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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-16-03
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC SERVICE	)	EXHIBIT NO. 12
TO ELECTRIC CUSTOMERS IN THE	)	
STATE OF IDAHO	)	TARA L. KNOX
	)	

FOR AVISTA CORPORATION

(ELECTRIC)

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED DECEMBER 31, 2015

Line	Column	Description of Adjustment	(000's)	Revenue	Expense	Plant	Accumulated Depreciation	Deferred Debits/Credits	Deferred Tax
						Production / Transmission			
1	1.00	Per Results Report		81,847	183,805	653,106	(250,980)	748	(78,260)
2	1.01	Deferred FIT Rate Base		-	-	-	-	-	(6,802)
3	1.02	Deferred Debits, Credits & Reg Amortizations		-	(497)	-	-	(581)	-
4	1.03	Restate Capital 2015 EOP		-	-	13,600	(4,378)	-	(4,050)
5	1.04	Working Capital		-	-	-	-	-	-
6	1.05	Plant Held For Future Use		-	-	-	-	-	-
7	2.01	Eliminate B & O Taxes		-	-	-	-	-	-
8	2.02	Uncollectible Expense		-	-	-	-	-	-
9	2.03	Regulatory Expense		-	-	-	-	-	-
10	2.04	Injuries and Damages		-	-	-	-	-	-
11	2.05	FIT/DFIT ITC/PTC Expense		-	-	-	-	-	-
12	2.06	SIT/SITC Expense		-	-	-	-	-	-
13	2.07	Revenue Normalization		-	2,801	-	-	-	-
14	2.08	Miscellaneous Restating		-	-	-	-	-	-
15	2.09	Restate Incentives		-	(7)	-	-	-	-
16	2.10	ID PCA		-	(7,757)	-	-	-	-
17	2.11	Nez Perce Settlement Adjustment		-	(31)	-	-	-	-
18	2.12	Colstrip / CS2 Maintenance		-	2,426	-	-	-	-
19	2.13	Restate Debt Interest		-	-	-	-	-	-
20	3.01	Pro Forma Power Supply		(58,168)	(55,277)	-	-	-	-
21	3.02	Pro Forma Transmission Rev/Exp		(38)	125	-	-	-	-
22	3.03	Pro Forma Labor Non-Exec		-	433	-	-	-	-
23	3.04	Pro Forma Employee Benefits		-	(32)	-	-	-	-
24	3.05	Pro Forma Property Tax		-	993	-	-	-	-
25	3.06	Planned Capital Add 2016 EOP		-	1,602	72,214	(9,939)	-	(13,735)
26	3.07	Planned Capital Add 2017 AMA		-	190	9,705	(5,363)	-	(3,911)
27	2017 Pro Forma Total			23,641	128,774	748,625	(270,660)	167	(106,758)

Exhibit No. 12
Case No. AVU-E-16-03
T. Knox, Avista
Schedule 1, p. 1 of 2

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED DECEMBER 31, 2015

Proposed Production and Transmission Revenue Requirement
2017 Pro Forma
Calculation of Load Change Adjustment Rate

Line			($000's)	Debt Cost
1	Prod/Trans	Pro Forma Rate Base	371,374	
2	Cost of Capital	Proposed Rate of Return	7.780%	2.83%
3	Rate Base	Net Operating Income Requirement	$28,893	
4	Tax Effect	Net Operating Income Requirement (Rate Base x Debt Cost x -35%)	($3,678)	
5	Net Expense	Net Operating Income Requirement (Expense - Revenue)	105,133	
6	Tax Effect	Net Operating Income Requirement (Net Expense x -.35%)	($36,797)	
7	Total Prod/Trans	Net Operating Income Requirement	$93,551	
8	1 - Tax Rate	Conversion Factor (Excl. Rev. Rel. Exp.)	0.65	
9	Prod/Trans	Revenue Requirement	$143,924	
10	Test Year WA Normalized Retail Load MWh		3,011,312	
11	Prod/Trans Rev Requirement per kWh		$ 0.04779	
12	Cost of Service Energy Classified Production/Transmission Costs		$77,203	Company Case at Unity AVU-E-16-03
13	Cost of Service Total Production/Transmission Costs		$147,851	Company Case at Unity AVU-E-16-03
14	Load Change Adjustment Rate per kWh (Line 11 * Line 12 / Line 13)		**$ 0.02496**	

