FY 2018–2019

FINAL
AVERAGE SYSTEM COST REPORT

Avista Corporation

July 2017
FY 2018–2019

FINAL
AVERAGE SYSTEM COST REPORT

FOR

Avista Corporation
Docket Number: ASC-18-AV-01

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

July 2017
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1 FILING DATA

Filing Utility: Avista Corporation (“Avista”)
1411 E. Mission Ave.
Spokane, Washington 99220-0500

Parties to the Filing:

Investor-Owned Utilities (“IOUs”):
   Idaho Power Company (“Idaho Power”)
   PacifiCorp
   Portland General Electric (“Portland General”)
   Puget Sound Energy (“Puget”)

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

Other Participants to the Filing:
   Public Utility Commission of Oregon (“OPUC”)

Average System Cost Base Period: Calendar Year (“CY”) 2015

Effective Exchange Period: Fiscal Years 2018–2019, October 1, 2017 – September 30, 2019

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 5(b)(1) and 5(b)(3) of the Act. 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 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.


This FY 2018–2019 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.


\(^1\) 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. 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. 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”).
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2 AVERAGE SYSTEM COST SUMMARY

2.1 Avista Corporation Background

Avista is an investor-owned Utility engaged in the production, transmission, and distribution of electricity, the distribution of natural gas, and other energy-related businesses. Avista’s electric and gas service territory covers approximately 30,000 square miles in the states of Idaho, Oregon, and Washington. The Company, based in Spokane, Washington, is subject to state and Federal regulations.

The focus of this report concerns Avista’s electric power generation and transmission system in eastern Washington and western Idaho. Avista’s installed generation capacity of 1,752 megawatts (“MW”) includes eight hydroelectric projects on the Spokane and Clark Fork rivers; four large natural gas-fired plants (Coyote Springs 2, Spokane N.E., Boulder Park, and Rathdrum); a 15 percent share of Colstrip; and a small CT and a biomass plant (Kettle Falls). Avista serves 367,000 electric customers across approximately 2,700 miles of transmission lines and 19,000 miles of distribution lines. Generation statistics for 2015 are shown in the Table below.

<table>
<thead>
<tr>
<th>Type</th>
<th>Capacity (MW)</th>
<th>Percent</th>
<th>Energy (MWh)</th>
<th>Percent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro</td>
<td>921</td>
<td>53</td>
<td>3,434,549</td>
<td>27</td>
</tr>
<tr>
<td>Coal</td>
<td>233</td>
<td>13</td>
<td>1,689,986</td>
<td>13</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>547</td>
<td>31</td>
<td>1,972,169</td>
<td>16</td>
</tr>
<tr>
<td>Biomass</td>
<td>51</td>
<td>3</td>
<td>320,517</td>
<td>3</td>
</tr>
<tr>
<td>Purchases</td>
<td></td>
<td></td>
<td>5,080,211</td>
<td>41</td>
</tr>
<tr>
<td>Total</td>
<td>1,752</td>
<td>100</td>
<td>12,495,969</td>
<td>100</td>
</tr>
</tbody>
</table>

Avista Corporation, 2015 FERC Form No. 1, April 15, 2016.

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 Federal Energy Regulatory Commission (“FERC”) Form 1 data for IOUs or the most recent audited financial statements (Annual Reports) for COUs. The Base Period data are 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 2018–2019 filing period, the Base Period is calendar year (“CY”) 2015.

---

2 Information stated in this section was sourced from Avista’s website and FERC Form 1.
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 identifies the CY 2015 Base Period ASC based on (1) the information contained in Avista’s June 1, 2016, ASC Filing (“As-Filed”), and (2) as adjusted by BPA (including errata corrections filed by Avista) for 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 2015 Base Period ASC  
(Results of Appendix 1 calculations)

