FY 2020-2021

FINAL
AVERAGE SYSTEM COST REPORT

PacifiCorp

July 2019

FY 2020-2021

FINAL
AVERAGE SYSTEM COST REPORT

FOR

PacifiCorp
Docket Number: ASC-20-PA-01

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

July 2019

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1 FILING DATA

Utility: **PacifiCorp**
825 NE Multnomah Street
Portland, Oregon 97232
http://www.pacificorp.com

Parties to the Filing:

Investor-Owned Utilities ("IOUs"):
Avista Corporation ("Avista")
Idaho Power Company ("Idaho Power")
Puget Sound Energy ("Puget")

Consumer-Owned Utilities ("COUs"):
Clark Public Utilities ("Clark")
Public Utility District No. 1 of Snohomish County ("Snohomish")

Average System Cost Base Period: Calendar Year ("CY") 2017

Effective Exchange Period: Fiscal Years 2020–2021, October 1, 2019 – September 30, 2021

Statement of Purpose:

Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act ("Northwest Power Act" or "Act"), 16 U.S.C. § 839c(c), established the Residential Exchange Program ("REP"). Under the REP, any Pacific Northwest utility interested in participating in the REP may offer to sell power to Bonneville Power Administration ("BPA") at the average system cost of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at a rate established pursuant to sections 7(b)(l) and 7(b)(3) of the Act. 16 U.S.C. §§ 839e(b)(1), 839e(b)(3); H.R. Rep. No. 976, Pt. I, 96th Cong., 2d Sess. 60 (1980). The cost benefits established by the REP are passed through directly to the exchanging utilities' residential and farm consumers. 16 U.S.C. § 839c(c)(3). A utility participating in the REP will hereinafter be referred to as a "Utility" or "Exchanging Utility."

The Northwest Power Act grants to BPA's Administrator the authority to determine Utilities' average system cost(s) ("ASC") based on a methodology established in a public consultation proceeding. 16 U.S.C. § 839c(c)(7). The Act specifically requires the Administrator to exclude from ASC three categories of costs:

(A) the cost of additional resources in an amount sufficient to serve any new large single load[1] of the Utility;

(B) the cost of additional resources in an amount sufficient to meet any additional load outside the region occurring after the effective date of this Act; and

(C) any costs of any generating facility which is terminated prior to initial commercial operation.

Id.

The Act limits eligibility for the REP to utilities and load located within the geographical area defined as the "Pacific Northwest" or "region." *See* 16 U.S.C. § 839a(14)(A)-(B). Specifically, "region" is defined as follows:

> the area consisting of the States of Oregon, Washington, and Idaho, the portion of the State of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin; and
>
> any contiguous areas, not in excess of seventy-five air miles from the area referred to in subparagraph (A), which are a part of the service area of a rural electric cooperative customer served by the Administrator on December 5, 1980, which has a distribution system from which it serves both within and without such region.

Id.

BPA has conducted an ASC review to determine PacifiCorp's ASC for fiscal years ("FY") 2020-2021 based on BPA's 2008 ASC Methodology ("2008 ASCM"). *See* 18 C.F.R. Part 301, *Sales of Electric Power to the Bonneville Power Administration, Revisions to Average System Cost Methodology*, 74 Fed. Reg. 47,052 (2009).

This FY 2020-2021 Final Average System Cost Report ("Final ASC Report") describes BPA's ASC review process and evaluation used to implement the 2008 ASCM and the results of BPA's ASC Filing review.

For more information regarding the 2008 ASCM, please refer to the Federal Energy Regulatory Commission's ("FERC") final ruling and the *2008 ASCM*, available at Federal Energy Regulatory Commission's Final Ruling and the 2008 ASCM, and the *Average System Cost Methodology Final Record of Decision ("2008 ASCM ROD")*, June 30, 2008, available at BPA's Residential Exchange Program website.

[1] A new large single load (NLSL) is defined in section 3(13) of the Northwest Power Act, and determined by BPA as specified in power sales contracts with its Regional Power Sales customers. 16 U.S.C. § 839a(13). See section 2.6 of this report for more details.

General information regarding the ASC Review Process can be found at [BPA's Residential Exchange Program] website.

NOTE: If a filing Utility or an intervenor wished to preserve any issue related to an ASC Filing for subsequent administrative or judicial appeal, it must have raised such issue in its comments on the Draft ASC Report covering that ASC Filing. If a party failed to do so, the issue is waived for subsequent appeal. *See* Rules of Procedure for BPA's ASC Review Processes ("Rules of Procedure"), § 3.6.1.3.

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2 AVERAGE SYSTEM COST SUMMARY

2.1 PacifiCorp Background[2]

PacifiCorp, which includes PacifiCorp and its subsidiaries, serves approximately 1.8 million retail customers, including residential, commercial, industrial, and other customers in a 136,000-square-mile service territory in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho, and California. PacifiCorp owns, or has interests in, a number of thermal, hydroelectric, wind-powered, and geothermal generating facilities, as well as electric transmission and distribution assets. PacifiCorp also buys and sells electricity on the wholesale market with public and private utilities, energy marketing companies, and incorporated municipalities. PacifiCorp is subject to state and Federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal-mining and environmental remediation services. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company ("MEHC"), based in Des Moines, Iowa, that owns subsidiaries principally engaged in energy businesses. MEHC is a consolidated subsidiary of Berkshire Hathaway Inc.

PacifiCorp owns 16,300 miles of transmission lines and 62,930 miles of distribution lines. In 2017, PacifiCorp's 80 generating plants had nameplate generation capacity of 11,669 megawatts ("MW"), and produced 52,432,064 megawatt hours ("MWh"). The focus of the report includes the generation and transmission for the states of Oregon, Washington, and Idaho only. Generation statistics for 2017 are shown in the table below.

PacifiCorp 2017 Total System Capacity and Energy				
Type	**Capacity (MW)**	**Percent**	**Energy (MWh)**	**Percent**
Hydro	1,048	9	4,729,189	7
Steam	6,431	55	39,882,510	60
Other	4,190	36	7,820,365	12
Purchases			14,002,749	21
Total	**11,669**	**100**	**66,434,813**	**100**

PacifiCorp, 2017 FERC Form No. 1, April 13, 2018.

2.2 Base Period ASC

The 2008 ASCM requires Utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 filing for IOUs or the most recent audited financial statements (Annual Reports) for COUs. The Base Period data are

[2] Information stated in this section was sourced from PacifiCorp's website and FERC Form 1.

derived from the Base Period FERC Form 1s (for IOUs) or the Annual Reports (for COUs), and underlying accounting system data for all Utilities. For purposes of the FY 2020−2021 filing period, the Base Period is CY 2017. The submitted information includes the "Appendix 1," an Excel-based workbook populated with financial and load data used to calculate the Base Period ASC.

Table 2.2-1 summarizes the Base Period ASC based on (1) the information contained in PacifiCorp's June 4, 2018, ASC Filing ("As-Filed"), and (2) as adjusted by BPA (including errata corrections filed by PacifiCorp) in this Final ASC Report. This table does not reflect the Exchange Period (defined below) ASC, which is noted in subsequent tables.

