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

Long-Term Financial and Rates Analysis

Reference Case Results

UPDATED: October 2015

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 the wholesale market prices for electricity. These changes to the market environment have coincided with an increasing need for BPA to reinvest in the Federal Columbia River Power System FCRPS hydro power 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 plans to think ahead, strategically aligning our decisions today with the changing needs of the future. If we fail to do so, upward pressure on BPA's long-term cost structure could call into question the ability of BPA to meet its statutory obligations and the continued use of and benefit from the FCRPS.

BPA's ability to continue to meet its multiple statutory obligations and public purpose objectives depends on maintaining our cost competitiveness and financial strength. This ability is a shared objective for the many customers, tribes, and stakeholders that rely on BPA for important services and programs.

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 meet its statutory mission in the coming decades will depend largely on how well we anticipate and position our business to address the challenges and opportunities arising from the evolution of technology, markets, regulation, and our physical environment. Existing and emerging factors that impact or may impact BPA's mission in the future include, but are not limited to, the following:

- Decarbonization
- 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 will remain dedicated to preserving a compliant and reliable transmission system that continues to meet the needs of the region.

Table of Contents

Introduction

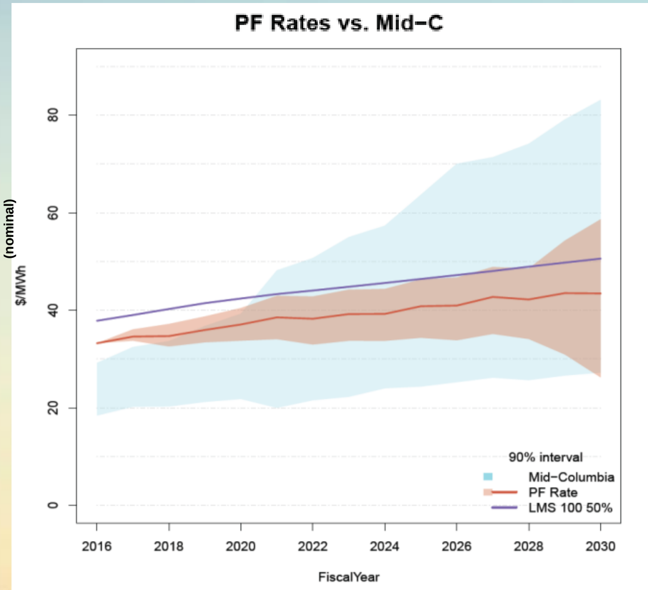
To facilitate strategic conversations among regional stakeholders and customers, BPA has produced a means for analyzing and comparing impacts of strategic choices and an initial **Long-Term Reference Case** (Reference Case) as a basis for comparison. The Reference Case is a 15-year analysis of BPA's financial condition and rates using spending level assumptions from recent public processes and current escalation, market and load forecasts.

The Reference Case is the result of analyses that gives BPA the capability to project program spending and rate levels over time based on a variety of assumptions, providing today's glide path for what BPA rate levels and other aspects of financial health might be if current assumptions were extended into the future. This is a product of repayment studies, long-term revenue requirement forecasts and power and transmission rates analyses. 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.

Through the **Focus 2028** process, BPA, its customers, tribes and stakeholders will consider major sources of uncertainty and potential impacts of strategic alternatives that can be analyzed and compared with the Reference Case. Discussions about BPA's proposed nearer-term actual investment and expense levels will occur during the routine Capital Investment Review (CIR) and Integrated Program Review (IPR) processes next year.

The Reference Case does not represent decisions about the future nor specific proposals. The Reference Case uses assumptions about the future that were vetted in other public processes such as the last IPR, CIR and rate case that may well play out differently in the future. It also does not apply any expert judgement on how program and capital levels may change over time. 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.

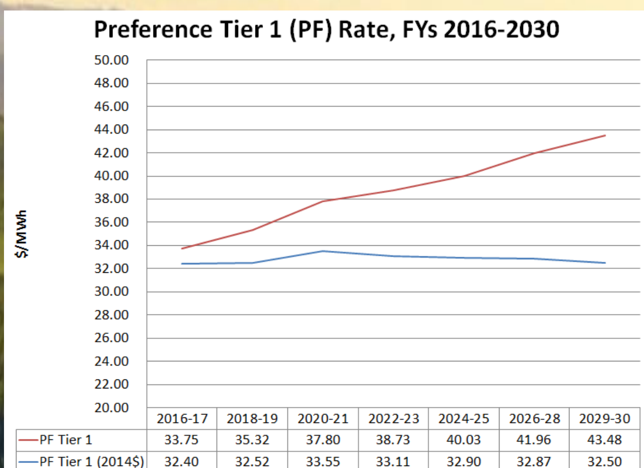
Strategic Dashboard

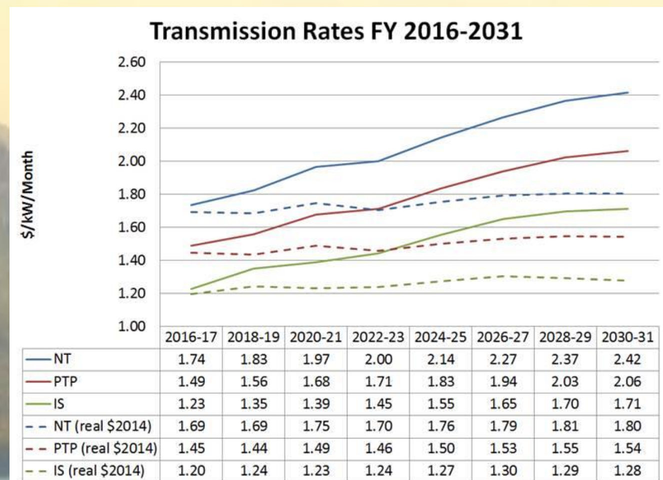


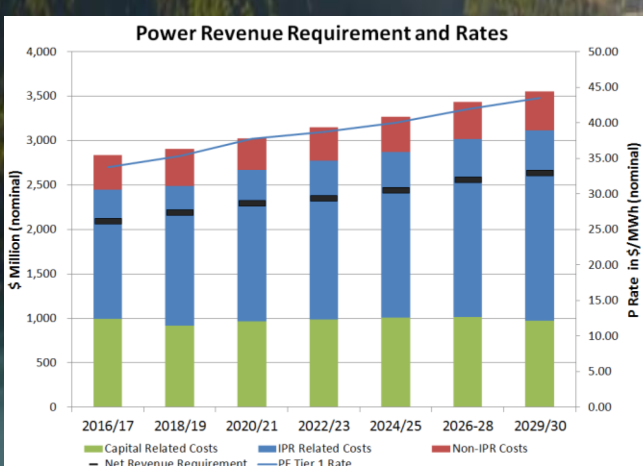
Rates Comparison and Performance on Metrics

