BONNEVILLE POWER ADMINISTRATION

Q3 Quarterly Business Review Technical Workshop

August 18, 2020

9:00 am – 11:30 a.m.

WebEx:

Bridge: (415) 527-5035

Access Code: 199 591 1125

SUSTAINABLE FINANCES & RATES

Agenda

Time	Min	Agenda Topic	Presenter
9:00	5	Introduction and safety moment	Nadine Coseo
9:05	10	Revisit Q2 COVID-19 "Bad Case" and Discuss Q3 COVID-19 Approach	Zach Mandell, Kevin Bernards, Daniela Schlough
9:15	60	Q3 Forecast Including Income Statement, Capital, Reserves, and ACNR Update	Cheryl Hargin, Karlee Manary, Kyle Hardy, Jeff Cook, Nadine Coseo, Damen Bleiler, Zach Mandell
10:15	30	Net Secondary Revenue and Point-to-Point Revenue Update	Steve Gaube, Danny Chen
10:45	30	Grid Modernization Update	Allie Mace
11:15	15	Q & A Session	All

Revisit Q2 COVID-19 "Bad Case" and Discuss Q3 COVID-19 Approach

Zach Mandell, Kevin Bernards, Daniela Schlough

BPA’s Current COVID-19 Posture

- After moving to a less restrictive response level of the pandemic plan in June, on August 12th BPA returned to a more restrictive posture, which focuses on remote work enablers such as telecommuting to reduce the concentration of employees in any one location and continue meeting business requirements.
- BPA is using the best available information from the public health sector and guidance from local, state and national authorities in its decision-making processes.
- BPA is deferring all maintenance and construction projects that are not directly tied to life safety or reliability.
- Crews will continue to respond to outages and other emergencies to continue delivering power to customers and operating the grid.
- There are no current operational impacts to BPA as a result of these actions. While some support activities may experience some dips in productivity due to workflow changes, BPA management is working to support seamless operations.

COVID-19 “Bad Case” Scenario:

In Q2, the base forecast did not assume any effects from COVID-19. Instead Staff developed a COVID-19 Bad Case Scenario to show alongside the base Q2 forecast.

The primary effects identified in the Bad Case Scenario were:

	Power	Transmission
Revenue	$39 million decrease due to load loss.	$4 million decrease due to load loss.
Expenses	$25 million decrease, primarily due to project delays at the Corps and Reclamation and Energy Efficiency. (Power Capital to Expense was not forecast in the scenario)	$48 million increase, consisting of: • $15 million increase in direct labor costs, • $50 million in indirect labor costs shifting from capital to expense, • $18 million decrease in other expenses
Capital	Capital execution reduction of $85 million.	Capital Execution reduction of $109 million

For Q3, then-expected COVID-19 impacts were built in to the base forecast. This does not include the August 12th change in posture.

In general, the financial impacts were forecast to be much lower than the Bad Case Scenario. The state of BPAs revenues, expenses, and capital will be discussed further throughout the presentation.

Status of Accounting Review of FY20 Capital Costs

Transmission

- Initial stay at home orders due to COVID-19 resulted in delays in executing capital projects for Transmission and resulted in an under clearing of indirect costs through Q3.
- Recent projections had showed optimism around executing most of the start of year capital budgets. However, BPA's decision to return to a more restrictive posture will negatively impact these forecasts.
- It is too early to know the impacts, but this will increase the risk that BPA may need to write off a portion of the indirect costs to expense. BPA will continue to monitor these impacts.

Power

- Initial stay at home orders due to COVID-19 resulted in delays in executing capital projects at the Corps and Reclamation hydro-power dams but the impacts on current year forecasted execution have not been significant so far.
- Both agencies reported a modest shift from capital to expense with no significant impacts on expense.
- Both agencies also reported a very slight decrease in their overhead rates due to a reduction in travel and training costs.
- BPA staff will continue to communicate with Corps and Reclamation Staff to monitor the impacts from COVID-19.
- No write-off actions has been taken as of Q3.

Q3 Forecast Including Income Statement, Capital and Reserves

Cheryl Hargin, Karlee Manary, Kyle Hardy, Jeff Cook, Nadine Coseo, Damen Bleiler, Zach Mandell

Report ID: 0123FY20
Requesting BL: Transmission Business Unit
Unit of Measure: $ Thousands

QBR Forecast Analysis: Transmission Services
Program Plan View
Through the Month Ended June 30, 2020
Preliminary / Unaudited

Data Source: PFMS
Run Date/Time: July 27, 2020 / 11:10
% of Year Elapsed = 75%

Unit of Measure: $ Thousands

		A	B	C
		FY 2020		FY 2020
		Rate Case	Current EOY Forecast	Current EOY Forecast - Rate Case
	Operating Revenues			
1	Sales	$ 919,467	$ 925,803	$ 6,336
2	Other Revenues	43,031	45,275	2,243
3	Inter-Business Unit Revenues	123,755	114,368	(9,387)
4	**Total Operating Revenues**	**1,086,253**	**1,085,445**	**(808)**
	Operating Expenses			
	Integrated Program Review Programs			
5	Asset Management	262,974	262,040	(934)
6	Operations	71,098	66,420	(4,679)
7	Commercial Activities	62,078	60,551	(1,527)
8	Enterprise Services G&A	92,528	103,397	10,869
9	Undistributed Reduction		-	
10	**Sub-Total Integrated Program Review Operating Expenses**	**488,678**	**492,408**	**3,730**
	Operating Expenses			
	Non-Integrated Program Review Programs			
11	Commercial Activities	128,005	121,262	(6,743)
12	Other Income, Expenses and Adjustments	-		
13	Depreciation & Amortization	342,088	339,550	(2,538)
14	**Sub-Total Non-Integrated Program Review Operating Expenses**	**470,093**	**460,812**	**(9,281)**
15	**Total Operating Expenses**	**958,771**	**953,220**	**(5,551)**
16	**Net Operating Revenues (Expenses)**	**127,482**	**132,225**	**4,743**
	Interest expense and other income, net			
17	Interest Expense	183,458	156,490	(26,967)
18	AFUDC	(14,211)	(14,800)	(589)
19	Interest Income	(5,078)	(2,225)	2,853
20	Other income, net	-	5,095	5,095
21	**Total interest expense and other income, net**	**164,169**	**144,561**	**(19,608)**
22	**Total Expenses**	**1,122,940**	**1,097,781**	**(25,159)**
23	**Net Revenues (Expenses)**	**$ (36,687)**	**$ (12,336)**	**$ 24,351**

<1 Although the forecasts in this report are presented as point estimates, BPA operates a hydro-based system that encounters much uncertainty regarding water supply and wholesale market prices. These uncertainties, among other factors, may result in large range swings +/- impacting the final results in revenues, expenses, and cash reserves.

Transmission Services QBR Analysis: FY 20 Q3 End of Year Forecast

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

Integrated Program Review Operating Expenses:

Row 6 - Transmission Operations: $5 million below rate case due to Enterprise Services direct charges for Grid Mod forecasted in rate case shifted from this program into the allocated Enterprise Services expense.

Row 8 – Enterprise Services G&A: $11 million higher due to a greater portion of the overall Enterprise Services support costs driven mainly by increased IT expense partially offset by a decrease in post retirement benefits.

Non-Integrated Program Review Operating Expenses:

Row 11 – Commercial Activities: $7 million lower reimbursable work.

Row 13 – Depreciation and Amortization: $2 million lower than rate case based on actual plant that has been placed into service as of the third quarter and the estimated capital expected to go into service over the remainder of FY20.

Row 21 – Net Interest Expense: $20 million below rate case due to putting less lease financing in place and slightly less Federal borrowing coupled with lower interest rates than assumed in the rate case.

Report ID: 0121FY20	**QBR Forecast Analysis: Power Services**	Data Source: PFMS
Requesting BL: POWER BUSINESS UNIT	**Program Plan View**	Run Date/Time: July 23,2020 / 12:16
Unit of measure: $ Thousands	Through the Month Ended June 30, 2020	% of Year Elapsed = 75%
	Preliminary / Unaudited	

		A	B	C
		FY 2020		FY 2020
		Rate Case	Q3 Forecast	Q3 Forecast - Rate Case
	Operating Revenues			
1	Gross Sales (excluding bookout adjustment)	$ 2,472,943	$ 2,539,595	$ 66,652
2	Bookout Adjustment to Sales	-	(29,212)	(29,212)
3	Other Revenues	28,016	33,520	5,504
4	Inter-Business Unit	117,901	116,074	(1,827)
5	U.S. Treasury Credits	90,850	104,376	13,526
6	**Total Operating Revenues**	**2,709,710**	**2,764,352**	**54,643**
	Operating Expenses			
	Integrated Program Review Programs			
7	Asset Management	961,496	949,909	(11,587)
8	Operations	124,378	131,587	7,208
9	Commercial Activities	106,852	95,866	(10,985)
10	Enterprise Services G&A	77,436	80,991	3,555
11	**Sub-Total Integrated Program Review Operating Expenses**	**1,270,162**	**1,258,353**	**(11,809)**
	Operating Expenses			
	Non-Integrated Program Review Programs			
12	Asset Management	36,708	30,897	(5,811)
13	Operations	351,361	336,805	(14,556)
14	Commercial Activities	214,630	218,091	3,461
15	Other Income, Expenses & Adjustments	-		
16	Non-Federal Debt Service <Note 2	-	-	-
17	Depreciation, Amortization & Accretion	518,295	477,360	(40,935)
18	**Sub-Total Non-Integrated Program Review Operating Expense**	**1,120,993**	**1,063,153**	**(57,840)**
19	**Total Operating Expenses**	**2,391,155**	**2,321,506**	**(69,649)**
20	**Net Operating Revenues (Expenses)**	**318,555**	**442,846**	**124,292**
	Interest expense and other income, net			
21	Interest Expense	305,707	305,044	(663)
22	AFUDC	(15,904)	(14,275)	1,629
23	Interest Income	(13,777)	(9,918)	3,859
24	Other income, net	(5,052)	(5,052)	()
25	**Total interest expense and other income, net**	**270,974**	**275,799**	**4,825**
26	**Total Expenses**	**2,662,129**	**2,597,305**	**(64,824)**
26	**Net Revenues (Expenses)**	**$ 47,580**	**$ 167,047**	**$ 119,467**

<1 Although the forecasts in this report are presented as point estimates, BPA operates a hydro-based system that encounters much uncertainty regarding water supply and wholesale market prices. These uncertainties, among other factors, may result in large range swings +/- impacting the final results in revenues, expenses, and cash reserves.

<2 In FY20, balances will be reflected in interest expense and amortization line items of the income statement.

Power Services QBR Analysis: FY 20 Q3 End of Year Forecast

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

Row 6 – Total Operating Revenues: Higher Gross Sales due to higher Demand Revenues, higher Secondary Sales, this is partially offset by a forecasted $10M Slice True-up Credit. The higher Gross Sales also includes $21M of Reserves Surchage which was not in the rate case forecast. There will be no more reserves surcharge collected for the remainder of the FY.