ELECTRIC COST OF SERVICE

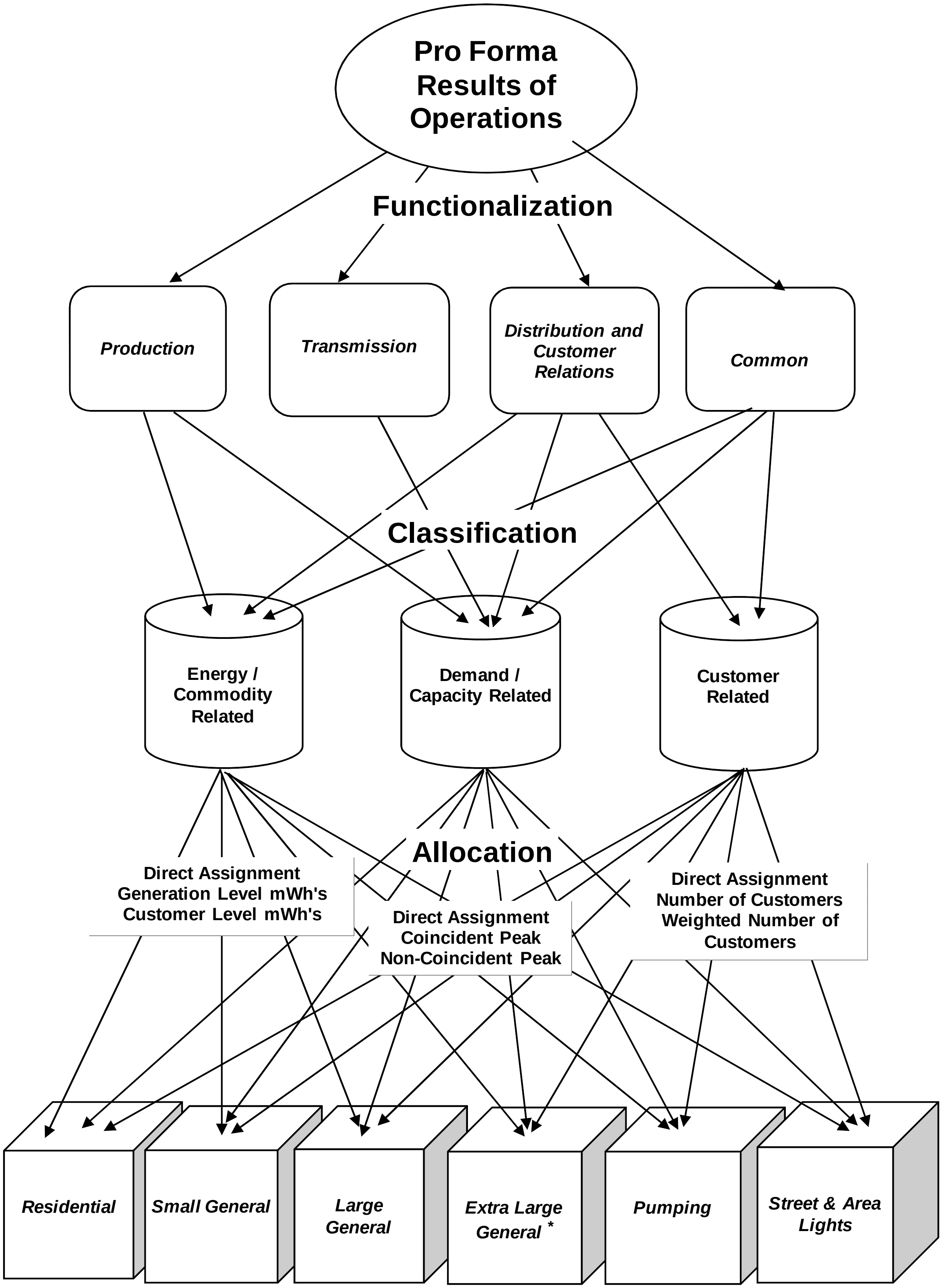
A cost of service study is an engineering-economic study, which apportions the revenue, expenses, and rate base associated with providing electric service to designated groups of customers. It indicates whether the revenue provided by customers recovers the cost to serve those customers. The study results are used as a guide in determining the appropriate rate spread among the groups of customers.

