BONNEVILLE POWER ADMINISTRATIO

Long-Term Financial and Rates Analysis

Reference Case Results

UPDATED: June 2016

Foreword

These are transformative times for the electric utility industry in the Pacific Northwest. The abundant supply of natural gas and robust development of renewable resources in the region have resulted in significant downward pressure on wholesale market prices for electricity. These events have coincided with an increasing need for BPA to reinvest in the Federal Columbia River Power System hydropower and transmission infrastructure as federal assets age and new assets are needed to meet changing demands. These pressures are set against a backdrop of technological change. Emerging technologies, evolving markets and new regulatory requirements could fundamentally change the role of the traditional utility.

BPA and its stakeholders must look beyond the current economic and fiscal environment to make sound decisions for the future. It is crucial for BPA and its stakeholders to assess the existing and emerging trends that will shape the region's electric industry landscape for years to come.

BPA's ability to continue to meet its statutory obligations and public purpose objectives relies heavily on maintaining long-term cost competitiveness and financial strength. It will also depend largely on how well we anticipate and position our business to address the challenges and opportunities arising from of the ever changing landscape. Existing and emerging factors that impact or may impact BPA's mission include:

- Decarbonization of utility resources
- Integration of distributed resources to the centralized grid
- Flat to declining regional loads
- Electrification of transportation
- Shifting market and regulatory structures
- Competitiveness of non-hydro resources (e.g., utility-scale wind and solar)

As the marketer and steward of the low-cost, low-carbon federal power system that provides incredible value to the region's economy, BPA strives to maintain the system's value for generations to come. BPA will remain focused on being the low-cost power provider of choice when new power sales contracts are offered in the next decade. BPA also operates a large component of the region's high-voltage transmission and provides open access transmission to customers. BPA is dedicated to preserving a compliant and reliable transmission system that continues to meet the needs of the region.

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Introduction

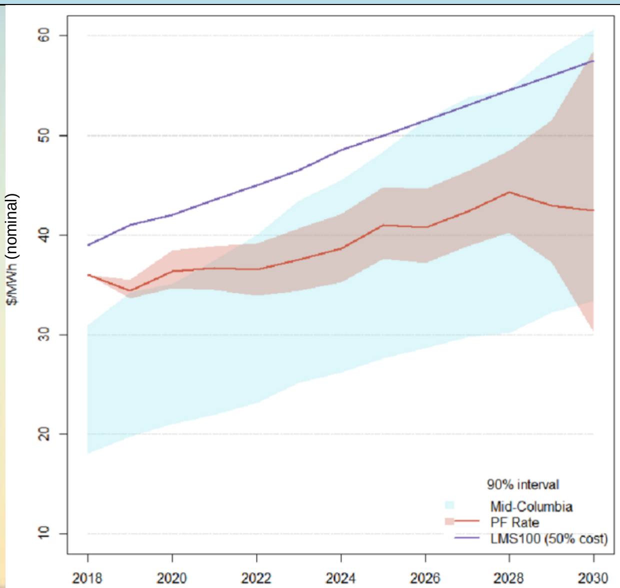
To facilitate strategic conversations among regional stakeholders and customers, BPA has produced a means for analyzing and comparing impacts of strategic choices using a **Long-Term Reference Case** (Reference Case) as a basis for comparison. The current June 2016 Reference Case provides a long-range view of BPA's potential financial and rates condition using initial spending levels from the 2016 IPR/CIR, with escalation assumptions for the out-years where long-term plans are unknown, as well as updates for current market prices, load and resources forecasts. The Reference Case is meant to serve as a beginning point for strategic discussions and as the basis for comparing the financial and rate implications of future scenarios or alternatives BPA may consider.

In October 2015, BPA first shared the Reference Case during Focus 2028 to inform discussions about BPA's long-term financial strength and competitiveness. In the current edition of the Reference Case, we have included forecast net secondary revenues (NSR) in the computation of Tier 1 Average Net Cost of Power rate (Tier 1 rate). This is a change from the version we shared during Focus 2028 when NSR was held constant in real terms at BP-16 levels. Including the forecast values of NSR presents a more complete view of the preference rate as it is calculated under the Tiered Rate Methodology.

Inputs to this analysis include debt repayment studies, long-term revenue requirement forecasts and power and transmission rates analyses. The Reference Case does not represent decisions about the future and it is not an official rate proposal. The actual long-term picture of power and transmission rates will likely play out differently as the landscape unfolds and BPA and its customers and stakeholders respond. It also does not apply any expert judgement on how program and capital levels may change over time in response to landscape changes. Therefore, it does not represent BPA's projection of future financial health and rates, as it does not capture the many uncertainties surrounding the assumptions.

Strategic Dashboard

Tier 1 Rate vs. Mid-C and LMS 100



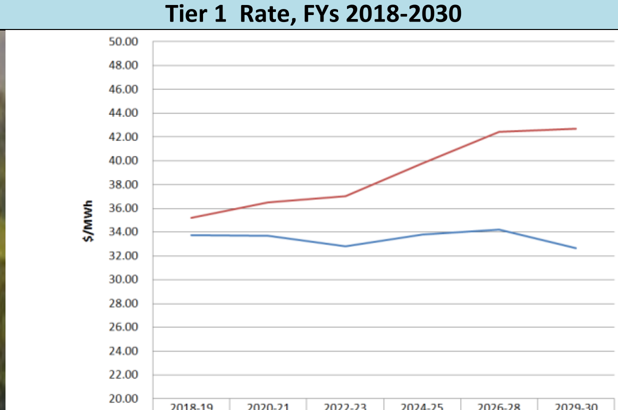
Rates Comparison

	BP-16 Rate Case	Nominal $ 2018	Nominal $ 2030	Real $2018 (2016 dollars)	Real $ 2030 (2016 dollars)
Tier 1 Rate ($/MWh)	33.75	35.19	42.68	33.73	32.66
NT Rate ($/kW/Mo)	1.74	1.76	2.76	1.68	2.08
PTP Rate ($/kW/Mo)	1.49	1.51	2.41	1.45	1.82
IS Rate ($/kW/Mo)	1.23	1.28	1.90	1.22	1.43

Performance on Metrics

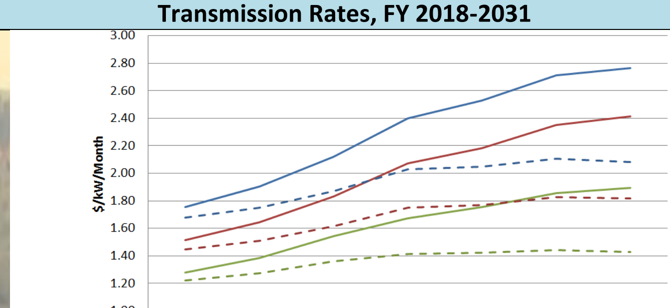
Financial Metrics	FY 2018	FY 2030
Rate of Change for IPR Costs (Rate of Cost Change / Inflation)	---	Px: 1.42 Tx: 1.19
Rate of Change in Capital Related Costs (Rate of Cost Change / Inflation)	---	Px: 0.42 Tx: 2.70
Financial Reserve Level	$800M	$755M
Days Cash on Hand	152	101
Remaining Borrowing Authority	$1,691M	$749.9M
Interest Expense as % of Revenue Requirement	16.56%	14.94%
Weighted Avg. Maturity of Debt Portfolio (Years)	16.49	17.26
Debt to Assets Ratio	92%	73%

Tier 1 Rate, FYs 2018-2030



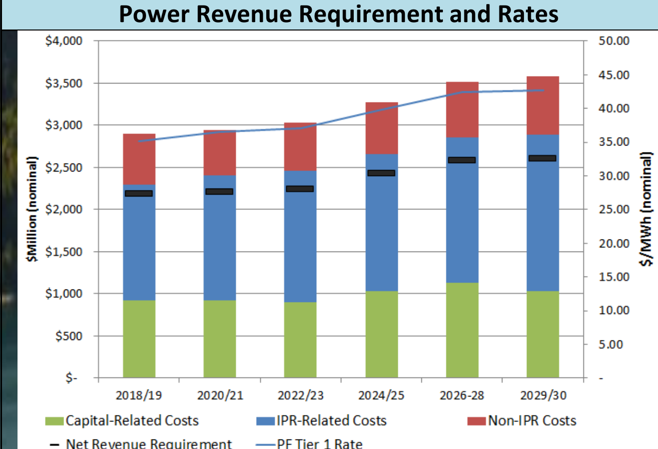
	2018-19	2020-21	2022-23	2024-25	2026-28	2029-30
PF Tier 1 Nominal	35.19	36.50	37.02	39.79	42.45	42.68
PF Tier 1 Real (2016$)	33.73	33.69	32.81	33.82	34.23	32.66

