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

BP-20 Rate Case Workshop: Revenue Requirement

July 25, 2018

Overview

- Issues, Assumptions & Updates
- Financial Statements

Issues, Assumption & Updates

Topics

Display of RCD Transactions
Lease Accounting
Transmission Depreciation & Amortization Expense
Leverage Policy
Capital Financing Assumptions
Transmission Replacements
Other Transmission Refinements
Follow-Up on LGIA Impacts

Direct Display of RCD Transactions

- RCD transactions were indirectly included in BP-16 and BP-18.
  - BPA was concerned that it would be committed to a large Treasury payment in the event the RCD refinancing did not occur.
  - The effect of RCD transactions was calculated and included in the revenue requirement, the "RCD Effect."
  - The RCD Effect forces the revenue requirement to the same total as if the RCD transactions had been forecast.

Calculating the RCD Effect

		Base Scenario		**RCD Scenario**		**RCD Effect**	
	($000s)	2018	2019	2018	2019	2018	2019
1	Non-Federal Debt Service	490,562	420,704	250,530	215,113	(240,032)	(205,591)
2	Depreciation	144,092	144,065	144,092	144,065	-	-
3	Amortization	86,796	87,458	86,796	87,458	-	-
4	Federal Net Interest	95,662	100,287	89,224	81,840	(6,438)	(18,447)
5	MRNR	220,252	67,984	478,493	288,354	258,242	220,370
6	Total	1,037,363	820,499	1,049,135	816,831	11,772	(3,668)

Direct Display of RCD Transactions, continued

- Staff propose to directly display any projected RCD transactions in the rate case.
  - Staff propose to bifurcate the Treasury payment. The base payment is the one that BPA commits to in the rate case. This is the payment that counts for a Treasury payment miss. On top of this would be a conditional payment that would only occur if the RCD transactions occur.
  - BPA and EN have a long history of successfully completing refinancings.
  - BPA and EN have significant experience with lines of credit in the event that we are not able to get to market exactly when desired.
- Directly displaying the RCD transactions produces the same total revenue requirement as the current indirect method.
- Impact on BP-20: Minimal at this point. The only RCD transaction anticipated today is a 2020 refinancing to repay of a line of credit expected to be issued in 2019. No RCD2 transactions have been approved although there are discussions underway.

Direct Display of RCD Transactions, continued

- The use of the RCD Effect resulted in rate case forecasts that looked nothing like operating year forecasts or actual results.
- Directly displaying RCD transactions in the revenue requirement will make rate case forecasts more comparable to the operating year.

Excerpt of Q2 FY18 Report

		C		D	E <Note 1
		FY 2018			
		Rate Case	Rate Case w/ Explicit RCD Display	SOY Budget	Current EOY Forecast
	Operating Revenues				
1	Gross Sales (excluding bookout adjustment) <Note 2	$ 2,592,707	$ 2,592,707	$ 2,603,367	$ 2,610,751
18	**Subtotal Power System Generation Resources**	**1,234,066**	**1,234,066**	**1,237,481**	**1,224,363**
24	Other Income, Expenses & Adjustments	(128,728)	(10,000)	(10,000)	(4,199)
25	Non-Federal Debt Service	490,562	250,530	258,344	256,091
26	Depreciation & Amortization	230,888	230,888	230,888	226,339
27	**Total Operating Expenses**	**2,533,417**	**2,412,113**	**2,425,931**	**2,411,299**
28	**Net Operating Revenues (Expenses)**	**293,995**	**415,299**	**417,233**	**430,099**
	Interest Expense and (Income)				
29	Interest Expense	105,435	99,502	85,763	89,608
30	AFUDC	(8,379)	(8,379)	(9,420)	(12,580)
31	Interest Income	(1,483)	(1,988)	(520)	(592)
32	**Net Interest Expense (Income)**	**95,572**	**89,134**	**75,823**	**76,436**
33	**Net Revenues (Expenses)**	**198,423**	**326,165**	**341,411**	**353,663**

Lease Accounting

- FASB lease accounting standards will be changing effective FY 2020 which causes BPA to reassess all contracts that could be impacted by the standard. This includes:
  - All Energy Northwest debt
  - Other power-related non-federal debt (Northern Wasco & Cowlitz Falls)
  - Transmission leases
- There will likely be significant changes to where and how these costs appear in financial statements. The changes would be to where costs are mapped on the income statement and statement of cash flows.
- Final decisions have not been made but should be in place by the Initial Proposal.