<table>
<thead>
<tr>
<th></th>
<th>June 1, 2016 As-Filed</th>
<th>July 26, 2017 Final ASC Report</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production Cost</td>
<td>$404,412,529</td>
<td>$403,610,397</td>
</tr>
<tr>
<td>Transmission Cost</td>
<td>$96,706,253</td>
<td>$96,176,600</td>
</tr>
<tr>
<td>(Less) NLSL Costs</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Contract System Cost (“CSC”)</td>
<td>$501,118,782</td>
<td>$499,786,997</td>
</tr>
<tr>
<td>Total Retail Load (MWh)</td>
<td>8,615,654</td>
<td>8,615,654</td>
</tr>
<tr>
<td>(Less) NLSL</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Total Retail Load (Net of NLSL)</td>
<td>8,615,654</td>
<td>8,615,654</td>
</tr>
<tr>
<td>Distribution Losses</td>
<td>396,320</td>
<td>396,320</td>
</tr>
<tr>
<td>Contract System Load (“CSL”)</td>
<td>9,011,974</td>
<td>9,011,974</td>
</tr>
<tr>
<td>CY 2015 Base Period ASC (CSC/CSL)</td>
<td>$55.61/MWh</td>
<td>$55.46/MWh</td>
</tr>
</tbody>
</table>

2.3 FY 2018–2019 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 five-year average total system loss factor using data from the FERC Form 1 or a comparable data source. *Id.*

---

3 Avista’s average Base Year cost to serve an NLSL ($48.12/MWh) is less than its ASC ($55.46/MWh). Therefore, removing the costs of serving NLSLs would raise Avista’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 Avista’s Final Report Appendix 1, Sch 4 –Average System Cost tab.*
BPA reviewed and accepted Avista’s supporting Distribution Loss Factor calculations. For purposes of this Final ASC Report, BPA used the Distribution Loss Factor of 4.60 percent included in Avista’s As-Filed Appendix 1.

2.4 FY 2018–2019 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, 2018. For purposes of the FY 2018–2019 ASC Review Period, the “Exchange Period” is October 1, 2017, through September 30, 2019.

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-18 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.

In addition to these changes, Avista’s Exchange Period ASC decreased from the Base Period ASC due to the following factors:

1. 4.6% increase in projected load growth (total retail sales at the meter) between the Base Year and Exchange Period as provided in Avista’s Appendix 1 Load forecast tab
2. No major New Resources coming on line
3. Low inflation
4. Small changes in natural gas and market prices
5. Decreased net plant costs

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 the associated Tiered Rates tab in the Appendix 1, and the rates in the PF-Rates tab of the Forecast Model to match what is being used in the BP-18 Final Proposal. In the Tiered Rates tab of the Forecast Model, the total cost of power purchased from BPA is calculated.

Table 2.4-1 identifies the Exchange Period ASC Avista filed on June 1, 2016, and as adjusted by BPA (including errata filed by Avista and BPA) for this Final ASC Report. The ASC shown will be Avista’s ASC for the entire Exchange Period.
### Table 2.4-1: Exchange Period FY 2018–2019 ASC ($/MWh) With No Major Resource Additions or Removals

<table>
<thead>
<tr>
<th>Date</th>
<th>June 1, 2016 As-Filed</th>
<th>July 26, 2017 Final ASC Report</th>
</tr>
</thead>
<tbody>
<tr>
<td>FY 2018–2019</td>
<td>55.84</td>
<td>54.67</td>
</tr>
</tbody>
</table>

#### 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.

However, although the 2008 ASCM permits adjustments, 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. 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 § 3.2.14 of this 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.

Avista submitted three new resource additions for review: NMR (on-line date of July 2016), and LFP and PFS (both on line in January 2016). Avista grouped all of the resources together (Group 1). For this Final ASC Report, the three grouped resources did not meet the REP materiality requirements, either as individual additions, or grouped together (see Sections 3.2.13 and 3.2.14). BPA removed all three new resource additions from the Final Report. Although

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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.
these resources may still be found in Avista’s Appendix 1 New Resources tab, they were not included in the calculation of Avista’s Exchange Period ASC.

Table 2.5-1 summarizes major new 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.