There are three basic steps involved in a cost of service study: functionalization, classification, and allocation. See flow chart below.

First, the expenses and rate base associated with the electric system under study are assigned to functional categories. The uniform system of accounts provides the basic segregation into production, transmission, and distribution. Traditionally customer accounting, customer information, and sales expenses are included in the distribution function, and administrative and general expenses and general plant rate base are allocated to all functions. This study includes a separate functional category for common costs. Administrative and general costs that cannot be directly assigned to the other functions have been placed in this category.

Second, the expenses and rate base items that cannot be directly assigned to customer groups are classified into three primary cost components: energy, demand or customer related. Energy related costs are allocated based on each rate schedule's share of commodity consumption. Demand (capacity) related costs are allocated to rate schedules on the basis of each schedule's contribution to peak demand. Customer related items are allocated to rate schedules based on the number of customers within each schedule. The number of customers may be weighted by appropriate factors such as relative cost of metering equipment. In addition to these three cost components, any revenue related expense is allocated based on the proportion of revenues by rate schedule.

1



Pro Forma Results of Operations by Customer Group

* Customer classes shown in this flowchart are illustrative and may not match the Company's actual rate schedules.

The final step is allocation of the costs to the various rate schedules utilizing the allocation factors selected for each specific cost item. These factors are derived from usage and customer information associated with the test period results of operations.

BASE CASE COST OF SERVICE STUDY

Production Classification (Load Factor Peak Credit)

This study utilizes a Peak Credit methodology to classify production costs into demand and energy classifications. The Peak Credit method acknowledges that energy production costs contain both capacity and energy components as they provide energy throughout the year as well as capacity during system peaks. The peak credit ratio (the proportion of total production cost that is capacity related) is determined using the electric system load factor inherent in the test year. The share of production costs attributable to demand is one minus the load factor[1] which is 36.10% for the 2015 test year. The same classification ratio is applied to all production costs.

Production Allocation

Production demand related costs are allocated to the customer classes by class contribution to the average of the twelve monthly system coincident peak loads. Although the Company is usually a winter peaking utility, it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season. Energy related costs are allocated to class by pro forma annual kilowatt-hour sales adjusted for losses to reflect generation level consumption.

[1] 1 – (average MW÷ peak MW).

Transmission Classification and Allocation

Transmission costs are classified as 100% demand related due in part to the fact that the facilities are designed to meet system peak loads. These costs are then allocated to the customer classes by class contribution to the average of the twelve monthly system coincident peak loads (12CP). The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season.

Distribution Facilities Classification (Basic Customer)

The Basic Customer method considers only services and meters and directly assigned Street Lighting apparatus (FERC Accounts 369, 370, and 373 respectively) to be customer related distribution plant. All other distribution plant is then considered demand related. This division delineates plant installed solely for an individual customer from plant which is part of the broader system. The basic customer method provides a clearly definable division between plant that provides service only to individual customers, from plant that is part of the interconnected system.