Transmission Rates, FY 2018-2031

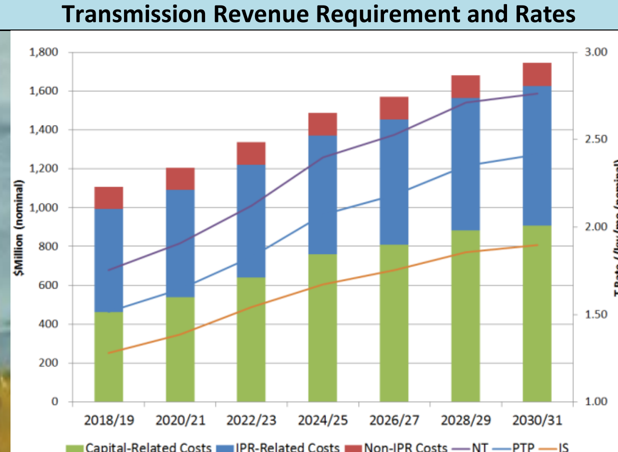


	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-31
NT	1.76	1.91	2.12	2.40	2.53	2.71	2.76
PTP	1.51	1.64	1.83	2.07	2.18	2.35	2.41
IS	1.28	1.39	1.54	1.67	1.76	1.86	1.90
NT (real $2016)	1.68	1.75	1.87	2.03	2.05	2.11	2.08
PTP (real $2016)	1.45	1.51	1.61	1.75	1.77	1.83	1.82
IS (real $2016)	1.22	1.27	1.36	1.42	1.42	1.44	1.43

Power Revenue Requirement and Rates



Transmission Revenue Requirement and Rates



* FY 2018/19 rate period increase may range between 4%-9% for Power and 3%-5% for Transmission. The rates shown are the low end of the range. Modeling observations shown in this analysis do not represent BPA's forecast of future financial health or rates. These numbers represent a status quo perspective continued through the analysis horizon to be used as a reference to test the impact of potential business decisions.

Findings

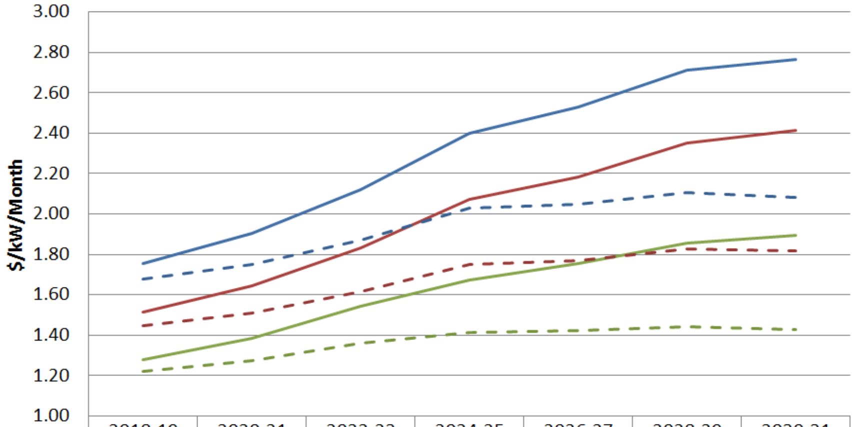
We have grouped our findings into five major categories. They include transmission rates, power rate, revenue requirements, capital investment and debt management, and financial health. The FY 2016 Reference Case assumes an extension of initial IPR spending levels but also factors in commitments we have made in the future that may cause changes.

Transmission Rates

The Transmission rates shown in Figure 1 reflect the results of assumptions used in the 2016 CIR and IPR. Beginning in 2022, federal debt repayment is accelerated, based on an assumption to maintain $750 million of access to U.S. Treasury borrowing authority for the short-term liquidity note. Additionally, compliance and reliability costs were assumed to increase every few years and were absorbed in the increase of O&M expenses. Investments in technology were assumed beginning in FY 2018. Revenues were assumed to have a relatively flat load growth with Point to Point (PTP) sales increasing due to the energization of the Transmission Service Request Study and Expansion Process (TSEP) projects that increase capacity on the Network. Oversupply and other rate designs were assumed to be the same as proposed in the BP-16 rate case.

Figure 1 below shows an increase in the Intertie South (IS) rate and the Network (NT) rates due to the revenue requirement impact of the expected energization of major capital projects that were identified in the 2014 CIR. The increase in the IS rate for FY 2018-19 is driven by the continued assumption that the Celilo Converter Station upgrade is fully energized and the related capital costs begin to affect revenue requirements in that rate period.

Figure 1: Transmission Rates, FY 2018-31



	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-31
NT	1.76	1.91	2.12	2.40	2.53	2.71	2.76
PTP	1.51	1.64	1.83	2.07	2.18	2.35	2.41
IS	1.28	1.39	1.54	1.67	1.76	1.86	1.90
NT (real $2016)	1.68	1.75	1.87	2.03	2.05	2.11	2.08
PTP (real $2016)	1.45	1.51	1.61	1.75	1.77	1.83	1.82
IS (real $2016)	1.22	1.27	1.36	1.42	1.42	1.44	1.43

More detailed information on pressures is provided in Figure 2 below.

Figure 2: Transmission Potential Rate Change Detail

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Change from BP-16 to FY 18/19		Change from FY18/19 to FY20/21		Change from FY20/21 to FY22/23		Change from FY22/23 to FY24/25		Change from FY24/25 to FY26/27		Change from FY26/27 to FY28/29		Change from FY28/29 to FY30/31	
Expenses	$ (Million)	% Change in Rates	$ (Million)	% Change in Rates	$ (Million)	% Change in Rates	$ (Million)	% Change in Rates	$ (Million)	% Change in Rates	$ (Million)	% Change in Rates	$ (Million)	% Change in Rates
1. Operations	15	1.9%	-2	-0.2%	5	0.5%	6	0.5%	6	0.4%	6	0.4%	8	0.3%
2. Maintenance	14	1.8%	8	0.8%	10	0.9%	10	0.9%	11	0.8%	11	0.8%	11	0.5%
3. Engineering	6	0.7%	8	0.8%	11	1.1%	14	1.2%	16	1.2%	18	1.2%	17	0.8%
4. Internal Support & Undistributed Reduction	7	0.8%	2	0.2%	1	0.1%	1	0.1%	0	0.0%	0	0.0%	1	0.1%
5. IPR Sub-Total	**42**	**5.3%**	**16**	**1.6%**	**27**	**2.6%**	**32**	**2.7%**	**33**	**2.4%**	**36**	**2.5%**	**38**	**1.7%**
6. Ancillary Services	4	0.6%	6	0.6%	1	0.1%	1	0.1%	1	0.1%	1	0.1%	3	0.1%
7. Non-IPR Sub-Total	**4**	**0.6%**	**6**	**0.6%**	**1**	**0.1%**	**1**	**0.1%**	**1**	**0.1%**	**1**	**0.1%**	**3**	**0.1%**
8. Capital Related Costs [1/]	**-24**	**-3.0%**	**76**	**7.9%**	**103**	**9.7%**	**120**	**10.2%**	**49**	**3.6%**	**73**	**5.0%**	**23**	**1.0%**
9. Total Revenue Requirement (Lines 5+7+8) [2/]	**22**	**2.8%**	**98**	**10.2%**	**131**	**12.3%**	**152**	**12.9%**	**82**	**6.1%**	**110**	**7.5%**	**64**	**2.8%**
10. Revenues	**0**	**0.0%**	**21**	**-2.2%**	**25**	**-2.3%**	**14**	**-1.2%**	**13**	**-0.9%**	**0**	**0.0%**	**0**	**0.0%**
11. Uncertainty [3/]	**18**	**2.0%**												
12. Total Change	**22 to 40**	**2.8% to 4.8%**	**77**	**8.0%**	**106**	**10.0%**	**138**	**11.7%**	**70**	**5.2%**	**110**	**7.5%**	**64**	**2.8%**

1/ Includes Net Interest Expense, Depreciation/Amortization and Minimum Required Net Revenues.
2/ Change in rates reflects average across all segments.
3/ To account for further uncertainties that may arise prior to initial proposal

Power Rate

The Tier 1 rate declines slightly in real terms over the planning horizon, with an overall nominal increase in the preference rate slightly below the forecast level of inflation through FY 2030. While greater than inflation increases are predicted in FY 2024-25 and FY 2026-28, expectations for all other rate periods show rate increases at or below the level of inflation.

Increases in initial IPR program spending levels are primarily driven by increases in operating and maintenance expenses for the FCRPS and Columbia Generating Station (CGS). In addition, there are planned increases in BPA's Fish and Wildlife program and the Residential Exchange Program (REP) under the 2012 REP settlement. These increases are somewhat offset by modest increases to NSR and increases in other revenues beyond FY 2018-19. As previously mentioned, this Reference Case assumes modeled NSR, as opposed to the previous assumption where NSR was held constant at BP-16 levels adjusted for inflation. Including the forecast values of NSR presents a more complete view.

Capital-related costs remain relatively stable in the near term, with large increases in FY 2024-25 and FY 2026-28. The shape of capital-related costs is primarily driven by early amortization of federal debt to maintain borrowing authority at $750 million, the shape of non-federal debt service associated with Regional Cooperation Debt (RCD), and additional plant-in-service associated with an expanded hydro capital program. The early amortization of debt begins in FY 2026 and continues through FY 2030. A smaller uptick in the power rate in FY 2020-21 is due to the expiration of actions taken to offset the effects of moving BPA's Energy Efficiency program from capital funding to expense.