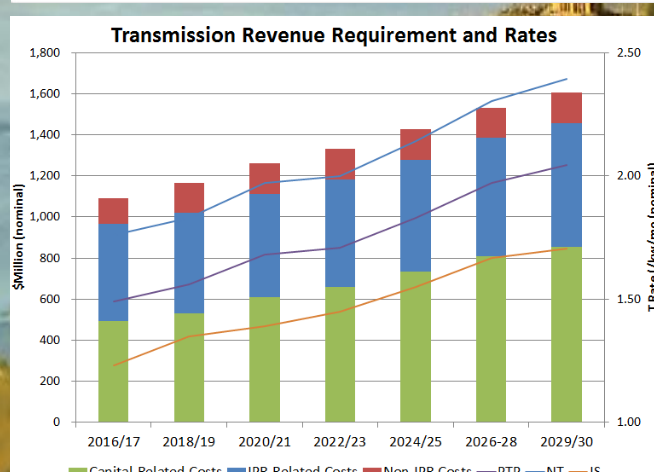
	Nominal $ 2016	Nominal $ 2018	Nominal $ 2030	Real $ 2016 (2014 dollars)	Real $ 2018 (2014 dollars)	Real $ 2030 (2014 dollars)
PF Rate (Tier 1)	33.75	35.32	43.48	32.40	32.52	32.50
NT Rate	1.74	1.83	2.42	1.69	1.69	1.80
PTP Rate	1.49	1.56	2.06	1.45	1.44	1.54
IS Rate	1.23	1.35	1.71	1.20	1.24	1.28

Financial Metrics	FY 2016	FY 2030
Rate of Change for IPR Costs (Rate of Cost Change / Inflation)	---	Px: 1.47 Tx: 0.97
Rate of Change in Capital Related Costs (Rate of Cost Change / Inflation)	---	Px: (0.08) Tx: 2.14
Financial Reserve Level	$830M	$755M
Days Cash on Hand	144	94
Remaining Borrowing Authority	$2,423M	$1,289M
Interest Expense as % of Revenue Requirement	18.73%	15.35%
Weighted Avg. Maturity of Debt Portfolio (Years)	23.09	19.82
Debt to Assets Ratio	89%	73%









*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 15-year analysis horizon to be used as reference to test the impact of potential business decisions.

Findings

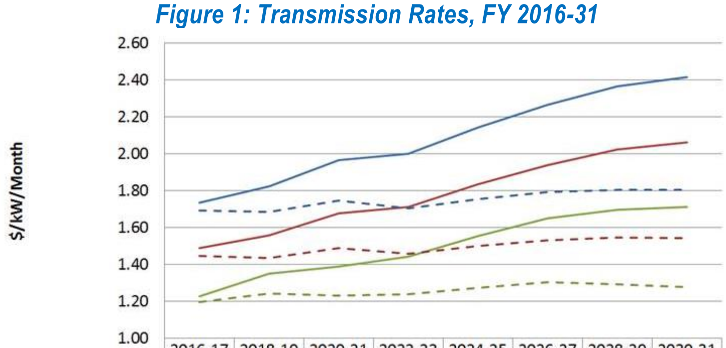
We have grouped our findings into five major categories. They include transmission rates, power rates, revenue requirements, capital investment and debt management, and financial health. The FY2016 Reference Case assumes an extension of current spending levels but also factors in commitments we have made in the future that may change those levels.

Transmission Rates

Transmission rates shown in Figure 1, in general reflect the results of assumptions used in the 2014 CIR and IPR. In the CIR transmission assumed capital investments will continue to increase over the next fifteen years due to the energization of projects identified in the Network Open Season (NOS). Additionally, compliance and reliability costs were assumed to increase every few years. Revenues were assumed to have a relatively flat load growth with Point to Point (PTP) sales increasing due to the energization of the NOS expansion projects that increase capacity on the Network. Oversupply and other rate designs were assumed to be the same as in the BP-16 rate case.

Figure 1 shows an increase in the Intertie South (IS) rate and the Network 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 IS rate for BP-18 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. The increase in the Network rate in BP-20 is mainly due to the assumption that a new I-5 Corridor Reinforcement Project is built and is fully energized in 2020/21 and the capital costs associated with this project begin to affect revenue requirements in the BP-20 rate period. The capital related costs associated with the capital expenditure assumption (inflation of the 2015-2023 average CIR levels) is the primary driver of projected rate increases in BP-24 and beyond. Other aspects of the revenue requirement increases reflect the inflation assumption.

Figure 1: Transmission Rates, FY 2016-31



	2016-17	2018-19	2020-21	2022-23	2024-25	2026-27	2028-29	2030-31
NT	1.74	1.83	1.97	2.00	2.14	2.27	2.37	2.42
PTP	1.49	1.56	1.68	1.71	1.83	1.94	2.03	2.06
IS	1.23	1.35	1.39	1.45	1.55	1.65	1.70	1.71
NT (real $2014)	1.69	1.69	1.75	1.70	1.76	1.79	1.81	1.80
PTP (real $2014)	1.45	1.44	1.49	1.46	1.50	1.53	1.55	1.54
IS (real $2014)	1.20	1.24	1.23	1.24	1.27	1.30	1.29	1.28

More detailed information on weighted rate pressures are provided in Figure 2.

Figure 2: Transmission Potential Rate Change Detail

Transmission Potential Rate Change Detail (in nominal $Million)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Change from BP-16 FP to FY 18/19		Change from FY 18/19 to FY 20/21		Change from FY 20/21 to FY 22/23		Change from FY 22/23 to FY 24/25		Change from FY 24/25 to FY 26/27		Change from FY 26/27 to FY 28/29		Change from FY 28/29 to FY 30/31	
Expenses	$ (Million)	% Change in Rev. Req.	$ (Million)	% Change in Rev. Req.	$ (Million)	% Change in Rev. Req.	$ (Million)	% Change in Rev. Req.	$ (Million)	% Change in Rev. Req.	$ (Million)	% Change in Rev. Req.	$ (Million)	% Change in Rev. Req.
1 Operations	15	1.3%	6	0.4%	7	0.2%	7	0.5%	8	0.5%	8	0.6%	7	0.4%
2 Maintenance	5	0.5%	6	0.4%	7	0.2%	7	0.5%	7	0.5%	8	0.5%	6	0.3%
3 Engineering	3	0.3%	3	0.2%	4	0.1%	5	0.4%	5	0.3%	4	0.3%	3	0.2%
4 Internal Support & Undistributed Reduction	3	0.3%	3	0.2%	3	0.1%	3	0.2%	3	0.2%	3	0.2%	2	0.1%
5 IPR Sub-total	**26**	**2.4%**	**19**	**1.1%**	**20**	**0.6%**	**22**	**1.6%**	**22**	**1.4%**	**23**	**1.6%**	**18**	**1.0%**
6 Ancillary Services	9	0.8%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
7 Non-IPR Sub-total	**9**	**0.8%**	**0**	**0.0%**	**0**	**0.0%**	**0**	**0.0%**	**0**	**0.0%**	**0**	**0.0%**	**0**	**0.0%**
8 Capital Related Costs 1/	**44**	**4.1%**	**76**	**4.4%**	**49**	**1.5%**	**74**	**5.4%**	**67**	**4.3%**	**41**	**3.0%**	**21**	**1.2%**
9 Total Change in Revenues (Lines 5+7+8) 2/	**80**	**7.3%**	**96**	**5.5%**	**69**	**2.1%**	**96**	**7.0%**	**90**	**5.7%**	**64**	**4.6%**	**39**	**2.2%**

1/ Includes Net Interest Expense, Depreciation/Amortization and Minimum Required Net Revenues
2/ This change in revenue also equals the weighted average rate change by rate period.

