Bonneville
POWER ADMINISTRATION

QUARTERLY BUSINESS REVIEW TECHNICAL WORKSHOP

Aug 10, 2023

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AGENDA

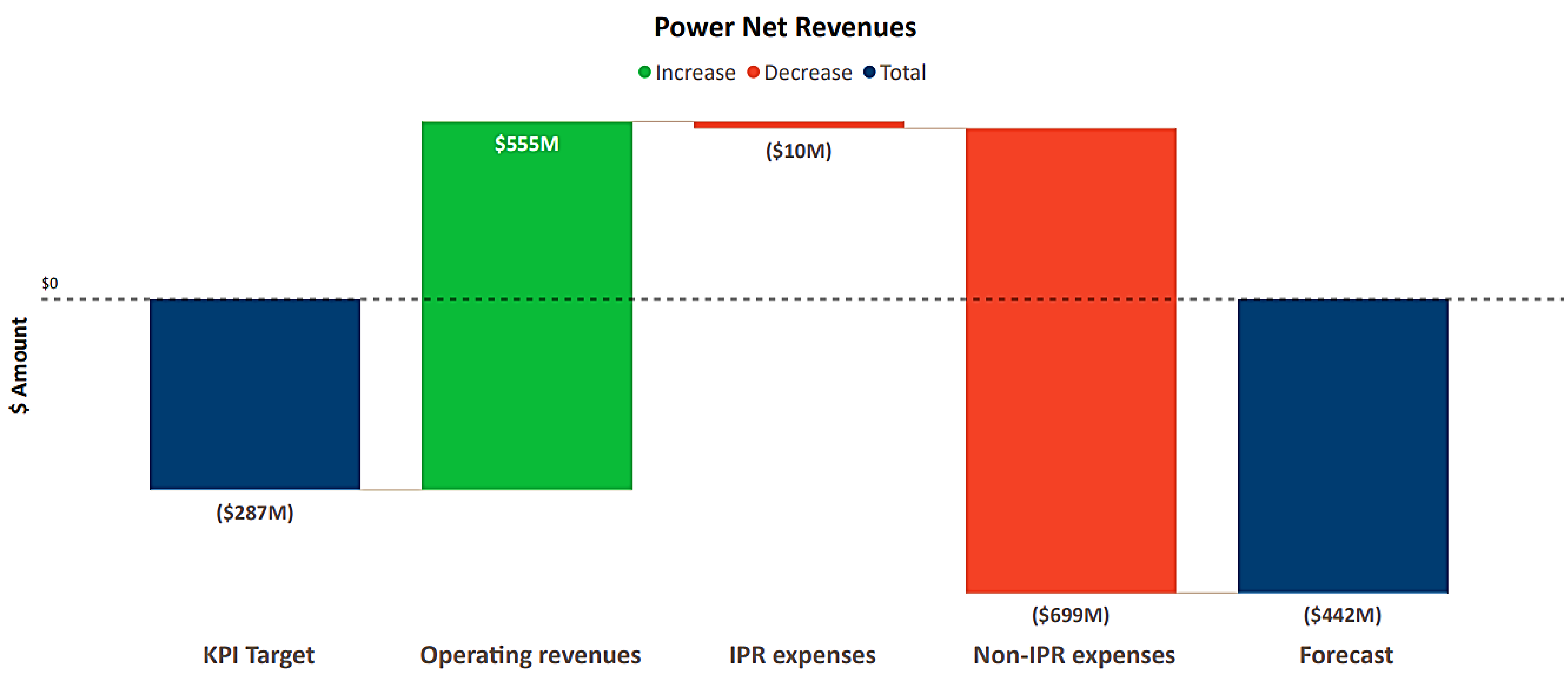
Time	Min	QBRTW Agenda Topic	Presenter
1:00	5	Introduction & Agenda	Kelly Akowskey
1:05	10	FY23 Q3 forecast: Power net revenue and Transmission net revenue	Karlee Manary, Pablo Zepeda-Martinez
1:15	15	FY23 Q3 forecast: Reserves for Risk	Damen Bleiler
1:30	10	FY23 Q3 forecast: Capital	Gwen Resendes, Heather Seibert
1:40	10	Transmission capital metrics	Jeff Cook, Mike Miller
1:50	20	CGS Decommissioning Trust Fund Update	Damen Bleiler
2:10	10	Grid Modernization Update	Tracey Stancliff
2:20	15	BPA EIM Metrics	Matt Germer, Mariano Mezzatesta, Kelii Haraguchi
2:35	15	Western Resource Adequacy Program (WRAP)	Steve Bellcoff
2:50	10	Q&A / Closing	Kelly Akowskey

* Comparable financial statements are located at https://www.bpa.gov/about/finance/quarterly-reports.

FY23 Q3 Forecast:
Power net revenue
Transmission net revenue

Presenters: Finance Team

Q3 FORECAST: POWER NET REVENUE



The KPI Target is less than Power's FY 23 Rate Case net revenue forecast due to the reserves Dividend Distribution, FY 23 budget increases, FY 22 budget carryover, and non-cash losses associated with B2H.

QBRTW ANALYSIS: POWER NET REVENUE

Operating Revenues increased by $555M due to the following:

- Gross sales are $471M higher than target due to additional Composite Revenues due to higher loads. Load Shaping and Demand Revenue are also higher due to colder-than-average temperatures experienced through April. Secondary Sales are higher than the target due to higher prices than assumed in the target. In addition, colder-than-normal weather conditions have increased loads. The Slice True-up forecast is a credit to customers of $4.6M. These items are offset by $82M in Bookouts, which are net revenue neutral.
- Other revenues are $8M greater than the target due to Financial Swaps revenues partially offset by a decrease in Energy Efficiency revenues due to the program ending.
- Inter-business Unit Revenues are $3M less than the target due to Balancing Reserve Capacity, Operating Reserve - Spinning, and Operating Reserve - Supplemental from joining the EIM.
- The remaining $161M delta is due to significantly higher forecast of U.S Treasury Credits from the 4h10c credit increase. The increase is due to higher predicted purchases and higher prices.

Integrated Program Review Operating Expenses increased $10M due to the following:

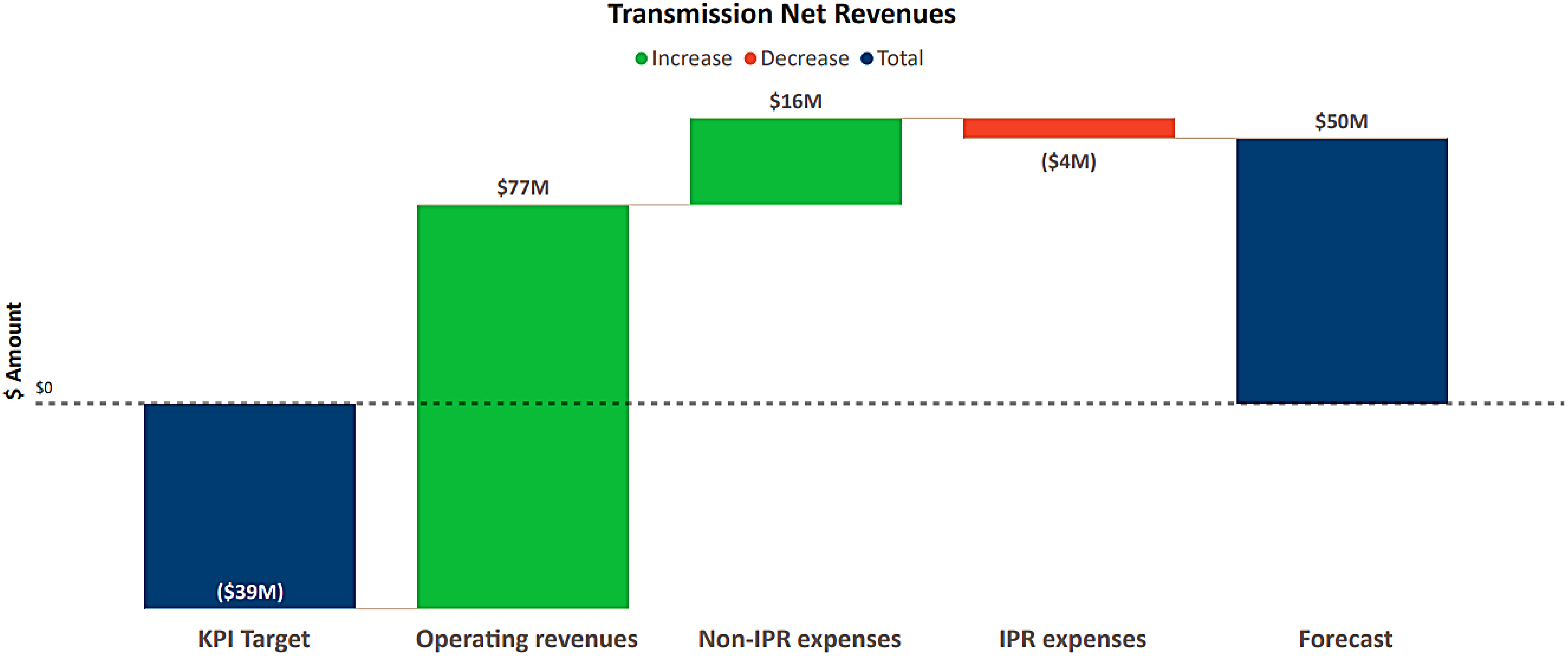
- The generating partners (Bureau of Reclamation, Corps of Engineers, Columbia Generating Station and Columbia River Fish Mitigation studies) are seeing increases in labor costs and inflation on materials which is creating cost pressure above the target of $20M.
- In addition, IT is experiencing inflation and higher demand, increasing the forecast by $9M.
- Partially offsetting the IPR Cost increases:
  - Energy Efficiency and Renewables expenses are coming in $17M below the target due to a lag in EE project billing and lower wind output.
  - The remaining $2M forecast reduction is related to reductions in travel, training, service contracts and federal personnel.

QBRTW ANALYSIS: POWER NET REVENUE (cont.)

Non-IPR Programs increased by $699M due to the following:

- The Power Purchases forecast is $877M higher than the target, driven by higher prices and low stream flows. The low stream flows are a significant component of the higher Q3 forecast due to increased loads and dry winter conditions, leading to increased purchases. Non-Treaty Storage Agreement and Libby expenses also increase Power Purchases by roughly $56M due to water releases throughout Q3.
- Year-to-date EIM Scheduling Coordinator charges of $10M were not forecast in the Rate Case or the Target but are included in the Q3 forecast. Higher EIM revenues offset some of these charges.
- The Colville and Spokane Generation Settlements are $5M higher than the target due to higher-than-average flows at Grand Coulee and high net secondary revenue experienced in FY22 that led to an increase in the FY23 payment.
- Partially offsetting the Non-IPR increases, as mentioned above, are:
  - There will be no Tier 2 Power Purchases. Instead, they will be met with the federal system rather than making a market purchase and reduce Non-IPR expenses by $47M.
  - Bookouts reduce Non-IPR expenses by $82M but are net revenue neutral due to a like amount in the revenue section.
  - Lower Transmission and Ancillary Services by $30M, mainly driven by lower total inventory. Total inventory decreased across FY23, driven by a dryer and colder hydro outlook with a reduced snowpack forecasted.
  - Net interest expense is down by $31M primarily due to additional interest income. Significantly higher interest earning rate than assumed in Rate case (~3% higher) and larger starting cash balance available for investment.
  - Finally, the remaining $3M decrease in Non-IPR expense is from smaller deltas in a few program areas.

Q3 FORECAST: TRANSMISSION NET REVENUE



The KPI Target is less than Transmission's FY 23 Rate Case net revenue forecast due to the reserves Dividend Distribution, FY 23 budget increases, and non-cash losses associated with B2H.

QBRTW ANALYSIS: TRANSMISSION NET REVENUE

Operating Revenues increased $77M primarily due to the following:

- $100M increase in Sales driven by:
  - Increased Long Term Point-to-Point revenues resulting from Conditional Firm Service offers accepted during FY 2022.
  - Increased Network Integration revenues as a result of server and residential load growth.
  - Increased Short-Term Point-to-Point and Southern Intertie Short-Term revenues resulting from increased wheeling due to favorable market prices.
- $7M increase in Other Revenues driven by increased Reimbursable and Oversupply revenues.
- Partially offset by a $30M decrease in Inter-Business Unit Revenues related to lower hydro inventory forecasts from Power Services and a lower forecast of Short-Term Point-to-Point purchases from the Transmission Business Line.

Integrated Program Review Operating Expenses increased $4M primarily due to the following:

- $11M increase in Commercial Activities and Enterprise Services Programs primarily due to an increase in large Agency-wide IT service contracts leading to an increase in G&A allocations and a forecast increase in the Additional Post Retirement Contribution.
- $7M decrease in the Asset Management Program and Other Income, Expenses, and Adjustments driven by improved capital work plan execution spread throughout the various programs, slightly offset by higher vegetation management and wildfire mitigation costs, inflation, and higher costs of the material.

Non-IPR Programs are on the next slide.

QBRTW ANALYSIS: TRANSMISSION NET REVENUE

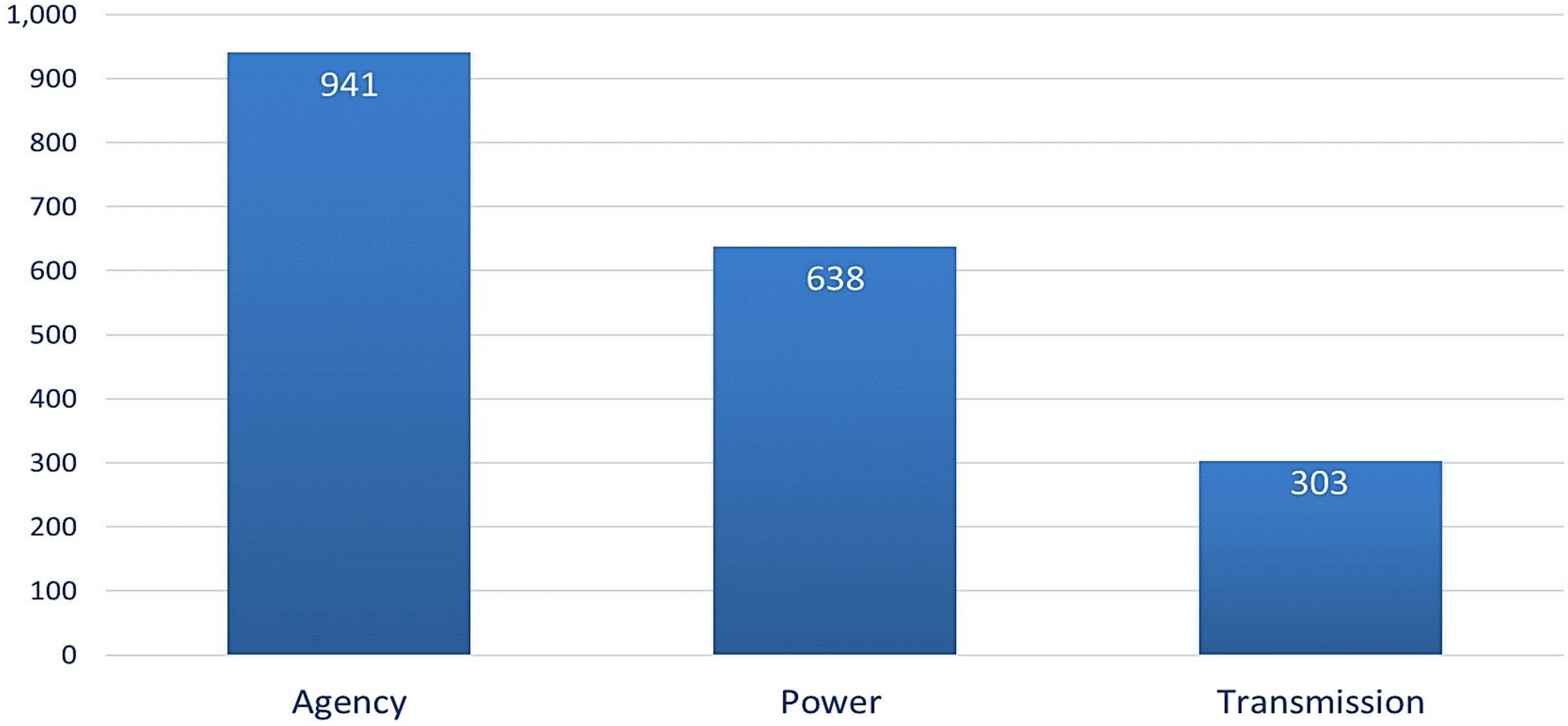
Non-IPR Program Expenses decreased by $16M primarily due to the following:

- $11M decrease in Net Interest expense and other income primarily driven by significantly higher interest income and AFUDC, which is partially offset higher interest expense on federal debt.
- $16M decrease in Depreciation expense resulting from less capital being placed in service during prior periods than forecast during the Rate Case, which is partially offset by a $5M increase in Amortization expense resulting from the Lease accounting change in a previous year.
- $5M increase in Commercial Activities Non-IPR primarily driven by EIM Entity Scheduling Coordinator (EESC) Settlements charges that were not forecasted in the BP-22 rate case.

