

FY25 ACTUALS: EF&W CAPITAL



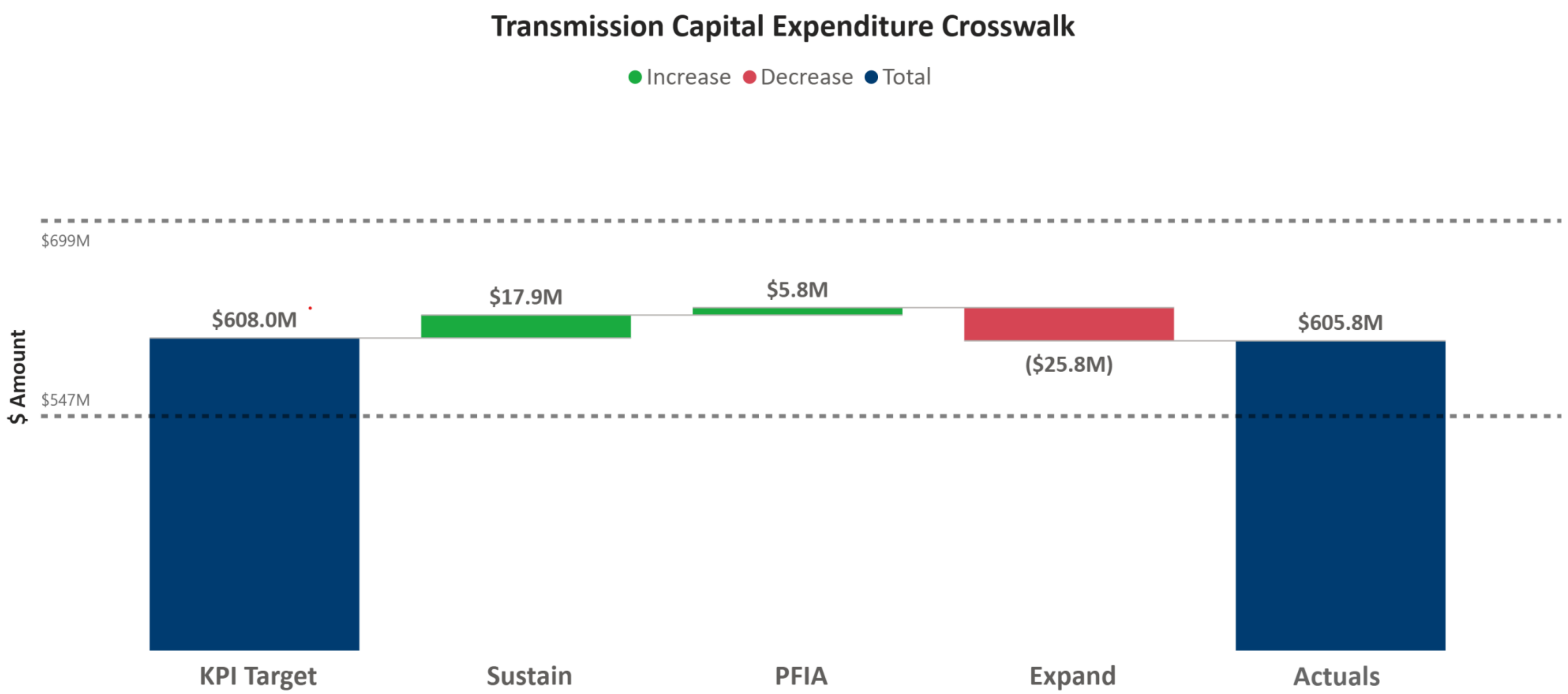
EF&W does not have its own capital expenditure target, but does roll up to the Agency capital KPI target. The range is equal to +15% and -10% of the target midpoint and is displayed to support tracking capital execution and how these expenditures could impact the Agency KPI target.

QBRTW ANALYSIS: EF&W

The FY25 actuals for Environment, Fish & Wildlife direct capital ended ($22.4M) below or 65% of the Target midpoint.

- The delta between Target and Actuals of ($21M) for F&W is due to several factors, including:
  - BPA staffing shortages; weather delays; boundary and landowner issues; tribal partner's inability to complete their due diligence on land acquisitions; and site access issues.
  - All areas (land, hatchery, and passage) of F&W had significant underspend in FY25 due to one or more of the above factors.

FY25 ACTUALS: TRANSMISSION CAPITAL



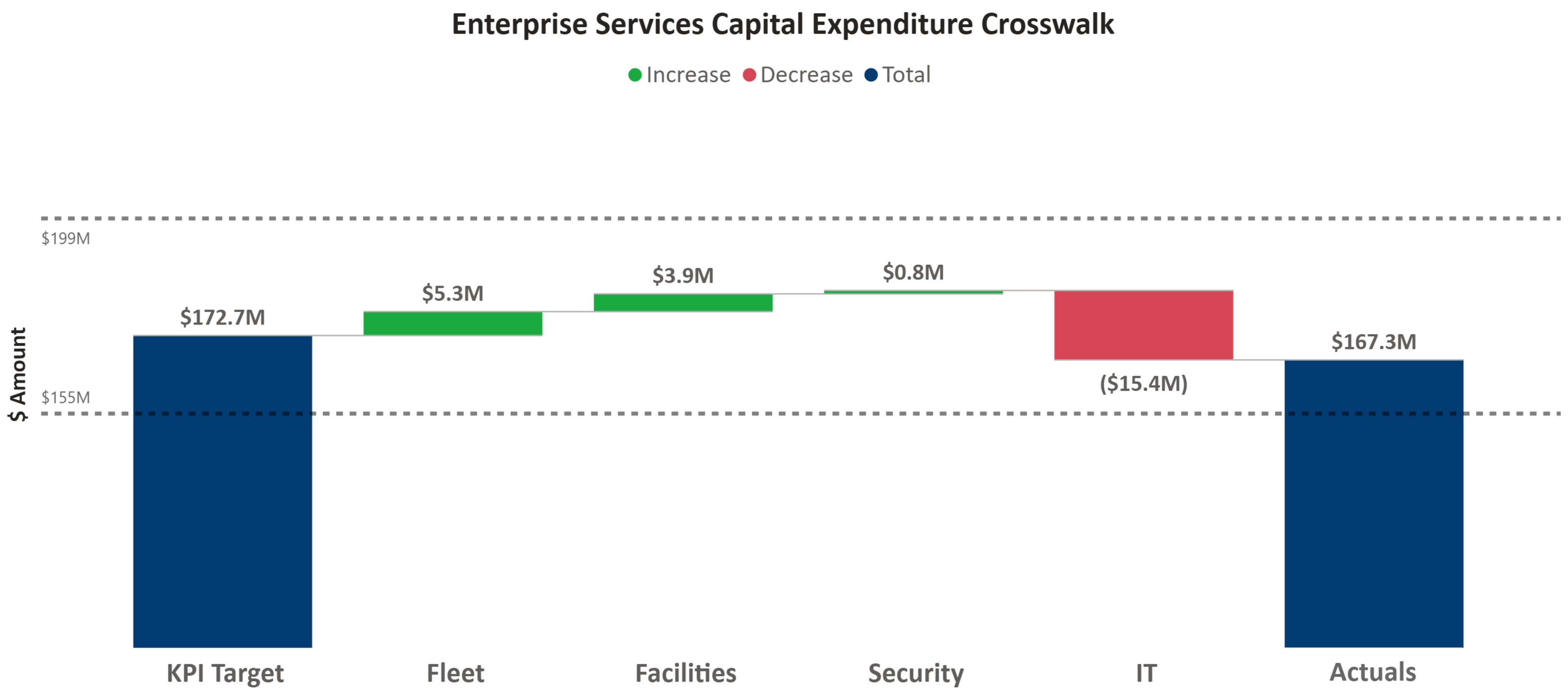
The Transmission capital expenditure KPI target is a range. The range is equal to +15% and -10% of the target midpoint. If Transmission direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: TRANSMISSION

The FY25 actuals for Transmission's direct capital ended ($2M) below or 99.6% of the Target midpoint.

- The Expand/Sustain combined deltas of ($8M) below were offset by $5.8M above the Target midpoint for Projects Funded In Advance (PFIA). The individual deltas for Expand/Sustain were mainly due to shifting of resources from expand work to sustain work.
  - For Expand, there were also remaining impacts of EOs even after the Target Reset, which resulted in additional delays.

FY25 ACTUALS: ENTERPRISE SERVICES CAPITAL



The Enterprise Services capital expenditure KPI target is a range. The range is equal to +15% and -10% of the target midpoint. If Enterprise Services direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: ENTERPRISE SERVICES

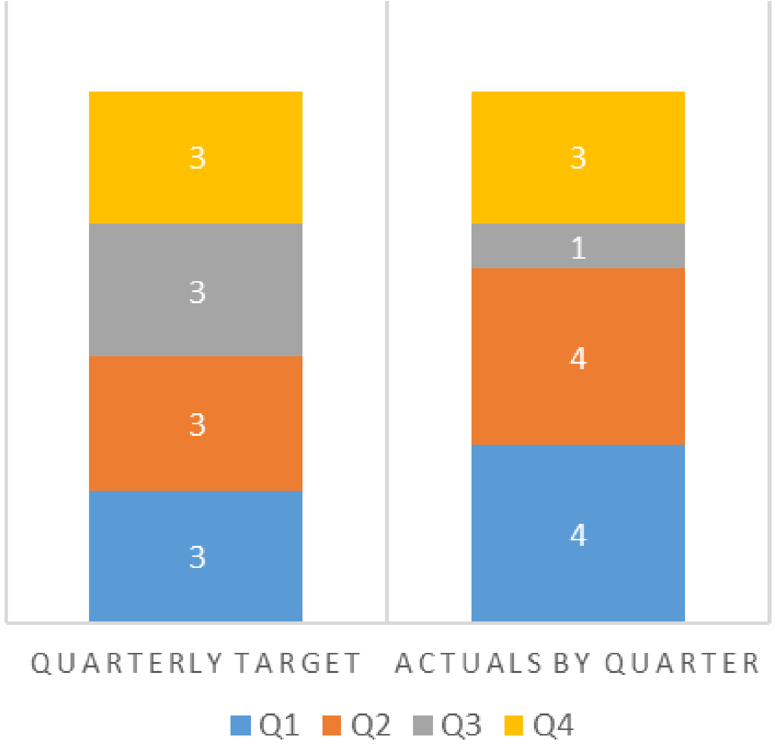
The FY25 actuals for Enterprise Services direct capital ended ($5.4M) below or 97% of the Target midpoint as follows:

- Fleet ended the year $5M above their target primarily due to higher-than-forecast costs on Transmission equipment.
- Facilities ended $4M above their target primarily driven by the Vancouver Control Center project which accounted for 82% of Facilities total expenditures for the year. This project is ahead of schedule and brought forward material purchases originally scheduled for FY26.
- IT ended ($15M) below their target primarily driven by the cancellation of an IT project that resulted in a capital to expense transfer. Otherwise, IT expenditures were largely on track and executed according to plan.