Power Rates

Power rates are expected to remain flat in real terms over the planning horizon, with the overall nominal increases in rates at or slightly below the forecast level of inflation through 2030. Increases in program spending due to Columbia Generating Station, the U.S. Army Corps of Engineers and the Bureau of Reclamation for operating and maintaining the FCRPS, and BPA's Fish and Wildlife program, in addition the planned increases in the Residential Exchange Program payments to participating investor-owned utilities and customer-owned utilities under the 2012 Residential Exchange Program (REP) Settlement may be partially offset by modest increases to secondary revenues, which are due to the inflation assumption. Capital expenditures are forecast to remain relatively stable over the planning horizon. The uptick in power rates between 2018-19 and 2020-21 rates is due to the expiration of rate mitigation 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 load and resource, and natural gas 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 net secondary revenues for the Reference Case are held constant in real terms at BP-16 levels even though the current market price forecast is expected to increase at a rate somewhat higher than inflation. Including these increases in the Reference Case would tend to obfuscate the effects of program spending on BPA's competitiveness in the future.

It should also be noted that the REP Settlement expires within the horizon of this analysis. The REP benefits paid under the REP Settlement throughout the settlement period account for over-payments of REP benefits prior to the 2007 Ninth Circuit's opinion remanding BPA's 2002 power rates. Therefore, REP benefits could increase substantially post-2028. On the other hand, the settlement suspended significant issues in litigation that, if addressed in the future, could virtually eliminate post-2028 REP benefits. Thus, the Reference Case maintains the current status quo and the potential distribution of rate outcomes incorporates plus or minus $300 million of REP benefits after the REP Settlement period.

Figure 3 shows the Preference Tier 1 (PF) power rate with a 90% confidence interval around the Reference Case output and the fractional cost of an LMS 100 along with Mid-Columbia market prices expressed as a 90% confidence interval. Figure 4 shows a point forecast generated by the standard BPA rates analysis process with a set of spending level, debt management, and market condition assumptions assumed in order to project the rates for 15 years. More detailed information on rate pressures are provided in Figure 5.

Figure 3: Power Rates Compared to Mid-C

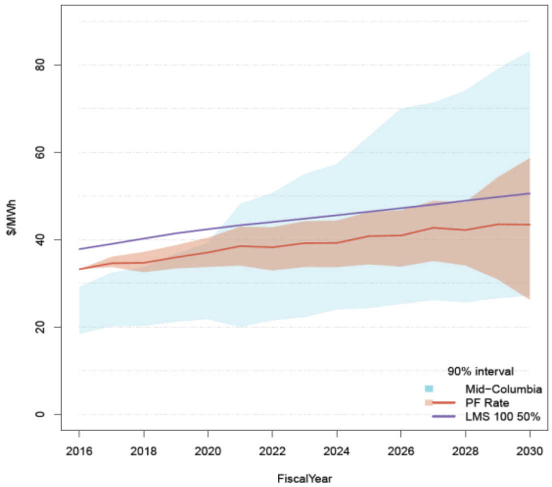
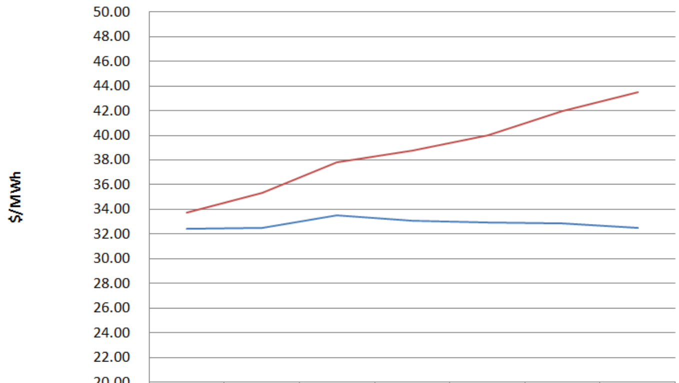


Figure 4: Preference Tier 1 (PF) Rates, FYs 2016-2030



	2016-17	2018-19	2020-21	2022-23	2024-25	2026-28	2029-30
PF Tier 1	33.75	35.32	37.80	38.73	40.03	41.96	43.48
PF Tier 1 (2014$)	32.40	32.52	33.55	33.11	32.90	32.87	32.50

Figure 5: Power Potential Rate Change Detail

Power Potential Rate Change Detail (in nominal $Million)

		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	
	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
1	Columbia Generating Station	43	2.1%	20	1.0%	38	1.6%	22	0.9%	62	2.5%	71	2.8%
2	Bureau of Reclamation	(14)	-0.7%	0	0.0%	9	0.4%	8	0.3%	11	0.4%	12	0.5%
3	Corps of Engineers	15	0.7%	16	0.8%	15	0.7%	15	0.6%	21	0.8%	23	0.9%
4	Residential Exchange	19	0.9%	11	0.5%	15	0.6%	16	0.7%	11	0.5%	13	0.5%
5	Fish and Wildlife	15	0.7%	16	0.7%	17	0.7%	18	0.8%	24	1.0%	25	1.0%
6	Energy Efficiency	26	1.3%	68	3.2%	(0)	0.0%	3	0.1%	0	0.0%	(7)	-0.3%
7	Transmission and Ancillary Services	18	0.9%	6	0.3%	3	0.1%	8	0.3%	11	0.4%	7	0.3%
8	Internal Operations	17	0.8%	4	0.2%	(1)	0.0%	7	0.3%	9	0.4%	9	0.3%
9	Capital-Related Costs	(74)	-3.7%	48	2.3%	20	0.9%	18	0.8%	8	0.3%	(42)	-1.6%
10	Other Costs	3	0.2%	5	0.2%	6	0.2%	7	0.3%	11	0.5%	9	0.3%
11	**Expense Sub-Total**	**68**	**3.3%**	**195**	**9.2%**	**121**	**5.3%**	**121**	**5.2%**	**167**	**6.8%**	**119**	**4.6%**
	Revenues and Costs Affected by Gas Price												
12	Net Power Purchase and Sales*	2	0.1%	(22)	-1.0%	(49)**	-2.2%	(18)	-0.8%	(29)	-1.2%	(22)	-0.9%
13	4(h)(10)(C)	(2)	-0.1%	(7)	-0.3%	(5)	-0.2%	(7)	-0.3%	(8)	-0.3%	(9)	-0.3%
14	Generation Inputs	3	0.1%	(6)	-0.3%	(9)	-0.4%	(8)	-0.3%	(11)	-0.5%	(12)	-0.5%
15	DSI Sales	(1)	-0.1%	0	0.0%	(1)	0.0%	(1)	-0.1%	(2)	-0.1%	(2)	-0.1%
16	Other Revenues	31	1.5%	15	0.7%	(0)	0.0%	3	0.1%	3	0.1%	(1)	0.0%
17	**Revenues Sub-Total**	**32**	**1.6%**	**(19)**	**-0.9%**	**(64)**	**-2.8%**	**(32)**	**-1.4%**	**(47)**	**-1.9%**	**(45)**	**-1.8%**
18	**Load Effect**		**0.1%**		**-1.2%**		**0.1%**		**-0.3%**		**-0.2%**		**0.8%**
19	**Total Change in Net Revenue Requirement**	**100**	5.0%	**176**	7.1%	**57**	2.5%	**89**	3.4%	**120**	4.7%	**73**	3.7%

*Net Power Purchase and Sales includes the value of net secondary, decremented for augmentation purchases. Net secondary was held constant in real terms, starting in FY 2016/17. Augmentation purchases were computed based upon forecast augmentation need, valued at FY 2016/17 prices escalated at the rate of inflation.