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

<table>
<thead>
<tr>
<th>As-Filed FY 2018–2019 Exchange Period ASC ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource</td>
</tr>
<tr>
<td>July 2016</td>
</tr>
<tr>
<td>Delta*</td>
</tr>
<tr>
<td>1.53</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Final ASC Report FY 2018–2019 Exchange Period ASC ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource</td>
</tr>
<tr>
<td>N/A</td>
</tr>
<tr>
<td>Expected On Line or Removal Date</td>
</tr>
<tr>
<td>Not material</td>
</tr>
<tr>
<td>Delta* Refer to Table 2.7-1</td>
</tr>
<tr>
<td>0</td>
</tr>
</tbody>
</table>

*The Delta is the incremental change in the ASC as major resources come on line. See Avista’s As-Filed and BPA-Adjusted Appendix 1s and the “New Resources” and “ASCs” tabs in their ASC Forecast Model.

### 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). 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.

NLSLs are not determined in the ASC Review Process. Instead, NLSLs are identified through a separate process conducted by BPA’s NLSL Staff. The ASC Review Process determines the cost of resources in an amount sufficient to serve the Utility’s NLSL and then excludes these costs (and associated NLSL) from the Utility’s ASC.
Avista has one NLSL on record. However, because the cost to serve Avista’s NLSL is less than Avista’s ASC, removing the NLSL (and its associated cost) would actually increase Avista’s ASC. The 2008 ASCM does not allow an ASC to increase due to the addition of an NLSL; as such, BPA will not remove the NLSL and associates costs in Avista’s Base Year ASC. Avista has no other NLSLs currently under review. See Table 2.6-1.

Table 2.6-1: New Large Single Loads Under Review

<table>
<thead>
<tr>
<th>As-Filed FY 2018–2019</th>
<th>NLSL Load Amount (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NLSL(s)</td>
<td>Load</td>
</tr>
<tr>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Final ASC Report FY 2018–2019</th>
<th>NLSL Load Amount (MWh)</th>
</tr>
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<tbody>
<tr>
<td>NLSL(s)</td>
<td>Load</td>
</tr>
<tr>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

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 2018–2019 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 Staff will review and evaluate the NLSL and, as necessary, calculate a new ASC using the inputs and formula method as defined below:

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

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 escalated inputs Contract System Cost ($), Cost of Serving NLSL ($/MWh), and Contract System Load (MWh) from the ASC Forecast Model and can be found in the ASCs tab, rows 64, 66, and 76 respectively. 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

<table>
<thead>
<tr>
<th>Resource Addition or Removal</th>
<th>Contract System Cost ($)</th>
<th>Cost of Serving NLSL ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>None</td>
<td>515,249,827</td>
<td>N/A</td>
</tr>
<tr>
<td>Prior to</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>During</td>
<td>N/A</td>
<td>N/A</td>
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</tbody>
</table>

During the Exchange Period, the average cost to serve an NLSL ($48.26/MWh) is less than Avista’s (BPA-Adjusted) FY 2018-2019 ASC ($54.67/MWh). Therefore, removing the costs of serving new NLSLs would raise Avista’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.

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.

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

<table>
<thead>
<tr>
<th>FY 2018–2019 Contract System Load (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>9,424,556</td>
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</tbody>
</table>
3 FILING REQUIREMENTS


Utilities’ ASCs are established in BPA’s ASC Review Processes which began on June 1, 2016, with the submittal of ASC Filings by the following eight Utilities: Avista, Clark, Idaho Power, NorthWestern, PacifiCorp, Portland General, Puget, and Snohomish. An “ASC Filing” consists of two Excel-based models developed by BPA (the Appendix 1 workbook and the ASC Forecast Model), which are populated with supporting data and documentation provided by the Utility.

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 1, 2016, filing deadline. 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 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 this discovery throughout the entire ASC Review Processes.

Draft ASC Reports were issued November 17, 2016, for each of the eight Utilities. The schedule afforded Parties with an approximately 5-month period (through April 10, 2017) in which to submit comments to the Draft ASC Reports. 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. See Sections 4 and 5 to review comments, if any, submitted by the Utilities and intervenors.

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


3.2 Explanation of Appendix 1 Schedules

The Appendix 1 consists of a series of seven schedules and other supporting information that presents 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
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, if required. 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 Commission’s 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 (“ROR”) 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.

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Federal income taxes are included in ASC and are calculated, as applicable, in Schedule 2 – Capital Structure and Rate of Return.