The Reference Case is further informed by a modeled risk distribution. This distribution incorporates loads and resources, natural gas prices and electric market variability into the analysis and produces a range of rate outcomes. In this way, a distribution of potential rate levels is produced, which widens further into the planning horizon as more sequentially bad, or good, years add up to inform the tails of the distribution.

It should be noted that the REP settlement expires within the horizon of this analysis. The settlement postponed disputes over significant issues that, depending upon the resolution of those issues, could either significantly increase post-2028 benefits or virtually eliminate them. In addition, a follow-on settlement is also a possible outcome. Thus, the Reference Case maintains the status quo, and the potential distribution of rate outcomes incorporates plus or minus $200 million of REP benefits after the REP settlement period to account for this uncertainty.

Figure 3 shows the Tier 1 rate with a 90 percent confidence interval around the Reference Case output and the fractional cost of an LMS 100 (an industry standard aero-derivative natural gas plant capable of providing load-following service) along with Mid-Columbia market prices. Figure 4 shows a point forecast generated by the standard BPA rate analysis process using 2016 IPR and CIR initial spending levels and capital-related costs accompanied by debt management and market condition assumptions to estimate rates through the planning horizon. Additional detail on rate pressures is provided in Figure 5.

Figure 3: Tier 1 Rate Compared to Mid-C

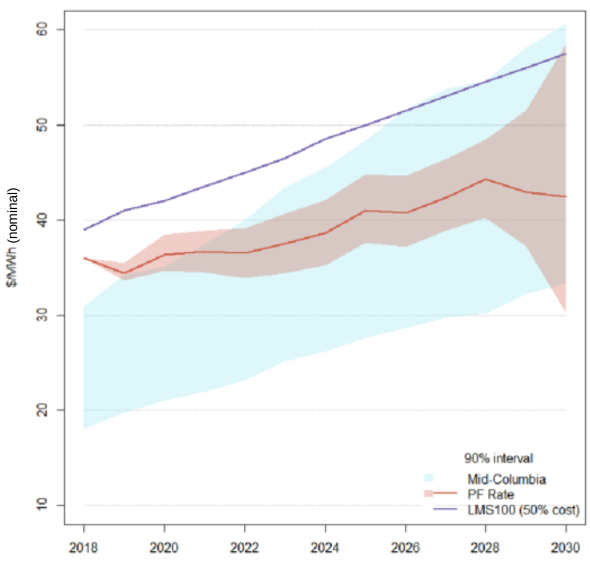


Figure 4: Tier 1 Rate, FYs 2018-2030

	2018-19	2020-21	2022-23	2024-25	2026-28	2029-30
PF Tier 1 Nominal	35.19	36.50	37.02	39.79	42.45	42.68
PF Tier 1 Real (2016$)	33.73	33.69	32.81	33.82	34.23	32.66

Figure 5: Power Potential Rate Change Detail

		A	B	C	D	E	F	G	H	I	J	K	L
		Change from FY16/17 to FY18/19		Change from FY18/19 to FY20/21		Change from FY20/21 to FY22/23		Change from FY22/23 to FY24/25		Change from FY24/25 to FY26/27/28		Change from FY26/27/28 to FY29/30	
	Revenue Requirement Costs	$(Million)	% Change in Rates	$(Million)	% Change in Rates	$(Million)	% Change in Rates	$(Million)	% Change in Rates	$(Million)	% Change in Rates	$(Million)	% Change in Rates
1	Columbia Generating Station	14	0.7%	20	0.9%	22	1.0%	15	0.7%	26	1.1%	64	2.5%
2	Bureau of Reclamation	10	0.5%	7	0.3%	11	0.5%	11	0.5%	15	0.7%	16	0.6%
3	Corps of Engineers	10	0.5%	12	0.6%	16	0.7%	17	0.8%	23	1.0%	25	1.0%
4	Fish and Wildlife	8	0.4%	9	0.4%	13	0.6%	13	0.6%	18	0.8%	19	0.7%
5	Renewables	(3)	-0.1%	(1)	-0.1%	(7)	-0.3%	(6)	-0.3%	(7)	-0.3%	(17)	-0.7%
6	Energy Efficiency 1/	0	0.0%	5	0.2%	7	0.3%	7	0.3%	9	0.4%	10	0.4%
7	Internal Operations 2/	15	0.7%	9	0.4%	6	0.3%	3	0.2%	7	0.3%	8	0.3%
8	Targeted Undistributed Reduction 3/	20	1.0%	(0)	0.0%	(0)	0.0%	(0)	0.0%	(1)	0.0%	(1)	0.0%
9	**IPR Expense Sub-Total**	**73**	**3.6%**	**59**	**2.8%**	**68**	**3.1%**	**61**	**2.7%**	**90**	**4.0%**	**124**	**4.8%**
10	Capital-Related Costs 4/	(77)	-3.8%	(4)	-0.2%	(13)	-0.6%	127	5.6%	105	4.7%	(99)	-3.8%
11	Other Costs 5/	(3)	-0.1%	2	0.1%	1	0.0%	1	0.1%	1	0.1%	2	0.1%
12	Residential Exchange	22	1.1%	10	0.5%	15	0.7%	13	0.6%	10	0.5%	14	0.6%
13	Transmission and Ancillary Services	22	1.1%	13	0.6%	15	0.7%	19	0.8%	20	0.9%	18	0.7%
14	Energy Efficiency Expense Offset	9	0.4%	44	2.1%	(1)	0.0%	8	0.4%	9	0.4%	0	0.0%
15	**Non-IPR Cost Sub-Total**	(27)	-1.3%	65	3.1%	17	0.8%	168	7.5%	145	6.4%	(65)	-2.5%
	Revenues and Rate Discounts												
16	Rate Discounts	1	0.0%	4	0.2%	2	0.1%	8	0.4%	11	0.5%	4	0.1%
17	Net Power Purchase and Sale	(14)	-0.7%	(27)	-1.3%	(37)	-1.7%	(42)	-1.8%	(57)	-2.5%	(18)	-0.7%
18	4(h)10(c)	(8)	-0.4%	(1)	-0.1%	(4)	-0.2%	(7)	-0.3%	(8)	-0.4%	(6)	-0.2%
19	Generation Inputs	22	1.1%	(8)	-0.4%	(12)	-0.5%	(13)	-0.6%	(18)	-0.8%	(18)	-0.7%
20	DSI Sales	5	0.2%	(3)	-0.2%	(1)	0.0%	(2)	-0.1%	(2)	-0.1%	(1)	0.0%
21	Other Revenues	30	1.5%	16	0.8%	0	0.0%	3	0.1%	3	0.2%	(0)	0.0%
22	**Revenues Sub-Total**	**35**	**1.7%**	**(18)**	**-0.9%**	**(52)**	**-2.3%**	**(52)**	**-2.3%**	**(71)**	**-3.2%**	**(39)**	**-1.5%**
23	**Uncertainty 6/**	**100**	**5.0%**										
24	**Load Effect**		**0.2%**		**-1.2%**		**-0.1%**		**-0.4%**		**-0.1%**		**-0.2%**
25	**Total Change in Net Revenue Requirement 7/**	**82 to 182**	4% to 9%	**105**	3.7%	**33**	1.4%	**177**	7.5%	**165**	7.2%	**20**	0.5%

1/ **Energy Efficiency** - excludes Legacy and EE Development Program (those estimates are captured in Other Costs).
2/ **Internal Operations** - includes Power's Non-Generation Operations, Agency Services G&A, Post Retirement Benefits and KSI Costs ($8.7M)
3/ **Targeted Undistributed Reduction** - estimated at $10 million on average, annually for FY 2018-19 and targets the Operating Generation Resources Program.
4/ **Capital Related Costs -** includes Depreciation, Amortization, MRNR, Net Interest and Non-Federal Debt Service. Also includes a portion of debt management actions not otherwise allocated to offsetting the effect of
5/ **Other Costs** - includes LT Gen Projects, Colville Settlement, WNP 1,3&4 O&M, EE Legacy and Reimbursable EE Development Program.
6/ **Uncertainty** - includes changes to loads, resources, generation inputs, financial reserves policy, and updated market price expectations.
7/ These are **not final results** and Initial Proposal PF Rates will change as market and other **expectations change**.

Revenue Requirements

Revenue requirements are the accumulation of costs that BPA needs to recover through power or transmission rates. These costs are incurred because of various programs, such as the operation and maintenance of the transmission system or the Corps and Reclamation dams, or from the acquisition of resources needed to ensure BPA meets its contractual obligations to supply power. Revenue requirements also include the costs associated with capital investments. These capital-related costs, such as depreciation and interest, are spread over time within the life of the investment. In general, past capital investment decisions affect current revenue requirements, and current capital investment decisions will affect future revenue requirements.

While power and transmission rates will be set to recover the costs identified in revenue requirements, rates over time will be influenced by factors other than costs. For instance, adding or upgrading generating resources or expanding transmission capacity can result in greater sales, which would offset higher costs.