**Incorporates the roll-off of the interim SE Idaho load service hedge power purchases; assumes transmission solution post the bridge agreement period.

Revenue Requirements

Revenue requirements are the accumulation of costs which BPA's power and transmission rates need to recover. These costs are incurred because of various programs, such as the operation and maintenance of the transmission system or the Corps of Engineers and Bureau of Reclamation dams, or from the acquisition of resources needed to ensure BPA meets its contractual obligations to supply power. The revenue requirement also includes the costs associated with capital investments ("Capital-Related Costs"). These costs, such as depreciation and interest, are spread over time within the life of the investment. In general, capital investment decisions made in the past affect today's revenue requirements and capital investment decisions made today 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 & Rates

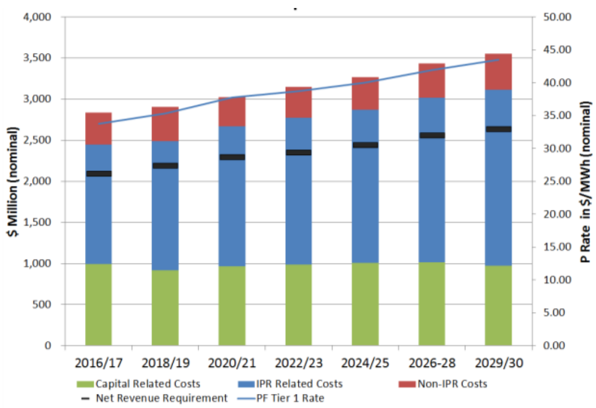
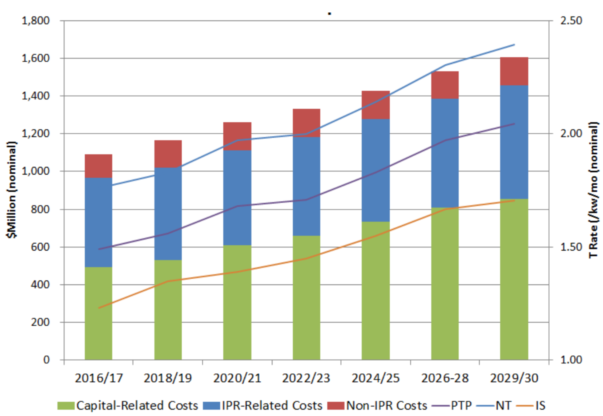


Figure 7: Transmission Revenue Requirement & Rates



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 2016 through 2030 is 1.9%. In the table below, 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: 1.47 Tx: 0.97
Change in Capital Related Costs (Rate of Cost Change / Inflation)	Px: (0.08) Tx: 2.14

Capital Investment and Debt Management

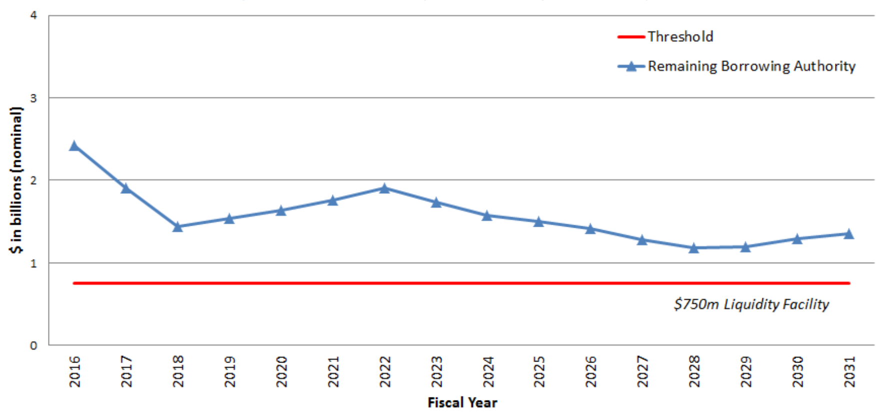
Capital-related costs, of which debt service is a primary component, make up 35% of current power revenue requirements, 45% of current transmission revenue requirements, and are a critical component of long-term power and transmission overall cost structures. One of BPA's top strategic priorities is to preserve and enhance transmission and federal generation assets and the economic, environmental and operation value they create. Capital investment levels assumed in the Reference Case through 2023 mirror the 2014 CIR less Energy Efficiency capital which is now an expense. These levels were based upon the then-current asset strategies and results of BPA's newly introduced prioritization process. Capital investment levels in the Reference Case after 2023 are the 2014-2023 average CIR increasing at the rate of inflation.

Virtually all capital investments are financed through debt. Debt management strategies must consider both near- and long-term impacts on capital-related revenue requirement. Capital Investment decisions and debt management actions taken today will have an impact on overall cost structure 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;
- Ensuring long-term cost stability for each business unit; and
- Maintaining $750 million of access to the U.S. Treasury Borrowing Authority for the short term liquidity note.
  - After the use of 3rd party tools (full Regional Cooperation Debt Program and 50% Lease Purchase), maintaining the $750 million is achieved through the accelerated repayment of Federal debt.

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 depends on maintaining our cost competitiveness and financial strength. Strong BPA financial targets result in a strong BPA credit rating. A strong credit rating lowers the cost of BPA's non-federal borrowing for CGS and transmission lease financing and translates directly to a lower revenue requirement and thus more competitive BPA power and transmission rates.

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 % 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 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 amounts of BPA revenue producing assets versus the amount of total outstanding debt. Figure 10 shows BPA currently has a debt ratio of 89% driven primarily by debt issuance for non-revenue producing assets.

Figure 10: Summary of Financial Health Metrics

Metrics	FY 2016	FY 2030
Financial Reserve Level	$830M	$755M
Days Cash on Hand	144	94
Remaining Borrowing Authority	$2,423M	$1,289M
Interest Expense as % of Revenue Requirement	18.73%	15.35%
Weighted Avg. Maturity of Debt Portfolio (Years)	23.09	19.82
Debt to Assets Ratio	89%	73%

Summary

Overview of Rates, Risks and Uncertainties

The comparison of rates from current rates to those in 2030 is summarized in Figure 11. Rates in the Reference Case appear nearly level in 2030 in real dollar terms for both Transmission and Power. 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 enable the display of effects of different scenarios on BPA's rates and financial health going forward.

