Bonneville
POWER ADMINISTRATION

QUARTERLY BUSINESS REVIEW TECHNICAL WORKSHOP

May 11, 2023

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AGENDA

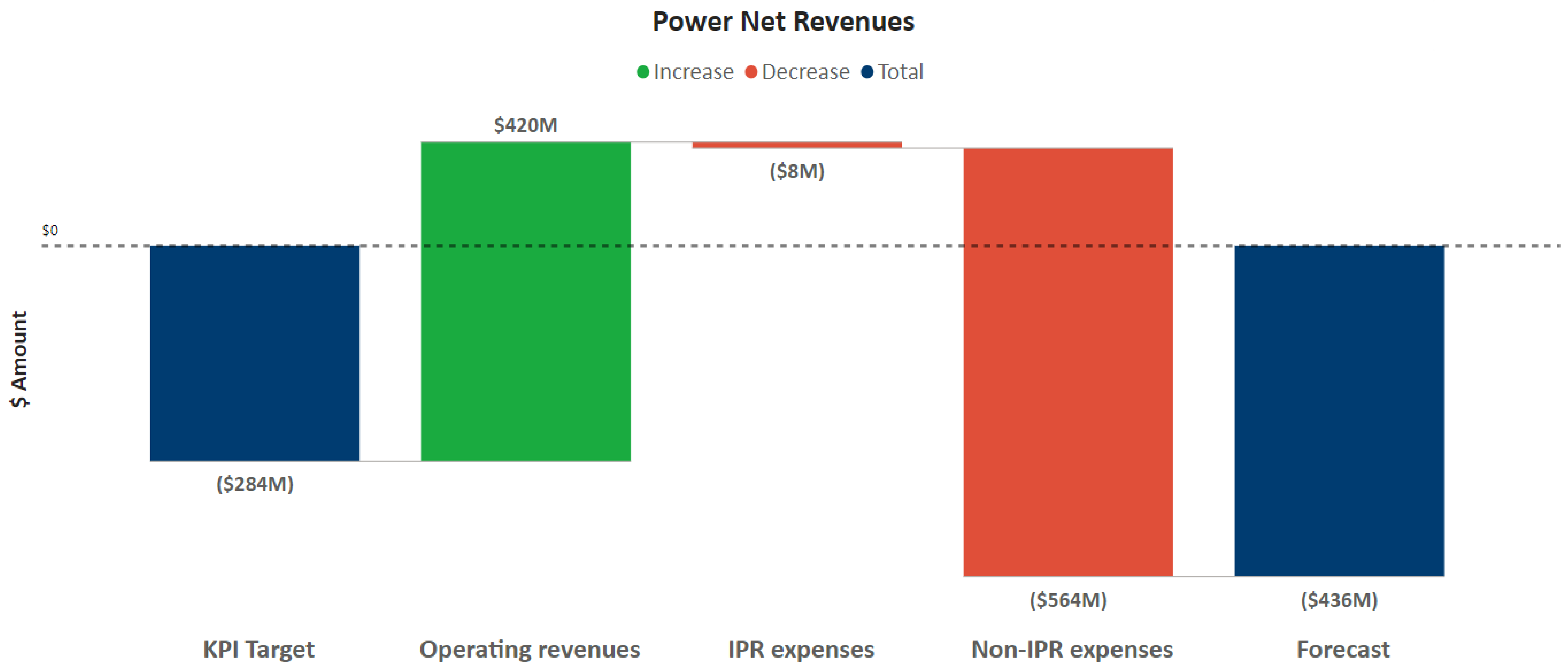
Time	Min	QBRTW Agenda Topic	Presenter
1:00	5	Introduction & Agenda	Kelly Akowskey
1:05	10	FY23 Q2 forecast: Power net revenue and Transmission net revenue *	Karlee Manary, Ben Agre
1:15	15	FY23 Q2 forecast: Reserves for Risk	Damen Bleiler
1:30	10	FY23 Q2 forecast: Capital *	Gwen Resendes, Heather Siebert
1:40	10	Transmission capital metrics	Mike Miller, Jana Jusupovic
1:50	25	Grid Modernization update	Tracey Stancliff, Allie Mace
2:15	10	Q&A / Closing	Kelly Akowskey

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

FY23 Q2 Forecast: Power net revenue Transmission net revenue

Presenters: Finance Team

Q2 FORECAST: POWER NET REVENUE



The KPI Target is less than Power's FY23 Rate Case net revenue forecast due to the reserves Dividend Distribution, FY 23 budget increases and FY 22 budget carryover.

QBRTW ANALYSIS: POWER NET REVENUE

Operating Revenues increased $420M due to the following:

- Gross sales are $357M higher than target due to additional Composite Revenues due to higher loads. Load Shaping Revenue is also higher due to colder-than-average temperatures. 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 $35K. These items are slightly offset by Bookouts, which are net revenue neutral.
- Other revenues are $1M 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 $4M less than the target due to Balancing Reserve Capacity, Operating Reserve - Spinning, and Operating Reserve - Supplemental from joining the EIM.
- The remaining delta is due to a 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 $8M due to the following:

- The generating partners are seeing increases in labor costs and inflation on materials but these are mostly offset by lower Energy Efficiency and Renewables expenses.
- IT is experiencing inflation and higher demand which has increase the forecast by $7.5M.
- The Unfunded Post-Retirement Benefit forecast increased by $1.5M due to updated cost factors provided by OPM.
- Lower staffing has reduced personnel costs by $1M.

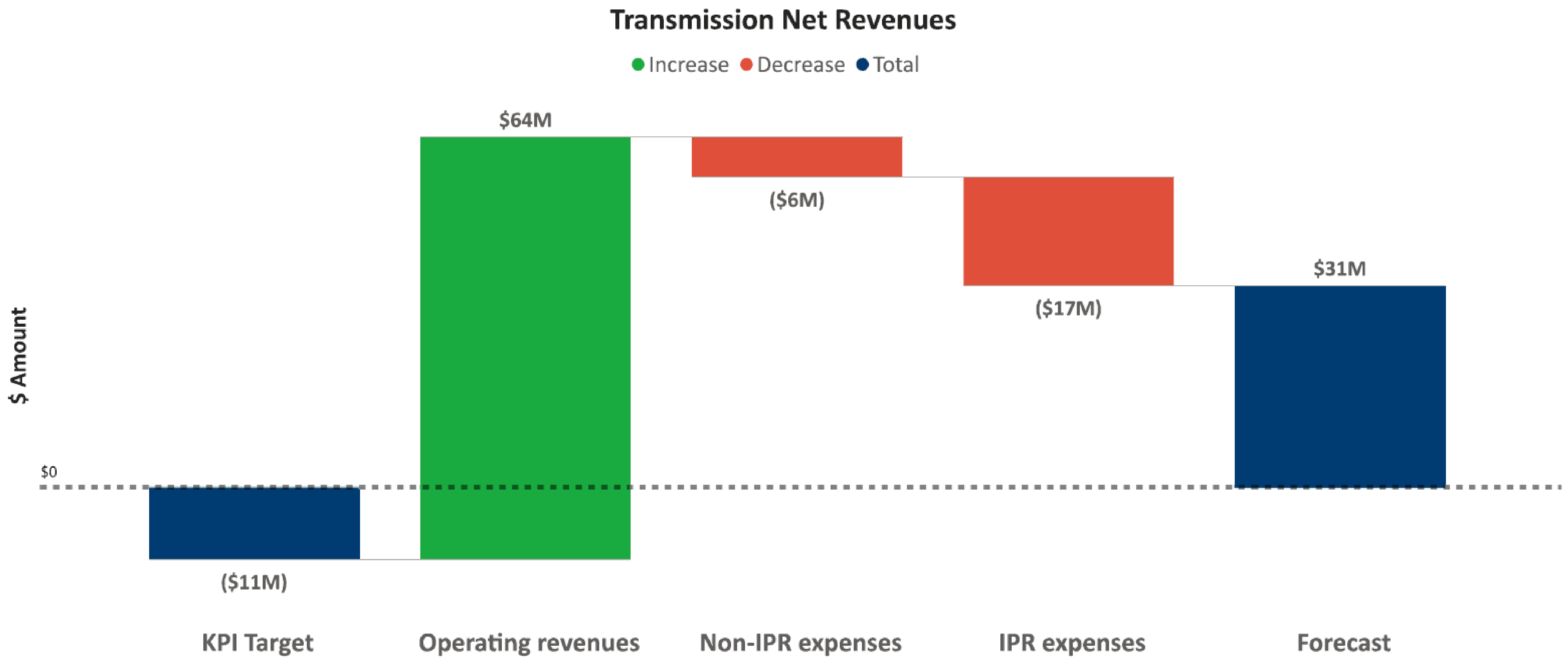
Non-IPR Programs are on the next slide.

QBRTW ANALYSIS: POWER NET REVENUE (cont.)

Non-IPR Programs increased $564M due to the following:

- The Power Purchases forecast is $708M higher than the target driven by higher prices and low stream flows. The low stream flows are a big component of the higher Q2 forecast due to the impact of increased loads and dry winter conditions, leading to increased purchases. Non-Treaty Storage Agreement and Libby expenses are also increasing Power Purchases by roughly $55M due to water releases throughout Q2.
- Year-to-date EIM Scheduling Coordinator charges of $8M were not forecast in Rate Case or the Target, but are included in the Q2 forecast. Some of these charges are being offset by higher EIM revenues.
- 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 aforementioned Non-IPR increases 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 expense by $47M.
  - Bookouts reduce Non-IPR expenses by $66M but are net revenue neutral due to a like amount in the revenue section.
  - Lower Transmission and Ancillary Services by $28M, which are 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 $13M 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.

Q2 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 and FY 23 budget increases.

QBRTW ANALYSIS: TRANSMISSION NET REVENUE

Operating Revenues increased $64m primarily due to the following:

- $89m 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 weather-related load increases
  - Increased Short Term Point-to-Point and Southern Intertie Short Term revenues resulting from increased wheeling as a result of favorable market prices
- $3m increase in Other Revenues driven by increased Fiber Revenues and Other revenues
- Partially offset by a $28m 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

QBRTW ANALYSIS: TRANSMISSION NET REVENUE (cont.)

Non-IPR Program Expenses increased $6m primarily due to the following:

- $19m increase in Net Interest expense and other income primarily driven the financial loss on B2H, higher interest expense on federal debt partially offset by higher interest income and AFUDC
- $5m increase in Amortization expense resulting from the Lease accounting change in previous year
- Partially offset by a $19m decrease in Depreciation expense resulting from less capital being placed in service during prior periods than forecast

Integrated Program Review Operating Expenses increased $17m primarily due to the following:

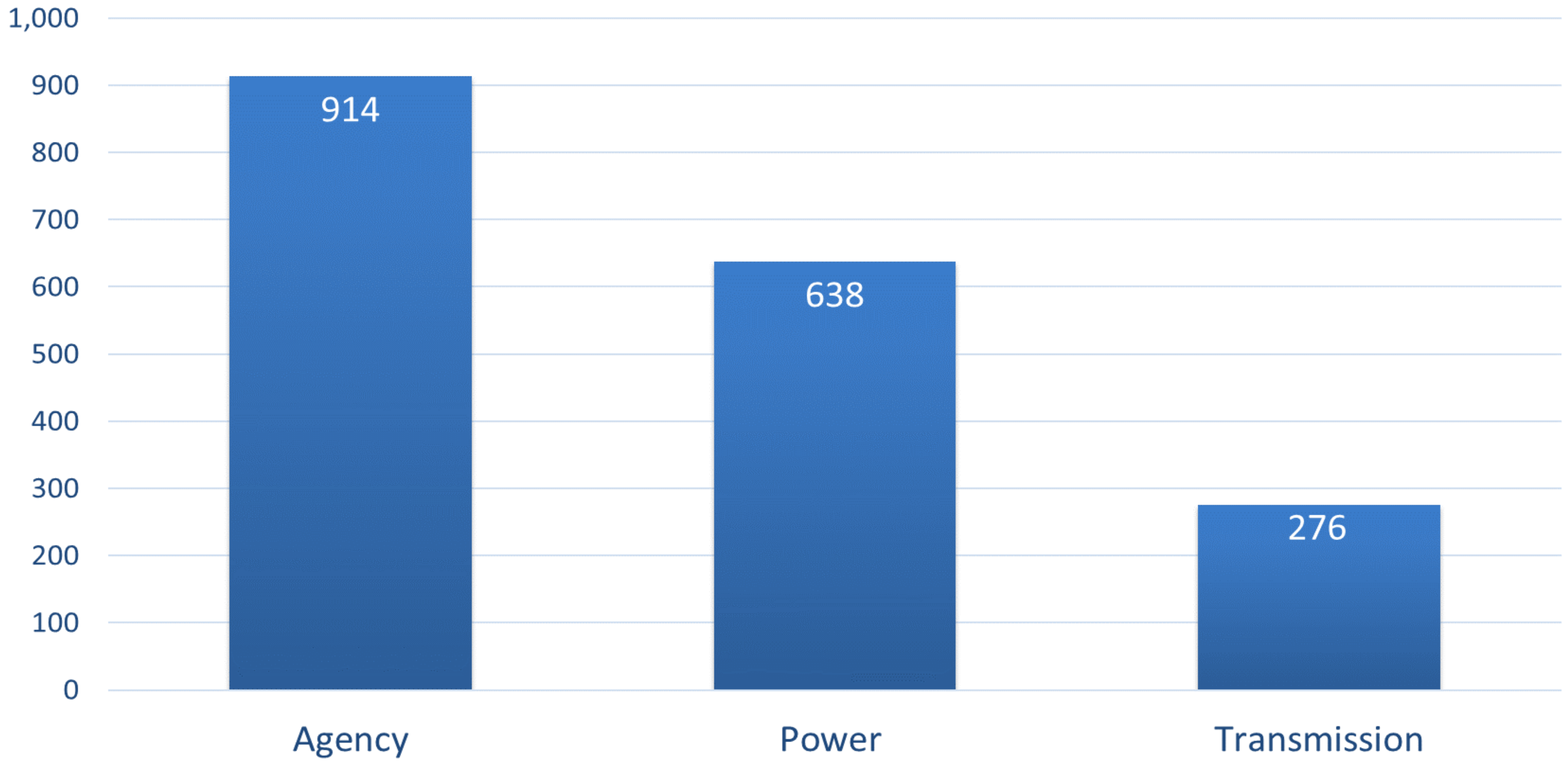
- $10m increase in the Asset Management Program resulting from increased maintenance work, higher wildfire mitigation costs, higher software licensing costs, and shift from capital to expense.
- $7m increase in the Enterprise Services Program primarily due to less direct charging than expected leading to an increase in G&A allocations and a forecast increase in the Additional Post Retirement Contribution