Integrated Program Review Operating Expenses:

Row 7 – Asset Management: $10 million F&W contracting and observed delays in proceeding with seasonal project work.

Row 8 - Operations and Row 9 - Commercial Activities: When BP20 was created Program Plans did not exist therefore there has been a shift of costs between the Program Plans.

Power Services QBR Analysis: FY 20 Q3 End of Year Forecast

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

Non-Integrated Program Review Operating Expenses:

Row 12 – Asset Management: $6 million lower than Rate Case to reflect actual Colville Settlement.

Row 13 – Operations: $15 million lower than Rate Case reflects lower loads and lower 3rd Party GTA wheeling.

Row 14 – Commercial Activities: $3 million higher than Rate Case due to higher power purchase due to dry weather conditions experienced early in FY as well as seasonality of runoff in the late spring.

Row 17 – Depreciation, Amortization and Accretion: $41 million lower than Rate Case is due to the implementation of new accounting treatment for Energy Northwest and other nonfederal assets as discussed at Q1. Rate Case levels were set prior to the new accounting treatment being finalized and as such a Rate Case to actuals difference was created for the BP-20 rate period.

Row 25 - Net interest Expense: $5 million higher than Rate Case primarily due to federal interest income being lower because of lower interest rates than assumed in Rate Case.

Row 26 – Total Net Revenues: $167 million, which is $119 million greater than Rate Case.

Agency Capital Expenditures: FY 20 Performance

Report ID: 0027FY20	**QBR Forecast Analysis: BPA Capital Expenditures**	Data Source: PFMS
Requesting BL: Corporate Business Unit	FYTD Through the Month Ended June 30, 2020	Run Date/Time: July 27,2020 / 03:13
Unit of Measure: $Thousands	Preliminary Unaudited	% of Year Elapsed = 75%

		A	B	C
		FY 2020		FY 2020
		Rate Case	Current EOY Forecast	Current EOY Forecast - Rate Case
	Transmission Business Unit			
1	MAIN GRID	$ 2,320	$ 1,430	$ (890)
2	AREA & CUSTOMER SERVICE	73,359	32,593	(40,766)
3	SYSTEM REPLACEMENTS	316,710	222,736	(93,975)
4	UPGRADES & ADDITIONS	58,319	61,812	3,494
5	ENVIRONMENT CAPITAL	6,898	7,965	1,067
	PFIA	-	-	-
6	MISC. PFIA PROJECTS	14,034	6,263	(7,771)
7	GENERATOR INTERCONNECTION	69,157	18,777	(50,380)
8	SPECTRUM RELOCATION	1,522	224	(1,298)
9	CORPORATE CAPITAL INDIRECTS, undistributed	()	()	()
10	TBL CAPITAL INDIRECTS, undistributed	()	()	
11	LAPSE FACTOR	(13,125)	()	13,125
12	**TOTAL Transmission Business Unit**	**529,194**	**351,801**	**(177,394)**
	Power Business Unit			
13	BUREAU OF RECLAMATION *<Note 1*	120,893	32,163	(88,730)
14	CORPS OF ENGINEERS *<Note 1*	133,011	163,538	30,526
15	POWER INFORMATION TECHNOLOGY	3,900	757	(3,143)
16	FISH & WILDLIFE *<Note 2*	47,266	42,000	(5,266)
17	**TOTAL Power Business Unit**	**305,070**	**238,457**	**(66,613)**
	Corporate Business Unit			
18	CORPORATE PROJECTS	13,200	22,972	9,772
19	**TOTAL Corporate Business Unit**	**13,200**	**22,972**	**9,772**
20	**TOTAL BPA Capital Expenditures**	**$ 847,465**	**$ 613,230**	**$ (234,235)**

< 1 Excludes projects funded by federal appropriations.
< 2 Amounts are reported as regulatory assets and not utility plant

Agency Capital Expenditures: FY20 Performance

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

Transmission Business Unit

Transmission is $177 million below rate case due to a shift in Transmission's Sustain and Expand Program prioritizations in FY18 and project delays due to work stoppages on non-essential projects during the COVID-19 pandemic. Regarding the prioritization change, analysis revealed BPA's need to focus on the Sustain Program was required in order to maintain the reliability of the Grid. This resulted in a change to the mix and size of projects & their corresponding demand for resources. A Sustain-focused program requires a larger amount of resources. Due to staffing change limitations, Transmission reduced their Start of Year (SOY) Budget to what they believed to be an accurate reflection of what could be delivered. The Q3 forecasts do not reflect BPA's 8/12 decision to stop all non-essential construction and maintenance work as part of returning to a more restrictive posture .

Row 2 – Area and Customer Service: $41 million below rate case due to a shift to more Sustain projects, including an $11 million decrease due to work stoppage and project delays due to COVID-19.

Row 3 – System Replacements: $94M less than rate case due to increase in smaller, complex projects with high resource demands.

Row 4 – Upgrades and additions: $3.5 million above rate case due to higher loading costs* forecasted at the Start of Year (SOY) Budget than included in Rate Case.

Rows 6-8 – Projects Funded in Advance (PFIA): $59.5 million less than rate case due to a change in strategy above. This was budgeted for a reduced amount at SOY and currently on track.

Power Business Unit

Row 13 – Bureau of Reclamation: $89 million below rate case due to reprioritization in the capital program that has shifted more investment in FY20 to the Corps. Additional project delays further decreased FY20 expected spending by approximately $14 million compared to the Q2 End of Year forecast.

Row 14 – Corps of Engineers: $31 million above rate case due to Asset Investment Excellence initiative, projects were prioritized and pulled forward. Delays due to COVID-19 work stoppages have decreased FY20 expected spending by approximately $8 million compared to Q2 End of Year forecast.

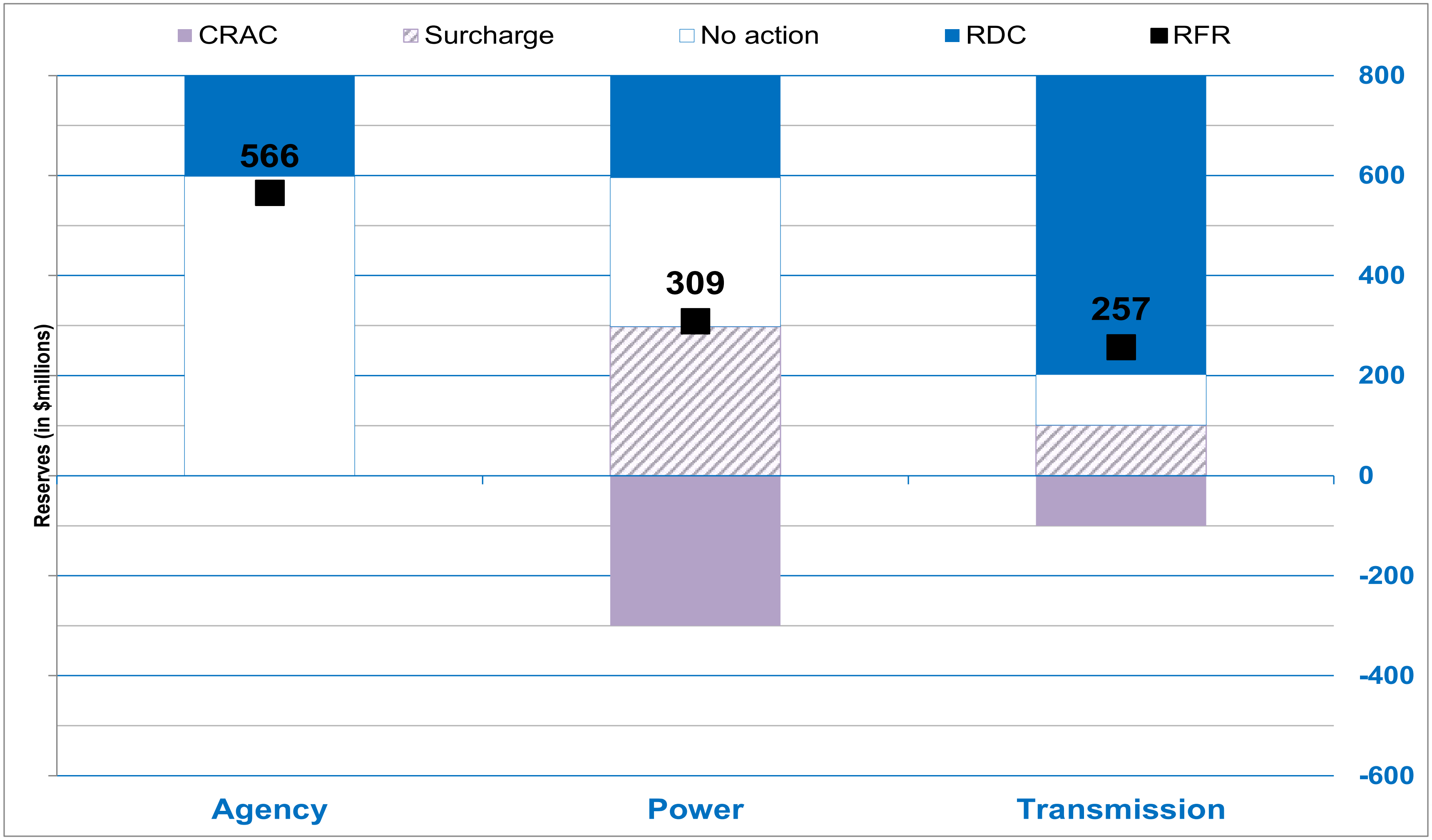
Row 15 – Power IT: $3 million below rate case due to project prioritization resulting in EE tracking and reporting being the only Power specific IT project moving forward.

Row 16 – Fish and Wildlife: $5 million below rate case due to expected delay of qualified land acquisitions.

Corporate Business Unit

Row 18 – Corporate IT projects: $10 million above rate case due to project prioritization of new customer billing and enterprise business system disaster recovery project for DOE policy compliance, project components qualifying for capital when assumed to be expense, and updated project estimates.