Figure 11: Summary of Rates Results

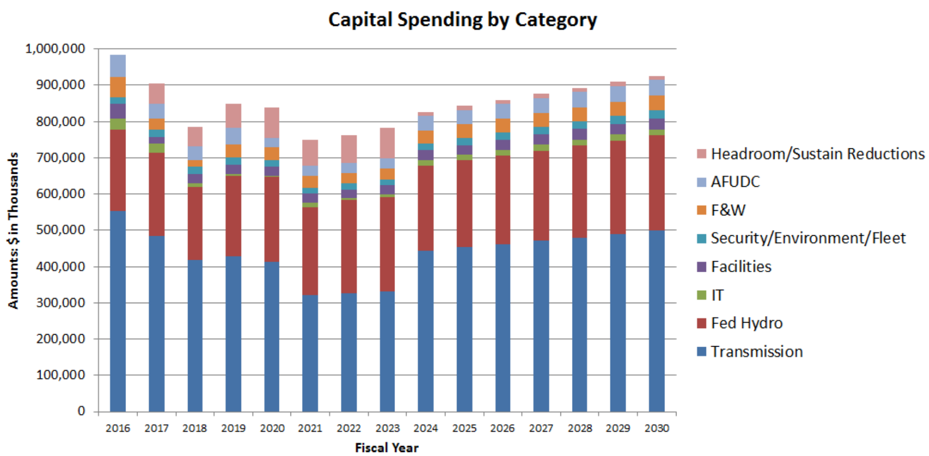
	Nominal $ 2016	Nominal $ 2018	Nominal $ 2030	Real $ 2016 (2014 dollars)	Real $ 2018 (2014 dollars)	Real $ 2030 (2014 Dollars)
PF Rate	33.75	35.32	43.48	32.40	32.52	32.50
NT Rate	1.74	1.83	2.42	1.69	1.69	1.80
PTP Rate	1.49	1.56	2.06	1.45	1.44	1.54
IS Rate	1.23	1.35	1.71	1.20	1.24	1.28

Financial Disclosure: This information has been made publicly available by BPA on October 23, 2015 and contains information not reported in agency financial statement.

Appendix

Spending Level Inputs

1. Capital Investment



Capital Investment by Asset Category
($ in Thousands)

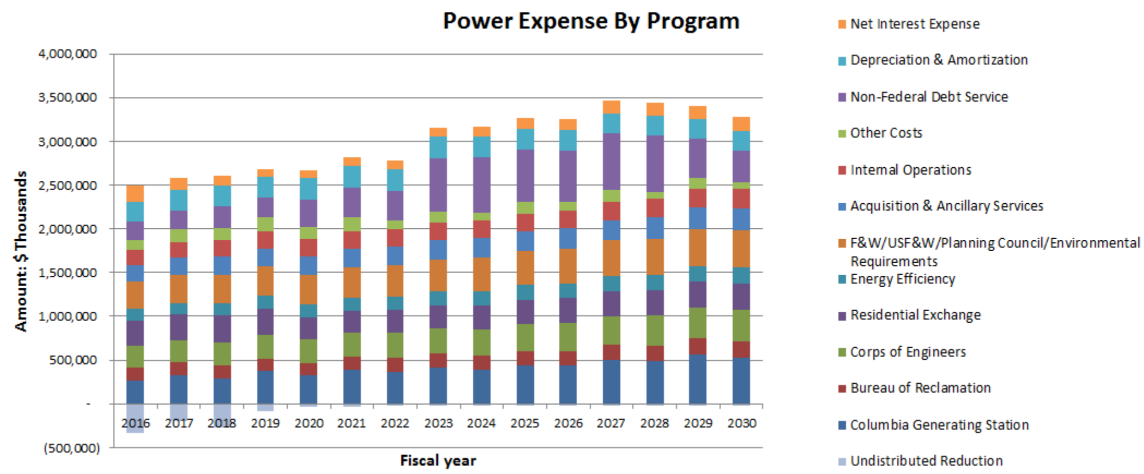
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Transmission ^2	552,363	484,832	417,511	429,372	413,302	321,180	326,891	330,998	444,460	453,394	462,235	471,156	480,485	489,470	498,623
2	Fed Hydro^2	224,173	230,218	203,302	220,376	234,299	243,325	256,302	260,976	234,930	239,652	244,326	249,041	253,972	258,721	263,559
3	Information Technology	32,800	25,386	10,036	5,036	2,500	12,000	4,736	6,536	14,761	15,058	15,351	15,648	15,957	16,256	16,560
4	Facilities	38,876	17,005	25,005	25,005	25,005	25,005	25,005	25,005	26,326	26,856	27,379	27,908	28,460	28,993	29,535
5	Security/ Environment/ Fleet	18,585	20,570	19,617	22,007	19,231	16,200	16,500	16,500	19,679	20,075	20,466	20,861	21,274	21,672	22,077
6	Fish and Wildlife	54,807	30,795	18,646	34,806	35,033	33,599	29,047	29,291	36,014	36,738	37,454	38,177	38,933	39,661	40,403
7	AFUDC ^1	63,165	39,170	38,068	45,032	24,827	26,251	27,094	28,795	39,053	39,837	40,614	41,398	42,218	43,007	43,812
8	Headroom/Sustain Reductions ^2	-	56,000	54,302	68,376	85,299	71,325	77,302	83,976	11,318	11,509	11,723	11,920	11,391	11,634	11,820
9	**TOTAL BPA Capital Expenditures ^3**	**984,769**	**903,976**	**786,486**	**850,009**	**839,497**	**748,886**	**762,879**	**782,076**	**826,541**	**843,118**	**859,549**	**876,109**	**892,691**	**909,414**	**926,388**

1> AFUDC will be updated later in September

2> Fed Hydro and Transmission assume approximalty 50% of "Headroom" and "Sustain Reductions"

3> Capital displayed I the above table ties to the Capital Investment Review (CIR) public process and was updated to remove Energy Efficiency Capital, a decision that resulted from the Integrated Program review (IPR) 2 public process.

2. Power Expenses



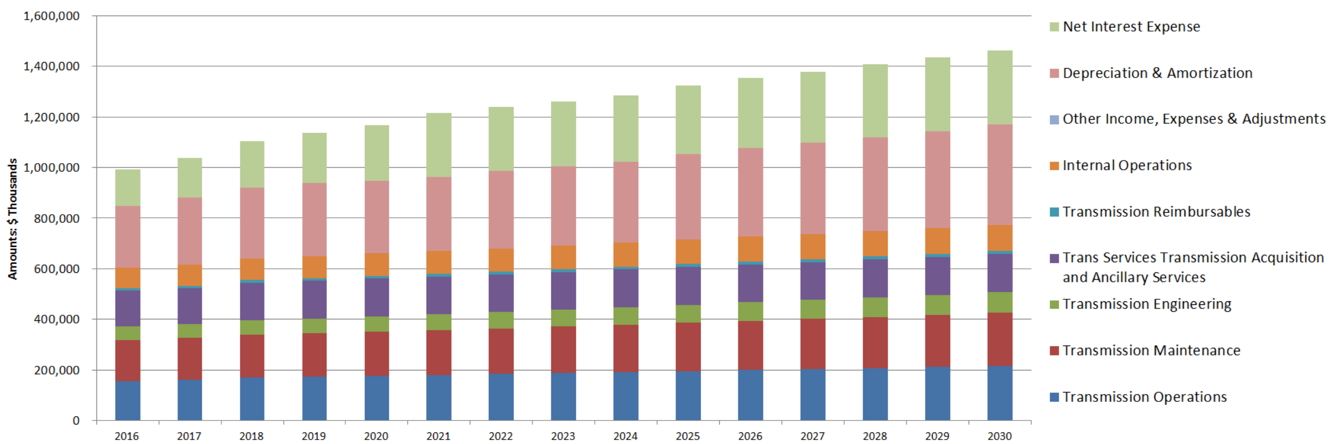
Power Services Summary Statement of Revenues and Expenses
($ in Thousands)