FEDERAL HYDRO CAPITAL METRICS

Presenter: Wayne Todd

FED HYDRO CAPITAL MILESTONES



Actuals against
Quarterly Target
100%

Q4 Target
Met

EOY Target
Met

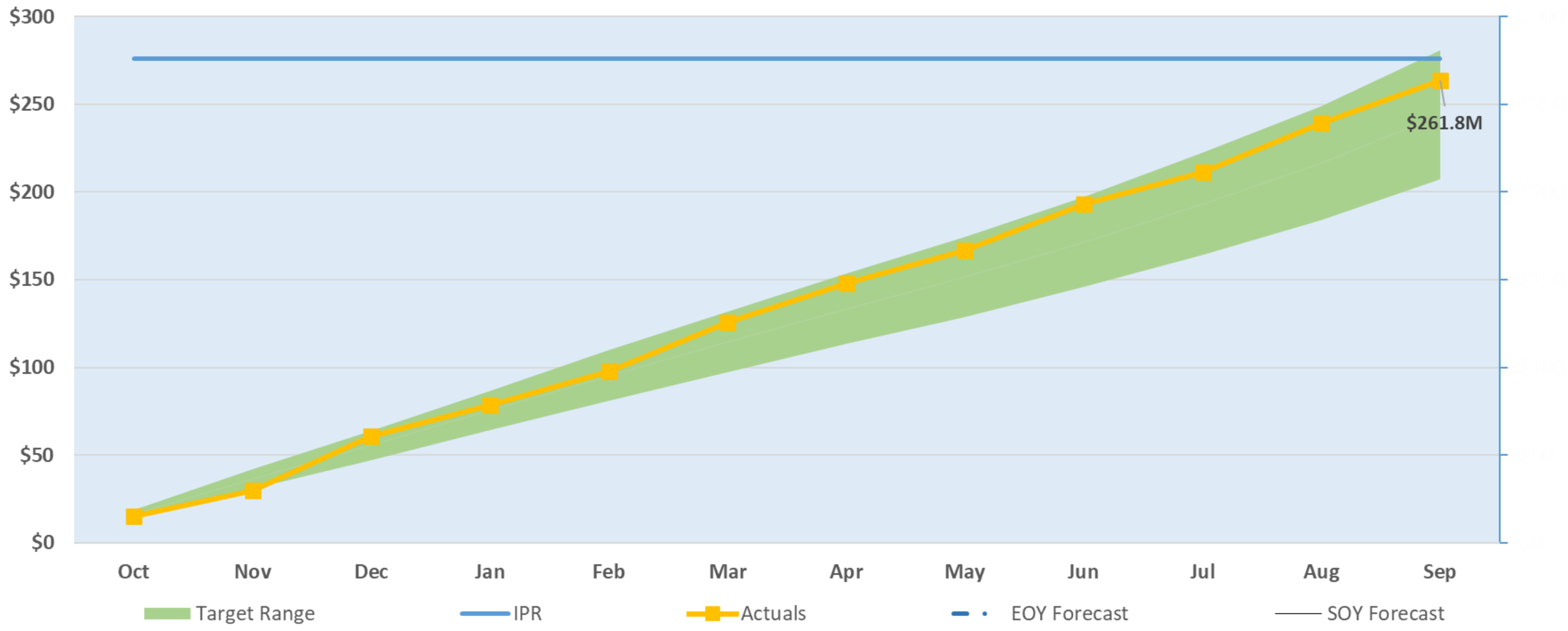
Key Takeaway: FY25 Target met.

FED HYDRO CAPITAL PROJECT MILESTONES

Project	Expenditure Name	Milestone Name
John Keys PGP Structure	GCL PGP Crane Modernization #2805	**Award Contract**
Grand Coulee	Block 31 Elevator	**Physical Completion**
Grand Coulee	GCL LPH RPH Bridge Crane Replacement	Physical Completion
McNary	Upgrades to station Service Units	**Physical Completion Unit 2**
Ice Harbor	IHR Intake Gate Hydraulic System Upgrades	**Complete Design**
John Day	JDA Submerged Traveling Screen (STS) Crane	**Physical Completion**
Albeni Falls	ALB Powerhouse Bridge Crane Rehab	**Award Contract**
Grand Coulee	GCL LPH/RPH Cyclops Semi-Gantry Crane Replacement #3917	**Award Contract**
Grand Coulee	GCL Replace Underground Town of Coulee Dam Feeders 1, 3 & 4 #3340	**Complete Design**
Bonneville	BON 1 Spillway Cranes	**Complete Design**
Chief Joseph	CHJ Powerbus- Units 1-16	**Award Contract**
Chief Joseph	CHJ Exciter Replacement Units 1-16	**Award Contract**
Grand Coulee	GCL WPP Crane Control Upgrades #3238	**Physical Completion**
Grand Coulee	GCL Radio System Modernization #3918	**Construction Contract Awarded**
John Day	JDA HVAC System Upgrade	**Award Contract**
Bonneville	BON 2 Tailrace Gantry Crane	**Physical Completion**
Chief Joseph	CHJ Intake Gantry Crane	**Physical Completion**
Chief Joseph	CHJ 480V - SU1-4	**Physical Completion**
Ice Harbor	IHR Intake Gate Hydraulic System Upgrades	**Award Contract**
Lower Granite	LWG Turbine Intake Gate Hydraulic System Upgrade	**Award Contract**
Lower Monumental	LMN PH Bridge Crane Wheel and Drive System Upgrade	**Award Contract**
Lower Granite	LWG MU2 Blade Sleeve Upgrade and Rehab	**Award Contract**
Little Goose	LGS Turbine Intake Gate Hydraulic System Upgrade	**Complete Design**
Lower Monumental	LMN DC System and LV Switchgear Upgrade	**Physical Completion**
Grand Coulee	GCL TPP Roof Replacement	**Physical Completion**

Key Takeaway: Design Completion, Awarded Contracts, and Construction milestones for projects over $10 million in direct funded capital costs are tracked toward the milestone target.

FED HYDRO CAPITAL SPEND



FY25 Key Performance Indicators

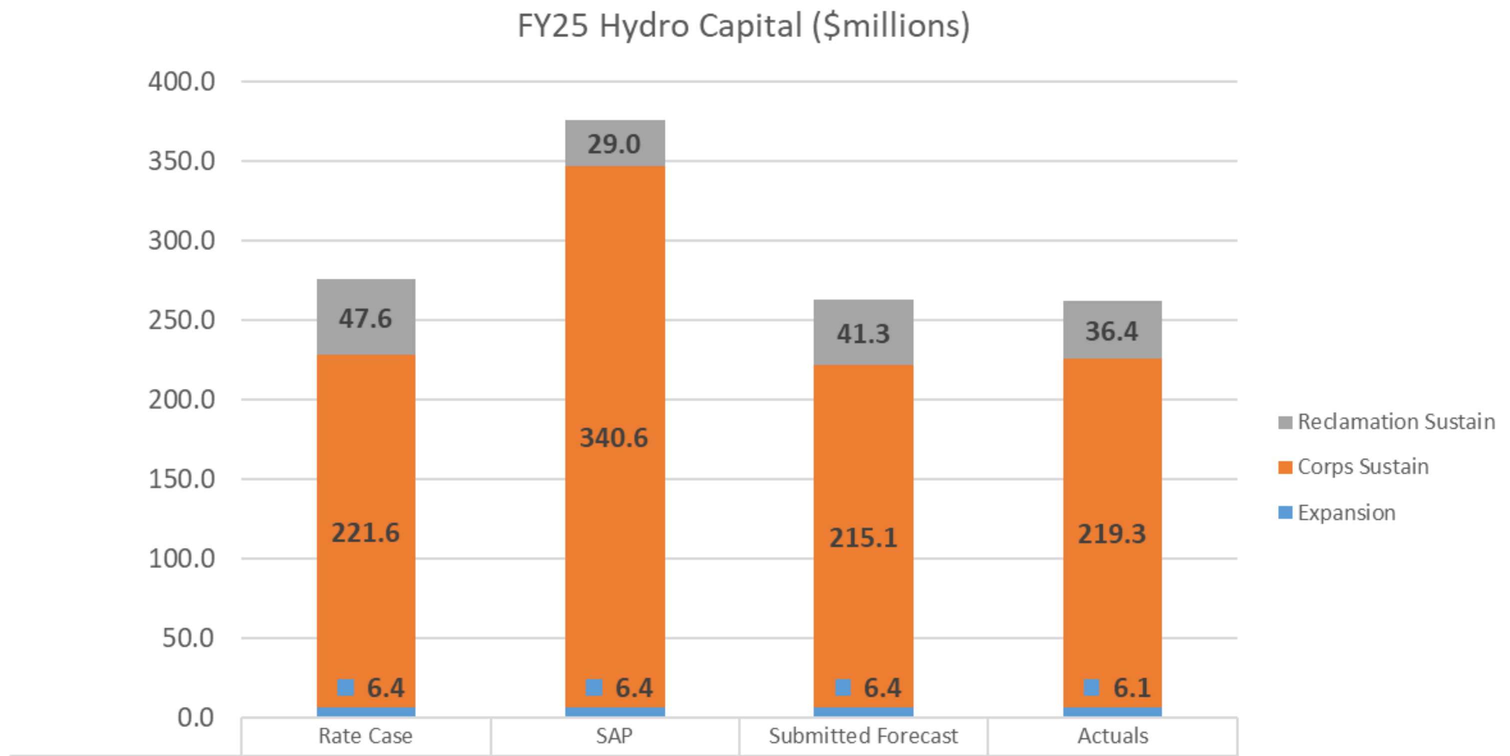
IPR: $276 million

SOY Forecast: $244 million

Target Range: $220-$280 million

Key Takeaway: Capital expenditures met the target for FY25. KPI is green.

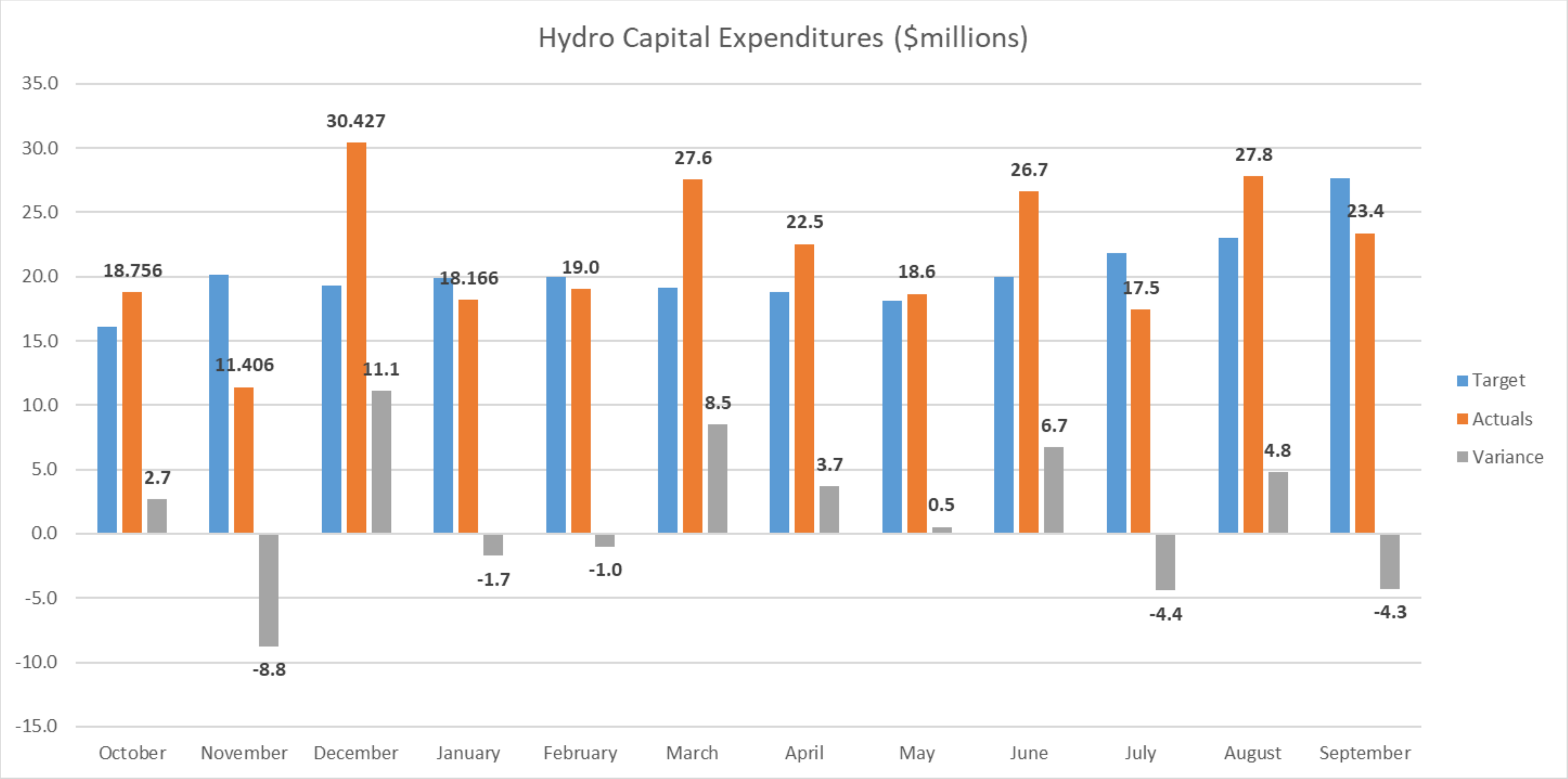
FED HYDRO CAPITAL SUSTAIN VS EXPAND



	Rate Case	SAP	Submitted Forecast	Actuals
Reclamation Sustain	47.6	29.0	41.3	36.4
Corps Sustain	221.6	340.6	215.1	219.3
Expansion	6.4	6.4	6.4	6.1