RESERVES

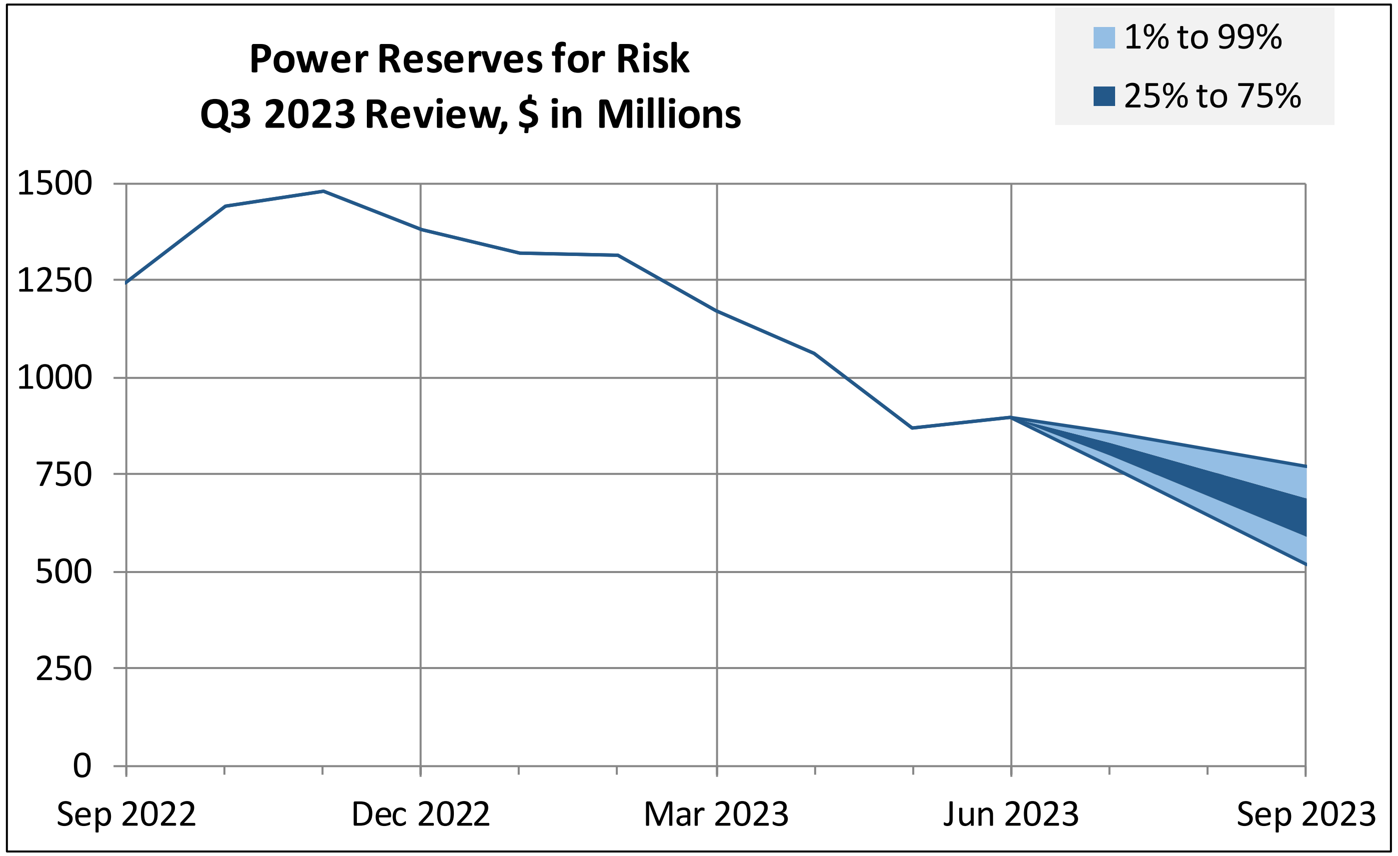
Presenters: Finance Team

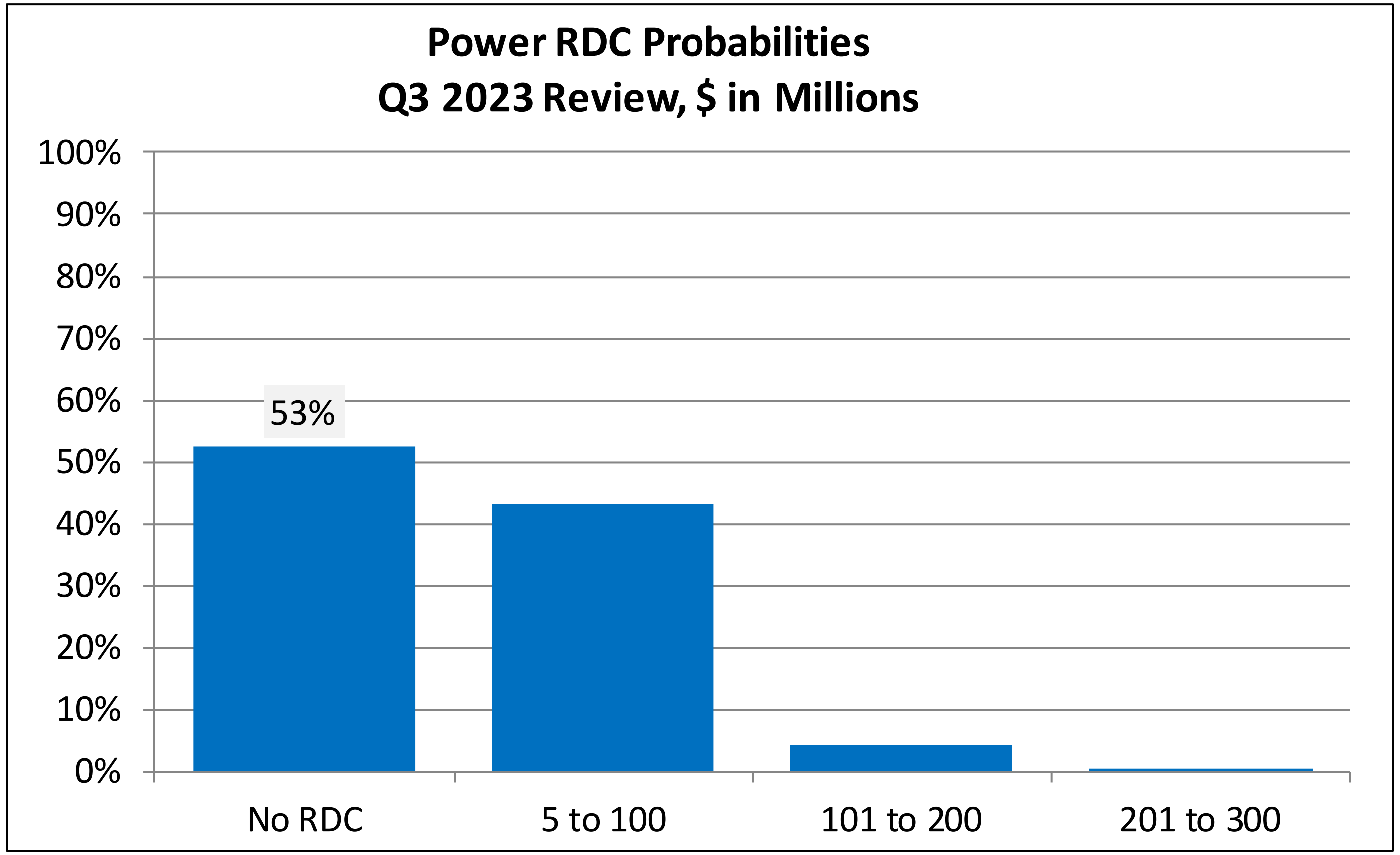
Q3 FORECAST: RESERVES FOR RISK



	Agency	Power	Transmission
DCOH (Q3)	140	131	164
<u>Thresholds</u>			
RDC	>\$653M	>\$638M	>\$233M
Surcharge		<\$319M	<\$116M

Q3 FORECAST: POWER FINANCIAL RESERVES





<u>Power Reserves Range</u>

- 1% to 99% Range:
  $516m to $773m

- 25% to 75% Range:
  $589m to $687m

<u>Power Risk Mechanisms</u>

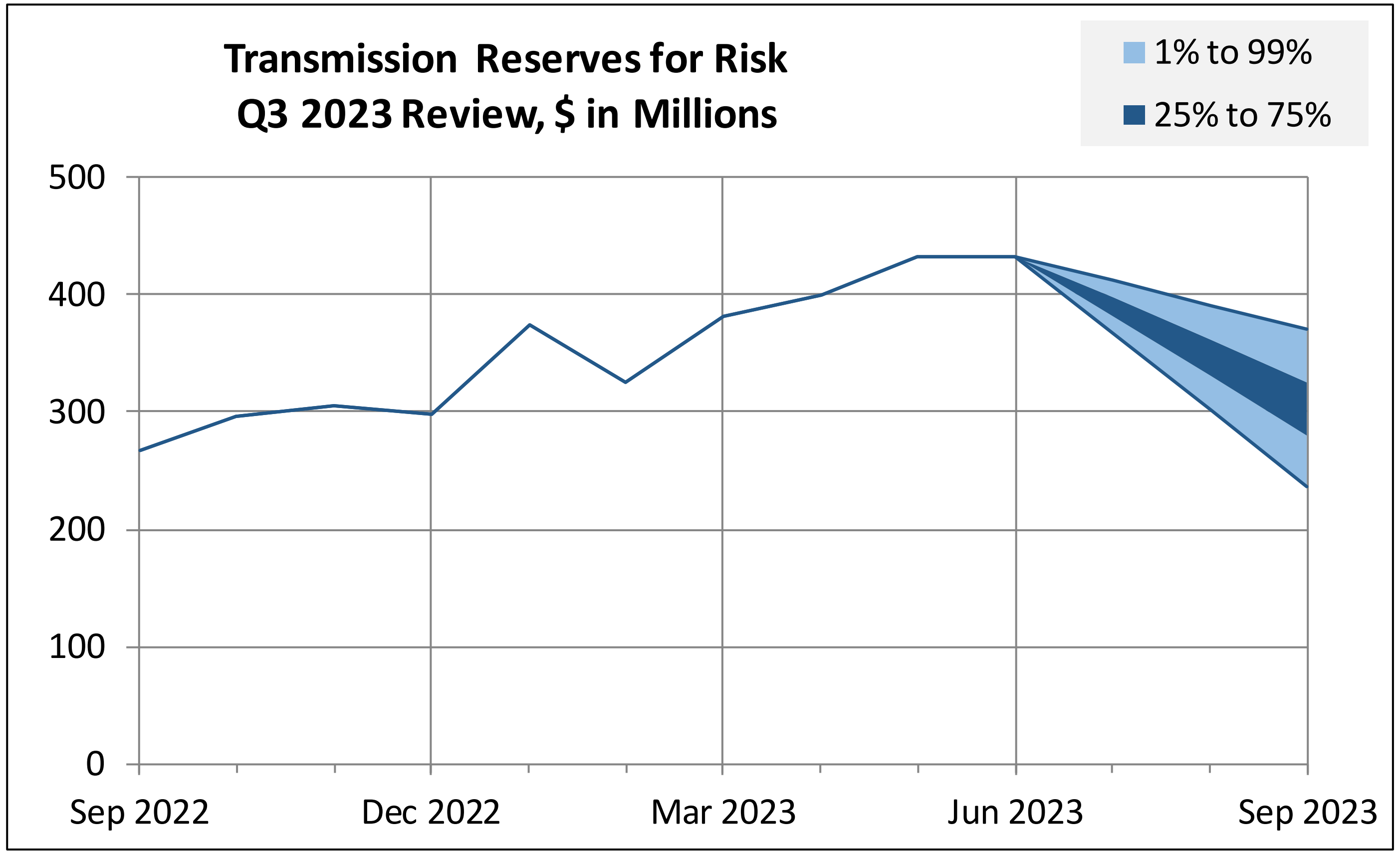
- 47% modeled probability of an RDC with an expected value of $26m

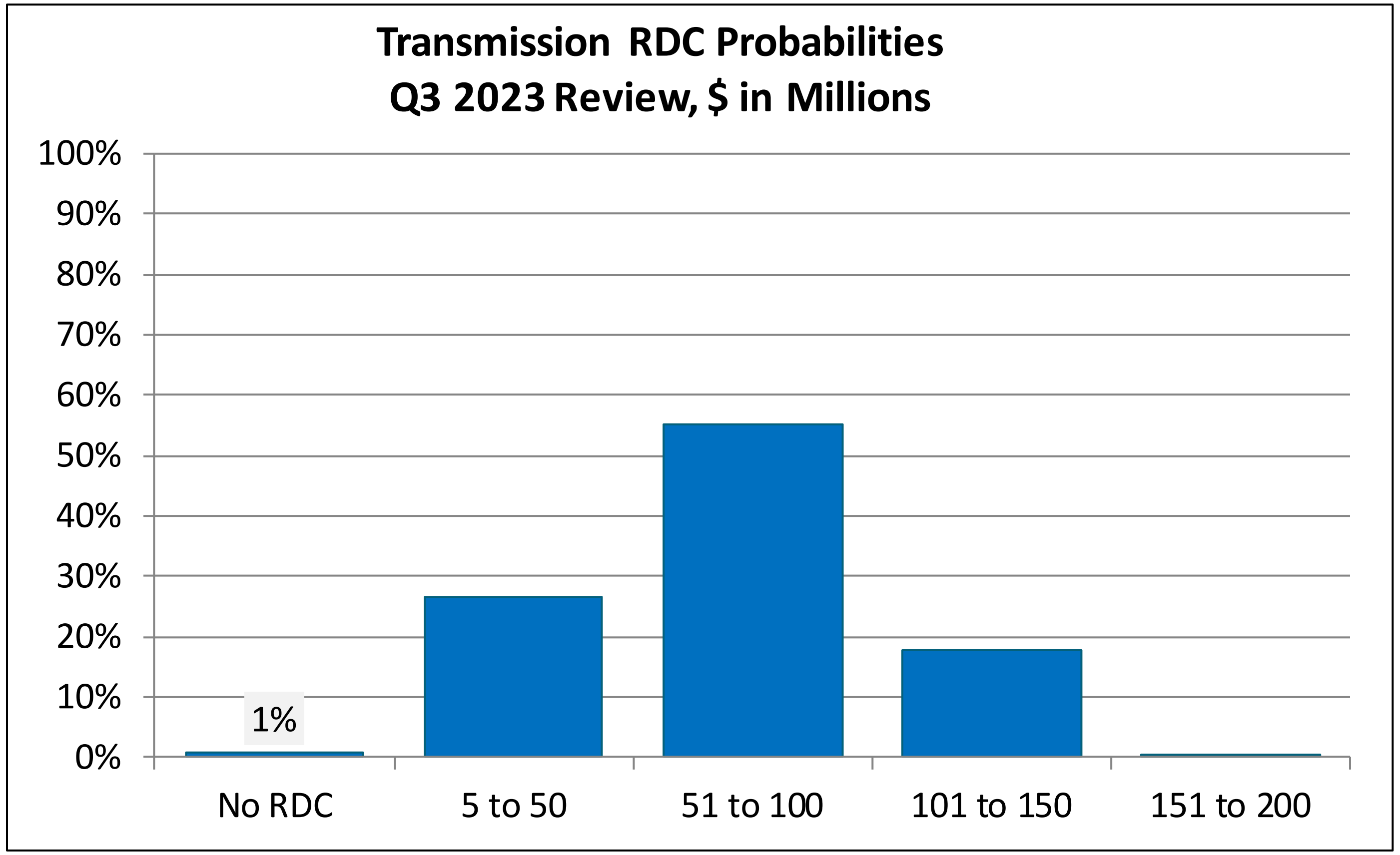
- 0% modeled probability of an FRP Surcharge or CRAC

Q3 FORECAST: POWER FINANCIAL RESERVES

- BPA has tools available to preserve liquidity, with application of these tools informed by various rate case settlements. For Power Services these include unwinding or halting some or all of the following:
  - $40M of BP22 revenue financing in FY23
  - $100M additional debt reduction/revenue financing from the FY22 RDC
- The Q3 Reserves for Risk (RFR) forecast mirrors the Q2 methodology and unwinds these liquidity tools to the extent necessary to keep RFR at or near the upper RDC threshold of $638M. At Q3 we are preserving $90M of liquidity:
  - Unwound the full $40M of revenue financing
  - Decreased the FY22 RDC debt payment by $50M
- Treasury will implement this in its FY23 debt and liquidity plans. This approach balances liquidity preservation with our leverage goals, while meeting the settlement commitments.