Table 2.2-1: CY 2017 Base Period ASC
(Results of Appendix 1 calculations)

	June 4, 2018 As-Filed	**July 25, 2019 Final ASC Report**
Production Cost	$1,410,621,210	$1,410,940,923
Transmission Cost	$300,519,381	$300,678,693
(Less) NLSL Costs[3]	$0	$0
Contract System Cost ("CSC")	**$1,711,140,591**	**$1,711,619,616**
Total Retail Load (MWh)	21,024,246	21,024,246
(Less) NLSL	0	0
Total Retail Load (Net of NLSL)	21,024,246	21,024,246
Distribution Losses	909,880	909,880
Contract System Load ("CSL")	**21,934,126**	**21,934,126**
CY 2017 Base Period ASC (CSC/CSL)	**$78.01/MWh**	**$78.03/MWh**

2.3 FY 2020-2021 Distribution Loss Factor

The 2008 ASCM requires a Utility to include with its ASC Filing a current distribution loss analysis as described in Endnote e. *See* 18 C.F.R. § 301, End. e.

Losses are the distribution energy losses occurring between the transmission portion of the Utility's system and the meters measuring firm energy load. *Id.* The distribution loss can be measured using one of the three methods outlined in Endnote e of the 2008 ASCM: (1) a loss study, (2) revenue grade meter readings, or (3) calculating a

[3] As of 2017, PacifiCorp has one NLSL on record. PacifiCorp's average cost to serve an NLSL ($60.82/MWh) is less than its ASC ($78.03/MWh). Therefore, removing the costs of serving NLSLs would raise PacifiCorp's ASC. The ASCM does not permit a Utility's ASC to increase as a result of excluding the cost of resources used to serve NLSLs. See 2008 Average System Cost Methodology, Final Record of Decision, at 93, and PacifiCorp's Final Report Appendix 1, Sch 4 –Average System Cost tab.

five-year average total system loss factor using data from the FERC Form 1 or a comparable data source. *Id.*

BPA reviewed and accepted PacifiCorp's Distribution Loss Factor calculations. For the purposes of this Final ASC Report, BPA used the Distribution Loss Factor of 4.33 percent included in PacifiCorp's As-Filed Appendix 1.

2.4 FY 2020-2021 Exchange Period ASC

BPA and intervenors had the opportunity to review, evaluate, and comment on each Utility's Appendix 1 historical costs and forecast loads submitted in the ASC Review Process. Once the Base Period ASC was determined, the cost data were escalated forward using the "ASC Forecast Model," an Excel-based macro model, to the midpoint of the Exchange Period, which in this instance is October 1, 2020. For purposes of the FY 2020-2021 ASC Review Period, the Exchange Period is October 1, 2019, through September 30, 2021 ("Exchange Period").

A Utility's As-Filed Exchange Period ASC may increase or decrease by the time of the Final ASC Report because of adjustments made during the ASC Review Process, such as updates to BPA's natural gas and market price forecasts, errata corrections, or other changes made by BPA. For all Utilities, BPA updated natural gas and market price forecasts to match natural gas and market price forecasts in the Final Proposal for the BP-20 Rate Proceeding. See the "Input" tab of the ASC Forecast Model for the Utility's (1) As-Filed and (2) BPA-Adjusted models for additional details.

Although PacifiCorp's Base Period ASC remains unchanged, its Exchange Period ASC increased from the Draft ASC Report due to higher natural gas and market prices. In October 2018, a portion of the Enbridge natural gas pipeline ruptured in British Columbia, Canada. The ensuing outage, repairs, and inspections reduced import capacity from Canada to the Pacific NW at Sumas throughout the winter, and will likely continue to do so through this summer. This restriction, in addition to the strong winter demand, escalated the natural gas price throughout the region and increased the natural gas price used to calculate the FY 2020-2021 ASCs from 2.004 $/MMBtu (Draft ASC Reports) to 5.234 $/MMBtu (Final ASC Reports).

All other adjustments, if any, made during the review are explained in section 4 of this Final ASC Report.

For the COUs only, BPA updated Rate Period High Water Marks ("RHWMs") in the 'Tiered Rates' tab of the Appendix 1, and the rates in the 'PF-Rates' tab of the Forecast Model to match what is being used in the BP-20 Final Proposal. In the 'Tiered Rates' tab of the Forecast Model, BPA calculated the total cost of power purchased from BPA.

Table 2.4-1 identifies the Exchange Period ASC for PacifiCorp, and as adjusted by BPA (including erratum filed by PacifiCorp) for this Final ASC Report. The ASC shown will be the Utility's ASC for the entire Exchange Period unless the Utility acquires (or loses) a major resource as defined by the 2008 ASCM and discussed in section 2.5 of this Final ASC Report, or the Utility is subject to NLSL adjustments as discussed in section 2.6.

Table 2.4-1: Exchange Period FY 2020-2021 ASC ($/MWh) With No Major Resource Additions or Removals

Date	June 4, 2018 As-Filed	July 25, 2019 Final ASC Report
FY 2020-2021	$76.07	$79.43

2.5 ASC Major Resource Additions or Removals

Under the 2008 ASCM, a Utility's ASC may be adjusted to reflect the addition or loss of a major resource if such resource commences commercial operation (or ceases production) at any point between the end of the Base Period and the end of the Exchange Period. Such new or existing resource must be used to meet a Utility's retail load during the Exchange Period.

For ASC calculation purposes, a major resource adjustment may be included in an IOU's ASC at the commencement of the Exchange Period if such resource becomes commercially operational (or ceases production) after the Base Period, but before the Exchange Period begins. For COUs only, a major resource adjustment may be included in a COU's ASC at the commencement of or during the Exchange Period.

Before a Utility's ASC is adjusted to reflect the addition or loss of a major resource, the Utility must demonstrate that the proposed resource will meet the materiality requirements set forth in the 2008 ASCM. Section 301.4(c) of the 2008 ASCM provides that only a resource that affects a Utility's Base Period ASC by two and one-half percent (2.5%) or more will be considered a major resource. 18 C.F.R. § 301.4(c)(4). This is the materiality threshold. The 2008 ASCM also allows Utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. Id. However, each individual resource in the stack must result in a change in Base Period ASC of one-half percent (0.5%) or more. *Id., see also* section 3.2.14 of this Final ASC Report.

In order for major resource additions to be included in a Utility's Exchange Period ASC at the beginning of the Exchange Period, a Major Resource Attestation must be received by BPA no later than the tenth (10th) business day after the Exchange Period begins.

Table 2.5-1 summarizes the major resource additions, prior to any NLSL adjustments, that are projected to become commercially operational, and major resources that will cease to be commercially operational, prior to the beginning of the Exchange Period (*i.e.*, January 1, 2018 − September 30, 2019).

PacifiCorp has no major resources coming on line or being removed prior to the FY 2020-2021 Exchange Period.