Customer Relations Distribution Cost Classification

Customer service, customer information and sales expenses are the core of the customer relations functional unit which is included with the distribution cost category. For the most part they are classified as customer related. Exceptions are sales expenses which are classified as energy related and uncollectible accounts expense which is considered separately as a revenue conversion item. Demand Side Management expenses (if any) recorded in Account 908 would be considered separately from the other customer information costs.

Any demand side management investment and amortization included in base rates would be classified implicitly to demand and energy by the sum of production plant in service, then allocated to rate schedules by coincident peak demand and energy consumption, respectively. At this point in time, the Company's demand side management investments in base rates have been fully amortized except for some minor outstanding loan balances that will remain on the books until satisfied. All current demand side management costs are managed through the Schedule 91 Public Purpose Tariff Rider balancing account which is not included in this cost study.

Distribution Cost Allocation

Distribution demand related costs, which cannot be directly assigned, are allocated to customer class by the average of the twelve monthly non-coincident peaks for each class. Distribution facilities that serve only secondary voltage customers are either allocated by the non-coincident peaks of secondary voltage customers (excludes demand from customers receiving service at primary voltage)[2], or by the average number of secondary voltage customers. This includes secondary voltage overhead or underground conductors and devices, line transformers, and service lines to the customer's premises. The costs of specific substations and related primary voltage distribution facilities are directly assigned to Extra Large General Service customers (Schedule 25 and 25P) based on their load ratio share of the substation capacity from which they receive service.

Most customer costs are allocated by average number of customers. Weighted customer allocators have been developed using typical current cost of meters, estimated meter reading time, and direct assignment of billing costs for hand-billed customers. Street and area light customers are excluded from metering and meter reading expenses as their service is not metered.

[2] Customers taking service below 11 kV are secondary voltage customers, customers taking service at greater than 11kV are primary voltage customers.

Administrative and General Costs

Administrative and general costs which are directly associated with production, transmission, distribution, or customer relations functions are directly assigned to those functions and allocated to customer class by the relevant plant or number of customers. The remainder of administrative and general costs are considered common costs, and have been left in their own functional category. These common costs are classified by the implicit relationship of energy, demand and customer within the four-factor allocator applied to them. The four-factor allocator consists of a 25% weighting of each of the following: 1) operating & maintenance expenses excluding resource costs, labor expenses, and administrative and general expenses; 2) operating and maintenance labor expenses excluding administrative and general labor expenses; 3) net production, transmission, and distribution plant; and 4) number of customers.

Revenue Conversion Items

In this study uncollectible accounts and commission fees have been classified as revenue related and are allocated by pro forma revenue. These items vary with revenue and are included in the calculation of the revenue conversion factor. Income tax expense items are allocated to schedules by net income before income tax adjusted by interest expense.

For the functional summaries on pages 2 and 3 of the cost of service study, these items are assigned to component cost categories. The revenue related expense items have been reduced to a percent of all other costs and loaded onto each cost category by that ratio. Similarly, income tax items have been reduced to a percent of net income before tax then assigned to cost categories by relative rate base (as is net income).

The following matrix outlines the methodology applied in the Company Base Case cost of service study.