Figure 6: Power Revenue Requirement & Rate

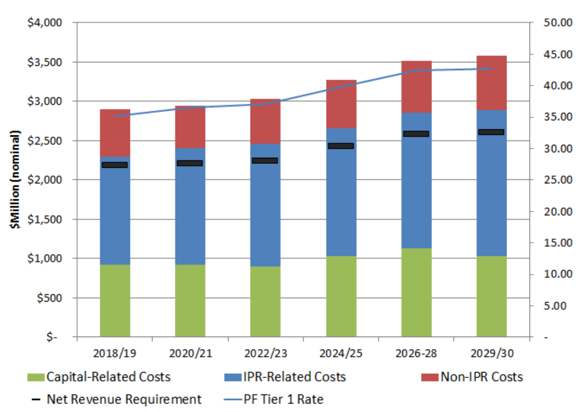
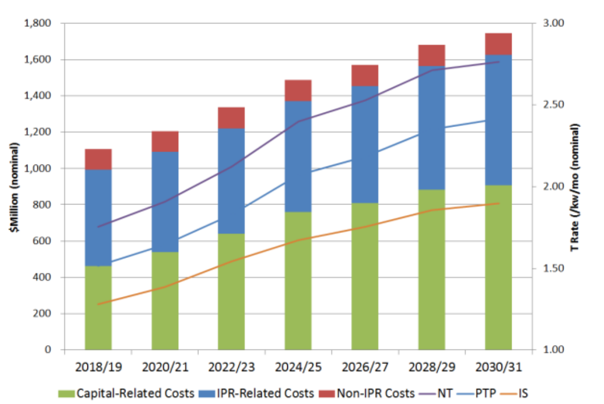


Figure 7: Transmission Revenue Requirement & Rates



The growth of IPR and capital-related costs compared to inflation are displayed in Figure 8 below. BPA's assumed average rate of inflation for the period of 2018 through 2030 is 1.9 percent. In Figure 8, a rate of increase of 1.0 represents the rate of inflation. Anything above 1.0 means that costs are increasing at a rate higher than inflation. Anything below 1.0 means rate of change is less than the rate of inflation.

Figure 8: Cost Metrics

Metrics	Cumulative Change vs Inflation
Rate of Change for Program (IPR) Costs (Rate of Cost Change / Inflation)	Px: 1.42 Tx: 1.19
Change in Capital-Related Costs (Rate of Cost Change / Inflation)	Px: 0.42 Tx: 2.70

Capital Investment and Debt Management

Capital-related costs, of which debt service is a primary component, make up about a third of the power revenue requirement, nearly half of the transmission revenue requirement, and are a critical component of long-term power and transmission overall cost structures. One of BPA's top priorities is to preserve and enhance transmission and federal generation assets and the economic, environmental, and operational value they provide. Capital investment levels assumed in the Reference Case through 2030 are consistent with initial levels presented in the 2016 CIR.

Virtually all capital investments are financed through debt. Debt management strategies must consider both near- and long-term impacts on capital-related costs within the revenue requirement. Capital investment decisions and debt management actions taken today will have an impact on BPA's overall cost structure and debt portfolio for years to come.

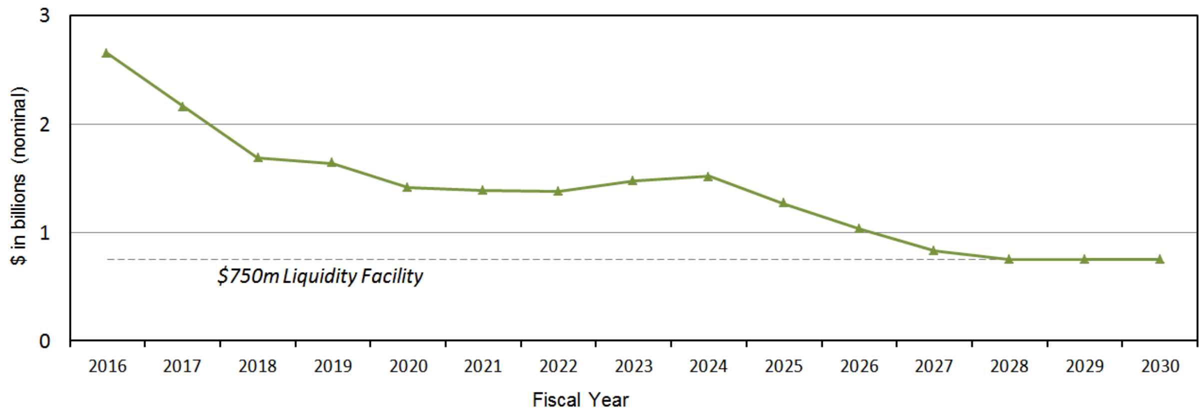
Debt management assumptions in the Reference Case are consistent with achieving three primary objectives:

- Ensuring capital financing requirements are met at the lowest overall cost based on long-term modeling assumptions;
- Managing the long-term cost stability for each business unit; and
- Maintaining $750 million of access to U.S. Treasury borrowing authority for the short-term liquidity note.

After the use of third-party tools (full Regional Cooperation Debt Program and 50 percent Lease Purchase), maintaining the $750 million is achieved through the accelerated repayment of federal debt.

Figure 9 on the following page shows the remaining U.S. Treasury borrowing authority over time.

Figure 9: Remaining Borrowing Authority



Financial Health

Figure 10 showcases the most relevant metrics to quickly assess BPA's financial health. These metrics focus on the following:

- BPA's current and future liquidity position (the ability to buffer against financial losses).
- BPA's financial flexibility (interest as a percent of BPA's projected revenue requirement).
- BPA's financial leverage (comparing the weighted average maturity of outstanding debt).
- BPA's debt ratio - the relationship between assets and debt.

BPA's ability to continue to meet its multiple statutory obligations and public purpose objectives relies heavily on maintaining our cost competitiveness and financial strength. BPA financial targets strengthen and support BPA's credit rating. A high credit rating lowers the cost of BPA's non-federal borrowings for CGS and transmission lease financing and translates directly to lower capital-related costs.

Specifics about Financial Metrics

Reserves for Risk levels represent unobligated cash and short-term investments in the BPA fund that can be used to buffer against unexpected losses. Higher reserves for risk result in a greater buffer against unexpected losses and thus are preferred over lower levels.

Days Cash On Hand is a metric that measures the number of days a business can operate if revenue stops coming in. This metric which is an evaluation of liquidity is an important indicator of financial strength and a key element in the financial analysis of utilities.

Remaining Borrowing Authority represents the amount of U.S. Treasury borrowing capacity available to finance BPA construction projects and provide liquidity. Since $750 million of borrowing authority must be reserved for operating liquidity, this analysis assumes BPA will take debt management actions to ensure that amount is available in any given year.

Interest as a Percent of Revenue Requirement is a metric that highlights the amount of BPA's revenue requirement that goes to paying interest expense. This metric is important from a financial flexibility standpoint, as interest expense represents the most fixed component of

BPA’s cost structure. The lower the percentage of interest in BPA’s power and transmission revenue requirement, the more competitive BPA rates will be and the more flexible BPA can be in other cost areas from rate period to rate period.

Weighted Average Maturity of Outstanding Debt represents the weighted average amount of time, in years, that it takes for BPA to repay all of its debt. This metric is important when comparing one long-term rate scenario to another. A declining weighted average maturity means BPA is paying off debt faster and thus lowering interest expense at a faster rate than if the weighted average maturity stays the same or increases.

Debt to Asset Ratio represents the relationship between the amount of BPA revenue producing assets versus the amount of total outstanding debt. Figure 10 shows BPA is projecting to have a debt ratio of 92 percent in FY 2018, driven primarily by debt issuance for non-revenue producing assets.

Figure 10: Summary of Financial Health Metrics

Metrics	FY 2018	FY 2030
Financial Reserve Level	$800M	$755M
Days Cash on Hand	152	101
Remaining Borrowing Authority	$1,691M	$749.9M
Interest Expense as % of Revenue Requirement	16.56%	14.94%
Weighted Avg. Maturity of Debt Portfolio (Years)	16.49	17.26
Debt to Assets Ratio	92%	73%

Summary

Overview of Rates, Risks and Uncertainties

The comparison of current rates to those in FY 2030 is summarized in Figure 11. Rates in the Reference Case appear slightly lower in FY 2030 in real dollar terms for the Tier 1 rate and slightly higher for Transmission rates. However, these rates are the product of multiple assumptions about the future which, taken together, represent a large degree of uncertainty. For this analysis, uncertain future contractual relationships or legal obligations were assumed to continue as currently implemented for the analysis horizon. These, along with general power and transmission market and environmental variability, are significant sources of uncertainty. Thus, the Reference Case is of limited value for predicting the future. This limitation is addressed in two ways: first, a confidence interval is placed around the Reference Case to display the effects of known and measurable risks on the assumptions used; second, the Reference Case serves as a point of reference to compare the effects of different scenarios on BPA's rates and financial health going forward.