Table 2.5-1: Major Resources Coming On Line or Being Removed *Prior to* the Exchange Period

As-Filed FY 2020-2021 Exchange Period ASC ($/MWh)				
Resource	**N/A**	**N/A**	**N/A**	**N/A**
Expected On Line or Removal Date				
Delta*				

Final ASC Report FY 2020-2021 Exchange Period ASC ($/MWh)				
Resource	**Group 1**	**N/A**	**N/A**	**N/A**
Expected On Line or Removal Date				
Delta*				

* The Delta is the incremental change in the ASC as major resources come on line or are removed.

Although the 2008 ASCM permits a Utility's ASC to be adjusted to reflect the inclusion of a major new resource that comes on-line during the Exchange Period, as part of the 2012 Residential Exchange Program Settlement Agreement, BPA Contract No. 11PB-12322 ("2012 REP Settlement"), all six regional IOUs agreed to waive this right: "Each IOU waives . . . the right to include in its ASC. . . the cost of any major resource addition forecasted to occur during the Exchange Period as allowed by the ASC Methodology." 2012 REP Settlement, § 6.4. As a result of this waiver, the ASC reports do not include major resource additions that are scheduled to come on line during the Exchange Period for any IOU. [4]

2.6 NLSL Adjustment

An NLSL is any load associated with a new facility, an existing facility, or an expansion of an existing facility that was not contracted for or committed to ("CF/CT") prior to September 1, 1979, and which will result in an increase in power requirements of ten average megawatts ("aMW") or more in a consecutive 12-month period. 16 U.S.C. § 839a(13)(A)-(B).

By law, NLSLs and associated resource costs in an amount sufficient to serve them are not included in Utilities' ASCs. *See* 16 U.S.C. § 839c(c)(7)(A). In addition, the ASCM does not permit a Utility's ASC to increase as a result of excluding the cost of resources used to serve NLSLs. *See* 2008 Average System Cost Methodology, Final Record of Decision, at 93. In such cases, BPA will not remove a Utility's NLSL and associated costs. BPA determines the cost of resources in an amount sufficient to serve NLSLs through the methodology provided in Endnote d of the 2008 ASCM and section 2.7 of this Final ASC Report.

[4] The exchanging COUs did not make such a waiver and will continue to include major new resource additions during the Exchange Period under the rules of the 2008 ASCM.

NLSLs are not determined in the ASC Review Process. Instead, NLSLs are identified through a separate process conducted by BPA's NLSL Staff, which is tasked with implementing BPA's NLSL policy. The ASC Review Process determines the cost of resources in an amount sufficient to serve the Utility's NLSL and then excludes these costs from the Utility's ASC.

As of 2017, PacifiCorp has one NLSL on record. However, because the cost to serve PacifiCorp's NLSL is less than PacifiCorp's ASC, removing the NLSL (and its associated cost) would increase PacifiCorp's ASC. The 2008 ASCM does not allow an ASC to increase due to the addition or removal of an NLSL; as such, BPA will not remove the NLSL and associated costs in PacifiCorp's Exchange Period ASC. PacifiCorp has no other NLSLs currently under review.

Table 2.6-1: New Large Single Loads Under Review

As-Filed FY 2020-2021 NLSL Load Amount (MWh)	
NLSL(s)	**Load**
N/A	N/A

Final ASC Report FY 2020-2021 NLSL Load Amount (MWh)	
NLSL(s)	**Load**
N/A	N/A

Table 2.6-2: New Large Single Loads that Begin Taking Power *Prior to* the Exchange Period

As-Filed FY 2020-2021 Exchange Period ASC (MWh)				
Customer	**N/A**	**N/A**	**N/A**	**N/A**
Expected Start Date				

Final ASC Report FY 2020-2021 Exchange Period ASC (MWh)				
Customer	**N/A**	**N/A**	**N/A**	**N/A**
Expected Start Date				

Table 2.6-3: New Large Single Loads that Begin Taking Power *During* the Exchange Period

As-Filed FY 2020-2021 Exchange Period ASC (MWh)				
Customer	**N/A**	**N/A**	**N/A**	**N/A**
Expected Start Date				

Final ASC Report FY 2020-2021 Exchange Period ASC (MWh)				
Customer	**N/A**	**N/A**	**N/A**	**N/A**
Expected Start Date				

2.7 NLSL Formula Rate

Beginning with the FY 2014–2015 Exchange Period, BPA and Utilities agreed to use a formula rate calculation to remove resource costs from a Utility's ASC when an NLSL occurs after the Base Period. The reason was to alleviate additional administrative and calculation issues surrounding NLSLs taking power during an Exchange Period.

Base Period NLSLs will remain constant throughout the duration of the Exchange Period (*see* FY 2012-2013 Final ASC Report, section 5.2.2).

For purposes of this Final ASC Report, no Utility identified potential new NLSLs taking power prior to or during the FY 2020-2021 Exchange Period. However, in the event a Utility learns it will begin to serve an NLSL during this period, even though the NLSL is not identified herein, BPA will review and evaluate the NLSL and, as necessary, calculate a new ASC using the inputs and formula method as defined below:

$$ASC = \frac{\text{Contract System Cost} - (\text{Cost of Serving New NLSL} * \text{Actual New NLSL MWh})}{\text{Contract System Load MWh} - \text{Actual New NLSL MWh}}$$

Tables 2.7-1 and 2.7-2 show the inputs necessary to calculate a Utility's Exchange Period ASC using the above NLSL Formula Rate. The tables include the inputs Contract System Cost ($), Cost of Serving NLSL ($/MWh), and Contract System Load (MWh). A Utility's Contract System Cost and Cost of Serving NLSL will change with each new resource addition.

Table 2.7-1: NLSL Formula Rate Inputs:
Contract System Cost and Cost of Serving NLSL

Inputs for both *Prior to* and *During* the Exchange Period			
	Timing of New Resource	**Contract System Cost ($)**	**Cost of Serving NLSL ($/MWh)**
None	No new resources coming on line	$ 1,682,951,042	N/A[5]
Prior to	N/A	N/A	N/A
During	N/A[6]	N/A	N/A

Table 2.7-2: Formula Rate Input:
Contract System Load

FY 2020-2021 Contract System Load (MWh)
21,188,922

[5] During the Exchange Period, PacifiCorp's average cost to serve an NLSL ($75.05 MWh) would be less than its FY 2020-2021 ASC ($79.43.MWh). Therefore, removing the costs of serving new NLSLs would raise PacifiCorp's ASC. The ASCM does not permit a Utility's ASC to increase as a result of excluding the cost of resources used to serve NLSLs. See 2008 Average System Cost Methodology, Final Record of Decision, at 93.

[6] Under the 2012 REP Settlement Agreement, IOUs no longer include new resource additions during the Exchange Period. COUs will continue to include new resource additions during the Exchange Period under the rules of the 2008 ASCM.