Line	Account	Functional Category	Classification	Allocation
	Production Plant			
1	Thermal Production	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
2	Hydro Production	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
3	Other Production (Coyote Springs)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
4	Other Production	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
	Transmission Plant			
5	All Transmission	T = Transmission	Demand	D01 Coincident Peak Demand (12CP)
	Distribution Plant			
6	360 Land	D = Distribution	Demand	D03 Non-coincident Peak Demand (NCP)
7	361 Structures	D = Distribution	Demand	D04/D05/D06 Direct Assign Large / Non-coincident Peak Demand Excl DA
8	362 Station Equipment	D = Distribution	Demand	D04/D05/D06 Direct Assign Large / Non-coincident Peak Demand Excl DA
9	364 Poles Towers & Fixtures	D = Distribution	Demand	D04/D05/D07/D08 Direct Assign Large & Lights / NCP Excl DA / NCP Secondary
10	365 Overhead Conductors & Devices	D = Distribution	Demand	D04/D05/D07 Direct Assign Large / NCP Excl DA / NCP Secondary
11	366 Underground Conduit	D = Distribution	Demand	D04/D05/D07 Direct Assign Large / NCP Excl DA / NCP Secondary
12	367 Underground Conductors & Devices	D = Distribution	Demand	D04/D05/D07 Direct Assign Large / NCP Excl DA / NCP Secondary
13	368 Line Transformers	D = Distribution	Demand	D07 Non-coincident Peak Demand Secondary
14	369 Services	D = Distribution	Customer	C02 Secondary Customers unweighted Excl Lighting
15	370 Meters	D = Distribution	Customer	C04 Customers weighted by Current Typical Meter Cost
16	373 Street and Area Lighting Systems	D = Distribution	Customer	C05 Direct Assignment to Street and Area Lights
	General Plant			
17	All General	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Intangible Plant			
18	301 Organization	O=Other	Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
19	302 Franchises & Consents - Hydro Relicensing	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
20	303 Misc Intangible Plant - Transmission Agreements	T = Transmission	Demand	D01 Coincident Peak Demand (12CP)
21	303 Misc Intangible Plant - Software	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Reserve for Depreciation/Amortization			
22	Intangible	P/T/O	Follows Related Plant	S01/S02/S23 Sum of Production Plant / Sum of Transmission Plant / Corp Cost Allocator
23	Production	P = Production	Follows Related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
24	Transmission	T = Transmission	Follows Related Plant	D01 Coincident Peak Demand (12CP)
25	Distribution	D = Distribution	Follows Related Plant	D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
26	General	O=Other	Follows Related Plant	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Other Rate Base			
27	252 Customer Advances for Construction	D = Distribution	Customer	S13 Sum of Account 369 Services Plant
28	282/190 Accumulated Deferred Income Tax	P/T/D/O	Per Functional Analysis	S01/S02/S03/S04 Sums of Production / Transmission / Distribution / General Plant
29	Hydro Relicensing Related Settlements	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
30	Demand Side Management Investment	DSM	Demand/Energy by Load Factor Peak Credit	S01 Sum of Production Plant
31	Working Capital	P/T/D/G	Demand/Energy/Customer as in related Plant	S06 Sum of Production, Transmission, Distribution, and General Plant