Impact on Power Non-Federal Debt

- Power's non-federal debt probably will look like federal debt in the financial statements.
  - Interest will be included in the non-federal interest line of the Net Interest calculation.
  - Principal payments will appear in the statement of cash flows.
  - A new amortization expense will appear on the income statement. Amortization will be calculated on a straight-line basis:
    - CGS will be over the remaining life of the license, December 31, 2043.
    - Project 1 & 3 regulatory asset amortization period not yet determined. We used 2044 for this workshop.
    - Northern Wasco will be through 2025 when the debt is fully repaid.
    - Cowlitz Falls will be through 2032 when the debt is fully repaid.
- The Minimum Required Net Revenues (MRNR) calculation will be affected.
  - Non-federal amortization expense and the non-federal principal payments will be included in the MRNR calculation.
  - There will probably be MRNR in all years.
- The revenue requirement should not be any higher because of the change to the accounting treatment.

Impact on Power Non-Federal Debt, continued

- Changing the mapping does not affect total costs, in red, which remain the same in both scenarios.

		Current Accounting 2022		Potential Accounting 2022
1	Non-Federal Debt Service	**491,467**	Amortization Expense (NEW)	244,136
2				
3	Composed of:		Non-Federal Interest	227,769
4	WNP 1 Interest	39,322		
5	CGS Interest*	139,281	Impact on MRNR	19,562
6	WNP 3 Interest	45,530		
7	N. Wasco Interest	355	Total	**491,467**
8	Cowlitz Falls Interest	3,280		
9	**Total Interest**	227,769		
10				
11	WNP 1 Principal	-	MRNR Calculation	
12	CGS Principal *^	256,660	Amortization Expense	244,136
13	WNP 3 Principal	1,425	Non-Federal Principal	263,698
14	N. Wasco Principal	1,593	Difference	(19,562)
15	Cowlitz Falls Principal	4,020		
16	**Total Principal**	263,698		
*	Includes interest or principal on fuel, net of TVA revenues			
^	Does not include repayment of EN lines of credit which are already included in the MRNR calculation			

Impact on Transmission Leases

Income Statement Effects	Finance Lease	Operating Lease
Programmatic Expenses		X
Interest Expense	X	In Review
Depreciation	X	In Review
Minimum Required Net Revenues (MRNR)*	X	

**Included in the calculation of MRNR, as a use of cash*

- Updated categorization of leases expected under the new standard
  - Expecting to see a shift between the finance and operating lease categories, with an increased number of finance leases currently anticipated.
- Treatment of finance leases is expected to remain the same, with potential modifications to operating leases
  - Operating leases have historically been part of the respective programmatic expense line items.
  - Per the lease guidance, balance sheet changes will occur to recognize operating leases as assets and liabilities, which will be reduced over time on the accounting records as the principal payments are made. The effect of this treatment on depreciation within the income statement is still under review. However, as the asset is reduced by principal, currently do not anticipate an added depreciation expense.
  - Income statement geography changes may occur to account for the operating leases. Reviewing whether the interest that currently resides in programmatic expenses may be split into a separate line item.

Transmission Depreciation & Amortization Expense

- Transmission depreciation expense is increasing
  - BPA is using a new depreciation study. Depreciation studies are performed every 5-6 years.
  - Depreciation rates are higher primarily because of higher net cost of retirement.
  - Enhancements occurred to the depreciation forecast calculations to be inclusive of all applicable FERC accounts, based on the updated depreciation study.
  - Combining the new depreciation study with updated plant results in a $46 million/year increase to transmission depreciation expense.

- Transmission amortization expense is increasing
  - BPA terminated the South of Allston (SOA) project in 2017. Approximately $130 million was spent on the project.
  - The administrator chose to treat the SOA spending as a regulatory asset and amortize it over five years, beginning in BP-20, at $26 million/year. The spending had been on planning studies which have a 2-5 year life.