RESERVES

Presenters: Finance Team

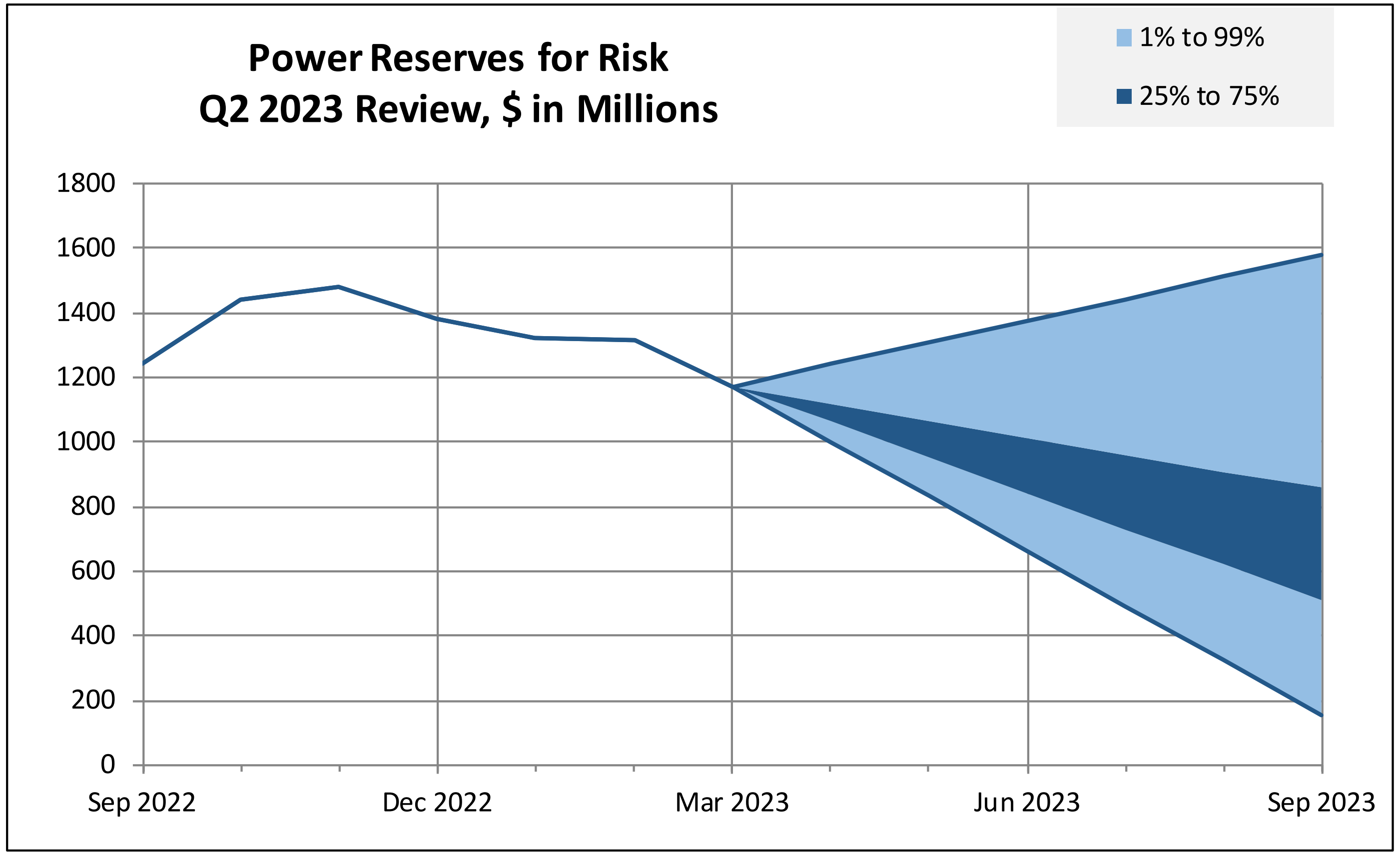
Q2 FORECAST: RESERVES FOR RISK

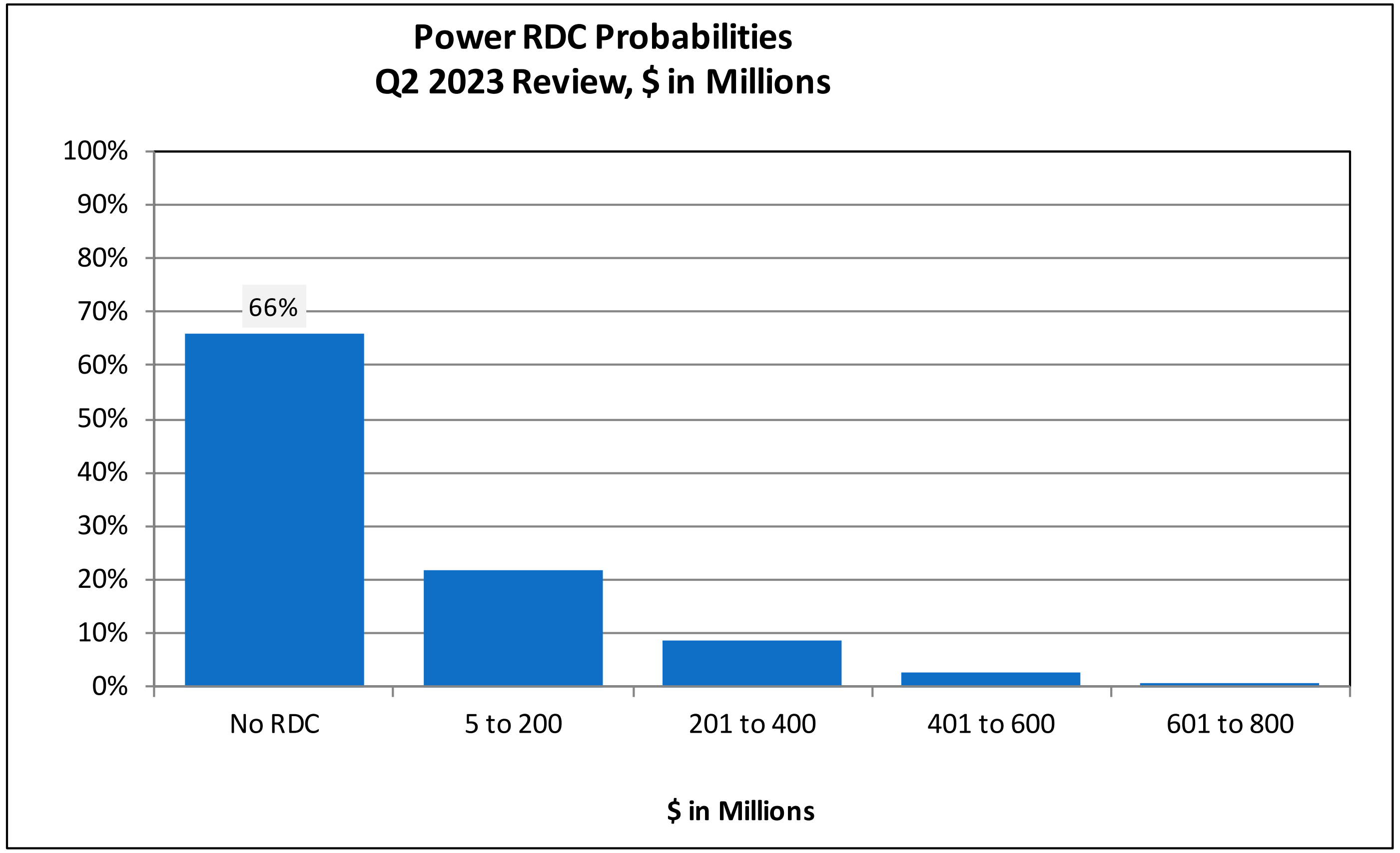
FY23 End of Year Reserves For Risk Forecast ($MM)



	Agency	Power	Transmission
DCOH	134	129	148
<u>Thresholds</u>			
RDC	>$653M	>$638M	>$233M
Surcharge	N/A	<$319M	<$116M

Q2 FORECAST: POWER FINANCIAL RESERVES





Power Reserves Range

- 1% to 99% Range:
  $153m to $1,580m

- 25% to 75% Range:
  $511m to $857m

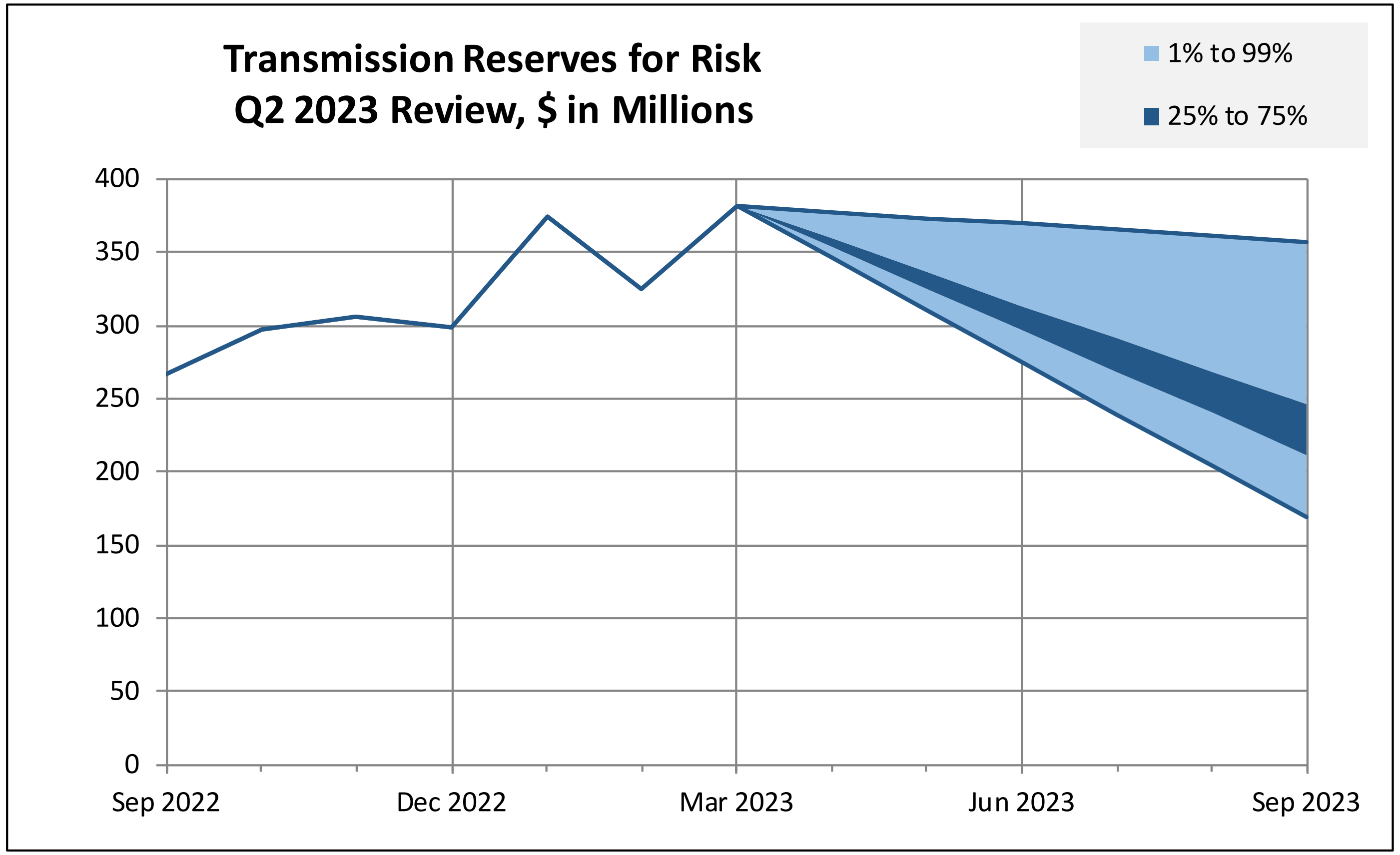
Power Risk Mechanisms

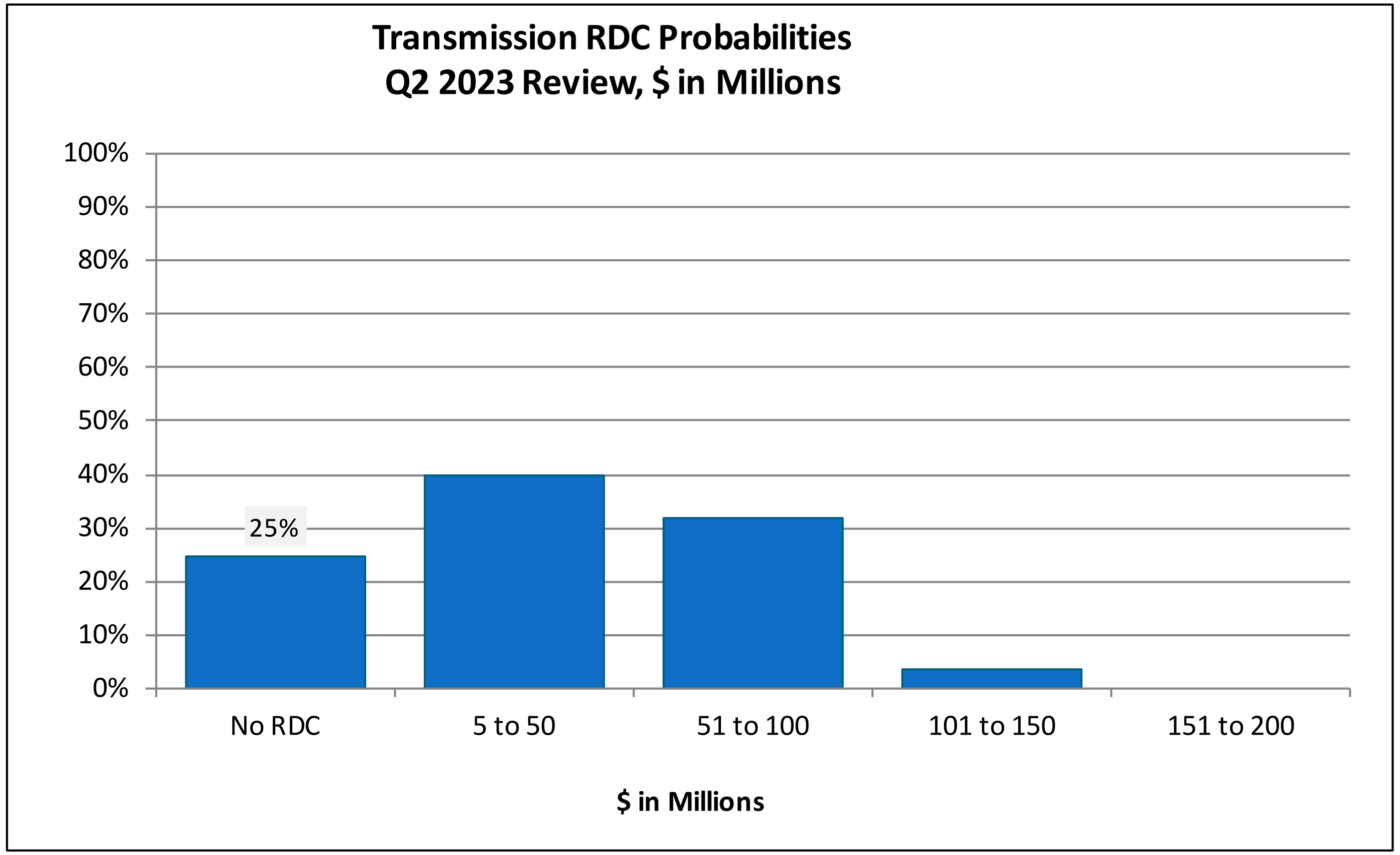
- 34% modeled probability of an RDC with an expected value of $64.4m

