Q4 Quarterly Business Review Technical Workshop

Nov 16, 2022

1:00 p.m. – 3:00 p.m.

WebEx:

Join Meeting Link

Bridge: (415) 527-5035

Access Code: 2760 255 7570

Meeting password: xpUdH4RWR95

#1 STRENGTHEN FINANCIAL HEALTH

Agenda

Time	Min	Agenda Topic	Presenter
1:00	5	Introduction	Veronica Wittig
1:05	5	Agenda	Will Rector
1:10	25	FY22 Q4 Results: Including Income Statement, Capital, and Transmission Capital Metrics	Mario Molina, Ben Agre, Manny Holowatz, Kyle Hardy, Mike Miller, Jeff Cook
1:35	30	Reserves and RDC	Damen Bleiler, Miranda McGraw, Emily Traetow
2:05	15	Grid Modernization Update	John Nguyen/Allison Mace
2:20	15	Question & Answer	Will Rector
2:35	5	Closing	Will Rector

FY22 Q4 Results: Including Income Statement, Capital and Reserves

Presenters: Mario Molina, Ben Agre, Manny Holowatz, Gwen Resendes, Heather Seibert, Damen Bleiler

Report ID: 0121FY22
Requesting BL: POWER BUSINESS UNIT
Unit of measure: $ Thousands

QBR Forecast Analysis: Power Services
Program Plan View
Through the Month Ended September 30, 2022
Preliminary / Unaudited

Data Source: PFMS
Run Date/Time: October 24,2022 / 07:45
% of Year Elapsed = 100%

		A	B	C
		FY 2022		FY 2022
		Rate Case	Actuals: FYTD	EOY Actuals - Rate Case
	Operating Revenues			
1	Gross Sales (excluding bookout adjustment)	$ 2,557,504	$ 3,494,647	$ 937,143
2	Bookout Adjustment to Sales	-	(62,570)	(62,570)
3	Other Revenues	32,173	54,568	22,395
4	Inter-Business Unit	104,113	97,575	(6,538)
5	U.S. Treasury Credits	98,771	116,919	18,148
6	**Total Operating Revenues**	**2,792,561**	**3,701,138**	**908,578**
	Operating Expenses			
	Integrated Program Review Programs			
7	Asset Management	979,404	946,059	(33,345)
8	Operations	140,380	124,272	(16,108)
9	Commercial Activities	94,842	76,090	(18,752)
10	Enterprise Services G&A	83,602	94,132	10,530
11	Undistributed Reduction	(2,971)	-	2,971
12	Other Income, Expenses & Adjustments (IPR O&M)	-	-	-
13	**Sub-Total Integrated Program Review Operating Expenses**	**1,295,257**	**1,240,553**	**(54,704)**
	Operating Expenses			
	Non-Integrated Program Review Programs			
14	Asset Management	45,359	43,819	(1,540)
15	Operations	355,684	350,030	(5,654)
16	Commercial Activities	222,251	488,428	266,177
17	Other Income, Expenses & Adjustments (Non-IPR O&M)	-	(1,014)	(1,014)
18	Non-Federal Debt Service <Note 2	-	-	-
19	Depreciation, Amortization & Accretion	498,603	502,247	3,644
20	**Sub-Total Non-Integrated Program Review Operating Expenses**	**1,121,897**	**1,383,510**	**261,612**
21	**Total Operating Expenses**	**2,417,154**	**2,624,063**	**206,909**
22	**Net Operating Revenues (Expenses)**	**375,407**	**1,077,076**	**701,669**
	Interest expense and other income, net			
23	Interest Expense	266,152	255,641	(10,510)
24	AFUDC	(11,005)	(10,166)	839
25	Interest Income	(1,514)	(6,875)	(5,361)
26	Other income, net	(13,256)	(20,318)	(7,062)
27	**Total interest expense and other income, net**	**240,377**	**218,283**	**(22,094)**
28	**Total Expenses**	**2,657,531**	**2,842,346**	**184,815**
28	**Net Revenues (Expenses)**	**$ 135,030**	**$ 858,793**	**$ 723,763**

Power Services QBR Analysis: FY22 Results

(Note: Variance explanations are for +/-$2M or greater)

Operating Revenues:

Row 1 – Gross Sales came in $937M higher than rate case, mainly driven by the following:

- FY22 Priority Firm revenues came in $25M higher than rate case due to higher Composite revenues mainly due to higher loads. Demand Revenues came in $16M higher than rate case and Load Shaping revenues came in $30M higher than rate case due to variability in weather.
- Trading Floor Sales came in $901M higher than rate case driven by higher than expected market prices and favorable water conditions.
- The Reserves Distribution Clause, which was applied out in December through the remainder of FY22 as a credit to customer bills of roughly $14M.
- The Slice True-up resulted in a credit to customers of $8.6M, which slightly offsets higher gross sales.

Row 3 – Other Revenues: came in at $22M higher due to the Financial Swap revenues which are not forecast in the rate case. This increase is partially offset by decreasing EE revenues of $7.7M because the federal EE reimbursable program is ending.

Row 4 – Inter-Business Unit Revenues: Generation Inputs are $6.5M lower than rate case. $3M of this decrease is due to forecasting differences in Balancing Reserves Regulation and Non-Regulation, which are updated monthly with more accurate data from Transmission. Additionally all penalties (imbalance, oversupply, and financials for inaccuracy) are not forecasted in the rate case but reflected in actuals and this year these penalties amount to a credit to Transmission. Additionally, the Financial for Inaccuracy penalty and Oversupply were not forecasted in the rate case but are reflected in actuals.

Row 5 – U.S. Treasury Credits: Treasury Credits are $18.1M higher than rate case due to higher prices and higher replacement power purchases.

Power Services QBR Analysis: FY22 Results

(Note: Variance explanations are for +/-$2M or greater)

Integrated Program Review Operating Expenses:

Row 7: Asset Management: came in at $33.3M below rate case due to the following: Corps of Engineers, Columbia Generating Station, Bureau of Reclamations, and F&W all coming in under budget due to project delays and supply chain issues. Lastly, the Nuclear Electric Insurance Limited (NEIL) rebate Energy Northwest received at the end of March further reduced costs.

Row 8 – Operations: came in at $16M below rate case mainly due to a ~$4M reduction in the Conservation Infrastructure program to better align with the firm fixed pricing that the Energy Efficiency program has negotiated. In addition, Renewable Power Purchases came in under budget due to wind generation. Also contributing to this were reductions in personnel cost and service contracts.

Row 9 - Commercial Activities: came in at $18.7M below rate case due to lower Conservation Purchases from BPA's Energy Efficiency Program. The rate at which utilities submitted claims for Energy Efficiency Incentive reimbursement has been lower than the seasonal average for year 1 of the past 4 rate periods. BPA also had a soft launch for BEETS, a new invoicing software, so some of the utilities involved in the pilot held their claims until they could enter into BEETS. Also, contributing to this is lower Enterprise Services direct charging into Power.

Row 10 – Enterprise Services: came in at $10.5M above rate case the main drivers include: Enterprise Services costs are rising from the new Chief Workforce and Strategy Office, which was not anticipated in the rate case. Also, there are expected increases in IT costs such as conference room retrofitting for hybrid meetings, and less direct charging than assumed in rate case.

Power Services QBR Analysis: FY22 Results

(Note: Variance explanations are for +/-$2M or greater)

Non-Integrated Program Review Operating Expenses:

Row 16 – Commercial Activities: came in at $266M higher than rate case due to Power Purchases (short term) coming in $375.5M higher than rate case. The increase in power purchase was mainly driven by the colder than expected conditions which, increased load and decreased hydro generation from snowmelt during the spring months. The increased power purchase expense during the spring were caused by increased prices reflecting the relative scarcity of generation in the markets prompted by the delayed generation. Partially offsetting this expense increase was no Tier 2 power purchases and lower spending from the Energy Efficiency Development program.

Row 19 – Depreciation, Amortization & Accretion: Amortization is $3.6M above rate case due to placing more regulatory assets in service compared to rate case assumptions.

Row 23 - Interest Expense: interest expense is $10.5M lower due to the following:

- Overall lower Non-Federal interest expense is $15.0M lower primarily due to the premium amortization of $18.0M from the FY21 and FY22 bond transactions that was not anticipated in the rate case. This is partially offset by a $3.0M increase in interest expense based Energy Northwest's budget true-up for their FY22, which ended on June 30.
- Offset by higher Federal Interest which is $4.5M higher due to a higher appropriation balance outstanding compared to rate case expectations resulting in a $2.6M variance, as well as new federal bonds issued at higher rates than anticipated contributing $2.0M to the variance.

Row 25 – Interest Income: increased interest income of $5.4M is due to much larger cash balances invested at higher interest rates than anticipated in the rate case.

Row 26 – Other Income, net: $7.1M higher than rate case due to a $2.0M non-cash gain on the extinguishment of Energy Northwest debt combined with higher than expected recognized gains ($5.1M) on the Columbia Generating Station Decommissioning trust fund driven primarily by dividends.

Row 28 – Total Net Revenues: came in at $859 million, which is $724 million greater than rate case. This increase is caused by higher than expected operating revenues.

Report ID: 0123FY22
Requesting BL: Transmission Business Unit
Unit of Measure: $ Thousands

QBR Forecast Analysis: Transmission Services
Program Plan View
Through the Month Ended September 30, 2022
Preliminary / Unaudited

Data Source: PFMS
Run Date/Time: October 15, 2022 / 09:57
% of Year Elapsed = 100%

		A	B	C
		FY 2022		FY 2022
		Rate Case	Actuals: FYTD	EOY Actuals - Rate Case
	Operating Revenues			
1	Sales	$ 991,201	$ 1,070,446	$ 79,245
2	Other Revenues	44,956	47,540	2,584
3	Inter-Business Unit Revenues	126,731	131,972	5,241
4	**Total Operating Revenues**	**1,162,889**	**1,249,958**	**87,069**
	Operating Expenses			
	Integrated Program Review Programs			
5	Asset Management	286,951	294,401	7,451
6	Operations	64,284	67,336	3,052
7	Commercial Activities	56,470	54,337	(2,132)
8	Enterprise Services G&A	103,195	121,778	18,583
9	Undistributed Reduction	-	-	-
10	Other Income, Expenses and Adjustments (IPR O&M)	-	-	-
11	**Sub-Total Integrated Program Review Operating Expenses**	**510,899**	**537,853**	**26,953**
	Operating Expenses			
	Non-Integrated Program Review Programs			
12	Commercial Activities	112,521	125,628	13,106
13	Other Income, Expenses and Adjustments (Non-IPR O&M)	-	(1,252)	(1,252)
14	Depreciation & Amortization	352,384	338,768	(13,616)
15	**Sub-Total Non-Integrated Program Review Operating Expenses**	**464,905**	**463,143**	**(1,762)**
16	**Total Operating Expenses**	**975,805**	**1,000,996**	**25,191**
17	**Net Operating Revenues (Expenses)**	**187,084**	**248,961**	**61,878**
	Interest expense and other income, net			
18	Interest Expense	161,283	159,113	(2,170)
19	AFUDC	(15,937)	(14,773)	1,164
20	Interest Income	(3,135)	(3,714)	(579)
21	Other income, net	-	-	-
22	**Total interest expense and other income, net**	**142,210**	**140,625**	**(1,585)**
23	**Total Expenses**	**1,118,015**	**1,141,621**	**23,606**
24	**Net Revenues (Expenses)**	**$ 44,873**	**$ 108,336**	**$ 63,463**

Transmission Services QBR Analysis: FY22 Results

(Note: Variance explanations are for +/-$2M or greater)

Operating Revenues:

Row 1 – Sales: $79 million above rate case primarily driven by increased Conditional Firm Long-term Point-to-Point, Point-to-Point Short-term, Southern Intertie Short-term, Scheduling, System Control & Dispatch, and Network Integrated Transmission Service sales.

Row 2 – Other Revenues: $3 million above rate case primarily due to penalty and misc. revenues.

Row 3 – Inter-Business Unit Revenues: $5 million above rate case primarily due to an increase in short-term sales.