Leverage Policy

- The leverage policy record of decision (ROD) is not expected until later this summer. The comment period was extended until August 2, 2018.
- No decisions have been made about how the policy will affect BP-20.
  - There was never an expectation that it would affect power.
  - For transmission, the policy includes a phase-in period for BP-20. Interpretation of that clause is open for comment.
  - Current revenue requirements do not include the application of the policy in BP-20.
- The IPR workshop included initial estimates of the ending BP-18 and ending BP-20 debt to asset ratios, shown below. These estimates will change as variables are updated for the Initial Proposal.

	BP-18	BP-20	Change
Power	93.35%	91.44%	-1.91%
Transmission	81.49%	82.55%	1.06%

Capital Financing Assumptions

- Power:
  - Prepay funds are expected to be fully expended in 2020 to finance hydro capital investments. The last $82 million had been used to accelerate the savings of the RCD refinancings.
  - All other federal capital investments are financed with federal debt.
- Transmission:
  - Projected federal investments are financed with federal debt (75%) or lease purchase funds (25%).
  - The reserve financing assumption of $15 million/year has been removed. The use of reserves is governed by the Financial Reserves Policy.
- Deferred Borrowing:
  - Deferred borrowing represents cash used to pay for capital investments before funds are borrowed from the treasury.
  - BPA usually carries a large deferred borrowing balance during the operating year.
  - In rate cases, it is assumed that all deferred borrowing is converted to debt.
  - In BP-20, it will be assumed that a deferred borrowing balance will be carried until the end of the rate period at which point it will be converted to debt.
  - This will reduce interest expense during the rate period because the treasury bonds will not be issued until the last month of the rate period.

Transmission Replacements

- Staff propose a much simplified methodology for forecasting Transmission replacement capital investments in the repayment period.
- In calculating level debt service over the 35-year repayment period, the repayment model includes assumptions about capital investments over the repayment period.
- The current method is an actuarial approach. It is very complex and difficult to explain and understand. It uses Iowa Curves and the Handy-Whitman Index to calculate a stream of future investments based on BPA's historical investments. Replacements are calculated by FERC account for the major components of the FCRTS.
- The proposed approach is based on the IPR capital forecast, most of which is a replacement program.
- This is consistent with how replacements are determined on the Power side.
- This approach is much simpler and easier to reproduce.
- Replacements, under either approach, are not a driver in repayment results.

Other Transmission Refinements

- California Oregon Intertie (COI) credits
  - Scheduled to be repaid by the end of BP-18 and associated MRNR calculation was removed for BP-20.
- Ancillary Services plant forecasting update
  - Implemented methodology to utilize the forecast by FERC account and split based on the historic ratio of Ancillary Services and General Plant within the account. This provides a proxy for future expectations of plant investment, based on historic actuals.
- LGIA modeling refinements
  - Model updates occurred to improve tracking of historic and forecast LGIA investment for depreciation and investment base purposes.

Follow-Up on LGIA Impacts

- Revenue requirement tests:
  1. Forecast of total revenues must be at least equal to total expenses. (Non-negative net revenues)
  2. Cash from proposed rates must be sufficient to ensure repayment of debt. (Non-negative cash flow)
- Meeting the tests:
  - In developing revenue requirements, the initial assumption is that revenues match expenses exactly, thereby meeting the first test.
  - For the cash flow analysis, if the non-cash revenues and expenses are less than the cash requirements (debt repayment), minimum required net revenue (MRNR) is added, which serves as a net revenue target.
- LGIA non-cash effects:
  - Increase to Revenues: Although revenues are recognized from the sales to the generators, these are non-cash as BPA is providing billing credits to repay the contributions to construction.
  - Increase to Depreciation Expense: With the increase in assets, there is increased depreciation, which is a non-cash expense.
  - Increase to Interest Expense: Interest accrues on the funds provided for construction, which is a non-cash expense as the interest is repaid through billing credits.

Follow-Up on LGIA Impacts, continued

Within the cash flow statement, each of the LGIA non-cash line items impact the Cash from Current Operations:

Non-Cash Effects	Effect on Cash from Current Operations
Increase to Revenues	Reduction to Cash
Increase to Depreciation Expense	Increase to Cash
Increase to Interest Expense	Increase to Cash
Net Effect:	Negative Cash Flow

- LGIA MRNR:
  - When the non-cash line items result in negative cash flow, LGIA MRNR is added in order to meet the cash flow test.