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

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).

**Contract System Cost (CSC) ($)**

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.

**Contract System Load (CSL) (MWh)**

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. For identification of the classification codes, see FERC Form 1, pages 310-311 for Sales for Resale, and pages 326-327 for Purchased Power.

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 load forecast for the four-year period is determined in the Rate Period High Water Mark (“RHWM”) process. This is consistent with the Tiered Rate Methodology (“TRM”). See the Tiered Rates tab in Appendix 1. See also [http://www.bpa.gov/news/pubs/PastRecordsofDecision/2009/TRM-12S-A-02.pdf](http://www.bpa.gov/news/pubs/PastRecordsofDecision/2009/TRM-12S-A-02.pdf)

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 distribution loss calculation 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 the detailed salaries and wages 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 is 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 new 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 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 submitted by each Utility in its Draft ASC Reports. To make these determinations, BPA used the following instructions:

- The Utility must include the costs and operating characteristics for each new resource addition.
- The Utility must submit the resource additions (individual and/or grouped) that meet the materiality test(s) given the Utility’s Base Period costs.
- BPA Staff will review each new resource addition submitted by the Utility to determine the adequacy of costs and operating characteristics.
- For the Draft ASC Report, BPA Staff will calculate 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 Staff will remove all resources and/or groups of resource additions that do not meet the materiality test(s).

- BPA Staff will not unilaterally regroup resources.

- The Initial Proposal’s natural gas price forecast will be 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 will have the option to recommend a “regrouping” of resource additions that meet the materiality test(s).

- Utilities must submit the regrouped resource additions in their comments on the Draft ASC Reports.

- Only resources that were reviewed by BPA Staff and participants can be used in the regrouping process.

- BPA Staff will make a final materiality determination of the new resource additions in the Final ASC Report.

- For the Final ASC Reports, BPA will calculate the materiality of the Utility’s resources using the Utility’s final Base Period ASC.

The final grouping of new resources will be 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 both the Draft and Final ASC Reports are based on the Utility’s BPA-Adjusted Base Period ASC in these Reports, respectively, and reflect the natural gas price forecast from the BP-18 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). 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 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 RHWM ASC of a COU that is participating in the REP.

\[
\text{RHWM ASC} = \frac{\text{Contract System Cost} - \text{NewRes$}}{\text{Contract System Load} - \text{NewResMWh}}
\]

- 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.
- 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.

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 and calculate the Exchange Period ASC.

The ASC Forecast Model uses IHS Markit’s (an international economic and market forecasting company formally known as IHS Global Insight) 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-18 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, forecasts of qualifying residential and farm retail loads, as measured at the retail meter, are required. See Section 3.2.9.

Each Utility is required to submit a distribution loss calculation 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 2018–2019 ASC Review Process of Avista’s ASC Filing in June 2016. With the exception of errata correction, BPA did not identify any issues related to Avista’s ASC Filing and Avista concurred with this finding; no other party raised issues. See BPA’s Issue and Clarification Issue List for Avista’s FY 2018-2019 ASC Filing.

This Final ASC Report summarizes BPA’s review of Avista’s ASC Filing and any comments received during the Draft 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 12, 2016, prior to the start of the FY 2018–2019 ASC Review Processes, BPA held a conference call with parties interested in the processes to review the schedule, rules of procedure, 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.

During this meeting, BPA proposed the use of errata as a uniform approach to correcting inadvertent errors and other ministerial, non-substantive changes. Previously, these matters were often addressed in data requests and responses and incorporated into Draft and Final ASC Reports as Resolved Issues. BPA’s proposal was met with agreement by the workshop participants as a simple and uniform practice to document these or similar types of corrections.

In addition to the discussions stated herein, BPA provided clarification and requested input to the generic issue that was not resolved in the FY 2016-2017 ASC Review. See Section 5 of this report for additional information. Following review and discussion, the Parties and BPA resolved all questions and were satisfied with the outcome. No further public discussions took place.

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 summarizes any direct adjustments BPA made to Avista’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.