- 4% modeled probability of an FRP Surcharge with an expected value of $1.4m

- 0% modeled probability of a CRAC

Q2 FORECAST: TRANSMISSION FINANCIAL RESERVES





<u>Transmission Reserves Range</u>

- 1% to 99% Range:
  $168m to $357m
- 25% to 75% Range:
  $211m to $246m

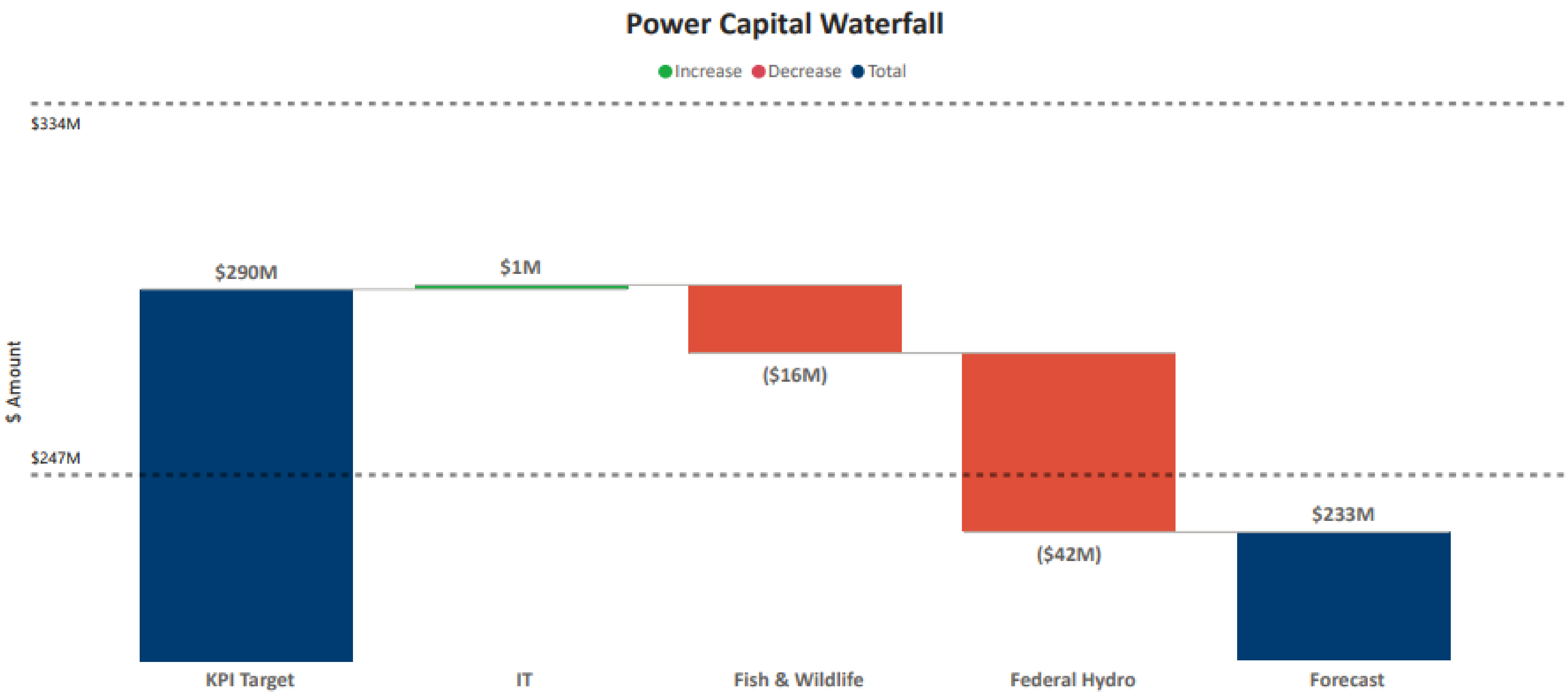
<u>Transmission Risk Mechanisms</u>

- 75% modeled probability of an RDC with an expected value of $37.4m
- 0% modeled probability of a CRAC or FRP Surcharge

FY23 Capital forecast

Presenters: Finance Team

Q2 FORECAST: POWER CAPITAL



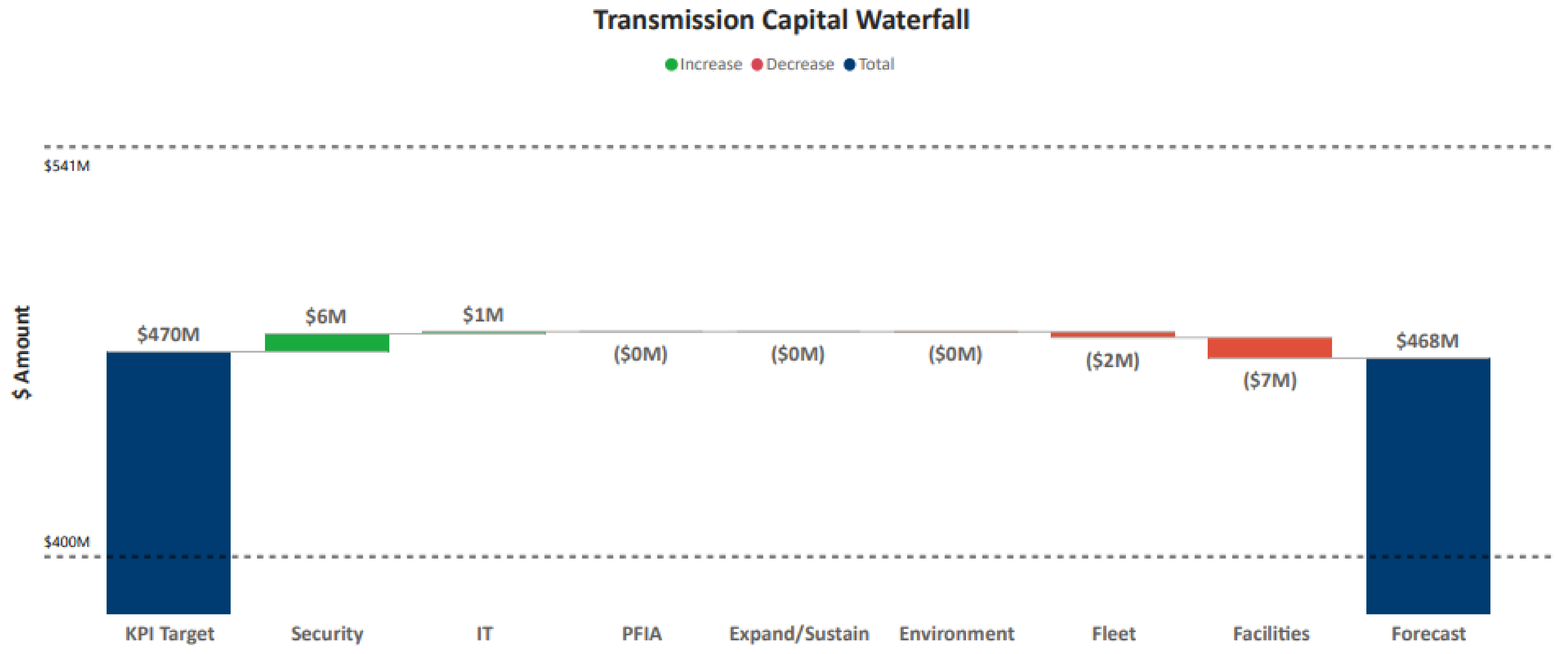
The Power capital expenditure KPI target is a range. The range is equal to +/- 15% of the target midpoint. If Power direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: POWER CAPITAL

Power direct capital decreased $57m primarily due to:

- $1m increase for IT to accommodate Power's EE tracking and Reporting and Ops Log replacement projects.
- $16m decrease in Fish & Wildlife due to hatchery projects design/permitting/bidding delays and passage project delayed to FY24.
- $42m decrease in Fed Hydro due to contracting and staffing constraints. McNary Dam in particular had cascading schedule slippage on a number of 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.

Q2 FORECAST: TRANSMISSION CAPITAL



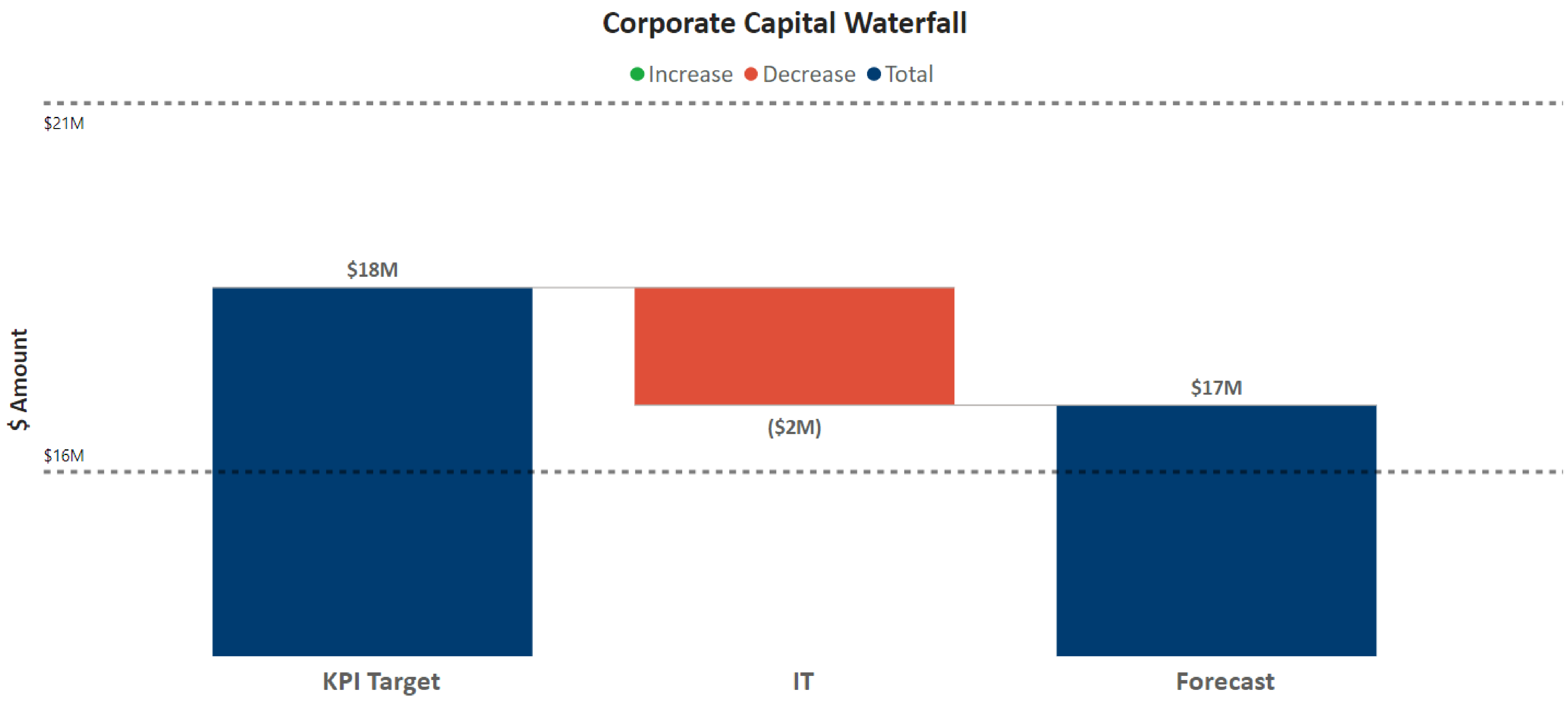
The Transmission capital expenditure KPI target is a range. The range is equal to +/- 15% of the target midpoint. If Transmission direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: TRANSMISSION CAPITAL

Transmission direct capital (in total) decreased by $2m broken down the following ways:

- $6m 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.
- $2m decrease in Fleet due to changes in manufacturer lead times, moving multiple orders and certain pieces into FY 24.
- $7m 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 VCC project which pushed a large portion of design into FY24.