Figure 11: Summary of Rates Results

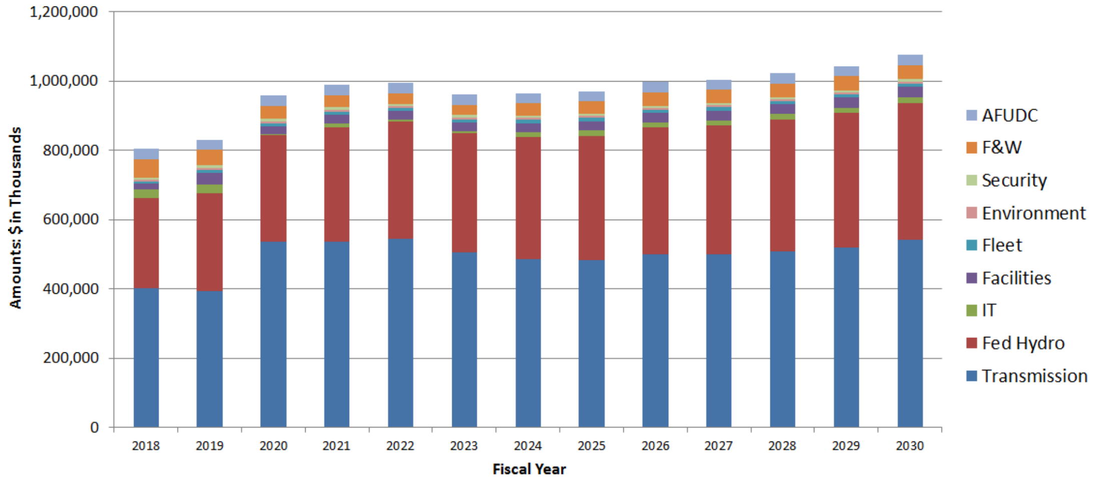
	BP-16 Rate Case	Nominal $ 2018	Nominal $ 2030	Real $ 2018 (2016 dollars)	Real $ 2030 (2016 Dollars)
Tier 1 Rate ($/MWh)	33.75	35.19	42.68	33.73	32.66
NT Rate ($/kW/Mo)	1.74	1.76	2.76	1.68	2.08
PTP Rate ($/kW/Mo)	1.49	1.51	2.41	1.45	1.82
IS Rate($/kW/Mo)	1.23	1.28	1.90	1.22	1.43

Financial Disclosure: This information has been made publicly available by BPA on June 27, 2016 and contains information not reported in agency financial statements.

Appendix

Spending Level Inputs

1. Capital Investment



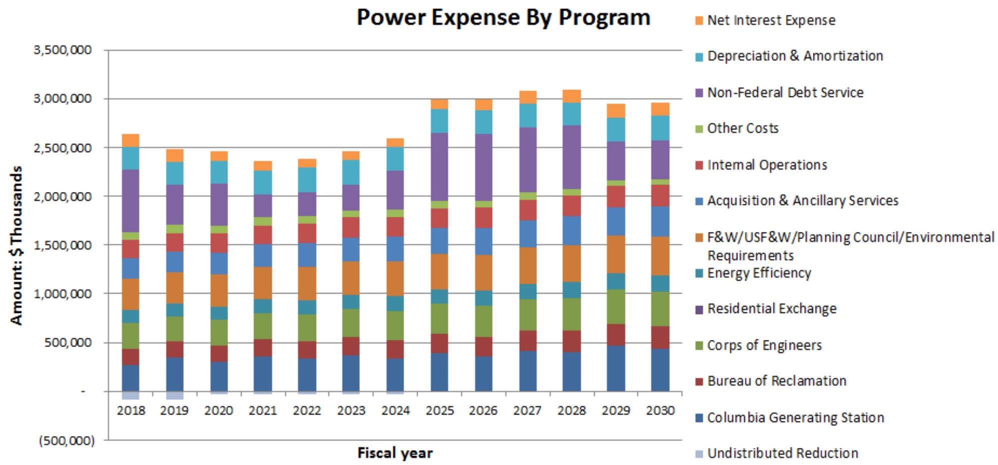
Capital Investment by Asset Category
($ in Thousands)

		A	B	C	D	E	F	G	H	I	J	K	L	M
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Transmission	402,511	394,372	536,129	535,181	545,327	504,625	485,883	482,835	499,427	498,368	507,925	518,778	541,504
2	Fed Hydro	257,969	281,137	306,208	331,062	337,650	344,369	351,222	358,212	365,340	372,610	380,025	387,588	395,301
3	Information Technology	25,000	25,000	2,500	12,000	4,736	6,536	14,761	15,058	15,351	15,648	15,957	16,256	16,560
4	Facilities	17,900	35,000	25,005	25,005	25,005	25,005	26,300	26,900	27,400	27,900	28,500	29,000	29,500
5	Fleet	6,700	7,200	7,500	8,000	8,200	8,500	9,200	9,500	9,500	9,800	9,800	10,000	10,000
6	Security	6,000	8,000	7,000	7,000	7,000	7,000	5,418	5,527	5,635	5,744	5,858	5,967	6,079
7	Environment	5,529	5,585	5,641	5,697	5,754	5,811	5,614	5,614	5,614	5,614	5,614	5,614	5,614
8	Fish and Wildlife	50,532	44,000	38,033	33,599	29,047	29,291	36,014	36,738	37,454	38,177	38,933	39,661	40,403
9	AFUDC ^1	31,552	30,248	30,439	31,335	31,420	30,399	30,010	30,234	30,316	30,366	30,379	30,354	30,288
10	TOTAL BPA Capital Expenditures ^2	803,694	830,542	958,455	988,879	994,139	961,536	964,422	970,617	996,037	1,004,227	1,022,991	1,043,218	1,075,247

1> AFUDC will be updated later in September

2> Capital displayed I the above table ties to the 2016 Intigrated Program Review (IPR) public process.

2. Power Expenses

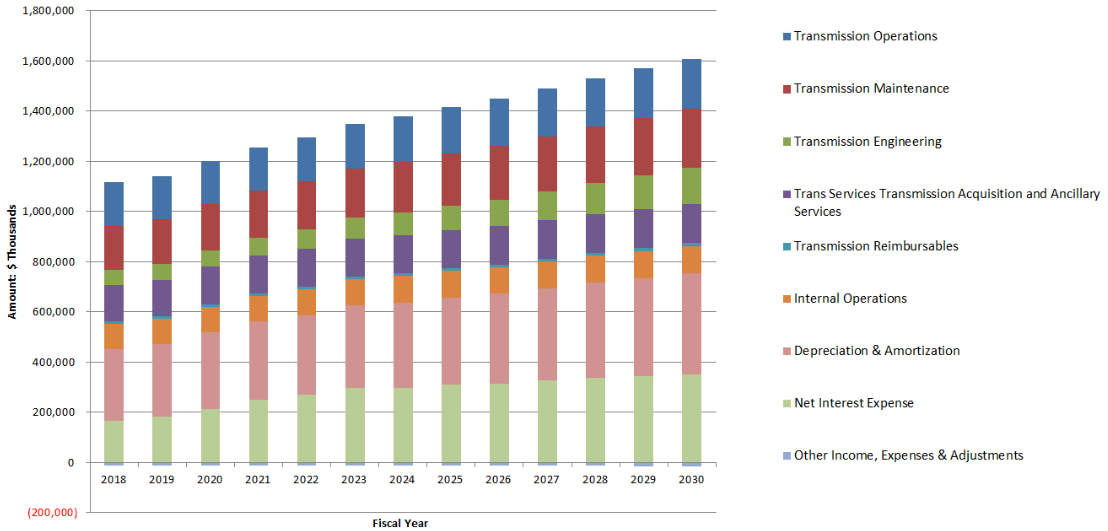


Power Services Summary Statement of Revenues and Expenses
($ in Thousands)