Integrated Program Review Operating Expenses:

Row 5 – Asset Management: $8 million above rate case primarily driven by a reprioritization in Transmission departmental program spending, cost shifts from capital to expense, increased wildfire mitigation costs, increased costs related to compliance workload, and increased personnel costs driven by compensation higher than forecast in the rate case.

Row 6 – Operations: $3 million above rate case primarily due to increased personnel costs driven by compensation higher than forecast in the rate case

Row 7 – Commercial Activities: $2 million below rate case resulting from Transmission departmental spending shifting to the Asset Management program and Corporate departmental spending shifting to Enterprise Services G&A and other Programs.

Row 8 – Enterprise Services G&A: $19 million above rate case primarily driven by less direct charging than assumed in rate case, a termination of the direct support allocations, an increase in the Additional Post-Retirement Payment, increased funding for security and COVID testing, and an increase to fund the new Chief Workforce & Strategy Organization.

Transmission Services QBR Analysis: FY22 Results

(Note: Variance explanations are for +/-$2M or greater)

Non-Integrated Program Review Operating Expenses:

Row 12 – Commercial Activities: $13 million above rate case due primarily to EIM Entity Scheduling Coordinator (EESC) expenses which were not forecast in the rate case, these expenses are offset by increased revenues related to customer sub-allocations of these EESC expenses which results in a net impact of a $2m reduction to Transmission Net Revenue.

Row 14 – Depreciation and Amortization: $14 million lower than rate case based on lower Transmission Capital and Plant-in-Service than forecast in the rate case, which is partially offset by increased Amortization expense resulting from the lease accounting transition in FY20.

Row 18 – Interest Expense: $2 million lower than rate case primarily driven by the FY21 $300M Lease Purchase bond transaction closing at approximately 1% lower than assumed.

Agency Capital Expenditures: FY22 EOY Results

	Thousands $	Rate Case	Actuals	Actuals - Rate Case	Actuals/ Rate Case
	Transmission Business Unit				
1	EXPAND/SUSTAIN	312,000	289,550	(22,450)	93%
2	PFIA	45,000	26,152	(18,848)	58%
3	SECURITY	8,000	330	(7,670)	4%
4	FLEET	10,000	7,625	(2,375)	76%
5	IT	8,000	2,958	(5,042)	37%
6	FACILITIES	53,200	38,947	(14,253)	73%
7	ENVIRONMENT	5,580	6,298	718	113%
8	LOADINGS	115,369	125,240	9,871	109%
9	**TOTAL Transmission Business Unit**	557,149	497,100	(60,049)	89%
	Power Business Unit				
10	FED HYDRO	264,120	180,374	(83,746)	68%
11	F&W	43,000	16,119	(26,881)	37%
12	IT	4,300	762	(3,538)	18%
13	FACILITIES	-	1,002	1,002	-
14	AFUDC	10,823	9,966	(857)	92%
15	**TOTAL Power Business Unit**	322,243	208,224	(114,019)	65%
	Corporate Business Unit				
16	IT	7,628	15,367	7,739	201%
17	AFUDC	182	663	481	364%
18	**TOTAL Corporate Business Unit**	7,810	16,030	8,220	205%
19	**Total BPA Capital Expenditures**	887,202	721,354	(165,848)	81%

Agency Capital Expenditures: FY22 EOY Results

(Note: Variance explanations are for +/-$2M or greater; all numbers are loaded)

Transmission Business Unit

Row 1 – Expand/Sustain: $22 million below rate case primarily due to concerns around supply chain and resourcing issues. However, $290 million in actuals is an increase from the Q3 forecast due to strong performance in the Control Center projects, Grid Mod, and Line Ratings programs.
Row 2 – PFIA: $19 million below rate case due to contracting delays, customer requests to delay/cancel projects, supply chain, and resourcing issues.
Row 3 – Security: $8 million below rate case due to contracting delays for Sno-King and Tacoma substation security fence projects.
Row 4 – Fleet: $2 million below rate case due to supply chain disruptions and market instability that pushed manufacture and delivery of equipment to FY23.
Row 5 – IT: $5 million below rate case due to focus on Corporate IT projects for Grid Mod, EIM, and Enterprise budgeting and forecasting.
Rows 6 – Facilities: $14 million below rate case to account for supply chain disruptions on the TSB, Fuel Island and Ross HazMat building projects which are limiting materials and delaying delivery of equipment. The VCC building project also saw a decrease as Phase 1 was extended by one quarter to incorporate technology requirements that pushed spending out of FY22 and into future years.
Row 8 – Loadings: $10 million above rate case due to higher transmission and corporate indirects.

Power Business Unit

Row 10 – Fed Hydro: $84 million total below rate case due to COVID supply chain issues, labor constraints, and contracting setbacks for both the Bureau and Army Corps.

-Bureau of Reclamation: $24 million below rate case
-Army Corps of Engineers: $60 million below rate case

Row 11 – Fish and Wildlife: $27 million below rate case due to delays in hatchery projects and land purchases as well as coming in under budget by approximately $4 million on the Steigerwald reconnection project.

Row 12 – Power IT: $4 million below rate case due to focus on Corporate IT projects for Grid Mod, EIM, and Enterprise budgeting and forecasting.

Corporate Business Unit

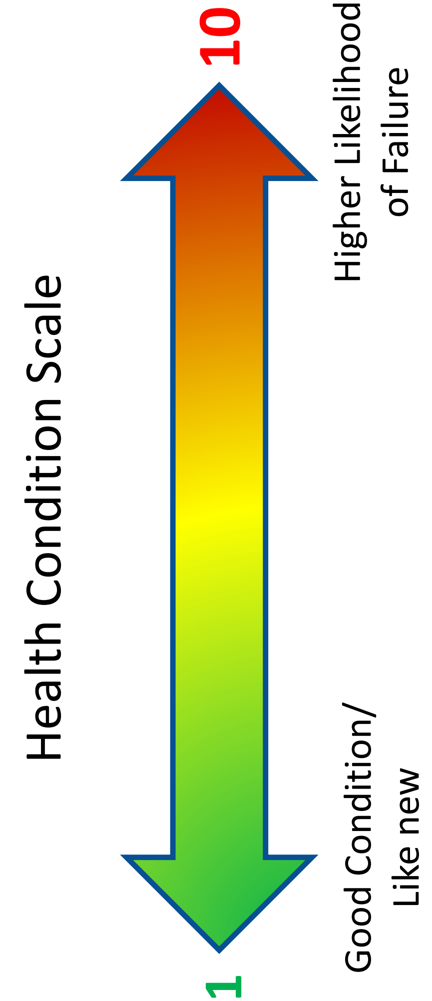
Row 16 – Corporate IT projects: $8 million above rate case due to focus on Corporate IT projects including Grid Mod, EIM and Enterprise budgeting and forecasting projects. Across business units the agency IT budget ended less than $1 million below rate case.

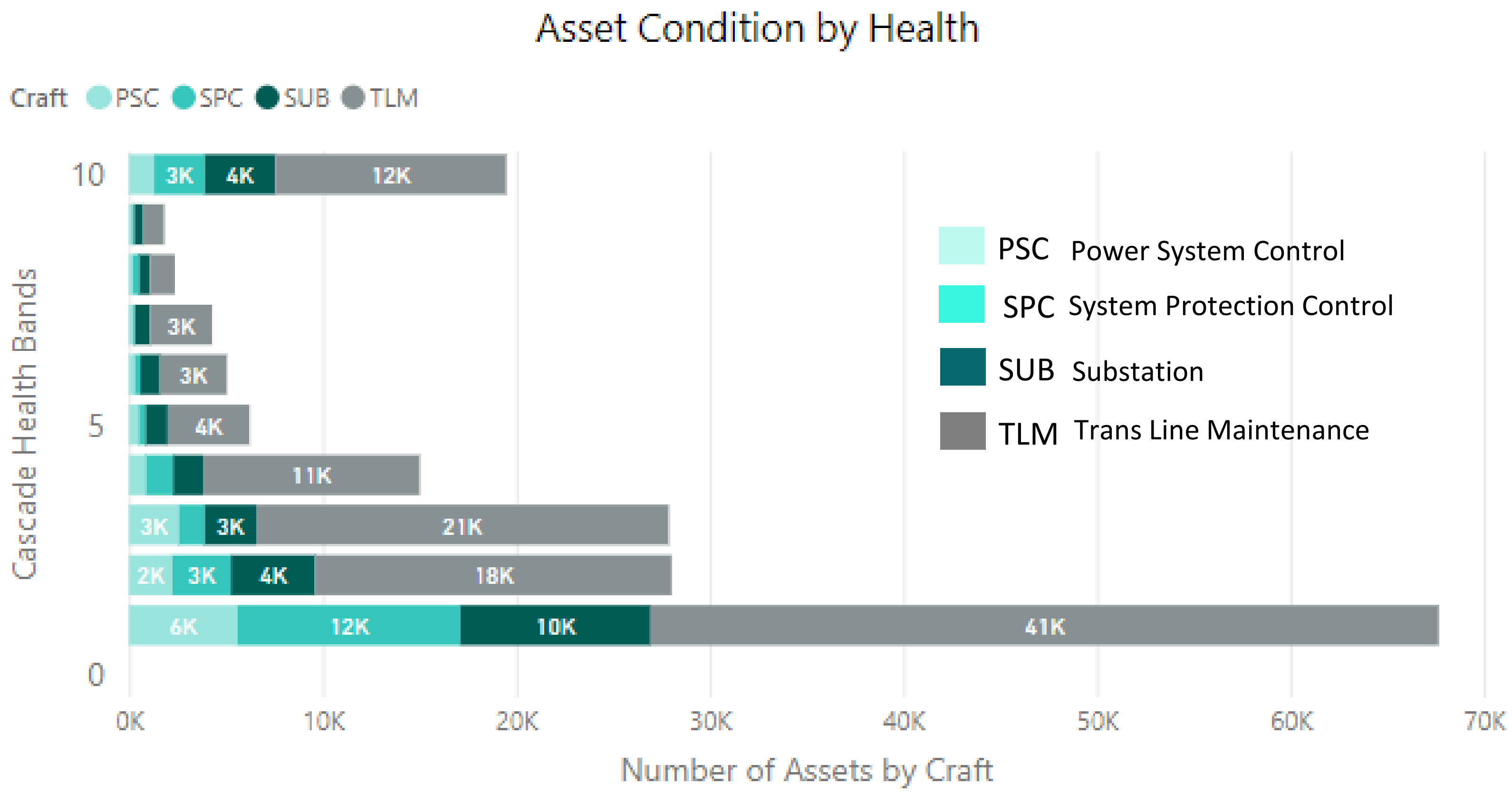
Transmission Capital Metrics

Jeff Cook and Mike Miller

#1 STRENGTHEN FINANCIAL HEALTH

Asset Management Health Metric



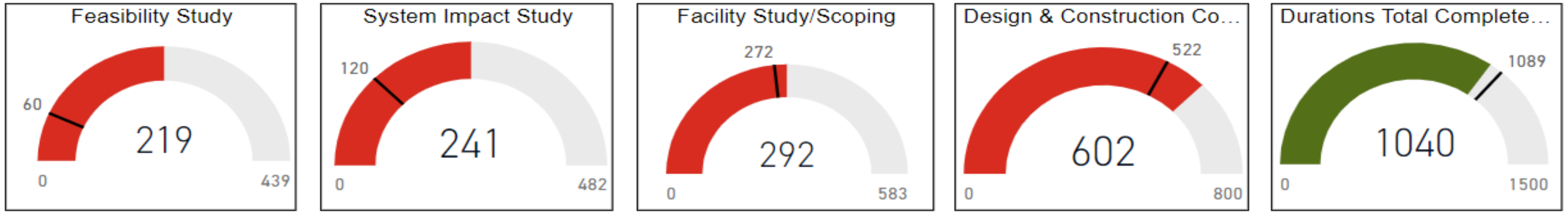


***Transmission is defining its population of critical assets as assets represented in Transmission's sustain program. The definition of critical assets will continue to evolve as we get further into the Asset Hierarchy effort.