Q3 FORECAST: TRANSMISSION FINANCIAL RESERVES





Transmission Reserves Range

- 1% to 99% Range:
  $237m to $371m

- 25% to 75% Range:
  $281m to $326m

Transmission Risk Mechanisms

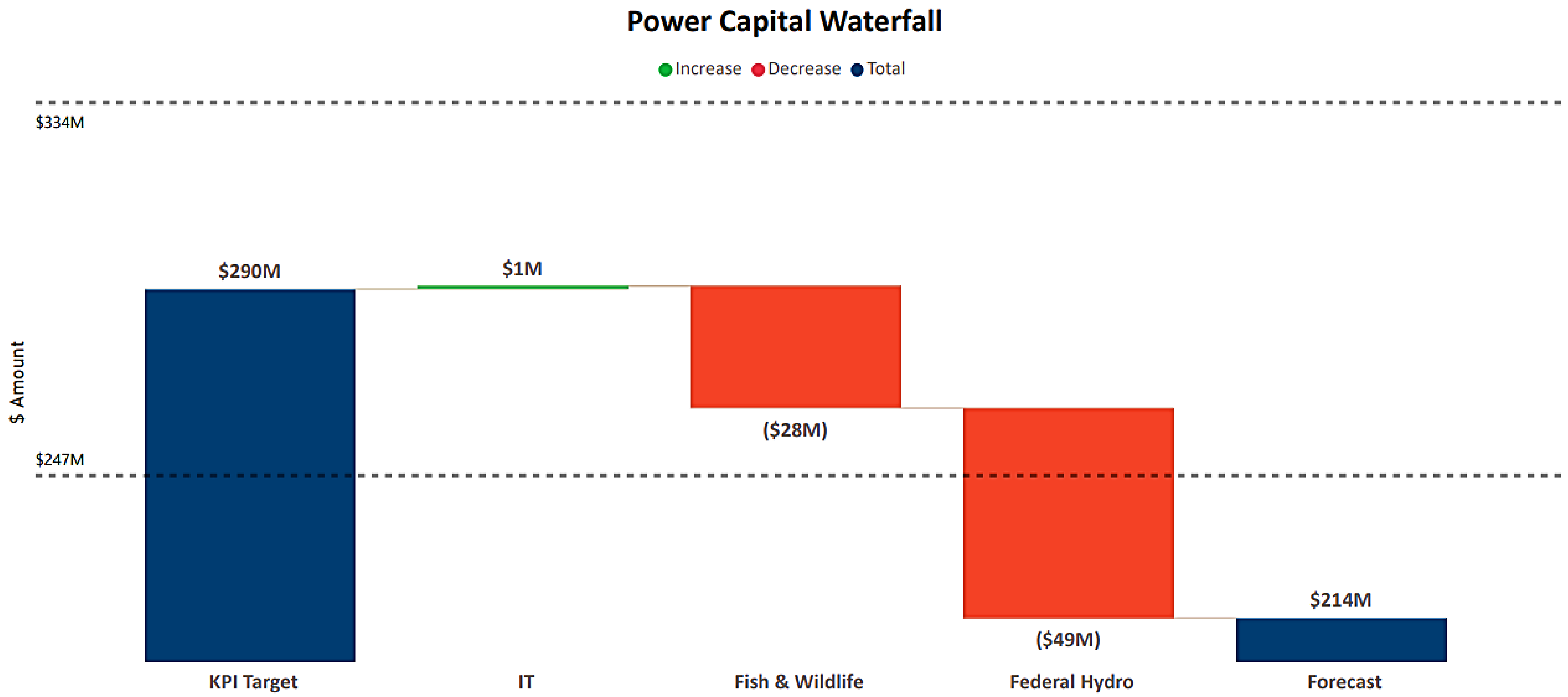
- 99% modeled probability of an RDC with an expected value of $70m

- 0% modeled probability of a CRAC or FRP Surcharge

FY23 Capital forecast

Presenters: Finance Team

Q3 FORECAST: POWER CAPITAL



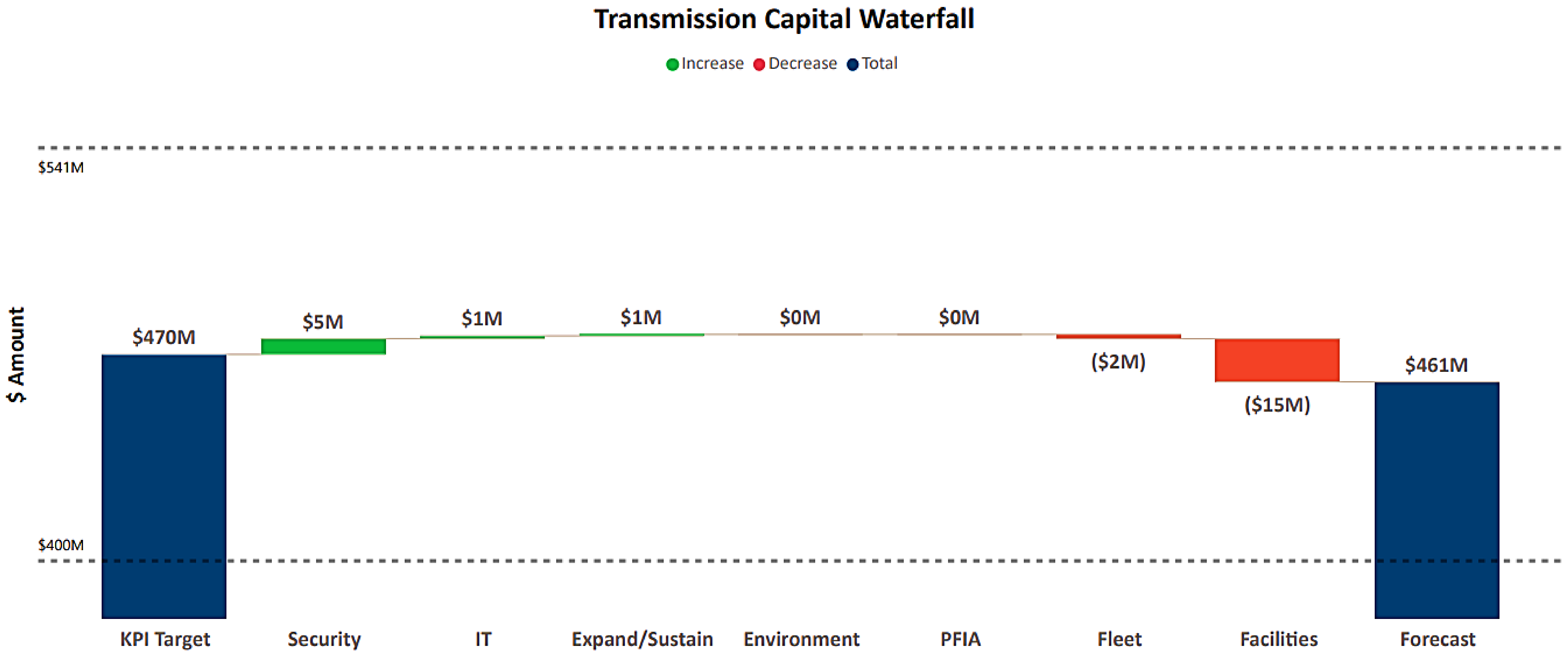
The Power capital expenditure KPI target is a range. The range is equal to +/- 15% of the target midpoint. If Power direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: POWER CAPITAL

Power direct capital decreased $76M primarily due to:

- $1M increase for IT to accommodate Power's EE tracking and Reporting and Ops Log replacement projects.
- $28M decrease in Fish & Wildlife due to hatchery projects design/permitting/bidding delays and passage project delayed to FY24.
- $49M decrease in Fed Hydro due to contracting and staffing constraints. McNary Dam had cascading schedule slippage on a few related projects. The U.S. Army Corps of Engineers Seattle district also has some uncertainty around several projects due to district-wide reprioritization associated with limited staff.

Q3 FORECAST: TRANSMISSION CAPITAL



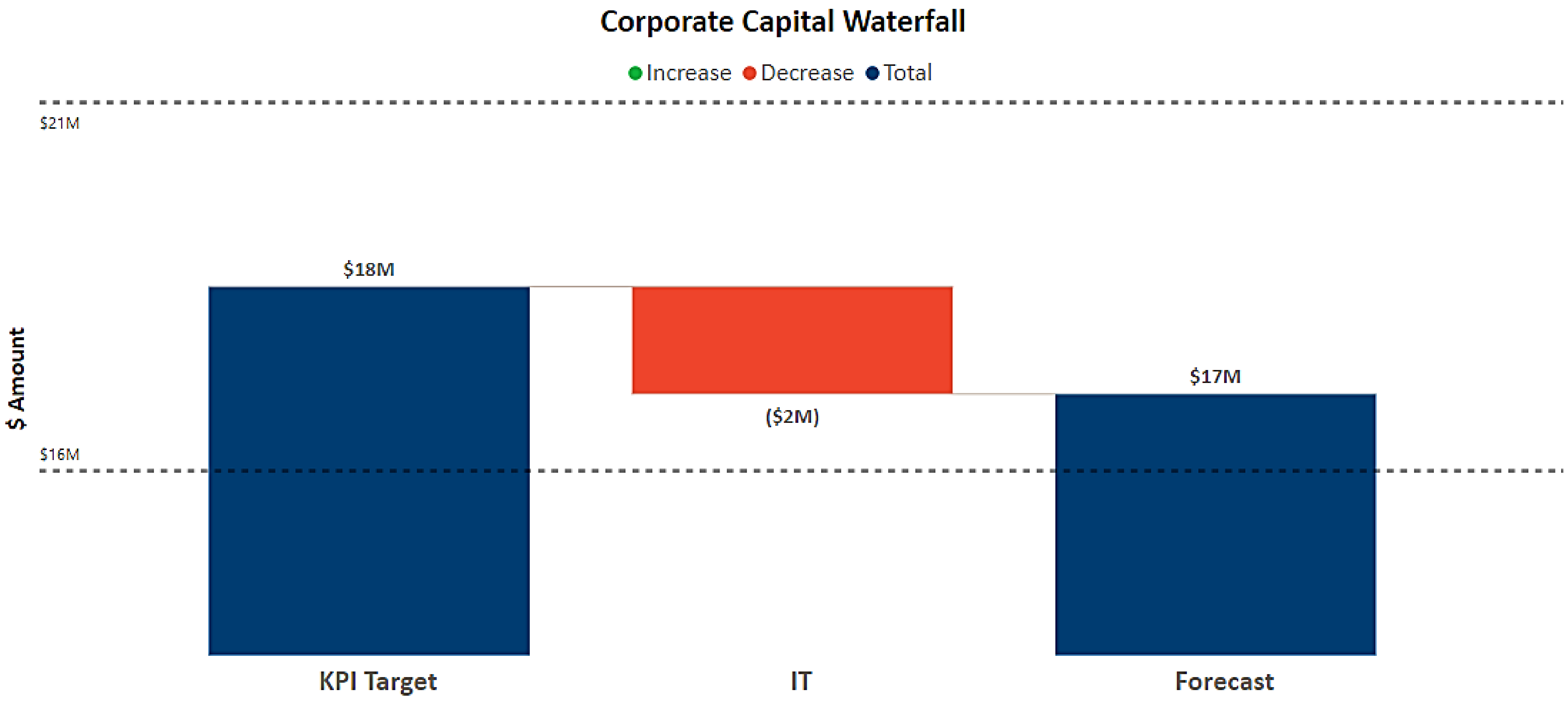
The Transmission capital expenditure KPI target is a range. The range is equal to +/- 15% of the target midpoint. If Transmission direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: TRANSMISSION CAPITAL

Transmission direct capital decreased by $9M primarily related to:

- $5M increase in Security to accommodate spending for the Sno-King and Tacoma build projects that shifted from FY22 to FY23 due to issues with contracting.
- $1M increase for IT to accommodate the Telecom Circuit and Transmission System Rating’s project.
- $1M increase in the Transmission Sustain program to accommodate strong execution in Critical Infrastructure projects, Mission Critical IT, and Outage Management Systems.
- $2M decrease in Fleet due to changes in manufacturer lead times, moving multiple orders and certain pieces into FY 24.
- $15M decrease in Facilities due to design delays related to legal/compliance contract clarifications on the Ampere Demo Project as well as contractor issues on the Vancouver Control Center project which pushed a large portion of design into FY24.

Q3 FORECAST: CORPORATE CAPITAL



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

QBRTW ANALYSIS: CORPORATE CAPITAL

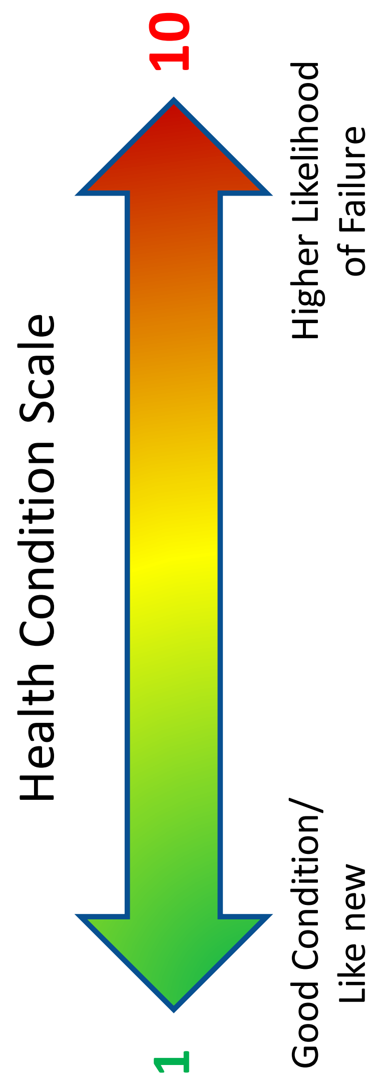
Corporate direct capital decreased $2M due to:

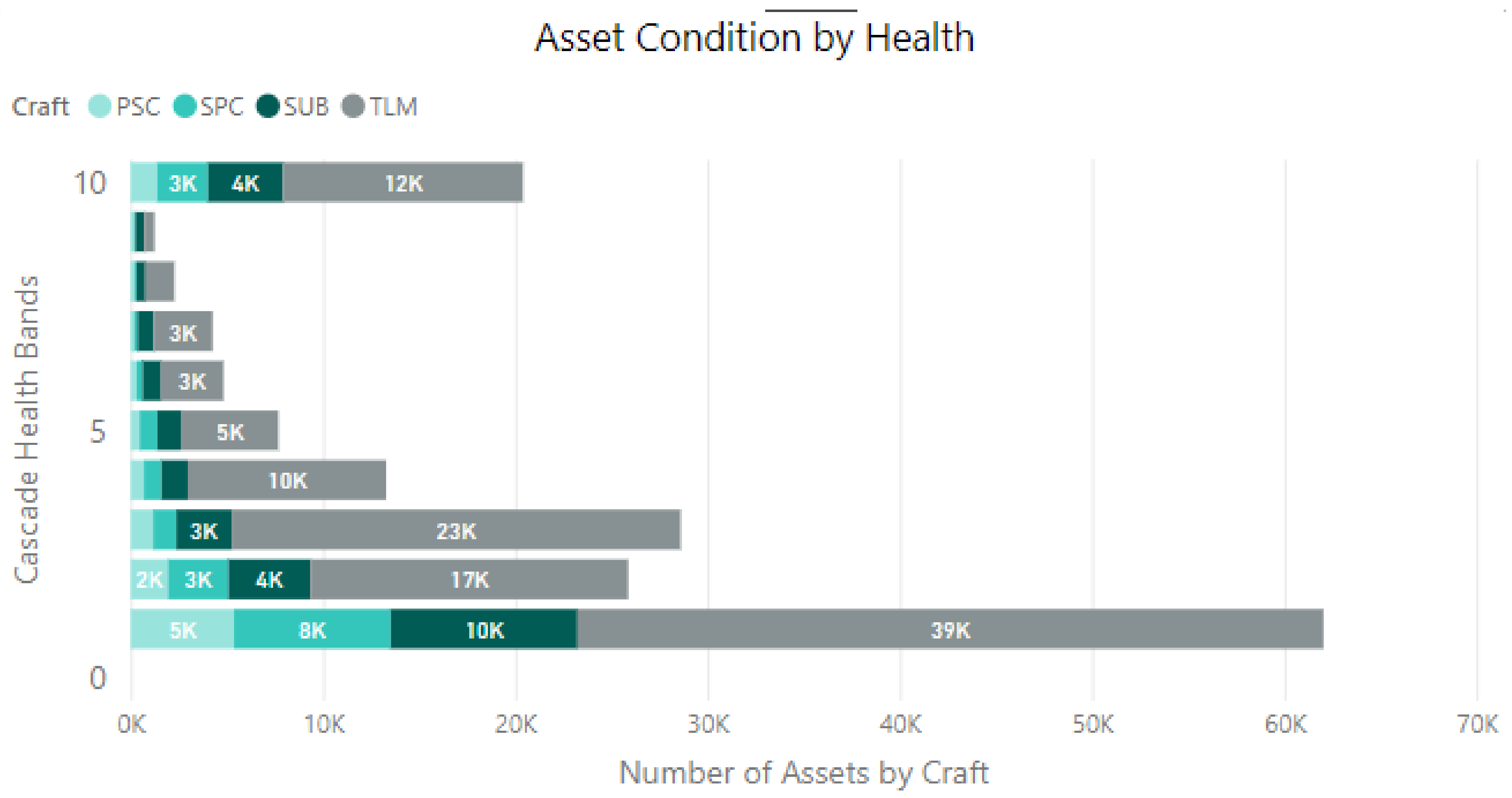
- $2M decrease in corporate IT mainly due to reduced spending on the Corporate IT Land Information System project and increased spending on Power and Transmission projects.
- Note that while a decrease in corporate IT spending is forecasted, the combined increase in Power and Transmission IT spending offsets the corporate decrease resulting in the overall Agency IT capital Q3 forecast being approximately equal to the KPI Target.

TRANSMISSION SERVICES CAPITAL METRICS

Presenters: Jeff Cook and Mike Miller

ASSET MANAGEMENT HEALTH METRIC

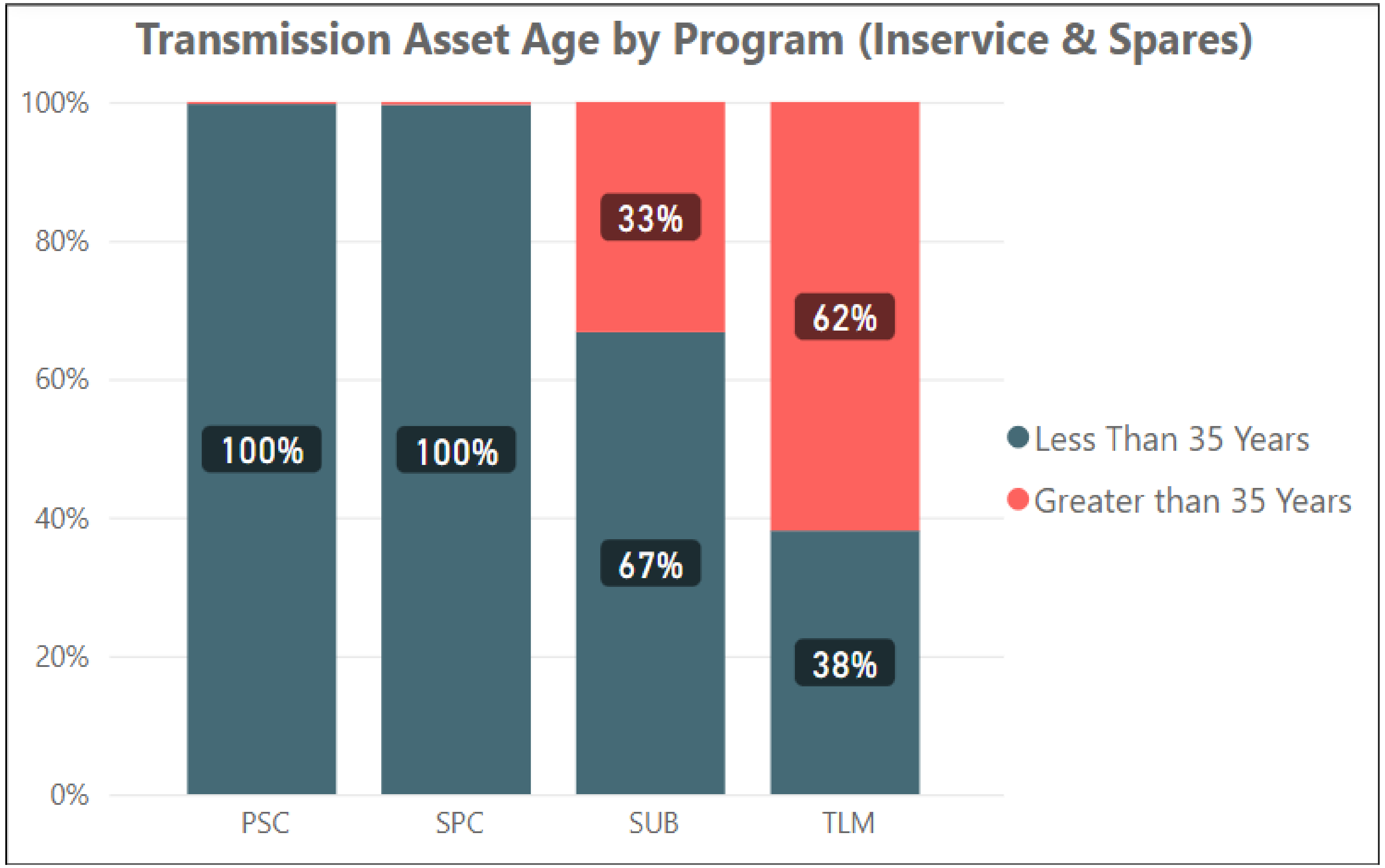




PSC: Power System Control, SPC: System Protection Control, Sub: Substation, TLM: Trans Line Maintenance