Q2 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

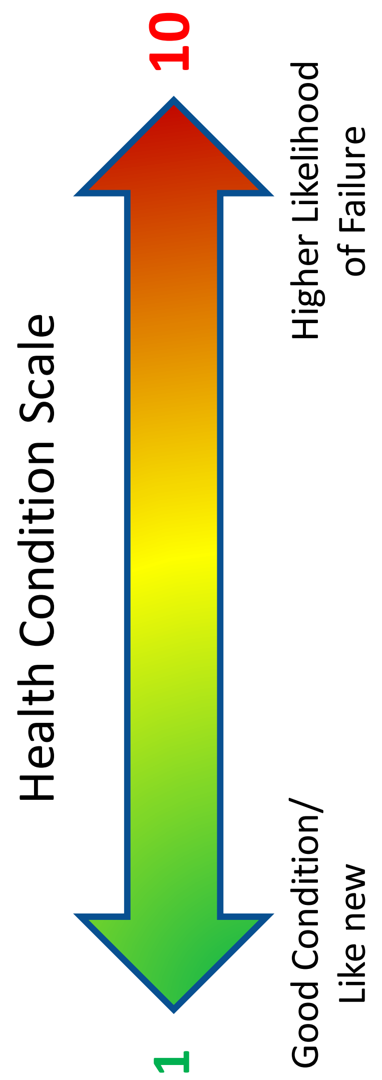
Corporate direct capital decreased $2m due to:

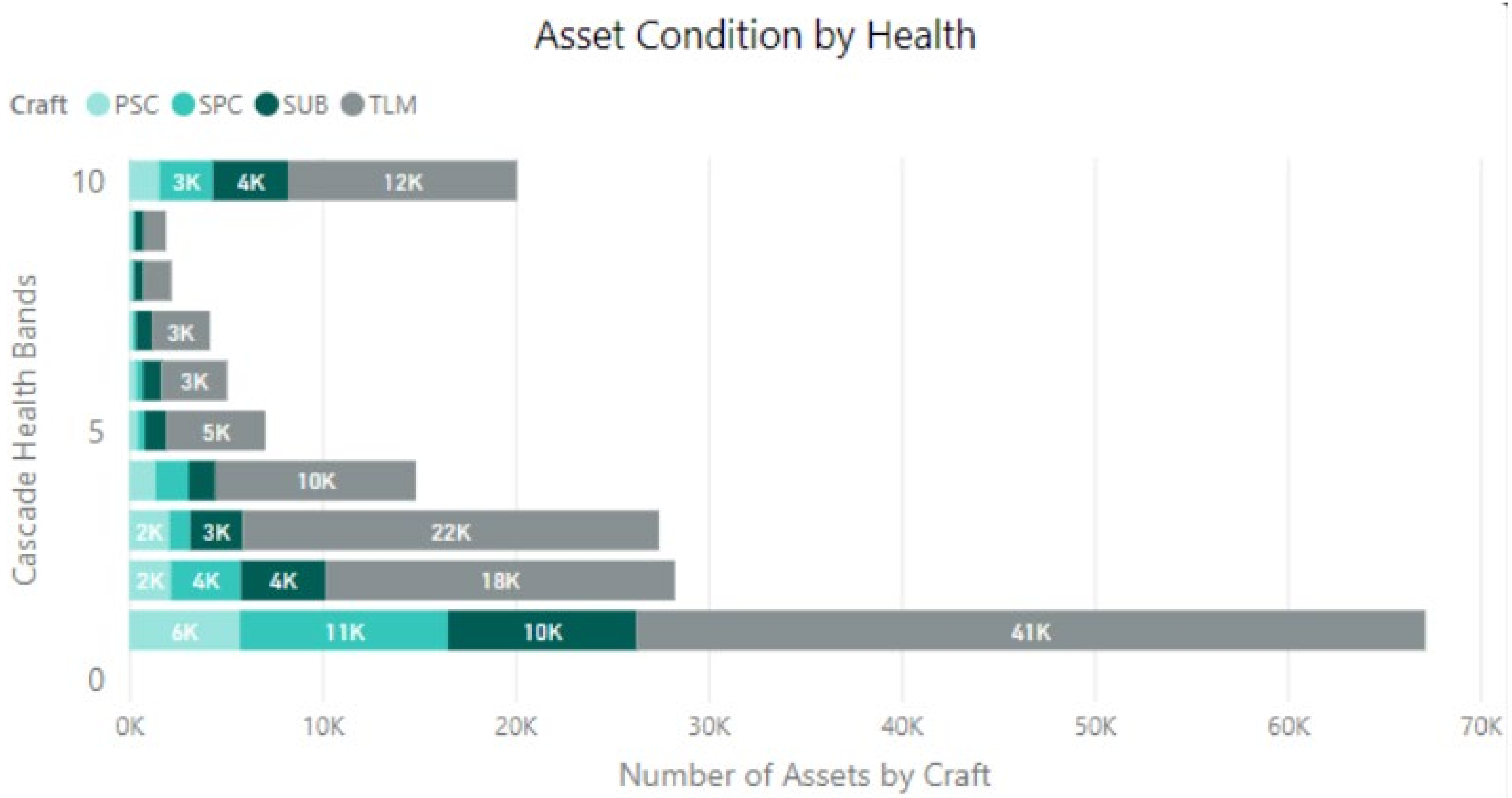
- $2m decrease in corporate IT mainly due to reduced spending on the Corporate IT Land Information System project and increased spending on Power and Transmission projects.
- Note that while a decrease in corporate IT spending is forecasted, the combined increase in Power and Transmission IT spending mostly offsets the corporate decrease resulting in the overall Agency IT capital Q2 forecast being only $5k less than the KPI Target.

TRANSMISSION SERVICES CAPITAL METRICS

Presenters: Jana Jusupovic and Mike Miller

ASSET MANAGEMENT HEALTH METRIC

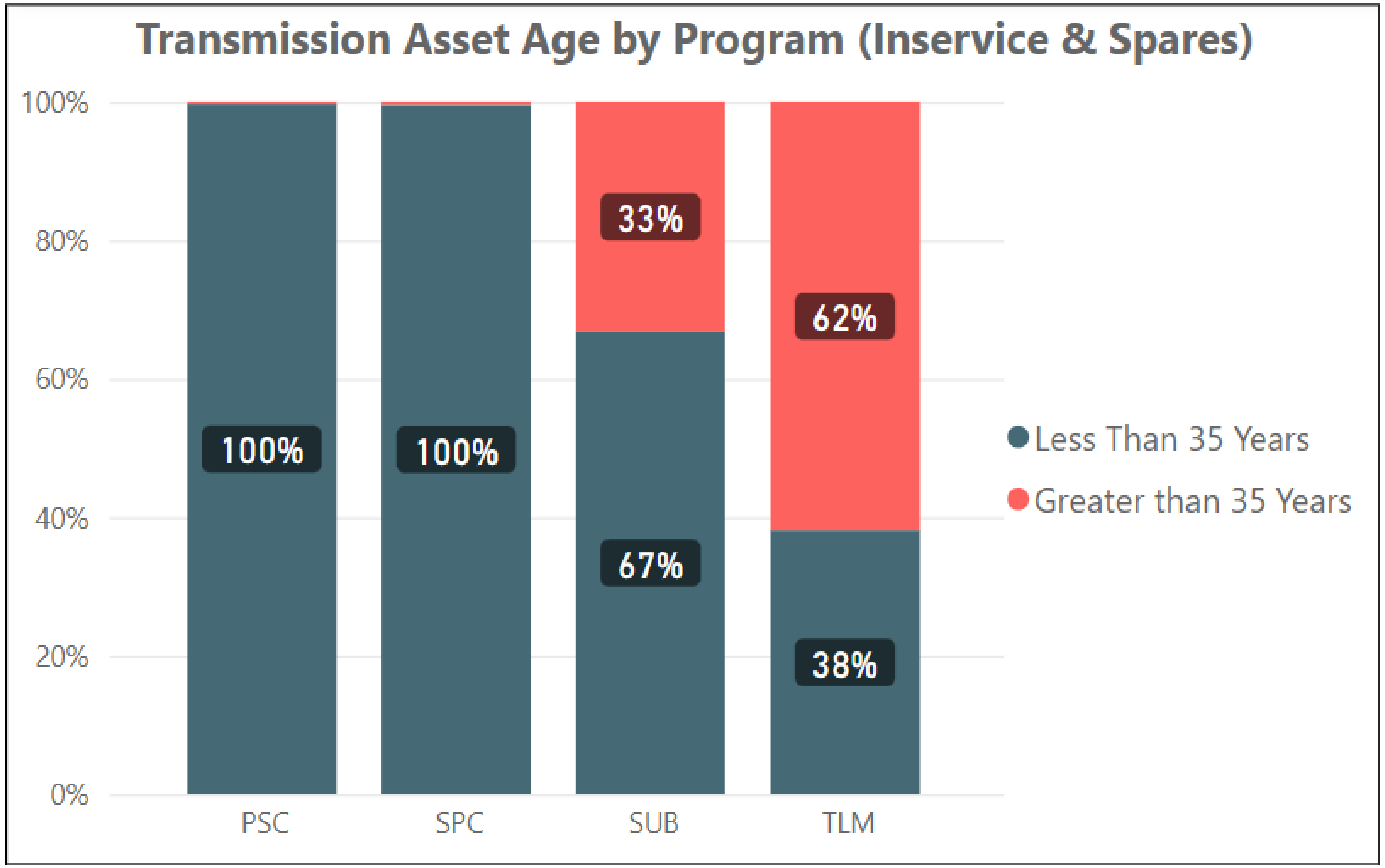




PSC: Power System Control, SPC: System Protection Control, Sub: Substation, TLM: Trans Line Maintenance

***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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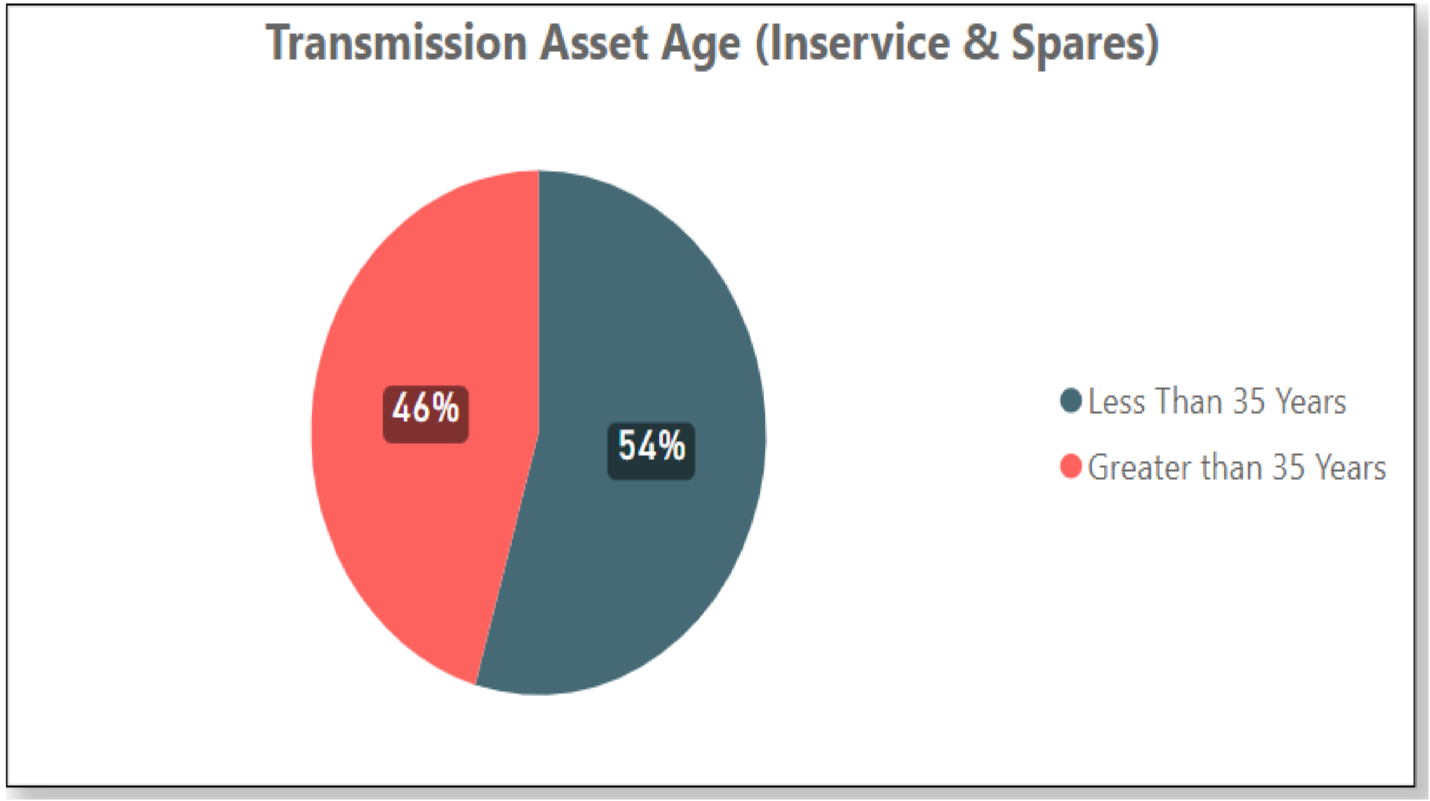
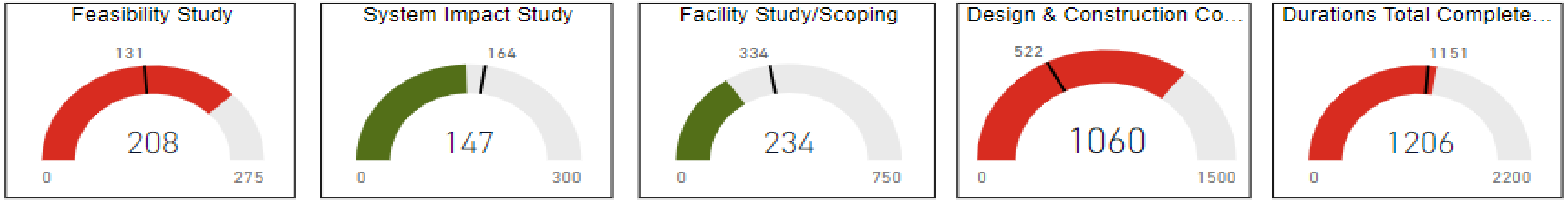
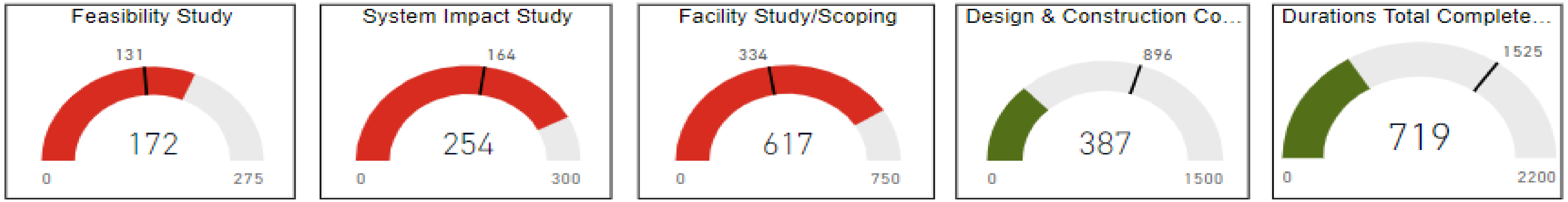


CUSTOMER DURATION METRIC

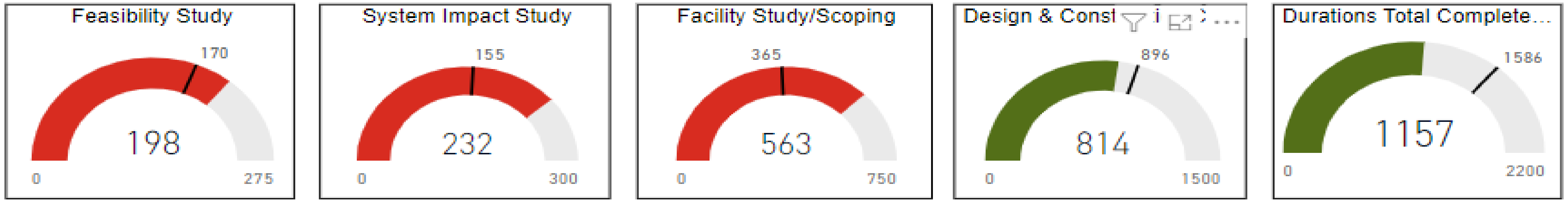
Small Generation Interconnection projects: Projects with an aggregation of generators, whose single or combined generating capacity is > than 0.2MW and = to or < 20MW