		B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
		FY 2016	FY 2017	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	262,948	322,473	290,798	380,428	323,183	388,843	369,707	417,376	391,754	439,338	434,220	504,303	492,695	566,181	529,669
2	Bureau of Reclamation	156,818	158,121	149,691	136,581	141,500	145,534	151,427	153,621	158,077	162,624	166,347	170,952	175,983	181,190	184,931
3	Corps of Engineers	243,885	250,981	258,510	266,266	274,254	282,482	291,565	295,727	304,299	313,048	320,182	329,035	338,716	348,735	355,888
4	Long-term Contract Generating Projects	22,303	17,034	17,206	17,378	17,558	17,749	17,945	18,146	18,350	18,560	18,780	19,010	19,245	19,485	19,730
5	Operating Generation Settlement Payment	19,323	19,651	20,018	20,385	20,764	21,154	21,556	21,970	22,405	22,855	23,301	23,751	24,221	24,674	25,136
6	Non-Operating Generation	1,600	1,863	2,429	2,254	2,269	2,310	2,361	2,567	3,200	3,445	3,520	3,658	3,912	4,050	4,170
7	Gross Contracted Power Purchases and Aug Power Purchases	26,117	76,012	56,330	84,766	54,224	79,765	19,089	54,298	19,709	58,443	20,382	62,192	21,063	64,406	21,749
8	Bookout Adjustment to Power Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Residential Exchange/IOU Settlement Benefits	291,369	288,816	309,433	308,782	244,914	245,265	258,428	261,156	275,833	275,826	287,588	286,861	287,117	299,857	299,815
10	Renewables	40,987	41,641	42,262	42,863	43,497	39,909	39,764	31,110	29,612	30,058	30,524	22,623	12,522	4,434	4,442
11	Generation Conservation	136,649	131,665	138,209	142,513	146,858	151,346	152,677	157,251	161,877	165,587	168,609	172,386	176,322	180,204	184,181
12	**Subtotal Power System Generation Resources**	**1,201,999**	**1,308,257**	**1,284,886**	**1,402,216**	**1,269,021**	**1,374,357**	**1,324,519**	**1,413,222**	**1,385,116**	**1,489,784**	**1,473,453**	**1,594,771**	**1,551,796**	**1,693,216**	**1,629,711**
13	Power Services Transmission Acquisition and Ancillary Services	187,589	196,217	210,732	209,133	218,063	214,133	220,364	218,382	228,454	225,755	236,239	233,429	243,680	240,719	248,379
14	Power Non-Generation Operations	96,542	99,836	111,672	112,636	113,633	114,660	109,968	111,957	114,012	116,132	118,294	120,518	122,810	125,093	127,426
15	Fish and Wildlife/USF&W/Planning Council/Environmental Requirements	310,539	318,395	325,862	333,497	341,330	349,361	357,813	366,481	375,390	384,531	393,866	403,418	413,230	423,222	433,458
	BPA Internal Support															
16	Additional Post-Retirement Contribution	19,143	19,478	19,842	20,205	20,581	20,968	21,366	21,777	22,208	22,654	23,096	23,542	24,008	24,457	24,914
17	Agency Services G&A	53,138	55,168	56,200	57,228	58,292	59,388	60,517	61,679	62,900	64,164	65,415	66,678	67,998	69,270	70,565
18	Other Income, Expenses & Adjustments	(334,785)	(197,885)	(267,693)	(82,797)	(37,723)	(38,570)	(21,939)	(22,360)	(22,803)	(23,261)	(23,715)	(24,173)	(24,651)	(25,112)	(25,582)
19	Non-Federal Debt Service	215,667	214,755	244,049	217,636	316,405	338,595	339,505	611,670	625,343	605,105	586,902	652,423	639,330	449,041	354,034
20	Depreciation & Amortization	222,551	228,502	235,153	240,161	243,786	248,217	251,205	249,939	242,454	238,892	232,854	227,499	226,241	230,354	234,175
21	**Total Operating Expenses**	**1,972,383**	**2,242,723**	**2,220,703**	**2,509,915**	**2,543,389**	**2,681,109**	**2,663,318**	**3,032,747**	**3,033,074**	**3,123,757**	**3,106,405**	**3,298,105**	**3,264,442**	**3,230,259**	**3,097,080**
	Interest Expense and (Income)															
22	Interest Expense	214,028	177,523	159,446	125,758	127,301	126,928	126,257	130,562	141,397	151,620	159,339	169,498	180,441	187,236	189,414
23	AFUDC	(10,731)	(10,731)	(12,354)	(13,511)	(14,256)	(14,853)	(15,341)	(15,818)	(15,818)	(15,818)	(15,818)	(15,818)	(15,818)	(15,818)	(15,818)
24	Interest Income	(16,099)	(24,146)	(24,167)	(19,982)	(19,596)	(19,377)	(19,412)	(15,731)	(15,694)	(15,952)	(16,160)	(15,350)	(15,399)	(17,640)	(18,937)
25	**Net Interest Expense (Income)**	**187,198**	**142,646**	**122,925**	**92,265**	**93,449**	**92,698**	**91,504**	**99,013**	**109,885**	**119,850**	**127,361**	**138,330**	**149,224**	**153,778**	**154,659**
26	**Net Revenues (Expenses)**	**2,159,581**	**2,385,369**	**2,343,628**	**2,602,180**	**2,636,838**	**2,773,807**	**2,754,822**	**3,131,760**	**3,142,959**	**3,243,607**	**3,233,766**	**3,436,435**	**3,413,666**	**3,384,037**	**3,251,739**