Q3 Reserves for Risk* Forecast – FY20 EOY



Days Cash	87	65	151

* Reminder – Rate mechanics trigger off of ACNR, not RFR

Reserves Forecast – FY20 EOY

		A	B	C	D	E
	(in $ Thousands)	BP-20		FY 2020		Delta
	POWER	FY 2020	Days Cash	Q3	Days Cash	(C - A)
1	**PS RESERVES for RISK**	**320,594**	**65**	**308,869**	**65**	**(11,725)**
2	PS RESERVES not for RISK	121,509		95,709		**(25,800)**
3	**PS TOTAL RESERVES**	**442,103**		**404,578**		**(37,525)**
	TRANSMISSION					
4	**TS RESERVES for RISK**	**147,750**	**88**	**256,835**	**151**	**109,085**
5	TS RESERVES not for RISK	114,538		65,691		**(48,846)**
6	**TS TOTAL RESERVES**	**262,288**		**322,527**		60,238
	AGENCY					
7	RESERVES for RISK	**468,344**	**70**	**565,705**	**87**	**97,360**
8	RESERVES not for RISK	236,046		161,400		**(74,646)**
9	**AGENCY TOTAL RESERVES**	**704,391**		**727,105**		**22,714**

Power Crosswalk – Key Drivers

PS FY20 EOY Reserves for Risk (RFR) is forecasted to be $309m, which is ~$12m less than the rate case forecast of $321m. Key drivers:

- The BP-20 Rate Case assumed PS ended FY19 with RFR = $288m, but PS ended FY19 with $203m, resulting in $85m less in RFR heading into FY20 than assumed in the rate case.
- FY20 Driver: The Q3 Net Revenue* forecast is $119M higher than the rate case projection.
  - Higher Gross Sales due to higher demand, higher secondary sales and **lower Depreciation/Amortization**
  - Depreciation/Amortization is lower by $41m, but is non-cash
  - Power has not seen a significant decrease due to Covid-19

($ in millions)

Power Crosswalk	
Q3 FY20 EOY RFR Forecast	309
BP-20 RFR Forecast	321
Delta	($12)
Explain the ($12)m Delta	
FY20 SOY RFR Beg Bal Delta from RC	(85)
Plus: Increase in Net Revenues	119
Minus: Non-Cash Portion of Net Revenues	(41)
Plus: Cash and Booking Timing	6
Less: Customer Payment Extension to FY21	(7)
Less: Miscellaneous	(4)
	($12)

* Forecast reflects reduced revenues due to FRP Surcharge suspension.

Transmission Crosswalk – Key Drivers

TS FY20 EOY Reserves for Risk (RFR) is forecasted to be $257m, which is ~$109m more than the rate case forecast of $148m. Key drivers:

- The BP-20 Rate Case assumed TS ended FY19 with RFR = $207m, but TS ended FY19 with $281m, resulting in $75m more in RFR heading into FY20 than assumed in the rate case.
- FY20 Drivers: The Q3 Net Revenue forecast and other cash receipts.
  - Q3 NR forecast is $24m higher than rate case due primarily to a decrease in Interest Expense by $21m and other, including Depreciation/ Amortization
  - $10m cash receipt from a customer settlement not included in the rate case
  - $5m non cash expense related to converting the POM line of credit to long-term bonds

($ in millions)

Transmission Crosswalk	
Q3 FY20 EOY RFR Forecast	257
BP-20 RFR Forecast	148
Delta	$109
Explain the $104m Delta	
FY20 SOY RFR Beg Bal Delta from RC	75
Plus: Increase in Net Revenues	24
Minus: Non-Cash Portion of Net Revenues	(3)
Plus: Non Cash POM Termination Fee	5
Plus: Cash and Booking Timing	10
Less: Miscellaneous	(3)
	$109

Reserves Forecast Uncertainties

- As part of our continued focus on strengthening key processes, including our Reserve forecasting ability, there are two areas of uncertainty to highlight with the current forecast.
  - Forecast Model Differences:
    - To forecast the end of year (EOY) reserves, BPA uses an annual reserves model that starts with the current net revenue forecast and adjusts for non-cash revenues and expenses (aka the “annual model”).
    - BPA also maintains a model that forecasts reserves 90 days out, known as the “short-term model”.
    - At Q3, comparison of the EOY reserves forecasts produced by these two models revealed: Power – only a $2M difference; Transmission – a $25M difference, with the short-term model coming in higher than the annual model.
  - True Up for Prior Year Financing Adjustments:
    - Most BPA construction projects are multi-year; prior to project close out the source of financing may change, e.g. from master lease (ML) to US Treasury (UST) financing, or vice versa. This change requires a “lookback” or true up process to ensure financing sources stay aligned.
    - From a Reserves perspective there should be no impact as the cash to fund the project is either from UST borrowings or from ML draws.
    - We are improving (systemizing and standardizing) this prior year lookback process. Analysis of prior year spending and the timing of cash draws will indicate the amount of the prior year adjustment, if any.
- These uncertainties have been incorporated into the Transmission risk distribution and risk mechanism probabilities (*discussed further Transmission Risk Distribution slide*).

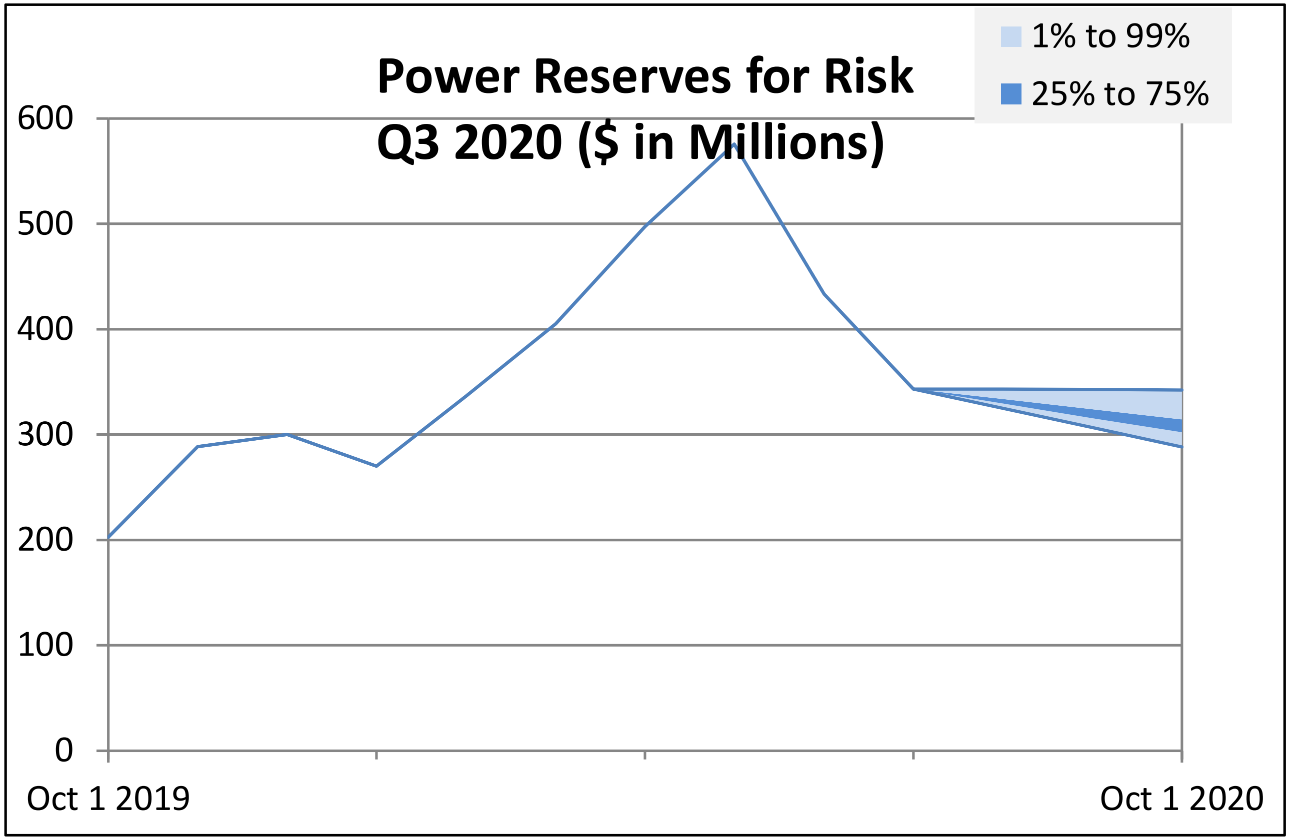
Financial Reserves Update

Power Reserves Distribution

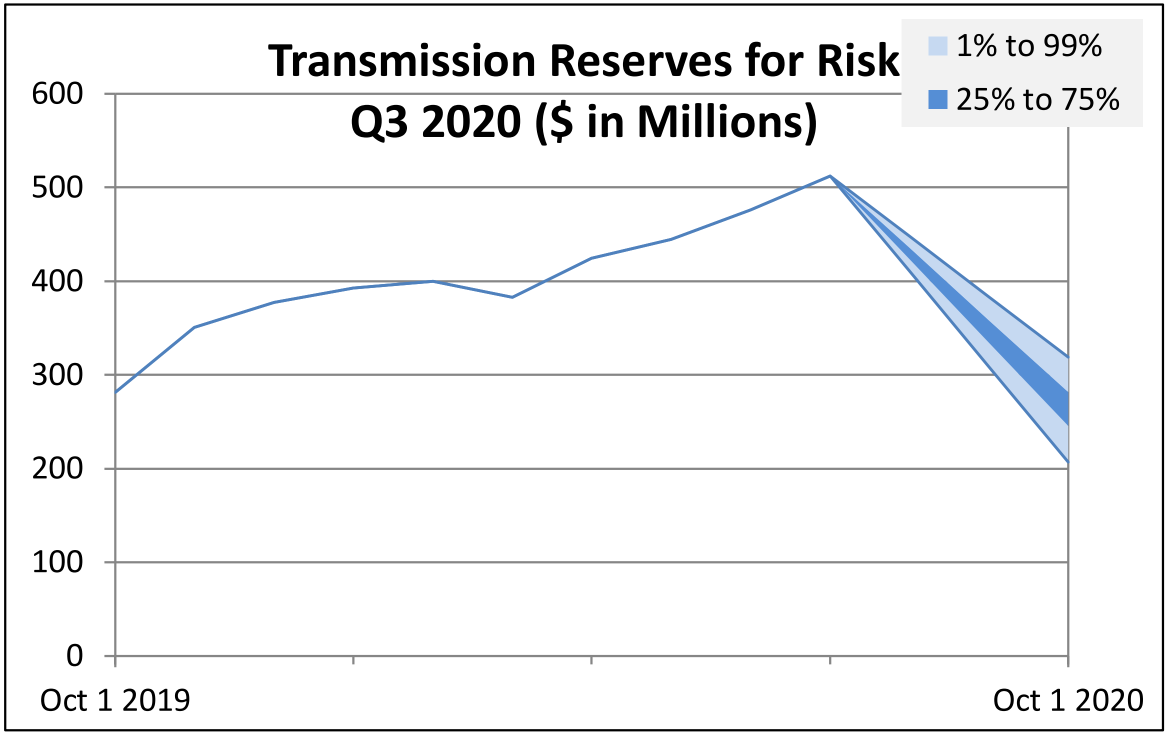
- 1% to 99% Range: $288m to $342m
- 25% to 75% Range: $302m to $314m