		A	B	C	D	E	F	G	H	I	J	K	L	M
		FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030
	Operating Expenses													
	Power System Generation Resources													
	Operating Generation Resources													
1	Columbia Generating Station	271,669	341,447	296,807	355,926	330,555	366,592	335,137	391,790	354,553	408,726	404,309	470,102	436,346
2	Bureau of Reclamation	168,179	166,103	171,086	176,218	181,505	186,950	192,559	198,335	204,285	210,414	216,726	223,228	229,925
3	Corps of Engineers	256,957	256,957	264,666	272,606	280,784	289,207	297,884	306,820	316,025	325,505	335,271	345,329	355,689
4	Long-term Contract Generating Projects	16,143	17,235	17,380	17,532	17,694	17,859	18,026	18,197	18,373	18,554	18,740	18,930	19,125
5	Operating Generation Settlement Payment	22,612	22,997	23,450	23,928	24,433	24,951	25,475	26,010	26,562	27,130	27,711	28,306	28,918
6	Non-Operating Generation	1,500	1,534	1,612	1,631	1,584	1,200	1,400	1,500	1,500	1,600	1,700	1,700	1,800
7	Gross Contracted Power Purchases and Aug Power Purchases	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100
8	Bookout Adjustment to Power Purchases													
9	Residential Exchange/IOU Settlement Benefits													
10	Renewables	38,332	39,060	39,159	35,366	34,707	26,714	25,055	25,063	25,071	18,329	10,087	409	418
11	Generation Conservation	131,182	131,102	134,115	137,268	140,568	143,967	147,443	151,015	154,114	157,925	161,843	165,881	170,043
12	**Subtotal Power System Generation Resources**	**909,674**	**979,535**	**951,375**	**1,023,575**	**1,014,930**	**1,060,540**	**1,046,079**	**1,121,830**	**1,103,583**	**1,171,283**	**1,179,487**	**1,256,985**	**1,245,364**
13	Power Services Transmission Acquisition and Ancillary Services	213,211	213,422	225,856	227,427	241,448	242,763	259,745	261,683	273,883	276,002	290,782	292,391	303,135
14	Power Non-Generation Operations	98,298	99,249	102,474	102,809	103,747	104,734	105,744	106,797	107,413	108,094	108,821	109,607	110,953
15	Fish and Wildlife/USF&W/Planning Council/Environmental Requirements	322,107	322,916	328,633	334,691	341,106	347,691	354,346	361,140	368,150	375,381	382,767	390,349	398,133
	BPA Internal Support													
16	Additional Post-Retirement Contribution	19,345	20,100	20,861	21,784	22,718	23,723	21,405	21,855	22,318	22,796	23,283	23,784	24,298
17	Agency Services G&A	67,210	69,492	70,872	72,062	73,555	74,877	76,427	78,009	79,640	81,321	83,038	84,801	86,609
18	Other Income, Expenses & Adjustments	(82,636)	(80,742)	(26,787)	(27,445)	(28,790)	(29,610)	(29,838)	(11,310)	(11,550)	(11,797)	(12,050)	(12,309)	(12,575)
19	Non-Federal Debt Service	646,533	410,596	427,831	238,033	244,694	263,480	397,046	697,123	686,854	671,426	653,670	402,982	399,363
20	Depreciation & Amortization	232,529	232,751	238,447	244,884	249,460	249,954	244,693	244,254	240,472	241,125	239,388	245,913	252,560
21	**Total Operating Expenses**	**2,426,272**	**2,267,319**	**2,339,562**	**2,237,821**	**2,262,868**	**2,338,152**	**2,475,648**	**2,881,381**	**2,870,763**	**2,935,631**	**2,949,186**	**2,794,502**	**2,807,839**
	Interest Expense and (Income)													
22	Interest Expense	143,443	151,456	108,880	114,574	109,635	105,372	104,413	117,291	129,292	142,648	148,821	156,917	157,634
23	AFUDC	(7,128)	(7,065)	(7,351)	(7,682)	(7,970)	(7,946)	(7,861)	(7,682)	(7,412)	(7,109)	(6,769)	(6,390)	(5,969)
24	Interest Income	(6,617)	(7,656)	(6,911)	(7,553)	(7,530)	(7,587)	(7,551)	(7,448)	(7,784)	(7,760)	(7,264)	(9,190)	(9,327)
25	**Net Interest Expense (Income)**	**129,698**	**136,735**	**94,618**	**99,339**	**94,135**	**89,839**	**89,001**	**102,161**	**114,096**	**127,779**	**134,788**	**141,337**	**142,338**
26	**Net Revenues (Expenses)**	**2,555,970**	**2,404,054**	**2,434,180**	**2,337,160**	**2,357,003**	**2,427,991**	**2,564,649**	**2,983,542**	**2,984,859**	**3,063,410**	**3,083,974**	**2,935,839**	**2,950,177**

3. Transmission Expenses

Transmission Expense By Program



Transmission Services Summary Statement of Revenues and Expenses

($ in Thousands)

		A	B	C	D	E	F	G	I	J	K	L	M	N
		2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
	Operating Expenses													
1	Transmission Operations	174,772	171,983	171,426	172,033	175,044	178,156	181,322	184,574	187,452	190,459	193,562	196,783	200,625
2	Transmission Maintenance	176,893	178,365	182,828	187,512	192,399	197,404	202,483	207,667	212,993	218,468	224,058	229,786	235,655
3	Transmission Engineering	59,688	60,765	65,962	70,308	76,791	82,419	90,150	97,043	105,101	113,350	122,776	132,415	143,275
4	Trans Services Transmission Acquisition and Ancillary Services	145,059	145,274	150,842	151,280	151,697	152,126	152,569	153,026	153,497	153,984	154,485	155,003	155,537
5	Transmission Reimbursables	9,929	9,936	10,132	10,339	10,557	10,781	11,007	11,238	11,477	11,722	11,973	12,231	12,495
	BPA Internal Support	98,602	100,786	101,493	102,081	103,200	103,710	104,809	105,287	105,779	106,286	106,804	107,335	107,881
6	Other Income, Expenses & Adjustments	(11,831)	(11,825)	(12,058)	(12,304)	(12,564)	(12,830)	(13,100)	(13,375)	(13,658)	(13,950)	(14,249)	(14,555)	(14,870)
7	Depreciation & Amortization	285,467	289,445	304,736	312,696	315,946	329,393	341,339	348,223	356,863	366,446	378,405	390,379	403,233
8	**Total Operating Expenses**	**938,579**	**944,729**	**975,361**	**993,945**	**1,013,071**	**1,041,160**	**1,070,579**	**1,093,684**	**1,119,504**	**1,146,765**	**1,177,814**	**1,209,377**	**1,243,831**
	Interest Expense and (Income)													
9	Interest Expense	199,526	215,864	244,511	281,519	301,750	327,709	326,956	340,236	346,626	360,161	371,289	377,785	383,311
10	AFUDC	(24,424)	(23,183)	(23,089)	(23,653)	(23,450)	(22,453)	(22,150)	(22,552)	(22,904)	(23,257)	(23,611)	(23,965)	(24,319)
11	Interest Income	(8,415)	(10,199)	(9,299)	(9,217)	(9,068)	(9,564)	(9,342)	(9,340)	(9,432)	(9,442)	(9,490)	(9,549)	(9,643)
12	**Net Interest Expense (Income)**	**166,687**	**182,482**	**212,124**	**248,650**	**269,232**	**295,692**	**295,464**	**308,345**	**314,290**	**327,462**	**338,189**	**344,271**	**349,349**
13	**Net Expenses**	**1,105,266**	**1,127,211**	**1,187,485**	**1,242,595**	**1,282,303**	**1,336,851**	**1,366,043**	**1,402,029**	**1,433,794**	**1,474,227**	**1,516,002**	**1,553,648**	**1,593,180**

Reference Case Assumptions

Type	Summary of Assumptions
Capital	• Forecasts in years FY 2017 through FY 2030 are consistent with initial spending levels from the 2016 IPR/CIR.
Expense	• Forecasts in years FY 2017 through FY 2019 are consistent with initial spending levels from the 2016 IPR/CIR. • Most program expense between FY 2020 and FY 2030 are inflated from FY 2019 expense using common agency inflation assumptions unless specified in Programmatic/Detailed Assumptions.
Transmission Rates	• The NT loads use the 12 non-coincidental peak method for allocation of costs and 12 coincidental peak method for billing determinants to calculate rates. These methods were used to calculate the current BP-16 rates and were assumed for twenty years. • The growth rate is approximately 1%.
Power Rate	• The risk bands around the Reference Case include expected Mid-C prices modeled using AURORA using all regular risk modeling (e.g., hydro variation, gas prices, loads). The forecast includes: –50% California RPS by FY 2030 –Henry Hub gas prices increase from $2.15 per MMBtu in CY 2016 to $5.61 per MMBtu in CY 2030 (nominal) with risk variation –Regional annual load growth 0.7% with weather and economic risk variation • No significant changes in BPA firm requirements power obligations or BPA resources (only moderate changes to the Tier 1 system are forecast, keeping Tier 1 loads relatively constant). • COE/USBR/CGS costs consistent with FY 2016 CIR and IPR proposals. • Residential Exchange costs follow the Settlement through FY 2028 and assume the same 7% per rate period escalation thereafter. Risk analysis shows expectations that the actual post-settlement amounts could be between $100 -$500 million.
Debt Management	• Debt management modeling ensures at least $750 million U.S. Treasury Borrowing Authority is available on an annual basis beginning in FY 2020. • 50% of the Transmission capital program is assumed to be financed through the lease purchase program starting in 2020. • Conservation 100% expensed starting in FY 2016. • No additional customer prepays. • Full Regional Cooperation Debt (RCD) through FY 2024 and acceleration through FY 2020.

Programmatic/Detailed Assumptions

Category	Topic	Assumptions-2016
Capital Assumptions	Capital Spending	Forecasts in years FY 2017 through FY 2030 are consistent with initial spending levels from the 2016 IPR/CIR. FY 2018 and FY 2019 are expected to be assumed in BP-18. In areas where investment plans are uncertain or unknown, the standard agency inflation rate was applied. For detailed asset category spending see public materials.
Capital Assumptions	Corporate Allocation for capital	Debt from corporate capital is allocated at the rate of 35% and 65% to Power and Transmission respectively.
Capital Assumptions	Plant-In-Service	Plant-in-service is based on FY 2016 CIR.
Corporate Expenses Assumptions	Cost Allocation	Corporate Pool costs are allocated between Power and Transmission using approved allocation percentages set by BPA Accounting.
Corporate Expenses Assumptions	Program Expenses (General)	Program costs are based on initial spending levels from the 2016 IPR, inflated in the out-years using standard agency assumptions for all program in areas where specific costs were not known.
Corporate Expenses Assumptions	FTE Assumptions	FTE related costs are assumed constant over time.
Debt Management Assumptions	Treasury	Maintain an annual minimum of $750 million of U.S. Treasury Borrowing Authority.
Debt Management Assumptions	Lease Purchase	50% of Transmission Capital is financed via 3rd Party Lease Financing.
Debt Management Assumptions	Reserve Financing	Transmission Only - $15 million /annually through FY 2023.
Debt Management Assumptions	Revenue Financing	n/a
Debt Management Assumptions	Prepay	No new prepay.
Debt Management Assumptions	Interest Income	Official 2015 interest rates forecasts and 2016 CIR forecasts.
Debt Management Assumptions	Outstanding Federal Bonds	Amount of Federal Bonds as of 4/30/16.
Debt Management Assumptions	Outstanding Non-Federal Debt	Amount of non-Federal debt as of 4/30/16.
Debt Management Assumptions	Outstanding Appropriations	Amount of Federal Appropriations as of 4/30/16.
Debt Management Assumptions	Outstanding Capital Leases	Transmission Only – Amount of debt being held as capital leases as of 4/30/16.