3 FILING REQUIREMENTS

3.1 ASC Review Process – FY 2020-2021

Utilities' ASCs are established in BPA's ASC Review Processes. The ASC Review Processes for FY 2020-2021 began on June 4, 2018, with the submittal of ASC Filings by the following eight Utilities: Avista, Clark, Idaho Power, NorthWestern, PacifiCorp, Portland General, Puget, and Snohomish.

Notice of the ASC Review Processes was provided on BPA's REP public website, BPA's Secure REP website and via email. The Utilities posted ASC Filings on BPA's Secure REP website by the June 4, 2018, filing deadline. BPA released the FY 2020-2021 ASC Forecast Model in late June, 2018; the model included updated data to be consistent with the BP-20 Rate Proceeding (see section 3.4). Each Utility was then required to run the Forecast Model with its associated As-Filed Appendix 1 to develop its As Filed Exchange Period ASC. PacifiCorp posted its ASC Forecast Model to the Secure REP website on July 2, 2018.

Parties interested in reviewing a Utility's ASC had the opportunity to request access to the Utility's ASC Filing by contacting BPA. Parties wishing to formally intervene in a Utility's ASC proceeding could file an intervention by the date identified in BPA's ASC Review Process schedule. Intervenors were afforded the opportunity to request data, submit comments, and raise issues with the Utilities' ASCs throughout a three month discovery period; the filing Utilities, in turn, were afforded the opportunity to respond to requests for data, raise and respond to issues, and answer any questions relative to the ASC Filings. BPA engaged in the discovery process throughout the entire ASC Review Process.

Draft ASC Reports were issued January 14, 2019, for each of the eight Utilities. The schedule afforded parties with an approximately three-month period (through April 17, 2019) in which to submit comments to the Draft ASC Reports. See sections 4 and 5 to review comments, if any, submitted by the Utilities and intervenors. Additionally, BPA offered to hold both a clarification workshop and oral argument if requested by any party. BPA did not receive any requests, and as a result, neither event was held.

This Final ASC Report reflects BPA's findings following its review of PacifiCorp's ASC Filing and addresses the errata, issues and questions, if any, raised by the Utility, intervenors, and/or BPA during the ASC Review Process.

For details of the ASC Review Period and guidelines, please see the Rules of Procedure available at BPA's Residential Exchange Program website.

Final ASC Reports for each Utility are available at https://www.bpa.gov/Finance/ResidentialExchangeProgram/Pages/FY-20-21-ASC-Utility-Filings.aspx

3.2 Explanation of Appendix 1 Schedules

The Appendix 1 consists of a series of seven schedules and other supporting information that present the data necessary to calculate a Utility's ASC. The schedules and supporting data include the following:

1. Schedule 1 – Plant Investment/Rate Base ("Rate Base")
2. Schedule 1A – Cash Working Capital Calculation ("Cash Working Capital")
3. Schedule 2 – Capital Structure and Rate of Return ("Rate of Return")
4. Schedule 3 – Expenses
5. Schedule 3A – Taxes
6. Schedule 3B – Other Included Items ("Other Items")
7. Schedule 4 – Average System Cost
8. Purchased Power and Sales for Resale ("3-Year PP & OSS Worksheet")
9. Load Forecast
10. Distribution Loss Calculation ("Distribution Loss Calc")
11. Distribution of Salaries and Wages ("Salaries")
12. Ratios
13. New Resources – Individual and Grouped
14. Materiality – Individual and Grouped
15. New Large Single Loads ("NLSL Base New-Calc")
16. Tiered Rates
17. Above-RHWM Base Calculation

3.2.1 Schedule 1 – Plant Investment/Rate Base

Schedule 1 of the Appendix 1 establishes the Utility's "Rate Base", which is the value of property on which the Utility is permitted to earn a specific rate of return (calculated in Schedule 2), in accordance with rules set by the state's Public Utility Commission or other regulatory agency. The Rate Base computation begins with a determination of the Gross Electric Plant-In-Service's historical costs for Intangible, General, Production, Transmission, and Distribution Plant.

For Exchanging Utilities that provide electric, natural gas, and water services, only the portion of common plant allocated to electric service is included. These values (and all subsequent values) are entered into the Appendix 1 as line items based on FERC's Uniform System of Accounts. Each line item ("Account") is functionalized to Production, Transmission, and/or Distribution/Other in accordance with the functionalizations prescribed in Table 1 of the 2008 ASCM.

The Net Electric Plant-In-Service is determined next by entering and functionalizing depreciation and amortization reserves in the Appendix 1 and adjusting the above-calculated Gross Electric Plant-In-Service for the depreciation and amortization reserves.

Total Rate Base is then determined by adjusting Net Electric Plant for Cash Working Capital (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, Deferred Debits, Current and Accrued Liabilities, and Deferred Credits.

3.2.2 Schedule 1A – Cash Working Capital

Cash working capital is an estimate of investor-supplied cash used to finance operating costs during the time lag before revenues are collected. This approach (cash) ignores the lag in recovery of non-cash costs of service (depreciation), deferred taxes, and other items. The Cash Working Capital concept is widely used by State Commissions and is the basic premise of the Commissions' proposed working capital formula. The purpose of working capital is to compensate a Utility for funds used in day-to-day operations.[7]

Cash Working Capital is a ratemaking convention that is not included in FERC's Uniform System of Accounts, but is part of all electric utility rate filings as a component of Rate Base. To determine the allowable amount of Cash Working Capital in Rate Base for a utility, BPA allows one-eighth (1/8) of the functionalized costs of total production expenses, transmission expenses, and administrative and general expenses, less purchased power, fuel costs, and public purpose charges, into Rate Base. *See* 18 C.F.R. § 301, End. f.

3.2.3 Schedule 2 – Capital Structure and Rate of Return

Schedule 2 calculates the Utility's rate of return on the utility's Rate Base developed in Schedule 1.

The 2008 ASCM requires IOUs to use the weighted cost of capital ("WCC") from their most recent State Commission rate orders. The return on equity used in the WCC calculation is grossed-up for Federal income taxes at the marginal Federal income tax rate using the formula described in Endnote b of the 2008 ASCM. *See* 18 C.F.R. § 301, End. b. The 2008 ASCM requires a COU to use a rate of return equal to the COU's weighted cost of debt.

3.2.4 Schedule 3 – Expenses

This Schedule represents operations and maintenance expenses for the production, transmission, and distribution of electricity. Each expense item is functionalized as outlined in Table 1 of the 2008 ASCM. Also included in Schedule 3 are additional expenses associated with customer accounts, sales, administrative and general expense, conservation program expense, and depreciation and amortization expense associated with Electric Plant-in-Service. The sum of the items in Schedule 3 reflects the Total Operating Expenses for the Utility.

3.2.5 Schedule 3A – Taxes

This schedule presents allowable ASC costs for Federal employment tax and certain non-Federal taxes, including property and unemployment taxes. COUs are allowed to include state taxes paid "in lieu" of property taxes. State income taxes, franchise fees, regulatory fees, and city/county taxes are accounted for in this Schedule, but are functionalized to Distribution/Other and therefore not included in ASC. Taxes and fees for each state listed are grouped together and entered as "combined" line items for Appendix 1 purposes.