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

<table>
<thead>
<tr>
<th>Appendix 1 Schedule</th>
<th>Adjustment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Schedule 1 – Plant Investment/Rate Base</td>
<td>Erratum Correction. See Section 4.1.1</td>
</tr>
<tr>
<td>Schedule 1A – Cash Working Capital</td>
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</tr>
<tr>
<td>Schedule 2 – Capital Structure and Rate of Return</td>
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<tr>
<td>Schedule 3 – Expenses</td>
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<tr>
<td>Schedule 3A – Taxes</td>
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<td>Schedule 3B – Other Included Items</td>
<td>Errata Corrections. See Sections 4.1.2 and 4.1.3</td>
</tr>
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<td>Schedule 4 – Average System Cost</td>
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</tr>
<tr>
<td>Appendix 1 Supporting Worksheets</td>
<td>Adjustment</td>
</tr>
<tr>
<td>Load Forecast</td>
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<tr>
<td>New Resource Additions – Individual</td>
<td>Erratum Correction. See Section 4.1.4</td>
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<td>Materiality - Individual</td>
<td>Erratum Correction. See Section 4.1.5</td>
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<tr>
<td>Materiality - Grouped</td>
<td>Erratum Correction. See Section 4.1.6</td>
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<td>NLSL Calculation</td>
<td>Erratum Correction. See Section 4.1.7</td>
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<tr>
<td>3-Year PP &amp; OSS Worksheet</td>
<td>Erratum Correction. See Section 4.1.9</td>
</tr>
<tr>
<td>Wind Resources</td>
<td>No direct adjustments.</td>
</tr>
<tr>
<td>Tiered Rates</td>
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<tr>
<td>Salary and Wages</td>
<td>No direct adjustments.</td>
</tr>
<tr>
<td>Ratios</td>
<td>No direct adjustments.</td>
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<tr>
<td>FERC pg 262-263 Taxes</td>
<td>Erratum Correction. See Section 4.1.8</td>
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<td>Adjustment</td>
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<tr>
<td>Market Price Updates</td>
<td>Nat_Gas_Mkt_Prices_Tab</td>
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4.1 Errata Corrections Filed by Utility

Avista and BPA agreed to the following errata corrections. These corrections were submitted by Avista to BPA’s Secure REP website on September 23, 2016, and revised on November 1, 2016, with the exception of 4.1.9. This erratum was submitted April 10, 2017.

4.1.1 Schedule 1

1. Add “Avista” to merged cells E5, F5, and G5.

4.1.2 Schedule 3B.1 Other Expense Support

Summary: The item “Amortization of Spokane River TDG” in cell H129 for $290,395 should be reclassified to Production. The totals formula on H289 has been updated to include reclassified production amount from cell H129. Accordingly, the amount in cell H296 has been zeroed out so that the formula in cell H299 does not include this amount.

1. **Cell I129:** Delete “D” and insert “P” in its place.
2. **Cell H289:** Add “H129” to the end of the formula. The revised formula should reflect “=SUM(H279:H288)-2+H129.” The Total 407.3 Production in cell H289 should now equal 5,582,580.
3. **Cell H296:** Delete “=H129” The revised entry should reflect an empty cell. The Total 407.3 Distribution in cell H299 should now equal “(2,932,055).”

4.1.3 Schedule 3B.2 Revenue Support

Summary: The item “RW REC’s Exclusive to Washington State” in cell I21 for $97,500 should be functionalized to Production. The totals formula on I35 has been updated to include reclassified production amount from cell I21, and the formula in cell I37 has been updated to exclude this amount. The total in cell I39 should equal 96,650,357.77.

1. **Cell J21:** Delete “Distribution” and insert “Production” in its place.
2. **Cell I35:** Add “+I21” to the formula. The revised formula should reflect “=I8+I10+I15+I16+I17+I18+I19+I21+I29+I30+I31”
3. **Cell I37:** Delete “+I21” from the end of the formula. The revised formula should reflect “=I9+I11+I12+I13+I14+I20+I22+I23+I25+I26+I27+I28”

4.1.4 New Resources-Individual

Summary: Add additional generation resulting from upgrades to Nine Mile Unit #1 (8,804 MWh) and Nine Mile Unit #2 (13,146) for 2017.