Financial Statements

Topics

Power Financial Statements

Transmission Financial Statements

Caveat

- The following tables include repayment modeling results revised since the IPR capital-related cost presentation.
- We continue to assess ways to bring down costs further.
- The Initial Proposal will incorporate all modeling updates as well as final decisions on the issues discussed earlier (e.g. lease accounting treatment).

Power Income Statement

	($000s)	A 2020	B 2021
1	OPERATING EXPENSES		
2	POWER SYSTEM GENERATION RESOURCES		
3	OPERATING GENERATION RESOURCES	703,445	759,192
4	OPERATING GENERATION SETTLEMENT PAYMENTS	22,997	22,997
5	NON-OPERATING GENERATION	1,631	1,531
6	CONTRACTED POWER PURCHASES*	3,100	3,100
7	AUGMENTATION POWER PURCHASES*		
8	EXCHANGES & SETTLEMENTS*		
9	RENEWABLE GENERATION	36,523	34,869
10	GENERATION CONSERVATION	121,530	121,644
11	POWER NON-GENERATION OPERATIONS	84,348	86,367
12	PS TRANSMISSION ACQUISITION AND ANCILLARY SERVICES*	202,512	197,788
13	F&W/USF&W/PLANNING COUNCIL	291,789	292,004
14	GENERAL AND ADMINISTRATIVE/SHARED SERVICES	78,836	79,916
15	OTHER INCOME, EXPENSES AND ADJUSTMENTS	-	-
16	NON-FEDERAL DEBT SERVICE	335,757	491,467
17	DEPRECIATION	139,221	141,185
18	AMORTIZATION	86,651	88,840
19	TOTAL OPERATING EXPENSES	2,108,339	2,320,899
20			
21	INTEREST EXPENSE:		
22	INTEREST		
23	APPROPRIATED FUNDS	55,777	55,376
24	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)
25	BONDS ISSUED TO U.S. TREASURY	61,584	71,519
26	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	-	-
27	NON-FEDERAL INTEREST	9,826	8,863
28	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(13,413)	(14,083)
29	INTEREST CREDIT ON CASH RESERVES	(1,918)	(2,747)
30	NET INTEREST EXPENSE	65,919	72,991
31			
32	TOTAL EXPENSES	2,174,259	2,393,890
33			
34	MINIMUM REQUIRED NET REVENUE	196,670	70,968
35	PLANNED NET REVENUE FOR RISK	40,000	40,000
36	PLANNED NET REVENUE, TOTAL (34+35)	236,670	110,968
37			
38	**TOTAL REVENUE REQUIREMENT**	**2,410,929**	**2,504,858**
*	Costs determined in rate case		

Power Statement of Cash Flows

		Current Accounting	
		A	B
	($000s)	2020	2021
1	CASH FROM OPERATING ACTIVITIES		
2	MINIMUM REQUIRED NET REVENUE 1/	196,670	70,968
3	NON-CASH ITEMS:		
4	NON-FEDERAL INTEREST	9,826	8,863
5	DEPRECIATION AND AMORTIZATION	225,872	230,025
6	NON-CASH EXPENSES	-	-
7	DSR REFINANCING FREE-UP	16,590	-
8	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	-	-
9	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)
10	NON-CASH REVENUES	(30,600)	(30,600)
11	CASH PROVIDED BY OPERATING ACTIVITIES	372,421	233,318
12			
13	CASH FROM INVESTMENT ACTIVITIES		
14	INVESTMENT IN:		
15	UTILITY PLANT (INCLUDING AFUDC)	(293,470)	(316,349)
16	ENERGY EFFICIENCY		
17	FISH & WILDLIFE	(47,266)	(47,266)
18	CASH USED FOR INVESTMENT ACTIVITIES	(340,736)	(363,615)
19			
20	CASH FROM BORROWING AND APPROPRIATIONS:		
21	INCREASE IN BONDS ISSUED TO U.S. TREASURY	226,940	327,479
22	REPAYMENT OF BONDS ISSUED TO U.S. TREASURY	(139,100)	(218,571)
23	INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS	31,796	36,136
24	REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS	(40,002)	-
25	REPAYMENT OF NON-FEDERAL OBLIGATIONS	(169,000)	-
26	CUSTOMER PROCEEDS	82,000	-
27	PAYMENT OF IRRIGATION ASSISTANCE	(24,319)	(14,747)
28	CASH PROVIDED BY BORROWING AND APPROPRIATIONS	(31,685)	130,297
29			
30	ANNUAL INCREASE (DECREASE) IN CASH	-	-
31			
32	PLANNED NET REVENUE FOR RISK	40,000	40,000
33			
34	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	40,000	40,000

