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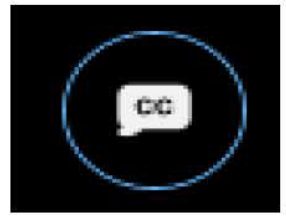

Select the **CC icon** in the lower-left of the WebEx screen

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Select the **ellipsis** in the lower right

Select **font size**

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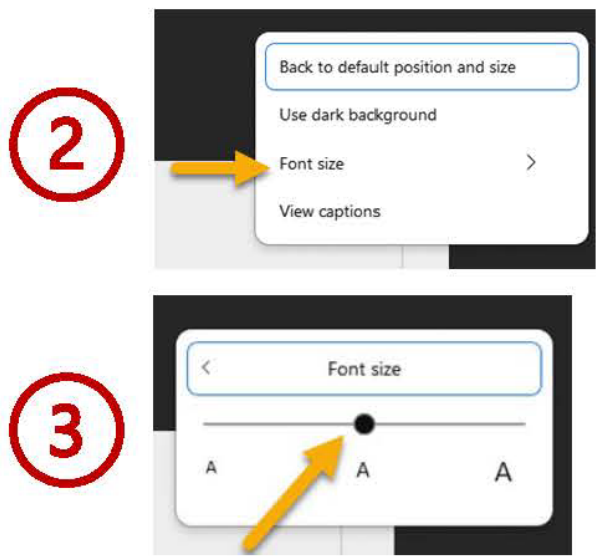

Change background contrast

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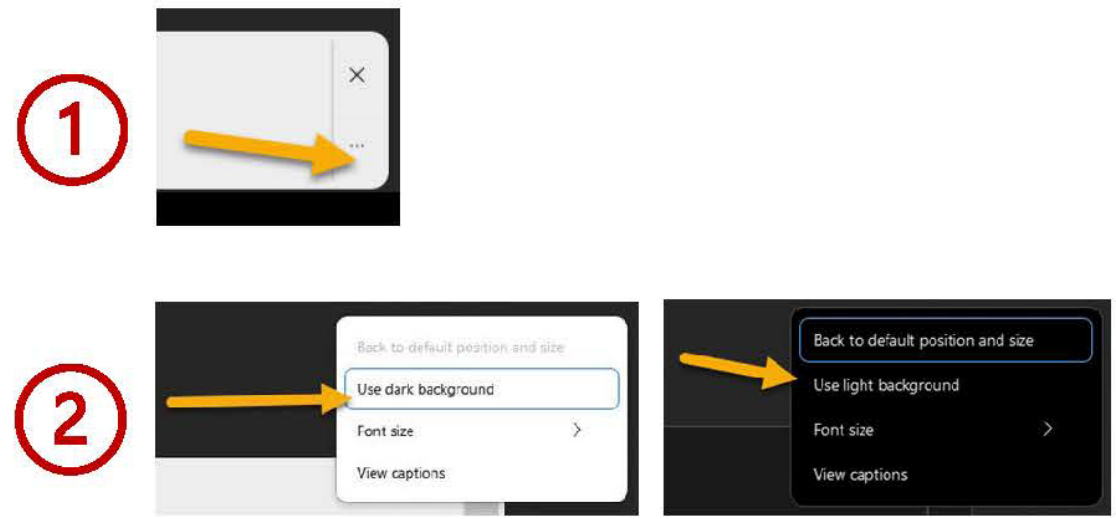
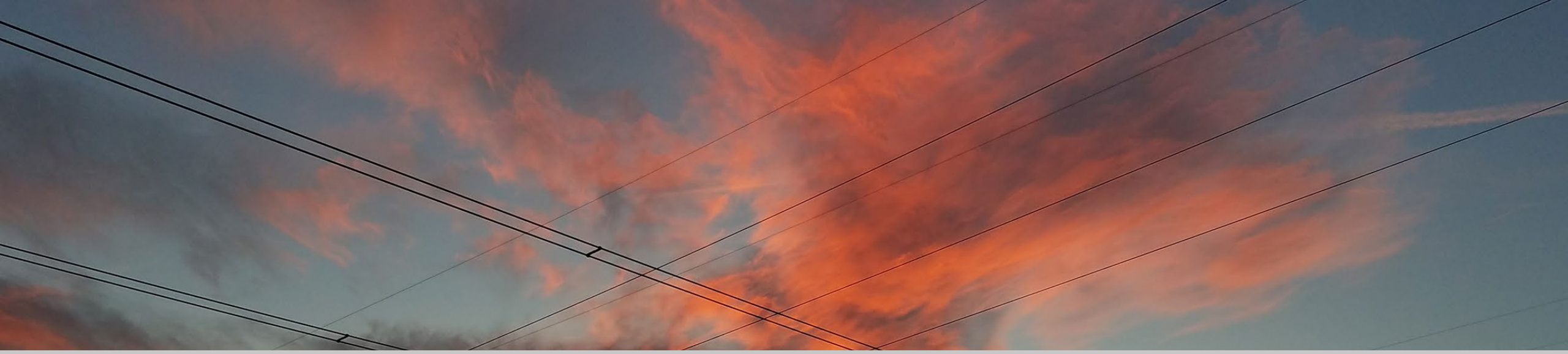




Bonneville
POWER ADMINISTRATION

QUARTERLY BUSINESS REVIEW TECHNICAL WORKSHOP

November 12, 2026

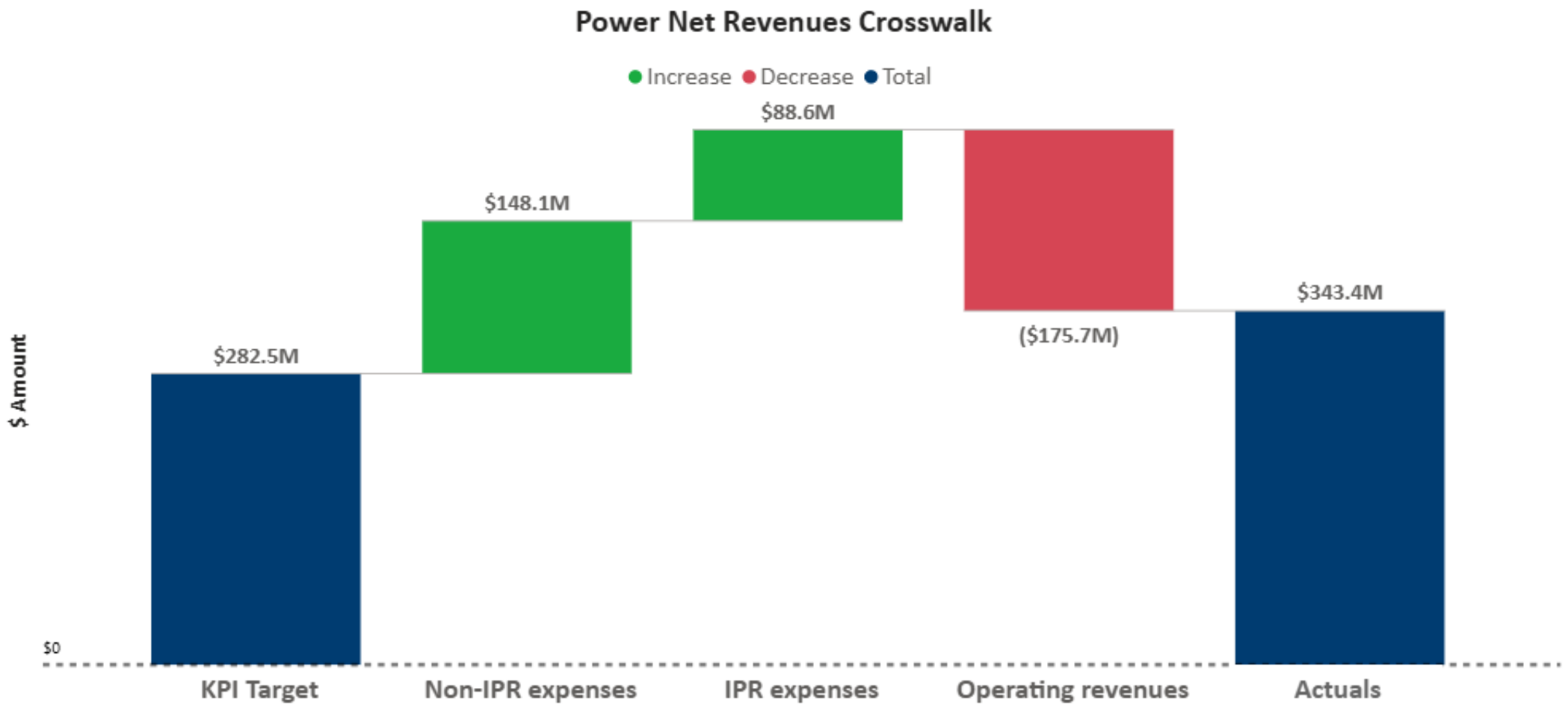
AGENDA

Time	Min.	QBRTW Topic	Presenter
1:00	5	Introduction	Taryn Redinger
1:05	10	Power and Transmission Net Revenue	Karlee Manary, Manny Holowatz
1:15	10	FY26 Results: Reserves for Risk	Darren Heim
1:25	10	FY26 Results: BPA Capital	Heather Seibert, Gwen Resendes
1:35	10	Fed Hydro Capital Metrics	Doug Komoroski
1:45	10	Transmission Capital Metrics	Salah Kitali, Doug Hunter
1:55	10	Questions & Answers / Closing	Taryn Redinger

FY26 Results: Transmission and Power Net Revenues

Karlee Manary, Manny Holowatz

FY26 RESULTS: POWER NET REVENUE



Power's net revenue KPI target is equal to the FY26 Rate Case net revenue forecast.

QBRTW ANALYSIS: POWER NET REVENUE (cont.)

FY26 results for Non-IPR Program expenses: $148M below target

- Overall gross power purchases decreased driven by a change in assumption since the rate case, namely the plan to serve Tier 2 from the FCRPS or short-term market purchases rather than a forward purchase. This means we zeroed out the forecast for Tier 2 purchases and that was only partially offset by an increase in other power purchase expense with purchase volumes at least marginally higher in every month, with the most pronounced differences in April. Purchase prices were uniformly down from Target, moderating the increase to expenditures, which were nevertheless up in all months particularly in October and September.
- Bookouts reduce Non-IPR expenses by $97M but are net revenue neutral due to a like amount in the revenue section.
- Net interest expense is lower than Target from a non-recurring gain of $39 million from Mid C settlement and a gain of $18 million from discounts on early payoff of federal debt.
- Lower 3rd Party GTA wheeling expense by $9M due to new loads coming online later than expected, overall lower loads than expected and lower rates than expected.
- These decreases are partially offset by the following:
  - The Fish & Wildlife and Lower Snake Hatcheries program spent $16M of the Reserves Distribution Clause funding they received, which wasn't included in the target. Cumulative RDC expenses since the agreements were implemented are:
    - Of the $25M FY22 F&W RDC Funds, $14M was spent through FY26. The remaining balance is ~$11M.
    - Of the $25M FY22 F&W Lower Snake Hatcheries RDC Funds, $23M was spent through FY26. The remaining balance is ~$2M.
    - Of the $30M FY23 F&W RDC, $13M has been spent through FY26. The remaining balance is $17M.