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.

Customer Duration Metric

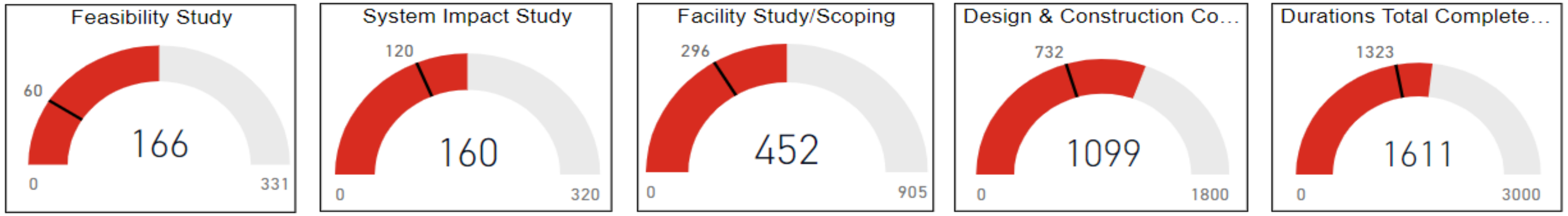
Small Projects: Line tap, ratings upgrade, minor equipment or communications gear



Includes LGI, LLI, SGI projects with a Queue date on or after 1/1/2016

*123 Days *222 Days *212 Days

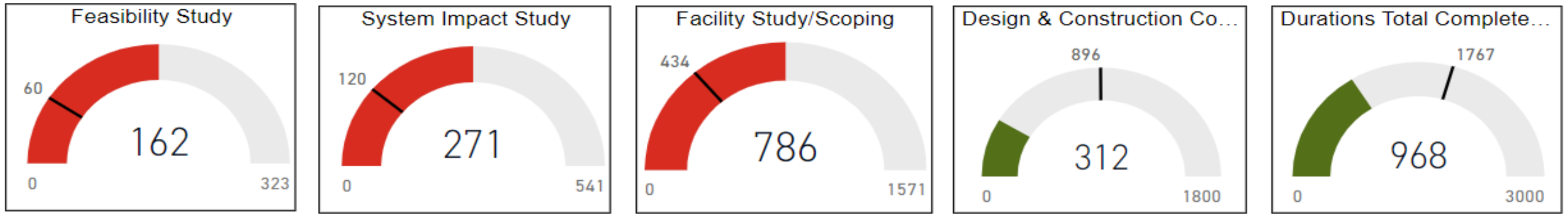
Medium Projects: bay addition, breaker addition, line loop, transformer, disconnect - major equipment



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

*123 Days *146 Days *554 Days

Large Projects: New substation, new line (BPA build), new line plus generation interconnection.



Includes LGI, LLI, SGI projects with a Queue date on or after 1/1/2016

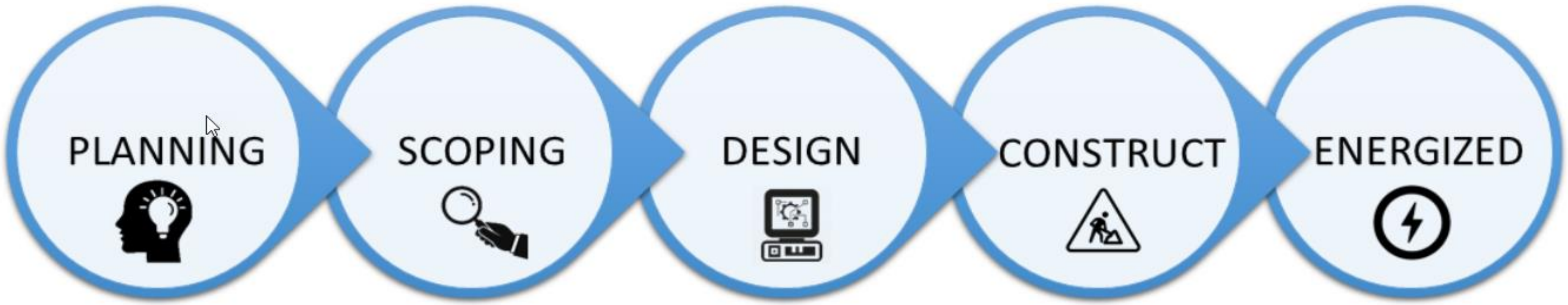
*148 Days *249 Days *563 Days

Primary vs Secondary Capacity Throughput

Transmission as of FY22 Q4:

PRIMARY VS SECONDARY CAPACITY THROUGHPUT – CURRENT FY

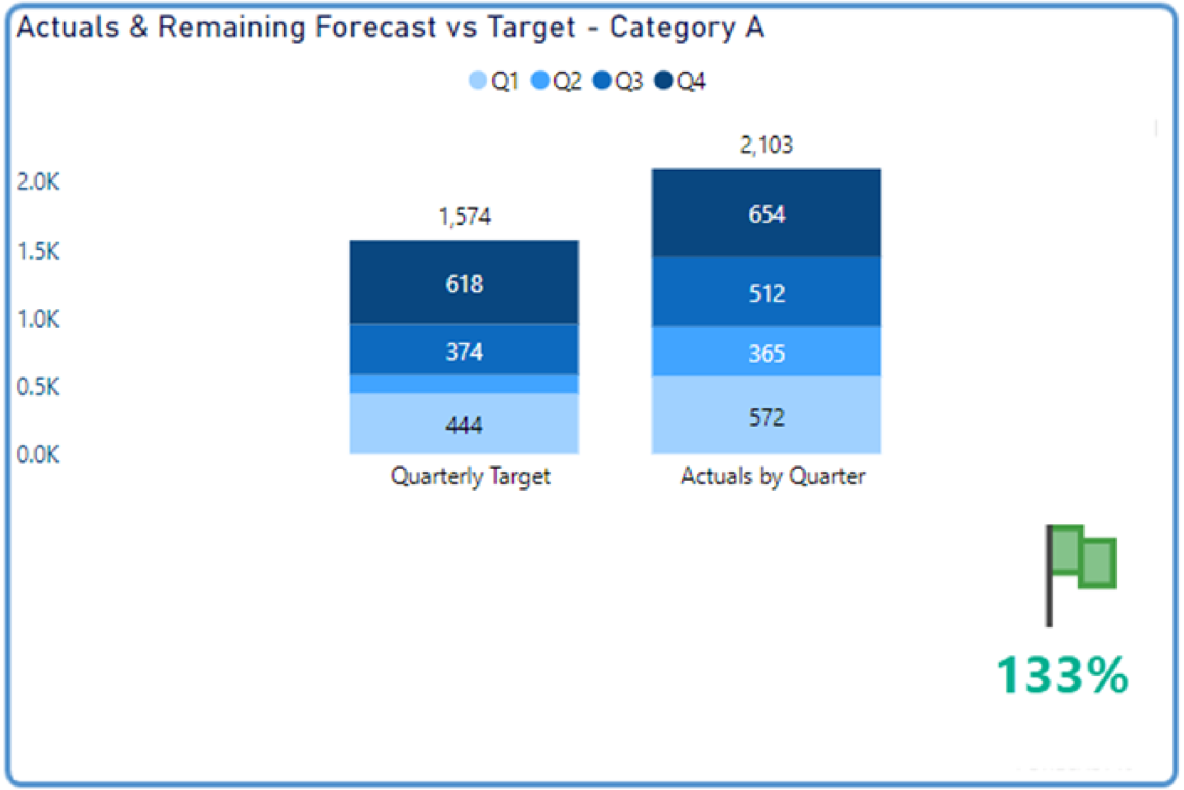
FY22

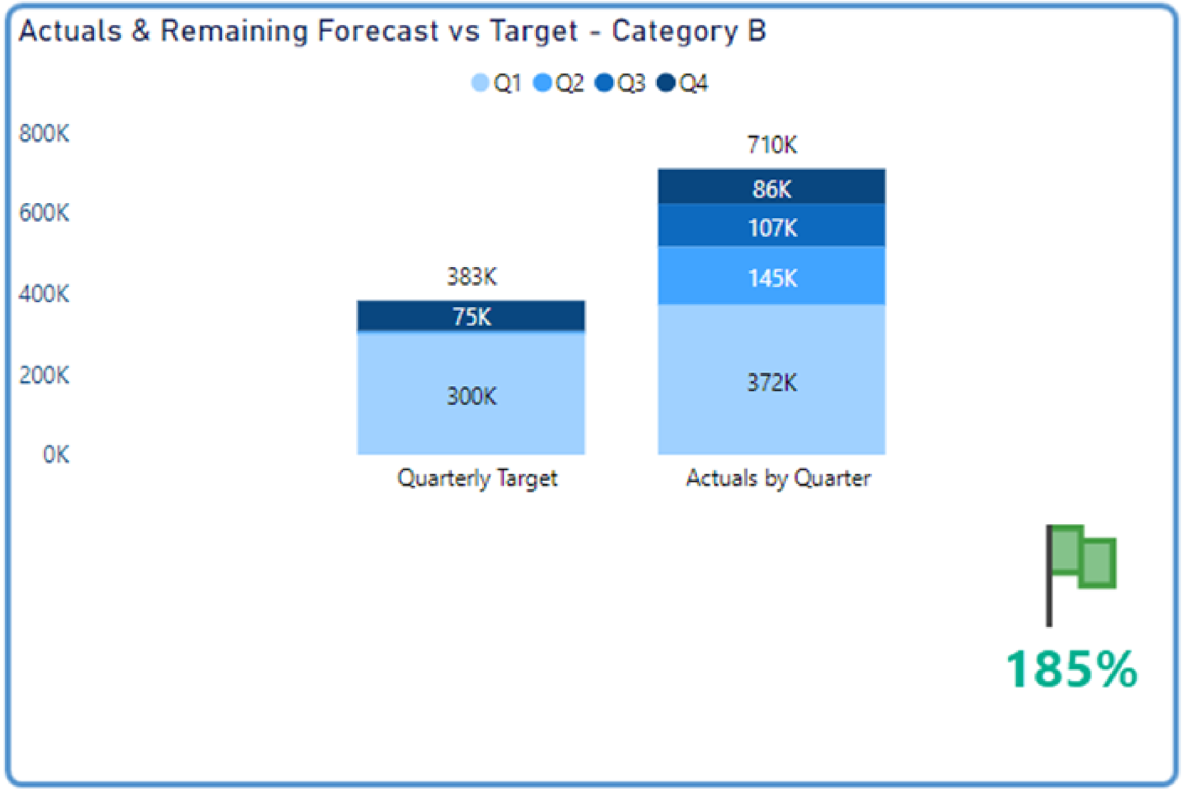


	PLANNING	SCOPING	DESIGN	CONSTRUCT	ENERGIZED
PRIMARY CAPACITY MODEL	267	78	171	134	152
SECONDARY CAPACITY MODEL	0	28	11	0	0