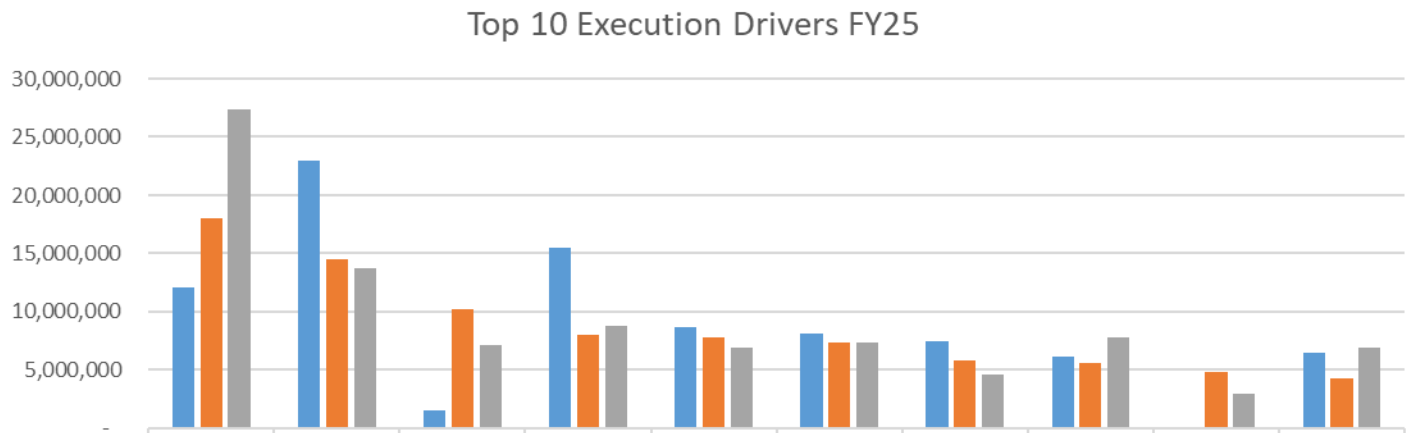
Key Takeaway: The two expansion projects in the portfolio, Libby Unit 6 and Dworshak Unit 4 have limited expenditures in FY25.

FED HYDRO CAPITAL FORECAST VARIANCE



Key Takeaway: Monthly variances occur but on aggregate we are on track with forecasted expenditures.

FED HYDRO CAPITAL TOP 10 EXECUTION DRIVERS FOR FY25



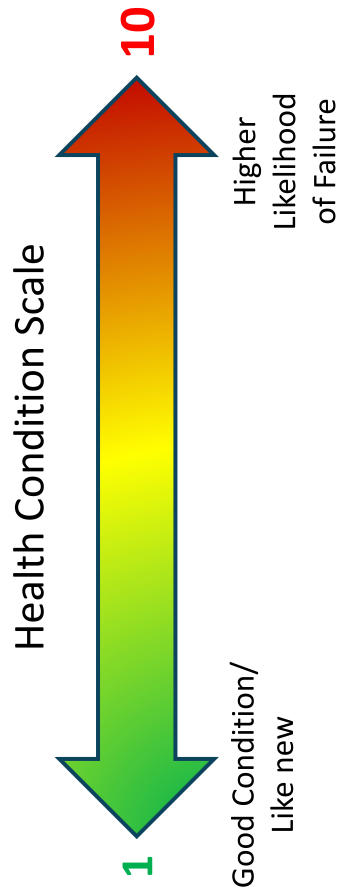
	McNary Turbine Design and Replacement	Chief Joseph Unit 1-16 Generator Rewind	Grand Coulee LPH/RPH Bridge Crane Replacement	McNary Headgate System Rehabilitation	Ice Harbor Turbine Runner Design & Repl. Units 1,2,3	McNary Iso-phase, HV Bus and Switch Upgrade	Chief Joseph Upgrades for Station Service Units	McNary Drainage, Unwatering, and Equalization System Rehabilitation	Lower Monumental DC System and LV Switchgear Upgrade	Chief Joseph 480V - SU1-4
SAP	12,069,16	22,961,12	1,567,405	15,460,00	8,665,000	8,125,000	7,504,000	6,180,000	-	6,438,221
SOY	18,000,00	14,500,00	10,173,64	8,000,000	7,800,000	7,350,000	5,800,000	5,600,000	4,800,000	4,300,000
Actuals YTD	27,393,00	13,719,00	7,142,000	8,799,000	6,883,000	7,332,000	4,641,000	7,787,000	3,002,000	6,937,000

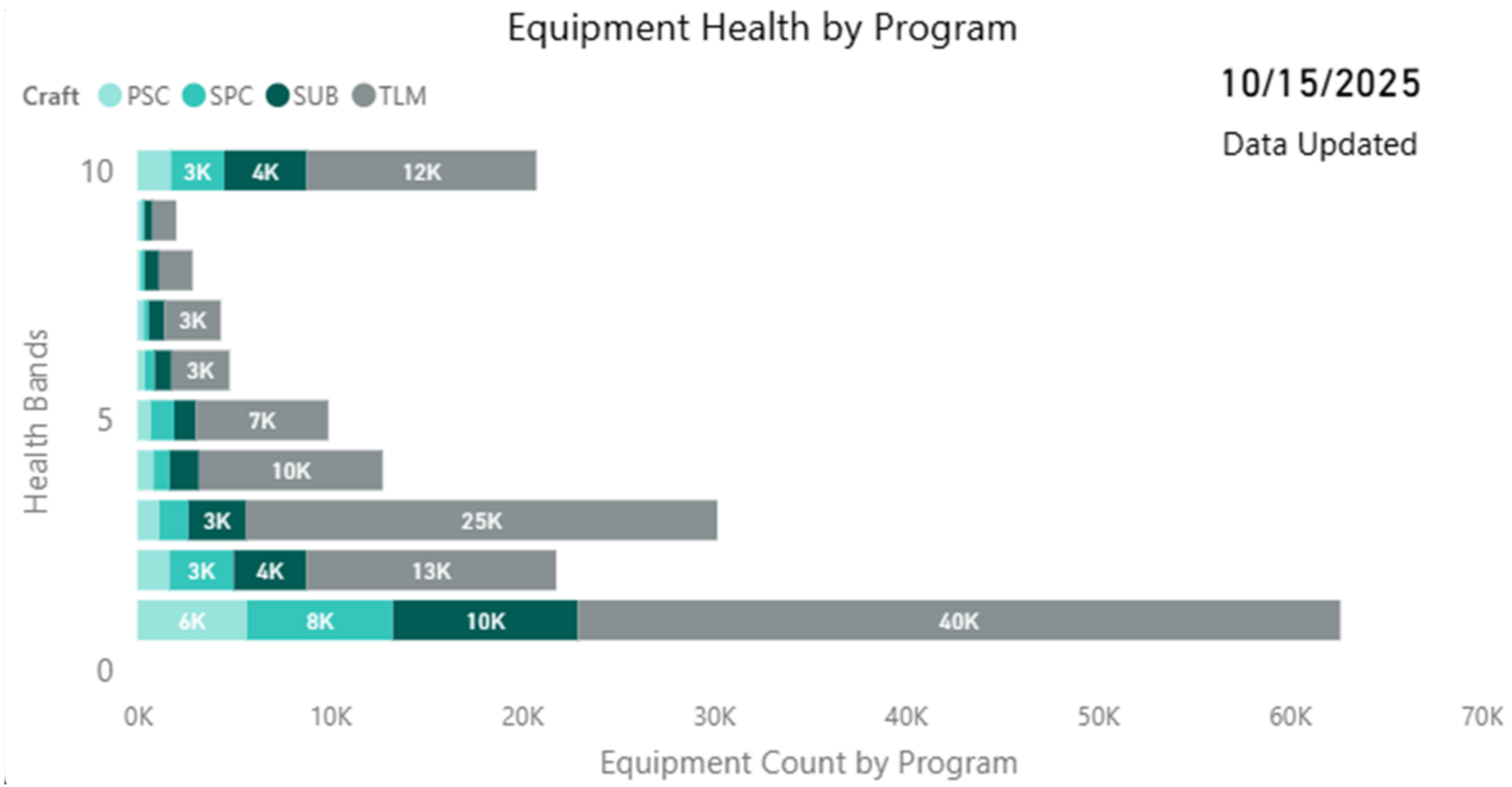
Key Takeaway: The large construction projects underway will continue to be major drivers for years to come.

TRANSMISSION SERVICES CAPITAL METRICS

Presenters: Jeff Cook and Jana Jusupovic

ASSET MANAGEMENT HEALTH





PSC: Power System Control, SPC: System Protection Control, Sub: Substation, TLM: Trans Line Maintenance

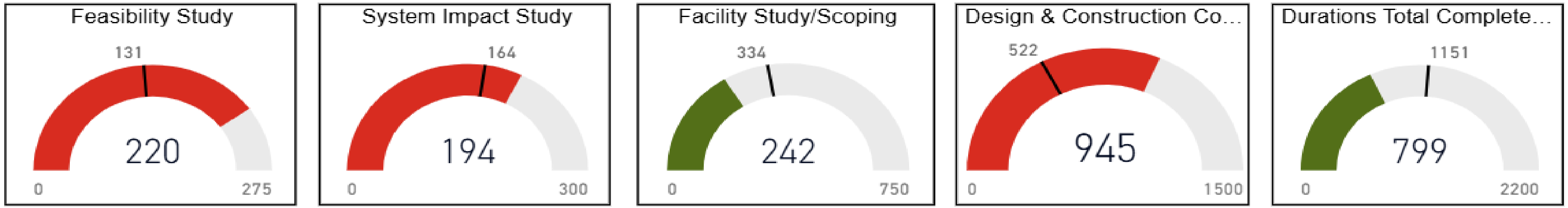
Transmission's health scoring methodology is most mature for substations and some lines assets, or about 40% of the assets included in Transmission's sustain program.

ASSET MANAGEMENT METRIC MATURITY

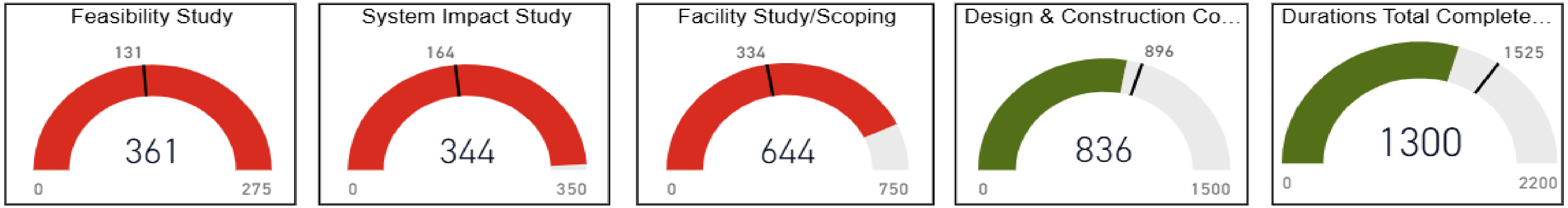
- Transmission has developed Excel-based models, which contain algorithms related to asset replacement and project value.
- In FY25, initial data requirements were mapped and understood technically to support future capability development.
- In FY26, Transmission will continue to mature its asset management capability, with additional information coming in future QBRs.