QBRTW ANALYSIS: POWER NET REVENUE

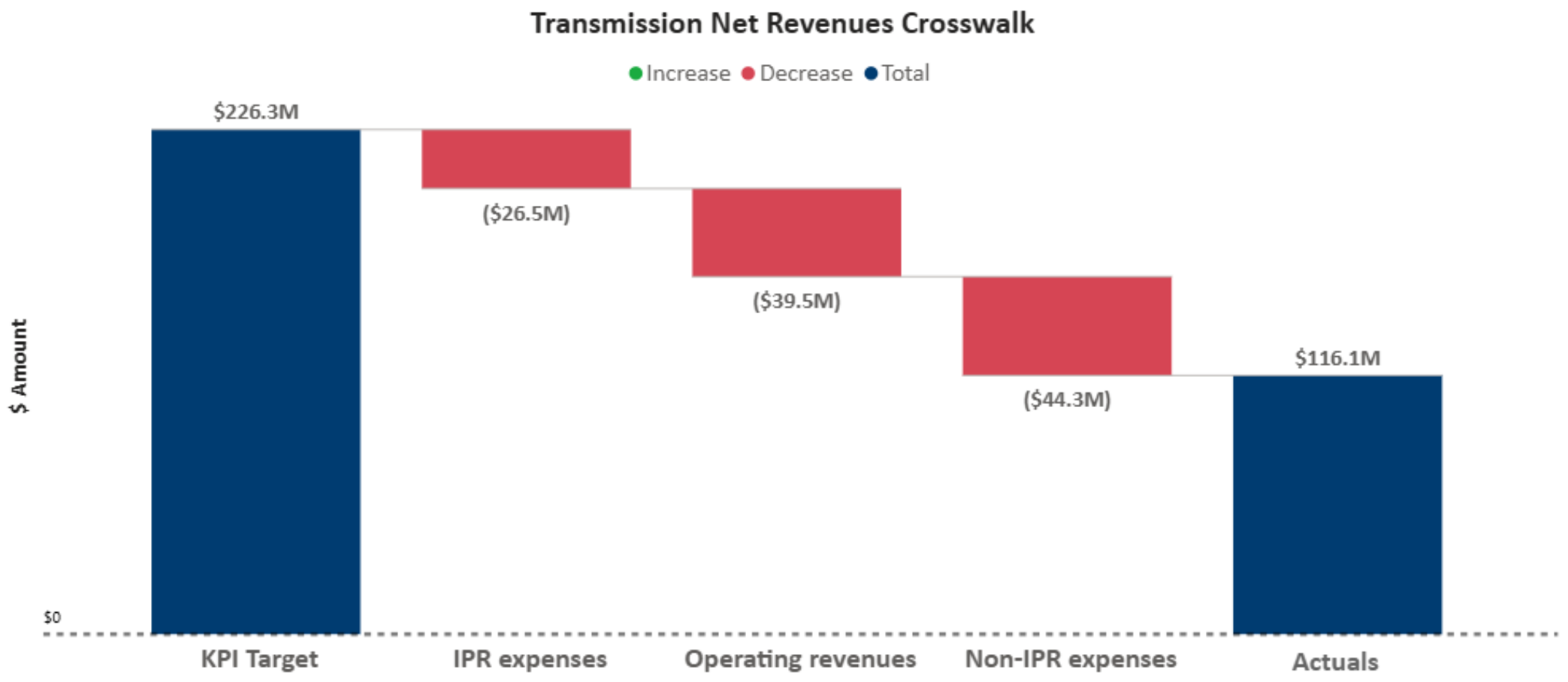
FY26 results for Integrated Program Review Operating Expenses: $89M below target

- The Asset Management program is $30M below Target due to Federal Hydro lower staffing levels than planned, a member distribution from CGS's nuclear insurance, and a lower F&W spending.
- The Operations program is $31M below Target due to slower hiring on the Power side and lower Conservation Infrastructure spending due to a slow start in contracting.
- Enterprise Services is $28M below Target mainly from lower staffing levels than planned and Corporate costs saw a shift from Power to Transmission either through direct charging or change in the cost pools that have a higher allocation rate to Transmission.

FY26 results for Operating Revenues: $176M below the target

- Gross Sales decreased from Target driven by lower PF Revenues. PF Revenues decreased from Target driven by lower Composite Revenue, Tier 2 Revenue, Load Shaping Revenue and Demand Revenue.
  - Composite Revenue is lower than Target due to lower Net Requirement resulting in a TOCA change.
  - Tier 2 Revenue decreased due to an update to Tier 2 billing determinants to include customers' final elections which reduce Tier 2 amounts and increase non-federal amounts. A revision to the Tiered Rates Methodology billing determinants model was issued after Final Proposal.
  - Load Shaping and Demand Revenues are significantly lower than Target due to warmer than average temperatures experienced during the fiscal year.
  - Finally, the 4h10c credit is less than the Target driven by lower predicted purchases.
- These decreases are partially offset by:
  - Slightly higher trading floor sales revenue due to higher quantities sold.
  - The $40M reserves surcharge from FY25 that is being collected this fiscal year.
  - Additionally, the $2M Slice True-up forecast is a charge to customers mainly due to a shift in debt repayment. In order to meet the settlement terms, rates reflected pre-shift principal repayment; to meet other RC tests, RC documentation reflected post-shift principal repayment. Principal repayment in the operating year reflects post-shift amortization.

FY26 RESULTS: TRANSMISSION NET REVENUE



The KPI Target is equal to the Transmission's FY26 Rate Case net revenue forecast.

QBRTW ANALYSIS: TRANSMISSION NET REVENUE

FY26 results for Integrated Program Review Operating Expenses: $27M above target

- $32M increase in Asset Management programs driven mainly by increased maintenance work in break-fix maintenance and other non- electric system infrastructure projects as well as increased compliance cost related to NERC/WECC.
- $4M decrease in Enterprise Services programs driven by a reduced G&A allocations and more direct support primarily in various asset management programs.
- $1.5M decrease in Operations and Commercial Activities programs driven by a shift in cost from commercial activities to operations programs.

FY26 results for Operating Revenues : $40M below target

- $72M decrease in Sales resulting from lower than Point to Point long term revenues. This was driven by customer deferrals associated with projects energizing later than the reservation service date. There were also reductions in Network revenues due to lower loads resulting from warmer than normal temperatures.

Offset by:

- $17M increase in other revenues driven by an increase in customer funded projects.
- $16M increase in Inter-Business Unit Revenues, driven EIM sub-allocated charges not forecasted in Rate Case.

QBRTW ANALYSIS: TRANSMISSION NET REVENUE

FY26 results for Non-IPR Program Expenses was $44M above target

- $27M Increase in the Commercial Activities Non-IPR Program driven by EIM Settlement charges and reimbursable program expenses that both have an offsetting revenues.
- $17M Increase in total Interest Expense and Other Income, Net due to lower interest income resulting from a lower cash balance than assumed in target. Also contributing to this amount was an increase in amortization expense.

FY26 Results: Reserves for Risk

Darren Heim

FY26 ACTUALS: RESERVES FOR RISK

- Share FY 2026 EOY Reserves for Risk, or RFR, results by business unit
- Financial Reserves Policy Results – Power Surcharge Calculation & Amount
- Preliminary Surcharge Rates
- Refresh on the Surcharge Process per GRSPs
- Timeline

FY26 ACTUALS: RESERVES FOR RISK

($M)	EOY RFR		Thresholds		Rate Action
	RFR	Days Cash	Surcharge	Reserves Dist.	
BPA	$550	70	--	$768	--
Power	$252	46	$370	$741	Surcharge: $40
Transmission	$298	125	$141	$283	None (2-tier test not met)

Power RFR: is ~$322M lower than Rate Case expectations. Key drivers:

1) RFR starting balance is ~$232M lower than assumed in RC.
2) Cash from operations is ~$113M lower than assumed in RC. Drivers: significant work capital cash drag due to YOY AP/AR changes, offset by higher NR than rate case, although ~$40M of revenue is non-cash in FY26.
3) Cash from financing includes an increase of $39M from unwinding FY26 revenue financing.

Transmission RFR: is ~$47M lower than RC expectations. Key drivers:

1) RFR starting balance is ~$30M lower than assumed in RC.
2) Cash from operations is ~$16M lower than assumed in RC. Lower NR of ~$110M largely offset by working capital boost due to YOY higher AP balances outstanding along with an increase of in non-cash income statement items like depreciation expense.

Note: Both Power and Transmission RFR are higher than would otherwise be due to rate case cash flow shaping; FY26 NR were set to build RFR, intended to be used to cover FY28 expenses. Neither hit RC expectations, putting pressure on FY28 RFR.

FY26 ACTUALS: Financial Reserve Policy Results

Power: EOY RFR = $252M which is below the FRP Surcharge threshold. Per the FRP calculation, the Surcharge amount is $40M.

- Upper threshold $741M
- Lower threshold $370M
- Surcharge calculation threshold: lower threshold ($370M) – FY27 Revenue Financing ($37M) = $333M

Transmission: EOY RFR = $298M which is above the upper FRP threshold however, because BPA consolidated reserves ($550M) remained below the BPA upper threshold ($768M), the two-tier test failed. No reserve distribution will trigger.

- Upper threshold $283M
- Lower threshold $141M

Power Surchage for FY27 Application ($M)	
FY26 EOY Actual RFR	$252
Surcharge RFR Threshold (less FY27 RF)	$333
Amount below Threshold	$81
Surcharge Amount (Cap = $40M)	Surcharge = $40

Transmission RDC: Two-Tier Test ($M)		
Tier-1 Test: BU RFR vs Threshold	**RFR**	**Test 1**
FY26 Transmission EOY Actual RFR	$298	
Transmission RDC Threshold	$283	
Amount above Transmission RDC	$15	Met
Tier-2 Test: BPA RFR vs Threshold	**RFR**	**Test 2**
FY26 BPA Consolidated EOY Actual RFR	$550	
BPA Consolidated RDC Threshold	$768	
Amount below BPA Consolidated RDC	($218)	Not Met

FY26 ACTUALS: Power Surcharge Preliminary Rates

- Annual Average Effective Rate to recover $40M of FRP Surcharge over the ten-month billing period of Dec. 2026 – Sept. 2027 is 2.0%.
- Preliminary Rate impacts for Power average effective PF Non-Slice Tier 1 Rates is estimated around $0.77 MWh.

	A	B	C	D	E	F
1	*(a) Power FRP Surcharge Rate:*					**FY2027**
2		Power FRP Surcharge Amount:				$40,000,000
3		Sum of Dec - Sept Billing Determinants (MWh):				44,045,340
4		Power FRP Surcharge rate ($/MWh):				**$0.91**
5						
6	*(c) Adjusted PF Tier 1 Equivalent Energy Rates:*					
7				HLH ($/MWh)	LLH ($/MWh)	
8			Oct-26	46.04	44.26	
9			Nov-26	34.94	37.05	
10			**Dec-26**	**43.95**	**45.11**	
11			**Jan-27**	**39.88**	**40.12**	
12			**Feb-27**	**41.75**	**45.50**	
13			**Mar-27**	**25.51**	**30.86**	
14			**Apr-27**	**18.65**	**23.41**	
15			**May-27**	**4.92**	**9.05**	
16			**Jun-27**	**11.42**	**12.40**	
17			**Jul-27**	**47.30**	**44.38**	
18			**Aug-27**	**50.12**	**46.64**	
19			**Sep-27**	**56.83**	**55.38**	
20						
21	*(d) Annual Power FRP Surcharge Rate and Other Adjustments:*					
22		Sum of Annual Billing Determinants (MWh):				51,922,707
23		Annual Power FRP Surcharge Rate ($/MWh):				**$0.77**
24						
25		Adjusted Load Shaping Charge True-Up rate:				$3.82
26		Adjusted PF Melded Equivalent Energy Scalar rate:				$1.30
27						
28				Average Effective Non-Slice Tier 1 Rate		$38.40
29				New Average Effective Non-Slice Tier 1 Rate		$39.17
30				**Annual Effective Rate Increase**		**2.0%**

FY26 ACTUALS: Surcharge Process per GRSPs

- The Financial Reserves Policy establishes actions based on reserves levels. When reserves decline below established thresholds, rates increase through the 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:

By November 30, 2026, BPA shall complete the calculation of Power/Transmission RFR and BPA RFR as of the end of FY 2026, for use in calculating the Power/Transmission Surcharge applicable to rates for December through September of FY 2027.

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.

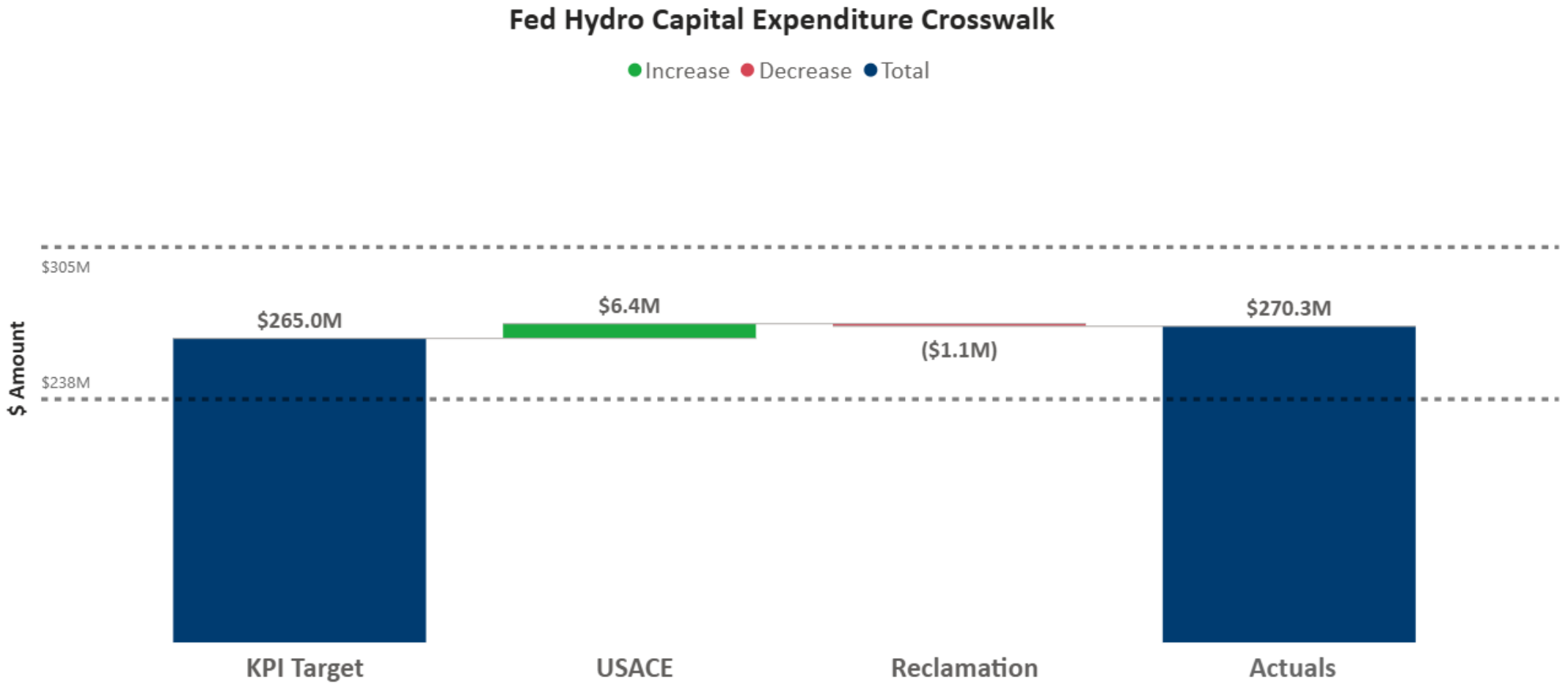
Surcharge Timeline

- **Nov. 9**: Post QBRTW presentation to the QBR webpage; public comment period begins.
- **Nov. 12**: Surcharge Calculated Rate Adjustment shared at QBR/QBRTW.
- **Nov. 30**: Comment period ends.
- **NLT Dec. 15**: Share final decision via a Tech Forum notice and updates to BPA's Risk Mechanisms & Rate Adjustments webpage.