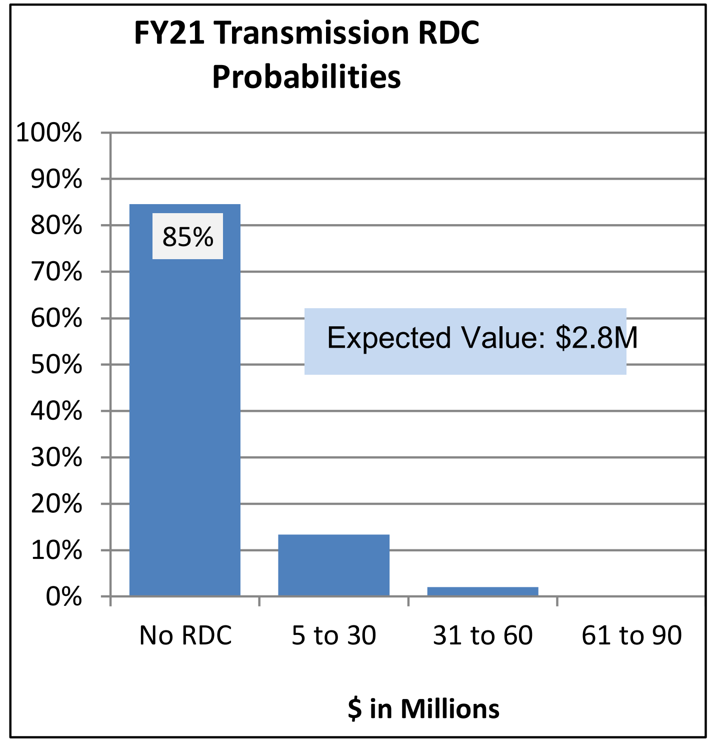
Power Risk Mechanisms

- Power FRP Surcharge is suspended for FY 2021
- 0% modeled probability of a Power CRAC or Power RDC



Financial Reserves Update





Transmission Reserves Distribution

- 1% to 99% Range:
  $210m to $320m
- 25% to 75% Range:
  $247m to $283m

Transmission Risk Mechanisms

- Transmission FRP Surcharge Suspended for FY 2021
- 0% modeled probability of a Transmission CRAC
- 15% modeled probability of a Transmission RDC with an Expected Value of $2.8m

FY 2020 Risk Mechanisms and ACNR

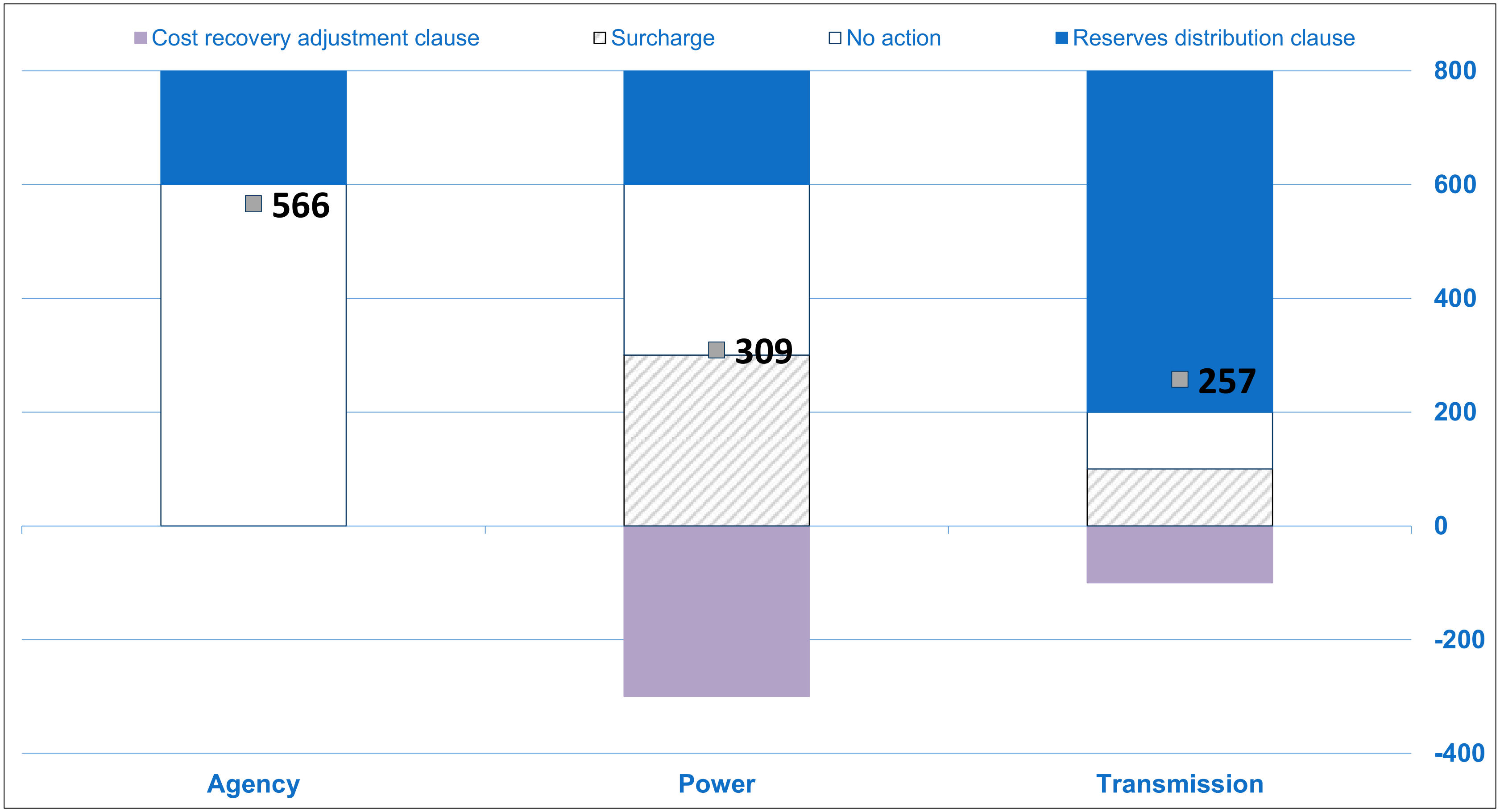
The Power and Transmission Risk Mechanisms include the Cost Recovery Adjustment Clause (CRAC), the Reserves Distribution Clause (RDC), and the Financial Reserves Policy Surcharge (FRPS). The FRPS has been suspended for application in FY 2021.

The Risk Mechanisms trigger based on Accumulated Calibrated Net Revenue (ACNR). ACNR is a Net Revenue based metric, designed to track with Reserves for Risk (with certain exceptions). Calibrations are included in ACNR in order to maintain the relationship between ACNR and Reserves for Risk.

Calibration Events are defined as financial events not forecast in the BP-20 rate case that

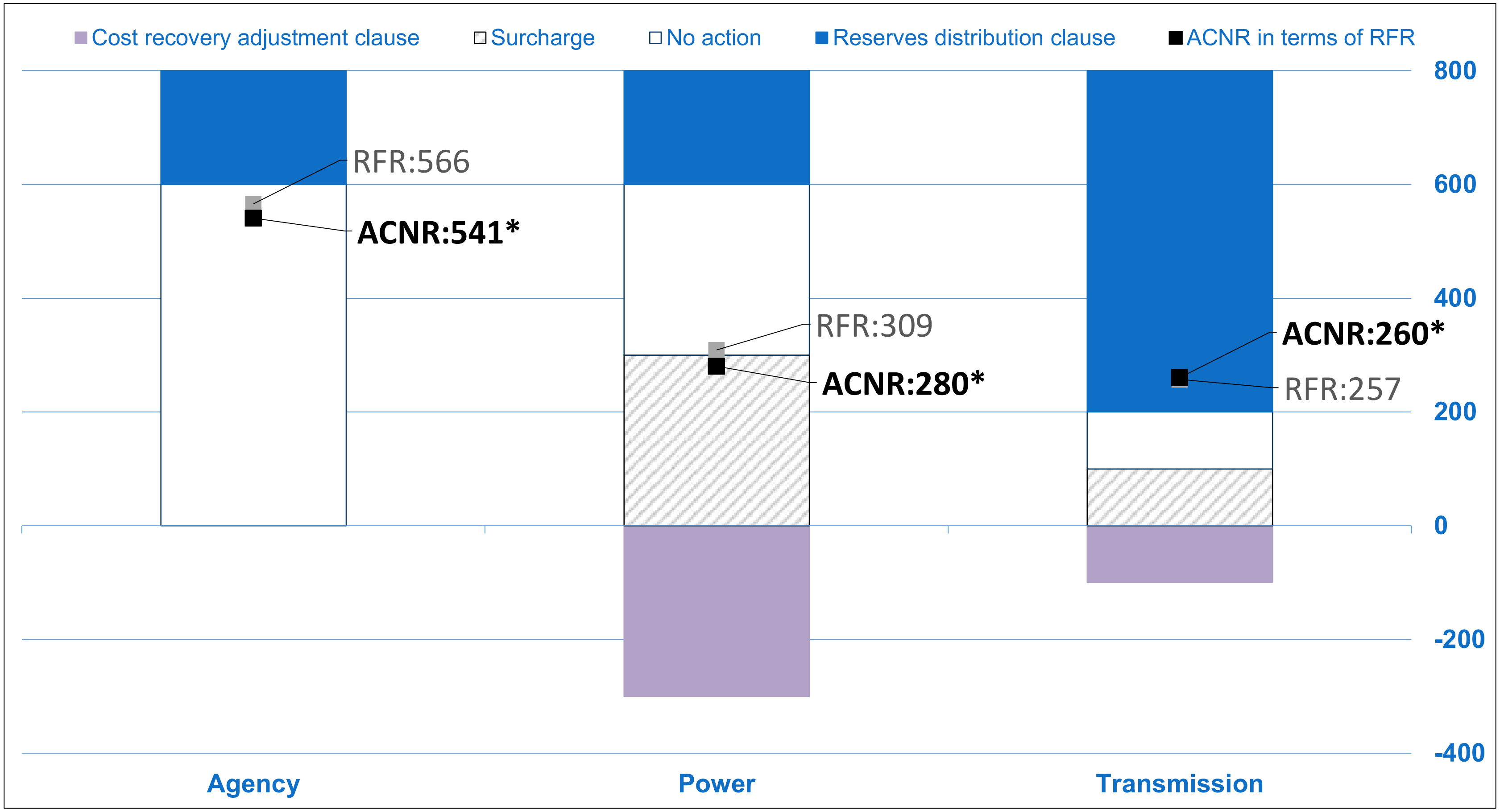
1. Impact Net Revenue differently than they impact Reserves For Risk,
2. Result in a difference of at least $5 million (positive or negative), and
3. Last more than 12 months (i.e. is not a difference of cash timing lag between one fiscal year and the next)