Category	Topic	Assumptions-2016
Debt Management Assumptions	CRFM Capital Forecast	Projected capital needs for CRFM activities based 3/15/2016 forecast.
Debt Management Assumptions	Long-Term Federal Capital Forecast	Forecasts in years FY 2017 through FY 2030 are consistent with initial spending levels from the 2016 IPR/CIR.
Debt Management Assumptions	Current Rate Period Federal Borrowing Plan	Detailed monthly or quarterly projected federal bonds through the end of the next rate period.
Debt Management Assumptions	Replacements and Credit Stream	Amount of capital needed to maintain systems.
Debt Management Assumptions	CGS Capital Projections	Power Only –Capital needed to keep CGS up and running based on 12/31/15 forecast.
Debt Management Assumptions	TVA Revenues	Power Only - Income that Energy Northwest is expected to receive and offset expenditures based on the 2012 Uranium Tails transaction.
Debt Management Assumptions	Interest Rate Forecast	The official BPA Interest Rate Forecast from Global Insight Forecast.
Debt Management Assumptions	Energy Northwest Regional Cooperation Debt Program (RCD)	Includes all regional cooperation debt transactions (up to $2.8 Billion) through which Energy Northwest issues BPA-supported bonds to refinance debt.
Power Expenses Assumptions	Program Expense (General)	Program costs are based on initial spending levels from the 2016 IPR. Some program levels are tied to long-range plans, known agreements, to a program-specific inflation rate.
Power Expenses Assumptions	Columbia Generating Station (O&M)	Long-Range Plan from FY 2020 through FY 2030 assumes 2.75% Inflation for labor expenses and 2.5% inflation for non-labor expenses. Does not include a reduction for DOE settlement dollars.
Power Expenses Assumptions	Columbia Generating Station (Decommissioning Trust Fund)	Long-Range Plan from FY 2020 through FY 2030 assumes 4% Inflation. Assumes no significant changes to expected decommissioning costs or fund earnings.
Power Expenses Assumptions	Columbia Generating Station (Neil Insurance)	Consistent with initial spending levels from the 2016 IPR. FY 2020 through FY 2030 assumes 4% Inflation. Investment performance and insurance losses are consistent with history and do not result in increases greater than inflation.
Power Expenses Assumptions	Bureau of Reclamation	FY 2017-19 consistent with initial spending levels from the 2016 IPR. Consistent with BOR long-range plan through FY 2021. Beyond that, Reclamation is using a 3% increase for FY 2022-30 based on our expected increases in trades & crafts wages.

Category	Topic	Assumptions-2016
Power Expenses Assumptions	Corps of Engineers	FY 2017-19 consistent with initial spending levels from the 2016 IPR. Consistent with COE long range plan through FY 2021. The Corps is using a 3.0% increase based on similar expectations for wages as well as expected increases in non-routine maintenance in that time period.
Power Expenses Assumptions	Idaho Falls Bulb Turbine	Assumes costs are flat-lined after FY 2019. Assume contract renewal in September 2021 (maintains tier 1 resources) and purchase the output of the City of Idaho Falls hydro project's four bulb turbines.
Power Expenses Assumptions	Cowlitz Falls O&M	Assumes common agency inflation assumptions. Assumes O&M costs increase consistent with inflation.
Power Expenses Assumptions	Billing Credits Generation	Assumes Billing Credits costs are flat-lined.
Power Expenses Assumptions	Wauna	Assume no contract renewal in FY 2017. (Decrease in tier 1 resources)
Power Expenses Assumptions	Colville Generation Settlement	Assumes common agency inflation assumptions.
Power Expenses Assumptions	Tier 2 Power Purchases	Contracts are set through FY 2019. Actual forecasts are done just prior to each rate period and are based on loads and resources. Forecast assumes current product selections and options continue. All costs are passed along to Tier 2 customers.
Power Expenses Assumptions	Augmentation	Augmentation is a rate case construct and is based on HydSim studies and customer loads and product selections. Augmentation purchase prices are escalated from BP-16 levels by general inflation. Risk analysis includes expected prices and quantities after application of risk factors.
Power Expenses Assumptions	Renewables	Assume power purchase contracts will not be renewed (decrease in tier 1 resources), support services costs will inflate based on agency assumptions after FY 2019 and no resource development funds.
Power Expenses Assumptions	Trojan O&M	Assumes a 1.95% inflation rate.
Power Expenses Assumptions	WNP-1,3&4 O&M	Assumes a 3.5% inflation rate.
Power Expenses Assumptions	3rd Party Transmission and Ancillary Services	Assumes a 5% rate of inflation.
Power Expenses Assumptions	Clearwater Hatchery Generation	Assumes common agency inflation assumptions.
Power Expenses Assumptions	Renewables (Legal)	Assumes common agency inflation assumptions.

Category	Topic	Assumptions-2016
Power Expenses Assumptions	DR & Smart Grid	Assumes common agency inflation assumptions.
Power Expenses Assumptions	Energy Efficiency Development (Reimbursable)	Assumes common agency inflation assumptions.
Power Expenses Assumptions	3rd party GTA Wheeling	Assumes common agency inflation assumptions.
Power Expenses Assumptions	Generation Integration	Assumes common agency inflation assumptions.
Power Expenses Assumptions	Planning Council	Assumes common agency inflation assumptions.
Power Expenses Assumptions	Lower Snake Hatcheries (Lower Snake River Compensation Plan)	Assumes common agency inflation assumptions.
Power Expenses Assumptions	Post-Retirement Benefits	BPA uses the methodology outlined for all government agencies by Office of Personnel Management (OPM) to generate forecasts of the amount of additional annual contributions, and then determine actual payments required each year for post-retirement benefits. Out-year estimates are based on forecasts of key inputs such as employee numbers, participation in retirement systems, health and life insurance and OPM actuarial estimates of longevity and inflation. Post FY 2024, the common agency inflation assumptions are applied.
Power Expenses Assumptions	Corporate G&A	Assumes common agency inflation assumptions.
Power Expenses Assumptions	Low Income Weatherization and Tribal Grants	Assumes common agency inflation assumptions. Assumes that BPA will not scale low income funding with EEI acquisition funding levels.
Power Expenses Assumptions	Non Generating Operations (Internal Ops)	Assumes common agency inflation assumptions. Assumes that labor costs increase by common agency assumptions.
Power Expenses Assumptions	Corporate Undistributed Reduction	Assumes common agency inflation assumptions. Assumes the undistributed reduction does not continue past FY 2017.
Power Expenses Assumptions	Fish and Wildlife (BPA F&W Program)	Assumes stable program levels, with inflation, including accords and existing BiOps.
Power Expenses Assumptions	PNCA Headwater Benefits	Assumes costs are flat-lined after FY 2019.
Power Expenses Assumptions	Market Transformation (NEEA)	Assumes level spending within the NEEA fiscal year (calendar year) and 2.8% inflation after the current contract expires.
Power Expenses Assumptions	New resources integration wheeling	Assumes new resources integration wheeling costs are flat.

Category	Topic	Assumptions-2016
Power Expenses Assumptions	Residential Exchange	IOU benefits for years FY 2018 through FY 2028 were established by settlement agreement (increase 7% per rate period). Increase for FYs 2029-30 assumed to be 7%.
Power Expenses Assumptions	Conservation Acquisition	Conservation Acquisition is increased based on Employment Cost projections for FY 2020 to FY 2030 averaged at 3.8%.
Power Expenses Assumptions	Legacy (Tacoma)	Uncertainty in the exact payment amounts through FY 2025.
Power Expenses Assumptions	Other Power Purchase (Short Term)	Modeled in RAM. Costs are calculated annually based on Hoss study forecasts. Reference case escalates BP-16 purchase prices using general inflation.
Power Expenses Assumptions	Power Undistributed Reduction IPR-16	Assumes the undistributed reduction included in the initial spending levels for the 2016 IPR/CIR continues through FY 2030.
Power Expenses Assumptions	PBL- Transmission and Ancillary Services	Assumes a 5% rate of inflation.
Power Rates Assumptions	Loads	Transmission Retail Load Forecasts are calibrated to the updated forecast of the Tier 1 System Capability and RHWM Augmentation forecasts out of the new TRM billing determinants model maintained by Power Rates. These were decomposed into the following product groupings: Block, Slice-Block, Slice Resource, Load Following System Shape Load, Load Following Load Shaping, and Tier 2. Conservation Augmentation, as forecast by Load Forecasting, was included to arrive at net Preference Load. DSI Loads assumed current long-term contract demand quantities as included in Alcoa and Port Townsends' contracts. Alcoa's load reflects the recent reduction in contract demand and assumes this level continues throughout the forecast period even though the contract expires earlier. Other contract loads rely on forecasts from Loads, Obligations and Resources Analyzer (LORA's) BP-16 study for the Initial Proposal.
Power Rate Assumptions	Resources	Both Federal and non-federal/contracted resource amounts rely on forecasts from LORA's BP-16 study for the proposal.