[7] James C. Bonbright *et al., Principles of Public Utility Rates* 244 (2d ed. 1998)

Federal income taxes are included in ASC and are calculated, as applicable, in Schedule 2 − Capital Structure and Rate of Return. For this FY 2020-2021 ASC Review Process, BPA continued to use the Federal Income Tax factor of 35 percent which was current during the CY 2017 Base Period.

3.2.6 Schedule 3B – Other Included Items

This Schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity for others (wheeling). The revenues in this Schedule are deducted from the total costs of each Utility.

3.2.7 Schedule 4 – Average System Cost ($/MWh)

This Schedule summarizes the cost information calculated in Schedules 2 through 3B: Capital Structure and Rate of Return, Expenses, Taxes, and Other Included Items. The Schedule also identifies the Contract System Cost and Contract System Load, as defined below, and calculates the Utility's Base Period ASC ($/MWh).

<u>Contract System Cost ($)</u>
CSC includes the Utility's costs for production and transmission resources, including power purchases and conservation measures, which are includable in and subject to the provisions of the 2008 ASCM. CSC does not include distribution costs or the cost of serving a Utility's NLSLs. CSC is the numerator in the ASC calculation.

<u>Contract System Load (MWh)</u>
CSL is the total regional retail load of a Utility, adjusted for distribution losses and NLSLs. CSL is the denominator in the ASC calculation.

3.2.8 Purchased Power and Sales for Resale

Purchased Power is an Account in Schedule 3 – Expenses, and includes all power purchases the Utility made during the year, including power exchanges. Sales for Resale is an Account in Schedule 3B – Other Included Items, and includes power sales to purchasers other than ultimate consumers. Listed in the information for both accounts are the statistical classification codes for all transactions. *See* FERC Form 1, pages 310-311 for Sales for Resale, and pages 326-327 for Purchased Power, for identification of the classification codes.

3.2.9 Load Forecast

Each IOU is required to provide a four-fiscal-year forecast of its total retail load beginning October 1 of the Base Year, as measured at the meter. For COUs, the total retail loads for this time period are forecast by BPA with the net requirements being computed consistent with the Tiered Rate Methodology ("TRM"). *See* the Tiered Rates tab in Appendix 1.

Additionally, each COU is required to provide a four-fiscal-year forecast of its qualifying residential and farm retail load, as measured at the retail meter. However, due to the 2012 REP

Settlement Agreement, the IOUs are no longer required to submit residential and farm load forecasts.

The total retail load forecasts for all Utilities, and residential and farm load forecasts for the COUs, are adjusted for distribution losses. In addition, the total retail load forecasts are adjusted for any NLSL. The resulting load forecasts are the Contract System Load forecast and Exchange Load forecast, respectively.

3.2.10 Distribution Loss Calculation

Each Utility is required to provide a current distribution loss study as described in Endnote e of the 2008 ASCM. *See* 18 C.F.R. § 301, End. e. The total retail and residential and farm load forecasts are adjusted for distribution losses (and NLSLs when appropriate).

3.2.11 Distribution of Salaries and Wages

This supporting tab is used to determine the Labor Ratio calculations. It includes salaries and wages from relevant operations and maintenance of the electric plant.

3.2.12 Ratios

The Ratios tab calculates all functionalization ratios by assigning costs included in the Utility's FERC Form 1 on a pro rata basis using values taken from the gross plant data (Schedule 1) for Production, Transmission, and Distribution/Other functions, and data taken from the salary and wage tab for Labor functions. For COUs, comparable information comes from detailed salary and wage data used in the Utilities' financial reports.

3.2.13 New Resources – Individual and Grouped

The 2008 ASCM allows a Utility's ASC to adjust during the Exchange Period to reflect the addition or loss of a major resource, when adding or removing the resource results in a change of the Utility's Base Period ASC of two and one-half percent (2.5%) (the materiality threshold) or more. New resources are defined as any new production or new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments. *See* 18 C.F.R. § 301.4(c)(3)(i)-(vii). For major resource reductions, the change to ASC will become effective when the resource is sold, retired, or transferred. 18 C.F.R. § 301.4(c)(2)

See section 2.5 for a discussion of ASC Major Resource Additions or Removals.

To determine the effects of a major resource addition or reduction on a Utility's Exchange Period ASC, BPA performs one of the following calculations: (1) for major resources of all Exchanging Utilities that are expected to be on line, or be removed, prior to the start of the Exchange Period, BPA projects the costs of the resource forward to the midpoint of the Exchange Period; or (2) for major resources of COUs only that are expected to be on line, or be removed, during the Exchange Period, BPA calculates the resource cost as if the resource came on line, or was removed, at the midpoint of the Exchange Period. Under the REP Settlement, IOUs no longer include major resource additions that come on line during the Exchange Period. *See* section 2.5.

Each resource that satisfies the minimum materiality threshold of one-half percent (0.5%) may be entered individually in the "New Resources – Individual" tab. Resources that do not meet the two and one-half percent (2.5%) materiality requirement independently may be grouped together with other resources within "New Resources – Grouped" tab to meet the two and one-half percent (2.5%) materiality requirement. The grouping and timing of materiality for new resource additions are discussed in section 3.2.14 of this Report.

3.2.14 Materiality for New Resource Additions – Individual and Grouped

The 2008 ASCM states:

> Major resource additions or reductions that meet the criteria identified in paragraph (c)(3) of this section will be allowed to change a Utility's ASC within an Exchange Period provided that the major resource addition or reduction results in a 2.5 percent or greater change in a Utility's Base Period ASC. Bonneville will allow a Utility to submit stacks of individual resources that, when combined, meet the 2.5 percent or greater materiality threshold, provided, however, that each resource in the stack must result in a change to the Utility's Base Period ASC of 0.5 percent or more.

18 C.F.R. § 301.4(c)(4)

Under the 2008 ASCM, a Utility may group or stack resources that individually result in a change in a Utility's Base Period ASC by one-half percent (0.5%) or more to meet the two and one-half percent (2.5%) materiality threshold. A stacked group of resources will not be added to the Utility's Base Year ASC until the last resource in that stack comes on line. The grouping of resources together, therefore, has a significant impact on the timing of when a Utility's ASC is changed as a result of a new resource addition.

BPA made materiality determinations for all new resources, if any, submitted by each Utility. To make these determinations, BPA followed the instructions below:

- The Utility must have included the costs and operating characteristics for each new resource addition.

- The Utility must have submitted the resource additions (individual and/or grouped) that meet the materiality test(s) given the Utility's Base Period costs.

- BPA reviewed each new resource addition submitted by the Utility to determine the adequacy of costs and operating characteristics.

- For the Draft ASC Report, BPA calculates the materiality of a Utility's resources using the Utility's adjusted Base Period ASC and forecast natural gas prices used in BPA's

Rate Case Initial Proposal. BPA removed all resources and/or groups of resource additions that did not meet the materiality test(s).