Q3 Reserves for Risk Forecast – FY20 EOY



Days Cash	87	65	151

Q3 Rate Triggers Forecast – FY20 EOY

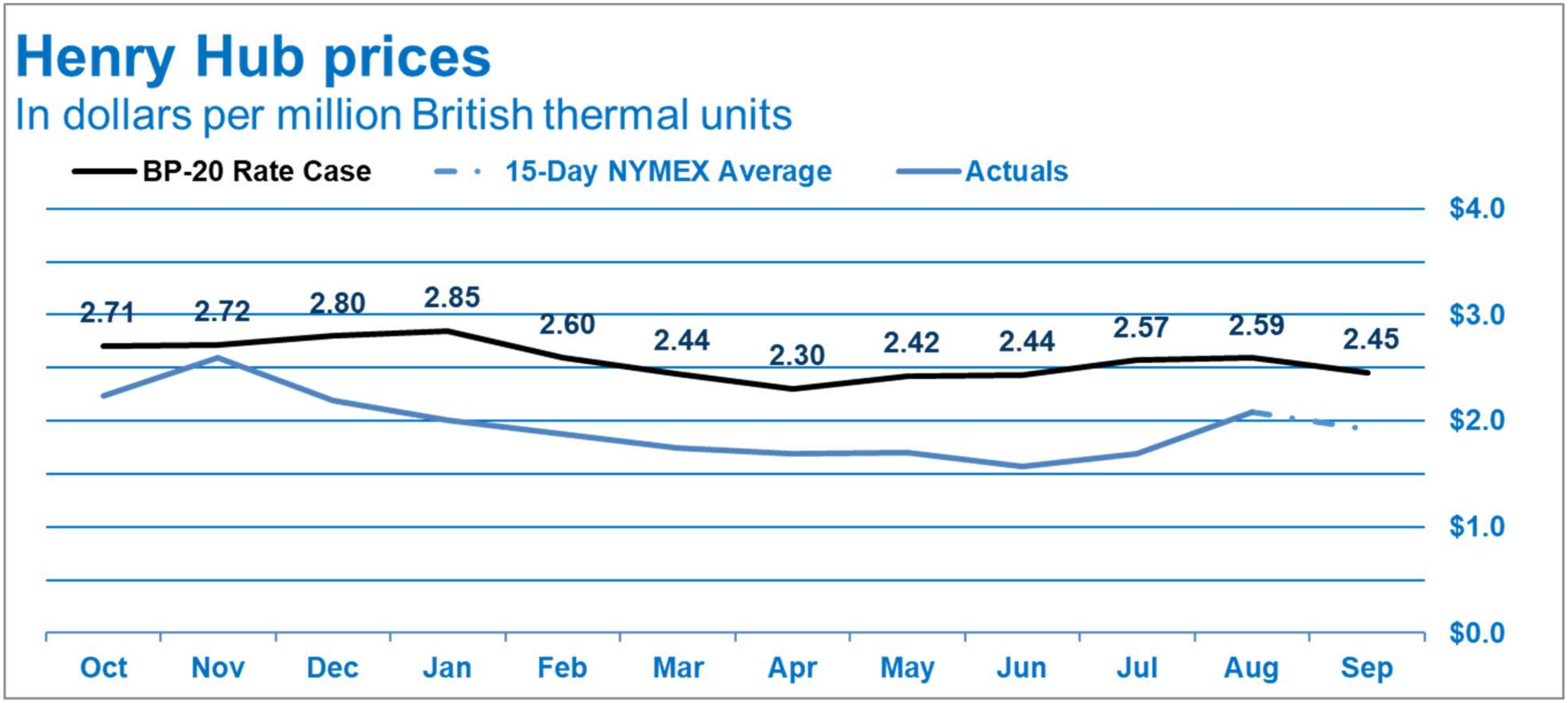


"ACNR" values shown are adjusted to be comparable with Reserves for Risk based thresholds

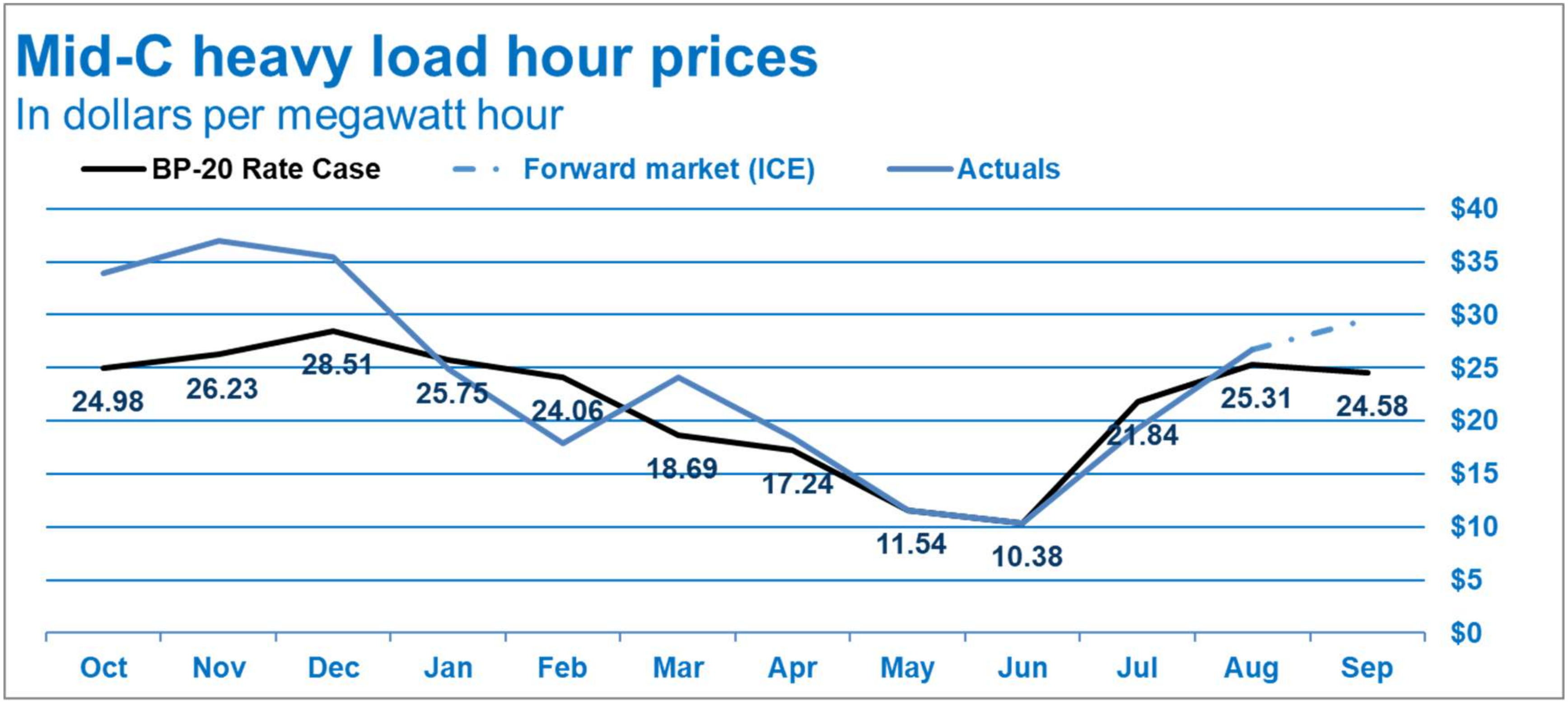
Risk Mechanisms Trigger based on ACNR. Power ACNR is $29m lower than Power RFR due to cash timing shifts between FY 2020 and FY 2021. This difference is not calibrated for because the cash flow occurs within 12 months.