***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.

ASSET MANAGEMENT HEALTH METRIC



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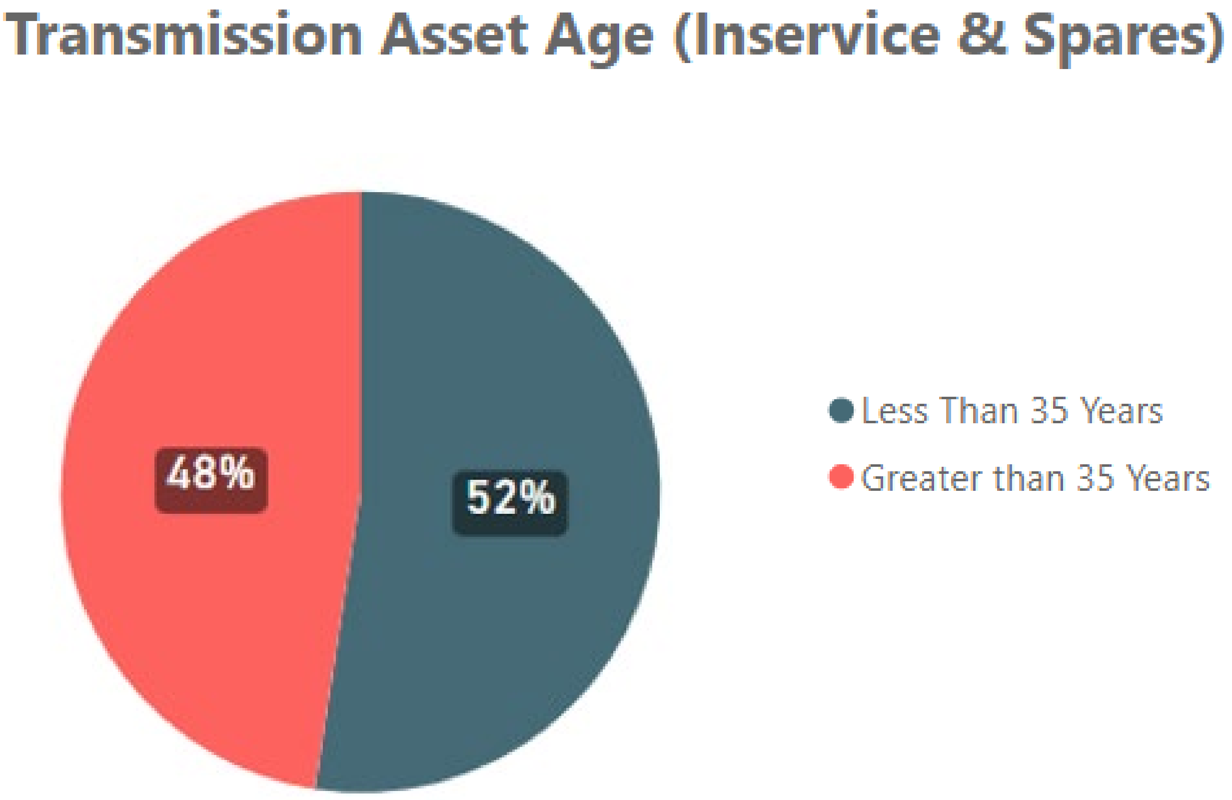
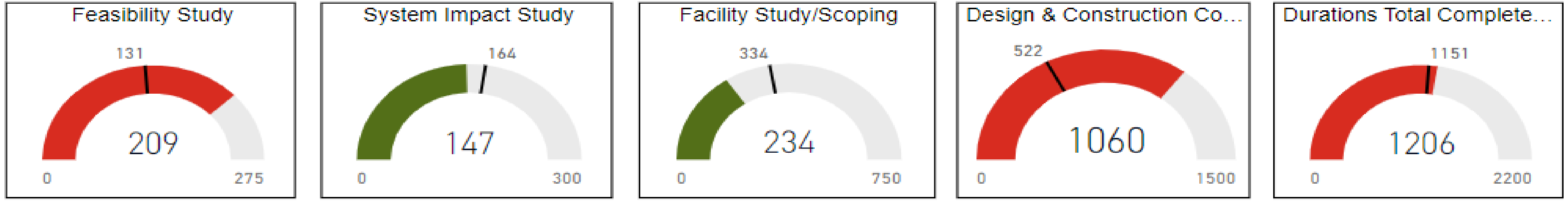
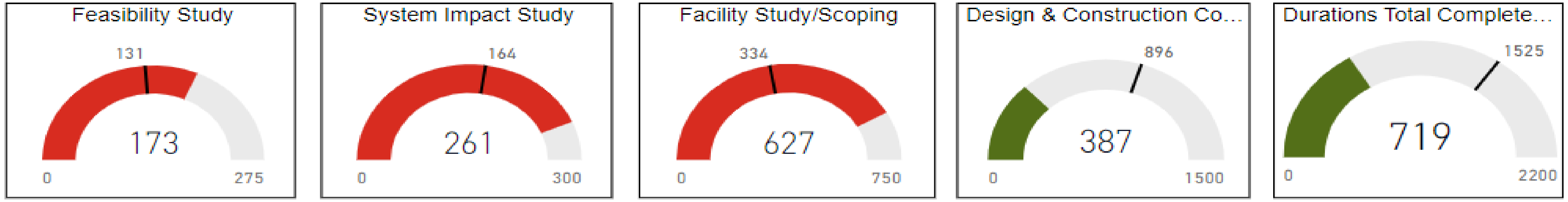


CUSTOMER DURATION METRIC

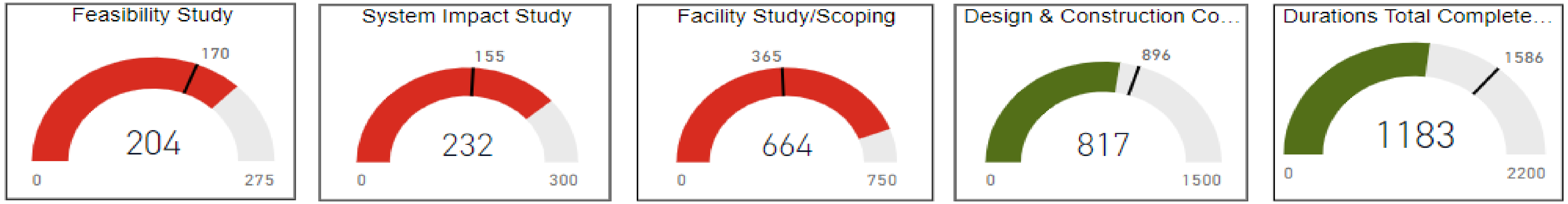
Small Generation Interconnection projects: Projects with an aggregation of generators, whose single or combined generating capacity is > than 0.2MW and = to or < 20MW



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



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



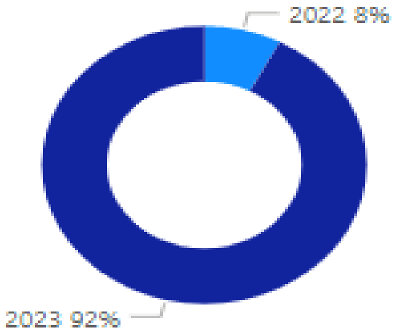
Includes LGI, LLI, SGI projects with a Queue date on or after 01/01/2015

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

* Completed Projects Only

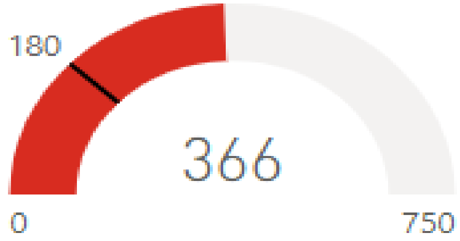
CUSTOMER DURATION METRIC

FAS Study Completion by Year



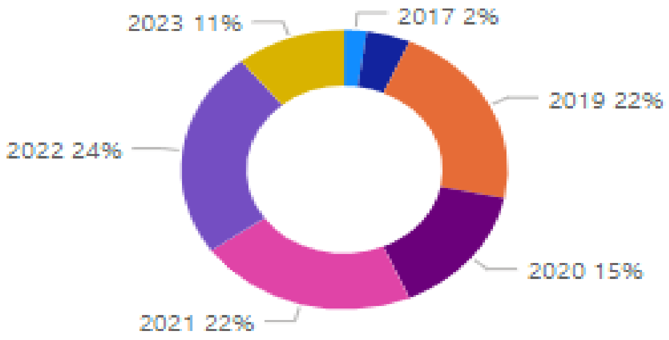
FAS/Scoping No CDD | New Process (14 Projects)

Average Days for Facility Study/Scoping



Includes the time projects were waiting for Scoping Resources prior to starting the New Process

FAS Study Completion by Year



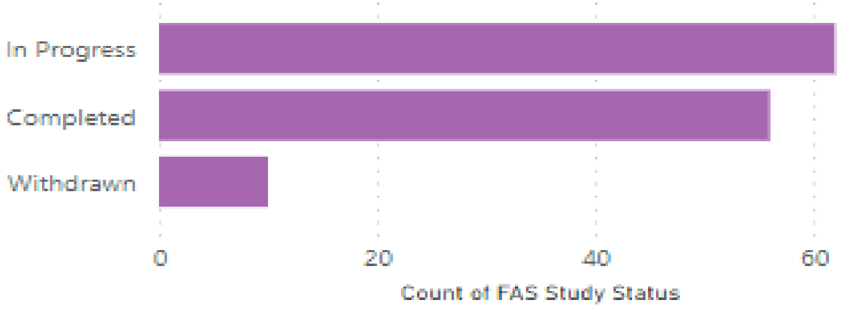
FAS/Scoping with CDD | Old Process (46 Projects)

Average Days for Facility Study/Scoping

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

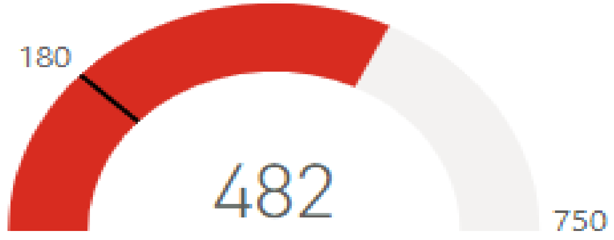
Optimal performance is below the lines, which denote the target ceiling levels

FAS Study Status



FAS/Scoping | New and Old Process (60 Projects)

Average Days for Facility Study/Scoping



* Completed Projects Only

PRIMARY VS SECONDARY CAPACITY THROUGHPUT

Transmission as of FY23 Q3:

TEBI

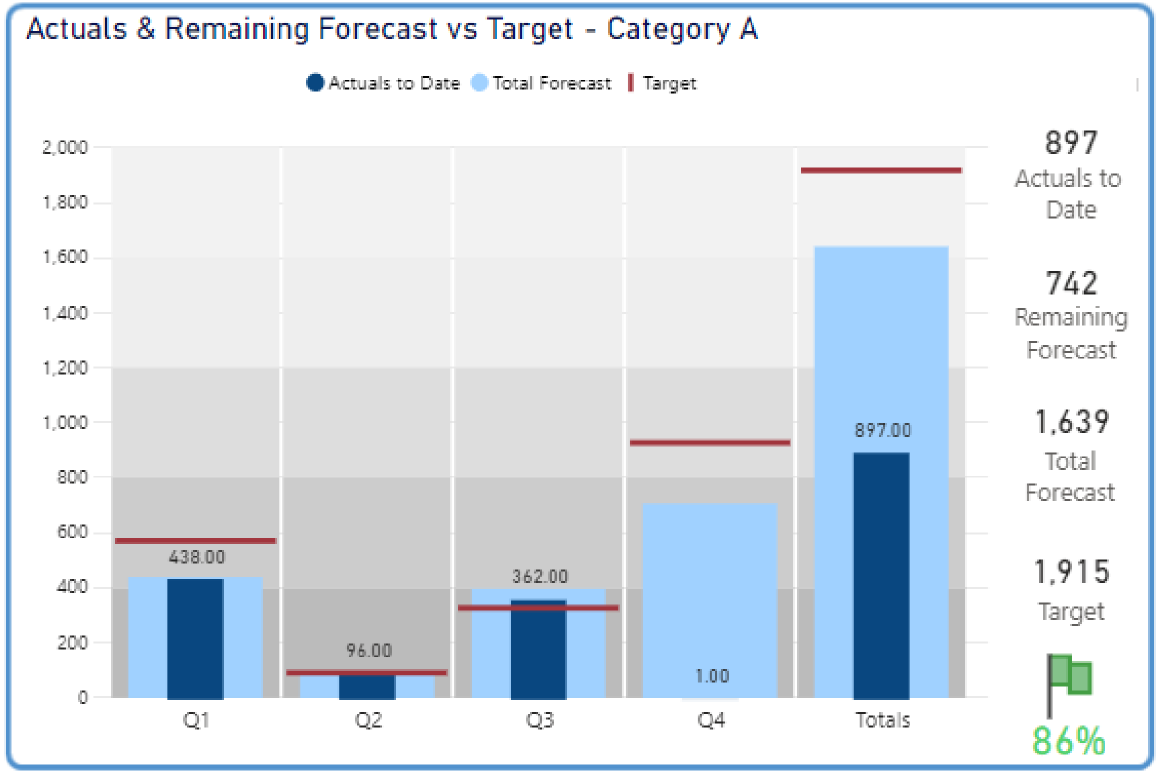
PRIMARY VS SECONDARY CAPACITY THROUGHPUT – CURRENT FY

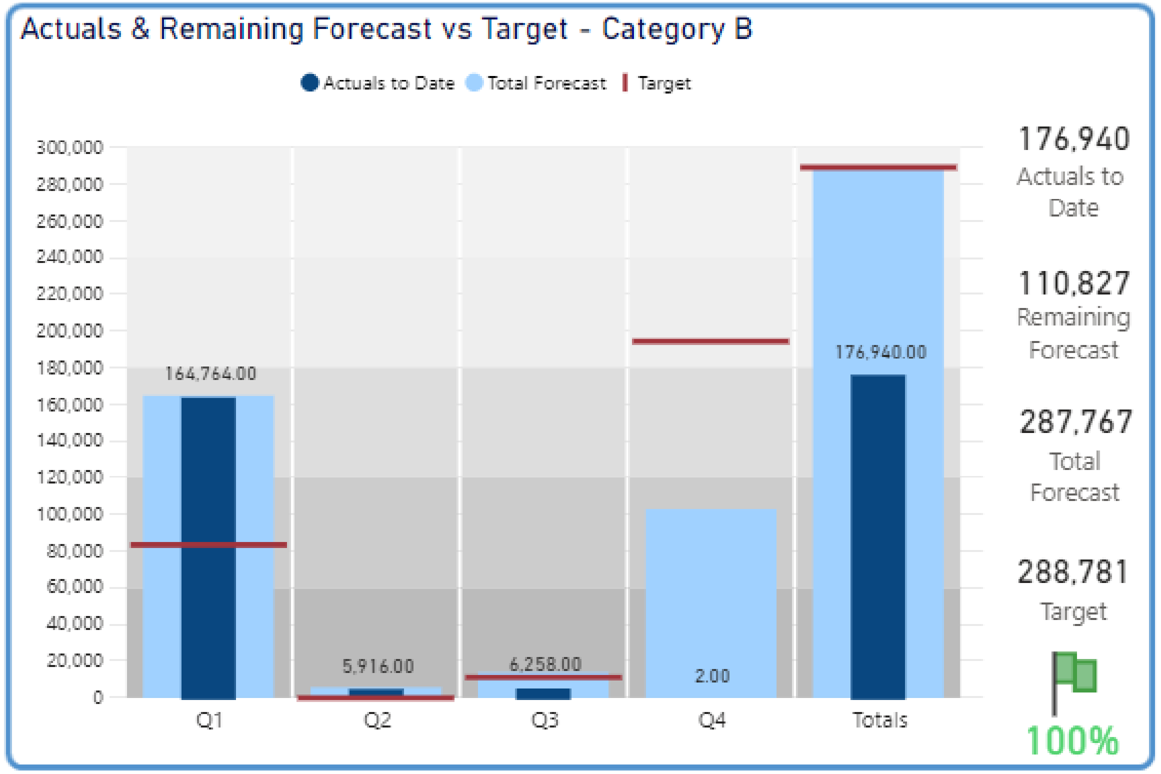
FY23

	PLANNING	SCOPING	DESIGN	CONSTRUCT	ENERGIZED
PRIMARY CAPACITY MODEL	246	90	171	137	348
SECONDARY CAPACITY MODEL	0	31	11	0	0

CAPITAL ASSETS PLANNED VS COMPLETED

Transmission as of FY23 Q3:

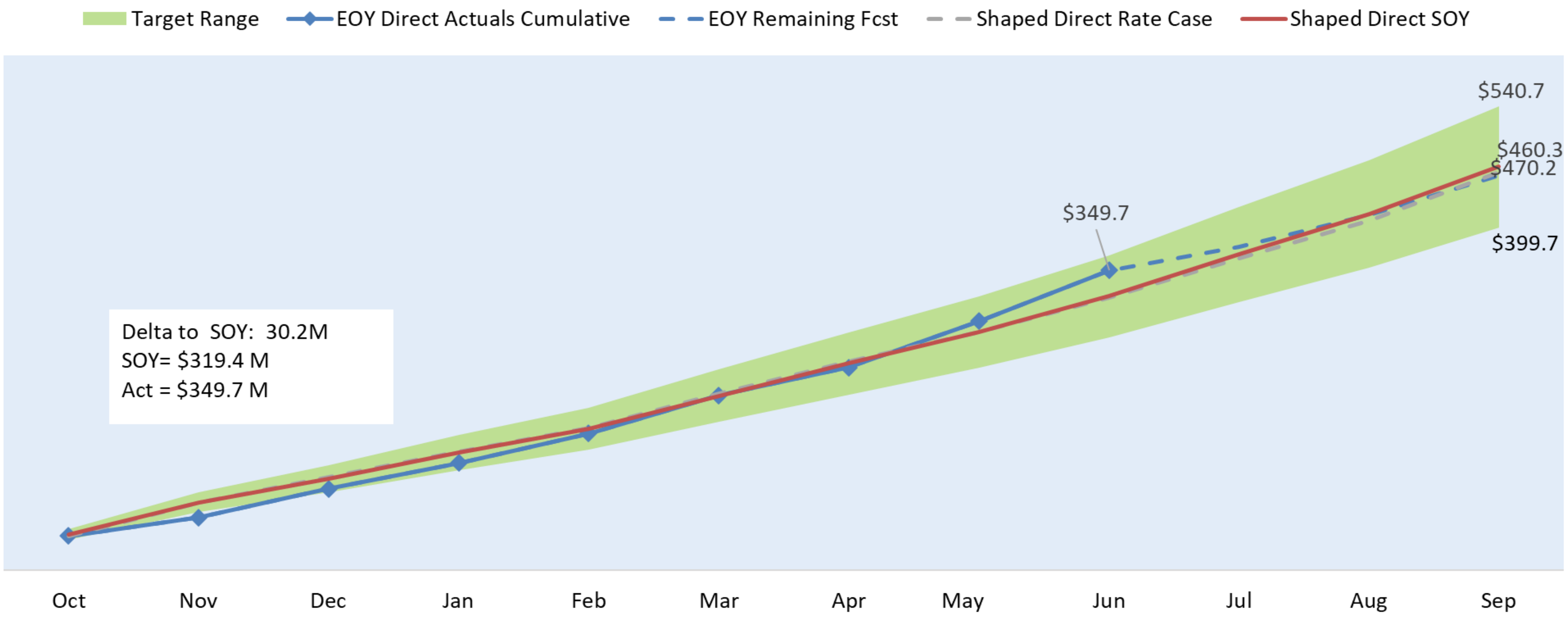




Priority Projects	Target Milestones
Q1 FIN Replacement -- work begins in Q1	Completed
Q2 Buckley GIS Substation replacement – bypass construction to be completed by Q2 FY'23	Completed
Q3 Longhorn Substation – Civil construction begins Q3 FY'23	Completed
Wautoma Series Capacitors – Substation work in support to be completed Q3 FY'23	Completed
FIN Replacement -- preliminary PRD's done by Q3 FY'23 for all 3 regions	Completed
Q4 Transmission Services Building – Facility to be 100% completed by EOY/Q4 FY'23	On Track

Key Takeaway: On Track: On track to meet the target for EOY

CAPITAL SPEND



FY23 Key Performance Indicator

- Structured differently than previous years
- This includes all Transmission Expand, Sustain, PFIA, Non T

- Range using Direct Budget (no loadings)
- High end is +15% of SOY = $540.7M
- Midpoint is equal to SOY = $470.2M
- Low end is -15% of SOY = $399.7M

Key Takeaway: On track Spend is on track to our EOY forecast/Rate Case. We are still experiencing material lead time and ongoing supply chain issues that may have impacts later in the construction season

Grid Modernization Update

Tracey Stancliff

Grid Modernization Mobilization

0%

Identify

3%

AMS MRU Device Event Reporting – 09.30.2023

Define

5%

Power Ops Log Replacement – 01.30.2025
MCIT – Re-Platforming – 03.31.2027

Integrate

47%

Agency Enterprise Portal – TBD
AGC Modernization – 09.30.2023
AMS Replacement – 08.31.2024
AOP & Reliability Assessment – 03.25.2025
BPA Network Model – 12.31.2023
CBC Replacement – 11.05.2024
Concurrent Losses – 12.02.2023
Data Analytics – 09.30.2023
EIM Bid & Base Scheduling – 06.30.2023
EIM Settlements Implementation – 09.30.2023
EIM Testing Program – 09.30.3023
FDGDM – 09.30.2023
Load & Renewable Forecasting – 09.30.2023
Metering Review & Update – 09.30.2026
MCIT – Infrastructure – 07.31.2023
Outage Management System – 11.30.2023
Sub-Hourly Scheduling on the DC – 02.28.2024

Deliver

44%

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
PRADA – 06.30.2023
RAS Automatic Arming – 08.11.2021
RC Decision, Planning & Exec. – 07.14.2021
ST Available Transfer Capability – 07.20.2022

Complete

Canceled Projects: VSA/DTC Phase 2 , Real Time Ops Modernization, AEP 2 , Wildfire Risk Modeling

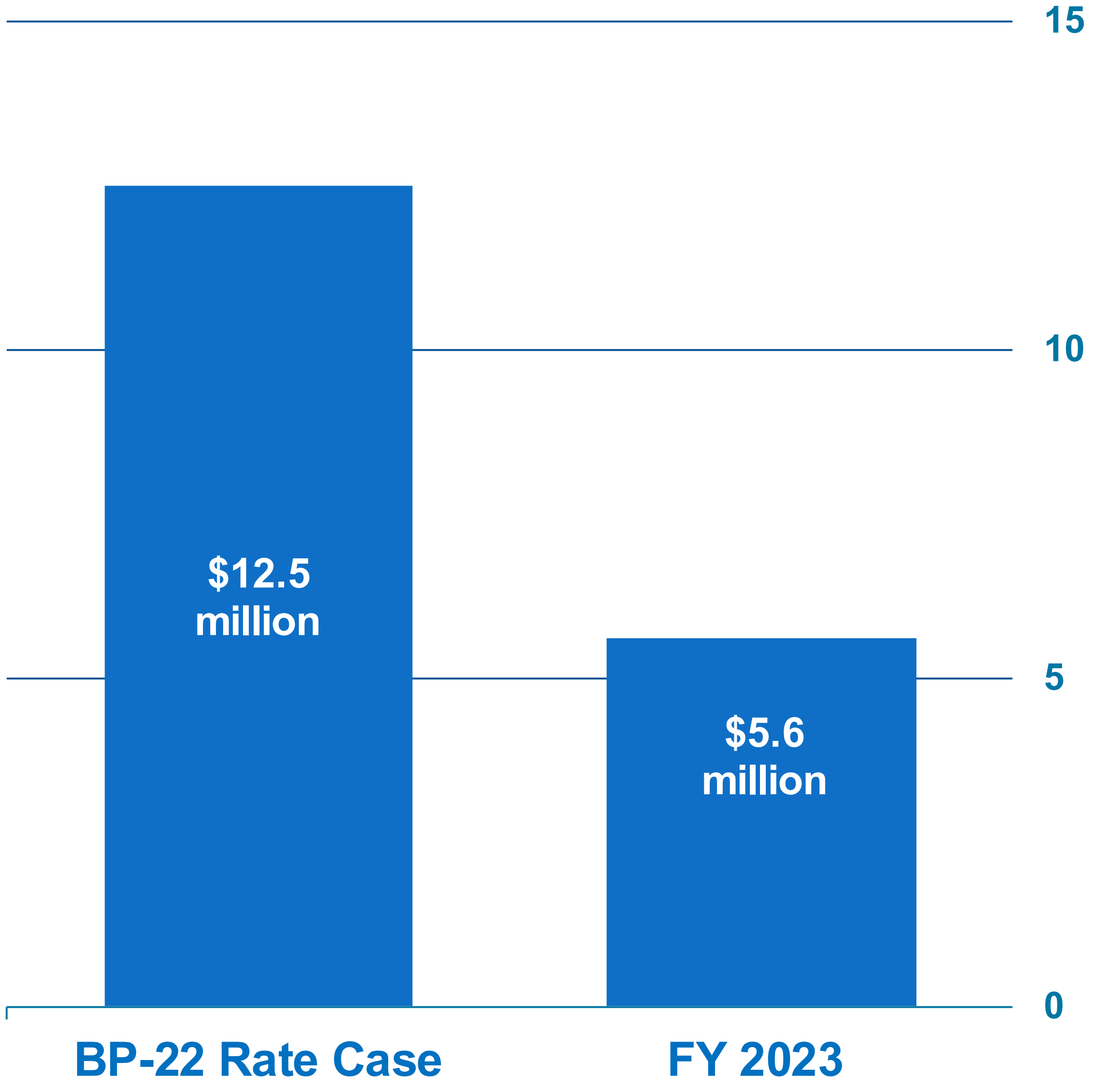
Updated: 07.27.2023
Date = Completion Date

Grid Modernization Progress Metric

93%

- 93% of milestones for projects in deliver are complete or on track
- A milestone identifies the completion of significant events and/or key decisions associated with the grid modernization project. Examples include (but are not limited to) a formal project kickoff, RFO release dates, "go-live" dates for new software, targets for completing training for new processes, and project conclusion.
- The minimum to meet "green" for Q3 FY23 is 80%
- **Status:** **Green**

Grid Mod FY23 Spending



- BPA spent a total of $5.6m as of the end of Q3 FY23. Total FY23 Grid Mod expense budget for FY23 is $12.5 million.

More Information

On grid modernization:
www.bpa.gov/goto/gridmodernization

On EIM:
www.bpa.gov/goto/eim

BPA EIM Metrics Q3 FY2023

Presenters: Matt Germer
Mariano Mezzatesta
Kelii Haraguchi

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 workshop on January 27, 2022, 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).

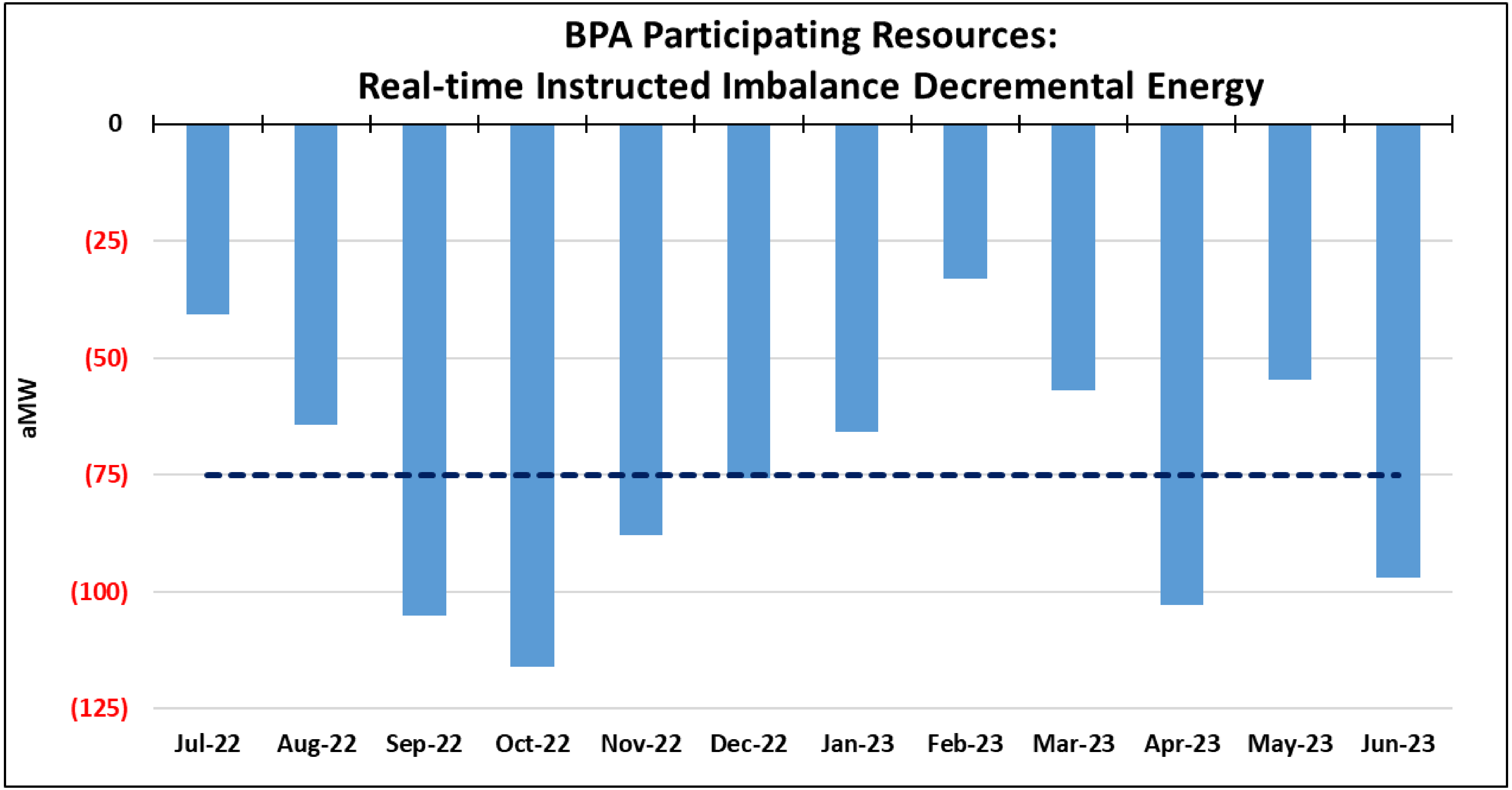
Phase 2 Metrics

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.

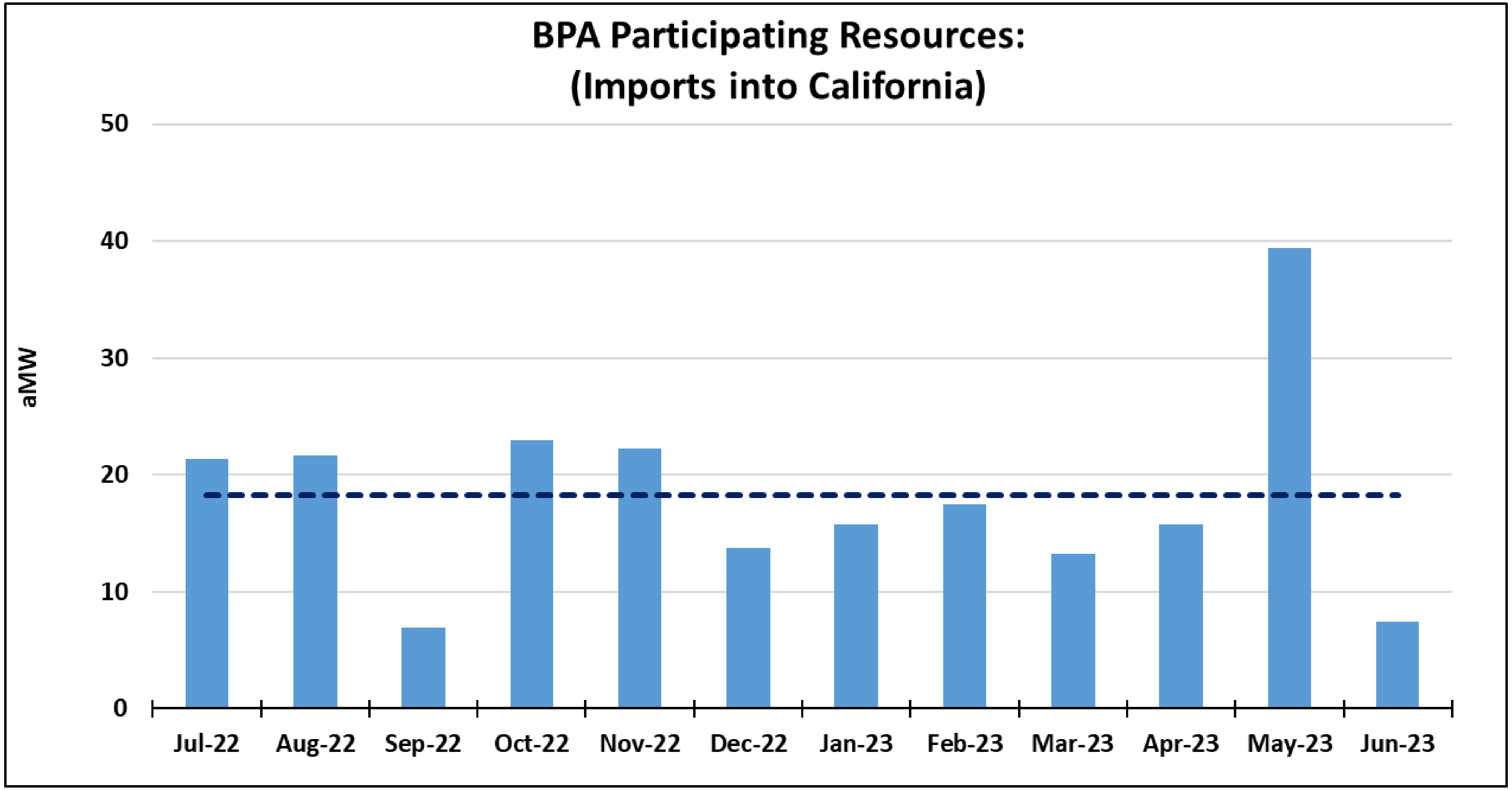
These metrics will be reported by BP-26.