- BPA did not unilaterally re-group resources.
- The Initial Proposal's natural gas price forecast was the basis for the natural gas fuel costs used to calculate the materiality for new resource additions in both the Draft and Final ASC Reports.
- The Utility had the option to recommend a "regrouping" of resource additions that meet the materiality test(s).
- Utilities must have submitted the regrouped resource additions in their comments on the Draft ASC Report.
- Only resources that were reviewed by BPA and participants could be used in the regrouping process.

The final grouping of new resources, if any, was determined after considering the filing Utilities' and other parties' comments on the Draft ASC Report based on the foregoing instructions.

The materiality determinations provided in this Final ASC Report are based on the Utility's Base Period ASC and reflect the natural gas price forecast form the BP-20 Initial Proposal.

3.2.15 New Large Single Loads

This tab calculates the cost of resources in an amount sufficient to serve an NLSL, which BPA must exclude from a Utility's ASC pursuant to Northwest Power Act Section 5(c)(7). 16 U.S.C. § 839c(c)(7). An NLSL is any load associated with a new facility, an existing facility, or an expansion of an existing facility which was not CF/CT prior to September 1, 1979, and which will result in an increase in power requirements of ten (10) aMW or more in a consecutive 12-month period. 16 U.S.C. § 839a(13)(A)–(B). By law, BPA must exclude from a Utility's ASC the load associated with an NLSL and an amount of resource costs sufficient to serve such NLSL. *See* 16 U.S.C. § 839c(c)(7)(A). To determine the amount of resource costs to exclude from a Utility's ASC, BPA follows the methodology described in Endnote d of the 2008 ASCM. *See* 18 C.F.R. § 301, End. d. Base Period NLSLs will remain constant throughout the duration of the Exchange Period (*see* FY 2012-2013 Final ASC Report, section 5.2.2).

3.2.16 Tiered Rates

All exchanging COUs have the right to purchase power at BPA's Tier 1 rate by executing Contract High Water Mark ("CHWM") Contracts with BPA. By signing the CHWM Contract, the Utility agrees to limit the resources it will exchange in the REP. Under the CHWM Contract, the COU agrees to exclude from its ASC the cost of resources necessary to serve the COU's Above-RHWM load. The CHWM Contracts require the cost of serving Above-RHWM loads to be calculated using a methodology similar to Endnote d of the 2008 ASCM. *See* section 3.3 of this Final ASC Report for details.

Data input in this tab is used to calculate the cost of Tier 1 Power Purchases from BPA, and comes from BPA's Power Rates group. For background information and details, *see* http://www.bpa.gov/news/pubs/PastRecordsofDecision/2009/TRM-12S-A-02.pdf.

3.2.17 Above-RHWM Base Calculation

The Above-RHWM Base Calc tab calculates the cost of resources in an amount sufficient to serve a COU's Above-RHWM load. Under the TRM and CHWM Contracts, BPA must exclude from a Utility's ASC any Above-RHWM load and an amount of resource costs sufficient to serve such Above-RHWM load. To determine the amount of resource costs to exclude from a Utility's ASC, BPA follows the methodology described in Exhibit D of the Utility's CHWM Contract.

The associated Above-RHWM Ratios tab calculates the functionalization ratios used to allocate the total amount of materials and supplies cost, general plant and general plant depreciation expense, administrative and general costs, federal and state employment taxes, and property taxes that are to be included in the total costs of resources used to meet a Utility's Above-RHWM load.

3.3 Rate Period High Water Mark ASC Calculation under the Tiered Rate Methodology

CHWM Contracts require that the cost of resources used to meet Above-RHWM loads be calculated using a methodology similar to Endnote d of the 2008 ASCM. BPA uses the following method to determine the ASC of a COU that is participating in the REP.

- $\text{RHWM ASC} = \dfrac{\text{Contract System Cost} - \text{NewRes\$}}{\text{Contract System Load} - \text{NewResMWh}}$

- NewRes$ is the forecast cost of resources used to serve a customer's Above-RHWM Load. The costs included in NewRes$ will be determined using a methodology similar to Appendix 1, Endnote d, of BPA's 2008 ASCM and as described below.

- NewResMWh is the forecast generation from resources used to serve a customer's Above-RHWM Load. For this Final ASC Report, the NewResMWh has been set equal to the customer's Above-RHWM Load.

- For calculating both NewRes$ and NewResMWh, Existing Resources for CHWMs specified in Attachment C, Column D, of the TRM (*see* TRM-12S-A-03, September 2009, Attachment C) and purchases of power at Tier 1 rates from BPA are excluded.

A number of considerations are used in calculating the cost of serving Above-RHWM Loads using Endnote d of the 2008 ASCM:

- Types of resources to serve Above-RHWM Loads may be different from those resources used in the NLSL resource cost calculation and will be recognized in calculating RHWM ASC:
    - Power purchases less than five years in duration.
- Total output of new resources may exceed Above-RHWM Load:
    - RHWM ASC does not specify removal of costs associated with this excess.

RHWM ASC calculation methodology:

- Set NewResMWh equal to Above-RHWM Load.
- NewRes$ = NewResMWh times Fully Allocated Cost (calculated using Endnote d).
- If output of material new resources fails to meet Above-RHWM Load, meet deficit with short-term ("ST") market purchases at utility-specific market price.
- If output of new resources exceeds Above-RHWM Load, reduce ST market purchases by excess to the extent possible in Contract System Cost calculation.
- Sell any remaining surplus at utility-specific Sales for Resale price in the Contract System Cost calculation.

3.4 ASC Forecast

Once the Base Period ASC is calculated, BPA uses the ASC Forecast Model to escalate forward the Base Period ASC to the midpoint of the Exchange Period. The ASC Forecast Model uses IHS Global Insight's (an international economic and market forecasting company) forecast of cost increases for capital costs and fuel (except natural gas), operations and maintenance ("O&M"), and general and administrative ("G&A") expenses; BPA's forecast of market prices for purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF rate and other products. For both the Draft and Final ASC Reports, BPA updates the escalators in the ASC Forecast Model to be consistent with the escalators used in the BP-20 rate proceeding. For additional background on the determination of Exchange Period ASCs, *see* the 2008 ASCM, 18 C.F.R. § 301.4.

3.4.1 Forecast Contract System Cost

Forecast Contract System Cost includes a Utility's forecast costs for production and transmission resources, including power purchases and conservation measures, which are includable in and subject to the provisions of the 2008 ASCM. BPA escalates Base Period costs to the midpoint of the Exchange Period to calculate Exchange Period ASCs. *See* 18 C.F.R. § 301.4(a).

3.4.2 Forecast of Sales for Resale and Power Purchases

BPA does not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period are used as the starting values for the forecast. Utilities are then allowed to include new plant additions and use utility-specific forecasts for the (1) price of long-term purchased power contracts, and (2) long-term sales for resale price contracts to value purchased power expenses and sales for resale revenue. *See* 18 C.F.R. § 301.4(b).