Power and Transmission Market Landcape
Steve Gaube and Danny Chen

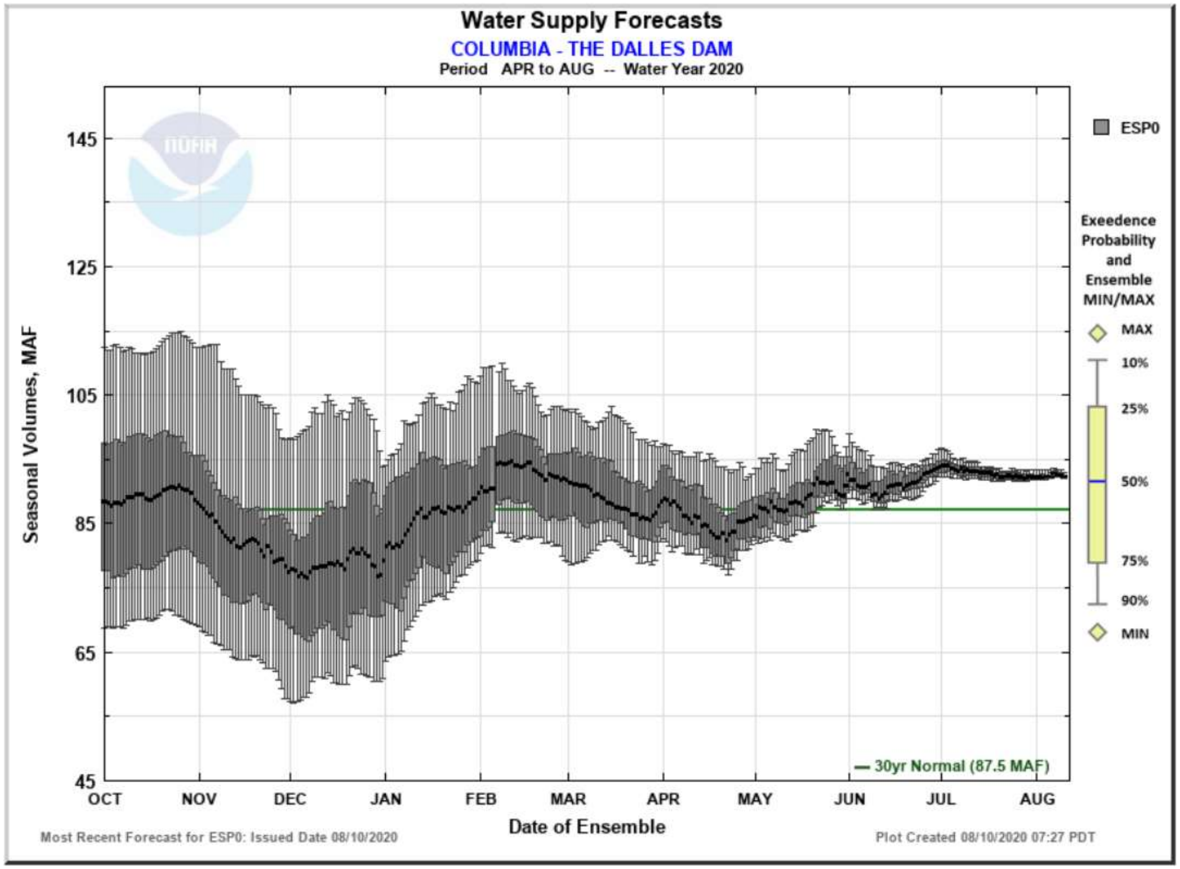
Henry Hub Prices



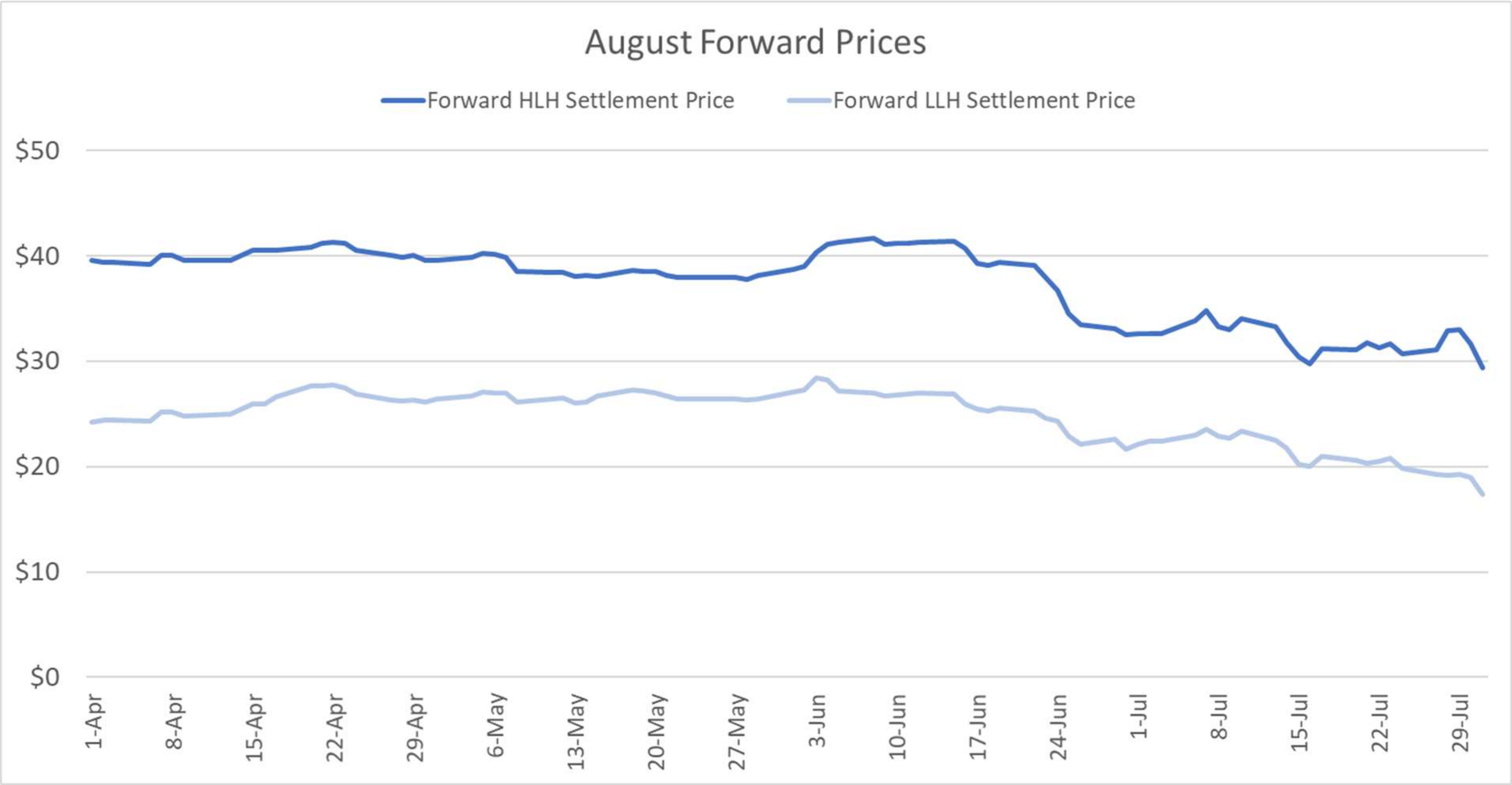
Mid-C Prices


Mid-C heavy load hour prices
In dollars per megawatt hour
BP-20 Rate Case
Forward market (ICE)
Actuals
$40
$35
$30
$25
$20
$15
$10
$5
$0
24.98
26.23
28.51
25.75
24.06
18.69
17.24
11.54
10.38
21.84
25.31
24.58
Oct
Nov
Dec
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep

Water Supply Forecast



Forward Prices



Net Secondary Revenue Uncertainty
– or lack thereof

- Since the previous QBR, Net Secondary Revenue (NSR) has been affected by offsetting factors, water volume increase (positive for NSR) and price decrease (negative for NSR).
- BPA does not expect significant changes to its NSR forecast for the remainder of FY20.
- As the volatility of Mid-C prices and the water supply forecast has declined over the past several months, the NSR forecast volatility has reduced as well.
- Although there are still modest fluctuations expected in both Mid-C prices and water inventory, the inherent volatility is small and within reasonable bounds relative to earlier in the fiscal year.

Transmission Revenue Forecast

- Revenue forecast is $1.085 million for FY 2020 Third Quarter.

- Third Quarter revenue forecast is $1 million below rate case
  - Forecast has increased from second quarter update due June oversupply and wireless lease true-ups.
  - NT revenues are now projected to be close in line with rate case expectations. Upward potential could be driven by NT revenues from warmer than normal summer temperatures that are offsetting COVID impacts for the rest of the fiscal year.
  - Downward risks to revenues through end of year are projected to be minimal.

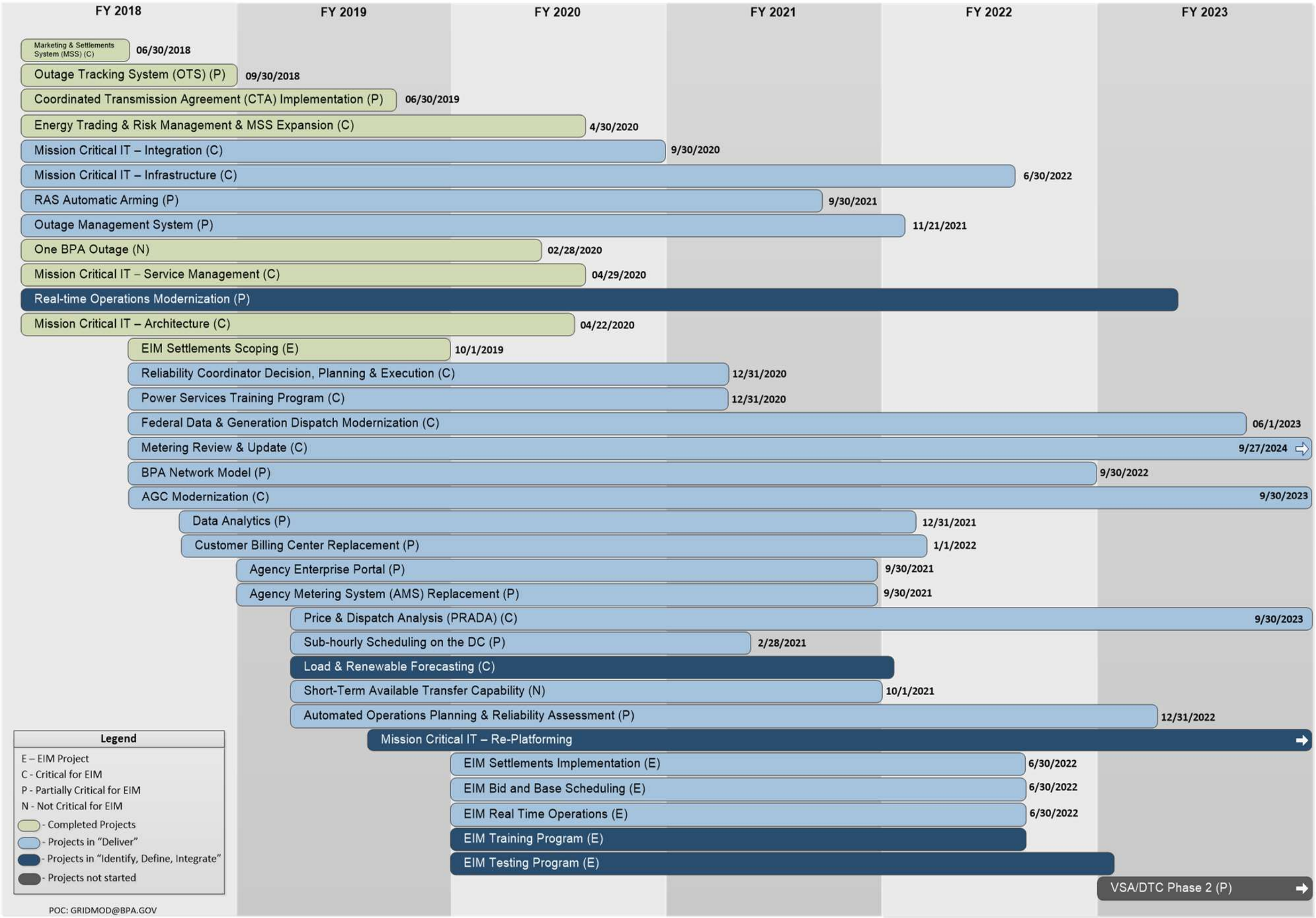
- FY 2020 Actuals to date (Oct to July)
  - Revenues are tracking against third quarter forecast, but reduction against Rate Case is primarily due to non-renewal of long term service.

Grid Modernization Update
Allie Mace

Grid Modernization Roadmap

FY20 Q4

As of 08/06/2020 – Subject to Change



Bonneville POWER ADMINISTRATION

GM Mobilization Status

Identify — 0%

Define — 0%

Integrate — 15%

- EIM Training Project
- EIM Testing Program
- Load & Renewable Forecasting
- Mission Critical IT – Re-Platforming
- Real Time Ops Modernization

Deliver — 62%

- AGC Modernization
- Agency Enterprise Portal
- Agency Metering System Replacement
- Automated Operations Planning & Reliability Assessment
- BPA Network Model
- Customer Billing Center Replacement
- Data Analytics
- EIM Bid & Base Scheduling
- EIM Real Time Operations
- EIM Settlements Implementation
- Federal Data & Generation Dispatch Modernization
- Metering Review & Update
- Mission Critical IT – Infrastructure
- Mission Critical IT – Integration
- Outage Management System
- Power Services Training
- Price and Dispatch Analysis
- RAS Automatic Arming
- Reliability Coordinator Decision, Planning & Execution
- ST Available Transfer Capability
- Sub-Hourly Scheduling on the DC

Complete — 23%

- CTA Implementation
- EIM Settlements Scoping
- Energy Trading & Risk Management & MMS Expansion
- Marketing & Settlements System
- Mission Critical IT – Architecture
- Mission Critical IT – Service Management
- One BPA Outage
- Outage Tracking System