Capital Assets Planned vs Completed

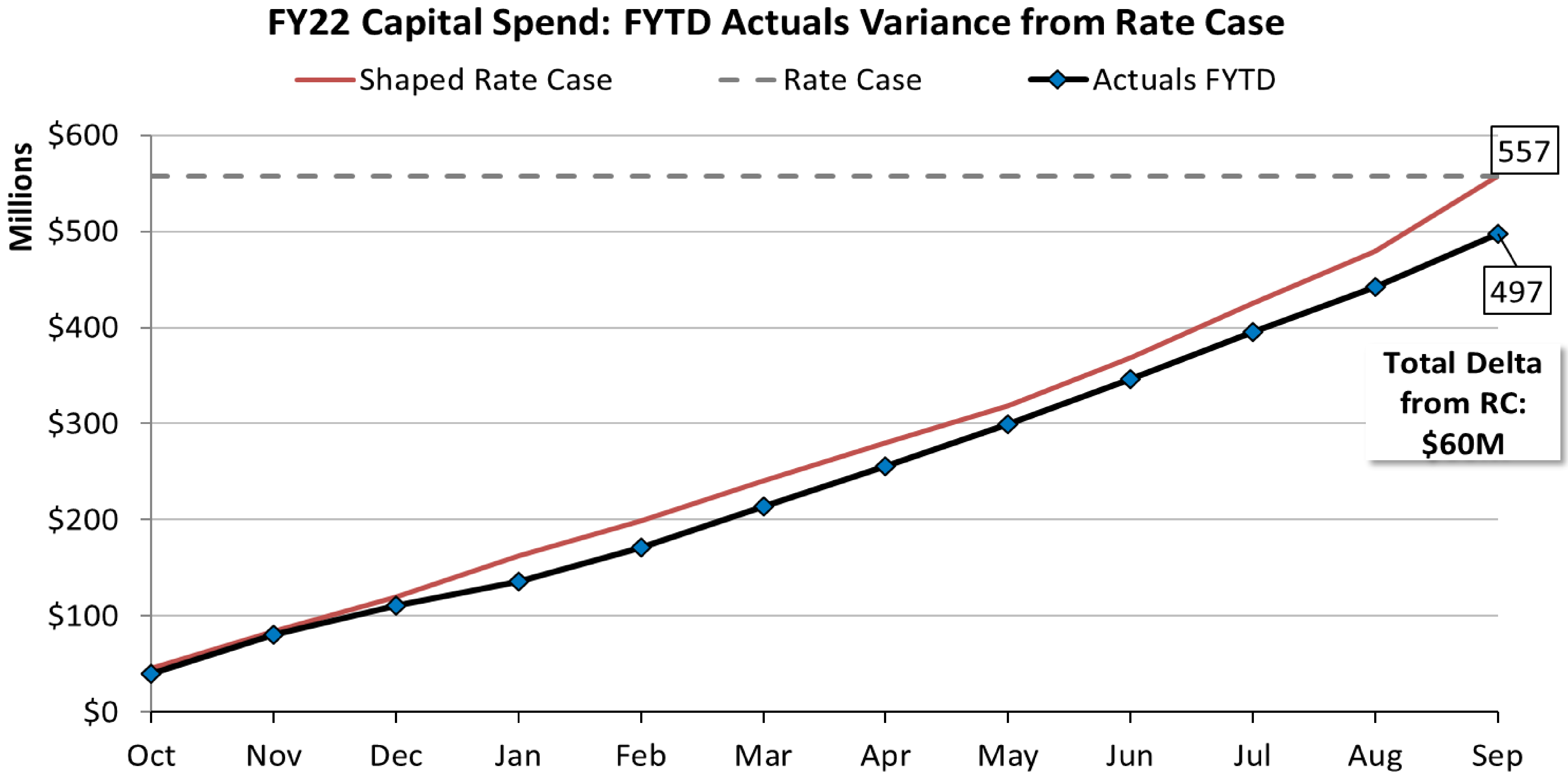
Transmission as of FY22 Q4:





Ended the year at 133% of Category A assets complete and 185% of Category B assets complete.

Capital Spend



Reserves & Reserves Distribution Clause Agenda

- Refresh on the Reserves Distribution Clause (RDC) process
- Share FY22 EOY Reserves for Risk (RFR) results by business unit
- Review Power and Transmission RDC calculations
- Share preliminary proposals for the Power and Transmission RDC amounts
- Share the Dividend Distribution application and effect
- Next steps:
    - BPA welcomes comments through December 1, 2022. Please submit your comments at Public Comments (bpa.gov).
    - BPA will announce its determination for applying the RDC amounts no later than December 15, 2022, with Tech Forum notice.

Reserves Distribution Clause Process

- The RDC is a component of the Financial Reserves Policy. When reserves decline below certain thresholds, rates increase through the FRP Surcharge and CRAC. The RDC determines when financial reserves are sufficiently high 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 RDC process and requirements. The language is the same for both business units and states:

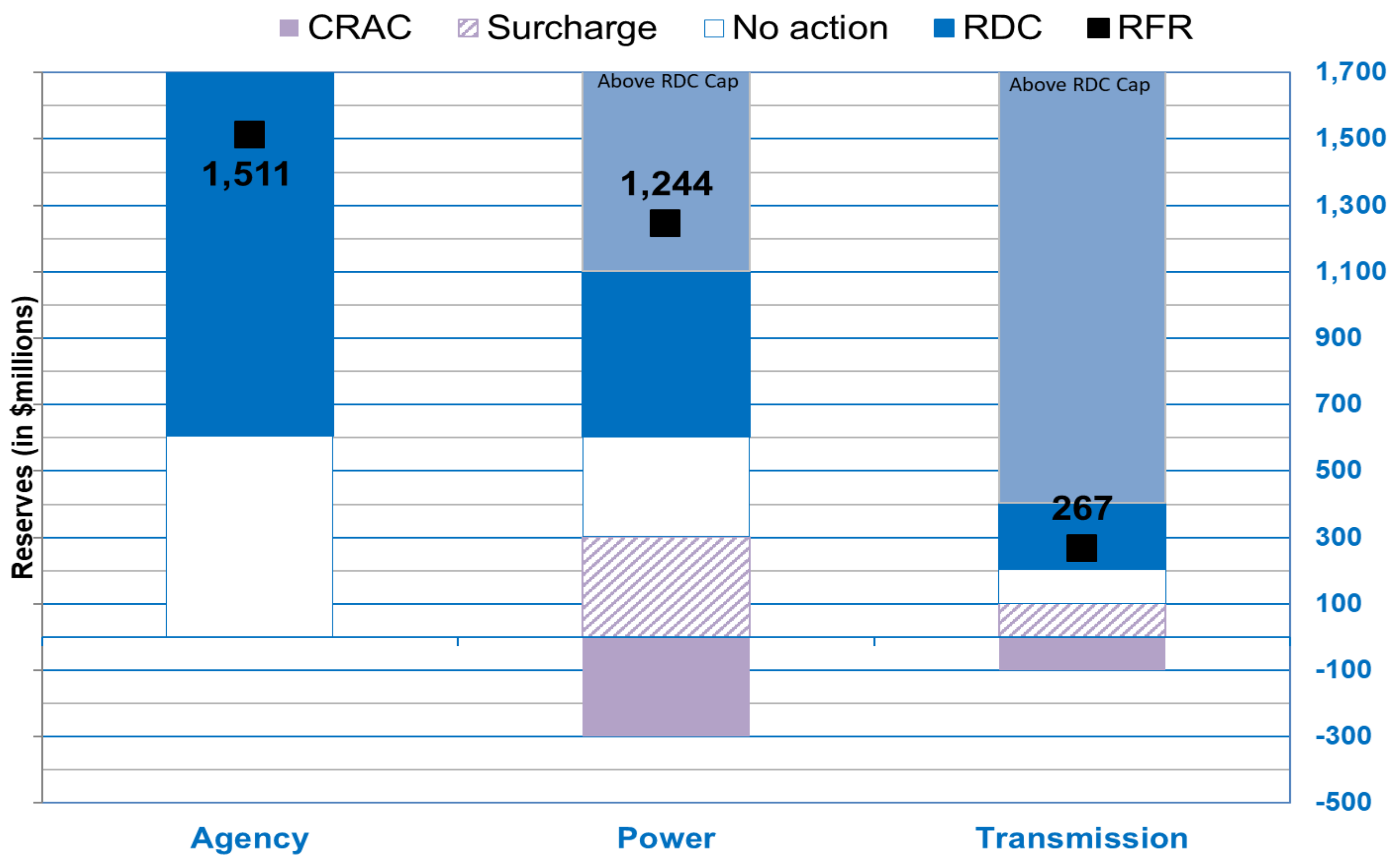
  By November 30, 2022, BPA shall complete the calculation of Power/Transmission RFR and BPA RFR as of the end of FY 2022, for use in calculating the Power/Transmission RDC applicable to rates for December through September of FY 2023.

  If the Power/Transmission RDC triggers, BPA will notify customers of the preliminary Power/Transmission RDC Amount and whether the amount will be used to reduce debt, incrementally fund capital projects or other high-value Power/Transmission purposes, or reduce rates, 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 RDC Amount.

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

- At today's meeting, we will cover: RFR amounts; the RDC calculation and resulting RDC amounts; the preliminary proposal on RDC use and DD credit information; and details on the comment period.

FY 2022 Reserves Policy Thresholds and Reserves for Risk



Days Cash	233	267	147

Power and Transmission FY 2022 RDC

- The FY 2022 EOY RFR levels for Power and Transmission result in the Reserve Distribution Clause triggering for each business unit (BU). The RDC triggers for ***the lesser of***:
  - The amount Agency RFR is over the Agency Threshold, set at $605.0M, equivalent of 90 Days Cash on Hand (DCOH).
  - The amount BU RFR is over its Threshold, set at the equivalent of 120 DCOH, which is: $603.0M for Power and $204.0M for Transmission.
  - Further, the RDC is capped for each BU: Power cap = $500.0M; Transmission cap = $200.0M.
- This calculation results in RDCs for each BU as shown below.

	Power RDC		Transmission RDC	
(in millions)	Agency	Power	Agency	Transmission
Actual RFR	$1,511.5	$1,244.3	$1,511.5	$267.1
RDC RFR Threshold	$605.0	$603.0	$605.0	$204.0
Amount above Threshold	$906.5	$641.3	$906.5	$63.1
RDC with Cap (if applicable)	**Power RDC = $500.0**		**Transmission RDC = $63.1**	

Reserve Distribution Clause Application

- The RDC application options are outlined in the Financial Reserves Policy, which is Appendix A of the BP-22 Final Proposal Power and Transmission Risk Study. The policy notes:
  - *3.4.1 Financial Reserves Distributions:* If business line financial reserves and agency financial reserves are above their respective upper thresholds, the Administrator shall consider the above-threshold financial reserves for investment in other high-value business line-specific purposes including, but not limited to, debt retirement, incremental capital investment, or rate reduction.

- The Power and Transmission GRSPs also outline the RDC application: If the Power/Transmission RDC quantitative criteria are met, the Administrator will calculate the Power/Transmission RDC Amount, and determine what part, if any, will be applied to debt reduction, incremental capital investment, rate reduction through a Power/Transmission Dividend Distribution (DD), distribution to customers, or any other Power- or Transmission-specific purposes determined by the Administrator.

Power RDC Application: Preliminary Proposal

- The Power RDC amount = $500.0M
- The preliminary proposal for applying the Power RDC is consistent with a tentative settlement agreement for BP-24.
- The preliminary proposal is to apply:
  - 70% toward rate reduction, equivalent to a $350.0M dividend distribution for FY 2023
  - 20% toward debt reduction or revenue financing, equivalent to an additional $100.0M in FY 2023, with any amount not used to reduce debt or revenue finance left as financial reserves to support Bonneville's liquidity and/or increase the probability of a 2023 Power RDC Amount;
  - 10% toward addressing, on an accelerated, one-time basis, certain non-recurring maintenance needs of existing fish and wildlife mitigation assets that (i) Bonneville anticipates would otherwise need to be addressed during future rate periods and (ii) will result in avoidance of those costs in future rate periods, equivalent to $50.0M for various project spending

Power Dividend Distribution Credit Rate

	A	B	C	D	E	F
1	*(a) Power DD Credit Rate:*					**FY2023**
2		Power RDC Amount being used for a Power DD:				$350,000,000
3		Sum of Dec - Sept Billing Determinants (MWh):				36,461,402
4		Power DD Credit rate ($/MWh):				**$9.60**
5						

- Under the preliminary proposal, the preliminary FY 2023 Power Dividend Distribution (Power DD) credit rate is 9.60 mills per kilowatt-hour and is equal to the preliminary Power RDC Amount being proposed for a Power DD divided by the sum of forecast billing determinants for December 2022 – September 2023.

- The Power DD Credit rate is calculated in accordance with the 2022 Power Rate Schedules and General Rate Schedule Provisions (GRSP section II.P.2) and would be used to bill PF and IP customers. The rate would also be used to adjust the December 2022 – September 2023 PF Tier 1 equivalent energy rates.