3.4.3 Forecast Contract System Load and Exchange Load

As a part of its ASC Filing, each IOU is required to provide a four-fiscal-year forecast of its total retail load, as measured at the meter. For the COUs only, total retail forecast loads, as determined by BPA under the TRM, will be provided through the end of the Exchange Period. In addition, for the COUs, qualifying residential and farm retail loads, as measured at the retail meter, are required. The IOUs' qualifying residential and farm retail loads are determined in a separate process as described in the 2012 REP Settlement.

Each Utility is required to submit a current distribution loss study as described in the 2008 ASCM, Appendix 1, Endnote e. The total retail and the residential and farm load forecasts are adjusted for distribution losses (and NLSLs when appropriate). The resulting load forecasts are the Contract System Load forecast and Exchange Load forecast, respectively.

3.4.4 Load Growth Not Met by New Resource Additions

All load growth not met by new resource additions is met by purchased power at the forecast utility-specific short-term purchased power price. To calculate the cost of serving load growth not served by new resource additions, BPA uses the method outlined in the 2008 ASCM. *See* 18 C.F.R. § 301.4(e).

4 REVIEW OF THE ASC FILING

Pursuant to the 2008 ASCM, the Rules of Procedure for ASC Review Processes, and section 5(c) of the Northwest Power Act, BPA is responsible for reviewing all costs, revenues, and loads used to establish ASCs for the REP. BPA began the FY 2020-2021 ASC Review Process of PacifiCorp's ASC Filing in June 2018. BPA raised one issue related to PacifiCorp's ASC Filing as identified in the BPA Issue List for FY 2020-2021 ASC Filing: PacifiCorp ("Issue List"); no other party raised issues. PacifiCorp responded to the issue, and also submitted a separate erratum correction.

The Final ASC Report summarizes BPA's review of PacifiCorp's ASC Filing and any comments received during the Draft ASC Report comment period.

BPA's ASC determinations for all Utilities are limited to specific findings on issues identified for comment, with the exception of ministerial or mathematical errors or deviations due to changes in functionalizations. There may be additional issues BPA has not identified for comment in this Final ASC Report. Acceptance of a Utility's treatment of an item without comment does not signify a decision as to the proper interpretation to be applied either in subsequent ASC Filings or universally under the 2008 ASCM. Similarly, further experience under the 2008 ASCM may result in BPA adopting a modified or different interpretation of the 2008 ASCM in future ASC reviews.

On April 11, 2018, prior to the start of the FY 2020–2021 ASC Review Processes, BPA held a conference call/workshop with parties interested in the ASC Review Processes to review the schedule, rules of procedure, errata corrections, and past generic issues; explain the latest revisions to the Forecast Model; remind Utilities on general accounting and functionalization guidelines for the Appendix 1; and provide time to discuss other REP topics of interest from the workshop participants.

In addition to the discussions stated above, BPA requested input on how the Utilities are recording the treatment of costs and revenues from the EIM (Energy Imbalance Market), and provided clarification on the changes in the marginal federal income tax rate. In regards to the tax issue, for this ASC filing, BPA will continue to use the 35 percent marginal tax rate as reported in the CY 2017 Base Period. The parties and BPA resolved all questions and were satisfied with the outcome. No further public discussions took place.

Table 4-1 summarizes any direct adjustments BPA made to PacifiCorp's Appendix 1 in this Final ASC Report as a result of BPA's review and evaluation. Supporting arguments may be found in the Errata, Resolved Issues and/or Unresolved Issues sections listed in Table 4-1.

Although a Utility's state, county, or municipal regulatory bodies, or the Commission, may allow a particular functionalization to a specific account, BPA is not required to follow that treatment when calculating ASCs under the 2008 ASCM. Rather, BPA is tasked with making an independent determination of the appropriateness of inclusion or exclusion of particular costs, the reasonableness of the costs included in Contract System Costs, the appropriateness of

Contract System Loads, and the functionalization method used in the calculation of any cost in conformance with the 2008 ASCM. *See* Rules of Procedure, § 3.2.2.

Table 4-1: Summary of ASC Errata Corrections and Issues

Appendix 1 Schedule	Adjustment
Schedule 1 – Plant Investment/Rate Base	Direct adjustment. See section 4.2.1.
Schedule 1A – Cash Working Capital	No direct adjustments.
Schedule 2 – Capital Structure and Rate of Return	No direct adjustments.
Schedule 3 – Expenses	No direct adjustments.
Schedule 3A – Taxes	No direct adjustments.
Schedule 3B – Other Included Items	No direct adjustments.
Schedule 4 – Average System Cost	No direct adjustments.
Appendix 1 Supporting Worksheets	**Adjustment**
Load Forecast	Erratum Correction. See section 4.1.1.
New Resource Additions	No direct adjustments.
Materiality – Individual	No direct adjustments.
Materiality – Grouped	No direct adjustments.
NLSL Calculation	No direct adjustments.
Wind Resources	No direct adjustments.
3-Year Purchased Power and Sales for Resale	No direct adjustments.
Salary and Wages	No direct adjustments.
Ratios	No direct adjustments.
ASC Forecast Model	**Adjustment to Model**
Natural Gas Updates	Nat_Gas_Mkt_Prices_Tab
Market Price Updates	Nat_Gas_Mkt_Prices_Tab

4.1 Errata Corrections Filed by Utility

PacifiCorp and BPA agreed to the following erratum correction. This correction was submitted by PacifiCorp to BPA's Secure REP website on August 23, 2018.

4.1.1 Load Forecast

PacifiCorp submitted errata corrections to the Load Forecast tab to remove direct access sales. As such, all values had to be replaced.

<u>Erratum Correction:</u>

Load Forecast Tab
Cells C29:F29; C31:F31; C36:F47:
Delete values
Insert values:

Row	Column C	Column D	Column E	Column F
29	7,160,109	7,131,346	7,027,695	6,947,377
31	20,481,182	20,501,910	20,341,582	20,201,568
36	769,781	768,588	757,297	752,151
37	626,018	624,866	635,802	610,257
38	607,054	605,202	594,323	589,052
39	526,678	524,446	514,030	508,986
40	512,326	509,407	499,210	494,018
41	535,143	532,186	522,493	517,495
42	639,178	636,221	626,753	622,036
43	579,035	576,009	566,437	561,578
44	470,426	467,350	457,433	452,480
45	498,360	495,411	484,599	479,576
46	612,795	610,539	599,651	594,881
47	783,316	781,122	769,666	764,867

4.2 Decision on Draft Report Resolved Issues

During the ASC Review Process, BPA raised the issues discussed in this section. PacifiCorp responded to these issues in its Issue List, submitted on September 19, 2018. Following the issuance of the Draft ASC Report, PacifiCorp submitted a comment letter to the Secure REP website on April 16, 2019, notifying BPA that it “does not have comments to the…draft report.” No other party raised issues or commented on PacifiCorp’s ASC Filing. BPA considers the issues identified in this section resolved.