CUSTOMER DURATION METRIC

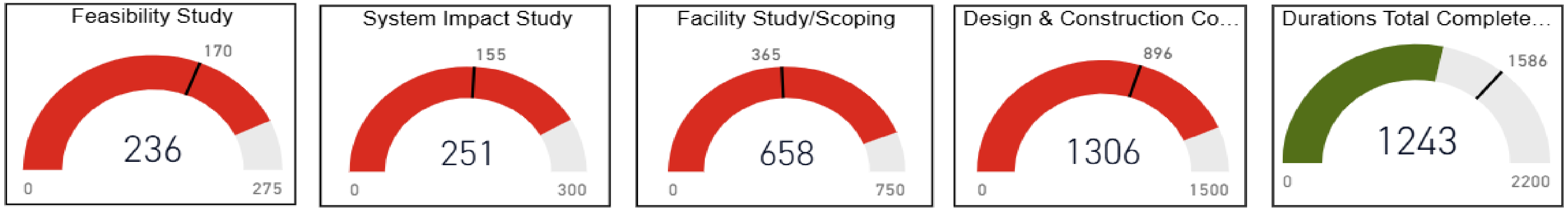
Small Generation Interconnection projects: Projects with an aggregation of generators, whose single or combined generating capacity is > than 0.2MW and = to or < 20MW



Large Generation Interconnection Projects: Projects with an aggregation of generators, whose single or combined generating capacity is greater than 20MW



Line and Load Interconnection Projects: Projects can be a customer owned line terminated at a BPA facility, a tap of a BPA owned line or other plans of service



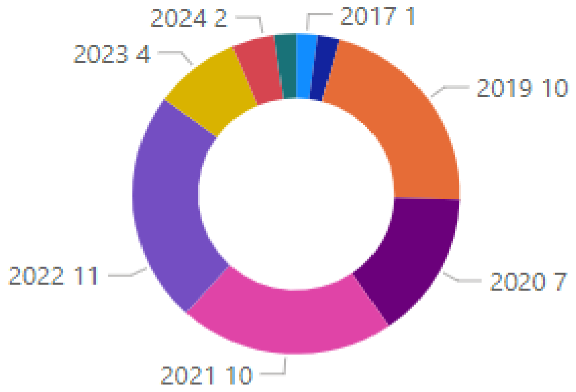
Includes LGI, LLI, SGI projects with a Queue date on or after 01/01/2015

Optimal performance is below the lines, which denote the target ceiling levels

* Completed Projects Only

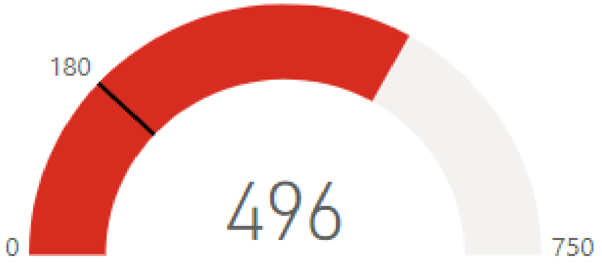
CUSTOMER DURATION METRIC (NEW)

FAS Study Completion by Year



PCM Process | FAS with CDD (47 Projects)

Average Days for Facility Study/Scoping



Primary Capacity Model
(Internal Scoping Resources)

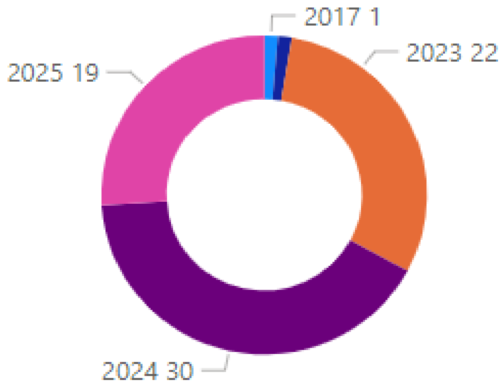
Includes LGI, LLI, SGI projects with a Queue date on or after 01/01/2017

Optimal performance is below the lines, which denote the target ceiling levels

Completed Projects Only

Does not includes the time projects were waiting for Scoping Resources prior to New Process starting

FAS Study Completion by Year



ECM Process | FAS/Scoping No CDD (73 Projects)

Average Days for Facility Study

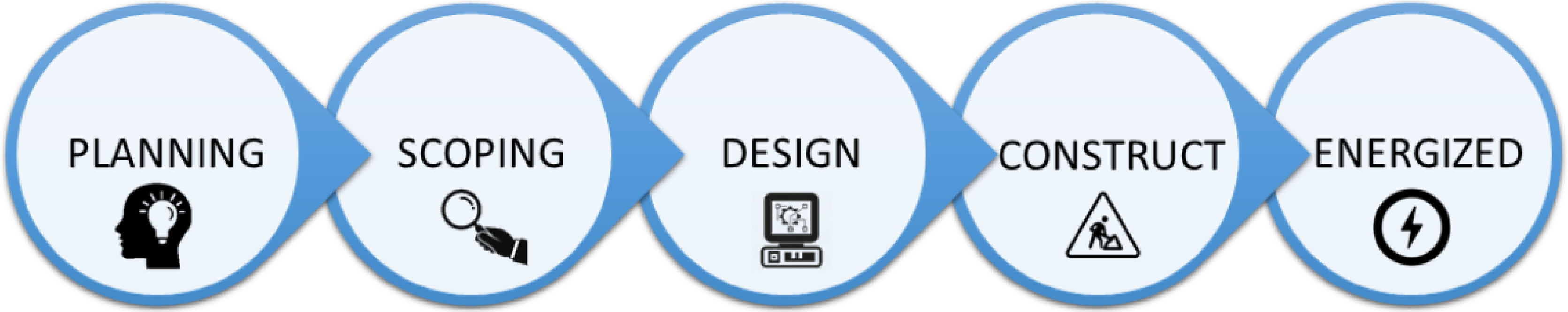
Engineering Capacity Model
(Internal Consulting Resources)

PRIMARY VS SECONDARY CAPACITY THROUGHPUT

Transmission as of FY25 Q4:

PRIMARY VS SECONDARY CAPACITY THROUGHPUT – CURRENT FY

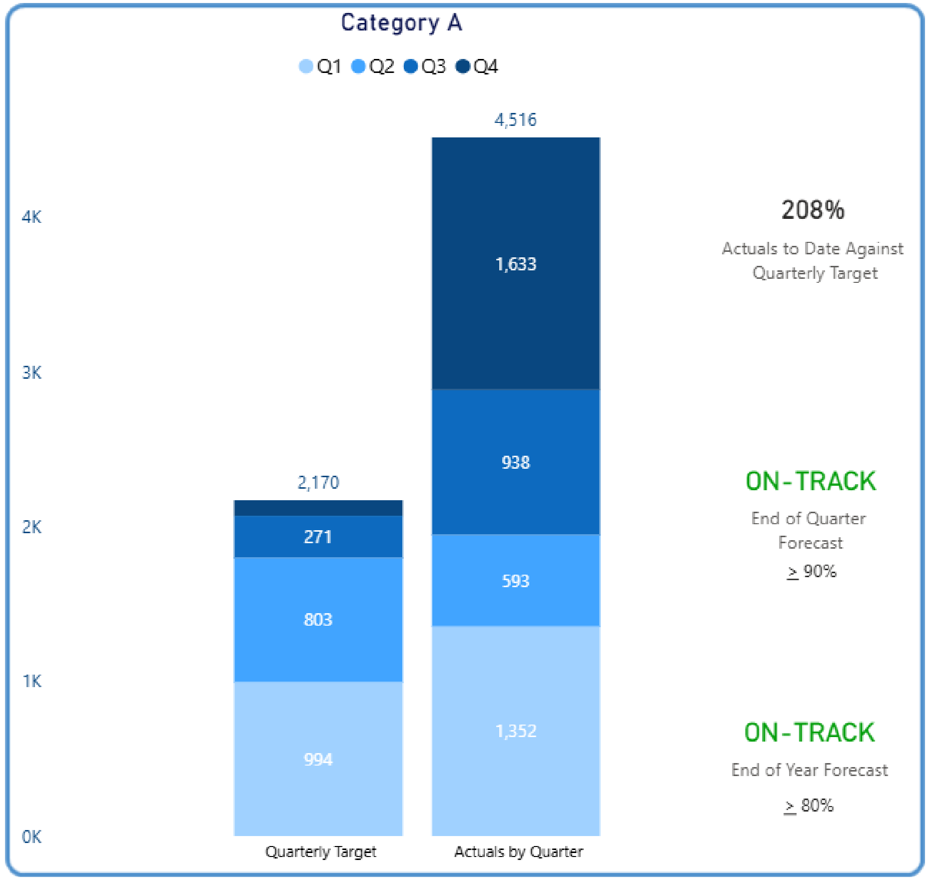
2025

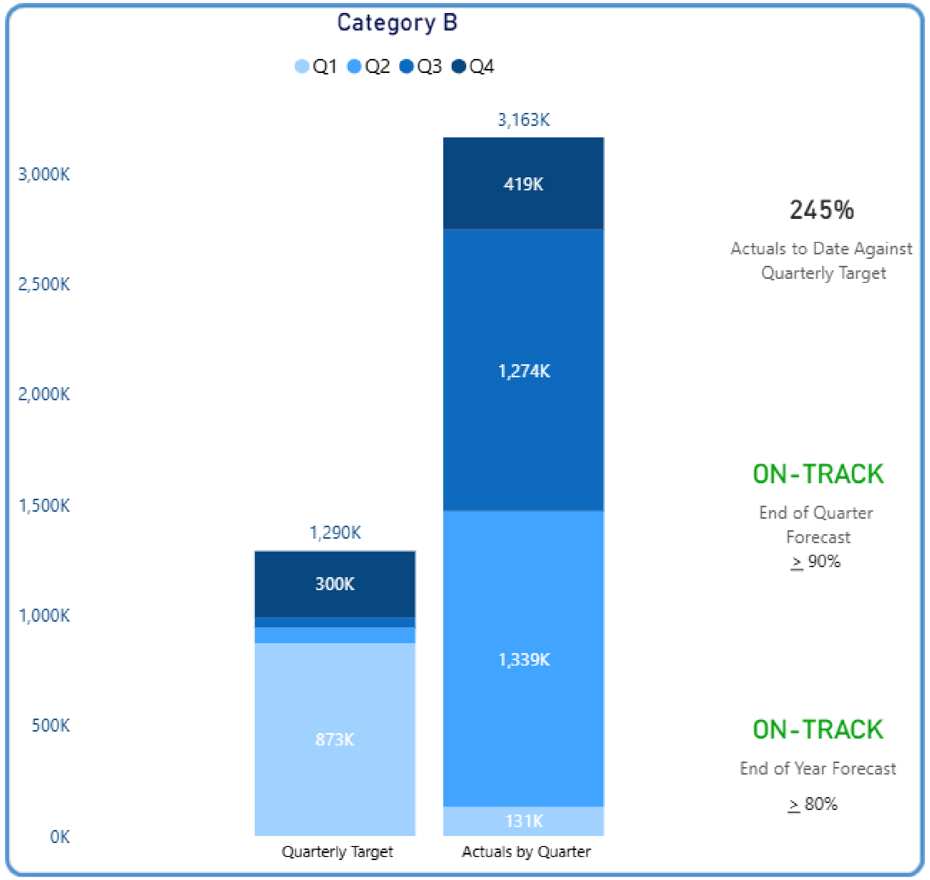


	PLANNING	SCOPING	DESIGN	CONSTRUCT	ENERGIZED
PRIMARY CAPACITY MODEL	339	63	116	164	274
	$3,671,815,970	$631,189,398	$1,917,268,105	$1,827,486,838	$343,435,275
SECONDARY CAPACITY MODEL	3	36	16	7	3
	$78,245,054	$2,278,763,581	$1,101,077,371	$180,609,600	$228,197,926

CAPITAL ASSETS PLANNED VS COMPLETED

Transmission as of FY25 Q4





Key Takeaway: On Track: For FY25 EOY we have exceeded both Asset Categories.