- For PF customers, the Power DD Credit rate would be applied to the sum of each customer's HLH and LLH System Shaped Load, multiplied by -1, for December 2022 – September 2023. A customer's System Shaped Load is equal to its non-Slice TOCA multiplied by the RHWM Tier 1 System Capability (RT1SC).

- For IP customers, the Power DD Credit rate would be subtracted from the December 2022 – September 2023 IP rates and will be applied to an IP (DSI) customer's actual load.

Annual Power DD Credit Rate

	A	B	C	D	E	F
1	*(c) Annual Power DD Credit Rate and Other Adjustments:*					**FY2023**
2		Power RDC Amount being used for a Power DD:				$350,000,000
22		Sum of Annual Billing Determinants (MWh):				44,187,877
23		Annual Power DD Credit Rate ($/MWh):				**$7.92**
24						
25		Adjusted Load Shaping Charge True-Up rate:				$1.81
26		Adjusted PF Melded Equivalent Energy Scalar rate:				$2.14

- Under the preliminary proposal, the preliminary FY 2023 Annual Power DD credit rate is 7.92 mills per kilowatt-hour and is equal to the preliminary Power RDC Amount being used for a Power DD divided by the sum of forecast billing determinants for FY 2023.
- The annual rate is used to adjust the Load Shaping Charge True-Up rate and the PF Melded Equivalent Energy Scalar rate (which is used in the actual DSI revenue credit calculation in the Slice True-Up.)
- The annual rate is not used to bill monthly Power DD Credit amounts.
- The full rate adjustment calculation with customer bill estimates can be found on bpa.gov, here: Rate Adjustments - Bonneville Power Administration (bpa.gov)

Transmission RDC Application: Preliminary Proposal

- The Transmission RCD amount = $63.1M.
- The preliminary proposal for the Transmission RDC amount is to apply about 50% for rate reduction and to hold about 50% to cover FY 2023 forecast increased costs due to inflationary pressure.
- The preliminary proposed is consistent with a tentative settlement to hold BP-24 Transmission rates flat. The current estimate of the amount needed to hold BP-24 rates flat for the 2-year rate period = $16.6M.
- The preliminary proposal is to apply:
  - Rate reduction = $29.3M
    - ~$16.6M to hold BP-24 rates flat
    - ~$12.7M for Transmission Dividend Distribution, applied in FY 2023
  - Hold to cover Transmission’s forecast cost increase in FY 2023 = $33.8M

Transmission Forecast Cost Pressure

- BPA conducted an extensive budget process to ensure budgets were only increased for costs which BPA was unable to absorb or control.
- BPA increased the Transmission Business Unit's FY 2023 budget by $33.8M to address targeted areas which have increased significantly above the Integrated Program Review Operating Expense forecast used in the BP-22 Rate Case:
  - The predominant cost pressure - Federal personnel costs (salaried employees, hourly craft and trade employees) have increased significantly as a result of inflation related to Cost of Living Increases (COLAs) and benefits.
  - Other areas of cost pressure - insurance premiums and security costs.
  - Cost management discipline has been and will continue to be at the forefront for BPA. Strict cost management must be balanced with the reality of the funding needed to continue with critical work.
- Applying some of the RDC to fund these areas would provide certainty for the source of funding; and helps ensure BPA does not slow down completing critical work or that our current level of service is not degraded. Should Transmission revenues come in higher than anticipated in the Rate Case, this may position the Transmission business unit for an RDC based on FY 2023 results as well.

Transmission Dividend Distribution Credit

1	(a) Transmission DD Credit Percentage:	FY2023
2	Transmission DD Amount ($000):	12,700
3	Sum of Dec - Sept Revenue Forecast ($000):	884,285
4	Transmission DD Credit Percentage:	1.44%
5	Subtracted from 1:	**98.56%**

- Under the preliminary proposal, the preliminary FY 2022 Transmission Dividend Distribution (Transmission DD) credit percentage is 1.44%. This is calculated in accordance with the 2022 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions (GRSP section II.H.1.b) by dividing the Transmission DD Amount by the sum of the Dec to Sept Revenue forecast for FY23.
- Revised rates are calculated by subtracting the Transmission DD Credit Percentage from 1.0, and then multiplying by the applicable rates. These revised rates will be used to bill NT-22, PTP-22, FPT-22.1, IS-22, Scheduling Control and Dispatch (ASC-22), Utility Delivery rate (GRSPs Section II.A.1.b) and IM-22. The revised rates will apply to December 2022 – September 2023.
- The full rate adjustment calculation can be found on bpa.gov, here: Rate Adjustments - Bonneville Power Administration (bpa.gov).

Next Steps

- BPA welcomes comments through December 1, 2022. Please submit your comments at Public Comments (bpa.gov).
- If you have questions, please contact us at Communications@bpa.gov and cc your AE with the Subject: *RDC comments.*
- BPA will announce its determination for applying the RDC amounts no later than December 15, 2022, with Tech Forum notice.

Grid Modernization Update

Grid Modernization Mobilization

Updated: 11.08.2022
Date = Completion Date

Identify
0%

Define
8%

- AMS MRU Device Event Reporting – 09.30.2023
- Power Ops Log Replacement – 09.30.2023
- MCIT – Re-Platforming – 10.01.2024

Integrate
3%

- Wildfire Risk Modeling – 08.01.2024

Deliver
49%

- Agency Enterprise Portal – 10.10.2022
- AGC Modernization – 09.30.2023
- AMS Replacement – 07.10.2023
- AOP & Reliability Assessment – 03.25.2025
- BPA Network Model – 12.31.2023
- CBC Replacement – 10.30.2023
- Concurrent Losses – 09.30.2023
- Data Analytics – 12.31.2022
- EIM Bid & Base Scheduling – 06.30.2023
- EIM Settlements Implementation – 09.30.2023
- EIM Testing Program – 09.30.3023
- FDGDM – 12.29.2023
- Load & Renewable Forecasting – 10.01.2022
- Metering Review & Update – 09.27.2024
- MCIT – Infrastructure – 06.30.2023
- Outage Management System – 06.23.2023
- PRADA – 09.30.2023
- Sub-Hourly Scheduling on the DC – 03.01.2023

Complete
40%

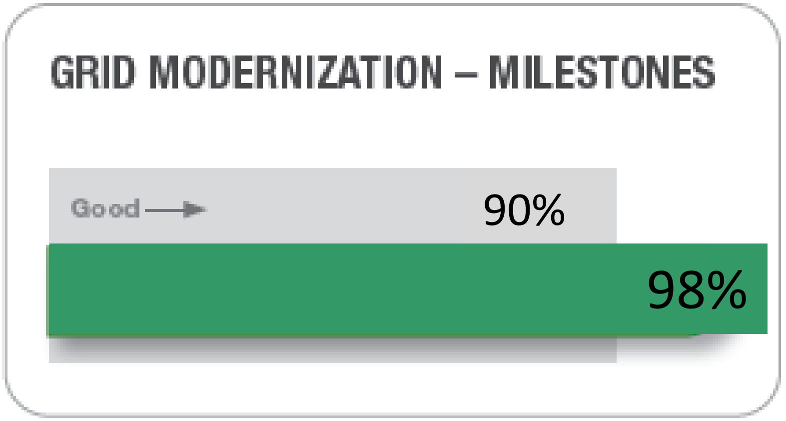
- CTA Implementation – 06.30.2019
- EIM Real Time Operations – 08.10.2022
- EIM Settlements Scoping – 10.01.2019
- EIM Training Program – 08.31.2022
- ETRM & MMS Expansion – 05.13.2020
- Marketing & Settlements System – 06.30.2018
- MCIT – Architecture – 04.22.2020
- MCIT – Integration – 09.30.2020
- MCIT – Service Management – 04.29.2020
- One BPA Outage – 02.28.2020
- Outage Tracking System - 09.30.2018
- Power Services Training – 12.31.2020
- RAS Automatic Arming – 08.11.2021
- RC Decision, Planning & Exec. – 07.14.2021
- ST Available Transfer Capability – 07.20.2022

Deferred

- Real Time Ops Modernization – 09.14.2022
- AEP 2 – 9.28.2022

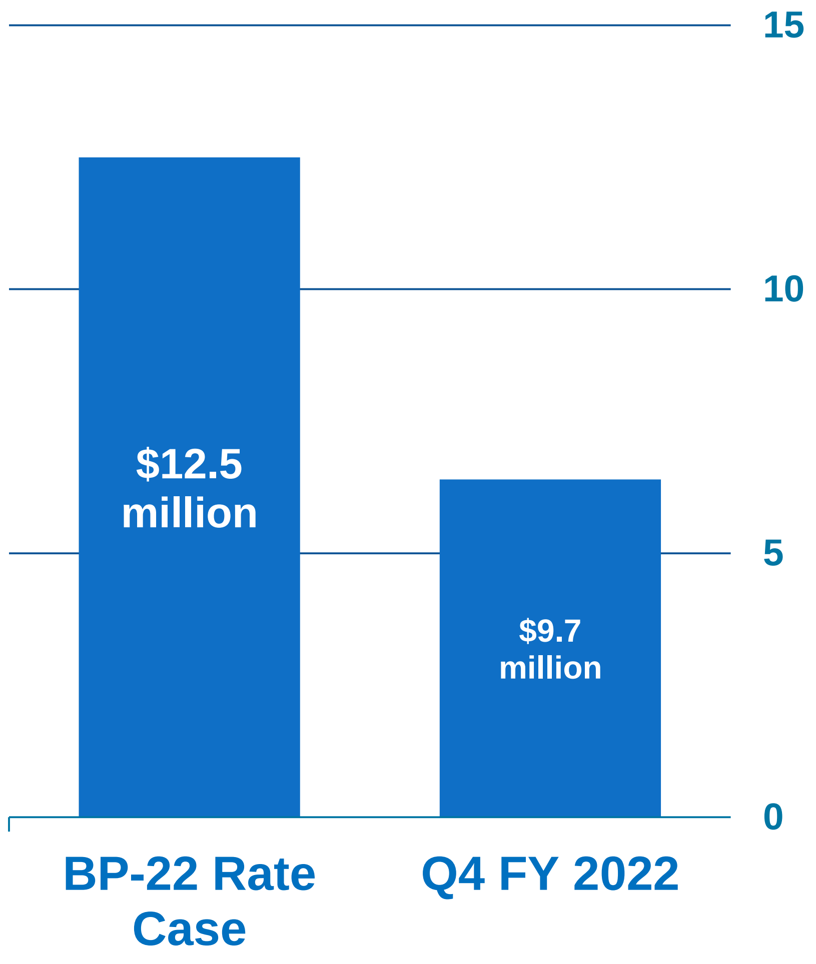
Grid Modernization Progress Metric

Key Strategic Initiative:



- 98% of milestones for projects in deliver are complete or on track
- The minimum to meet “green” for Q4 FY22 is 90%
- **Status:** Green

Grid Mod FY22 Spending



- In Q4 FY22, BPA spent a total of $9.7 million out of a total $12.5 million BP-22 Rate Case budget

EIM Metrics

External Reporting Background

- In the Final EIM Close out letter, BPA committed to work with customers to develop metrics.
- This collaboration took place at stakeholder workshops in FY21 and FY22.
- At the January 27, 2022 workshop, BPA committed to two phases of metrics.