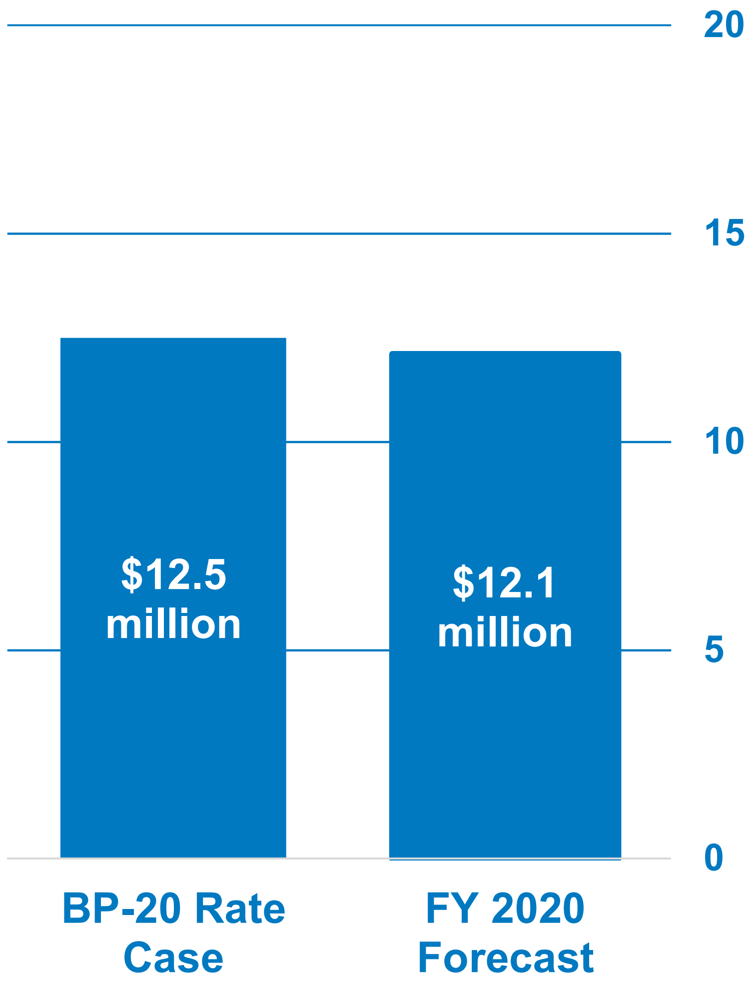
GM Progress Metric

- 89% of milestones for projects in deliver are on-track or completed.
- 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.
- **Status: Green**

GM Finance Metric

- 52% of the FY 2020 IPR expense budget has been spent at the close of the third quarter for projects in deliver.
- This is the equivalent of $4.7 million out of an expected $9 million.
- **Status: Green**

GM FY 2020 Spending



- BPA had previously anticipated an overspend in FY 2020.
- The official Q3 forecast reflects a total need of $12.1 million.

EIM Timeline

	FY 2019	FY 2020		FY 2021			FY 2022	
	Grid Modernization Projects							
EIM Decision Phases	**Phase II:** Implementation Agreement	**Phase III:** Policy Decisions		**Phase IV:** Rate and Tariff Proceedings		**Phase V:** Close-Out*		
CAISO EIM Milestones	Implementation Agreement Effective Date	Detail Project Management Plan	System Implementation and Connectivity Testing		Market Simulation	Parallel Operations	EIM Go-Live: March 1, 2022	
EIM Projects	Projects - Identify	Projects – Define/Integrate	Projects – Deliver				Post go-live evaluation	

*Phase V will not start until the rates and tariff process concludes and a letter is drafted. Phase V must also be complete before the start of parallel operations.

- **Five EIM-specific grid modernization projects include:**
  - EIM Bid & Base Scheduling
  - EIM Settlements Implementation
  - EIM Real-time Operations
  - EIM Training Project
  - EIM Testing Program

EIM Phase III Decision Document

- BPA issued the draft Phase III Decision Document for comment on Aug. 14.
- The document covers decisions on:
  - Sub-allocation of resource sufficiency requirements
  - Non-federal resource participation
  - Metering
  - EIM losses
- Questions on the draft can be addressed at the Aug. 25 TC-22/BP-22/EIM workshop.
- Comments will be due Sept. 18 with a final document issued in October.

EIM Implementation Q4 Milestones

- Finalize CAISO commitment to operations automation capability and timeline.
- EIM Bid and Base Scheduling
  - Begin software integration.
- EIM Settlements
  - Hire team and develop implementation plan.
- EIM Testing
  - Complete building project team and start building parallel environment.

More Information

On grid modernization:

www.bpa.gov/goto/gridmodernization

On EIM:

www.bpa.gov/goto/eim

Q & A Session

Appendix

Slice Reporting
Composite Cost Pool Review
Forecast of Annual Slice True-Up Adjustment

Q3 Forecast of FY 2020 Slice True-Up Adjustment

	FY 2020 Forecast $ in thousands
February 11, 2020 First Quarter Technical Workshop	$(4,524)*
May 18, 2020 Second Quarter Technical Workshop	$(10,111)*
August 18, 2020 Third Quarter Technical Workshop	$(9,868)*
November 2020 Fourth Quarter Technical Workshop	

*Negative = Credit; Positive = Charge

Summary of Differences
From Q3 Forecast to FY 20 (BP-20)

#		A Composite Cost Pool True-Up Table Reference	B QTR3 – Rate Case $ in thousands
1	Total Expenses	Row 95	$(80,305)
2	Total Revenue Credits	Rows 113 + 122	$1,588
3	Minimum Required Net Revenue	Row 145	$40,872
4	TOTAL Composite Cost Pool (1 - 2 + 3) $(80,305) - $1,588 + $40,872 = (41,021)	Row 150	$(41,021)
5	TOTAL in line 4 divided by 0.9451467 sum of TOCAs $(41,021)/ 0.9451467 = $(43,402)	Row 152	$(43,402)
6	QTR Forecast of FY 20 True-up Adjustment 22.7358 percent of Total in line 5 0.227358 * $(43,402) = $(9,868)	Row 153	$(9,868)

FY20 Impacts of Debt Management Actions

FY20 Impacts of Acceleration of Debt

		A	B	C	D
#	Description	FY20 Q3 QBR	FY20 Rate Case	CCP	Delta from the FY20 rate case
1	MRNR Section of Composite Cost Pool Table				$ -
2	**Principal Payment of Federal Debt**				$ -
3	2020 Regional Cooperation Debt (RCD)	$ 18,803,026	$ 21,148,026		$ 2,345,000
4	2020 Debt Service Reassignment (DSR)	$ 1,506,974	$ 1,506,974		$ -
5	Prepay	$ -	$ -		$ -
6	Energy Northwest's Line Of Credit (LOC)	$ -	$ -		$ -
7	Rate Case Scheduled Base Power Principal	$ 151,000,000	$ 151,000,000		$ -
8	**Total Principal Payment of Fed Debt**	**$ 171,310,000**	**$ 173,655,000**	row 125	**$ 2,345,000**
					$ -
9	**Repayment of Non-Federal Obligations**	**$ 227,000,000**	**$ 227,000,000**	row 126	**$ -**
					$ -
10	**Customer Proceeds**	**$ -**	**$ -**	row 134	**$ -**
11	**Non-Cash Expenses**	**$ -**	**$ -**	row 133	**$ -**
12	**Nonfederal Bond Principal Payment**	$ 43,340,000	$ 41,581,000	row 127	$ (1,759,000)

Composite Cost Pool Interest Credit

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

		Q3 2020
1	Fiscal Year Reserves Balance	570,255
2	Adjustments for pre-2002 Items	16,341
3	Reserves for Composite Cost Pool (Line 1 + Line 2)	586,596
4	Composite Interest Rate	0.28%
5	Composite Interest Credit	(1,615)
6	Prepay Offset Credit	0
7	Total Interest Credit for Power Services	(1,100)
8	Non-Slice Interest Credit (Line 7 – (Line 5 + Line 6))	515

Net Interest Expense in Slice True-Up Forecast

	FY20 Rate Case ($ in thousands)	Q3 Forecast ($ in thousands)
• Federal Appropriation	44,686	45,891
• Capitalization Adjustment	(45,937)	(45,937)
• Borrowings from US Treasury	61,157	54,351
• Prepay Interest Expense	9,826	9,826
• **Interest Expense**	**69,733**	64,131
• AFUDC	(15,904)	(14,275)
• Interest Income (composite)	(13,777)	(1,615)
• Prepay Offset Credit	(0)	(0)
• **Total Net Interest Expense**	**40,052**	**48,241**

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

Dates	Agenda
February 11, 2020	First Quarter Technical Workshop
May 18, 2020	Second Quarter Technical Workshop
August 18, 2020	Third Quarter Technical Workshop
October 2020	BPA External CPA firm conducting audit for fiscal year end
Mid-October 2020	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, 2020	Mail notification to Slice Customers of the Slice True-Up Adjustment for the Composite Cost Pool
November 17, 2020	BPA to post Composite Cost Pool True-Up Table containing actual values and the Slice True-Up Adjustment
November 2020	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)
December 10, 2020	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 24, 2020	BPA posts a response to customer questions (Attachment A does not specify an exact date)
January 11, 2021	Customer comments are due on the list of tasks (The deadline can not exceed 10 days from BPA posting)
February 2, 2021	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

			Q3 ($000)		Rate Case forecast for FY 2020 ($000)		Q3- Rate Case Difference
1	**Operating Expenses**						
2	**Power System Generation Resources**						
3	**Operating Generation**						
4	COLUMBIA GENERATING STATION (WNP-2)	$	265,896	$	262,471	$	3,425
5	BUREAU OF RECLAMATION	$	155,899	$	153,609	$	2,290
6	CORPS OF ENGINEERS	$	249,5[illegible]	$	252,557	$	(3,000)
7	LONG-TERM CONTRACT GENERATING PROJECTS	$	11,929	$	12,709	$	(780)
8	**Sub-Total**	**$**	**683,281**	**$**	**681,345**	**$**	**1,935**
9	**Operating Generation Settlement Payment and Other Payments**						
10	COLVILLE GENERATION SETTLEMENT	$	17,586	$	22,997	$	(5,411)
11	SPOKANE LEGISLATION PAYMENT	$	-	$	-	$	-
12	**Sub-Total**	**$**	**17,586**	**$**	**22,997**	**$**	**(5,411)**
13	**Non-Operating Generation**						
14	TROJAN DECOMMISSIONING	$	867	$	1,200	$	(333)
15	WNP-1&3 DECOMMISSIONING	$	1,144	$	431	$	713
16	**Sub-Total**	**$**	**2,011**	**$**	**1,631**	**$**	**380**
17	**Gross Contracted Power Purchases**						
18	PNCA HEADWATER BENEFITS	$	2,909	$	3,100	$	(191)
19	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchase	$	(19,560)	$	-	$	(19,560)
20	**Sub-Total**	**$**	**(16,651)**	**$**	**3,100**	**$**	**(19,751)**
21	**Bookout Adjustment to Power Purchases (omit)**						
22	**Augmentation Power Purchases (omit - calculated below)**						
23	AUGMENTATION POWER PURCHASES	$	-	$	-	$	-
24	**Sub-Total**	**$**	**-**	**$**	**-**	**$**	**-**
25	**Exchanges and Settlements**						
26	RESIDENTIAL EXCHANGE PROGRAM (REP)	$	249,767	$	249,767	$	0
27	OTHER SETTLEMENTS	$	-	$	-	$	-
28	**Sub-Total**	**$**	**249,767**	**$**	**249,767**	**$**	**0**
29	**Renewable Generation**						
30	RENEWABLES (excludes KIII)	$	27,570	$	26,475	$	1,095
31	**Sub-Total**	**$**	**27,570**	**$**	**26,475**	**$**	**1,095**
32	**Generation Conservation**						
33	CONSERVATION ACQUISITION	$	71,190	$	67,000	$	4,190
34	CONSERVATION INFRASCTRUCTURE	$	23,254	$	27,296	$	(4,041)
35	LOW INCOME WEATHERIZATION & TRIBAL	$	5,746	$	5,739	$	7
36	ENERGY EFFICIENCY DEVELOPMENT	$	7,674	$	8,000	$	(326)
37	DR & SMART GRID	$	276	$	855	$	(579)
38	LEGACY	$	724	$	590	$	134
39	MARKET TRANSFORMATION	$	12,090	$	12,050	$	40
40	**Sub-Total**	**$**	**120,954**	**$**	**121,530**	**$**	**(576)**
41	**Power System Generation Sub-Total**	**$**	**1,084,517**	**$**	**1,106,845**	**$**	**(22,327)**
42							