WORK PLAN COMPLETE

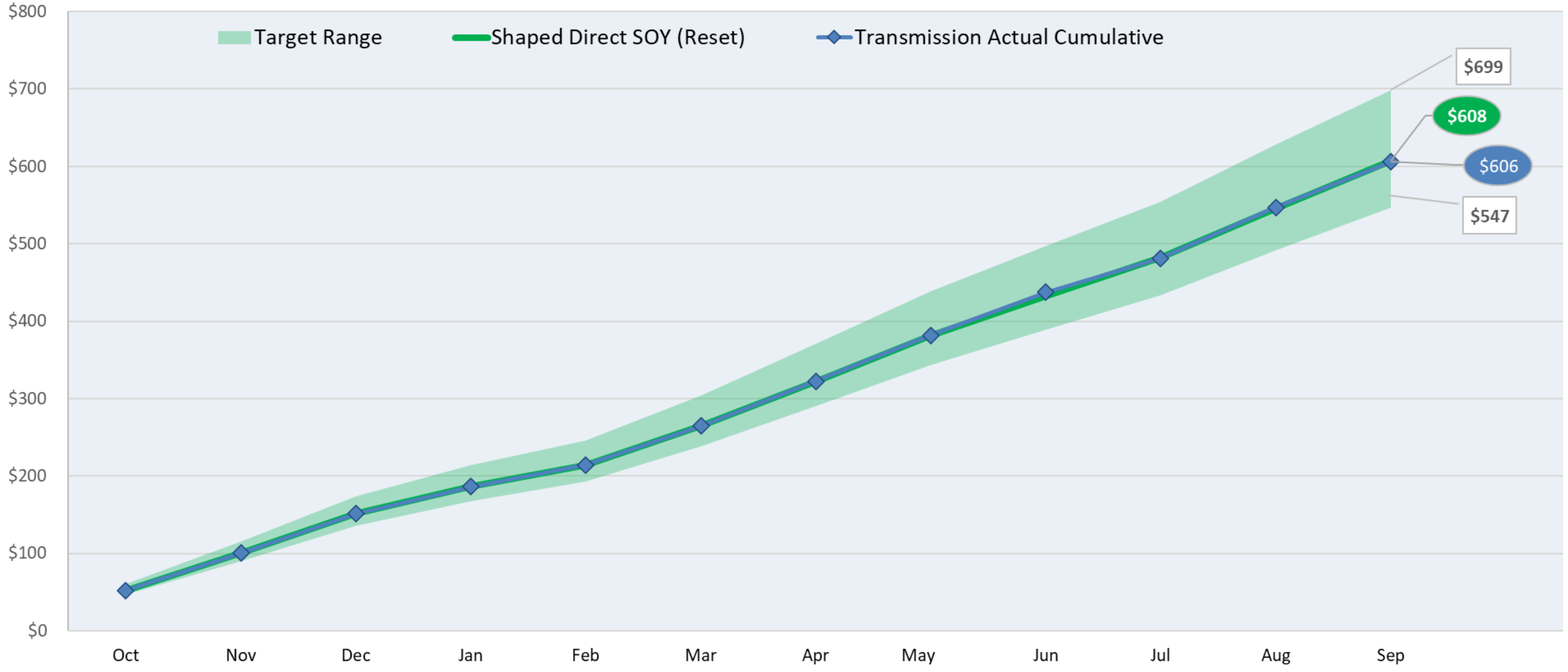
Transmission as of FY25 Q4:

FY25 Capital Work Plan Complete
Project Milestones

Qtr	Priority Projects	Target Milestones	Model	On Track
Q1	P05468, Big Eddy-Chemawa-1 500kV Line Rebuild TSEP 2022 (EGP1)	Award OC Scoping Contract in Q1	SCM	Complete
Q2	P04342, L0482 Longhorn 500/230kV Substation	Initial Energization	SCM	Complete
Q3	P02364 MCNARY-PATERSON TAP 115KV Line that includes a new 115KV bay and 30 miles of transmission line serving Customer Benton PUD	Complete Construction in FY25	PCM	Complete
Q3	P02230 WENDSON SUB Control House replacement, yard expansion, new bus-tie breaker, new disconnects, station service and ground grid upgrades	Complete Construction in FY25	PCM	Complete
Q3	P05580, L0510 Six Mile Canyon 500kV/230kV Substation (EGP – Not Tier 1)	Partial design complete in Q3	SCM	Complete
Q3	P03890 Vancouver Control Center	Construction start for Vancouver Control Center	PDB	Complete
Q3	P02307 DATS Technology Project	Design Start for Munro CC, Covington & Franklin.	PCM	Complete
Q3	P00837 Benton-Scooteney #1 Transmission Line Rebuild	Phase 2 Line Construction complete	PCM	Complete
Q3	P01361 New 230kV Midway to Ashe Tap	Energize new line	PCM	Complete
Q4	P04691 WEBBER CANYON new 500KV substation facility with 5 new bays in support of the South of Tri-Cities Reinforcement Project	Complete Design in FY25	PCM	Complete
Q4	P02259 FLATHEAD SUB add 3 new bays and bus sectionalizing breaker (WO's 484370, 484371 & 484375)	Complete Construction in FY25	PCM	No
Q4	P05847, L0543 Bonanza Substation (EGP – Not Tier 1)	Complete Scoping by the OC in Q4	SCM	Complete

Key Takeaway: On Track – Longhorn initial energization is complete but just missed the Q2 cutoff. Flathead Sub did not finish construction in FY25. Outage restrictions and an environmental issue pushed the final construction out. Target is still met at 83%

CAPITAL SPEND



Key Takeaway: On Track

Cancelling Reporting on BPA EIM Metrics

Presenters:

Matt Germer

BPA's EIM Metrics

Given staffing and resource availability, BPA will be prioritizing the implementation of Day Ahead Markets and joining Markets+ and will no longer be reporting EIM Metrics.

Phase 1 metrics have been reported since November 2022

1. Unspecified purchases and sales to California
2. EIM transfer limits and use
3. Resource Sufficiency balancing tests and pass rates

Phase 2 metrics were planned to be reported by BP-26

1. Charge code allocations
2. Transmission donations and usage
3. EIM impacts to BPA's system emission rate

Western Resource Adequacy Program (WRAP) Update

Presenter:

Matt Hayes

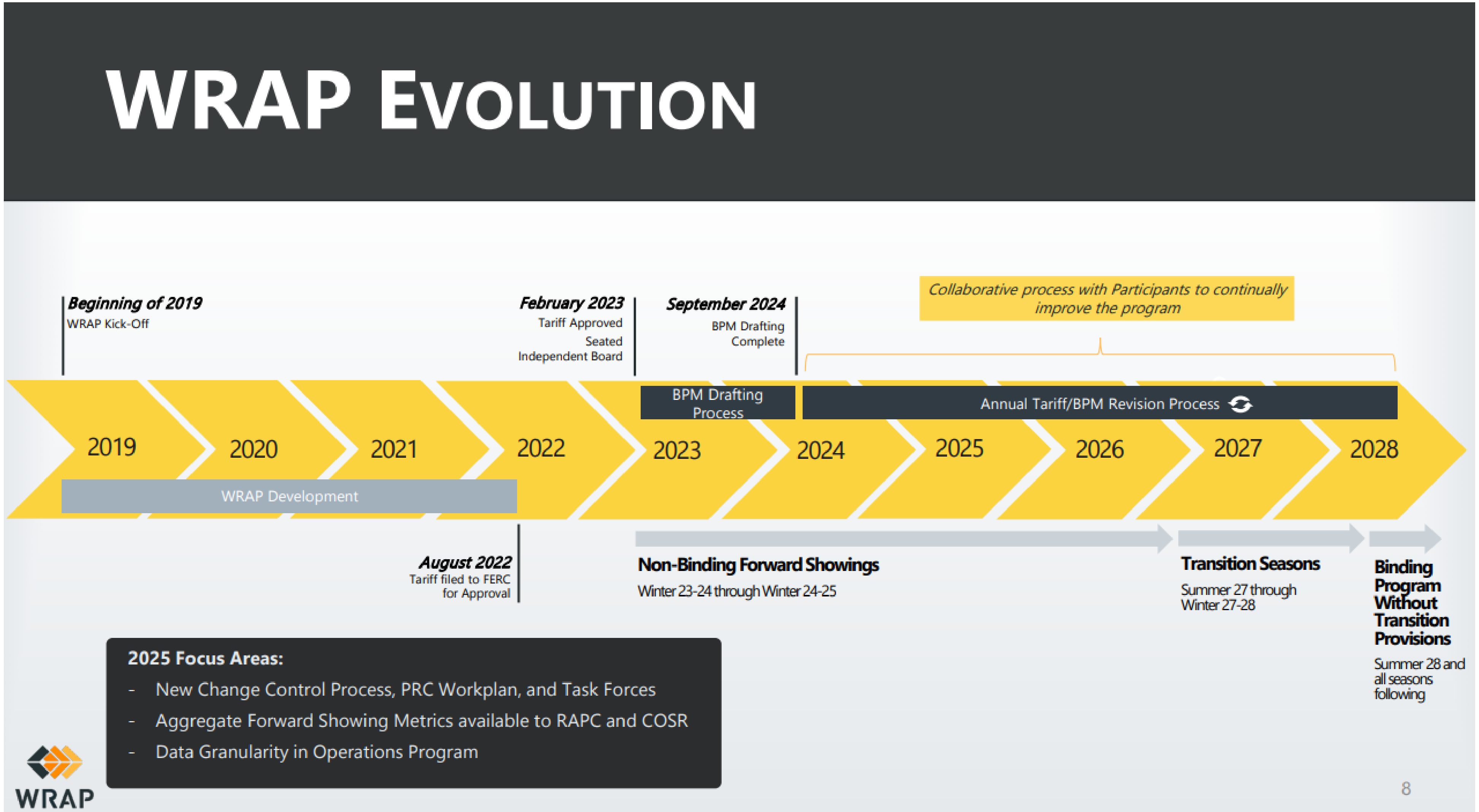
Agenda

- What's Happening in WRAP
  - WPP Implementation Timeline
  - Binding Season Commitments
  - Current PRC Task Force Activities

- BPA Active Work with WRAP
  - BPA Participation
  - BPA Technical Solution for WRAP Participation
  - Customer Meetings

What’s Happening in WRAP

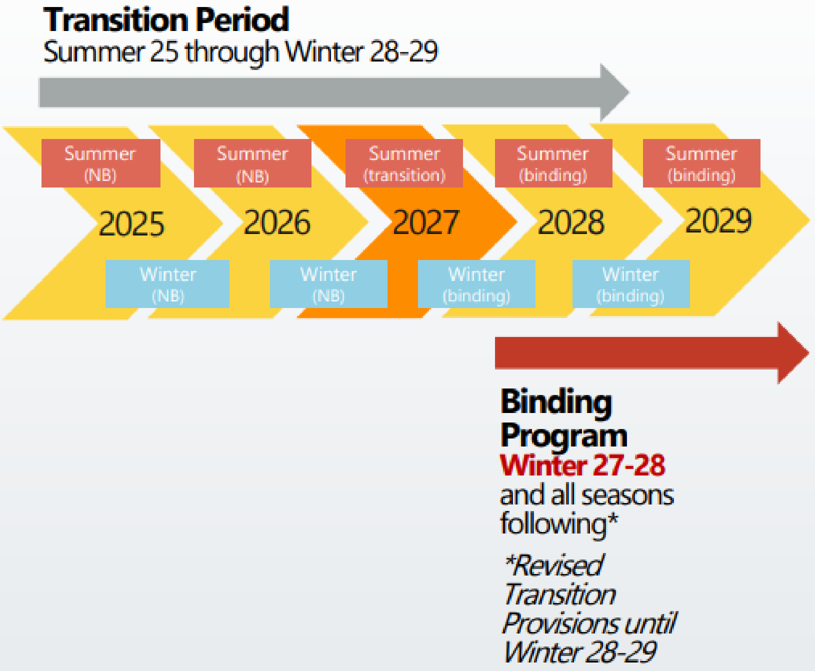
Western Power Pool WRAP Implementation Timeline



Revised Transition Plan Timeline

REVISED TRANSITION PLAN

- **Participants developed a proposal for a revised transition plan approved by the Board in September 2024 and by FERC in January 2025**
- Revised plan includes changes & additions pertaining to:
  - Summer 27 Binding Season
  - Discounted Deficiency Charges
  - Assumptions of diversity sharing
  - Operations Program data sharing