Phase 1 Metrics

1. Provide the quantity of unspecified purchases made through the EIM. BPA will also consider a metric on the amount delivered to California and the associated premium/costs.
2. Provide how frequently BPA passes the Resource Sufficiency (RS) balancing test, RS capacity test and RS flexibility test.
3. Provide data on EIM transfer limits and use.
4. Provide summary data on BA scheduling error and the frequency with which CAISO BA forecast was targeted on a quarterly basis. The scheduling error will be measured against either the CAISO BA forecast and/or actual load. BPA will collect and share data on how the BA did as a whole with every entity scheduling to their own best forecast. **Note that the scheduling error relative to the CAISO forecast is included in the Balancing Test results.**

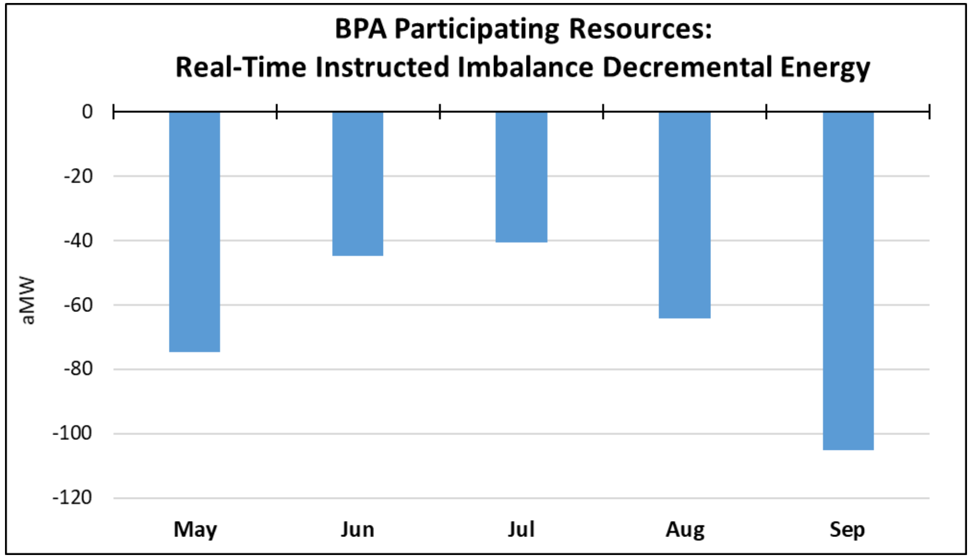
- BPA committed to reporting on Phase 1 metrics within six months of EIM go-live (November 2022 QBR Technical Workshop).

Phase 2 Metrics

1. Provide data on charge code allocations.
2. Provide data on transmission donations and how often they are used.
3. Provide information on EIM impacts to BPA system carbon emission rate.

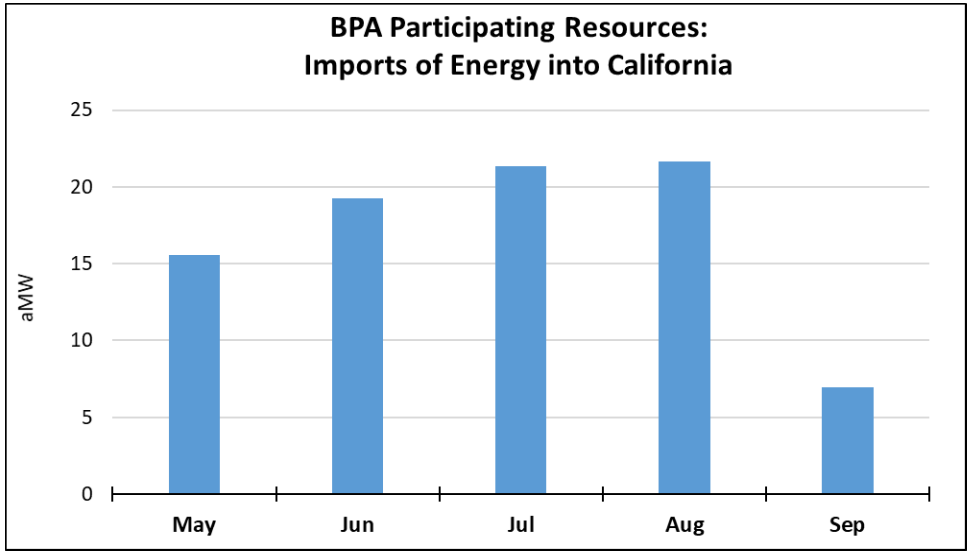
- Reporting on EIM impacts to BPA System carbon emission rate may transition to a different forum in the future as BPA engages on broader regional carbon issues and regulation.
- The goal is to have these metrics in place by BP-26.

Metric 1a: Unspecified purchases



- **Volume:** ~240,000 MWh (65 aMW) for the period of May-Sep

Metric 1b: Amount Delivered to California



- **Volume:** ~60,000 MWh (15 aMW) for the period of May-Sep
- **Premium:** ~$15.50/MWh (CC 491 GHG emission cost revenue)
- **Cost:** ~$0.50/MWh

Metric 2: Resource Sufficiency tests Pass rate

Background on RS Tests

- Balancing Test
  - The Balancing Test evaluates whether the BAA scheduled within +/-1% of the CAISO area load forecast
  - To incur an O/U scheduling penalty, the BAA must have scheduled 1). outside of +/-1% of the CAISO area load forecast and 2). outside of +/- 5% of the actual area load

- Bid Capacity Test
  - The Bid Capacity Test Over/Under evaluates whether the BAA had sufficient upward and downward bid range to meet the upward/downward 15-min load imbalance
  - During a failure, CAISO caps EIM Transfers in the direction of the failure, which may limit market participation during the failed 15-min interval

- Flex Ramp Test
  - The Flex Ramp Test evaluates whether the BAA had sufficient ramp up and down capability to meet the flex ramp up/down requirement from the current hour to the next hour
  - During a failure, CAISO caps EIM Transfers in the direction of the failure, which may limit market participation during the failed 15-min interval

RS Pass Rate Goals

RS Goals prior to joining the EIM:

- BPA will not set an RS pass target
- Why not set an RS pass target? Setting a specific pass target:
  - Flex Test
    - Could significantly increase the complexity of EIM implementation
    - Could expose BPA to uncertain RS requirements in the future
    - Does not align with EIM industry standards/pro forma
    - Could reduce BPA's operational and marketing flexibility
    - Could result in significant changes to the Balancing Reserve Capacity Business Practice and Rates
    - Does not seem necessary given BPA's high expected pass rate (98.7%)
  - Balancing Test
    - Could cause undue burden on BPA and the FCRPS
    - Allows for greater flexibility to manage the balancing test by not placing an obligation on BPA
    - Allows for EIM price signals to incentivize appropriate scheduling behavior by all members in the BAA

Balancing Test Results (May – Sep 2022)

- The Balancing Test evaluates whether the BAA scheduled within +/-1% of the CAISO area load forecast
- A failure means the BAA scheduled outside of +/-1% of the CAISO's area load forecast
- A failure does not mean the BAA necessarily incurred an Over/Under scheduling penalty

Percent of hours passed/failed

Balancing Test Over	May	Jun	Jul	Aug	Sep	Mean
Fail	1.75%	2.08%	0.54%	0.54%	0.83%	1.15%
Pass	98.25%	97.92%	99.46%	99.46%	99.17%	98.85%

Balancing Test Under	May	Jun	Jul	Aug	Sep	Mean
Fail	2.28%	2.36%	0.81%	0.40%	1.53%	1.48%
Pass	97.72%	97.64%	99.19%	99.60%	98.47%	98.52%

Bid Capacity Test Over Results (May – Sep 2022)

- The Capacity Test Over evaluates whether the BAA had sufficient upward bid range to meet the upward 15-min load imbalance

- The over requirement is calculated as the upward imbalance between the BAA's hourly load base schedule and the 15-min CAISO area load forecast

Percent of hours passed/failed

Capacity Test Over	May	Jun	Jul	Aug	Sep	Mean
Fail	0.00%	0.14%	0.00%	0.13%	0.56%	0.17%
Pass	100.00%	99.86%	100.00%	99.87%	99.44%	99.83%

Bid Capacity Test Under Results (May – Sep 2022)

- The Capacity Test Under evaluates whether the BAA had sufficient downward bid range to meet the downward 15-min load imbalance

- The under requirement is calculated as the downward imbalance between BAA's hourly load base schedule and the 15-min CAISO area load forecast

Percent of hours passed/failed

Capacity Test Under	May	Jun	Jul	Aug	Sep	Mean
Fail	0.13%	0.28%	0.00%	0.00%	0.28%	0.14%
Pass	99.87%	99.72%	100.00%	100.00%	99.72%	99.86%

Flex Test Up Results (May – Sep 2022)

- The Flex Ramp Test Up evaluates whether the BAA had sufficient ramp up capability to meet the flex ramp up requirement
- The BAA's ramp up capability depends on participating resources, non-participating resources, and net interchange

Percent of 15 minute intervals passed/failed

Flex Test Up	May	Jun	Jul	Aug	Sep	Mean
Fail	0.81%	3.12%	3.23%	1.01%	1.01%	1.84%
Pass	99.19%	96.88%	96.77%	98.99%	98.99%	98.16%

Flex Test Down Results (May – Sep 2022)

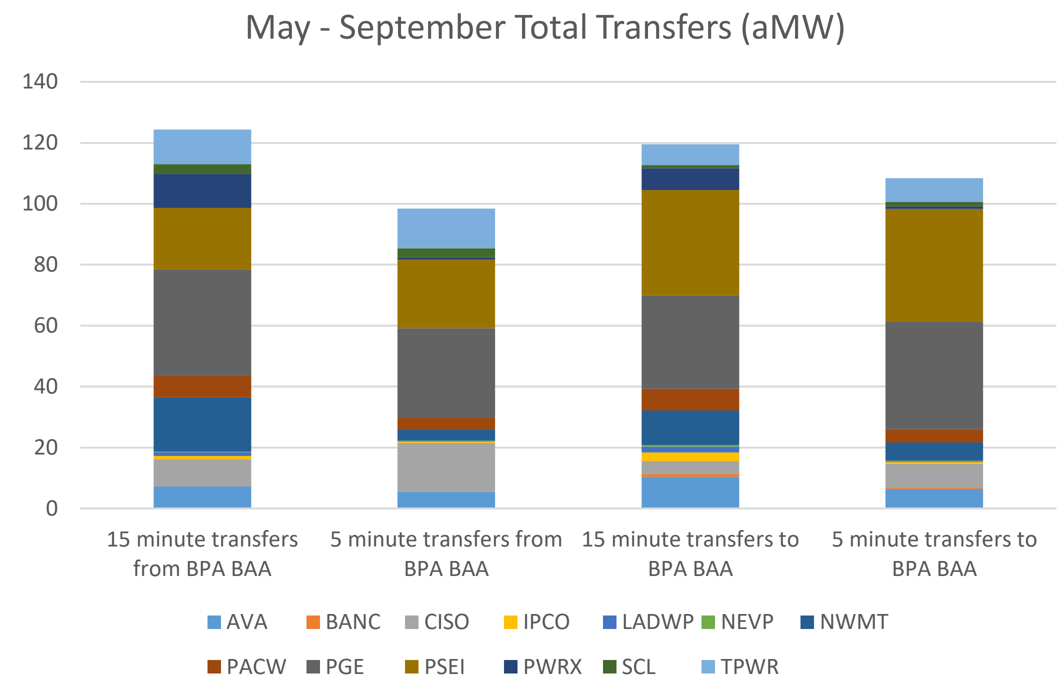
- The Flex Ramp Test Down evaluates whether the BAA had sufficient ramp down capability to meet the flex ramp down requirement

- The BAA's ramp down capability depends on participating resources, non-participating resources, and net interchange

Percent of 15 minute intervals passed/failed

Flex Test Down	May	Jun	Jul	Aug	Sep	Mean
Fail	0.13%	0.24%	0.00%	0.03%	0.35%	0.15%
Pass	99.87%	99.76%	100.00%	99.97%	99.65%	99.85%