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

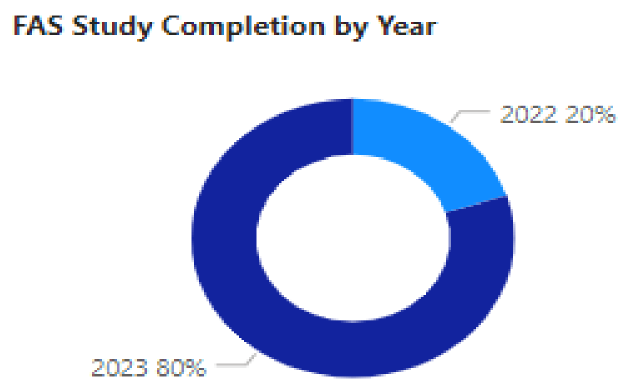


Includes LGI, LLI, SGI projects with a Queue date on or after 01/01/2015

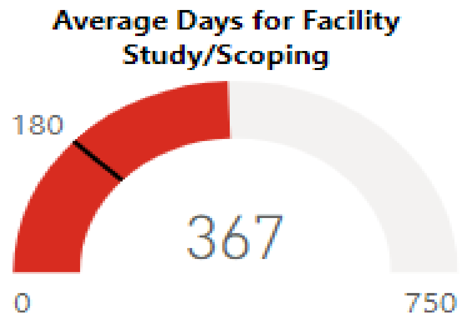
Optimal performance is below the lines, which denote the target ceiling levels

* Completed Projects Only

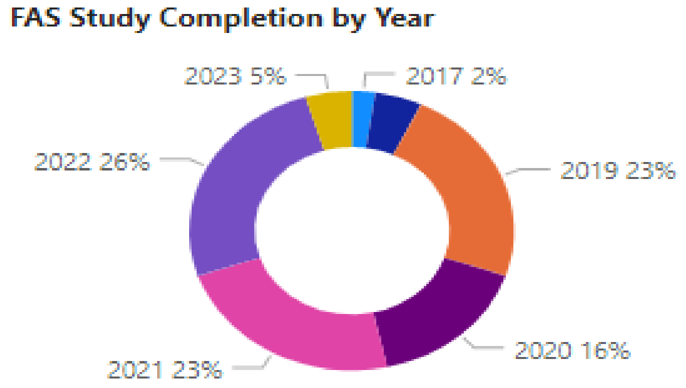
CUSTOMER DURATION METRIC



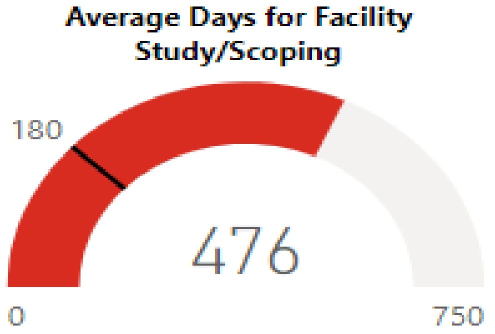
FAS/Scoping No CDD | New Process (5 Projects)



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

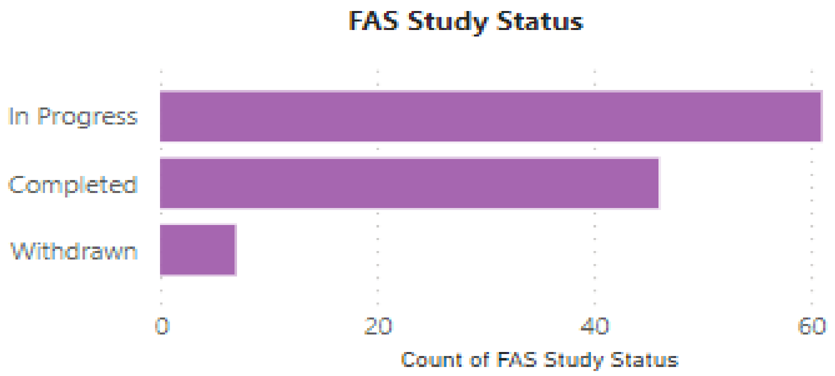


FAS/Scoping with CDD | Old Process (42 Projects)

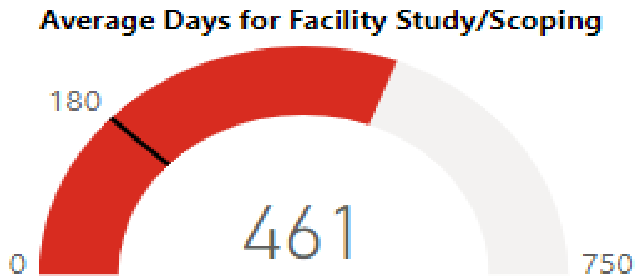


Includes LGI, LLI, SGI projects with a Queue date on or after 01/01/2017

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



FAS/Scoping | New and Old Process (47 Projects)



* Completed Projects Only

PRIMARY VS SECONDARY CAPACITY THROUGHPUT

Transmission as of FY23 Q2:

TEBI — BUSINESS INTELLIGENCE & INTEGRITY

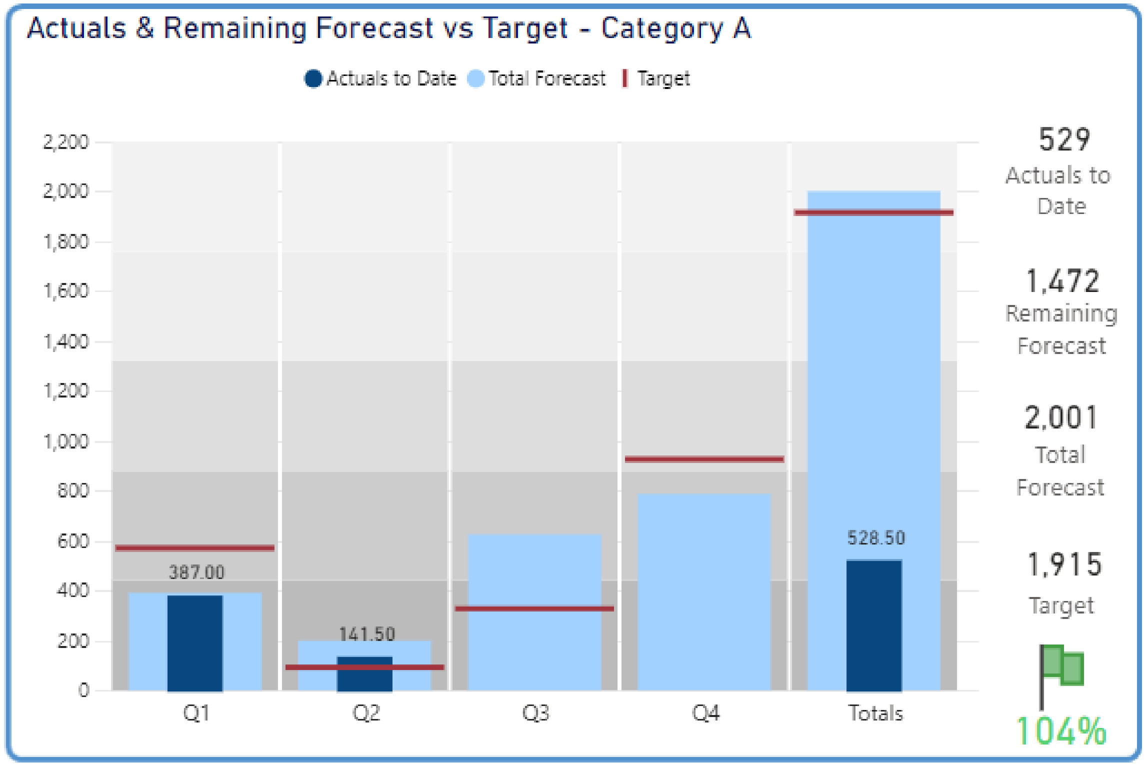
PRIMARY VS SECONDARY CAPACITY THROUGHPUT – CURRENT FY

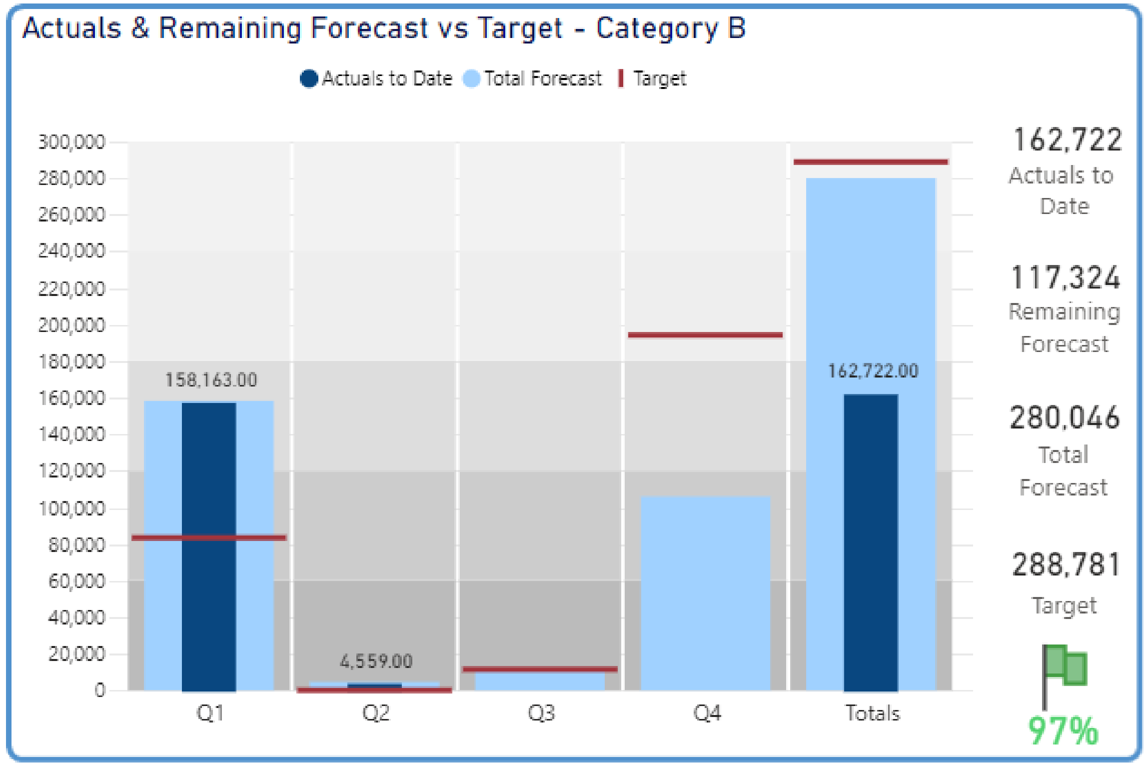
FY23

	PLANNING	SCOPING	DESIGN	CONSTRUCT	ENERGIZED
PRIMARY CAPACITY MODEL	237	88	189	137	202
SECONDARY CAPACITY MODEL	0	29	11	0	0

CAPITAL ASSETS PLANNED VS COMPLETED

Transmission as of FY23 Q2:

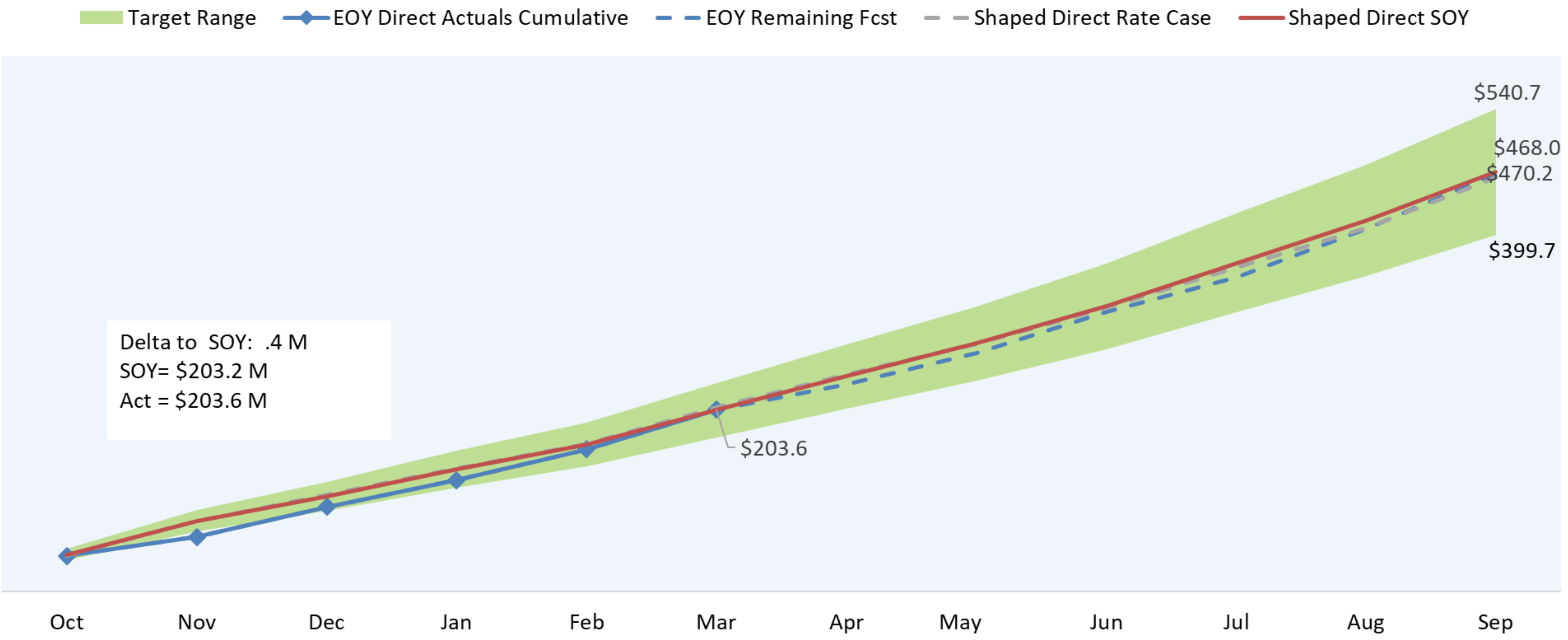




Priority Project Objectives	
Q1 FIN Replacement -- work begins in Q1	Completed
Q2 Buckley GIS Substation replacement – bypass construction to be completed by Q2 FY'23	Completed
Q3 Longhorn Substation – Civil construction begins Q3 FY'23	On Track
Wautoma Series Capacitors – Substation work in support to be completed Q3 FY'23	On Track
FIN Replacement -- preliminary PRD's done by Q3 FY'23 for all 3 regions	On Track
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

B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

Grid Modernization Update

Tracey Stancliff

Grid Modernization Mobilization

Updated: 05.08.2023
Date = Completion Date

0%
Identify

3%
Define

AMS MRU Device Event Reporting – 09.30.2023

5%
Integrate

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

50%
Deliver

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
PRADA – 06.30.2023
Sub-Hourly Scheduling on the DC – 02.28.2024