***Power purchases and augmentation has been updated on 11-04-15 to reflect the most recent rates analysis.**

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	O	P
		2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
	Operating Expenses															
1	Transmission Operations	155,797	161,323	171,000	174,112	177,335	180,655	184,075	187,595	191,290	195,115	198,908	202,740	207,077	211,507	216,076
2	Transmission Maintenance	162,552	164,272	167,344	170,406	173,576	176,839	180,199	183,659	187,295	191,060	194,786	198,545	202,298	206,081	209,934
3	Transmission Engineering	54,421	54,915	56,942	57,984	60,201	61,333	63,662	66,047	68,518	71,059	73,607	75,028	77,446	78,894	81,575
4	Trans Services Transmission Acquisition and Ancillary Services	140,767	140,782	149,690	149,712	149,735	149,759	149,783	149,808	149,833	149,859	149,886	149,915	149,944	149,974	150,004
5	Transmission Reimbursables	9,641	9,735	9,911	10,092	10,280	10,473	10,672	10,877	11,093	11,316	11,536	11,759	11,981	12,205	12,433
	BPA Internal Support	82,038	84,523	86,030	87,538	89,093	90,690	92,015	93,379	94,813	96,297	97,767	99,249	100,729	102,220	103,740
6	Other Income, Expenses & Adjustments	(2,100)	(2,100)	(2,139)	(2,178)	(2,219)	(2,261)	(2,304)	(2,348)	(2,394)	(2,442)	(2,490)	(2,538)	(2,586)	(2,634)	(2,684)
7	Depreciation & Amortization	243,996	264,353	279,754	288,129	286,418	292,361	306,315	313,212	320,168	338,594	349,332	359,519	370,701	382,594	395,164
8	**Total Operating Expenses**	**847,112**	**877,803**	**918,532**	**935,795**	**944,419**	**959,849**	**984,417**	**1,002,229**	**1,020,616**	**1,050,858**	**1,073,332**	**1,094,217**	**1,117,590**	**1,140,841**	**1,166,242**
	Interest Expense and (Income)															
9	Interest Expense	196,633	213,248	237,581	259,057	276,198	302,279	302,137	306,947	313,784	326,361	332,680	338,120	346,833	349,327	352,502
10	AFUDC	(42,640)	(40,910)	(40,376)	(45,125)	(40,479)	(33,372)	(33,924)	(34,362)	(37,195)	(37,941)	(38,680)	(39,425)	(40,171)	(40,924)	(41,688)
11	Interest Income	(9,173)	(15,162)	(14,931)	(15,930)	(15,686)	(15,294)	(15,309)	(15,238)	(15,513)	(16,574)	(16,551)	(16,561)	(17,395)	(16,792)	(16,541)
12	**Net Interest Expense (Income)**	**144,820**	**157,176**	**182,274**	**198,002**	**220,033**	**253,613**	**252,904**	**257,347**	**261,076**	**271,846**	**277,449**	**282,134**	**289,267**	**291,611**	**294,273**
13	**Net Revenues (Expenses)**	**991,932**	**1,034,979**	**1,100,806**	**1,133,797**	**1,164,452**	**1,213,462**	**1,237,321**	**1,259,576**	**1,281,692**	**1,322,704**	**1,350,781**	**1,376,351**	**1,406,857**	**1,432,452**	**1,460,515**

Reference Case Assumptions

Type	Summary of Assumptions
Capital	• Forecasts in FYs 16-17 are consistent with Final 2014 CIR and IPR spending levels. FYs 18-23 match CIR – updated for IPR2 (which excludes Energy Efficiency) spending levels. Forecasts in FYs 24-30 reflect a 9 year average of CIR spending levels (with adjustments for Energy Efficiency) increasing annually at the common agency inflation rate.
Expense	• BP-16 Final Proposal for FYs 16-17. • Most program expense between FYs 18-30 are inflated from BP-16 Final Proposal expense using common agency inflation assumptions unless specified in Programmatic/Detailed Assumptions section below. • Non-federal debt service reflects full Energy Northwest debt extension.
Transmission Rates	• 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. • The growth rate is approximately 1%.
Power Rates	• In order not to obscure the effect of BPA's costs on power rates in the Reference Case, future revenues from secondary sales and purchased power costs are held at BP-16 levels, adjusted for inflation. • 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 2030 –Henry Hub gas prices $3.30/6.74 CY 2016/2030 (nominal) with risk variation –Regional annual load growth 0.7% with weather and economic risk variation –Carbon pricing is not taken into account in the forecast • No significant changes in BPA firm requirements power obligations or BPA resources (T1SFCO reductions due to expiration of the Wauna cogeneration contract and renewables assumptions). • COE/USBR/CGS costs consistent with 2014 CIR and IPR. • Residential Exchange costs follow the Settlement through 2028 and assume the same 7% per rate period escalation thereafter. Risk analysis shows expectations that the actual post-settlement amounts could be between $0-$600 million.
Debt Management	• Debt management modeling ensures at least $750 million US Treasury Borrowing Authority is available on an annual basis. • 50% of the Transmission capital program is financed through the lease purchase program. • Assumes full Regional Cooperation Debt program. • Conservation 100% expensed starting in 2016. • No additional customer prepays.

Programmatic/Detailed Assumptions

Category	Topic	Assumption-2015
Capital Assumptions	Capital Spending	Forecasts in years FY 16 and FY 17 match BP-16 Final Proposal and FY 18- 23 match Final 2014 Capital Investment Review (CIR) spending levels and exclude Energy Efficiency starting in FY 16. Forecasts in years FY 24 through FY 30 reflect a ten-year average of CIR spending levels inflated using common agency inflation rate.
Capital Assumptions	Capital Spending Cap	The spending cap equals $857 million per year, which is consistent with the 2014 CIR (2014 CIR cap less expensed Energy Efficiency).
Capital Assumptions	Plant-In-Service	Plant-in-service is based on BP-16 Final Proposal in combination with 2014 CIR capital forecasts.
Capital Assumptions	Allocation of Headroom, Sustain & Other Reductions	Unallocated capital (Headroom) and Sustain & other Reductions are distributed equally to Fed Hydro and Transmission.
Capital Assumptions	Energy Efficiency	The Energy Efficiency program is no long capitalized starting in FY 16.
Capital Assumptions	Headroom	Headroom reduced by total EE program in each year.
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 2014 IPR and BP-16 Final Proposal, inflated in the out-years using standard agency assumptions.
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 21.
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 2014 CIR forecasts.
Debt Management Assumptions	Outstanding Federal Bonds	Amount of Federal Bonds as of 3/31/2015.
Debt Management Assumptions	Outstanding Non-Federal Debt	Amount of non-Federal debt as of 5/21/2015.

Category	Topic	Assumption-2015
Debt Management Assumptions	Outstanding Appropriations	Amount of Federal Appropriations as of3/31/2015.
Debt Management Assumptions	Outstanding Capital Leases	Transmission Only – Amount of debt being held as capital leases as of 5/31/2015.
Debt Management Assumptions	CRFM Capital Forecast	Projected capital needs for CRFM activities as of 9/30/2014.
Debt Management Assumptions	Long-Term Federal Capital Forecast	Yearly amounts broken out by category through the next ten years. Every year after that is an average of the first ten years.
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 requirement as of 3/31/2015.
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 as of 3/31/2015.
Debt Management Assumptions	Interest Income Rate	Rate of interest that we expect to earn on funds being held to pay off debt based on Global Insight Forecast.
Debt Management Assumptions	Energy Northwest Regional Cooperation Debt Program (RCD)	Includes all regional cooperation debt transactions (up to $2.94 Billion) through which Energy Northwest issues BPA-supported bonds to refinance debt. That action makes available BPA resources that are then used for the additional repayment to the U.S. Treasury of higher interest Federal Debt
Power Expenses Assumptions	Program Expense (General)	Ties to the Final IPR Report for FY 15-17. FYs 18-30 are inflated from approved Final IPR expenses. 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 FY18 through FY 30 assumes 3.5% Inflation. Does not include a reduction for DOE settlement dollars.
Power Expenses Assumptions	Columbia Generating Station (Decommissioning Trust Fund)	Long Range Plan from FY18 through FY 30 assumes 4 % Inflation. Assumes no significant changes to expected decommissioning costs or fund earnings.