FY26 Results: Agency Capital

Heather Seibert, Gwen Resendes

FY26 ACTUALS: FED HYDRO CAPITAL



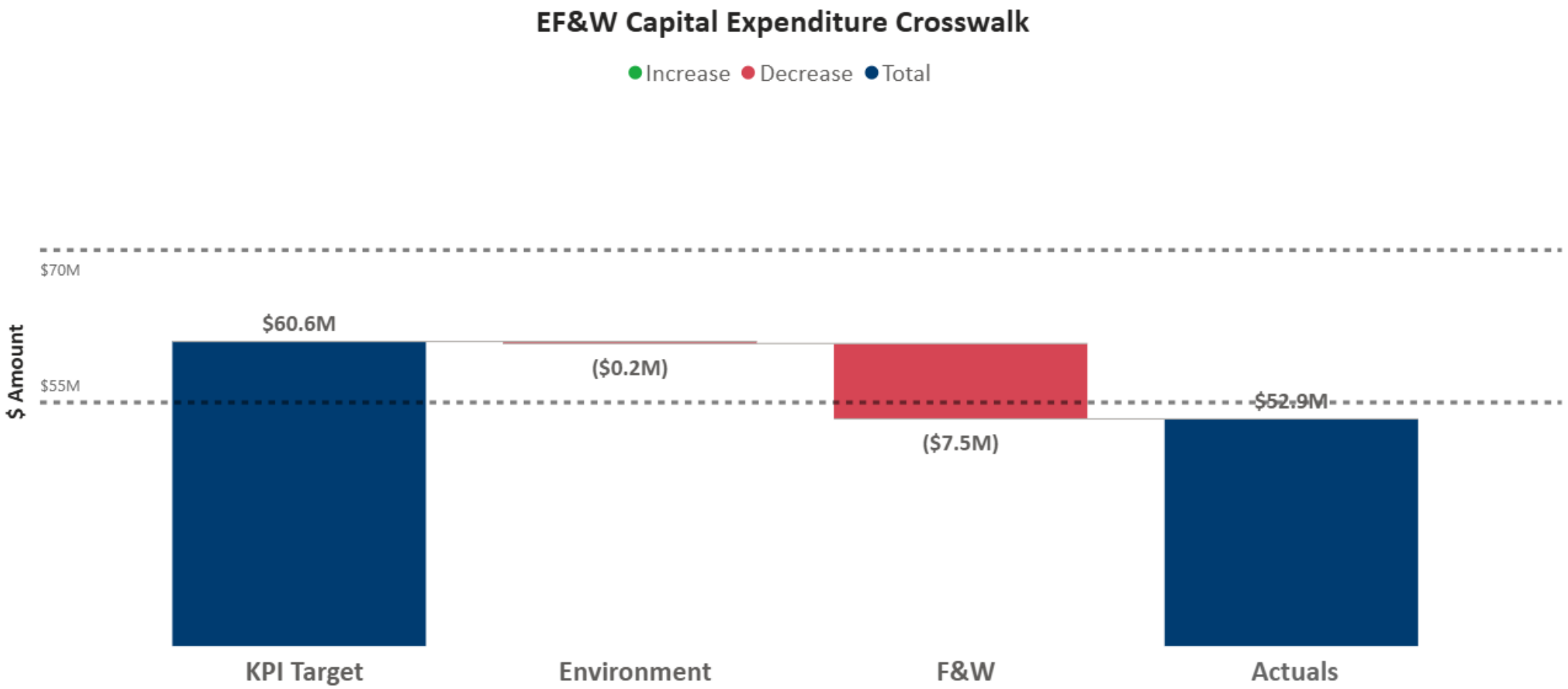
The Fed Hydro capital expenditure KPI target is a range. The range is equal to +15% and -10% of the target midpoint. If the Fed Hydro direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: FED HYDRO

The FY26 actuals for Fed Hydro's direct capital ended $5.3M above or 102% of the Target midpoint due to the following:

- The delta is driven largely by increased execution due to shifts in positive supply chain availability and contractor execution offset by long lead times for availability of personnel and materials/parts, and design and scope changes for some projects. The top projects for expenditures were McNary Dam for USACE at $92M and Grand Coulee for BOR at $20M.

FY26 ACTUALS: EF&W CAPITAL



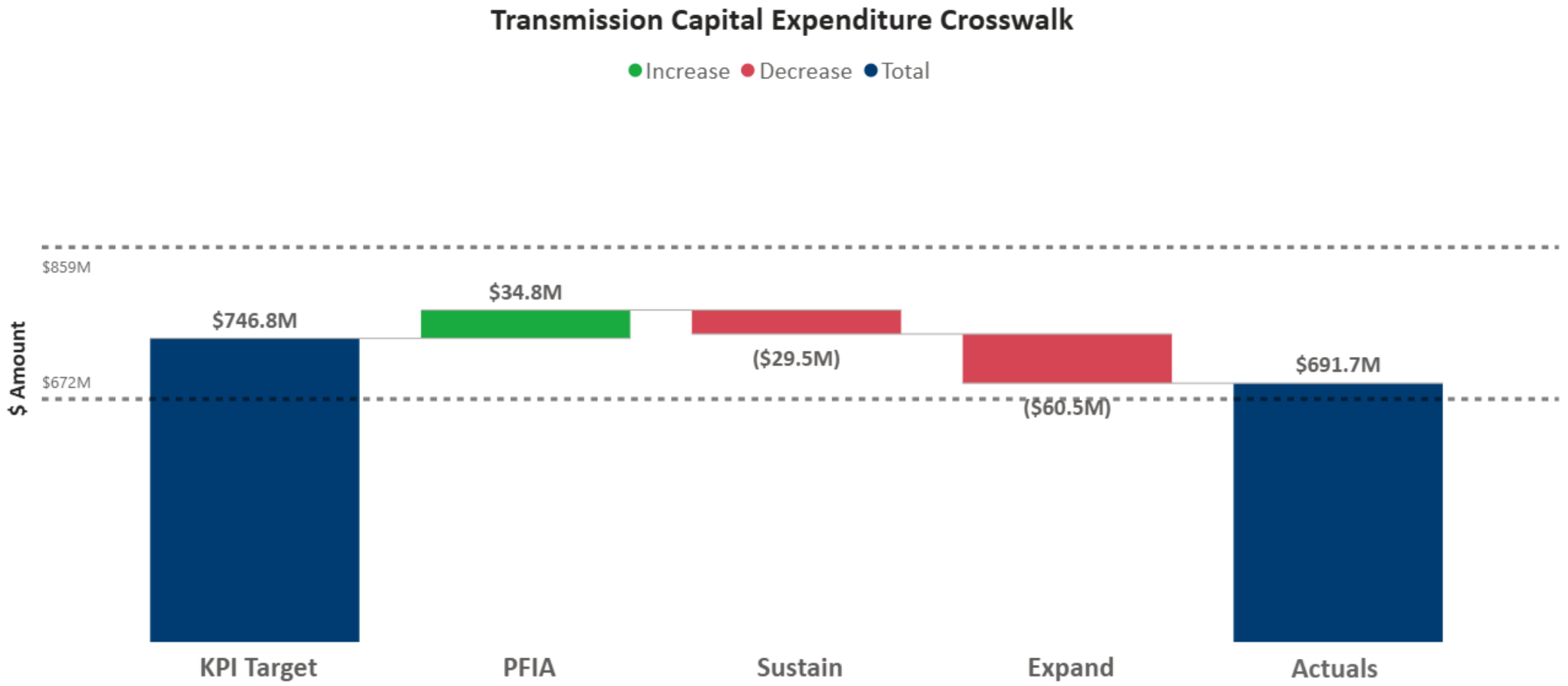
EF&W does not have its own capital expenditure target, but does roll up to the FCRPS capital KPI target. The range is equal to +15% and -10% of the target midpoint and is displayed to support tracking capital execution and how these expenditures could impact the FCRPS KPI target.

QBRTW ANALYSIS: EF&W

The FY26 actuals for Environment, Fish & Wildlife direct capital ended ($7.7M) below or 87% of the Target midpoint.

- The delta between Target and Actuals for Environment, F&W is due to a few factors, including:
  - The delta between EOY actuals and Target of ($7.5M) for F&W is mostly ($4.6M) due to slower progress on programmatic passage and habitat work. An additional ($4.5M) in delayed Willamette Valley land acquisitions reduced the EOY result.
  - This is partially offset by $1.7M higher expenditures than Target due to slightly increased project costs and improved construction execution in Hatchery.

FY26 ACTUALS: TRANSMISSION CAPITAL



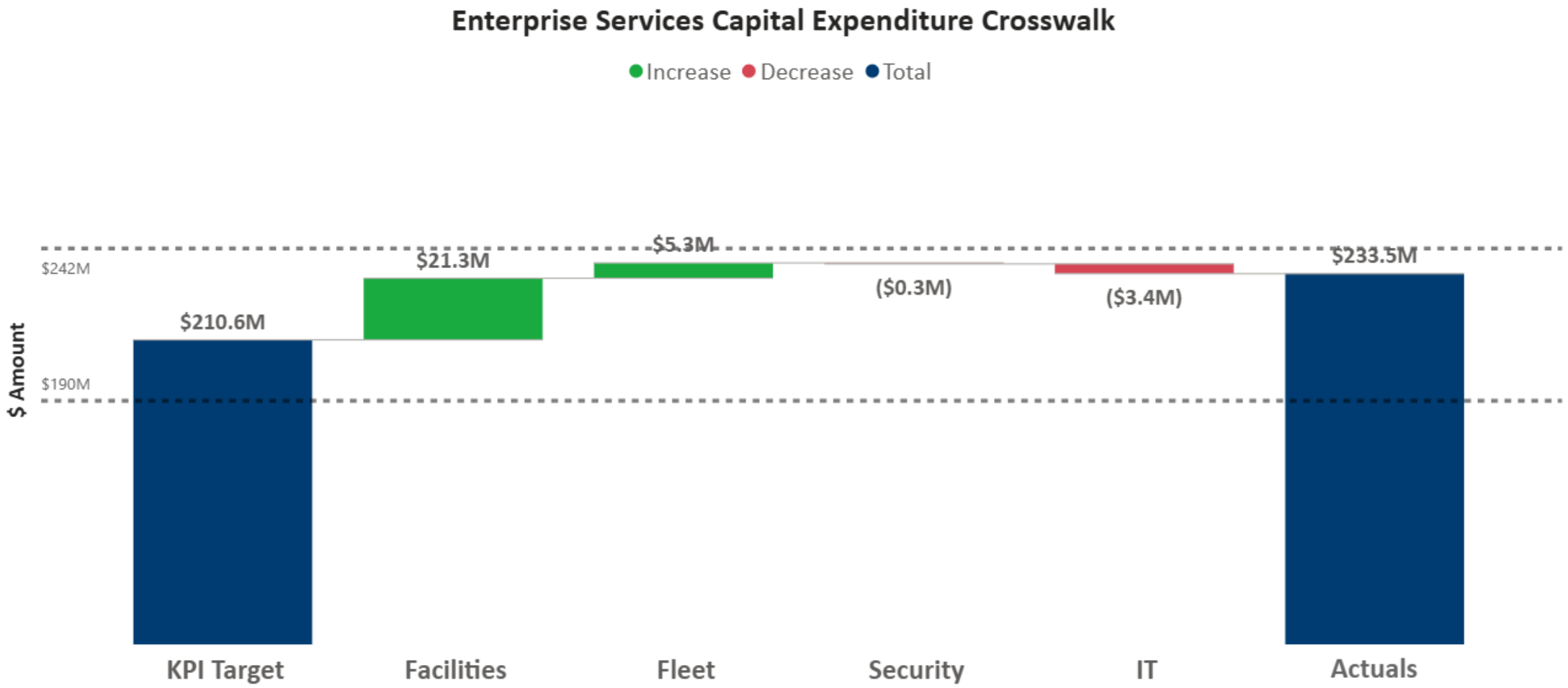
The Transmission capital expenditure KPI target is a range. The range is equal to +15% and -10% of the target midpoint. If Transmission direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: TRANSMISSION

Transmission's direct capital end-of-year actuals were $55M below or 93% of the target midpoint; broken down as follows:

- Transmission's PFIA ended the year $34.8M higher than the target. Most of the additional work was customer-funded transfers from Expand to PFIA and customer solar interconnection projects that ran ahead of schedule.
- Transmission's Sustain program finished the year $29.5M below the target. Investment focused on substation replacements, access roads, wood poles, steel assets and telecommunications, with some control center and land rights work shifting to FY27.
- Transmission's Expand program finished the year $60.5M below Target. This was primarily due to schedule shifts on Six Mile Canyon, McNary, and the control center projects. Major investments included Longhorn Substation wrap-up, Pearl Sherwood McLoughlin, Ross Substation, Carlton and South Tri-Cities project.