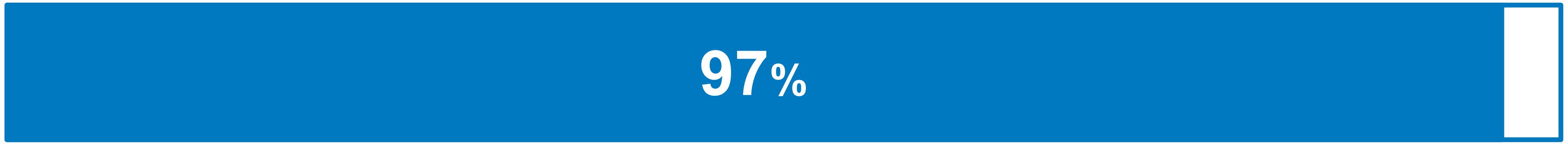
42%
Complete

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

Canceled

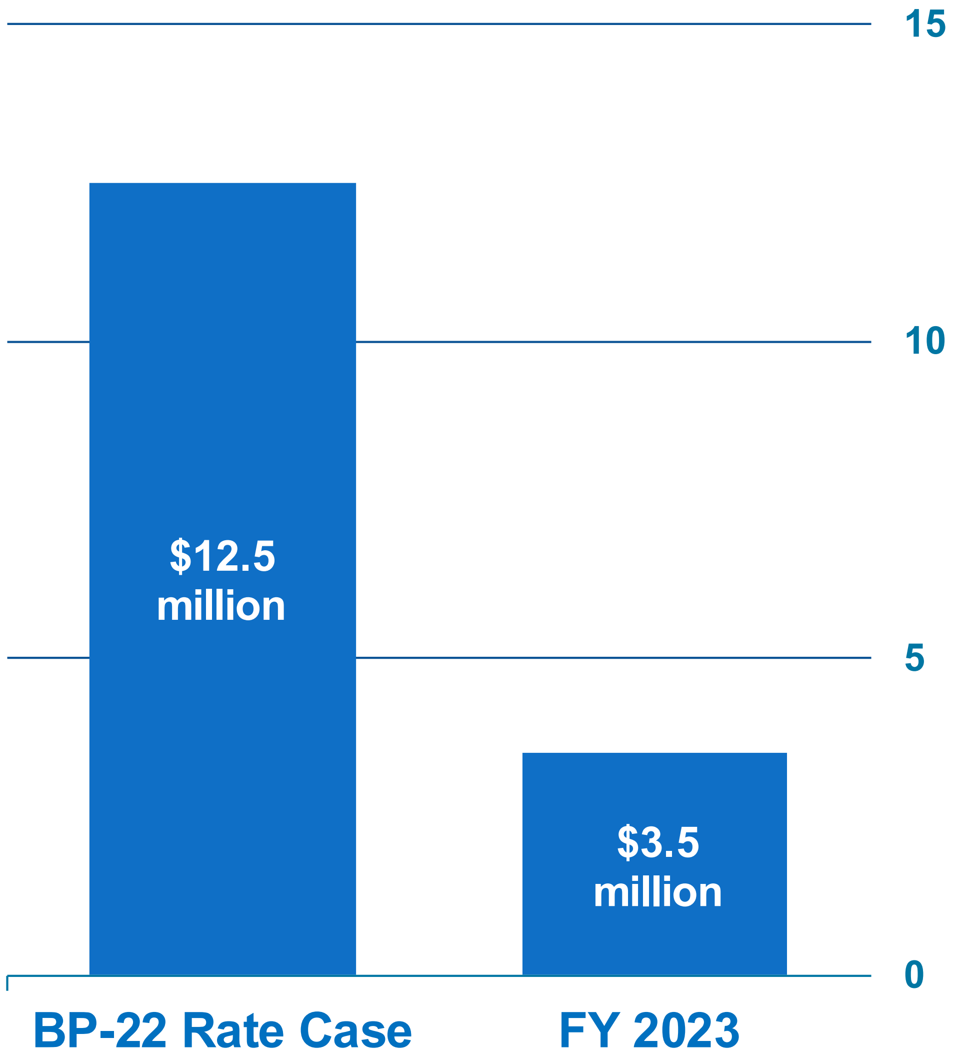
VSA/DTC Phase 2
Real Time Ops Modernization
AEP 2
Wildfire Risk Modeling

Grid Modernization Progress Metric



- 97% 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 Q2 FY23 is 70%
- **Status:** **Green**

Grid Mod FY23 Spending



- BPA spent a total of $3.5m as of the end of Q2 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
Q2 FY2023

Presenters: Allie Mace
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 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).

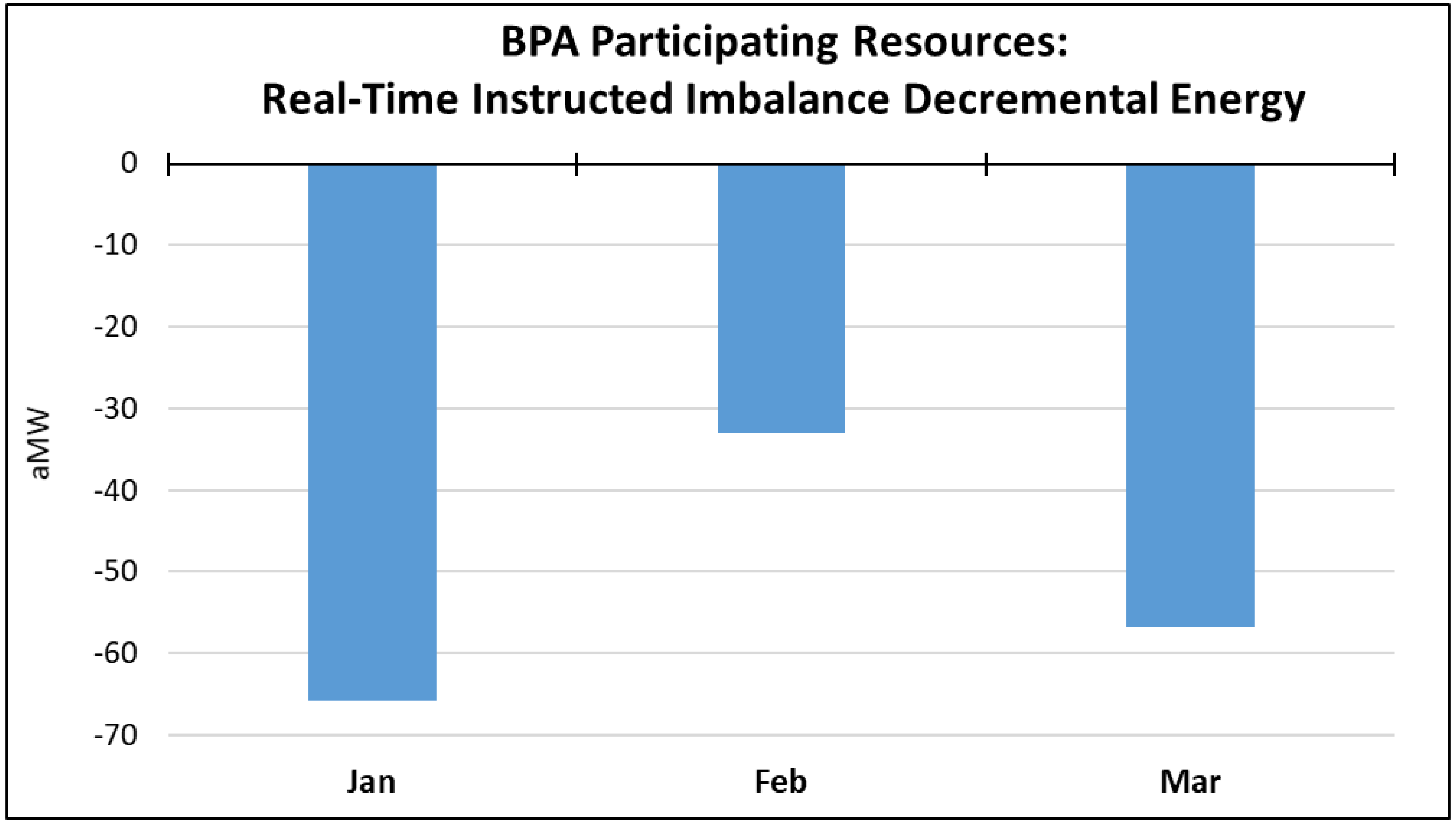
Phase 2 Metrics

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.

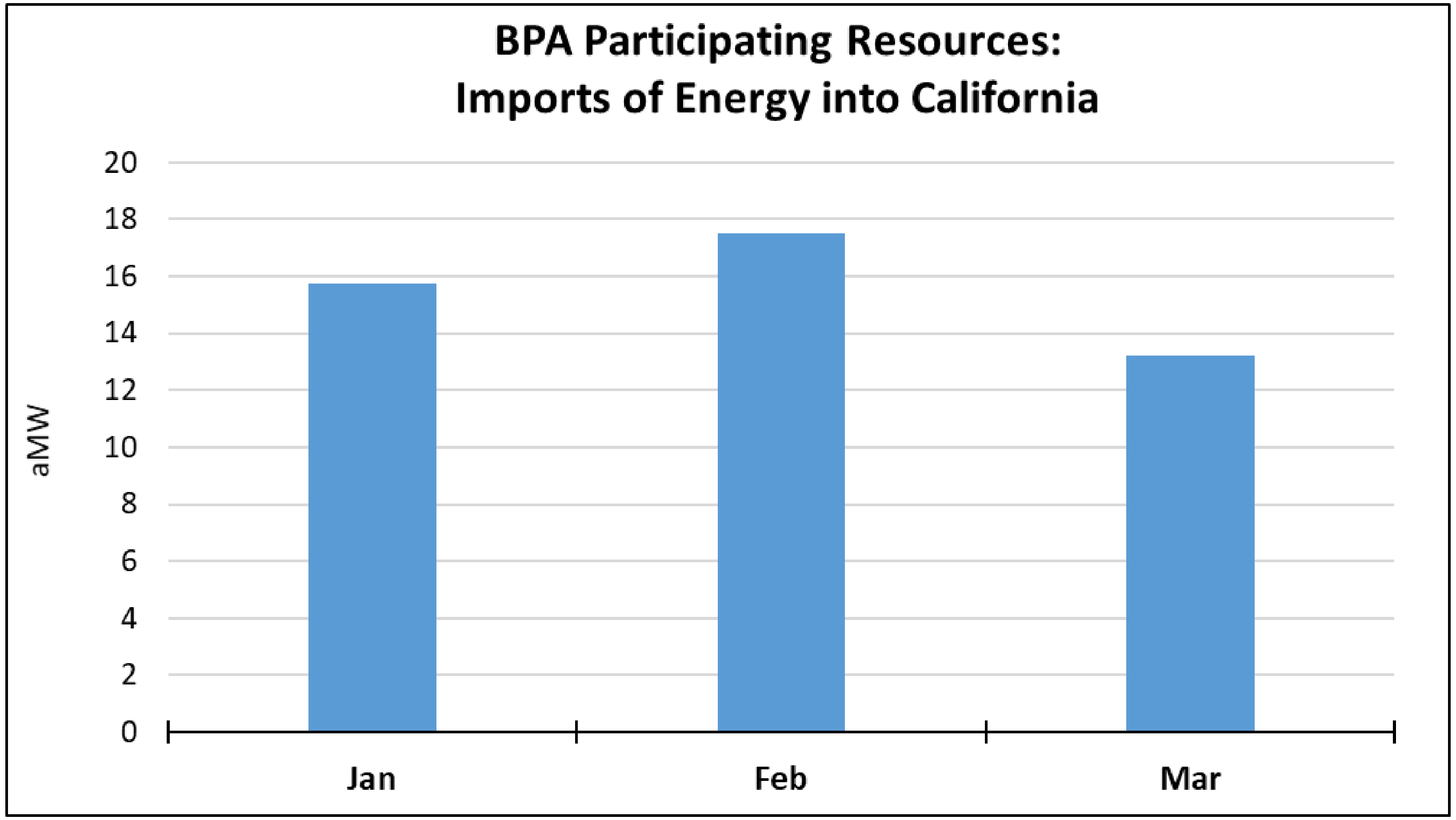
These metrics will be reported by BP-26.

Metric 1a: Unspecified purchases



Volume: ~110,000 MWh (50 aMW) for the period of Jan-Mar

Metric 1b: Amount Delivered to California



Volume:	~35,000 MWh (15 aMW) for the period of Jan-Mar
GHG Premium:	~$20/MWh (CC 491 GHG emission cost revenue)
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	Jan	Feb	Mar	Mean
Failed Over	0.40%	0.15%	0.13%	0.23%
Failed Under	0.00%	0.15%	0.27%	0.14%
Passed Both	99.60%	99.70%	99.60%	99.63%

Bid 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	Jan	Feb	Mar	Mean
Failed	0.00%	0.00%	0.00%	0.00%
Passed	100.00%	100.00%	100.00%	100.00%

Bid 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	Jan	Feb	Mar	Mean
Failed	0.00%	0.15%	0.00%	0.05%
Passed	100.00%	99.85%	100.00%	99.95%

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	Jan	Feb	Mar	Mean
Failed	0.00%	0.07%	0.60%	0.22%
Passed	100.00%	99.93%	99.40%	99.78%

Flex Test Down Results

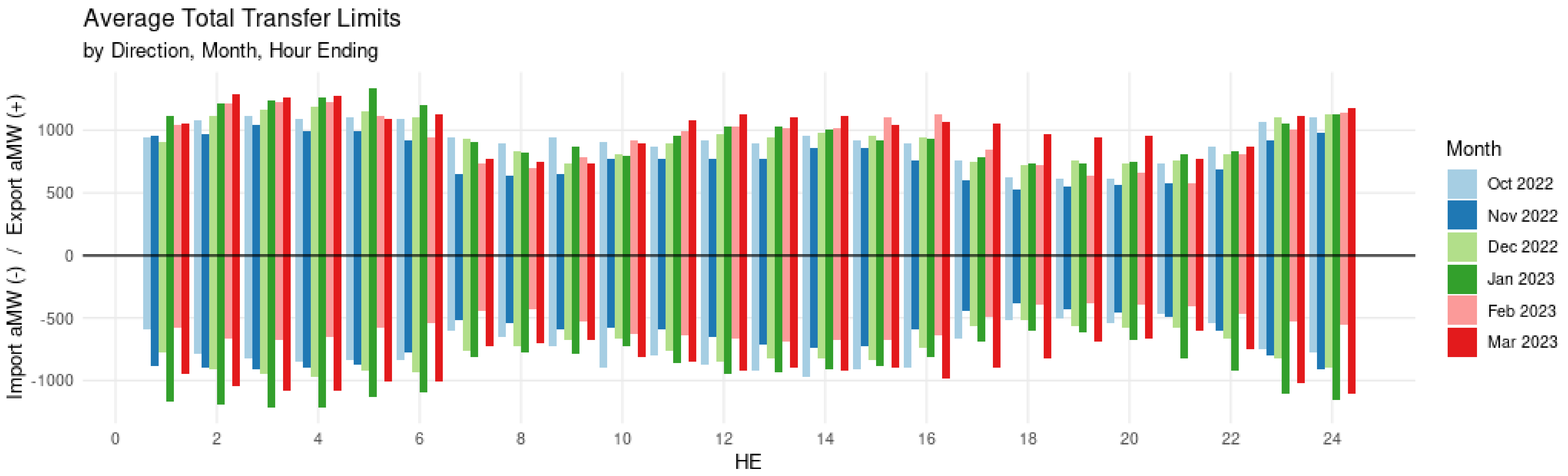
- The Flex Ramp Test Down evaluates whether the BAA had sufficient ramp down capability to meet the flex ramp down requirement
- The BAA’s ramp down capability depends on participating resources, non-participating resources, and net interchange