Metric 1a: Unspecified purchases



Total Volume: ~75 aMW (~650,000 MWh) for 7/1/22 – 6/30/23

Metric 1b: Amount Delivered to California



Total Volume: ~20 aMW (~160,000 MWh) for 7/1/22 – 6/30/23

GHG Premium: ~$15.5/MWh

GHG Cost: ~$0.50/MWh

Metric 2: Resource Sufficiency (RS) Evaluation Pass rates

Balancing Test Results

- 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	Apr	May	Jun	Mean
Failed Over	0.42%	0.27%	0.83%	0.51%
Failed Under	0.42%	1.48%	0.56%	0.82%
Passed Both	99.16%	98.25%	98.61%	98.67%

Balancing Test Results: July 22 – June 23

Balancing Test	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Average
Failed Over	0.54%	0.54%	0.83%	4.97%	0.69%	0.13%	0.40%	0.15%	0.13%	0.42%	0.27%	0.83%	0.92%
Failed Under	0.81%	0.40%	1.53%	11.83%	0.56%	2.42%	0.00%	0.15%	0.27%	0.42%	1.48%	0.56%	1.75%
Passed	98.65%	99.06%	97.64%	83.20%	98.75%	97.45%	99.60%	99.70%	99.60%	99.16%	98.25%	98.61%	97.33%

Capacity Test Over Results

- 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	Apr	May	Jun	Mean
Failed	0.42%	0.00%	0.28%	0.23%
Passed	99.58%	100.00%	99.72%	99.77%

Capacity Test Under Results

- 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	Apr	May	Jun	Mean
Failed	0.28%	0.13%	0.14%	0.18%
Passed	99.72%	99.87%	99.86%	99.82%

Capacity Test Results: July 22 – June 23

Capacity Test Over	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Average
Failed	0.00%	0.13%	0.56%	0.00%	0.00%	0.94%	0.00%	0.00%	0.00%	0.42%	0.00%	0.28%	0.19%
Passed	100.00%	99.87%	99.44%	100.00%	100.00%	99.06%	100.00%	100.00%	100.00%	99.58%	100.00%	99.72%	99.81%

Capacity Test Under	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Average
Failed	0.00%	0.00%	0.28%	0.00%	0.00%	0.00%	0.00%	0.15%	0.00%	0.28%	0.13%	0.14%	0.10%
Passed	100.00%	100.00%	99.72%	100.00%	100.00%	100.00%	100.00%	99.85%	100.00%	99.72%	99.87%	99.86%	99.90%

Flex Test Up Results

- 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	Apr	May	Jun	Mean
Failed	0.21%	1.24%	0.35%	0.60%
Passed	99.79%	98.76%	99.65%	99.40%

Flex Test Down Results

- 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	Apr	May	Jun	Mean
Failed	0.56%	5.44%	0.28%	2.09%
Passed	99.44%	94.56%	99.72%	97.91%

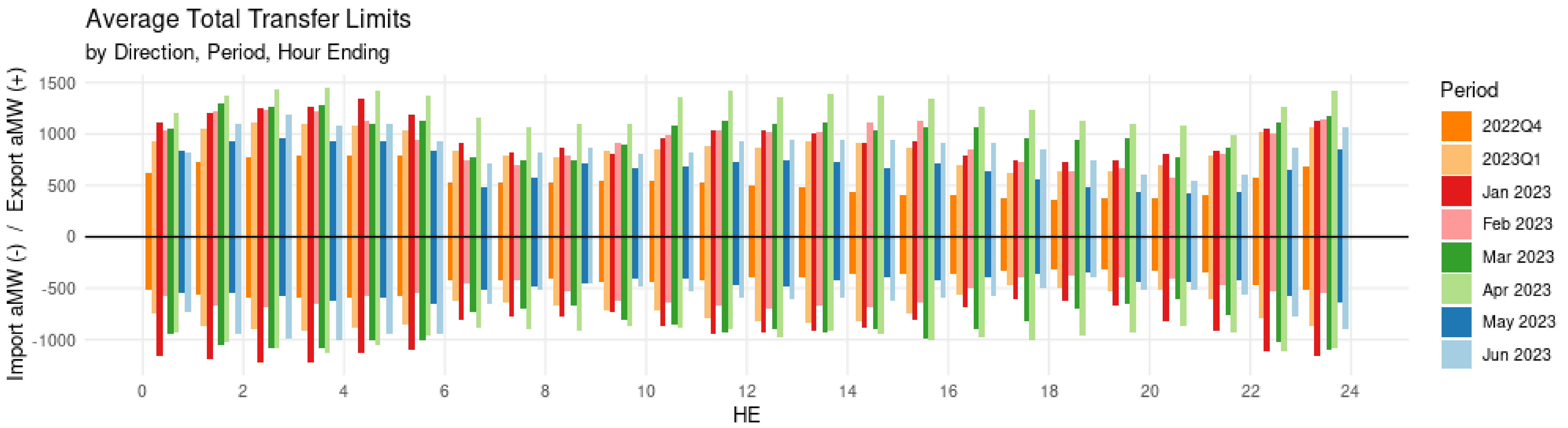
Flex Test Results: July 22 – June 23

Flex Test Up	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Average
Failed	3.23%	1.01%	1.01%	0.17%	0.07%	0.37%	0.00%	0.07%	0.60%	0.21%	1.24%	0.35%	0.88%
Passed	96.77%	98.99%	98.99%	99.83%	99.93%	99.63%	100.00%	99.93%	99.40%	99.79%	98.76%	99.65%	99.12%

Flex Test Down	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Average
Failed	0.00%	0.03%	0.35%	0.00%	0.21%	0.20%	0.00%	0.19%	0.10%	0.56%	5.44%	0.28%	0.58%
Passed	100.00%	99.97%	99.65%	100.00%	99.79%	99.80%	100.00%	99.81%	99.90%	99.44%	94.56%	99.72%	99.42%

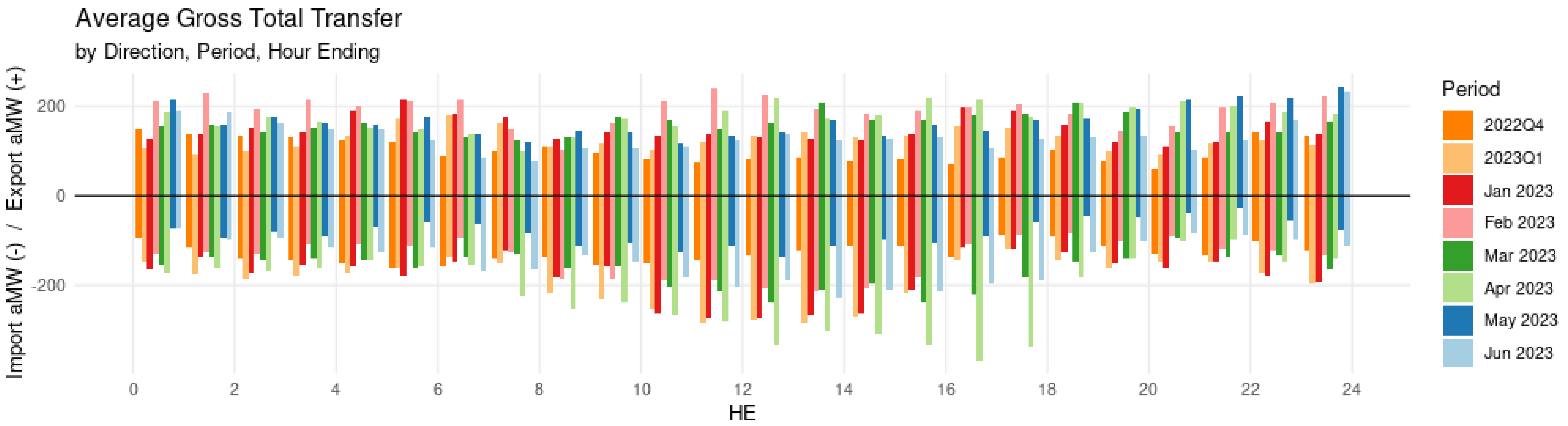
Metric 3: EIM Transfers

EIM Transfer Limits: Q4 2022 – Q3 2023



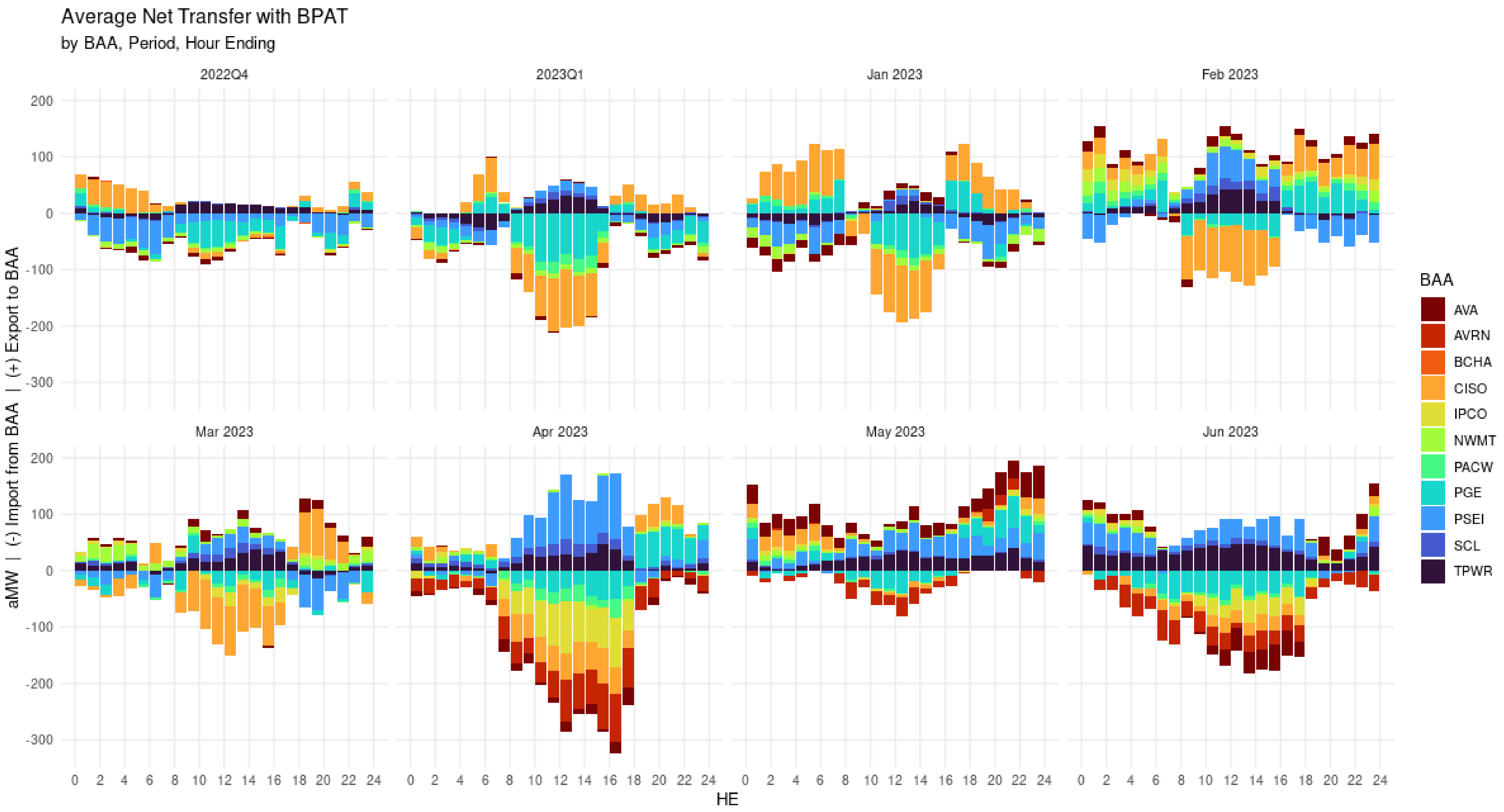
- Decline in transmission donation in May 2023, the bulk of the spring runoff period
- More transmission donation in LLH hours and “belly” hours
- Slight skew toward export transmission across most of the day

EIM Gross Transfer: Q4 2022 – Q3 2023

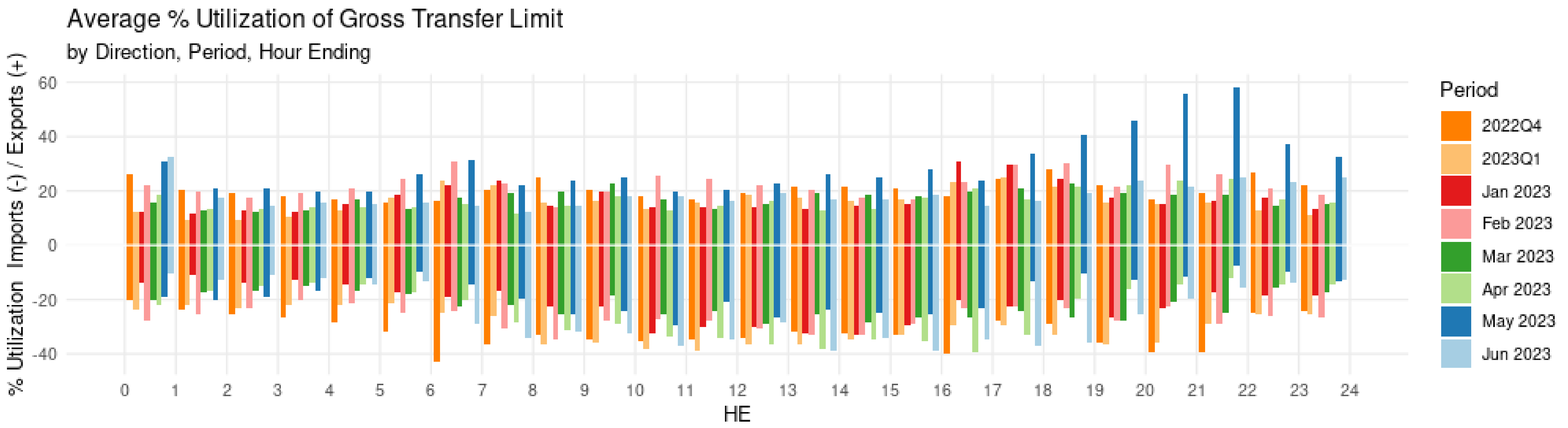


- Hourly shape of transfers generally aligns with price patterns and operational objectives
  - Market conditions in April (low to moderate load and robust renewable generation) led to relatively low prices in "belly" hours
  - Energy position long in May during runoff

EIM Net Transfer by BAA: Q4 2022 – Q3 2023

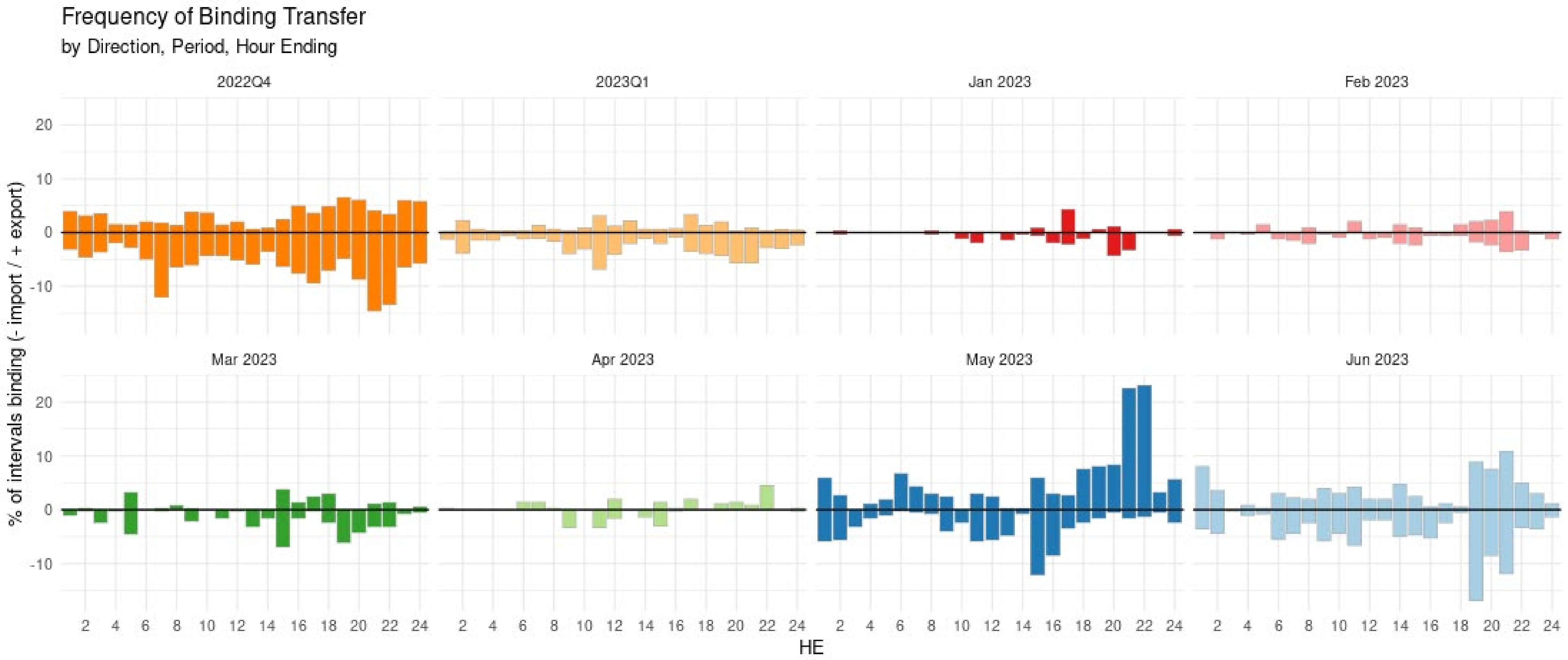


EIM Utilization of Transfer Limits: Q4 2022 – Q3 2023



- Percent utilization is consistent with
  - Greater limits in both directions during LLH hours (*intra-day shape*)
  - Tendency for net imports combined with relatively high export limits and relatively low import limits (*comparative levels of utilization for imports versus exports*)
  - Heat wave in September (2022Q4) led to relatively large gross imports, particularly in the evening peak hours (when transfer limits are lower)
  - Runoff in May led to high utilization of exports across the day, and particularly in the evening peak hours (when transfer limits are lower)

Frequency of binding EIM transfers: Q4 2022 – Q3 2023



- Import limits are more likely to bind, with the notable exception of May 2023, in which runoff and surplus hydro generation led to sizeable net exports.
- Binding frequency tends to be higher in evening peak hours, when transfer limits are smaller in magnitude.

Note: Transfers and limits include both static and dynamic transmission. Binding incidence flagged anytime gross transfer reaches gross import limit or gross export limit.

Metric 4: Not reporting at this time

- Metric: 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.