Category	Topic	Assumptions-2016
Power Rate Assumptions	Revenue Requirement	Load and resource forecasts were used to forecast the system augmentation amount required to achieve load resource amounts. Consistent with rate case practice, these modeled market purchases were valued at the average price from Aurora under 1937 water conditions, utilizing escalation assumptions in the market price forecast. Transmission Expenses for power were computed consistent with the model for the BP-16 period, and apply growth rate assumptions embedded in the Transmission Rate Forecast for the out-years.
Power Rate Assumptions	Tier 2 and RSS Costs	Tier 2 costs were estimated at the system augmentation price computed by RevSim. RevSim assumes escalation implied by the annual increase in Aurora Mid-C prices in the last two fiscal years modeled, and carries this escalation forward through FY 2030.
Power Rate Assumptions	Revenue Credits	4(h)(10)(C) was modeled consistent with RevSim and AURORA market price assumptions through FY 2030. Revenues from other contracts were flat-lined from BP-16 modeled levels for FY 2016-17 to contract termination date, or FY 2030, whichever comes first. This includes Downstream Benefits and Pumping Power, Colville and Spokane Settlements, Green Tags, Hungry Horse, Pasadena and Riverside exchange agreements, Upper Baker storage with PSE, miscellaneous credits (mainly associated with GTA), and WNP3 Settlement. Generation Inputs assume Corps and Bureau-implied inflation rates in the embedded costs, and assume elections for service move to 15-minute scheduling. The wind forecast is updated to expected RPS standards. Energy Efficiency Revenue Credits match Energy Efficiency Revenue Costs for this cost-credit program.
Power Rate Assumptions	REP – Average System Costs and Residential and Small Farm Loads	Forecasts were computed for ASCs and residential and small farm loads for BP-16. Escalation beyond the BP-16 period was assumed at the change in utility costs between FY 2016 and FY 2017, applies to FY 2018 and beyond. These assumptions do not affect overall REP benefit levels, just the distribution of benefits among participants.
Power Rate Assumptions	Transmission Rate Forecast	Power Services utilized the NT and Point to Point and Intertie rates as forecast by the Transmission group, incorporating all of Transmission's out-year assumptions.

Category	Topic	Assumptions-2016
Power Rate Assumptions	Market Price Forecast	Aurora market prices modeled at Mid-Columbia through FY 2030 with prices increasing moderately (4% per year, FY 2018 through FY 2030). Natural gas prices updated as of April 2016.
Power Rate Assumptions	Secondary and Balancing Purchases	Expectations for secondary sales and purchases are modeled in RevSim through FY 2030, using load and resource assumptions consistent with Power Rate, and Aurora market prices. These assume 50 games for 80 water years, and incorporate load and resource variability consistent with BP-16 modeling assumptions. Results are incorporated into risk assessment around the reference case.
Power Rate Assumptions	LDD and IRD Costs included in Power Rate	BPA maintains two rate discount programs – one for irrigation loads, and another for customers with a high proportion of pole-miles relative to loads (aka to the "low density discount"). These are modeled consistent with BP-16 assumptions for FY 2016 and FY 2017, and computed based on the modeled PF Tier 1 Average Net Cost of Power through FY 2030.
Transmission Expenses Assumptions	Transmission Program Expense General	Program costs are based on initial spending levels from the 2016 IPR. Program expenses between FY 2020 and FY 2030 are inflated from initial IPR spending levels with exceptions for those programs that have known long-range plans or agreements.
Transmission Expenses Assumptions	Transmission Operations	Use common agency inflation assumptions unless otherwise indicated in the following assumptions and exceptions: • Power System Dispatching Program – a 2% adder is applied above the rate of inflation for hourly wage increase. • Control Center Program – grows at the rate of inflation assuming a gradual technological build out and does not assume any proposed large replacements. • Substation Operations – a 2% adder is applied above the rate of inflation for hourly wage increase. • Incremental KSI costs are included.

Category	Topic	Assumptions-2016
Transmission Expenses Assumptions	Transmission Maintenance	Use common agency inflation assumptions unless otherwise indicated in the following assumptions and exceptions: • Non-Electric Maintenance Program – a 2% adder is applied above the rate of inflation for hourly wage increase. • Transmission Line Maintenance Program – a 2% adder is applied above the rate of inflation for hourly wage increase. • Substation Maintenance – a 2% adder is applied above the rate of inflation for hourly wage increase. • System Protection Control Maintenance – a 2% adder is applied above the rate of inflation for hourly wage increase. • Power System Control Maintenance – a 2% adder is applied above the rate of inflation for hourly wage increase. • Heavy Equipment and Maintenance (HMEM) – This program functions as a clearing pool accumulating costs for operating and maintaining vehicles and equipment and then allocating these costs to the projects that use HMEM. The out-year forecast captures the accounting treatment of HMEM cost matching actuals on the financial reports, so the assumption amount for this program is zero.

Transmission Expenses Assumptions	Transmission Engineering	Use common agency inflation assumptions unless otherwise indicated in the following assumptions and exceptions:
		• TSD Planning and Analysis Program – This program captures the amounts identified for Sustain Expense strategy efficiency improvements expense.
		• NERC/WECC Compliance program:
		  ○ Assumes WECC and PEAK costs grow at the rate of inflation assuming the current entity participation.
		  ○ Assumes a $1M increase over the rate of inflation every two year cycle due to the likelihood of increasing compliance standards and requirements.

Transmission Expenses Assumptions	Acquisition and Ancillary Services (Non-Between Business Line and Between Business Line)	Program expenses remain uninflated in the out-years at the rate assumed in FY 2019 with the following exceptions: • Settlement costs increased $500k per year beginning in FY 2020 and remain uninflated thereafter. • Reliability Demand Response/ Redispatch program costs increase to $10M per year beginning in FY 2020 and remain uninflated thereafter. This additional $10M per year is added to include South of Allston non-wires alternatives and demand response initiatives.

Category	Topic	Assumptions-2016
		• Leases will continue uninflated since they are based on long-term contracts.
Transmission Expenses Assumptions	Undistributed Reduction	Assumes the undistributed reduction included in the initial spending levels for the 2016 IPR continues at the rate of inflation through FY 2030.
Transmission Expenses Assumptions	Transmission Reimbursables	Common agency inflation assumptions.
Transmission Expenses Assumptions	Post-Retirement Benefits	BPA uses the methodology outlined for all government agencies by Office of Personnel Management (OPM) to generate forecasts of the amount of additional annual contributions, and then determine actual payments required each year for post-retirement benefits. Out-year estimates are based on forecasts of key inputs such as employee numbers, participation in retirement systems, health and life insurance and OPM actuarial estimates of longevity and inflation. Post FY 2024, the common agency inflation assumptions are applied.
Transmission Expenses Assumptions	Agency Services G&A	Common agency inflation assumption, IPR corporate allocation rates.
Transmission Rates Assumptions	Network Loads	The NT loads use the 12 Non Coincidental peak for allocation of costs and 12 Coincidental peak for billing determinants to calculate rates. This was used in the BP-16 Initial Proposal and was assumed for twenty years. 0.7% load growth.
Transmission Rates Assumptions	Point to-Point sales	There was an assumption of no sales for I-5 since the I-5 capital was not included in the reference case. There was no assumption for reduction in the short-term market due to market changes or decrease of long-term firm PTP sales since the base case assumes no B2H. There is an assumption of 940 MW of renewables start to come on in FY 2018 through FY 2025. There is also some decrease for the PTSA reform with an offset with assumption of increased sales based on load and resource information from Aurora. Short-term sales were updated to reflect the decrease in gas prices, thus the reduced sales.
Transmission Rates Assumptions	IS Rates (Southern Intertie)	There was a PDCI upgrade that would be energized FY 2017. There is a partial increase for BP-16 with a full effect in BP-18 with the 120 MW.
Transmission Rates Assumptions	Utility Delivery	No assumption of more delivery sales. 0.7% load growth.

Category	Topic	Assumptions-2016
Transmission Rates Assumptions	IM Rates (Montana Intertie)	There is no assumption of Colstrip shut down. There is an assumption that the MW do not go away in FY 2027 due to the contract expiration. Assumes16 MW for PAC.
Transmission Rates Assumptions	WECC and PEAK Rates	Assumption of costs increases with the common agency inflation rate.
Transmission Rates Assumptions	Gen Inputs	Assumes common agency inflation rate.
Transmission Rates Assumptions	Oversupply Rate	Pass thru costs.
Transmission Rates Assumptions	IR and FPT	Assumed to convert full amount capacity will convert to OATT service if the contract allowed