1. **Cell F43:** Add the formula “=SUM (8804 +13146)”
4.1.5 Materiality – Individual

**Summary:** at the end of, but inside, the internal parenthetical of each of the following cells, add “+'Sch 1A - Cash Working Capital'!$G$30”. As an example, the corrected formula for cell O84 should be “=(O196+O202+O207+O215+O235-(O176+O180+O187+O191+O194+O195+'Sch 1A - Cash Working Capital'!$G$30))/8”.

1. Add “+'Sch 1A - Cash Working Capital'!$G$30” to cells O84, P84, W84, X84, AE84 and AF84.

See also Section 4.4.1

4.1.6 Materiality – Group

**Summary:** at the end of, but inside, the internal parenthetical of each of the following cells, add “+'Sch 1A - Cash Working Capital'!$G$30”. As an example, the corrected formula for cell O84 should be “=(O196+O202+O207+O215+O235-(O176+O180+O187+O191+O194+O195+'Sch 1A - Cash Working Capital'!$G$30))/8”.

1. Add “+'Sch 1A - Cash Working Capital'!$G$30” to cells O84 and P84.

See also Section 4.4.2

4.1.7 NLSL Base New Calc

1. **Cell H14:** Add from dropdown “Form 1 LF.”

4.1.8 FERC p262-263.2 Taxes

**Summary:** revise the number in cell L65 to exclude the portion of Oregon property taxes attributable to Avista’s gas operations which total $2,727,875.38.

1. Delete the number in cell L65 (5,445,699) and insert in its place “2,717,825.62.”

4.1.9 3-Year PP & OSS Worksheet

**Summary:** On April 10, 2017, Avista uploaded an erratum stating the utility “inadvertently erred when it provided values on the 3-YEAR PP & OSS Worksheet tab of the Appendix 1 for PF Power purchased from BPA. This data input is reserved for COUs only.”

1. Delete the values in cell D82 ($18,212,673) and cell E82 (522,460 MWh).
4.2 Decision on Draft Report Resolved Issues
BPA did not raise any issues with Avista’s ASC Filing. Following the issuance of the Draft ASC Report, Avista submitted a letter (“Comment Letter”) on April 10, 2017 in agreement with BPA. No other Party raised issues or commented on Avista’s ASC Filing.

4.3 Decision on Draft Report Unresolved Issues
There were no unresolved issues identified in Avista’s Draft ASC Report. However, BPA identified one unresolved issue (see Section 4.3.1) with Puget Sound Energy just prior to publication of the Draft ASC Reports.

4.3.1 Revisions to Puget Sound Energy FERC Form No.1
In late October, 2016, BPA learned that Puget filed an updated FERC Form 1 which included changes to its Transmission Plant, Distribution Plant, Accumulated Depreciation Reserve (Schedule 1), and Depreciation Expense (Schedule 3). Based on BPA’s review, Puget’s update of the new Base Year data would increase its FY 2018-2019 ASC.

BPA has not previously experienced the situation where a Utility files an amended FERC Form 1, after the close of the Discovery period, with changes that could affect its ASC, and potentially impact the Exchange Period benefits for all Utilities. For this ASC Review Process, BPA did not revise Puget’s ASC with these updates because these adjustments were made after the close of the formal time for reviewing Puget’s Appendix 1 data. Allowing adjustments would not afford any party (including BPA) an opportunity to fully evaluate or review the data.

BPA sought Parties input on this issue and requested that the Parties direct any comments specifically to Puget’s Draft ASC Report. No Party submitted comment.

Prior to the next formal ASC Review Processes (June 2018), BPA Staff will propose a protocol to address this issue for future ASC Filings.

For this ASC Filing, BPA will not change its Draft Report proposal and will not revise Puget’s ASC to reflect the updates in the FERC Form 1.