FY26 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

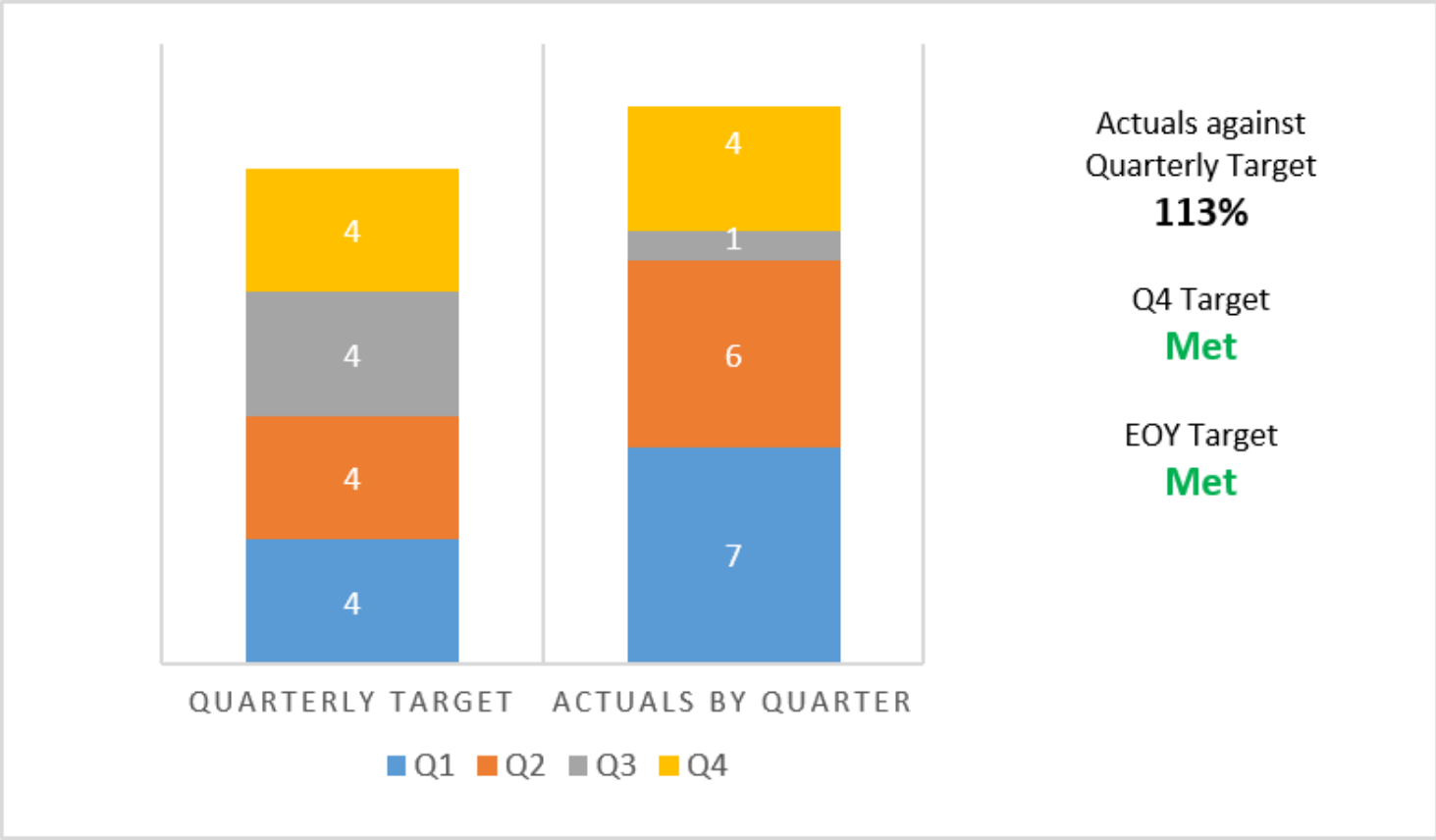
The FY26 actuals for Enterprise Services direct capital ended $23M above or 111% of the Target midpoint as follows:

- Facilities ended $21.3M above their target primarily driven by the Vancouver Control Center project which accounted for 86% of Facilities total expenditures for the year. This project is actually ahead of schedule and brought forward material purchases originally scheduled for FY27.
- Fleet ended the year $5.3M above their target primarily due to deliveries planned for FY27 arriving in FY26.
- Security ended the year within $300K of Target.
- IT ended ($3.4M) below their target primarily driven by longer-than-planned contracting lead times.

FEDERAL HYDRO CAPITAL METRICS

Doug Komoroski

FED HYDRO CAPITAL MILESTONES



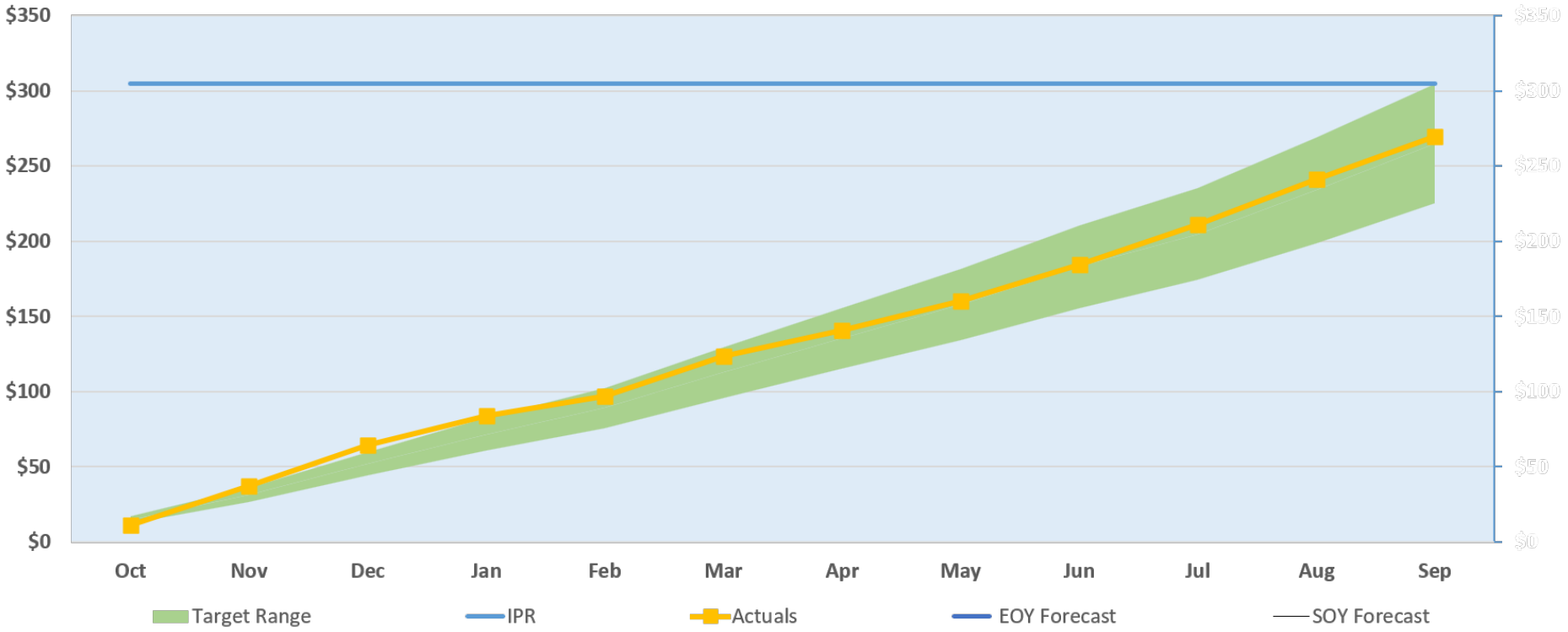
Key Takeaway: EOY Cumulative target exceeded: 18 met vs a target of 16.

FED HYDRO CAPITAL PROJECT MILESTONES MET FY26

Dam	Project Name	Milestone Metric	Date
Bonneville	BON Control Room Fire Protection Upgrades	Physical Completion	8/15/2025
Albeni Falls	ALB Intake Gates	Complete Design	9/1/2025
John Keys PGP Str	GCL PGP Crane Modernization #2805	Award Contract	9/2/2025
Anderson Ranch	Turbine Runner Replacement	Begin Constrction	9/15/2025
Lower Granite	LWG Turbine Intake Gate Hydraulic System Upgra	Award Contract	9/26/2025
Ice Harbor	IHR Intake Gate Hydraulic System Upgrades	Award Contract	11/21/2025
Little Goose	LGS Spare Transformers for LSR Plants	Begin Solicitation	12/4/2025
Albeni Falls	ALB Spillway Gate Recoating and HSS weld Repair	Award Contract	2/26/2026
Lower Granite	LWG DC System and LV Switchgear Upgrade	Physical Completion	2/26/2026
Hungry Horse	HGH Static Exciters	Contract Award	3/6/2026
Grand Coulee	GCL Replace Underground Town of Coulee Dam F	Award Contract	3/9/2026
Bonneville	BON 1 Spillway Cranes	Begin Solicitation	3/11/2026
Lower Monunenta	LMN Powerhouse HVAC System Upgrade	Complete Design	3/16/2026
Bonneville	BON 1 Main Unit Breaker Replacement	Contract Award	4/30/2026
Grand Coulee	GCL RAHCO Crane Controls Modernization - 6838	Complete Design	7/1/2026
Lower Monument	LMN PH Bridge Crane Wheel and Drive System Up	Complete Design	7/7/2026
Lower Monument	LMN PH Bridge Crane Wheel and Drive System Up	Begin Solicitation	8/6/2026
Libby	LIB Intake Gantry Crane	Physical Completion	9/3/2026

Key Takeaway: Design Completion, Awarded Contracts, and Construction milestones for projects over $10 million in direct funded capital costs are tracked toward the milestone targets for FY26.