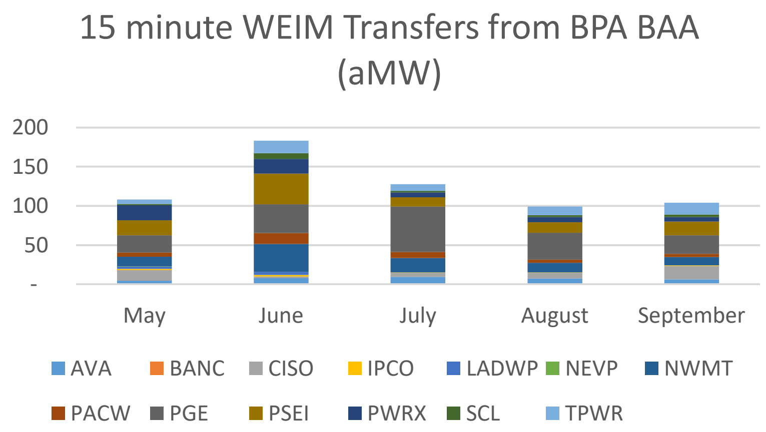
Metric 3: Gross EIM Transfers

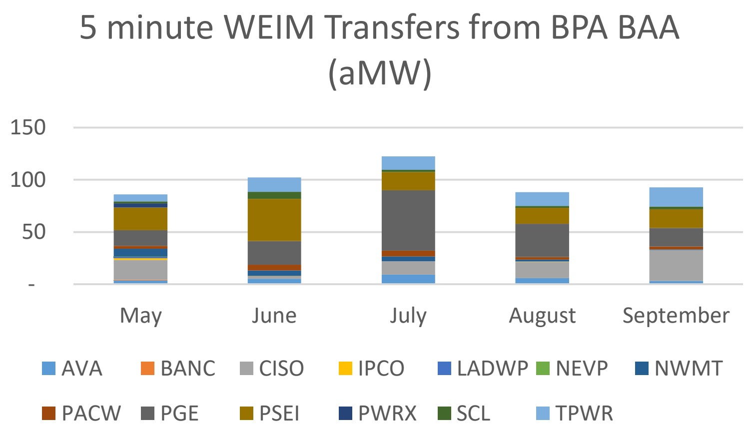


Source: CAISO Quarterly Benefits Reports: [iso-western-energy-imbalance-market-benefits-report-q2-2022.pdf (westerneim.com)]

[iso-western-energy-imbalance-market-benefits-report-q3-2022.pdf (westerneim.com)]

Metric 3: Gross EIM Transfers: From BPA BAA

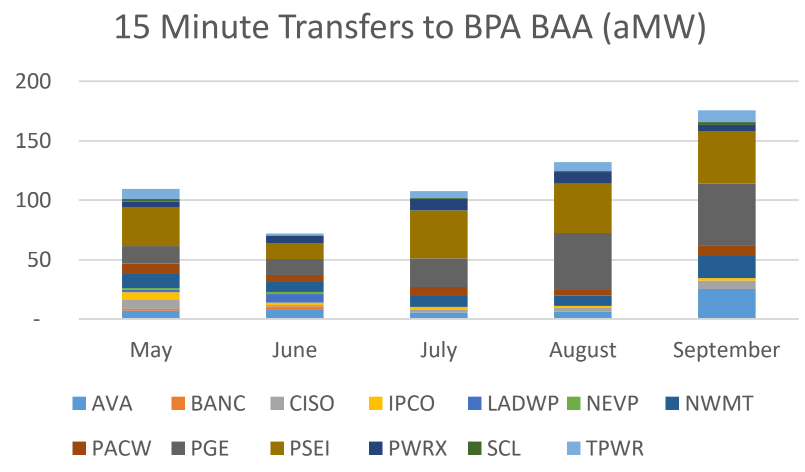


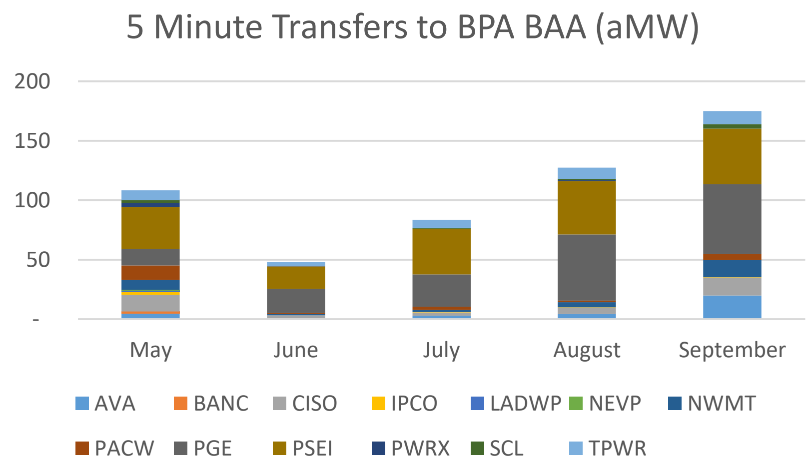


Source: CAISO Quarterly Benefits Reports: iso-western-energy-imbalance-market-benefits-report-q2-2022.pdf (westerneim.com)

iso-western-energy-imbalance-market-benefits-report-q3-2022.pdf (westerneim.com)

Metric 3: Gross EIM Transfers: To BPA BAA





Source: CAISO Quarterly Benefits Reports: iso-western-energy-imbalance-market-benefits-report-q2-2022.pdf (westerneim.com)

iso-western-energy-imbalance-market-benefits-report-q3-2022.pdf (westerneim.com)

Metric 4: BA scheduling error

- The scheduling error relative to the CAISO forecast is part of the balancing test.
- At this time we are not providing scheduling error relative to the actual load, but may provide it in the future.

Questions

On grid modernization:

www.bpa.gov/goto/gridmodernization

On EIM:

www.bpa.gov/goto/eim

QUESTION AND ANSWER

Will Rector

THANK YOU

Didn’t get your question answered?

Email Communications@bpa.gov. Answers will be posted to www.bpa.gov/about/finance/quarterly-business-review

Appendix

Reserves for Risk

EOY Crosswalk – Beginning Balance to EOY Actuals

	($ in 000)	Power	Transmission
1	**RFR Beg Bal & Net Rev**		
2	RFR Beginning Balance	$616,655	$208,727
3	FY22 Net Revenues	858,793	108,336
4	Subtotal Beg Bal & Net Rev	1,475,448	317,063
5	**Adjustments**		
6	Depreciation, Amortization, Accret.	502,247	338,768
7	Capitalization Adjustment	(45,937)	(18,968)
8	Other Adjustments*	(157,487)	41,397
9	CGS Decom TF - Gains/Loss/Dividend	(20,318)	-
10	EN Cash Payments vs Accruals*	65,988	-
11	Subtotal Adjustments	344,493	361,196
12	**Cash Flow**		
13	Debt Payment	(496,364)	(313,196)
14	Revenue Financing	(40,000)	(40,000)
15	CSG Decom TF Contribution	(4,663)	-
16	Change in RNFR	(34,591)	(57,929)
17	Subtotal Cash Flow	(575,617)	(411,125)
18	**FY22 EOY RFR**	**$1,244,323**	**$267,135**

* See bullets for further details

- Crosswalk highlights key non-cash adjustments and balance sheet-related uses of cash.
- Other Adjustments (line 8): Covers changes in AP, AR, accrued revenue/expense; non-cash revenue/expense; and other miscellaneous items
  - Power: driver is large jump in non-cash accrued revenue, particularly from Sept sales.
  - Transmission: key items are non-cash revenues/credits from LGIA, AC Intertie and Fiber agreements, and related non-cash interest expense; changes in AP/AR and accrued revenues/expenses
- EN Cash Payments vs Accruals (line 10): reflects difference between accrued expenses (interest expense and O&M) and cash payments to EN. Drivers: FY timing differences and non-cash interest expense from amortization of premiums.
- Power and Transmission both had increases in RNFR due to customer deposits. Transmission had increases in LT Service Deposits, LGIA's and Funds Held in Escrow.

Appendix

Slice Reporting
Composite Cost Pool Review
Final Annual Slice True-Up Adjustment

Final True-Up of FY 2022 Slice True-Up Adjustment

	FY 2022 Forecast $ in thousands
February 15, 2022 First Quarter Technical Workshop	$7,145*
May 17, 2022 Second Quarter Technical Workshop	$2,082
August 16, 2022 Third Quarter Technical Workshop	$(12,186)
November 16, 2022 Final Slice True-Up Technical Workshop	$(8,556)

*Negative = Credit; Positive = Charge

Summary of Differences
From Final to FY22 (BP-22)

#		A Composite Cost Pool True-Up Table Reference	B Final – Rate Case $ in thousands
1	Total Expenses	Row 98	$(34,780)
2	Total Revenue Credits	Rows 117 + 126	$14,464
3	Minimum Required Net Revenue	Row 151	$12,587
4	TOTAL Composite Cost Pool (1 - 2 + 3) $(34,780) - $14,464 + $12,587 = $(36,656)	Row 156	$(36,656)
5	TOTAL in line 4 divided by <u>0.9580515</u> sum of TOCAs $(36,656)/ <u>0.9580515</u> = $(38,261)	Row 158	$(38,261)
6	QTR Forecast of FY22 True-up Adjustment 22.36267 percent of Total in line 5 0.2236267 * $(38,261) = $(8,556)	Row 159	$(8,556)

FY22 Impacts of Debt Management Actions

		A	B	C	D
#	Description	FY22 Final QBR	FY22 Rate Case	CCP	Delta from the FY22 rate case
1	MRNR Section of Composite Cost Pool Table				$ -
2	**Principal Payment of Federal Debt**				$ -
3	2022 Regional Cooperation Debt (RCD)	$ 319,193,190	$ 333,946,000		$ 14,752,810
4	2022 Debt Service Reassignment (DSR)	$ 15,245,000	$ 15,245,000		$ -
5	Energy Northwest's Line Of Credit (LOC)	$ -	$ -		$ -
6	Rate Case Scheduled Base Power Principal*	$ 144,861,810	$ 145,809,000		$ 947,190
7	**Total Principal Payment of Fed Debt**	**$ 479,300,000**	**$ 495,000,000**	row 129	**$ 15,700,000**
8	**Prepay**	$ 22,746,026	$ 22,746,026		$ -
					$ -
9	**Nonfederal Bond Principal Payment**	$ 42,185,000	$ 16,005,150	row 131	$ (26,179,850)

Composite Cost Pool Interest Credit

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

		Final 2022
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	0.70%
5	Composite Interest Credit	(4,105)
6	Prepay Offset Credit	0
7	Total Interest Credit for Power Services	(6,875)
8	Non-Slice Interest Credit (Line 7 – (Line 5 + Line 6))	(2,770)

Net Interest Expense in Slice True-Up Final

	FY22 Rate Case ($ in thousands)	Final ($ in thousands)
• Federal Appropriation	38,410	40,968
• Capitalization Adjustment	(45,937)	(45,937)
• Borrowings from US Treasury	44,753	46,713
• Prepay Interest Expense	7,854	7,854
• **Interest Expense**	**45,080**	**49,598**
• AFUDC	(11,005)	(10,166)
• Interest Income (composite)	(1,384)	(4,105)
• Prepay Offset Credit	(0)	(0)
• **Total Net Interest Expense**	**32,691**	**35,327**

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

Dates	Agenda
February 15, 2022	First Quarter Technical Workshop
May 17, 2022	Second Quarter Technical Workshop
August 16, 2022	Third Quarter Technical Workshop
October 2022	BPA External CPA firm conducting audit for fiscal year end
Mid-October 2022	Recording the Fiscal Year End Slice True-Up Adjustment Accrual
End of October	Final audited actual financial data is expected to be available
November 15, 2022	Mail notification to Slice Customers of the Slice True-Up Adjustment for the Composite Cost Pool
November 16, 2022	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 18, 2022	BPA to post Composite Cost Pool True-Up Table containing actual values and the Slice True-Up Adjustment
December 12, 2022	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 27, 2022	BPA posts a response to customer questions (Attachment A does not specify an exact date)
January 11, 2023	Customer comments are due on the list of tasks (The deadline can not exceed 10 days from BPA posting)
February 2, 2023	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