Percent of 15 minute intervals passed/failed

Flex Test Down	Jan	Feb	Mar	Mean
Failed	0.00%	0.19%	0.10%	0.10%
Passed	100.00%	99.81%	99.90%	99.90%

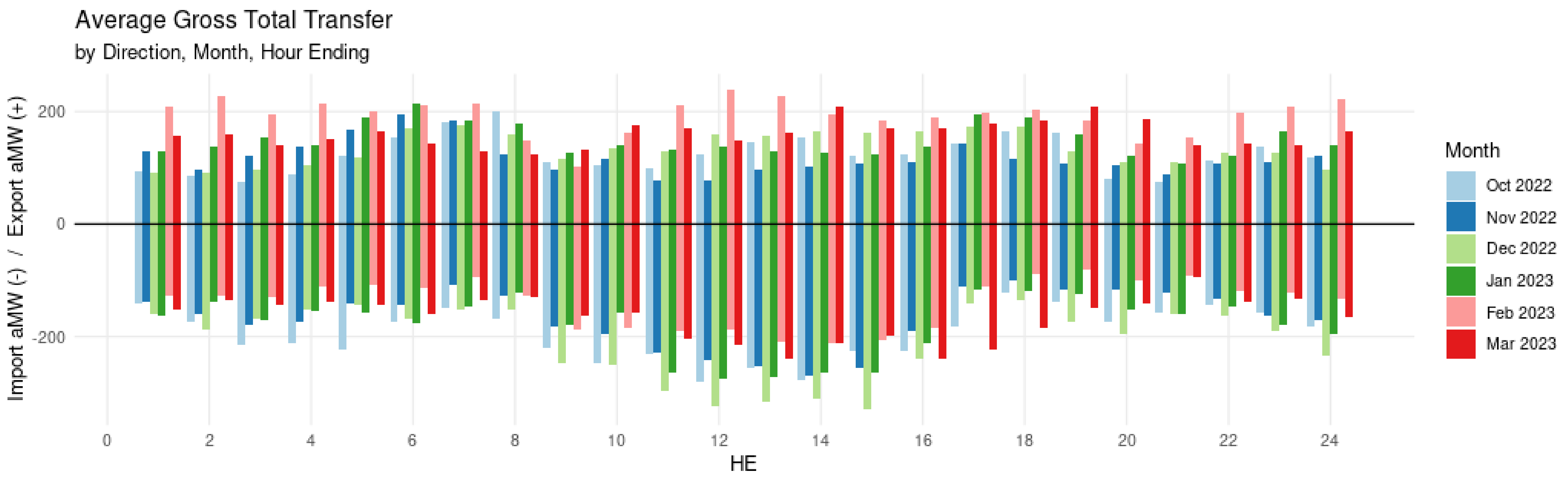
Metric 3: EIM Transfers

EIM Transfer Limits: Q1-Q2



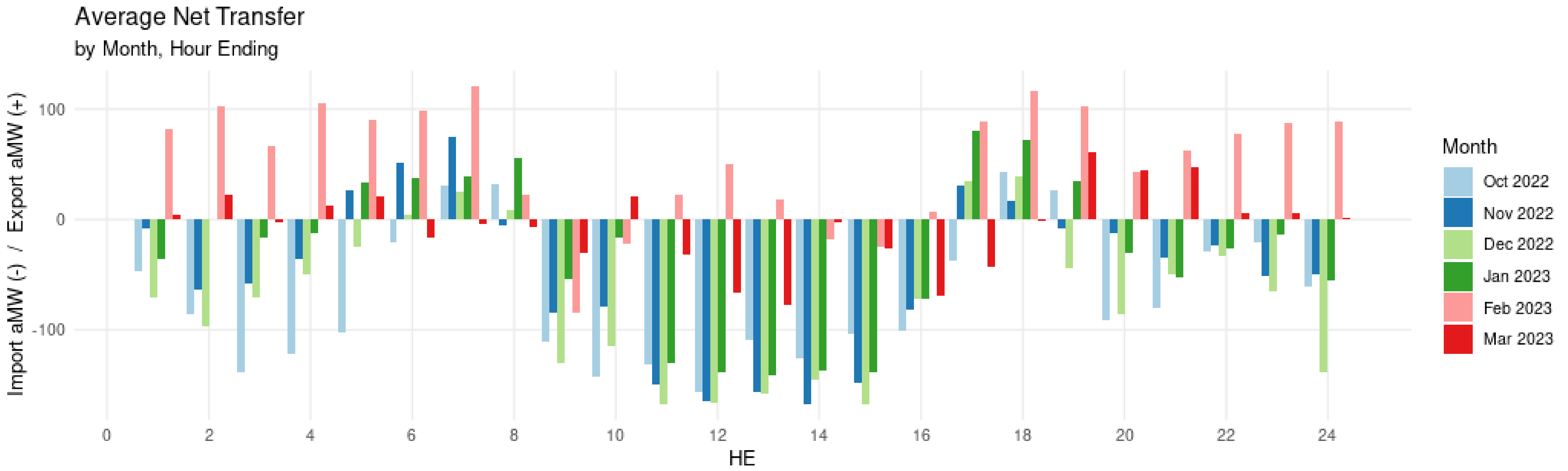
- Increase in transmission donation in Q2
- More transmission donation in LLH hours and “belly” hours
- Slight skew toward exports across most of the day

EIM Gross Transfer: Q1-Q2



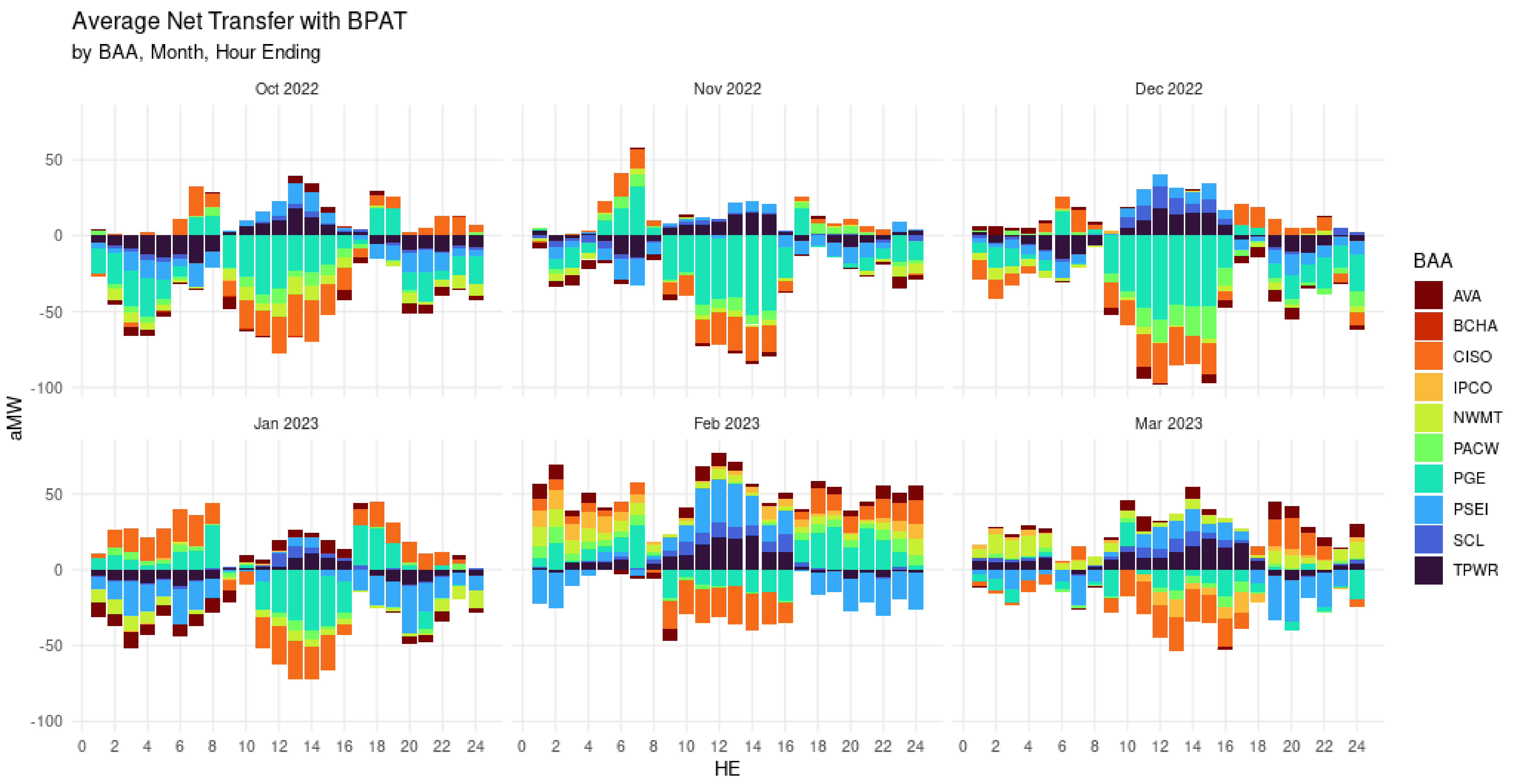
- Hourly shape of transfers generally aligns with price patterns and operational objectives
  - Consistent increase ingross imports during “belly” hours
  - Energy position generally longer in February

EIM Net Transfer: Q1-Q2

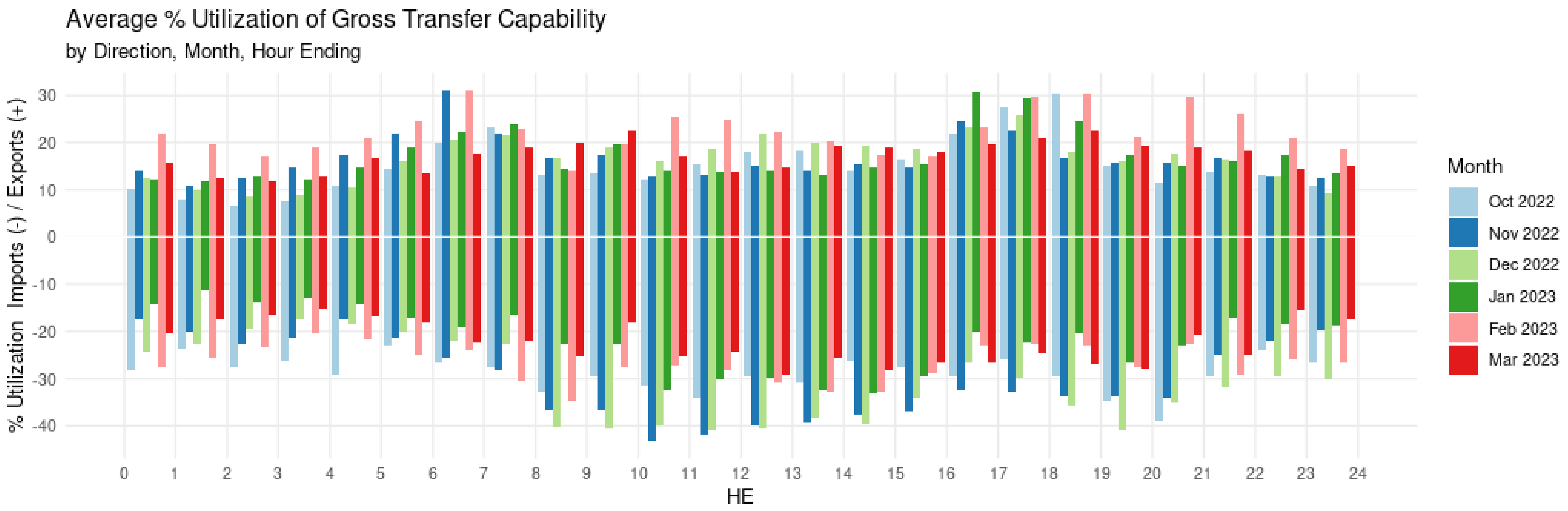


- Hourly shape of transfers generally aligns with price patterns and operational objectives
  - Fairly consistent net imports during “belly” hours
  - Energy position generally longer in February

EIM Net Transfer by BAA: Q1-Q2

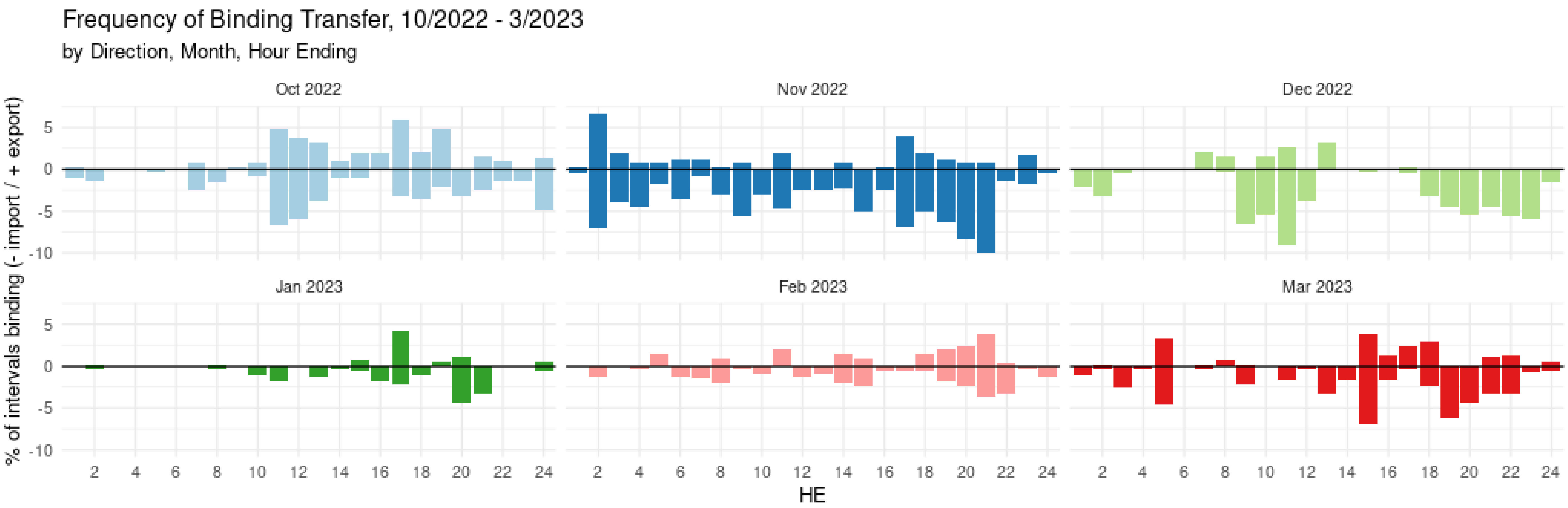


EIM Utilization of Transfer Capability: Q1-Q2



- 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*)

Frequency of binding EIM transfers: Q1-Q2



- For FYQ2, added static transfer and static transfer capability in this calculation, and modified calculation method to include anytime <u>*gross*</u> transfer limits were reached. All months above reflect this updated calculation. Previous iteration included only instances in which <u>*net*</u> transfers hit a transfer limit.
- Import limits still (in FYQ2) generally more likely to bind
- Binding frequency still generally "low", especially in January and February

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

Appendix

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

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

FINANCIAL DISCLOSURES

This information has been made publicly available by BPA on May 9, 2023 and contains information not sourced directly from BPA financial statements.