- The CAISO reports publically* on the accuracy of its area load forecast. In addition, the balancing test results show how frequently the BPA BAA has scheduled to CAISO's load forecast, and the BPA BAA has scheduled thus far to the CAISO's load forecast the majority of the time. When BPA proposed this metric, it was envisioned that BPA would not schedule to the CAISO's load forecast as frequently. However, throughout implementation, BPA has consistently scheduled to the CAISO's load forecast.

* CAISO reports quarterly at the Market Performance and Planning Forum

BPA EIM Metrics

Appendix

Background on Resource Sufficiency 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

Western Resource Adequacy Program Update

Presenters: Steve Bellcoff

August 10, 2023

Agenda: WRAP Update

- What’s Happening in WRAP
- WPP Implementation Plan
- BPA Active Work with WRAP
- Operations Program Testing
- Revisiting our commitments

What’s Happening in WRAP

Items in Progress

Forward Showing

- Reviewing Forward Showings for Winter 24/25
- Beginning work on Forward Showing technology solution

Operations Program

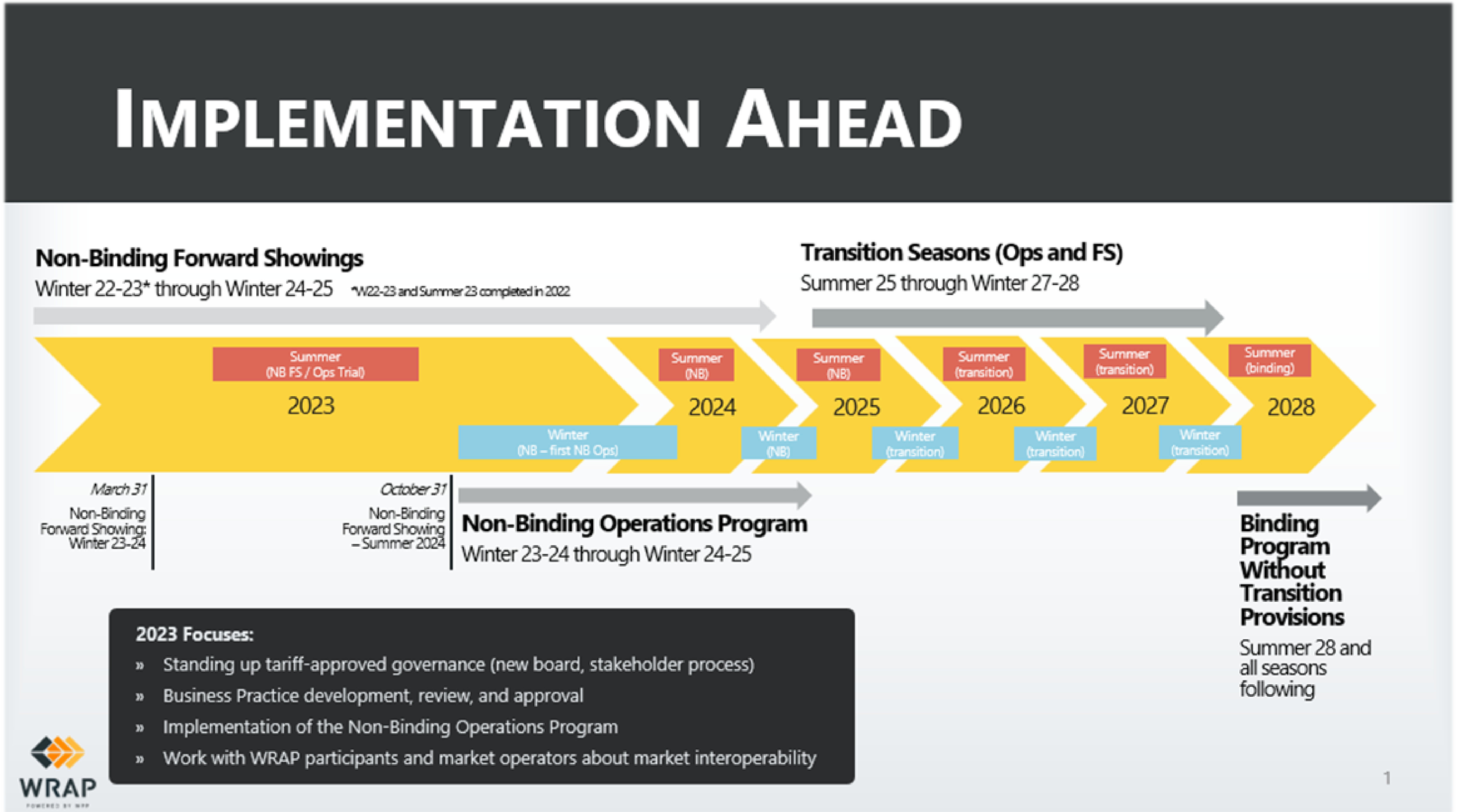
- Connectivity Testing (June 5 – July 28)
- Structured Testing (July 3 – August 14)
- Operations Trials (August 3 – November 1)
- Summer 2023 Interim RA Program underway

Governance

- Seated new Board of Directors in February 2023 and hosted first public meeting May 31
- **Upcoming Board of Directors meeting August 23**
- Working on first round of Business Practice Manuals

WRAP

WPP Implementation Plan



BPA Active Work with WRAP

- **WRAP participant work:**
  - RAPC – reviewing and continuing development and design getting to full binding seasons
  - Forward Showing Work Group – engaged in activities and discussion for FS submittals and well as discussions/suggestions/ feedback on development of Business Practice Manuals
  - Ops Work Group – engaged in setting up, early WRAP system testing, and preparing for Ops Trials, discussions/suggestions/ feedback on development of Business Practice Manuals
  - PRC – participating member, actively reviewing materials as available

- **Internal work:**
  - Forward Showing Submittal – preparation of submittals, documentation of processes, development of stand practices for submittals
  - Ops program – continued work to understand program, outline/development and documentation of BPA requirements and practices required for participation
  - Development work related to internal process and programs required for participation

Operations Program Testing Timeline

Registration
- In Progress
  - 1/17/23 – 4/17/23

COMPLETE

Connectivity Setup
- MTE
  - 5/2/23 – 6/2/23
- PRD
  - 6/1/23 – 6/16/23

COMPLETE

Connectivity Testing
- MTE
  - 6/5/23 – 6/30/23
- PRD
  - 7/10/23 – 7/28/23

COMPLETE

(Un)Structured Testing
- MTE
  - 7/3/23 - 8/14/23

We are Here

Ops Trials
- PRD
  - 8/3/23 -11/1/23

SPP

Revisiting Our Commitments

Questions

- More information on BPA’s participation in the Western Resource Adequacy Program can be found on the BPA RA webpage :

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

- For more information on the Western Power Pool’s Western Resource Adequacy Program at https://www.westernpowerpool.org/

Western Resource Adequacy Program Update

Appendix

Final Closeout Letter Commitments

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

Stakeholder Engagement Plan

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

Stakeholder Engagement Plan cont.

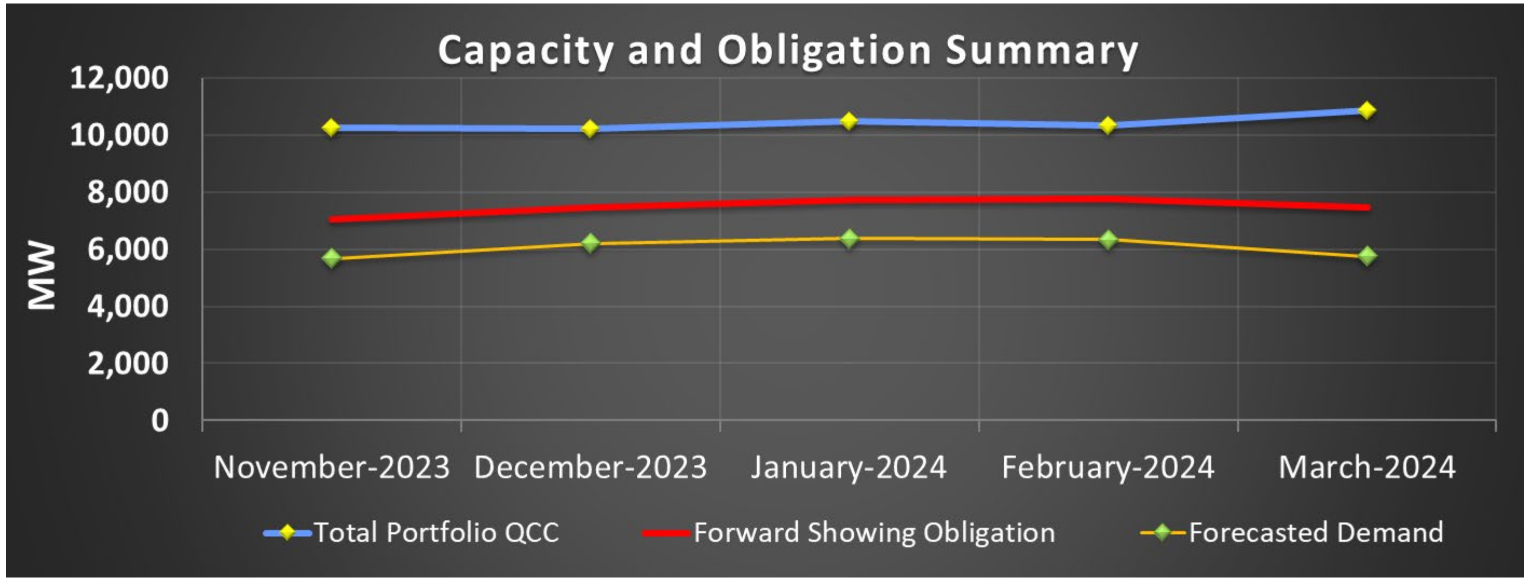
- Engagement with customers and stakeholders will consist of:
  - Public meetings with a minimum of 4 meetings, preferably through the QBR Technical Workshops
  - Short-term Issue-focused workshops, as needed
  - Customer-impacted meetings focused by topic, upon request
- BPA proposes to host meetings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

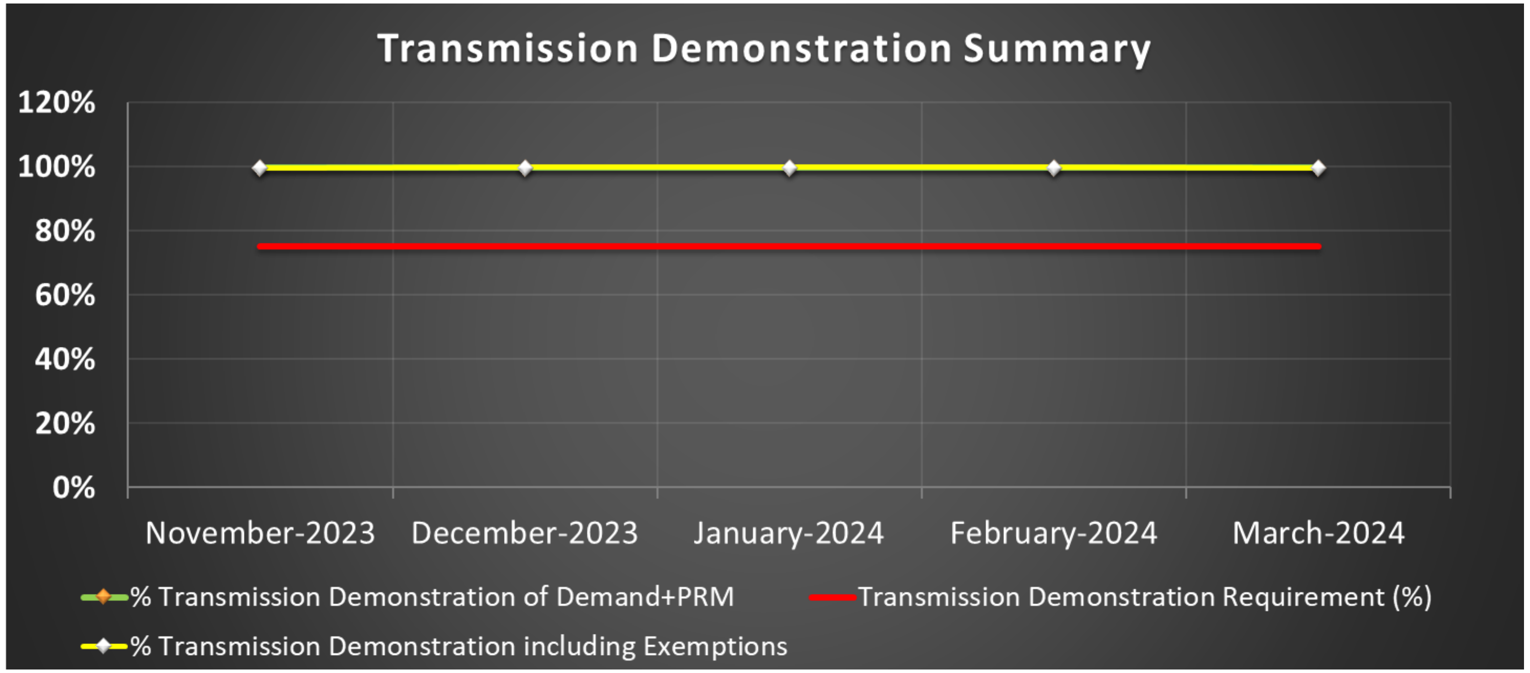
Stakeholder Engagement Topics

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

Forward Showing Results

Winter 2023/2024





Forward Showing Results Continued

Winter 2023/2024

Requirements Summary						
	Season	November-2023	December-2023	January-2024	February-2024	March-2024
Program Monthly PRM	Winter	21.6%	17.7%	19.0%	19.9%	26.9%
Peak Demand - DR Programs + PRM	Winter	6,906.7	7,293.3	7,571.2	7,596.8	7,297.4
Operating Reserves Adjustment	Winter	147.0	152.2	154.0	144.8	145.1
Forward Showing Obligation	Winter	7,053.7	7,445.6	7,725.2	7,741.6	7,442.5
Surplus/Deficient Capacity	Winter	3,196.7	2,783.5	2,767.5	2,579.7	3,424.4
Forward Showing Requirement Met	Winter	Yes	Yes	Yes	Yes	Yes

Transmission Demonstration Summary						
	Season	November-2023	December-2023	January-2024	February-2024	March-2024
Peak Demand - DR Programs + PRM	Winter	6,906.7	7,293.3	7,571.2	7,596.8	7,297.4
Transmission Demonstrated (Completed Paths)	Winter	6,881.7	7,269.8	7,547.1	7,572.9	7,271.2
Transmission Exemptions Requested	Winter	0.0	0.0	0.0	0.0	0.0
% Transmission Demonstration of Demand+PRM	Winter	99.6%	99.7%	99.7%	99.7%	99.6%
% Transmission Demonstration including Exemptio	Winter	99.6%	99.7%	99.7%	99.7%	99.6%
Transmission Demonstration Requirement (%)	Winter	75.0%	75.0%	75.0%	75.0%	75.0%
Transmission Requirement Met (75%)	Winter	Yes	Yes	Yes	Yes	Yes

QUESTION & ANSWER

Didn't get your question answered?

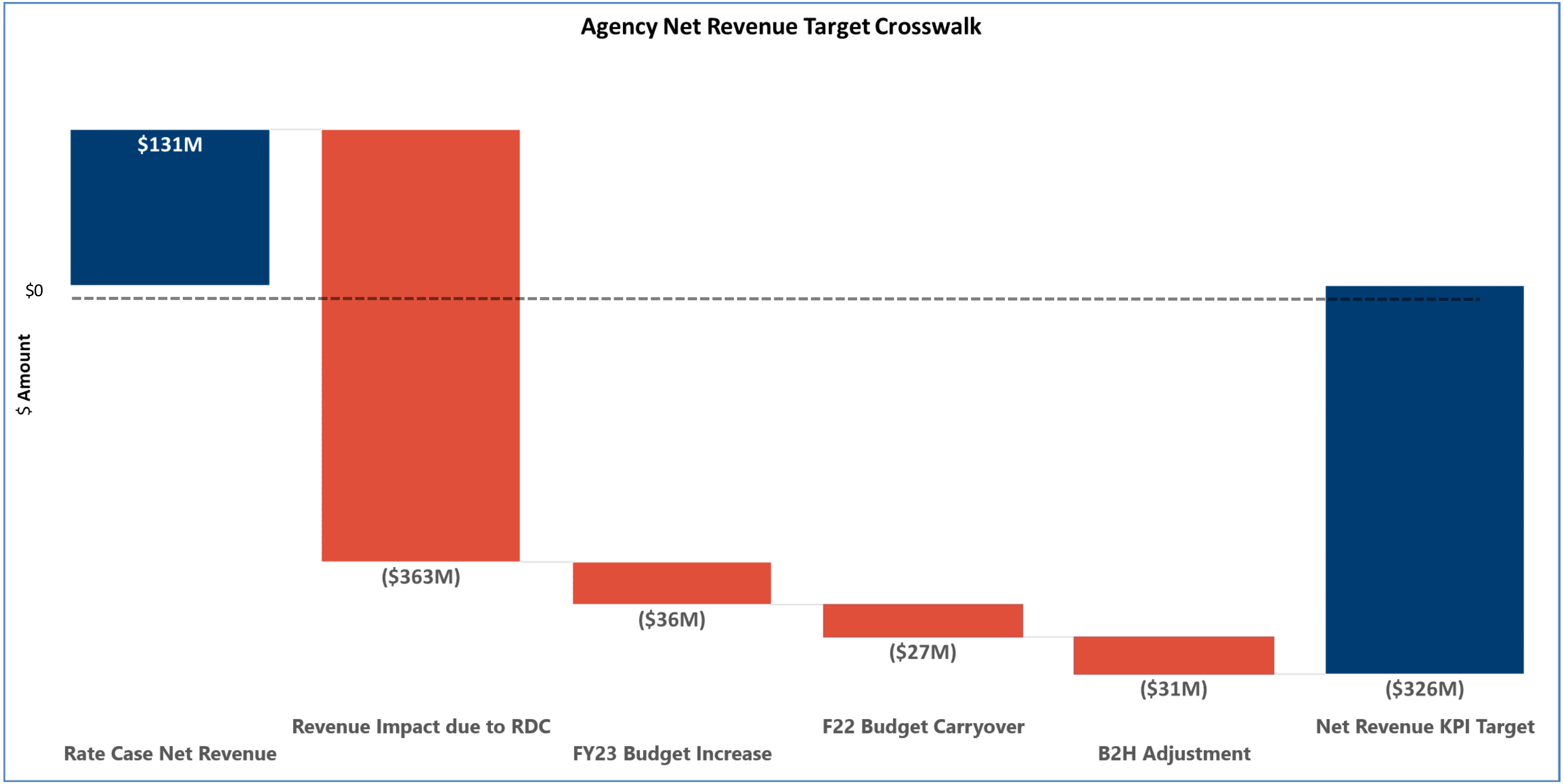
Email Communications@bpa.gov

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

APPENDIX

Crosswalk: Rate Case Net Revenue to KPI Target

CROSSWALK: RATE CASE NET REVENUE TO KPI TARGET



APPENDIX
SLICE REPORTING

Composite Cost Pool Review

Forecast of Annual Slice True-Up Adjustment

Q3 True-Up of FY 2023 Slice True-Up Adjustment

	FY 2023 Forecast **$ in thousands**
February 14, 2023 First Quarter Technical Workshop	$4,089*
May 11, 2023 Second Quarter Technical Workshop	$(35)*
August 10, 2023 Third Quarter Technical Workshop	$(4,583)*
November 14, 2023 Final Slice True-Up Technical Workshop	