FED HYDRO CAPITAL SPEND

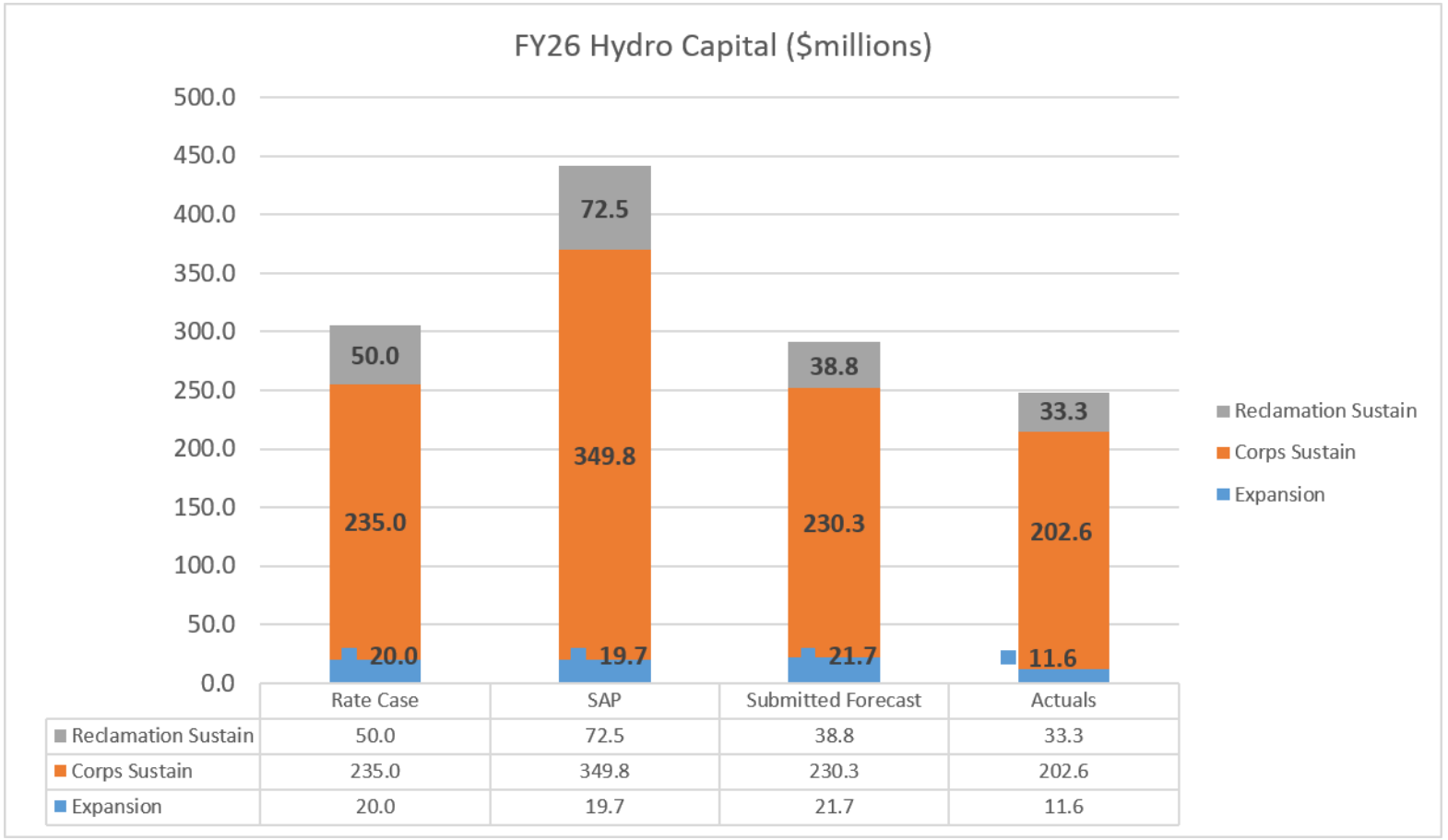


FY26 Key Performance Indicators

IPR: $305 million
SOY Forecast: $265 million
Target Range: $227-$290 million

Key Takeaway: End of year capital expenditures are within range at $270M.

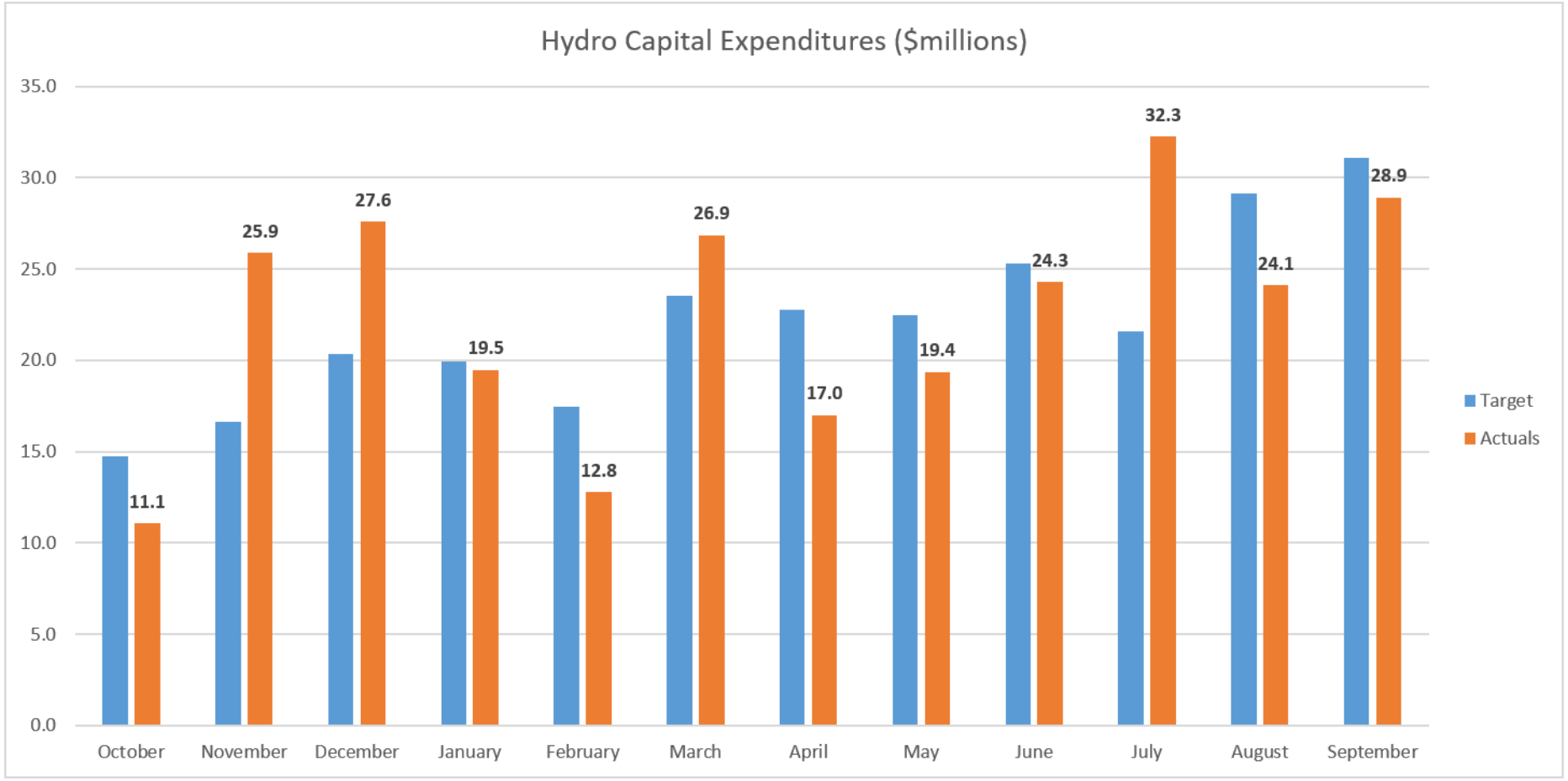
FED HYDRO CAPITAL SUSTAIN VS EXPAND



	Rate Case	SAP	Submitted Forecast	Actuals
Reclamation Sustain	50.0	72.5	38.8	33.3
Corps Sustain	235.0	349.8	230.3	202.6
Expansion	20.0	19.7	21.7	11.6

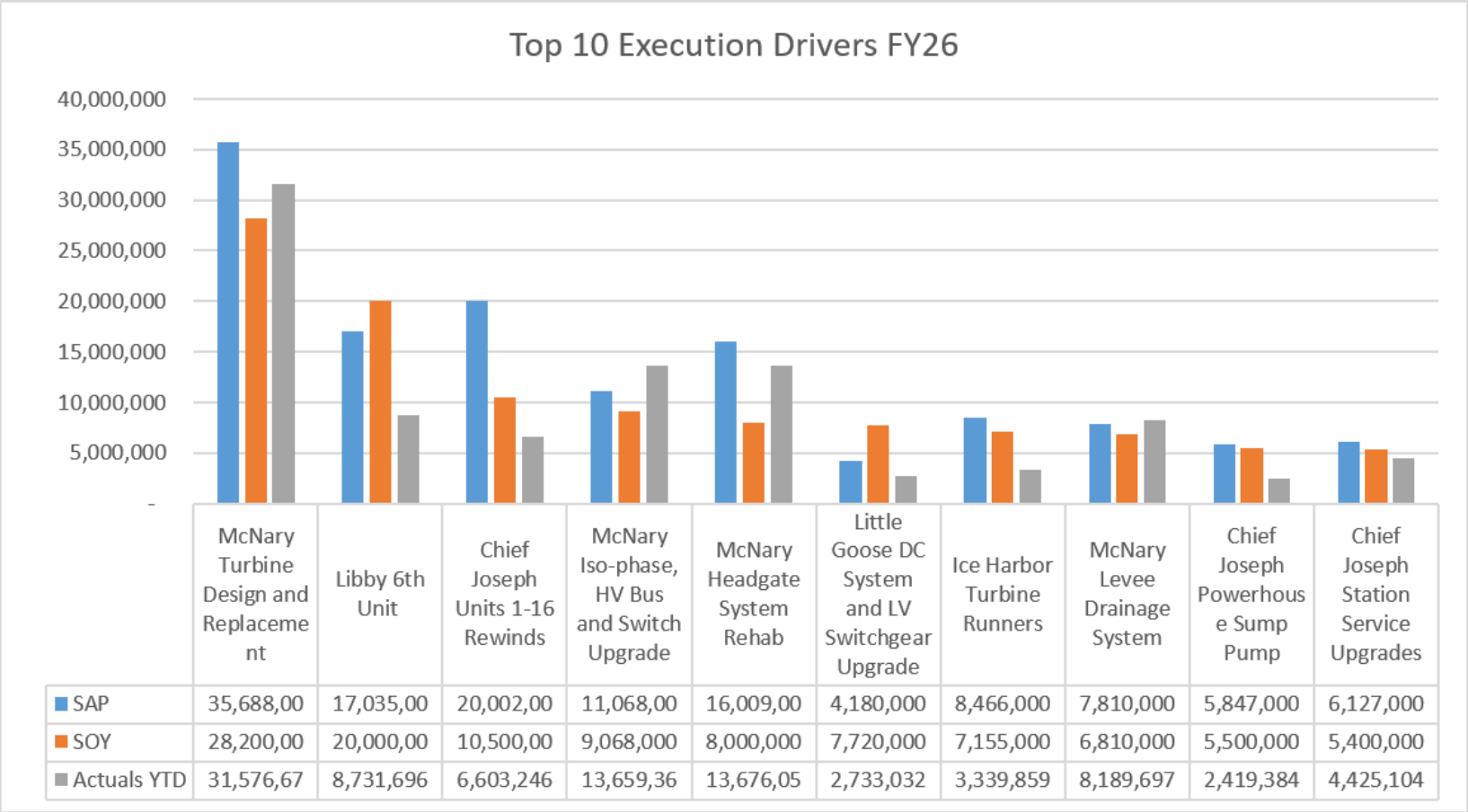
Key Takeaway: The program is focused on sustain projects, but the Corps does have two expansion projects, Libby Unit 6 and Dworshak Unit 4.

FED HYDRO CAPITAL FORECAST VARIANCE



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

FED HYDRO CAPITAL TOP 10 EXECUTION DRIVERS



	McNary Turbine Design and Replacement	Libby 6th Unit	Chief Joseph Units 1-16 Rewinds	McNary Iso-phase, HV Bus and Switch Upgrade	McNary Headgate System Rehab	Little Goose DC System and LV Switchgear Upgrade	Ice Harbor Turbine Runners	McNary Levee Drainage System	Chief Joseph Powerhouse Sump Pump	Chief Joseph Station Service Upgrades
SAP	35,688,00	17,035,00	20,002,00	11,068,00	16,009,00	4,180,000	8,466,000	7,810,000	5,847,000	6,127,000
SOY	28,200,00	20,000,00	10,500,00	9,068,000	8,000,000	7,720,000	7,155,000	6,810,000	5,500,000	5,400,000
Actuals YTD	31,576,67	8,731,696	6,603,246	13,659,36	13,676,05	2,733,032	3,339,859	8,189,697	2,419,384	4,425,104

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

TRANSMISSION SERVICES CAPITAL METRICS

Presenters: Salah Kitali, Doug Hunter

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



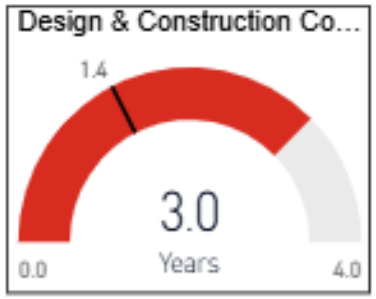
7 Projects



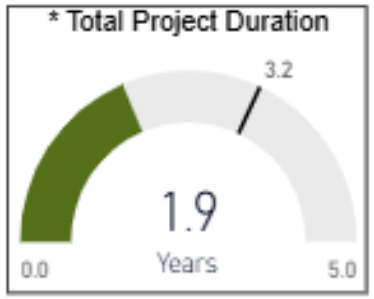
5 Projects



4 Projects



1 Projects



* 7 Projects

Line and Load Interconnection Projects: Projects are for interconnection of new load (or modification of existing points of delivery) related to PTP and NITS