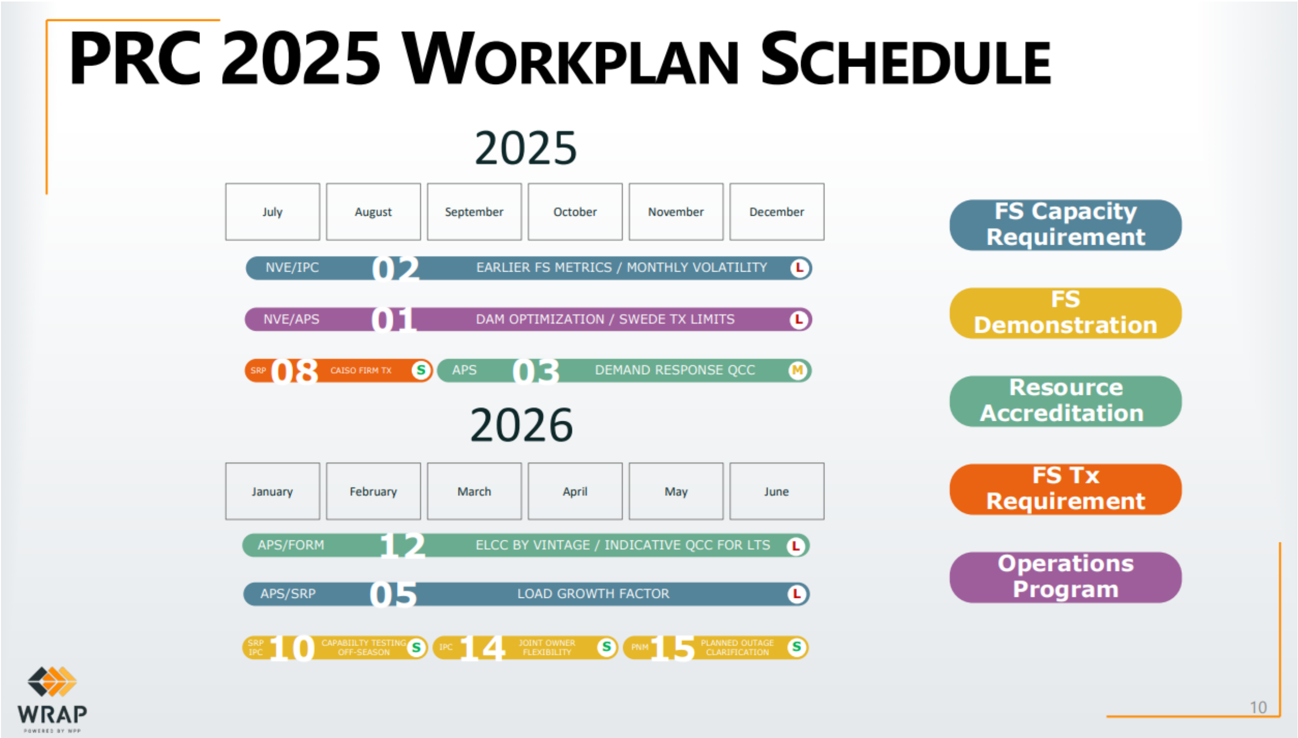
WRAP

Binding Season Commitments

- October 31st Program Commitment
  - Official notices of withdrawal were submitted by Calpine, EWEB, NVE, PAC, PGE and PNM. PAC.
  - As November 1st, there are 16 participants that are committed to the first binding season of Winter 2027/28. The committed participants bring significant load (over 58,000 MW in peak load) and resources and a large, diverse geographic footprint, making WRAP one of the largest RA programs in the country and giving us critical mass for a binding program.

WRAP 2025 PRC Workplan

- The 2025 PRC Work Plan was approved by the WPP BOD in late June.
- Task Forces 01 and 02 submitted concept papers that were approved at the 10/16 RAPC. The concept paper for the 08 Task Force has been released and the COSR comment period for the paper closed on November 7th.



Summary of Current PRC Task Force Activity

- 01 - DAM Optimization
  - WPP is continuing to draft red lines of the WRAP Tariff and Business Process Manuals (BPMs) for the preposed revamp of the Ops program to better align with DAMs
  - The group is continuing to explore next steps for both the Ops and Forward Showing program that will enhance program value for participants
  - the Task Force's current schedule is to deliver its final proposal for changes to the Ops program to the PRC at the end of the calendar year

- 02 – Earlier FS Metrics / Monthly Volatility
  - The RAPC officially endorsed this Task Force's concept paper on 10/16.
  - The PRM task force reviewed timeline issues and determined
    - Not to recommend any changes to the current 2-year exit/withdrawal provision
    - To recommend that the ELCC by Vintage taskforce specifically evaluate the timing of the ELCC study
    - Add a recommendation that the Load Growth Factor Task Force that starts in Jan 2026 evaluate the timing of setting the P50.
  - The task force also continues to look at approaches to stabilize the PRMs both year to year, and month to month.

Summary of Current PRC Task Force Activity Cont.

- 08 – CAISO Firm TX
  - The WRAP CAISO Firm TX task proposal was put out for public comment. BPA submitted comments on 10/17, supporting the proposal. The window for comment closed last Friday October 17th. All comments were in support of the proposal.
  - Since there were no objections or concerns, the proposal moved to a 2-week COSR comment period which ran from 10/24 – 11/7. The task force is not planning to meet again until after the COSR comment period and then only if the COSR comments require adjustments to the proposal. Following this comment period, the proposal will go to another public comment period before being presented to the RAPC for approval.

- 03 - Demand Response QCC
  - This task force is continuing to meet as it develops its proposal for refining QCCs for Demand Response Resources. The Taskforce is on schedule to deliver its proposal to the PRC by the end of this calendar year

BPA Active Work with WRAP

BPA Active Work with WRAP

Existing WRAP Participant Work:

- Resource Adequacy Participants Committee (RAPC) – Reviewing and continuing development and design of the program to prepare for full binding operations.
- Forward Showing Work Group – Engaged in activities and discussion for FS submittals
- Ops Work Group –Submitting operations data for upcoming nonbinding winter season
- Program Review Committee (PRC) – Participating member, actively reviewing materials (including prioritizing CRFs)
- Other ongoing workgroups
  - Preparation for Winter 2026/2027 Operations Season (non-binding season)

BPA Active Work with WRAP

Technical Solution for WRAP Participation:

- BPA continues to refine the now live WRAP Operations data submittal system
- Work is ongoing to identify enhancements that are needed to support BPA's binding operations
- Additional information and updates to BPA Resource Adequacy website are coming soon: Western Resource Adequacy Program - Bonneville Power Administration (bpa.gov)

Customer-impacted meetings

- BPA remains focused on the PRC Task Force work that is due at the end of the calendar year.
- BPA acknowledges that it needs to schedule meetings with customers who have new large single loads (NLSLs) to discuss the treatment of those loads in BPA's WRAP submittals.
- Topics to include:
  - Load Exclusion
  - Physical Resources serving those loads
  - etc.

Questions

- More information on BPA's participation in the WRAP can be found at: [Western Resource Adequacy Program - Bonneville Power Administration (bpa.gov)]

BPA.gov → Learn & Participate → Projects → Resource Adequacy

- More information on the Western Power Pool's WRAP program can be found at: https://www.westernpowerpool.org/

Regional Cooperation Debt Phase 2 (RCD2) Regional Check In

Presenter:

Ethan Postrel

Objective & Agenda

Objective:

Satisfy RCD2 Term Sheet requirement for public regional update in 2025

Agenda:

- Purpose
- Program History
- Impact and Benefits
- BPA Financial Performance
- Conclusion / Questions

Purpose

A "Regional Check In" is expected to occur in late calendar year 2025; BPA commits to a regional update with stakeholders including Energy Northwest Participant's Review Board, Executive Board, and a regional public meeting. The update is expected to address the status of the program and the benefits derived including the regional cooperation debt transactions impact on BPA's financial health.

- RCD2 Term Sheet, 11/5/2018

Program History

RCD1
(2014-2020)

Purpose: Save on interest of outstanding debt

RCD2
(2021-2030)

Purpose: Preserve BPA's access to capital through federal Borrowing Authority

BPA saved **$2.8B** in interest

BPA is required to

- Present BPA's financial operation with respect to RCD refinancing annually to the EN Board
- Hold a mid-point "Regional Check In" with stakeholders

RCD2 Program Description

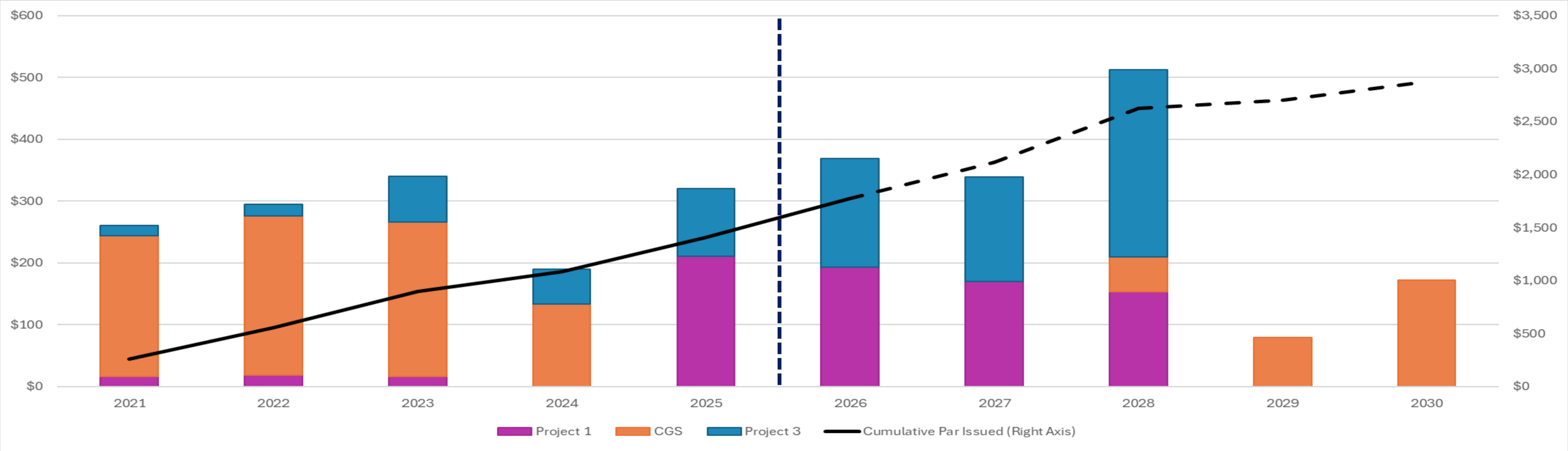
- Refinancing up to $3 billion of long-term tax-exempt debt (and $500 million in premiums) for the purpose of restoring and preserving U.S. Treasury borrowing authority by:
  - Early repayment of a like amount of BPA's U.S. Treasury bonds; OR
  - Use of freed up proceeds to fund new capital projects that would otherwise be funded by U.S. Treasury borrowing authority.
- Program years include maturities in EN's FY 2021-2030 to be refinanced with maturities not extending beyond July 1, 2044.

RCD2 Progress Tracker

RCD2 Program Authorized Amount:		**$3.500 billion**
EN 2021 A/B	$0.260 billion	
EN 2022 A/B	$0.295 billion	
EN 2023 A	$0.340 billion	
EN 2024 A/B	$0.189 billion	
EN 2025 A/B	$0.321 billion	
Total refinanced to-date		**$1.405 billion**
	Remaining Authorized	**$2.095 billion**

RCD2 Bond Issuances & Projections

(in millions)



(in million)	2021	2022	2023	2024	2025	Forecast 2026	2027	2028	2029	2030
Project 1	$16	$18	$16	$0	$211	$193	$170	$153	$0	$0
CGS	$227	$258	$250	$134	$0	$0	$0	$56	$79	$172
Project 3	$17	$19	$74	$56	$110	$175	$170	$303	$0	$0
Total	**$260**	**$295**	**$340**	**$189**	**$321**	**$368**	**$339**	**$513**	**$79**	**$172**
Cumulative Par Issued (Right Axis)	**$260**	**$555**	**$895**	**$1,085**	**$1,405**	**$1,774**	**$2,113**	**$2,625**	**$2,704**	**$2,876**

BPA Priority of Payments

First order of payment

Nonfederal debt and
Operations and maintenance expenses

Second order of payment

Payments to the U.S. Treasury

U.S Treasury payment is made only from net proceeds after all costs, including debt service on BPA supported bonds, have been met

RCD2 Impacts & Benefits

RCD Bond Deal	Benefits Gained
EN 2021 A/B	$332 million
EN 2022 A/B	$334 million
EN 2023 A	$401 million
EN 2024 A/B	$215 million
EN 2025 A/B	$353 million
Total Benefits Gained	**$1.636 billion**

Borrowing authority preserved to-date: $1.636 billion

RCD2 Impacts & Benefits

- To date, RCD has had a neutral to slightly positive impact on rating agency credit perception
  - They have come to understand the cost efficiency and credit capacity benefits

pfm

BPA Credit Ratings & Sentiment

Current Credit Ratings: High investment grade

Moody's: Aa2, Stable	**Fitch: AA, Stable**	**S&P: AA-, Stable**

Key interest to rating agencies:

- Wildfire risk
- Impacts of presidential executive orders

BPA meets annually with each rating agency to answer inquiries and provide frequent updates on agency results. Based on BPA's **comprehensive wildfire risk mitigation program**, the **essential products and services provided by the FCRPS**, and a **continuing history of sound financial management practices**,

<u>all three ratings remain high investment grade.</u>

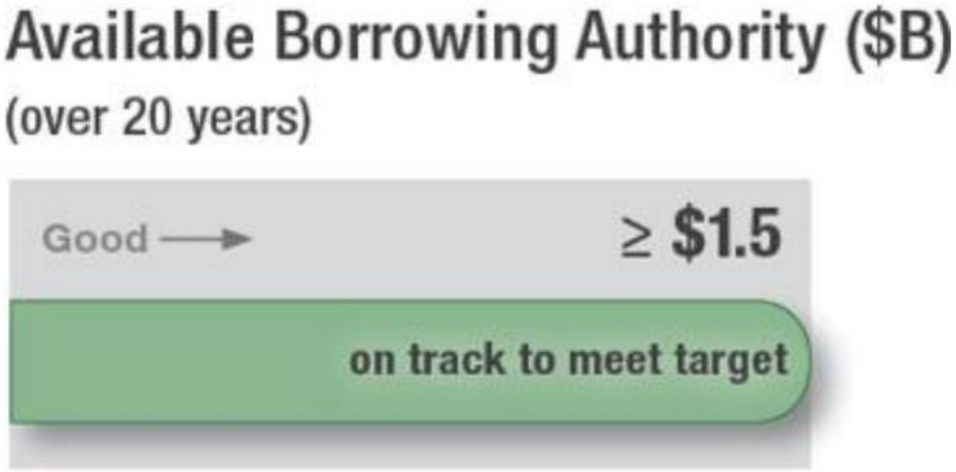
BPA Financial Strength

No shortfall in the first 10 yrs

Projects breaching the $1.5 billion cushion in the 11 – 20 years period

(Continually refining and updating forecasts)

Additional access to capital tools (funding), beyond borrowing authority, are needed to meet target



Conclusion

RCD2 is successful –
BPA and EN intend to continue the program through 2030.

Questions?

THANK YOU

The next QBR and Technical Workshop will be held on

February 12, 2026

Didn’t get your question answered?

Email Communications@bpa.gov.

Answers will be posted to www.bpa.gov/qbr.

FINANCIAL DISCLOSURES

This information has been made publicly available by BPA on November 13, 2025, and contains information not sourced directly from BPA financial statements.

APPENDIX

Final Closeout Letter Commitments

- On December 16, 2022, BPA issued its decision to join Phase 3B. In the WRAP Final Closeout Letter, BPA committed to:
  - Sharing its stakeholder engagement plan for Phase 3B participation (goal is within the first half of 2023);
  - Providing program implementation updates that impact BPA and its customers; and
  - Continue working with customers on outstanding items raised in comments related to WRAP implementation.

Stakeholder Engagement Plan

- Provide transparency of program design updates and information that may impact BPA and its customers, outcomes from BPA's participation in non-binding forward showing and operations program, and resolving BPA and customer raised issues in the Final Closeout Letter
- Engagement will be consistent with external WRAP engagement outside of BPA's process
- Pursue effective and efficient two-way communication between BPA and customers, stakeholders, and external interested parties
- Engage on a predictable, standardized cadence provided there is adequate content or relevant information to discuss
- Ensure engagement opportunities occur sufficiently to inform interested parties based on program timelines and information availability and applicability

Stakeholder Engagement Plan cont.

- Engagement with customers and stakeholders will consist of:
  - Public meetings with a minimum of 4 meetings, preferably through the QBR Technical Workshops
  - Short-term Issue-focused workshops, as needed
  - Customer-impacted meetings focused by topic, upon request
- BPA proposes to host meetings through the completion of BPA’s first binding season (winter 2027-2028). BPA will work with customers to reevaluate its engagement plan and the need for its proposed meeting schedule on an annual basis through its first binding season
- Meetings will focus on BPA’s participation, the development of the business practice manuals, and updates to the WRAP policies as determined by the WRAP project schedule

Stakeholder Engagement Plan cont.

Public meetings	• Regularly scheduled meetings four times per year, utilizing a combination of stand-alone workshops and preferably the Quarterly Business Review (QBR) Technical Workshops • Typically, February, May, August, and November • Provide program design updates and information that may include any topics relevant to customer and stakeholder questions on BPA's WRAP participation
Issue – focused workshops	• Workshops will be scheduled based on information availability from WRAP and applicability • Will address topics raised in comments related to WRAP implementation
Customer-impacted meetings focused by topic	• BPA will continue to meet with individual or groups of customers, upon request, to focus on their unique questions or needs. • To the extent that there is a nexus between the implications of the WRAP and other issues of focus for customers, BPA will coordinate discussion with other BPA meetings or initiatives • Resolution timing of customer identified items may depend on information availability from WRAP

Stakeholder Engagement Topics

- Topics raised in comments related to WRAP implementation, including:
  - Considerations related to BPA's binding season (Winter 2027-2028)
    - The availability of transmission between loads in the SWEDE region and the FCRPS create risks that may create costs in the Forward Showing Program,
    - The uncertainty in details and requirements for the Operations Program,
    - Identifying Bonneville system updates and business processes to support participation in the binding program, and
    - Alignment with the timing for joining emerging regional markets
  - Treatment of NLSLs and AHWM loads related to BPA's WRAP participation
    - WRAP load exclusion process update / BPA load exclusion process between BPA and customers
  - Load exclusion process for AHWM loads caused by a single large consumer load and served solely with non-federal resources
  - Resource Adequacy Incentive rates
- Updates on Business Practice Manual development
  - Future BPM on BPA's statutory preference obligations
- Updates on Forward Showing and Operations Program development

SLICE REPORTING

Composite Cost Pool Review

Forecast of Annual Slice True-Up Adjustment

Q4 True-Up of FY 2025 Slice True-Up Adjustment

	FY 2025 Forecast $ in thousands
February 13, 2025 First Quarter Technical Workshop	23,598*
May 15, 2025 Second Quarter Technical Workshop	(33,273)*
August 14, 2025 Third Quarter Technical Workshop	(15,731)*
November 13, 2025 Fourth Quarter Technical Workshop	(28,286)*

*Negative = Credit; Positive = Charge

Summary of Differences From Q4 to FY25 (BP-24)

#		Composite Cost Pool True-Up Table Reference	Q4 – Rate Case $ in thousands
1	Total Expenses	Row 103	$(78,702)
2	Total Revenue Credits	Rows 122 + 131	$38,960
3	Minimum Required Net Revenue	Row 159	$(18,582)
4	TOTAL Composite Cost Pool (1 - 2 + 3) $(78,702) - $38,960 + $(18,582)= $(136,244)	Row 164	$(136,244)
5	TOTAL in line 4 divided by <u>0.950855</u> sum of TOCAs $(136,244)/ <u>0.950855</u> = $(143,286)	Row 166	$(143,286)
6	QTR Forecast of FY25 True-up Adjustment 19.74071 percent of Total in line 5 0.1974071 * $(143,286) = $(28,286)	Row 167	$(28,286)

FY25 Impacts of Debt Management Actions

Description	FY25 Q4	FY25 Rate Case	CCP	Delta from the FY25 rate case
MRNR Section of Composite Cost Pool Table				
Principal Payment of Federal Debt	.			
Regional Cooperation Debt (RCD)	$ 352,972,812	$ 357,993,000		$ 5,020,188
Debt Service Reassignment (DSR)		$ -		$ -
Energy Northwest's Line Of Credit (LOC)	$ -	$ -		$ -
Rate Case Scheduled Base Power Principal*	$ 88,007,464	$ 88,007,000		$ (464)
Repayment due to FY25 RDC (based on FY24 results)		$ -		$ -
Total Principal Payment of Fed Debt	**$ 440,980,276**	**$ 446,000,000**	row 134	**$ 5,019,724**
Prepay	$ 26,061,326	$ 26,061,326		$ -
				$ -
Nonfederal Bond Principal Payment	$ 28,705,000	$ 21,092,850	row 136	$ (7,612,150)

Composite Cost Pool Interest Credit

Allocation of Interest Earned on the Bonneville Fund
($ in thousands)

		Q4 2025
1	Fiscal Year Reserves Balance	570,255
2	Adjustments for pre-2002 Items	16,341
3	Reserves for Composite Cost Pool (Line 1 + Line 2)	586,596
4	Composite Interest Rate	4.36%
5	Composite Interest Credit	(25,588)
6	Prepay Offset Credit	0
7	Total Interest Credit for Power Services	(19,512)
8	Non-Slice Interest Credit (Line 7 – (Line 5 + Line 6))	6,076

Net Interest Expense in Slice True-Up Q4

	FY25 Rate Case ($ in thousands)	Q4 ($ in thousands)
• Federal Appropriation	23,204	38,460
• Capitalization Adjustment	(45,937)	(45,937)
• Borrowings from US Treasury	44,265	55,324
• Prepay Interest Expense	4,539	4,539
• **Interest Expense**	**26,071**	**52,386**
• AFUDC	(18,137)	(24,778)
• Interest Income (composite)	(3,199)	(24,588)
• Prepay Offset Credit	0	0
• **Total Net Interest Expense**	**4,734**	**2,020**

Schedule for Slice True-Up Adjustment for Composite Cost Pool True-Up Table and Cost Verification Process

Dates	Agenda
February 13, 2025	First Quarter Technical Workshop
May 15, 2025	Second Quarter Technical Workshop
August 14, 2025	Third Quarter Technical Workshop
October 2025	BPA External CPA firm conducting audit for fiscal year end
Mid-October 2025	Recording the Fiscal Year End Slice True-Up Adjustment Accrual
End of October 2025	Final audited actual financial data is expected to be available
November 13, 2025	Fourth Quarter Business Review and Technical Workshop Meeting Provide Slice True-Up Adjustment for the Composite Cost Pool (this is the number posted in the financial system; the final actual number may be different)
November 14, 2025	Mail notification to Slice Customers of the Slice True-Up Adjustment for the Composite Cost Pool
November 18, 2025	BPA to post Composite Cost Pool True-Up Table containing actual values and the Slice True-Up Adjustment
December 10, 2025	Deadline for customers to submit questions about actual line items in the Composite Cost Pool True-Up Table with the Slice True-Up Adjustment for inclusion in the Agreed Upon Procedures (AUPs) Performed by BPA external CPA firm (customers have 15 business days following the BPA posting of Composite Cost Pool Table containing actual values and the Slice True-Up Adjustment)
December 26, 2025	BPA posts a response to customer questions (Attachment A does not specify an exact date)
January 12, 2026	Customer comments are due on the list of tasks (The deadline can not exceed 10 days from BPA posting)
February 3, 2026	BPA finalizes list of questions about actual lines items in the Composite Cost Pool True-Up Table for the AUPs