1/ Minimum required net revenues are added to ensure suffcient cash flow is available to repay the federal investment.

Power Comparison to BP-18

For comparability, this excludes power purchases and residential exchange costs calculated in BP-18.

		Annual Average	
			Current Acctg
	($000s)	BP-18	BP-20
1	OPERATING EXPENSES		
2	POWER SYSTEM GENERATION RESOURCES		
3	OPERATING GENERATION RESOURCES	731,564	731,319
4	OPERATING GENERATION SETTLEMENT PAYMENTS	22,805	22,997
5	NON-OPERATING GENERATION	1,517	1,581
6	CONTRACTED POWER PURCHASES*	3,100	3,100
7	AUGMENTATION POWER PURCHASES*		
8	EXCHANGES & SETTLEMENTS*		
9	RENEWABLE GENERATION	38,696	35,696
10	GENERATION CONSERVATION	126,227	121,587
11	POWER NON-GENERATION OPERATIONS	92,365	85,357
12	PS TRANSMISSION ACQUISITION AND ANCILLARY SERVICES*	213,342	200,150
13	F&W/USF&W/PLANNING COUNCIL	321,961	291,897
14	GENERAL AND ADMINISTRATIVE/SHARED SERVICES	80,385	79,376
15	OTHER INCOME, EXPENSES AND ADJUSTMENTS	(101,448)	-
16	NON-FEDERAL DEBT SERVICE	455,633	413,612
17	DEPRECIATION	144,079	140,203
18	AMORTIZATION	87,127	87,745
19	TOTAL OPERATING EXPENSES	2,217,353	2,214,619
20			
21	INTEREST EXPENSE:		
22	INTEREST		
23	APPROPRIATED FUNDS	82,991	55,577
24	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)
25	BONDS ISSUED TO U.S. TREASURY	59,876	66,552
26	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	-	-
27	NON-FEDERAL INTEREST	11,188	9,344
28	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(8,343)	(13,748)
29	INTEREST CREDIT ON CASH RESERVES	(1,799)	(2,332)
30	NET INTEREST EXPENSE	97,975	69,455
31			
32	TOTAL EXPENSES	2,315,327	2,284,074
33			
34	MINIMUM REQUIRED NET REVENUE	144,118	133,819
35	PLANNED NET REVENUE FOR RISK	20,000	40,000
36	PLANNED NET REVENUE, TOTAL (34+35)	164,118	173,819
37			
38	**TOTAL REVENUE REQUIREMENT**	2,479,445	2,457,893
*	Costs determined in rate case		

Transmission Income Statement

		A	B
	(000's)	2020	2021
1	OPERATING EXPENSES		
2	TRANSMISSION OPERATIONS	168,852	163,878
3	TRANSMISSION ENGINEERING	53,683	59,733
4	TRANSMISSION MAINTENANCE INCLUDING ENVIRONMENT	174,337	174,666
5	TRANSMISSION ACQ & ANCILLARY SERVICES	136,726	136,726
6	BPA INTERNAL SUPPORT	93,326	94,705
7	OTHER INCOME, EXPENSES & ADJUSTMENTS	-	-
8	DEPRECIATION & AMORTIZATION	346,786	354,952
9	TOTAL OPERATING EXPENSES	973,710	984,659
10			
11	INTEREST EXPENSE		
12	INTEREST EXPENSE		
13	FEDERAL APPROPRIATIONS	391	381
14	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
15	ON LONG-TERM DEBT	115,369	127,045
16	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
17	DEBT SERVICE REASSIGNMENT INTEREST	4,880	3,943
18	NON-FEDERAL INTEREST (INCL CUSTOMER FUNDED)	100,580	101,306
19	PREMIUMS/DISCOUNTS	-	-
20	AFUDC	(20,170)	(18,809)
21	INTEREST INCOME	(5,107)	(5,399)
22	NET INTEREST EXPENSE	177,532	190,058
23			
24	TOTAL EXPENSES	1,151,242	1,174,717
25			
26	MINIMUM REQUIRED NET REVENUE	1,402	3,301
27	PLANNED NET REVENUES FOR RISK	-	-
28	TOTAL PLANNED NET REVENUE	1,402	3,301
29			
30	**TOTAL REVENUE REQUIREMENT**	**1,152,643**	**1,178,019**