89 Projects



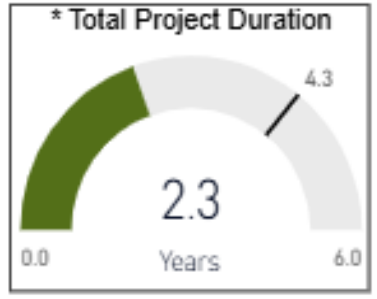
42 Projects



27 Projects



3 Projects



* 33 Projects

Includes SGI and LLI projects with a Queue date on or after 01/01/2020

Milestones represent the Full Tariff timeline

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

* Completed Projects Only

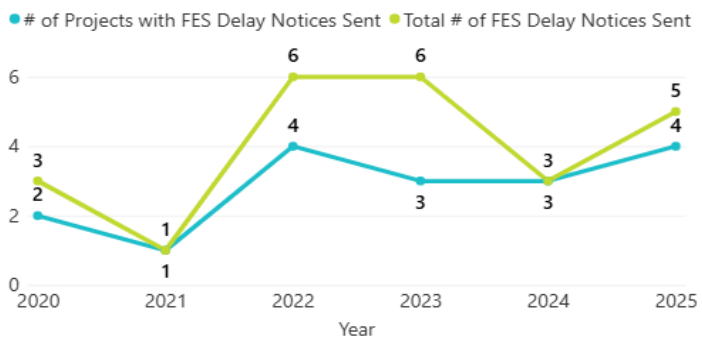
Line and Load Studies

LLI Feasibility Studies

Number of Completed FES with and without Delay Notices

Year	Count of FES Completed	Count of FES No Delay Notice Sent	Count of FES Delay Notice Sent
2026	12	11	1
2025	5	1	4
2024	3	1	2
2023	6	2	4
2022	2	0	2
2021	2	1	1
2020	2	1	1
Total	**32**	**17**	**15**

Number of LL Interconnection Requests with Delay Notices Sent

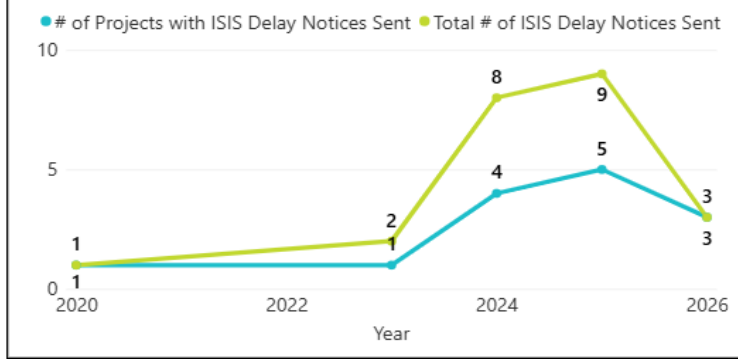


LLI System Impact Studies

Number of Completed SIS with and without Delay Notices

Year	Count of ISIS Completed	Count of ISIS No Delay Notice Sent	Count of ISIS Delay Notice Sent
2026	14	11	3
2025	8	5	3
2024	7	3	4
2023	5	4	1
2022	3	3	
2021	2	2	
2020	1	0	1
Total	**40**	**28**	**12**

Number of LL Interconnection Requests with Delay Notices Sent

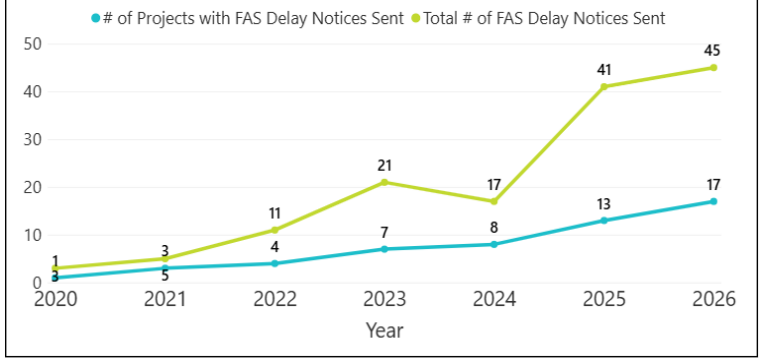


LLI Facility Studies

Number of Completed FAS with and without Delay Notices

Year	Count of FAS Completed	Count of FAS No Delay Notice Sent	Count of FAS Delay Notice Sent
2026	15	15	11
2025	12	12	10
2024	7	7	6
2023	7	7	6
2022	6	6	5
2021	2	2	1
2020	2	2	1
Total	**51**	**51**	**40**

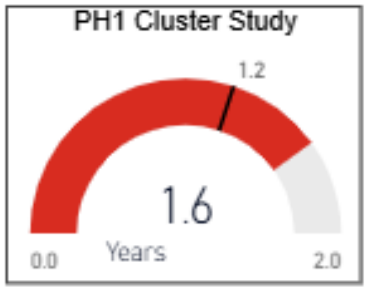
Number of LL Interconnection Requests with Delay Notices Sent



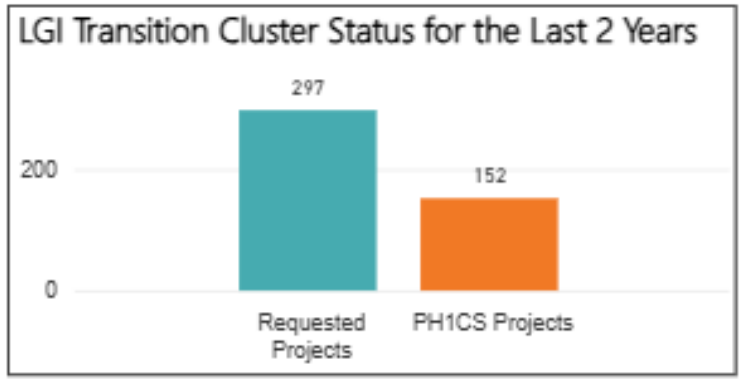
CUSTOMER DURATION METRIC – continued

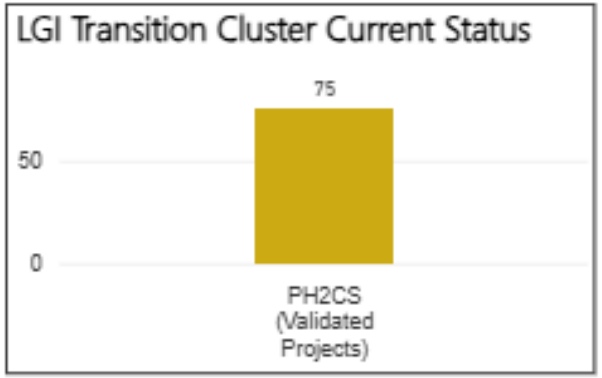
Large Generation Interconnection Projects: Projects with an aggregation of generators, whose single or combined generating capacity is greater than 20MW

LGI Cluster Process



167 Projects





Includes LGI projects with a Queue date on or after 01/01/2020

Milestones represent the Full Tariff timeline not just the Study time

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

* Completed Projects Only

LGI Serial Process (Includes Surplus & Repower, Transition Fast Track and Bypass)



124 Projects



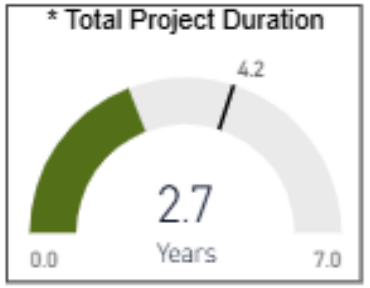
45 Projects



32 Projects



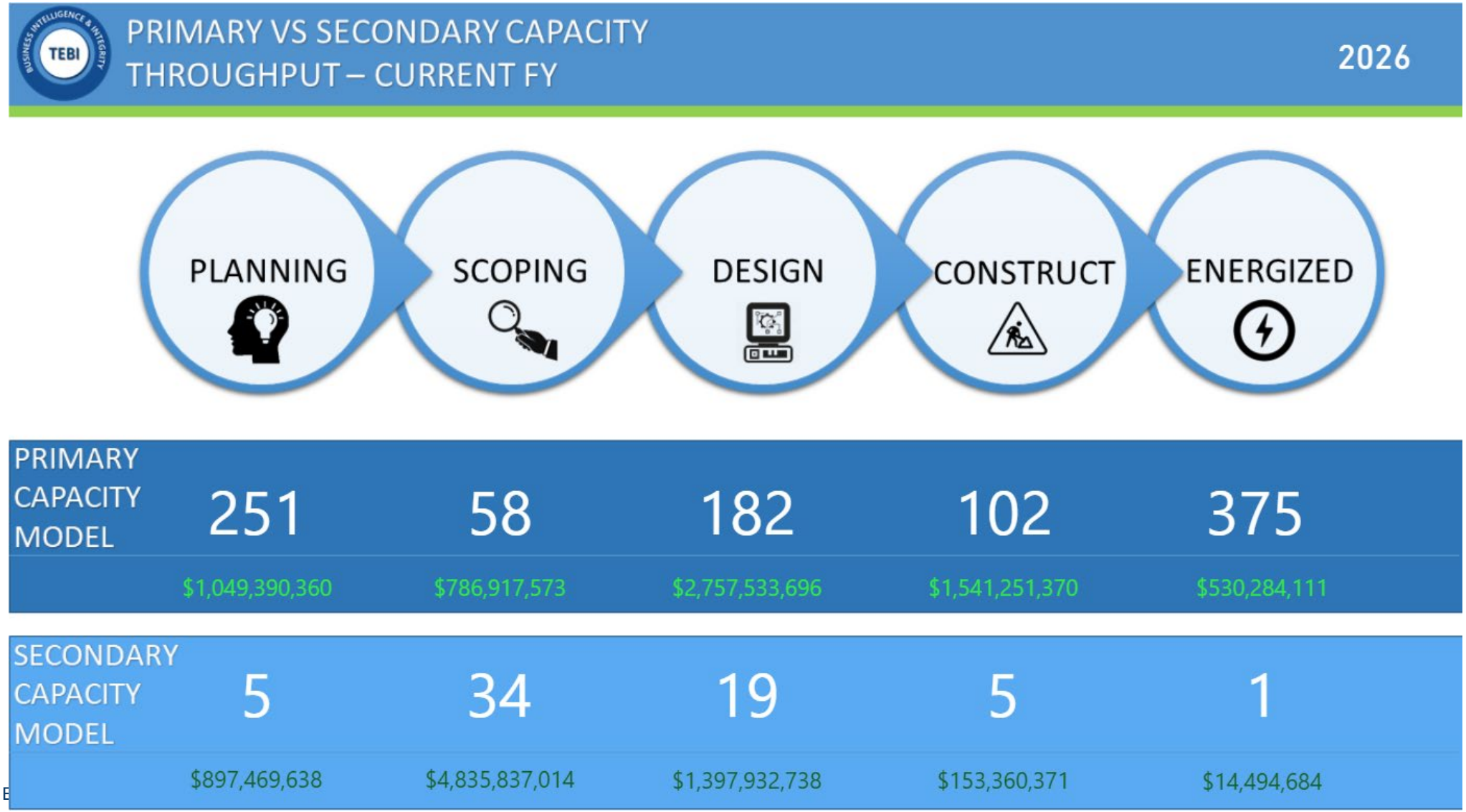
3 Projects



* 3 Projects

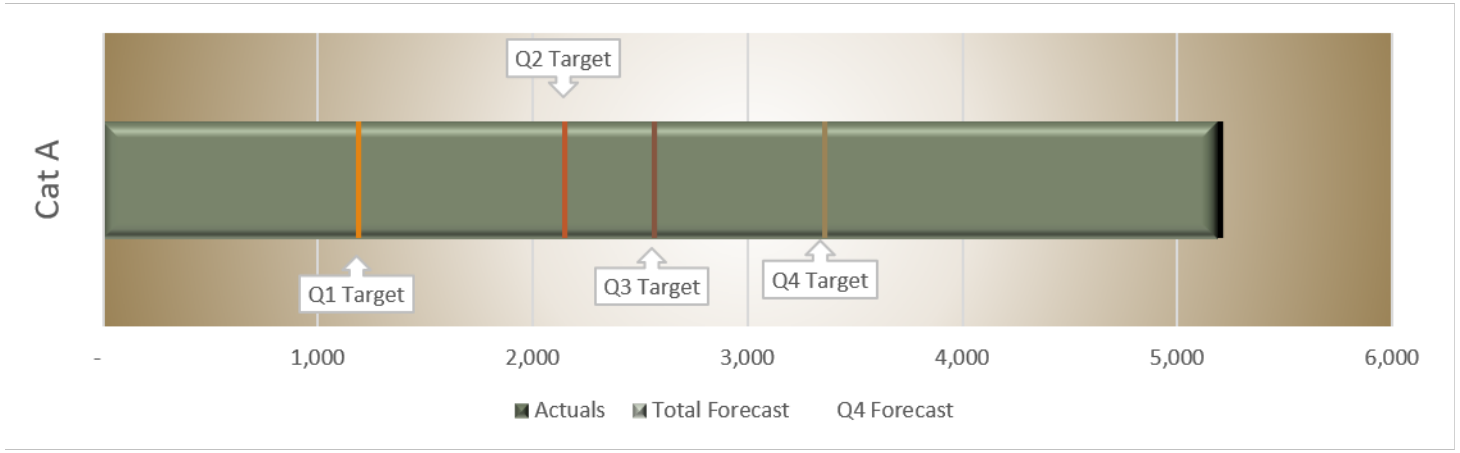
PRIMARY VS SECONDARY CAPACITY THROUGHPUT