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		(Q4) ($000)	Rate Case forecast for FY 2025 ($000)	Q4- Rate Case Difference
1	**Operating Expenses**			
2	**Power System Generation Resources**			
3	**Operating Generation**			
4	COLUMBIA GENERATING STATION (WNP-2)	$ 380,463	$ 351,133	$ 29,331
5	BUREAU OF RECLAMATION	$ 179,135	$ 157,218	$ 21,917
6	CORPS OF ENGINEERS	$ 283,628	$ 275,147	$ 8,481
7	CRFM STUDIES	$ 20,818	$ 6,051	$ 14,767
8	LONG-TERM CONTRACT GENERATING PROJECTS	$ 21,325	$ 17,123	$ 4,202
9	**Sub-Total**	**$ 885,370**	**$ 806,672**	**$ 78,698**
10	**Operating Generation Settlement Payment and Other Payments**			
11	COLVILLE GENERATION SETTLEMENT	$ 20,973	$ 22,000	$ (1,027)
12	SPOKANE LEGISLATION PAYMENT	$ 5,243	$ 5,500	$ (257)
13	**Sub-Total**	**$ 26,216**	**$ 27,500**	**$ (1,284)**
14	**Non-Operating Generation**			
15	TROJAN DECOMMISSIONING	$ (523)	1,200	$ (1,723)
16	WNP-1&3 DECOMMISSIONING	$ 1,550	1,175	$ 375
17	**Sub-Total**	**$ 1,027**	**$ 2,375**	**$ (1,348)**
18	**Gross Contracted Power Purchases**			
19	PNCA HEADWATER BENEFITS	$ 3,037	$ 3,100	$ (63)
20	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)	$ (27,357)	$ -	$ (27,357)
21	**Sub-Total**	**$ (24,319)**	**$ 3,100**	**$ (27,419)**
22	**Bookout Adjustment to Power Purchases (omit)**			
23	**Augmentation Power Purchases (omit - calculated below)**			
24	AUGMENTATION POWER PURCHASES	$ -	$ -	$ -
25	**Sub-Total**	**$ -**	**$ -**	**$ -**
26	**Exchanges and Settlements**			
27	RESIDENTIAL EXCHANGE PROGRAM (REP)	$ 274,281	$ 274,820	$ (539)
28	OTHER SETTLEMENTS	$ -	$ -	$ -
29	**Sub-Total**	**$ 274,281**	**$ 274,820**	**$ (539)**
30	**Renewable Generation**			
31	RENEWABLES (excludes KIII)	$ 9,173	$ 17,432	$ (8,260)
32	**Sub-Total**	**$ 9,173**	**$ 17,432**	**$ (8,260)**
33	**Generation Conservation**			
34	CONSERVATION ACQUISITION	$ 96,354	$ 69,027	$ 27,327
35	CONSERVATION INFRASCTRUCTURE	$ 16,829	$ 26,106	$ (9,277)
36	LOW INCOME WEATHERIZATION & TRIBAL	$ 5,071	$ 6,005	$ (934)
37	ENERGY EFFICIENCY DEVELOPMENT	$ -	$ -	$ -
38	DISTRIBUTED ENERGY RESOURCES	$ -	$ 215	$ (215)
39	LEGACY	$ 289	$ 590	$ (301)
40	MARKET TRANSFORMATION	$ 14,505	$ 11,800	$ 2,705
41	**Sub-Total**	**$ 133,048**	**$ 113,744**	**$ 19,305**
42	**Power System Generation Sub-Total**	**$ 1,304,796**	**$ 1,245,643**	**$ 59,153**
43				

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		(Q4) ($000)	Rate Case forecast for FY 2025 ($000)	Q4- Rate Case Difference
44	**Power Non-Generation Operations**			
45	**Power Services System Operations**			
46	EFFICIENCIES PROGRAM	$ -	$ -	$ -
47	INFORMATION TECHNOLOGY	$ -	$ 2,473	$ (2,473)
48	GENERATION PROJECT COORDINATION	$ 4,160	$ 4,571	$ (411)
49	ASSET MGMT ENTERPRISE SVCS	$ 1,320	$ -	$ 1,320
50	SLICE IMPLEMENTATION	$ 693	$ 632	$ 60
51	**Sub-Total**	**$ 6,172**	**$ 7,677**	**$ (1,504)**
52	**Power Services Scheduling**			
53	OPERATIONS SCHEDULING	$ 11,867	$ 9,945	$ 1,922
54	OPERATIONS PLANNING	$ 8,735	$ 10,102	$ (1,367)
55	**Sub-Total**	**$ 20,602**	**$ 20,047**	**$ 554**
56	**Power Services Marketing and Business Support**			
57	GRID MOD	$ 71	$ -	$ 71
58	EIM INTERNAL SUPPORT	$ -	$ -	$ -
59	POWER INTERNAL SUPPORT	$ 19,974	$ 27,812	$ (7,837)
60	COMMERCIAL ENTERPRISE SVCS	$ 8,901	$ 4,516	$ 4,385
61	OPERATIONS ENTERPRISE SVCS	$ 5,307	$ 4,725	$ 582
62	POWER R&D	$ 1,073	$ 2,527	$ (1,453)
63	SALES & SUPPORT	$ 13,273	$ 18,429	$ (5,156)
64	STRATEGY, FINANCE & RISK MGMT (REP support costs included here)	$ -	$ -	$ -
65	STRATEGIC PROJECTS COMM ACT	$ -	$ -	$ -
66	EXECUTIVE AND ADMINISTRATIVE SERVICES (REP support costs included here)	$ -	$ -	$ -
67	CONSERVATION SUPPORT	$ 10,006	$ 7,309	$ 2,697
68	**Sub-Total**	**$ 58,606**	**$ 65,319**	**$ (6,713)**
69	**Power Non-Generation Operations Sub-Total**	**$ 85,380**	**$ 93,042**	**$ (7,662)**
70	**Power Services Transmission Acquisition and Ancillary Services**			
71	TRANSMISSION and ANCILLARY Services - System Obligations	$ 29,700	$ 29,700	$ -
72	3RD PARTY GTA WHEELING	$ 82,293	$ 92,598	$ (10,305)
73	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)	$ 3,327	$ 3,300	$ 27
74	TRANS ACQ GENERATION INTEGRATION	$ 20,194	$ 20,194	$ (0)
75	EESC CHARGES (Composite)*	$ (1,922)	$ -	$ (1,922)
76	TELEMETERING/EQUIP REPLACEMT	$ -	$ -	$ -
77	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**	**$ 133,593**	**$ 145,792**	**$ (12,199)**
78	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
79	**Fish & Wildlife**	$ 268,624	$ 268,865	$ (242)
80	**USF&W Lower Snake Hatcheries**	$ 28,390	$ 32,765	$ (4,375)
81	**Planning Council**	$ 12,150	$ 11,942	$ 208
82	**Long Term Funding Agreements**	$ -	$ -	$ -
83	**Fish & Wildlife RDC Funds**	$ 11,526	$ -	$ 11,526
84	**Lower Snake Hatcheries RDC Funds**	$ 9,799	$ -	$ 9,799
85	**Resilient Columbia Basin Agreement (RCBA)**	$ 20,340	$ -	$ 20,340
86	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$ 350,829**	**$ 313,572**	**$ 37,256**

Composite Cost Pool True-Up Table

	COMPOSITE COST POOL TRUE-UP TABLE	(Q4) ($000)	Rate Case forecast for FY 2025 ($000)	Q4- Rate Case Difference
87	**BPA Internal Support**			
88	**Additional Post-Retirement Contribution**	$ 14,872	$ 19,844	$ (4,972)
89	**Agency Services G&A (excludes direct project support)**	$ 88,005	$ 87,248	$ 757
90	**BPA Internal Support Sub-Total**	**$ 102,876**	**$ 107,092**	**$ (4,215)**
91	**Bad Debt Expense**	$ (6)	$ -	$ (6)
92	**Other Income, Expenses, Adjustments**	$ 3,845	$ -	$ 3,845
93	**Depreciation**	$ 143,574	$ 143,600	$ (26)
94	**Amortization**	$ 323,523	$ 316,066	$ 7,457
95	**Accretion (CGS)**	$ 43,162	$ 41,798	$ 1,363
96	**Total Operating Expenses**	**$ 2,491,572**	**$ 2,406,606**	**$ 84,966**
97				
98	**Other Expenses and (Income)**			
99	Net Interest Expense	$ 12,059	$ 176,424	$ (164,366)
100	LDD	$ 39,262	$ 38,532	$ 731
101	Irrigation Rate Discount Costs	$ 21,737	$ 21,770	$ (33)
102	**Sub-Total**	**$ 73,058**	**$ 236,726**	**$ (163,668)**
103	**Total Expenses**	**$ 2,564,630**	**$ 2,643,332**	**$ (78,702)**
104				
105	**Revenue Credits**			
106	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	$ 113,572	$ 112,085	$ 1,487
107	Downstream Benefits and Pumping Power revenues	$ 20,884	$ 20,607	$ 277
108	4(h)(10)(c) credit	$ 160,764	$ 111,456	$ 49,308
109	PRSC Net Credit (Composite)	$ (9,394)	$ -	$ (9,394)
110	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ -
111	Energy Efficiency Revenues	$ -	$ -	$ -
112	PF Load Forecast Deviation Liquidated Damages	$ -	$ -	$ -
113	Miscellaneous revenues	$ 10,599	$ 12,306	$ (1,707)
114	Renewable Energy Certificates	$ -	$ -	$ -
115	Net Revenues from other Designated BPA System Obligations (Upper Baker)	$ 591	$ 510	$ 81
116	RSS Revenues	$ 3,271	$ 3,271	$ -
117	Firm Surplus and Secondary Adjustment (from Unused RHWM)	$ 85,501	$ 86,644	$ (1,143)
118	Balancing Augmentation Adjustment	$ 5,792	$ 5,792	$ -
119	Transmission Loss Adjustment	$ 33,639	$ 33,639	$ -
120	Tier 2 Rate Adjustment	$ 4,998	$ 4,998	$ -
121	NR Revenues	$ 1	$ 1	$ -
122	**Total Revenue Credits**	**$ 434,819**	**$ 395,909**	**$ 38,910**
123				
124	**Augmentation Costs (not subject to True-Up)**			
125	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)	$ 12,125	$ 12,125	$ (0)
126	Augmentation Purchases	$ -	$ -	$ -
127	**Total Augmentation Costs**	**$ 12,125**	**$ 12,125**	**$ (0)**
128				

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		(Q4) ($000)		Rate Case forecast for FY 2025 ($000)		Q4- Rate Case Difference
129	**DSI Revenue Credit**					
130	Revenues 12 aMW @ IP rate	$	4,038	$ 3,987	$	50
131	**Total DSI revenues**	**$**	**4,038**	**$ 3,987**	**$**	**50**
132						
133	**Minimum Required Net Revenue Calculation**					
134	Principal Payment of Fed Debt for Power	$	440,980	$ 446,000	$	(5,020)
135	Repayment of Non-Federal Obligations (EN Line of Credit)	$	-	$ -	$	-
136	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls)	$	28,705	$ 21,093	$	7,612
137	Irrigation assistance	$	14,442	$ 14,006	$	436
138	**Sub-Total**	**$**	**484,127**	**$ 481,099**	**$**	**3,028**
139	Depreciation	$	143,574	$ 143,600	$	(26)
140	Amortization	$	323,523	$ 316,066	$	7,457
141	Accretion	$	43,162	$ 41,798	$	1,363
142	Capitalization Adjustment	$	(45,937)	$ (45,937)	$	0
143	Amortization of Refinancing Premiums/Discounts (MRNR - Reverse Sign)	$	(43,090)	$ (38,006)	$	(5,085)
144	Amortization of Cost of Issuance (MRNR-reverse sign)	$	1,517	$ 500	$	1,017
145	Cash freed up by DSR refinancing	$	-	$ -	$	-
146	Gains/Losses on Extinguishment	$	(3,424)	$ -	$	(3,424)
147	Non-Cash Expenses	$	-	$ -	$	-
148	Prepay Revenue Credits	$	(30,600)	$ (30,600)	$	-
149	Non-Federal Interest (Prepay)	$	4,539	$ 4,539	$	(0)
150	Contribution to decommissioning trust fund	$	(15,100)	$ (15,100)	$	0
151	Gains/losses on decommissioning trust fund	$	(20,438)	$ (12,191)	$	(8,247)
152	Interest earned on decommissioning trust fund	$	(4)	$ (4,608)	$	4,604
153	Revenue Financing Requirement	$	-	$ (34,290)	$	34,290
154	Capital Financing (RCD)	$	-	$ -	$	-
155	Other Adjustments	$	-	$ -	$	-
156	Payments for Litigation Stay Agreements	$	(10,340)	$ -	$	(10,340)
157	**Sub-Total**	**$**	**347,382**	**$ 325,772**	**$**	**21,610**
158	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expenses	$	136,745	$ 155,327	$	(18,582)
159	Minimum Required Net Revenues	**$**	**136,745**	**$ 155,327**	**$**	**(18,582)**
160						
161	Annual Composite Cost Pool (Amounts for each FY)	**$**	**2,274,643**	**$ 2,410,887**	**$**	**(136,244)**
162						
163	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**					
164	TRUE-UP AMOUNT (Diff. between Rate Case and Forecast)		(136,244)			
165	Sum of TOCAs		0.950855			
166	Adjustment of True-Up Amount when actual TOCAs < 100 percent		**(143,286)**			
167	TRUE-UP ADJUSTMENT CHARGE BILLED (19.74071 percent)		(28,286)			