			Final ($000)		Rate Case forecast for FY 2022 ($000)		Final - Rate Case Difference
1	**Operating Expenses**						
2	**Power System Generation Resources**						
3	**Operating Generation**						
4	COLUMBIA GENERATING STATION (WNP-2)	$	275,176	$	278,643	$	(3,466)
5	BUREAU OF RECLAMATION	$	147,238	$	152,269	$	(5,031)
6	CORPS OF ENGINEERS	$	243,880	$	252,557	$	(8,677)
7	CRFM STUDIES	$	7,129	$	7,266	$	(137)
8	LONG-TERM CONTRACT GENERATING PROJECTS	$	17,220	$	16,036	$	1,184
9	**Sub-Total**	**$**	**690,644**	**$**	**706,771**	**$**	**(16,127)**
10	**Operating Generation Settlement Payment and Other Payments**						
11	COLVILLE GENERATION SETTLEMENT	$	19,783	$	22,000	$	(2,217)
12	SPOKANE LEGISLATION PAYMENT	$	4,946	$	5,749	$	(803)
13	**Sub-Total**	**$**	**24,729**	**$**	**27,749**	**$**	**(3,020)**
14	**Non-Operating Generation**						
15	TROJAN DECOMMISSIONING	$	1,571	$	1,200	$	371
16	WNP-1&3 DECOMMISSIONING	$	1,070	$	1,141	$	(71)
17	**Sub-Total**	**$**	**2,641**	**$**	**2,341**	**$**	**300**
18	**Gross Contracted Power Purchases**						
19	PNCA HEADWATER BENEFITS	$	2,764	$	3,100	$	(336)
20	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)	$	47,338	$	-	$	47,338
21	**Sub-Total**	**$**	**50,102**	**$**	**3,100**	**$**	**47,002**
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)	$	267,115	$	266,663	$	452
28	OTHER SETTLEMENTS	$	-	$	-	$	-
29	**Sub-Total**	**$**	**267,115**	**$**	**266,663**	**$**	**452**
30	**Renewable Generation**						
31	RENEWABLES (excludes KIII)	$	18,583	$	26,255	$	(7,671)
32	**Sub-Total**	**$**	**18,583**	**$**	**26,255**	**$**	**(7,671)**
33	**Generation Conservation**						
34	CONSERVATION ACQUISITION	$	53,417	$	67,357	$	(13,940)
35	CONSERVATION INFRASCTRUCTURE	$	23,020	$	27,300	$	(4,280)
36	LOW INCOME WEATHERIZATION & TRIBAL	$	6,205	$	6,005	$	200
37	ENERGY EFFICIENCY DEVELOPMENT	$	52	$	8,000	$	(7,948)
38	DISTRIBUTED ENERGY RESOURCES	$	189	$	215	$	(26)
39	LEGACY	$	617	$	590	$	27
40	MARKET TRANSFORMATION	$	11,773	$	11,800	$	(27)
41	**Sub-Total**	**$**	**95,274**	**$**	**121,267**	**$**	**(25,993)**
42	**Power System Generation Sub-Total**	**$**	**1,149,088**	**$**	**1,154,145**	**$**	**(5,057)**
43							

COMPOSITE COST POOL TRUE-UP TABLE

			Final ($000)		Rate Case forecast for FY 2022 ($000)		Final - Rate Case Difference
44	**Power Non-Generation Operations**						
45	**Power Services System Operations**						
46	EFFICIENCIES PROGRAM	$	-	$	-	$	-
47	INFORMATION TECHNOLOGY	$	-	$	3,804	$	(3,804)
48	GENERATION PROJECT COORDINATION	$	3,169	$	3,947	$	(778)
49	ASSET MGMT ENTERPRISE SVCS	$	1,090	$	-	$	1,090
50	SLICE IMPLEMENTATION	$	627	$	971	$	(344)
51	**Sub-Total**	**$**	**4,886**	**$**	**8,721**	**$**	**(3,835)**
52	**Power Services Scheduling**						
53	OPERATIONS SCHEDULING	$	10,241	$	9,600	$	640
54	OPERATIONS PLANNING	$	7,906	$	8,708	$	(802)
55	**Sub-Total**	**$**	**18,147**	**$**	**18,308**	**$**	**(162)**
56	**Power Services Marketing and Business Support**						
57	GRID MOD	$	1,678	$	2,223	$	(544)
58	EIM INTERNAL SUPPORT	$	-	$	-	$	-
59	POWER INTERNAL SUPPORT	$	15,877	$	13,976	$	1,900
60	COMMERCIAL ENTERPRISE SVCS	$	4,820	$	-	$	4,820
61	OPERATIONS ENTERPRISE SVCS	$	4,960	$	-	$	4,960
62	POWER R&D	$	1,952	$	2,527	$	(575)
63	SALES & SUPPORT	$	11,393	$	15,172	$	(3,780)
64	STRATEGY, FINANCE & RISK MGMT (REP support costs included here)	$	-	$	4,031	$	(4,031)
65	EXECUTIVE AND ADMINISTRATIVE SERVICES (REP support costs included here)	$	-	$	6,672	$	(6,672)
66	CONSERVATION SUPPORT	$	8,387	$	7,876	$	511
67	**Sub-Total**	**$**	**49,066**	**$**	**52,477**	**$**	**(3,411)**
68	**Power Non-Generation Operations Sub-Total**	**$**	**72,099**	**$**	**79,507**	**$**	**(7,407)**
69	**Power Services Transmission Acquisition and Ancillary Services**						
70	TRANSMISSION and ANCILLARY Services - System Obligations	$	31,919	$	31,919	$	0
71	3RD PARTY GTA WHEELING	$	77,190	$	81,854	$	(4,664)
72	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)	$	2,190	$	3,300	$	(1,110)
73	TRANS ACQ GENERATION INTEGRATION	$	14,726	$	14,723	$	3
74	EESC CHARGES (Composite)	$	(316)	$	-	$	(316)
75	TELEMETERING/EQUIP REPLACEMT	$	-	$	-	$	-
76	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**	**$**	**125,709**	**$**	**131,795**	**$**	**(6,087)**
77	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**						
78	**Fish & Wildlife**	$	234,971	$	247,508	$	(12,537)
79	**USF&W Lower Snake Hatcheries**	$	32,993	$	33,000	$	(7)
80	**Planning Council**	$	11,942	$	11,942	$	(0)
81	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$**	**279,906**	**$**	**292,450**	**$**	**(12,544)**
82	**BPA Internal Support**						
83	**Additional Post-Retirement Contribution**	$	18,181	$	18,666	$	(485)
84	**Agency Services G&A (excludes direct project support)**	$	75,951	$	66,805	$	9,146
85	**BPA Internal Support Sub-Total**	**$**	**94,132**	**$**	**85,471**	$	8,661

COMPOSITE COST POOL TRUE-UP TABLE

		Final ($000)	Rate Case forecast for FY 2022 ($000)	Final - Rate Case Difference
86	**Bad Debt Expense**	$ -	$ -	$ -
87	**Other Income, Expenses, Adjustments**	$ (973)	$ -	$ (973)
88	**Depreciation**	$ 140,495	$ 140,949	$ (454)
89	**Amortization**	$ 325,739	$ 320,900	$ 4,839
90	**Accretion (CGS)**	$ 36,013	$ 36,754	$ (741)
91	**Total Operating Expenses**	**$ 2,222,208**	**$ 2,241,971**	**$ (19,762)**
92				
93	**Other Expenses and (Income)**			
94	Net Interest Expense	$ 225,154	$ 240,508	$ (15,354)
95	LDD	$ 39,805	$ 39,482	$ 323
96	Irrigation Rate Discount Costs	$ 20,523	$ 20,509	$ 14
97	**Sub-Total**	**$ 285,482**	**$ 300,499**	**$ (15,017)**
98	**Total Expenses**	**$ 2,507,690**	**$ 2,542,470**	**$ (34,780)**
99				
100	**Revenue Credits**			
101	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	$ 97,575	$ 104,245	$ (6,670)
102	Downstream Benefits and Pumping Power revenues	$ 20,109	$ 20,661	$ (552)
103	4(h)(10)(c) credit	$ 112,319	$ 94,171	$ 18,148
104	PRSC Net Credit (Composite)	$ 6,824	$ -	$ 6,824
105	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ -
106	Energy Efficiency Revenues	$ 3,710	$ 8,000	$ (4,290)
107	PF Load Forecast Deviation Liquidated Damages	$ -	$ 1,070	$ (1,070)
108	Miscellaneous revenues	$ 10,545	$ 11,621	$ (1,076)
109	Renewable Energy Certificates	$ -	$ -	$ -
110	Net Revenues from other Designated BPA System Obligations (Upper Baker)	$ 598	$ 411	$ 187
111	RSS Revenues	$ 3,040	$ 3,040	$ -
112	Firm Surplus and Secondary Adjustment (from Unused RHWM)	$ 89,393	$ 86,168	$ 3,225
113	Balancing Augmentation Adjustment	$ (4,070)	$ (4,070)	$ -
114	Transmission Loss Adjustment	$ 30,187	$ 30,187	$ -
115	Tier 2 Rate Adjustment	$ 1,537	$ 1,537	$ 0
116	NR Revenues	$ 1	$ 1	$ -
117	**Total Revenue Credits**	**$ 376,366**	**$ 361,642**	**$ 14,724**
118				
119	**Augmentation Costs (not subject to True-Up)**			
120	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)	$ 10,249	$ 10,249	$ (0)
121	Augmentation Purchases	$ -	$ -	$ -
122	**Total Augmentation Costs**	**$ 10,249**	**$ 10,249**	**$ (0)**
123				
124	**DSI Revenue Credit**			
125	Revenues 12 aMW @ IP rate	$ 4,017	$ 4,277	$ (260)
126	**Total DSI revenues**	**$ 4,017**	**$ 4,277**	**$ (260)**
127				

COMPOSITE COST POOL TRUE-UP TABLE

		Final ($000)	Rate Case forecast for FY 2022 ($000)	Final - Rate Case Difference
128	**Minimum Required Net Revenue Calculation**			
129	Principal Payment of Fed Debt for Power	$ 479,300	$ 495,001	$ (15,701)
130	Repayment of Non-Federal Obligations (EN Line of Credit)	$ -	$ -	$ -
131	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls)	$ 42,185	$ 16,005	$ 26,180
132	Irrigation assistance	$ 17,064	$ 16,060	$ 1,004
133	**Sub-Total**	**$ 538,549**	**$ 527,066**	**$ 11,483**
134	Depreciation	$ 140,495	$ 140,949	$ (454)
135	Amortization	$ 325,739	$ 320,900	$ 4,839
136	Accretion	$ 36,013	$ 36,754	$ (741)
137	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ 0
138	Amortization of Refinancing Premiums/Discounts (MRNR - Reverse Sign)	$ (25,804)	$ (7,562)	$ (18,242)
139	Amortization of Cost of Issuance (MRNR-reverse sign)	$ 420	$ 169	$ 251
140	Cash freed up by DSR refinancing	$ 15,245	$ 16,510	$ (1,265)
141	Gains/Losses on Extinguishment	$ -	$ -	$ -
142	Non-Cash Expenses	$ 97,496	$ 77,926	$ 19,570
143	Prepay Revenue Credits	$ (30,600)	$ (30,600)	$ -
144	Non-Federal Interest (Prepay)	$ 7,854	$ 7,854	$ 0
145	Contribution to decommissioning trust fund	$ (4,663)	$ (4,472)	$ (191)
146	Gains/losses on decommissioning trust fund	$ (18,128)	$ (9,857)	$ (8,270)
147	Interest earned on decommissioning trust fund	$ (0)	$ (3,399)	$ 3,399
148	Revenue Financing Requirement	$ (40,000)	$ (40,000)	$ -
149	**Sub-Total**	**$ 458,130**	**$ 459,235**	**$ (1,104)**
150	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expenses	$ 80,418	$ 67,832	$ 12,587
151	Minimum Required Net Revenues	**$ 80,418**	**$ 67,832**	**$ 12,587**
152				
153	Annual Composite Cost Pool (Amounts for each FY)	**$ 2,217,975**	**$ 2,254,632**	**$ (36,656)**
154				
155	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**			
156	TRUE-UP AMOUNT (Diff. between Rate Case and Forecast)	(36,656)		
157	Sum of TOCAs	0.9580515		
158	Adjustment of True-Up Amount when actual TOCAs < 100 percent	**(38,261)**		
159	TRUE-UP ADJUSTMENT CHARGE BILLED (22.36267 percent)	(8,556)		

Financial Disclosures

This information has been made publicly available by BPA on November 15, 2022 and contains information not sourced directly from BPA financial statements.