Transmission as of FY26 Q4:



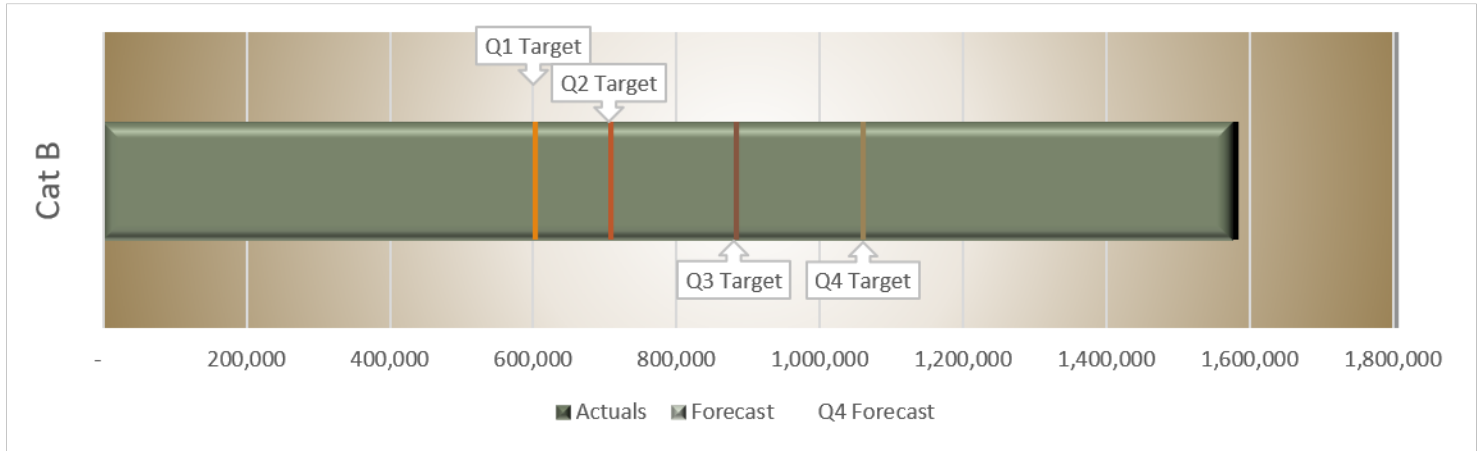
CAPITAL ASSETS PLANNED VS COMPLETED

Transmission as of FY26 Q4



Cat A = assets measured in units of EA

Actuals are 155.0% of EOY Target



Cat B = assets measured in units of LF

Actuals are 149.0 % of EOY Target

Key Takeaway:	On Track

WORK PLAN COMPLETE

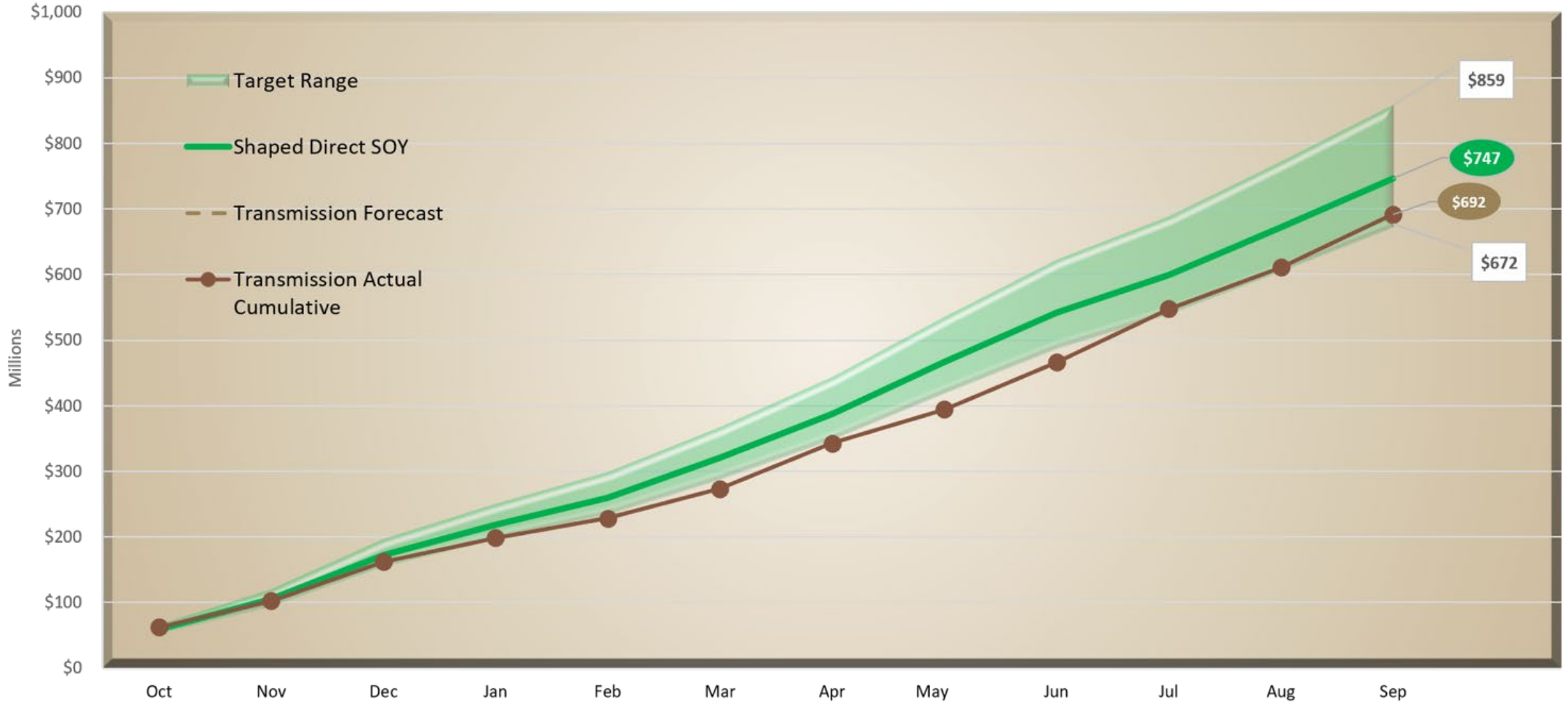
Transmission as of FY26 Q4:

Qtr	Priority Projects	Target Milestones	Model	On Track
Q1	P03252 Grand Coulee Upgrade Project	Complete RFP process	EPC	Complete
Q2	P05580 L0510 Six Mile Canyon 500kV/230kV Substation	Complete NEPA	SCM	Not Met
Q2	P05847 L0543 Bonanza Substation	Initiate Independent Cost Estimate	SCM	Complete
Q2	P02230 Wendson Substation Control House replacement, yard expansion, new bus-tie breaker, new disconnects, station service and ground grid upgrades	Complete Construction	PCM	Complete
Q2	P01277 Chehalis-Convington #1 Insulator Replacement	Construction Complete	PCM	Complete
Q3	P05738 Maple Valley Transformer Replacement	Complete Electrical Design	PCM	Complete
Q3	P00781 FY18 SER/SCADA	Construction Start for Alston	PCM	Complete
Q3	P03425 Ross Station Service Upgrade	Complete Contract Design	PDB	Not Met
Q3	P00695 Shelton-Fairmount #1 Line Rebuild	Fiber Design Substantially Complete	PCM	Complete
Q3	P02678 Wautoma-Rock Creek #1 Twisted Bundle Mitigation	Line Construction Complete	PCM	Complete
Q4	P05468 Big Eddy-Chemawa-1 500kV Line Rebuild	Initiate Procurement for EPC Contract	SCM	Complete
Q4	P001237 MREDI VHF Radio Replacement	Region 3 Contract Design Complete	PCM	Not Met

75% of Project Milestones On Track

Key Takeaway: On Track

CAPITAL SPEND



Key Takeaway: On Track

THANK YOU

The next QBR and Technical Workshop will be held on

February 18, 2027

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 12, 2026, and contains information not sourced directly from BPA financial statements.

APPENDIX

SLICE REPORTING

Composite Cost Pool Review

Forecast of Annual Slice True-Up Adjustment

Q4 True-Up of FY 2026 Slice True-Up Adjustment

	FY 2026 Forecast **$ in thousands**
February 12, 2026 First Quarter Technical Workshop	15,840*
May 14, 2026 Second Quarter Technical Workshop	11,321*
August 13, 2026 Third Quarter Technical Workshop	8,258*
November 12, 2026 Fourth Quarter Technical Workshop	1,768*

*Negative = Credit; Positive = Charge

Summary of Differences From Q4 to FY26 (BP-26)

#		Composite Cost Pool True-Up Table Reference	Q4 vs. Rate Case $ in thousands
1	Total Expenses	Row 101	$(114,668)
2	Total Revenue Credits	Rows 120 + 129	$(47,947)
3	Minimum Required Net Revenue	Row 156	$80,934
4	TOTAL Composite Cost Pool (1 - 2 + 3) $(114,668) - $(47,947) + $80,934 = $14,213	Row 161	$14,213
5	TOTAL in line 4 divided by 0.9440033 sum of TOCAs $14,213/ 0.9440033 = $15,056	Row 163	$15,056
6	QTR Forecast of FY26 True-up Adjustment 11.74505 percent of Total in line 5 0.1174505 * $15,056= $1,768	Row 164	$1,768

FY26 Impacts of Debt Management Actions

#	Description	FY26 Q4	FY26 Rate Case	CCP	Delta from the FY26 rate case
1	MRNR Section of Composite Cost Pool Table				
2	**Principal Payment of Federal Debt**				
3	Regional Cooperation Debt (RCD)	$ 367,154,857	$ 371,000,000		$ 3,845,143
4	Debt Service Reassignment (DSR)		$ -		$ -
5	Energy Northwest's Line Of Credit (LOC)	$ -	$ -		$ -
6	Rate Case Scheduled Base Power Principal*	$ 146,000,000	$ 66,000,000		$ (80,000,000)
7	Repayment due to FY26 RDC		$ -		$ -
8	**Total Principal Payment of Fed Debt**	**$ 513,154,857**	**$ 437,000,000**	row 132	**$ (76,154,857)**
9	**Prepay**	$ (27,270,544)	$ (27,270,544)		$ -
					$ -
10	**Nonfederal Bond Principal Payment**	$ 56,170,000	$ 36,162,000	row 134	$ (20,008,000)

Composite Cost Pool Interest Credit

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

		Q4 2026
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	4.53%
5	Composite Interest Credit	(23,990)
6	Prepay Offset Credit	0
7	Total Interest Credit for Power Services	(15,800)
8	Non-Slice Interest Credit (Line 7 – (Line 5 + Line 6))	8,190

Net Interest Expense in Slice True-Up Q4

	FY26 Rate Case ($ in thousands)	Q4 ($ in thousands)
• Federal Appropriation	28,017	38,132
• Capitalization Adjustment	(45,937)	(45,937)
• Borrowings from US Treasury	39,368	56,781
• Prepay Interest Expense	3,329	3,329
• **Interest Expense**	**24,778**	**52,305**
• AFUDC	(20,002)	(27,900)
• Interest Income (composite)	(18,891)	(23,990)
• Prepay Offset Credit	0	0
• **Total Net Interest Expense**	**(14,115)**	**415**

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

Dates	Agenda
February 12, 2026	First Quarter Technical Workshop
May 14, 2026	Second Quarter Technical Workshop
August 13, 2026	Third Quarter Technical Workshop
October 2026	BPA External CPA firm conducting audit for fiscal year end
Mid-October 2026	Recording the Fiscal Year End Slice True-Up Adjustment Accrual
End of October 2026	Final audited actual financial data is expected to be available
November 12, 2026	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 16,2026	Mail notification to Slice Customers of the Slice True-Up Adjustment for the Composite Cost Pool
November 18, 2026	BPA to post Composite Cost Pool True-Up Table containing actual values and the Slice True-Up Adjustment
December 10, 2026	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 28, 2026	BPA posts a response to customer questions (Attachment A does not specify an exact date)
January 21, 2027	Customer comments are due on the list of tasks (The deadline can not exceed 10 days from BPA posting)
February 4, 2027	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