COMPOSITE COST POOL TRUE-UP TABLE

		Q3 ($000)	Rate Case forecast for FY 2020 ($000)	Q3- Rate Case Difference
43	**Power Non-Generation Operations**			
44	**Power Services System Operations**			
45	EFFICIENCIES PROGRAM	$ -	$ -	$ -
46	INFORMATION TECHNOLOGY	$ 88	$ 6,714	$ (6,626)
47	GENERATION PROJECT COORDINATION	$ 6,505	$ 6,059	$ 445
48	ASSET MGMT ENTERPRISE SVCS	$ 429	$ -	$ 429
49	SLICE IMPLEMENTATION	$ 850	$ 555	$ 294
50	**Sub-Total**	**$ 7,871**	**$ 13,329**	**$ (5,457)**
51	**Power Services Scheduling**			
52	OPERATIONS SCHEDULING	$ 9,184	$ 8,806	$ 378
53	OPERATIONS PLANNING	$ 7,613	$ 5,643	$ 1,971
54	**Sub-Total**	**$ 16,797**	**$ 14,449**	**$ 2,348**
55	**Power Services Marketing and Business Support**			
56	COMMERCIAL ENTERPRISE SVCS	$ 2,373	$ -	$ 2,373
57	OPERATIONS ENTERPRISE SVCS	$ 5,023	$ -	$ 5,023
58	POWER R&D	$ 2,133	$ 2,662	$ (529)
59	SALES & SUPPORT	$ 11,847	$ 23,191	$ (11,344)
60	STRATEGY, FINANCE & RISK MGMT (REP support costs included here)	$ 19,100	$ 16,905	$ 2,195
61	EXECUTIVE AND ADMINISTRATIVE SERVICES (REP support costs include	$ 3,218	$ 3,880	$ (662)
62	CONSERVATION SUPPORT	$ 7,982	$ 8,399	$ (417)
63	**Sub-Total**	**$ 51,677**	**$ 55,038**	**$ (3,361)**
64	**Power Non-Generation Operations Sub-Total**	**$ 76,346**	**$ 82,815**	**$ (6,470)**
65	**Power Services Transmission Acquisition and Ancillary Services**			
66	TRANSMISSION and ANCILLARY Services - System Obligations	$ 32,028	$ 32,028	$ -
67	3RD PARTY GTA WHEELING	$ 80,000	$ 96,200	$ (16,200)
68	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)	$ 3,500	$ 2,338	$ 1,162
69	TRANS ACQ GENERATION INTEGRATION	$ 13,577	$ 13,577	$ -
70	TELEMETERING/EQUIP REPLACEMT	$ -	$ -	$ -
71	**Power Services Trans Acquisition and Ancillary Serv Sub-Tot**	**$ 129,105**	**$ 144,143**	**$ (15,038)**
72	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
73	**Fish & Wildlife**	$ 239,603	$ 249,603	$ (10,000)
74	**USF&W Lower Snake Hatcheries**	$ 30,483	$ 30,483	$ -
75	**Planning Council**	$ 11,522	$ 11,725	$ (203)
76	**Environmental Requirements**	$ -	$ -	$ -
77	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$ 281,608**	**$ 291,811**	**$ (10,203)**
78	**BPA Internal Support**			
79	**Additional Post-Retirement Contribution**	$ 17,289	$ 19,577	$ (2,287)
80	**Agency Services G&A (excludes direct project support)**	$ 63,701	$ 57,859	$ 5,842
81	**BPA Internal Support Sub-Total**	**$ 80,991**	**$ 77,436**	$ 3,555
82	**Bad Debt Expense**	$ -	$ -	$ -
83	**Other Income, Expenses, Adjustments**	$ -	$ -	$ -
84	**Depreciation**	$ 140,480	$ 138,968	$ 1,512
85	**Amortization**	$ 303,760	$ 345,589	$ (41,829)
86	**Accretion (CGS)**	$ 33,120	$ 33,738	$ (618)
87	**Total Operating Expenses**	**$ 2,129,927**	**$ 2,221,345**	**$ (91,418)**
88				

* The Residential Exchange Program Support costs have been moved from the Residential Exchange line into the respective Non-Gen Ops programs of Strategy, Finance & Risk Mgmt. and Executive and Administrative Services. This is a net zero impact but is different than what was shown in the final proposal rate case in Table F for these line items

COMPOSITE COST POOL TRUE-UP TABLE

Row		Q3 ($000)	Rate Case forecast for FY 2020 ($000)	Q3- Rate Case Difference
89	**Other Expenses and (Income)**			
90	Net Interest Expense	$ 280,336	$ 270,654	$ 9,682
91	LDD	$ 39,960	$ 38,505	$ 1,455
92	Irrigation Rate Discount Costs	$ 20,880	$ 20,905	$ (24)
93	Other Expense and (Income)	$ -	$ -	$ -
94	**Sub-Total**	**$ 341,177**	**$ 330,064**	**$ 11,113**
95	**Total Expenses**	**$ 2,471,104**	**$ 2,551,409**	**$ (80,305)**
96				
97	**Revenue Credits**			
98	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	$ 116,074	$ 119,815	$ (3,741)
99	Downstream Benefits and Pumping Power revenues	$ 20,799	$ 19,364	$ 1,435
100	4(h)(10)(c) credit	$ 99,776	$ 86,250	$ 13,526
101	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ 0
102	Energy Efficiency Revenues	$ 7,674	$ 8,000	$ (326)
103	PF Load Forecast Deviation Liquidated Damages	$ 1,493	$ 9,499	$ (8,006)
104	Miscellaneous revenues	$ 11,180	$ 12,362	$ (1,182)
105	Renewable Energy Certificates	$ -	$ -	$ -
106	Net Revenues from other Designated BPA System Obligations (Upper Baker)	$ 449	$ 353	$ 96
107	RSS Revenues	$ 2,728	$ 2,728	$ -
108	Firm Surplus and Secondary Adjustment (from Unused RHWM)	$ 68,746	$ 68,746	$ -
109	Balancing Augmentation Adjustment	$ 1,213	$ 1,213	$ -
110	Transmission Loss Adjustment	$ 30,066	$ 30,066	$ -
111	Tier 2 Rate Adjustment	$ 510	$ 510	$ -
112	NR Revenues	$ 1	$ 1	$ (0)
113	**Total Revenue Credits**	**$ 365,310**	**$ 363,507**	**$ 1,803**
114				
115	**Augmentation Costs (not subject to True-Up)**			
116	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation R	$ 12,367	$ 12,367	$ -
117	Augmentation Purchases	$ -	$ -	$ -
118	**Total Augmentation Costs**	**$ 12,367**	**$ 12,367**	**$ -**
119				
120	**DSI Revenue Credit**			
121	Revenues 12 aMW @ IP rate	$ 4,088	$ 4,303	$ (215)
122	**Total DSI revenues**	**$ 4,088**	**$ 4,303**	**$ (215)**
123				
124	**Minimum Required Net Revenue Calculation**			
125	Principal Payment of Fed Debt for Power	$ 171,310	$ 173,072	$ (1,762)
126	Repayment of Non-Federal Obligations (EN Line of Credit)	$ 227,000	$ 227,000	$ -
127	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Fa	$ 43,340	$ 41,581	$ 1,759
128	Irrigation assistance	$ 24,079	$ 24,331	$ (252)
129	**Sub-Total**	**$ 465,729**	**$ 465,984**	**$ (255)**

COMPOSITE COST POOL TRUE-UP TABLE

		Q3 ($000)	Rate Case forecast for FY 2020 ($000)	Q3- Rate Case Difference
130	Depreciation	$ 140,480	$ 138,968	$ 1,512
131	Amortization	$ 303,760	$ 345,589	$ (41,829)
132	Accretion	$ 33,120	$ 33,738	$ (618)
133	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ -
134	Non-Cash Expenses	$ -	$ -	$ -
135	Customer Proceeds	$ -	$ -	$ -
136	Cash freed up by DSR refinancing	$ 16,590	$ 16,590	$ -
137	Prepay Revenue Credits	$ (30,600)	$ (30,600)	$ -
138	Bond Call Premium/Discount	$ (192)	$ -	$ (192)
139	Non-Federal Interest (Prepay)	$ 9,826	$ 9,826	$ -
140	Contribution to decommissioning trust fund	$ (4,100)	$ (4,100)	$ -
141	Gains/losses on decommissioning trust fund	$ (5,052)	$ (5,052)	$ -
142	Interest earned on decommissioning trust fund	$ (8,818)	$ (8,818)	$ -
143	**Sub-Total**	**$ 409,078**	**$ 450,204**	**$ (41,127)**
144	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expen:	$ 56,651	$ 15,780	$ 40,872
145	Minimum Required Net Revenues	**$ 56,651**	**$ 15,780**	**$ 40,872**
146				
147	Annual Composite Cost Pool (Amounts for each FY)	**$ 2,170,724**	**$ 2,211,745**	**$ (41,021)**
148				
149	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**			
150	TRUE-UP AMOUNT (Diff. between Rate Case and Forecast)	(41,021)		
151	Sum of TOCAs	0.9451467		
152	Adjustment of True-Up Amount when actual TOCAs < 100 percent	**(43,402)**		
153	TRUE-UP ADJUSTMENT CHARGE BILLED (22.7358 percent)	(9,868)		

Financial Disclosures

This information has been made publicly available by BPA on August 14, 2020 and contains information not sourced directly from BPA financial statements.