*Negative = Credit; Positive = Charge

Summary of Differences From Q3 to FY23 (BP-22)

#		Composite Cost Pool True-Up Table Reference	Q3 – Rate Case $ in thousands
1	Total Expenses	Row 100	$93,242
2	Total Revenue Credits	Rows 119 + 128	$145,368
3	Minimum Required Net Revenue	Row 154	$32,235
4	TOTAL Composite Cost Pool (1 - 2 + 3) $93,242 - $145,368 + $32,235 = $(19,892)	Row 159	$(19,892)
5	TOTAL in line 4 divided by 0.9706591 sum of TOCAs $(19,892)/ 0.9706591 = $(20,493)	Row 161	$(20,493)
6	QTR Forecast of FY23 True-up Adjustment 22.36267 percent of Total in line 5 0.2236267 * $(20,493)= $(4,583)	Row 162	$(4,583)

FY23 Impacts of Debt Management Actions

#	Description	FY23 Q3 QBR	FY23 Rate Case	CCP	Delta from the FY23 rate case
1	MRNR Section of Composite Cost Pool Table				$ -
2	**Principal Payment of Federal Debt**				$ -
3	2023 Regional Cooperation Debt (RCD)	$ 400,949,076	$ 402,560,000		$ 1,610,924
4	2023 Debt Service Reassignment (DSR)	$ 16,015,000	$ 16,865,000		$ 850,000
5	Energy Northwest's Line Of Credit (LOC)	$ -	$ -		$ -
6	Rate Case Scheduled Base Power Principal*	$ 105,665,000	$ 105,665,000		$ -
	Repayment due to FY22 RDC	$ 79,000,000	$ -		$ (79,000,000)
7	**Total Principal Payment of Fed Debt**	**$ 601,629,076**	**$ 525,090,000**	row 131	**$ (76,539,076)**
8	**Prepay**	$ 23,801,393	$ 23,801,393		$ -
					$ -
9	**Nonfederal Bond Principal Payment**	$ 21,111,400	$ 21,111,400	row 133	$ -

Composite Cost Pool Interest Credit

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

		Q3 2023
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	5.57%
5	Composite Interest Credit	(32,654)
6	Prepay Offset Credit	0
7	Total Interest Credit for Power Services	(50,300)
8	Non-Slice Interest Credit (Line 7 – (Line 5 + Line 6))	(17,646)

Net Interest Expense in Slice True-Up Q3

	FY23 Rate Case ($ in thousands)	Q3 ($ in thousands)
• Federal Appropriation	38,609	42,793
• Capitalization Adjustment	(45,937)	(45,937)
• Borrowings from US Treasury	40,881	55,437
• Prepay Interest Expense	6,799	6,799
• **Interest Expense**	**40,352**	**59,091**
• AFUDC	(11,469)	(17,400)
• Interest Income (composite)	(1,235)	(32,654)
• Prepay Offset Credit	(0)	(0)
• **Total Net Interest Expense**	**27,648**	**9,037**

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

Dates	Agenda
February 14, 2023	First Quarter Technical Workshop
May 11, 2023	Second Quarter Technical Workshop
August 10, 2023	Third Quarter Technical Workshop
October 2023	BPA External CPA firm conducting audit for fiscal year end
Mid-October 2023	Recording the Fiscal Year End Slice True-Up Adjustment Accrual
End of October	Final audited actual financial data is expected to be available
November 13, 2023	Mail notification to Slice Customers of the Slice True-Up Adjustment for the Composite Cost Pool
November 14, 2023	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, 2023	BPA to post Composite Cost Pool True-Up Table containing actual values and the Slice True-Up Adjustment
December 8, 2023	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 22, 2023	BPA posts a response to customer questions (Attachment A does not specify an exact date)
January 9, 2024	Customer comments are due on the list of tasks (The deadline can not exceed 10 days from BPA posting)
January 31, 2024	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

		July (Q3) ($000)	Rate Case forecast for FY 2023 ($000)	July (Q3) - Rate Case Difference
1	Operating Expenses			
2	Power System Generation Resources			
3	Operating Generation			
4	COLUMBIA GENERATING STATION (WNP-2)	$ 315,182	$ 304,748	$ 10,434
5	BUREAU OF RECLAMATION	$ 160,248	$ 152,963	$ 7,285
6	CORPS OF ENGINEERS	$ 257,057	$ 252,557	$ 4,500
7	CRFM STUDIES	$ 5,373	$ 3,619	$ 1,754
8	LONG-TERM CONTRACT GENERATING PROJECTS	$ 16,655	$ 17,123	$ (468)
9	**Sub-Total**	**$ 754,516**	**$ 731,010**	**$ 23,506**
10	Operating Generation Settlement Payment and Other Payments			
11	COLVILLE GENERATION SETTLEMENT	$ 25,946	$ 22,000	$ 3,946
12	SPOKANE LEGISLATION PAYMENT	$ 6,487	$ 5,500	$ 987
13	**Sub-Total**	**$ 32,433**	**$ 27,500**	**$ 4,933**
14	Non-Operating Generation			
15	TROJAN DECOMMISSIONING	$ 1,794	$ 1,200	$ 594
16	WNP-1&3 DECOMMISSIONING	$ 1,129	$ 1,175	$ (46)
17	**Sub-Total**	**$ 2,923**	**$ 2,375**	**$ 548**
18	Gross Contracted Power Purchases			
19	PNCA HEADWATER BENEFITS	$ 2,691	$ 3,100	$ (409)
20	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)	$ 55,778	$ -	$ 55,778
21	**Sub-Total**	**$ 58,469**	**$ 3,100**	**$ 55,369**
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)	$ 266,696	$ 266,696	$ (0)
28	OTHER SETTLEMENTS	$ -	$ -	$ -
29	**Sub-Total**	**$ 266,696**	**$ 266,696**	**$ (0)**
30	Renewable Generation			
31	RENEWABLES (excludes KIII)	$ 16,629	$ 20,132	$ (3,504)
32	**Sub-Total**	**$ 16,629**	**$ 20,132**	**$ (3,504)**
33	Generation Conservation			
34	CONSERVATION ACQUISITION	$ 76,959	$ 67,357	$ 9,602
35	CONSERVATION INFRASCTRUCTURE	$ 25,832	$ 27,300	$ (1,468)
36	LOW INCOME WEATHERIZATION & TRIBAL	$ 6,005	$ 6,005	$ 0
37	ENERGY EFFICIENCY DEVELOPMENT	$ -	$ 8,000	$ (8,000)
38	DISTRIBUTED ENERGY RESOURCES	$ 141	$ 215	$ (74)
39	LEGACY	$ 585	$ 590	$ (5)
40	MARKET TRANSFORMATION	$ 11,800	$ 11,800	$ (0)
41	**Sub-Total**	**$ 121,322**	**$ 121,267**	**$ 55**
42	**Power System Generation Sub-Total**	**$ 1,252,987**	**$ 1,172,080**	**$ 80,907**
43				

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		July (Q3) ($000)	Rate Case forecast for FY 2023 ($000)	July (Q3) - Rate Case Difference
44	**Power Non-Generation Operations**			
45	**Power Services System Operations**			
46	EFFICIENCIES PROGRAM	$ -	$ -	$ -
47	INFORMATION TECHNOLOGY	$ -	$ 3,780	$ (3,780)
48	GENERATION PROJECT COORDINATION	$ 3,607	$ 4,035	$ (428)
49	ASSET MGMT ENTERPRISE SVCS	$ 689	$ 330	$ 359
50	SLICE IMPLEMENTATION	$ 657	$ 1,003	$ (345)
51	**Sub-Total**	**$ 4,953**	**$ 9,149**	**$ (4,195)**
52	**Power Services Scheduling**			
53	OPERATIONS SCHEDULING	$ 10,271	$ 9,910	$ 361
54	OPERATIONS PLANNING	$ 8,874	$ 9,006	$ (133)
55	**Sub-Total**	**$ 19,145**	**$ 18,917**	**$ 229**
56	**Power Services Marketing and Business Support**			
57	GRID MOD	$ 323	$ 2,285	$ (1,962)
58	EIM INTERNAL SUPPORT	$ -	$ -	$ -
59	POWER INTERNAL SUPPORT	$ 18,382	$ 15,251	$ 3,131
60	COMMERCIAL ENTERPRISE SVCS	$ 7,036	$ 2,192	$ 4,844
61	OPERATIONS ENTERPRISE SVCS	$ 4,994	$ 2,274	$ 2,720
62	POWER R&D	$ 2,527	$ 2,527	$ (0)
63	SALES & SUPPORT	$ 13,743	$ 15,563	$ (1,821)
64	STRATEGY, FINANCE & RISK MGMT (REP support costs included here)	$ -	$ 3,679	$ (3,679)
65	EXECUTIVE AND ADMINISTRATIVE SERVICES (REP support costs included here)	$ -	$ 6,886	$ (6,886)
66	CONSERVATION SUPPORT	$ 7,894	$ 8,131	$ (236)
67	**Sub-Total**	**$ 54,899**	**$ 58,788**	**$ (3,889)**
68	**Power Non-Generation Operations Sub-Total**	**$ 78,997**	**$ 86,853**	**$ (7,855)**
69	**Power Services Transmission Acquisition and Ancillary Services**			
70	TRANSMISSION and ANCILLARY Services - System Obligations	$ 31,933	$ 31,933	$ -
71	3RD PARTY GTA WHEELING	$ 83,243	$ 83,243	$ 0
72	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)	$ 2,227	$ 3,300	$ (1,073)
73	TRANS ACQ GENERATION INTEGRATION	$ 14,809	$ 14,809	$ 0
74	EESC CHARGES (Composite)	$ (3,773)	$ -	$ (3,773)
75	TELEMETERING/EQUIP REPLACEMT	$ -	$ -	$ -
76	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**	**$ 128,439**	**$ 133,285**	**$ (4,846)**
77	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
78	**Fish & Wildlife**	$ 250,179	$ 248,065	$ 2,114
79	**USF&W Lower Snake Hatcheries**	$ 29,000	$ 29,000	$ 0
80	**Planning Council**	$ 11,983	$ 12,431	$ (448)
81	**Fish & Wildlife RDC Funds**	$ -	$ -	$ -
82	**Lower Snake Hatcheries RDC Funds**	$ 18	$ -	$ 18
83	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$ 291,180**	**$ 289,496**	**$ 1,684**
84	**BPA Internal Support**			
85	**Additional Post-Retirement Contribution**	$ 18,912	$ 19,354	$ (442)
86	**Agency Services G&A (excludes direct project support)**	$ 83,425	$ 65,336	$ 18,090
87	**BPA Internal Support Sub-Total**	**$ 102,337**	**$ 84,689**	$ 17,648

Composite Cost Pool True-Up Table

	COMPOSITE COST POOL TRUE-UP TABLE	July (Q3) ($000)	Rate Case forecast for FY 2023 ($000)	July (Q3) - Rate Case Difference
88	**Bad Debt Expense**	$ -	$ -	$ -
89	**Other Income, Expenses, Adjustments**	$ (915)	$ (2,971)	$ 2,056
90	**Depreciation**	$ 143,100	$ 144,155	$ (1,055)
91	**Amortization**	$ 326,100	$ 317,320	$ 8,780
92	**Accretion (CGS)**	$ 37,600	$ 38,363	$ (763)
93	**Total Operating Expenses**	**$ 2,359,825**	**$ 2,263,269**	**$ 96,556**
94				
95	**Other Expenses and (Income)**			
96	Net Interest Expense	$ 232,771	$ 228,139	$ 4,632
97	LDD	$ 32,067	$ 40,009	$ (7,942)
98	Irrigation Rate Discount Costs	$ 20,505	$ 20,509	$ (4)
99	**Sub-Total**	**$ 285,344**	**$ 288,658**	**$ (3,315)**
100	**Total Expenses**	**$ 2,645,169**	**$ 2,551,927**	**$ 93,242**
101				
102	**Revenue Credits**			
103	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	$ 100,997	$ 104,245	$ (3,248)
104	Downstream Benefits and Pumping Power revenues	$ 20,653	$ 20,661	$ (8)
105	4(h)(10)(c) credit	$ 254,722	$ 94,216	$ 160,506
106	PRSC Net Credit (Composite)	$ (5,155)	$ -	$ (5,155)
107	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ 0
108	Energy Efficiency Revenues	$ -	$ 8,000	$ (8,000)
109	PF Load Forecast Deviation Liquidated Damages	$ -	$ 1,070	$ (1,070)
110	Miscellaneous revenues	$ 13,565	$ 11,696	$ 1,870
111	Renewable Energy Certificates	$ -	$ -	$ -
112	Net Revenues from other Designated BPA System Obligations (Upper Baker)	$ 1,459	$ 402	$ 1,058
113	RSS Revenues	$ 3,056	$ 3,056	$ -
114	Firm Surplus and Secondary Adjustment (from Unused RHWM)	$ 79,301	$ 79,301	$ -
115	Balancing Augmentation Adjustment	$ 4,019	$ 4,019	$ -
116	Transmission Loss Adjustment	$ 30,577	$ 30,577	$ -
117	Tier 2 Rate Adjustment	$ 1,767	$ 1,767	$ -
118	NR Revenues	$ 1	$ 1	$ -
119	**Total Revenue Credits**	**$ 509,563**	**$ 363,611**	**$ 145,952**
120				
121	**Augmentation Costs (not subject to True-Up)**			
122	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders	$ 11,421	$ 11,421	$ -
123	Augmentation Purchases	$ -	$ -	$ -
124	**Total Augmentation Costs**	**$ 11,421**	**$ 11,421**	**$ -**
125				
126	**DSI Revenue Credit**			
127	Revenues 12 aMW @ IP rate	$ 3,693	$ 4,277	$ (584)
128	**Total DSI revenues**	**$ 3,693**	**$ 4,277**	**$ (584)**
129				

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		July (Q3) ($000)	Rate Case forecast for FY 2023 ($000)	July (Q3) - Rate Case Difference
130	**Minimum Required Net Revenue Calculation**			
131	Principal Payment of Fed Debt for Power**	$ 601,629	$ 525,000	$ 76,629
132	Repayment of Non-Federal Obligations (EN Line of Credit)	$ -	$ -	$ -
133	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls)	$ 21,111	$ 21,111	$ -
134	Irrigation assistance	$ 13,355	$ 12,762	$ 593
135	**Sub-Total**	**$ 636,095**	**$ 558,873**	**$ 77,222**
136	Depreciation	$ 143,100	$ 144,155	$ (1,055)
137	Amortization	$ 326,100	$ 317,320	$ 8,780
138	Accretion	$ 37,600	$ 38,363	$ (763)
139	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ -
140	Amortization of Refinancing Premiums/Discounts (MRNR - Reverse Sign)	$ (23,695)	$ (7,491)	$ (16,204)
141	Amortization of Cost of Issuance (MRNR-reverse sign)	$ 363	$ 169	$ 194
142	Cash freed up by DSR refinancing	$ 16,015	$ 16,865	$ (850)
143	Gains/Losses on Extinguishment	$ -	$ -	$ -
144	Non-Cash Expenses	$ 95,072	$ 73,155	$ 21,917
145	Prepay Revenue Credits	$ (30,600)	$ (30,600)	$ -
146	Non-Federal Interest (Prepay)	$ 6,799	$ 6,799	$ -
147	Contribution to decommissioning trust fund	$ (4,651)	$ (4,651)	$ -
148	Gains/losses on decommissioning trust fund	$ (10,198)	$ (10,198)	$ -
149	Interest earned on decommissioning trust fund	$ (3,516)	$ (3,516)	$ -
150	Revenue Financing Requirement**	$ (14,000)	$ (40,000)	$ 26,000
151	Other Adjustments	$ 6,966	$ -	$ 6,966
152	**Sub-Total**	**$ 499,418**	**$ 454,431**	**$ 44,987**
153	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expenses	$ 136,677	$ 104,442	$ 32,235
154	Minimum Required Net Revenues	**$ 136,677**	**$ 104,442**	**$ 32,235**
155				
156	Annual Composite Cost Pool (Amounts for each FY)	**$ 2,280,010**	**$ 2,299,902**	**$ (19,892)**
157				
158	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**			
159	TRUE-UP AMOUNT (Diff. between Rate Case and Forecast)	(19,892)		
160	Sum of TOCAs	0.9706591		
161	Adjustment of True-Up Amount when actual TOCAs < 100 percent	**(20,493)**		
162	TRUE-UP ADJUSTMENT CHARGE BILLED (22.36267 percent)	(4,583)		

**For Q3 an assumption of $79M for RDC Debt Repayment & $14M for Revenue Financing was used. This matches the assumptions used in Q2 for the Reserves Forecast.

FINANCIAL DISCLOSURES

This information has been made publicly available by BPA on Aug 7, 2023, and contains information not sourced directly from BPA financial statements.