APPENDIX
SLICE REPORTING

Composite Cost Pool Review

Forecast of Annual Slice True-Up Adjustment

Q2 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 8, 2023 Third Quarter Technical Workshop	
November 14, 2023 Final Slice True-Up Technical Workshop	

*Negative = Credit; Positive = Charge

Summary of Differences From Q2 to FY23 (BP-22)

#		Composite Cost Pool True-Up Table Reference	Q2 – Rate Case $ in thousands
1	Total Expenses	Row 98	$109,388
2	Total Revenue Credits	Rows 117 + 126	$113,711
3	Minimum Required Net Revenue	Row 152	$4,173
4	TOTAL Composite Cost Pool (1 - 2 + 3) $109,388- $113,711 + $4,173 = $(150)	Row 157	$(150)
5	TOTAL in line 4 divided by <u>0.9706591</u> sum of TOCAs $(150)/ <u>0.9706591</u> = $(155)	Row 159	$(155)
6	QTR Forecast of FY23 True-up Adjustment 22.36267 percent of Total in line 5 0.2236267 * $(155)= $(35)	Row 160	$(35)

FY23 Impacts of Debt Management Actions

#	Description	FY23 Q2 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)	$	402,560,000	$	402,560,000		$	-
4	2023 Debt Service Reassignment (DSR)	$	16,775,000	$	16,775,000		$	-
5	Energy Northwest's Line Of Credit (LOC)	$	-	$	-		$	-
6	Rate Case Scheduled Base Power Principal*	$	105,665,000	$	105,665,000		$	-
7	**Total Principal Payment of Fed Debt**	**$**	**525,000,000**	**$**	**525,000,000**	row 129	**$**	-
8	**Prepay**	$	23,801,393	$	23,801,393		$	-
							$	-
9	**Nonfederal Bond Principal Payment**	$	21,111,400	$	21,111,400	row 131	$	-

Composite Cost Pool Interest Credit

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

		Q2 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	6.47%
5	Composite Interest Credit	(37,945)
6	Prepay Offset Credit	0
7	Total Interest Credit for Power Services	(48,800)
8	Non-Slice Interest Credit (Line 7 – (Line 5 + Line 6))	(10,855)

Net Interest Expense in Slice True-Up Q2

	FY23 Rate Case ($ in thousands)	Q2 ($ in thousands)
• Federal Appropriation	38,609	41,353
• Capitalization Adjustment	(45,937)	(45,937)
• Borrowings from US Treasury	40,881	60,074
• Prepay Interest Expense	6,799	6,799
• **Interest Expense**	**40,352**	**62,288**
• AFUDC	(11,469)	(15,000)
• Interest Income (composite)	(1,235)	(37,945)
• Prepay Offset Credit	(0)	(0)
• **Total Net Interest Expense**	**27,648**	**9,343**

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 8, 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

		Q2 ($000)	Rate Case forecast for FY 2023 ($000)	Q2 - Rate Case Difference
1	Operating Expenses			
2	Power System Generation Resources			
3	Operating Generation			
4	COLUMBIA GENERATING STATION (WNP-2)	$ 312,175	$ 304,748	$ 7,427
5	BUREAU OF RECLAMATION	$ 162,663	$ 152,963	$ 9,700
6	CORPS OF ENGINEERS	$ 252,557	$ 252,557	$ -
7	CRFM STUDIES	$ 3,619	$ 3,619	$ 0
8	LONG-TERM CONTRACT GENERATING PROJECTS	$ 18,910	$ 17,123	$ 1,787
9	**Sub-Total**	**$ 749,924**	**$ 731,010**	**$ 18,914**
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	$ 1,979	$ 1,200	$ 779
16	WNP-1&3 DECOMMISSIONING	$ 1,129	$ 1,175	$ (46)
17	**Sub-Total**	**$ 3,108**	**$ 2,375**	**$ 733**
18	Gross Contracted Power Purchases			
19	PNCA HEADWATER BENEFITS	$ 2,691	$ 3,100	$ (409)
20	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)	$ 55,191	$ -	$ 55,191
21	**Sub-Total**	**$ 57,882**	**$ 3,100**	**$ 54,782**
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)	$ 17,519	$ 20,132	$ (2,613)
32	**Sub-Total**	**$ 17,519**	**$ 20,132**	**$ (2,613)**
33	Generation Conservation			
34	CONSERVATION ACQUISITION	$ 78,500	$ 67,357	$ 11,143
35	CONSERVATION INFRASCTRUCTURE	$ 24,616	$ 27,300	$ (2,684)
36	LOW INCOME WEATHERIZATION & TRIBAL	$ 6,005	$ 6,005	$ 0
37	ENERGY EFFICIENCY DEVELOPMENT	$ 30	$ 8,000	$ (7,970)
38	DISTRIBUTED ENERGY RESOURCES	$ 215	$ 215	$ 0
39	LEGACY	$ 496	$ 590	$ (94)
40	MARKET TRANSFORMATION	$ 11,800	$ 11,800	$ (0)
41	**Sub-Total**	**$ 121,662**	**$ 121,267**	**$ 395**
42	**Power System Generation Sub-Total**	**$ 1,249,223**	**$ 1,172,080**	**$ 77,143**
43				

Composite Cost Pool True-Up Table

	COMPOSITE COST POOL TRUE-UP TABLE	Q2 ($000)	Rate Case forecast for FY 2023 ($000)	Q2 - 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	$ 3,420	$ 4,035	$ (615)
49	ASSET MGMT ENTERPRISE SVCS	$ 643	$ 330	$ 313
50	SLICE IMPLEMENTATION	$ 624	$ 1,003	$ (379)
51	**Sub-Total**	**$ 4,687**	**$ 9,149**	**$ (4,462)**
52	**Power Services Scheduling**			
53	OPERATIONS SCHEDULING	$ 10,414	$ 9,910	$ 503
54	OPERATIONS PLANNING	$ 9,398	$ 9,006	$ 392
55	**Sub-Total**	**$ 19,812**	**$ 18,917**	**$ 895**
56	**Power Services Marketing and Business Support**			
57	GRID MOD	$ 274	$ 2,285	$ (2,011)
58	EIM INTERNAL SUPPORT	$ -	$ -	$ -
59	POWER INTERNAL SUPPORT	$ 18,599	$ 15,251	$ 3,348
60	COMMERCIAL ENTERPRISE SVCS	$ 6,871	$ 2,192	$ 4,678
61	OPERATIONS ENTERPRISE SVCS	$ 4,349	$ 2,274	$ 2,075
62	POWER R&D	$ 2,527	$ 2,527	$ -
63	SALES & SUPPORT	$ 13,771	$ 15,563	$ (1,792)
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	$ 8,492	$ 8,131	$ 361
67	**Sub-Total**	**$ 54,883**	**$ 58,788**	**$ (3,905)**
68	**Power Non-Generation Operations Sub-Total**	**$ 79,382**	**$ 86,853**	**$ (7,471)**
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)	$ 2,780	$ 3,300	$ (520)
73	TRANS ACQ GENERATION INTEGRATION	$ 14,809	$ 14,809	$ 0
74	EESC CHARGES (Composite)	$ (2,764)	$ -	$ (2,764)
75	TELEMETERING/EQUIP REPLACEMT	$ -	$ -	$ -
76	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**	**$ 130,002**	**$ 133,285**	**$ (3,284)**
77	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
78	**Fish & Wildlife**	$ 250,175	$ 248,065	$ 2,110
79	**USF&W Lower Snake Hatcheries**	$ 29,000	$ 29,000	$ (0)
80	**Planning Council**	$ 11,983	$ 12,431	$ (448)
81	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$ 291,158**	**$ 289,496**	**$ 1,662**
82	**BPA Internal Support**			
83	**Additional Post-Retirement Contribution**	$ 18,912	$ 19,354	$ (442)
84	**Agency Services G&A (excludes direct project support)**	$ 82,626	$ 65,336	$ 17,290
85	**BPA Internal Support Sub-Total**	**$ 101,538**	**$ 84,689**	$ 16,848

Composite Cost Pool True-Up Table

	COMPOSITE COST POOL TRUE-UP TABLE	Q2 ($000)	Rate Case forecast for FY 2023 ($000)	Q2 - Rate Case Difference
86	**Bad Debt Expense**	$ -	$ -	$ -
87	**Other Income, Expenses, Adjustments**	$ 734	$ (2,971)	$ 3,705
88	**Depreciation**	$ 145,000	$ 144,155	$ 845
89	**Amortization**	$ 322,700	$ 317,320	$ 5,380
90	**Accretion (CGS)**	$ 37,600	$ 38,363	$ (763)
91	**Total Operating Expenses**	**$ 2,357,336**	**$ 2,263,269**	**$ 94,068**
92				
93	**Other Expenses and (Income)**			
94	Net Interest Expense	$ 252,444	$ 228,139	$ 24,304
95	LDD	$ 31,030	$ 40,009	$ (8,980)
96	Irrigation Rate Discount Costs	$ 20,505	$ 20,509	$ (4)
97	**Sub-Total**	**$ 303,979**	**$ 288,658**	**$ 15,321**
98	**Total Expenses**	**$ 2,661,315**	**$ 2,551,927**	**$ 109,388**
99				
100	**Revenue Credits**			
101	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	$ 99,835	$ 104,245	$ (4,410)
102	Downstream Benefits and Pumping Power revenues	$ 20,709	$ 20,661	$ 48
103	4(h)(10)(c) credit	$ 227,529	$ 94,216	$ 133,314
104	PRSC Net Credit (Composite)	$ (7,495)	$ -	$ (7,495)
105	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ 0
106	Energy Efficiency Revenues	$ 30	$ 8,000	$ (7,970)
107	PF Load Forecast Deviation Liquidated Damages	$ -	$ 1,070	$ (1,070)
108	Miscellaneous revenues	$ 13,477	$ 11,696	$ 1,781
109	Renewable Energy Certificates	$ -	$ -	$ -
110	Net Revenues from other Designated BPA System Obligations (Upper Baker)	$ 402	$ 402	$ (0)
111	RSS Revenues	$ 3,056	$ 3,056	$ -
112	Firm Surplus and Secondary Adjustment (from Unused RHWM)	$ 79,301	$ 79,301	$ -
113	Balancing Augmentation Adjustment	$ 4,019	$ 4,019	$ -
114	Transmission Loss Adjustment	$ 30,577	$ 30,577	$ -
115	Tier 2 Rate Adjustment	$ 1,767	$ 1,767	$ -
116	NR Revenues	$ 1	$ 1	$ -
117	**Total Revenue Credits**	**$ 477,809**	**$ 363,611**	**$ 114,198**
118				
119	**Augmentation Costs (not subject to True-Up)**			
120	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)	$ 11,421	$ 11,421	$ -
121	Augmentation Purchases	$ -	$ -	$ -
122	**Total Augmentation Costs**	**$ 11,421**	**$ 11,421**	**$ -**
123				
124	**DSI Revenue Credit**			
125	Revenues 12 aMW @ IP rate	$ 3,791	$ 4,277	$ (487)
126	**Total DSI revenues**	**$ 3,791**	**$ 4,277**	**$ (487)**
127				

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		Q2 ($000)	Rate Case forecast for FY 2023 ($000)	Q2 - Rate Case Difference
128	**Minimum Required Net Revenue Calculation**			
129	Principal Payment of Fed Debt for Power	$ 525,000	$ 525,000	$ -
130	Repayment of Non-Federal Obligations (EN Line of Credit)	$ -	$ -	$ -
131	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls)	$ 21,111	$ 21,111	$ -
132	Irrigation assistance	$ 13,355	$ 12,762	$ 593
133	**Sub-Total**	**$ 559,466**	**$ 558,873**	**$ 593**
134	Depreciation	$ 145,000	$ 144,155	$ 845
135	Amortization	$ 322,700	$ 317,320	$ 5,380
136	Accretion	$ 37,600	$ 38,363	$ (763)
137	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ -
138	Amortization of Refinancing Premiums/Discounts (MRNR - Reverse Sign)	$ (23,695)	$ (7,491)	$ (16,204)
139	Amortization of Cost of Issuance (MRNR-reverse sign)	$ 363	$ 169	$ 194
140	Cash freed up by DSR refinancing	$ 16,865	$ 16,865	$ -
141	Gains/Losses on Extinguishment	$ -	$ -	$ -
142	Non-Cash Expenses	$ 73,155	$ 73,155	$ (0)
143	Prepay Revenue Credits	$ (30,600)	$ (30,600)	$ -
144	Non-Federal Interest (Prepay)	$ 6,799	$ 6,799	$ -
145	Contribution to decommissioning trust fund	$ (4,651)	$ (4,651)	$ -
146	Gains/losses on decommissioning trust fund	$ (10,198)	$ (10,198)	$ -
147	Interest earned on decommissioning trust fund	$ (3,516)	$ (3,516)	$ -
148	Revenue Financing Requirement	$ (40,000)	$ (40,000)	$ -
149	Other Adjustments	$ 6,966	$ -	$ 6,966
150	**Sub-Total**	**$ 450,851**	**$ 454,431**	**$ (3,580)**
151	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expenses	$ 108,615	$ 104,442	$ 4,173
152	Minimum Required Net Revenues	**$ 108,615**	**$ 104,442**	**$ 4,173**
153				
154	Annual Composite Cost Pool (Amounts for each FY)	**$ 2,299,752**	**$ 2,299,902**	**$ (150)**
155				
156	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**			
157	TRUE-UP AMOUNT (Diff. between Rate Case and Forecast)	(150)		
158	Sum of TOCAs	0.9706591		
159	Adjustment of True-Up Amount when actual TOCAs < 100 percent	**(155)**		
160	TRUE-UP ADJUSTMENT CHARGE BILLED (22.36267 percent)	(35)		