		November (Q4) ($000)	Rate Case forecast for FY 2026 ($000)	November (Q4) – Rate Case Difference
1	**Operating Expenses**			
2	**Power System Generation Resources**			
3	**Operating Generation**			
4	COLUMBIA GENERATING STATION (WNP-2)	$ 363,024	$ 348,985	$ 14,039
5	BUREAU OF RECLAMATION	$ 175,956	$ 195,235	$ (19,279)
6	CORPS OF ENGINEERS	$ 311,927	$ 300,597	$ 11,330
7	CRFM STUDIES	$ 12,115	$ 12,510	$ (395)
8	LONG-TERM CONTRACT GENERATING PROJECTS	$ 22,542	$ 30,482	$ (7,940)
9	**Sub-Total**	**$ 885,564**	**$ 887,809**	**$ (2,245)**
10	**Operating Generation Settlement Payment and Other Payments**			
11	COLVILLE GENERATION SETTLEMENT	$ 21,761	$ 27,523	$ (5,762)
12	SPOKANE LEGISLATION PAYMENT	$ 6,821	$ 6,881	$ (60)
13	AMORTIZATION OF P2IP SETTLEMENT PAYMENTS	$ 14,077	$ 14,222	$ (145)
14	**Sub-Total**	**$ 42,659**	**$ 48,626**	**$ (5,967)**
15	**Non-Operating Generation**			
16	TROJAN DECOMMISSIONING	$ 801	1,300	$ (499)
17	WNP-1&3 DECOMMISSIONING	$ 2,092	1,400	$ 692
18	**Sub-Total**	**$ 2,893**	**$ 2,700**	**$ 193**
19	**Gross Contracted Power Purchases**			
20	PNCA HEADWATER BENEFITS	$ -	$ -	$ -
21	OTHER POWER PURCHASES (omit, except Designated Obligations or Purcha:	$ -	$ -	$ -
22	**Sub-Total**	**$ -**	**$ -**	**$ -**
23	**Bookout Adjustment to Power Purchases (omit)**			
24	**Augmentation Power Purchases (omit – calculated below)**			
25	AUGMENTATION POWER PURCHASES	$ -	$ -	$ -
26	**Sub-Total**	**$ -**	**$ -**	**$ -**
27	**Exchanges and Settlements**			
28	RESIDENTIAL EXCHANGE PROGRAM (REP)	$ 287,341	$ 287,051	$ 291
29	OTHER SETTLEMENTS	$ -	$ -	$ -
30	**Sub-Total**	**$ 287,341**	**$ 287,051**	**$ 291**
31	**Renewable Generation**			
32	RENEWABLES (excludes KIII)	$ 9,740	$ 15,396	$ (5,656)
33	**Sub-Total**	**$ 9,740**	**$ 15,396**	**$ (5,656)**
34	**Generation Conservation**			
35	CONSERVATION ACQUISITION	$ 71,891	$ 65,385	$ 6,506
36	CONSERVATION INFRASCTRUCTURE	$ 17,702	$ 32,443	$ (14,741)
37	LOW INCOME WEATHERIZATION & TRIBAL	$ 5,538	$ 6,005	$ (467)
38	DISTRIBUTED ENERGY RESOURCES	$ -	$ 500	$ (500)
39	MARKET TRANSFORMATION	$ 13,920	$ 15,000	$ (1,080)
40	**Sub-Total**	**$ 109,050**	**$ 119,333**	**$ (10,282)**
41	**Power System Generation Sub-Total**	**$ 1,337,248**	**$ 1,360,914**	**$ (23,666)**
42				

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		November (Q4) ($000)	Rate Case forecast for FY 2026 ($000)	November (Q4) - Rate Case Difference
43	**Power Non-Generation Operations**			
44	**Power Services System Operations**			
45	INFORMATION TECHNOLOGY	$ -	$ -	$ -
46	GENERATION PROJECT COORDINATION	$ 4,360	$ 4,501	$ (141)
47	ASSET MGMT ENTERPRISE SVCS	$ 1,846	$ -	$ 1,846
48	SLICE IMPLEMENTATION	$ 978	$ 835	$ 143
49	**Sub-Total**	**$ 7,184**	**$ 5,336**	**$ 1,848**
50	**Power Services Scheduling**			
51	OPERATIONS SCHEDULING	$ 11,543	$ 12,028	$ (485)
52	OPERATIONS PLANNING	$ 6,953	$ 11,861	$ (4,908)
53	**Sub-Total**	**$ 18,496**	**$ 23,889**	**$ (5,393)**
54	**Power Services Marketing and Business Support**			
55	GRID MOD	$ 82	$ 324	$ (242)
56	EIM INTERNAL SUPPORT	$ -	$ -	$ -
57	POWER INTERNAL SUPPORT (REP support costs included here)	$ 18,537	$ 23,323	$ (4,785)
58	COMMERCIAL ENTERPRISE SVCS	$ 8,648	$ -	$ 8,648
59	OPERATIONS ENTERPRISE SVCS	$ 4,718	$ -	$ 4,718
60	POWER R&D	$ 1,813	$ 2,156	$ (342)
61	SALES & SUPPORT	$ 13,330	$ 14,504	$ (1,174)
62	STRATEGY, FINANCE & RISK MGMT	$ -	$ 4,385	$ (4,385)
63	STRATEGIC PROJECTS COMM ACT	$ -	$ -	$ -
64	EXECUTIVE AND ADMINISTRATIVE SERVICES	$ -	$ -	$ -
65	CONSERVATION SUPPORT	$ 9,141	$ 9,555	$ (413)
66	**Sub-Total**	**$ 56,270**	**$ 54,246**	**$ 2,024**
67	**Power Non-Generation Operations Sub-Total**	**$ 81,950**	**$ 83,470**	**$ (1,521)**
68	**Power Services Transmission Acquisition and Ancillary Services**			
69	TRANSMISSION and ANCILLARY Services - System Obligations	$ 2,304	$ 2,304	$ -
70	3RD PARTY GTA WHEELING	$ 82,874	$ 92,013	$ (9,139)
71	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)	$ 3,230	$ 3,300	$ (70)
72	TRANS ACQ GENERATION INTEGRATION	$ 23,492	$ 23,492	$ (0)
73	EESC CHARGES (Composite)*	$ 2,959	$ -	$ 2,959
74	TELEMETERING/EQUIP REPLACEMT	$ -	$ -	$ -
75	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**	**$ 114,859**	**$ 121,109**	**$ (6,249)**
76	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
77	**Fish & Wildlife**	$ 276,615	$ 275,484	$ 1,130
78	**USF&W Lower Snake Hatcheries**	$ 33,653	$ 33,777	$ (123)
79	**Planning Council**	$ 12,255	$ 12,041	$ 214
80	**Long Term Funding Agreements**	$ -	$ 18,403	$ (18,403)
81	**Fish & Wildlife RDC Funds**	$ 12,536	$ -	$ 12,536
82	**Lower Snake Hatcheries RDC Funds**	$ 3,146	$ -	$ 3,146
83	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$ 338,206**	**$ 339,705**	**$ (1,499)**
84	**BPA Internal Support**			
85	**Additional Post-Retirement Contribution**	$ 14,014	$ 16,442	$ (2,429)
86	**Agency Services G&A (excludes direct project support)**	$ 83,312	$ 141,885	$ (58,573)
87	**BPA Internal Support Sub-Total**	**$ 97,325**	**$ 158,328**	**$ (61,002)**

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		November (Q4) ($000)	Rate Case forecast for FY 2026 ($000)	November (Q4) - Rate Case Difference
88	**Bad Debt Expense**	$ -	$ -	$ -
89	**Other Income, Expenses, Adjustments**	$ 1,683	$ -	$ 1,683
90	**Depreciation**	$ 146,189	$ 148,559	$ (2,370)
91	**Amortization**	$ 326,798	$ 334,392	$ (7,595)
92	**Accretion (CGS)**	$ 45,006	$ 42,607	$ 2,399
93	**Total Operating Expenses**	**$ 2,489,264**	**$ 2,589,084**	**$ (99,820)**
94				
95	**Other Expenses and (Income)**			
96	Net Interest Expense	$ 165,853	$ 180,472	$ (14,619)
97	Irrigation assistance	$ 23,483	$ 20,662	$ 2,821
98	LDD	$ 39,264	$ 42,155	$ (2,892)
99	Irrigation Rate Discount Costs	$ 21,875	$ 22,034	$ (159)
100	**Sub-Total**	**$ 250,475**	**$ 265,323**	**$ (14,848)**
101	**Total Expenses**	**$ 2,739,740**	**$ 2,854,407**	**$ (114,668)**
102				
103	**Revenue Credits**			
104	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	$ 115,068	$ 133,219	$ (18,151)
105	Downstream Benefits and Pumping Power revenues	$ 20,464	$ 21,193	$ (730)
106	4(h)(10)(c) credit	$ 96,082	$ 124,911	$ (28,829)
107	PRSC Net Credit (Composite)	$ 6,990	$ -	$ 6,990
108	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ -
109	NR Revenues from ESS (Capacity)	$ 4,067	$ 4,489	$ (422)
110	FPS Real Power Losses (Capacity)	$ 18,877	$ 22,372	$ (3,496)
111	Miscellaneous revenues	$ 4,228	$ 8,647	$ (4,419)
112	Renewable Energy Certificates	$ -	$ -	$ -
113	Net Revenues from other Designated BPA System Obligations (Upper Baker)	$ 470	$ 485	$ (14)
114	RSS Revenues	$ 3,416	$ 3,416	$ -
115	Firm Surplus and Secondary Adjustment (from Unused RHWM)	$ 96,131	$ 94,894	$ 1,237
116	Balancing Augmentation Adjustment	$ 834	$ 834	$ -
117	Transmission Loss Adjustment	$ 35,579	$ 35,579	$ -
118	Tier 2 Rate Adjustment	$ 8,243	$ 8,243	$ -
119	NR Revenues (Firm Energy)	$ 706	$ 706	$ (0)
120	**Total Revenue Credits**	**$ 415,754**	**$ 463,588**	**$ (47,833)**
121				
122	**Augmentation Costs (not subject to True-Up)**			
123	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC	$ 11,347	$ 11,347	$ -
124	Augmentation Purchases (including Other Augmentation)	$ 7,021	$ 7,021	$ -
125	**Total Augmentation Costs**	**$ 18,368**	**$ 18,368**	**$ -**
126				
127	**DSI Revenue Credit**			
128	Revenues 12 aMW @ IP rate	$ 4,280	$ 4,393	$ (114)
129	**Total DSI revenues**	**$ 4,280**	**$ 4,393**	**$ (114)**
130				

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		November (Q4) ($000)	Rate Case forecast for FY 2026 ($000)	November (Q4) - Rate Case Difference
131	**Minimum Required Net Revenue Calculation**			
132	Principal Payment of Fed Debt for Power*	$ 513,155	$ 437,000	$ 76,155
133	Repayment of Non-Federal Obligations (EN Line of Credit)	$ -	$ -	$ -
134	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls)	$ 56,170	$ 36,161	$ 20,009
135	**Sub-Total**	**$ 569,325**	**$ 473,161**	**$ 96,164**
136	Depreciation	$ 146,189	$ 148,559	$ (2,370)
137	Amortization	$ 326,798	$ 334,392	$ (7,595)
138	Accretion	$ 45,006	$ 42,607	$ 2,399
139	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ 0
140	Amortization of Refinancing Premiums/Discounts (MRNR - Reverse Sign)	$ (52,301)	$ (42,053)	$ (10,248)
141	Amortization of Cost of Issuance (MRNR-reverse sign)	$ 1,883	$ 208	$ 1,675
142	Gains/Losses on Extinguishment	$ -	$ -	$ -
143	Payments for Litigation Stay Agreements	$ (10,588)	$ (10,600)	$ 12
144	Amortization of P2IP Settlement Payments	$ 14,077	$ 14,222	$ (145)
145	Non-Cash Expenses	$ -	$ -	$ -
146	Prepay Revenue Credits	$ (30,600)	$ (30,600)	$ -
147	Non-Federal Interest (Prepay)	$ 3,329	$ 3,329	$ (0)
148	Contribution to decommissioning trust fund	$ (15,700)	$ (15,700)	$ -
149	Gains/losses on decommissioning trust fund	$ (24,342)	$ (16,849)	$ (7,494)
150	Interest earned on decommissioning trust fund	$ (6)	$ -	$ (6)
151	Revenue Financing Requirement		$ (39,000)	$ 39,000
152	Capital Financing (RCD)	$ -	$ -	$ -
153	Other Adjustments	$ -	$ -	$ -
154	**Sub-Total**	**$ 357,808**	**$ 342,578**	**$ 15,230**
155	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expenses	$ 211,516	$ 130,583	$ 80,934
156	Minimum Required Net Revenues	**$ 211,516**	**$ 130,583**	**$ 80,934**
157				
158	Annual Composite Cost Pool (Amounts for each FY)	**$ 2,549,590**	**$ 2,535,377**	**$ 14,213**
159				
160	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**			
161	TRUE-UP AMOUNT (Diff. between Rate Case and Forecast)	14,213		
162	Sum of TOCAs	0.9440033		
163	Adjustment of True-Up Amount when actual TOCAs < 100 percent	**15,056**		
164	TRUE-UP ADJUSTMENT CHARGE BILLED (11.74505 percent)	1,768		