Line	Account	Functional Category	Classification	Allocation
	Production O&M			
1	Thermal	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
2	Thermal Fuel (501)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
3	Hydro	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
4	Water for Power (536)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
5	Other (Coyote Springs)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
6	Other Fuel (547)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
7	Other	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
8	Purchased Power and Other Expenses (555 and 557)	P = Production	Demand/Energy by Load Factor Peak Credit	S01 Sum of Production Plant
9	System Control & Misc (556)	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
	Transmission O&M			
10	All Transmission	T = Transmission	Demand	D01 Coincident Peak Demand (12CP)
	Distribution O&M			
11	580 OP Super & Engineering	D = Distribution	Demand/Customer from Other Dist Op Exp	S16 Sum of Other Distribution Operating Expenses
12	581 Load Dispatching	D = Distribution	Demand	D03 Non-coincident Peak Demand
13	582 Station Expenses	D = Distribution	Demand	S09 Sum of Account 362 Station Equipment
14	583 Overhead Lines	D = Distribution	Demand	S10 Sum of Accounts 364 and 365 Poles, Towers, Fixtures & Overhead Conductors
15	584 Underground Lines	D = Distribution	Demand	S11 Sum of Accounts 366 and 367 Underground Conduit & Underground Conductors
16	585 Street Lights	D = Distribution	Customer	S15 Sum of Account 373 Street Light and Signal Systems
17	586 Meters	D = Distribution	Customer	S14 Sum of Account 370 Meters
18	587 Customer Installations	D = Distribution	Customer	S13 Sum of Account 369 Services
19	588 Misc Operating Expense	D = Distribution	Demand/Customer from Other Dist Op Exp	S16 Sum of Other Distribution Operating Expenses
20	589 Rents	D = Distribution	Demand	D03 Non-coincident Peak Demand
21	590 MT Super & Engineering	D = Distribution	Demand/Customer from Other Dist Mt Exp	S17 Sum of Other Distribution Maintenance Expenses
22	591 MT of Structures	D = Distribution	Demand	S08 Sum of Account 361 Structures & Improvements
23	592 MT of Station Equipment	D = Distribution	Demand	S09 Sum of Account 362 Station Equipment
24	593 MT of Overhead Lines	D = Distribution	Demand	S10 Sum of Accounts 364 and 365 Poles, Towers, Fixtures & Overhead Conductors
25	594 MT of Underground Lines	D = Distribution	Demand	S11 Sum of Accounts 366 and 367 Underground Conduit & Underground Conductors
26	595 MT of Line Transformers	D = Distribution	Demand	S12 Sum of Account 368 Line Transformers
27	596 MT of Street Lights	D = Distribution	Customer	S15 Sum of Account 373 Street Light and Signal Systems
28	597 MT of Meters	D = Distribution	Customer	S14 Sum of Account 370 Meters
29	598 Misc Maintenance Expense	D = Distribution	Demand/Customer from Other Dist Mt Exp	S17 Sum of Other Distribution Maintenance Expenses
	Customer Accounts Expenses			
30	901 Supervision	C = Customer Relations	Customer	S18 Sum of Other Customer Accounts Expenses Excluding Uncollectibles
31	902 Meter Reading	C = Customer Relations	Customer	C03/C06 Customers Weighted by Est. Meter Reading Time/Direct Assign Handbilled Cust
32	903 Customer Records & Collections	C = Customer Relations	Customer	C01/C06 All Customers unweighted / Direct Assign Handbilled Cust
33	904 Uncollectible Accounts	R = Revenue Conversion	Revenue	R01 Retail Sales Revenue
34	905 Misc Cust Accounts	C = Customer Relations	Customer	C01 All Customers unweighted
	Customer Service & Info Expenses			
35	907 Supervision	C = Customer Relations	Customer	C01 All Customers unweighted
36	908 Customer Assistance	C = Customer Relations	Customer	C01 All Customers unweighted
37	908 DSM Amortization Expenses	DSM	Demand/Energy from Production Plant	S01 Sum of Production Plant
38	909 Advertising	C = Customer Relations	Customer	C01 All Customers unweighted
39	910 Misc Cust Service & Info	C = Customer Relations	Customer	C01 All Customers unweighted
	Sales Expenses			
40	911 - 916	C = Customer Relations	Energy	E02 Annual Generation Level Consumption