Transmission Cash Flow Statement

		A	B
	(000's)	2020	2021
1	CASH FROM CURRENT OPERATIONS:		
2	MINIMUM REQUIRED NET REVENUE	1,402	3,301
3	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	-	-
4	EXPENSES NOT REQUIRING CASH:		
5	DEPRECIATION & AMORTIZATION	346,786	354,952
6	CUSTOMER FUNDED PROJECTS NET INTEREST	4,268	3,700
7	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
8	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
9	NON-CASH REVENUES		
10	CUSTOMER FUNDED	(18,713)	(18,252)
11	AC INTERTIE CO/FIBER	(3,410)	(3,410)
12	CASH PROVIDED BY CURRENT OPERATIONS	311,923	321,881
13			
14	CASH USED FOR CAPITAL INVESTMENTS:		
15	INVESTMENT IN:		
16	UTILITY PLANT	(478,190)	(482,550)
17	CASH USED FOR CAPITAL INVESTMENTS	(478,190)	(482,550)
18			
19	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
20	INCREASE IN LONG-TERM DEBT	478,190	482,550
21	DEBT SERVICE REASSIGNMENT PRINCIPAL	(19,592)	(20,571)
22	REPAYMENT OF CAPITAL LEASES	(79,361)	(79,543)
23	REPAYMENT OF LONG-TERM DEBT	(212,840)	(221,715)
24	REPAYMENT OF CAPITAL APPROPRIATIONS	(130)	(53)
25	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	166,268	160,669
26			
27	ANNUAL INCREASE (DECREASE) IN CASH	-	-
28	PLANNED NET REVENUES FOR RISK	-	-
29	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	-	-

Transmission Comparison to BP-18

			A	B
		(000's)	BP-18 Average	BP-20 Average
1	OPERATING EXPENSES			
2		TRANSMISSION OPERATIONS	167,529	166,365
3		TRANSMISSION ENGINEERING	57,034	56,708
4		TRANSMISSION MAINTENANCE INCLUDING ENVIRONMENT	177,353	174,501
5		TRANSMISSION ACQ & ANCILLARY SERVICES	115,722	136,726
6		BPA INTERNAL SUPPORT	94,773	94,015
7		OTHER INCOME, EXPENSES & ADJUSTMENTS	(8,043)	-
8		DEPRECIATION & AMORTIZATION	278,793	350,869
9	TOTAL OPERATING EXPENSES		883,160	979,185
10				
11	INTEREST EXPENSE			
12		INTEREST EXPENSE		
13		FEDERAL APPROPRIATIONS	1,588	386
14		CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
15		ON LONG-TERM DEBT	103,798	121,207
16		AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	559
17		DEBT SERVICE REASSIGNMENT INTEREST	9,538	4,411
18		NON-FEDERAL INTEREST (INCL CUSTOMER FUNDED)	87,354	100,943
19		PREMIUMS/DISCOUNTS	278	-
20		AFUDC	(24,776)	(19,490)
21		INTEREST INCOME	(3,176)	(5,253)
22	NET INTEREST EXPENSE		156,196	183,795
23				
24	TOTAL EXPENSES		1,039,356	1,162,980
25				
26	MINIMUM REQUIRED NET REVENUE		4,487	2,351
27	PLANNED NET REVENUES FOR RISK		-	-
28	TOTAL PLANNED NET REVENUE		4,487	2,351
29				
30	**TOTAL REVENUE REQUIREMENT**		**1,043,843**	**1,165,331**

Financial Disclosure

This information was publicly available on July 24, 2018, and contains information not sourced directly from BPA financial statements.