Category	Topic	Assumption-2015
Power Expenses Assumptions	Columbia Generating Station (Neil Insurance)	Consistent with IPR. FY18 through FY 30 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	FY15-17 consistent with the IPR2. Consistent with BOR long range plan through 2021. Beyond that, Reclamation is using a 3% increase for 2022-2030 based on our expected increases in trades & crafts wages.
Power Expenses Assumptions	Corps of Engineers	FY15-17 consistent with the IPR2. Consistent with COE long range plan through 2021. The Corps is using a 3.2% 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 common agency inflation assumptions. 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 at a market index with a floor of \$30.50/MWh and a cap of \$55.50/MWh.
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 2017. (Decrease in tier 1 resources)
Power Expenses Assumptions	Colville Generation Settlement	Assumes common agency inflation assumptions.
Power Expenses Assumptions	Tier 2 Power Purchases	Assumes common agency inflation assumptions. Contracts are set through 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), that the \$4M resource development budget will be held flat and that support services costs will inflate based on agency assumptions after 2021.

Category	Topic	Assumption-2015
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.
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	Assumes common agency inflation assumptions.
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 FY17.
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 FY17.
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.

Category	Topic	Assumption-2015
Power Expenses Assumptions	New resources integration wheeling	Assumes new resources integration wheeling costs are flat.
Power Expenses Assumptions	Residential Exchange	IOU benefits for years 2018 through 2028 were established by settlement agreement (increase 7% per rate period). Increase for 2029-2030 assumed to be 7%.
Power Expenses Assumptions	Conservation Acquisition	Conservation Acquisition is increased based on Employment Cost projections 2018 through 2023, 2024 to 2030 averaged at 3.8% based on 2015 through 2023.
Power Expenses Assumptions	Legacy (Tacoma)	Uncertainty in the exact payment amounts through 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-14	Assumes the IPR-2 determined undistributed reduction continues through 2030. The IPR-2 undistributed reduction to offset expensing conservation terminates with FY17.
Power Expenses Assumptions	PBL- Transmission and Ancillary Services	Assumes a 5% rate of inflation.
Power Rates Assumptions	Loads	TRL 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 PSR 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 KSL 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 LORA's BP-16 study for the Initial Final Proposal.
Power Rates Assumptions	Resources	Both Federal and non-federal/contracted resource amounts rely on forecasts from LORA's BP-16 study for the Initial Final Proposal.

Category	Topic	Assumption-2015
Power Rates 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 imbedded in the Transmission Rate Forecast to out years.
Power Rates 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 2030.
Power Rates Assumptions	Revenue Credits	4h10C was modeled consistent with RevSim and AURORA market price assumptions through 2030. Revenues from other contracts were flat-lined from BP-16 modeled levels for 2016-2017 to contract termination date, or 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 Corp 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 Rates 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 2016 and 2017, applies to 2018 and beyond. These assumptions do not affect overall REP benefit levels, just the distribution of benefits among participants.

Category	Topic	Assumption-2015
Power Rates 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.
Power Rates Assumptions	Market Price Forecast	Aurora market prices at Mid-Columbia modeled through FY 2030.
Power Rates Assumptions	Secondary and Balancing Purchases	Secondary and Balancing purchases are escalated from BP-16 levels by general inflation. Expectations for secondary sales and purchases are modeled in RevSim through 2030, using load and resource assumptions consistent with Power Rates, and Aurora market prices consistent with the escalation assumptions stated above 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 Rates Assumptions	LDD and IRD Costs included in Power Rates	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 2017, and computed based on the modeled PF Tier 1 Average Net Cost of Power through 2030.
Transmission Expenses Assumptions	Program Expense (General)	Program expenses tie to the BP 16 Final Proposal for FY 15-17. Program expenses between FY 18 and FY 30 are inflated off of approved 2014 Final IPR expenses, with exceptions for those programs that have known long-range plans or agreements.
Transmission Expenses Assumptions	Transmission Operations (EIM)	EIM costs continue uninflated.
Transmission Expenses Assumptions	Transmission Operations (O&M)	Common agency inflation assumption, except EIM and Control Center.
Transmission Expenses Assumptions	Transmission Engineering (NERC/WECC Expense)	Assumes adding $2M in 2018 for estimated amount of WECC Peak costs. Assumes a $1M increase over the rate of inflation every 2 year cycle due to likelihood of increasing compliance standards and requirements.
Transmission Expenses Assumptions	Acquisition and Ancillary Services (Non-BBL and BBL Expenses)	Non-BBL and BBL Ancillary costs will remain a flat amount in the out years at the rate assumed in FY17 with exceptions: 1) Settlement costs were increased to be $500k per year beginning in FY18 and then remain uninflated; 2) Transmission Renewables program costs will continue to increase at the rate of inflation; 3) Leases including Avista on-going parallel capacity support will continue uninflated.

Category	Topic	Assumption-2015
Transmission Expenses Assumptions	Undistributed Reduction	Miscellaneous expenses, including costs that are not assigned to specific programs. Assumes the IPR-determined undistributed reduction continues through 2030.
Transmission Expenses Assumptions	Transmission Operations (Control Center)	First, general inflation is applied. Second, an additional plan of forecasts is added to the inflated amounts.
Transmission Expenses Assumptions	Transmission Maintenance (O&M)	Common agency inflation assumption, except for HMEM.
Transmission Expenses Assumptions	Transmission Maintenance (HMEM)	This project captures accounting treatment of Heavy Equipment and Maintenance costs. This treatment will match actuals on the financial reports, so the assumption amount is zero.
Transmission Expenses Assumptions	Transmission Engineering (O&M)	Common agency inflation assumptions, except for WECC/NERC.
Transmission Expenses Assumptions	Transmission Reimbursables	Common agency inflation assumptions.
Transmission Expenses Assumptions	Post-Retirement Benefits	Common agency inflation assumption.
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.
Transmission Rates Assumptions	Point-to-Point sales	Increased based on sales in the queue for the capital builds of I-5. There was no assumption for reduction in the short-term market due to market changes or decrease of Long term firm PTP sales due to asset swaps. There is an assumption of 1350 MW of wind start to come on in FY 18 through FY 2025.
Transmission Rates Assumptions	IS Rates (Southern Intertie)	There was a PDCI upgrade that would be energized FY 17. There is a partial increase for BP-16 with a full effect in BP-18 with the 125 mw.
Transmission Rates Assumptions	Utility Delivery	No assumption of more delivery sales. 0.7% load growth.
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.

Category	Topic	Assumption-2015
Transmission Rates Assumptions	Gen Inputs	Assumes common agency inflation rate..
Transmission Rates Assumptions	Oversupply Rate	Pass thru costs.
Transmission Rates Assumptions	IR and FPT	By FY 2017, there are only a few legacy contracts. Legacy products are assumed to convert to OATT products using the current capacity.