4.4 ASC Appendix 1 Errata Corrections Filed by BPA
BPA discovered an error in the formula for calculating materiality, both individual and grouped. The error only affected two Utilities, Avista and Snohomish; they were notified prior to the issuance of the Draft ASC Reports. BPA will correct the error for the next ASC Filing and is providing the following summaries herein for information only.
4.4.1 Materiality – Individual Tab
Summary: at the end of, but inside, the internal parenthetical of each of the following cells, add “+'Sch 1A - Cash Working Capital'!$G$30”. As an example, the corrected formula for cell O84 should be “=(O196+O202+O207+O215+O235-(O176+O180+O187+O191+O194+O195+'Sch 1A - Cash Working Capital'!$G$30))/8”.

1. Add “+'Sch 1A - Cash Working Capital'!$G$30” to cells O84, P84, W84, X84, AE84, AF84, AM84, and AN84.

2. Cells H348, P348, X348, AF348, AN348
Delete = 'Sch 4 - Average System Cost'!$D$43.
Insert = 'Sch 4 - Average System Cost'!$D$42.

4.4.2 Materiality – Grouped Tab
Summary: at the end of, but inside, the internal parenthetical of each of the following cells, add “+'Sch 1A - Cash Working Capital'!$G$30”. As an example, the corrected formula for cell O84 should be “=(O196+O202+O207+O215+O235-(O176+O180+O187+O191+O194+O195+'Sch 1A - Cash Working Capital'!$G$30))/8”.

1. Add “+'Sch 1A - Cash Working Capital'!$G$30” to cells O84 and P84.

2. Cells H348, P348
Delete = 'Sch 4 - Average System Cost'!$D$43.
Insert = 'Sch 4 - Average System Cost'!$D$42.
5 GENERIC ISSUES

5.1 Rate of Return and Capital Structure

During the FY 2016-2017 ASC Review Process, Portland General raised a question on Endnote b regarding the timing of the Rate of Return (ROR), specifically on the meaning of “most recently approved Regulatory Body Rate Order.” BPA included Portland General’s argument in its FY 2016-2017 Draft ASC Report as an unresolved issue. Portland General and the Oregon Public Utility Commission provided the only comments. BPA provided a decision for Portland General’s Final FY 2016-2017 ASC Report, but removed the generic issue from all ASC Reports with the understanding the question would be addressed prior to the FY 2018-2019 ASC process. See Portland General’s FY 2016-2017 Final ASC Report, Section 4.3.1, and Section 5, Generic Issues.

In the FY 2016-2017 review process, BPA acknowledged that the interpretation of Endnote b would benefit from additional clarification. Accordingly, BPA met with Portland General in January 2016 to further understand its concern. Following the Portland General meeting, BPA met with the Utilities, including Portland General, on April 12, 2016, to clarify BPA’s interpretation of Endnote b. There were no objections to BPA’s current policy on the timing of rate orders, and BPA considers this issue resolved.

To calculate its weighted cost of capital, BPA will use the ROR data from the rate order that was in effect as of BPA’s official deadline for submittal of ASC Filings. The ASC Filing deadline date clarifies the timing issue.
6 FY 2018–2019 ASC

Avista’s As-Filed Base Period (CY 2015) ASC was $55.61/MWh. As a result of adjustments made during the ASC Review Process, Avista’s Base Period ASC decreased to $55.46/MWh.

Avista’s As-Filed Exchange Period ASC for FY 2018–2019 was $57.37/MWh. As a result of adjustments made during the ASC Review Process, Avista’s Exchange Period ASC decreased to $54.67/MWh (see Section 2.4). Avista does not have any material major resources coming on line or being removed prior to the FY 2018-2019 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 Avista’s FY 2018 and FY 2019 ASC based on the information and data provided by Avista, including comments, if any, received in response to the Draft ASC Report, and based on the professional review, evaluation, and judgment of BPA’s REP Staff.

In accordance with the 2008 ASCM and generally accepted accounting principles, BPA found no Issues to report; errata corrections were completed. The information and analysis contained herein properly establish Avista’s ASC for FY 2018–2019.

8 APPROVAL ON BEHALF OF THE BONNEVILLE POWER ADMINISTRATION

I have examined Avista’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 Avista’s ASC.

Issued in Portland, Oregon, this 26th day of July, 2017.

BONNEVILLE POWER ADMINISTRATION

By:  /s/ Garry R. Thompson  
Vice-President for Northwest Requirements Marketing
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