IPUC Case No. AVU-E-16-03 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Admin & General Expenses			
1	920 - 927 & 930 -935 Assigned to Production	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
2	920 - 927 & 930 -935 Assigned to Transmission	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
3	920 - 927 & 930 - 935 Assigned to Distribution	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
4	920 - 927 & 930 - 935 Assigned to Customer Relations	C = Customer Relations	Customer	C01 All Customers unweighted
5	920 - 935 Assigned to Other	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
6	928 FERC Commission Fees	P = Production	Energy	E02 Annual Generation Level Consumption
7	928 IPUC Commission Fees	R = Revenue Conversion	Revenue	R01 Retail Sales Revenue
	Depreciation & Amortization Expense			
8	Intangible	P/T/O	Demand/Energy/Customer as in related Plant	S01/S02/S23 Sum of Production Plant / Sum of Transmission Plant / Corp Cost Alloctor
9	Production	P = Production	Demand/Energy by Peak Credit as in related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
10	Transmission	T = Transmission	Demand	D01 Coincident Peak Demand (12CP)
11	Distribution	D = Distribution	Demand/Customer as in related Plant	D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
12	General	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Taxes			
13	Property Tax	P/T/D/O	Demand/Energy/Customer from related Plant	S01/S02/S03/S04 Sums of Production / Transmission / Distribution / General Plant
14	State kWh Generation Taxes	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
15	Misc Production Taxes	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
16	Misc Distribution Taxes	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
17	Idaho State Income Tax	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
18	Federal Income Tax	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
19	Deferred FIT	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
	Other Income Related Items			
20	Boulder Write-off Amort & Misc Renewable Items	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
21	Compass Deferral Amortization	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Operating Revenues			
22	Sales of Electricity- Retail	R = Revenue from Rates	Revenue	Input Pro Forma Revenue per Revenue Study
23	Sales for Resale (447)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
24	Misc Service Revenue (451)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
25	Sales of Water & Water Power (453)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
26	Rent from Production Property (454)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
27	Rent from Transmission Property (454)	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
28	Rent from Distribution Property (454)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
29	Other Electric Revenues - Generation (456)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
30	Other Electric Revenues - Wheeling (456)	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
31	Other Electric Revenues - Energy Delivery (456)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
	Salaries & Wages (allocation factor input)			
	Operation & Maintenance Expenses			
32	Production Total	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
33	Transmission Total	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
34	Distribution Total	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
35	Customer Accounts Total	C = Customer Relations	Customer	S18 Sum of Other Customer Accounts Expenses Excluding Uncollectibles
36	Customer Service Total	C = Customer Relations	Customer	C01 All Customers unweighted
37	Sales Total	C = Customer Relations	Energy	E02 Annual Generation Level Consumption
38	Admin & General Total	O=Other	Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
39	Interest Expense (allocation factor input)	R = Revenue Conversion	Demand/Energy/Customer from Rate Base components	S07 Total Rate Base

Sumcost
Scenario: AVU-E-16-03 Company Case
Load Factor Peak Credit
Transmission By Demand 12 CP

AVISTA UTILITIES
Cost of Service Basic Summary
For the Twelve Months Ended December 31, 2015