4.2.1 Schedule 1 – Rate Base

4.2.1.1 Account 254 – Other Regulatory Liabilities

Issue:

Whether line items '288002 Reg Liab – Excess Def Inc Taxes – ID,' '288003 Reg Liab – Excess Deferred Inc Taxes –OR,' and '288005 Reg Liab – Excess Def Inc Taxes – WA' are properly functionalized to PTD.

Parties' Positions:

In its FY 2020-2021 Appendix 1, PacifiCorp functionalized line items '288002 Reg Liab – Excess Def Inc Taxes – ID,' '288003 Reg Liab – Excess Deferred Inc Taxes –OR,' and '288005 Reg Liab – Excess Def Inc Taxes – WA' to PTD.

BPA's Position:

Line items '288002 Reg Liab – Excess Def Inc Taxes – ID,' '288003 Reg Liab – Excess Deferred Inc Taxes –OR,' and '288005 Reg Liab – Excess Def Inc Taxes – WA' should be functionalized to DIST.

Evaluation of Positions:

In PacifiCorp's FY 2020-2021 Appendix 1 filing, Schedule 1 – Rate Base, Account 254 – Other Regulatory Liabilities, several subaccounts representing excess deferred federal income taxes were given the functionalization treatment of PTD. Given that FERC Account 190 is prescribed to handle Accumulated Deferred Income Taxes, with a functionalization treatment of Distribution, BPA conducted discovery to obtain more information on these particular subaccounts. BPA issued BPA_PA_FY20_01 on July 23, 2018, and received a reply from PacifiCorp on August 14, 2018.

PacifiCorp stated in its data response:

> The amounts recorded in the above general ledger (G/L) accounts were previously included in the company's Accumulated Deferred Income Tax (ADIT) balance. With the passage of federal tax reform in December 2017, the ADIT balances were revalued with the excess deferred income taxes (EDIT) being recorded in regulatory liabilities. These accounts reflect the amounts to be returned to Idaho, Oregon and Washington customers, which is why they would be included in the company's average system costs (ASC) filing. They were functionalized to PTD because they encompass all functions of the business.

BPA disagreed with PacifiCorp's proposed functionalization treatment of PTD for accounts associated with deferred federal income taxes as this is not the route by which federal income tax enters the ASC calculation. The 2008 ASC Methodology Final Record of Decision, page 116, states:

> BPA disagrees that it should use the actual taxes paid as reported in the FERC Form 1 instead of grossing up the IOU equity return by the Federal marginal income tax rate for the reasons stated above and for the reasons stated below. First, use of the gross-up factor is how state commissions determine the after-tax revenue requirement in rate orders and is easy to understand and implement. It is simple, straightforward, and over time will approximate the actual taxes paid by the IOUs.

The Tax Cuts and Job Act of 2017 was signed into law by President Donald Trump on December 22, 2017, with an effective date of January 1, 2018. Bonneville initially considered changing the marginal federal income tax rate through an adjustment to ‘Schedule 2 – Rate of Return’ in the Appendix 1 distributed to the utilities to populate for the FY 2020-2021 filing. However, as addressed during the FY 2020-2021 process, BPA determined that it would be improper to adjust the base year values due to a change in the marginal tax rate that occurred after the end of the Base Year. As such, utilities were instructed to disregard the additional ‘Schedule 2 – Rate of Return’ tab in the Appendix 1 because the new marginal tax rate was not in effect in the Base Year and the proper treatment would be to adjust the tax rate in the next ASC review period.

The 2008 Average System Cost Methodology Final Record of Decision, page 32, states:

> The ASCM will not permit subsequent updates to return on equity, Federal income taxes, debt costs, or short-term purchases or sales of wholesale power.

In the BPA Issue List for FY 2020-2021 ASC Filing: PacifiCorp, No.1., BPA stated:

> For the foregoing reasons, BPA believes deferred federal income taxes should be functionalized to Distribution and it would be improper to “true-up” federal income tax related matters during this filing. BPA recommends functionalizing ‘288002 Reg Liab – Excess Def Inc Taxes – ID’, ‘288003 Reg Liab – Excess Deferred Inc Taxes –OR’ and ‘288005 Reg Liab – Excess Def Inc Taxes – WA’ to DIST.

In response to BPA’s Issue List, PacifiCorp agreed with BPA’s recommended functionalization adjustments.

See Response to BPA Issue List for FY 2020-2021 ASC Filing: PacifiCorp, No.1.

<u>Final Decision:</u>

BPA will functionalize line items ‘288002 Reg Liab – Excess Def Inc Taxes – ID,’ ‘288003 Reg Liab – Excess Deferred Inc Taxes –OR,’ and ‘288005 Reg Liab – Excess Def Inc Taxes – WA’ to DIST.

4.3 Decision on Draft Report Identification and Analysis of Unresolved Issues

There were no unresolved issues identified in PacifiCorp's Draft ASC Report.

5 GENERIC ISSUES AND STATEMENTS

There are no generic issues to report for this ASC Filing.

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6 FY 2020-2021 ASC

PacifiCorp's As-Filed Base Period (CY 2017) ASC was $78.01/MWh. As a result of adjustments made during the ASC Review Process, PacifiCorp's Base Period ASC increased to $78.03/MWh.

PacifiCorp's As-Filed Exchange Period ASC for FY 2020-2021 was $76.07/MWh. As a result of adjustments made during the preliminary ASC Review Process, PacifiCorp's Exchange Period ASC for FY 2020-2021 increased to $79.43/MWh. PacifiCorp does not have any major resources coming on line or being removed prior to the FY 2020-2021 Exchange Period.

This Exchange Period ASC does not reflect any changes in NLSL status. See section 2.7 for potential adjustments to Exchange Period ASCs.

7 REVIEW SUMMARY

This Final ASC Report is BPA's determination of PacifiCorp's FY 2020-2021 Base Period and Exchange Period ASCs based on the information and data provided by PacifiCorp, including comments, if any, received in response to the Draft ASC Report, and based on the professional review, evaluation, and judgment of BPA Staff.

BPA has resolved the issues set forth in Section 4 of this Report in accordance with the 2008 ASCM and with generally accepted accounting principles. The information and analysis contained herein properly establish PacifiCorp's ASC for FY 2020–2021.

8 APPROVAL ON BEHALF OF THE BONNEVILLE POWER ADMINISTRATION

I have examined PacifiCorp's ASC Filing, as amended, and the administrative record of the ASC Review Process. Based on this review and the foregoing analysis of the issues, I certify that the calculated ASC conforms to the 2008 ASCM and generally accepted accounting principles, and fairly represents PacifiCorp's ASC.

Issued in Portland, Oregon, this 25th day of July, 2019.

BONNEVILLE POWER ADMINISTRATION

GARRY THOMPSON

Digitally signed by GARRY THOMPSON
Date: 2019.07.19 13:57:27 -07'00'

Vice-President for Northwest Requirements Marketing

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BONNEVILLE POWER ADMINISTRATION
July 2019