Idaho Jurisdiction
Electric Utility

05/26/16

	(b)	(c) (d) (e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
				Residential	General	Large Gen	Extra Large	Extra Large	Pumping	Street &
			System	Service	Service	Service	Gen Service	Service CP	Service	Area Lights
	Description		Total	Sch 1	Sch 11-12	Sch 21-22	Sch 25	Sch 25P	Sch 31-32	Sch 41-49
	Plant In Service									
1	Production Plant		477,090,000	196,072,641	57,222,653	102,296,656	49,814,841	60,344,465	9,533,181	1,805,564
2	Transmission Plant		240,951,000	111,548,272	29,133,866	49,684,009	20,238,443	25,822,120	4,031,541	492,749
3	Distribution Plant		536,665,000	271,627,857	78,543,901	120,249,314	15,729,014	2,853,689	21,142,826	26,518,399
4	Intangible Plant		82,604,000	41,255,314	10,881,353	14,886,180	6,077,685	6,970,084	1,745,221	788,164
5	General Plant		121,432,000	68,567,219	17,085,521	18,591,742	6,289,870	6,584,144	2,670,560	1,642,944
6	Total Plant In Service		1,458,742,000	689,071,303	192,867,293	305,707,900	98,149,855	102,574,502	39,123,328	31,247,820
	Accum Depreciation									
7	Production Plant		(198,732,000)	(81,674,125)	(23,836,115)	(42,611,706)	(20,750,389)	(25,136,507)	(3,971,050)	(752,108)
8	Transmission Plant		(72,992,000)	(33,791,648)	(8,825,608)	(15,050,924)	(6,130,892)	(7,822,371)	(1,221,287)	(149,270)
9	Distribution Plant		(198,312,000)	(101,323,662)	(28,855,308)	(43,042,573)	(4,992,941)	(755,920)	(7,647,027)	(11,694,568)
10	Intangible Plant		(18,279,000)	(9,729,947)	(2,489,313)	(3,040,046)	(1,148,129)	(1,271,441)	(392,531)	(207,593)
11	General Plant		(42,219,000)	(23,839,181)	(5,940,227)	(6,463,904)	(2,186,837)	(2,289,149)	(928,490)	(571,212)
12	Total Accumulated Depreciation		(530,534,000)	(250,358,563)	(69,946,572)	(110,209,153)	(35,209,188)	(37,275,388)	(14,160,384)	(13,374,752)
13	Net Plant		928,208,000	438,712,740	122,920,721	195,498,747	62,940,666	65,299,113	24,962,944	17,873,068
14	Accumulated Deferred FIT		(198,108,000)	(93,222,166)	(26,085,873)	(41,456,242)	(13,635,053)	(14,427,762)	(5,230,323)	(4,050,581)
15	Miscellaneous Rate Base		24,536,000	11,065,654	3,200,813	5,466,879	1,736,861	1,804,577	688,466	572,749
16	Total Rate Base		754,636,000	356,556,229	100,035,661	159,509,384	51,042,474	52,675,929	20,421,087	14,395,236
17	Revenue From Retail Rates		243,599,000	105,522,000	36,021,000	52,133,000	19,419,000	21,247,000	5,742,000	3,515,000
18	Other Operating Revenues		25,414,000	10,913,437	3,106,854	5,425,112	2,392,942	2,866,380	529,890	179,384
19	Total Revenues		269,013,000	116,435,437	39,127,854	57,558,112	21,811,942	24,113,380	6,271,890	3,694,384
	Operating Expenses									
20	Production Expenses		92,268,000	37,919,953	11,066,716	19,783,915	9,634,064	11,670,467	1,843,693	349,191
21	Transmission Expenses		10,474,000	4,848,939	1,266,432	2,159,735	879,753	1,122,473	175,249	21,420
22	Distribution Expenses		12,102,000	6,036,603	1,820,710	2,699,093	430,169	97,394	478,213	539,819
23	Customer Accounting Expenses		4,930,000	3,534,370	780,769	292,331	124,150	108,055	69,071	21,254
24	Customer Information Expenses		633,000	516,311	103,228	5,725	55	5	6,955	721
25	Sales Expenses		0	0	0	0	0	0	0	0
26	Admin & General Expenses		23,881,000	13,176,741	3,342,253	3,830,067	1,293,169	1,356,909	537,940	343,920
27	Total O&M Expenses		144,288,000	66,032,917	18,380,109	28,770,865	12,361,360	14,355,303	3,111,121	1,276,325
28	Taxes Other Than Income Taxes		11,775,000	5,290,490	1,508,910	2,541,811	917,199	1,014,572	297,853	204,165
29	Other Income Related Items		779,000	457,079	111,931	112,401	34,457	34,145	17,357	11,631
	Depreciation Expense									
30	Production Plant Depreciation		10,193,000	4,189,081	1,222,559	2,185,562	1,064,291	1,289,256	203,676	38,576
31	Transmission Plant Depreciation		4,342,000	2,010,129	525,000	895,319	364,702	465,321	72,649	8,879
32	Distribution Plant Depreciation		16,280,000	8,400,799	2,518,842	3,518,584	437,800	52,608	641,048	710,318
33	General Plant Depreciation		12,579,000	7,102,799	1,769,869	1,925,897	651,560	682,044	276,640	170,191
34	Amortization Expense		3,553,000	1,472,969	427,933	760,686	364,030	439,851	71,704	15,827
35	Total Depreciation Expense		46,947,000	23,175,776	6,464,203	9,286,048	2,882,384	2,929,080	1,265,718	943,791
36	Income Tax		15,969,000	4,145,769	3,578,981	4,489,475	1,518,727	1,561,504	364,727	309,817
37	Total Operating Expenses		219,758,000	99,102,030	30,044,133	45,200,601	17,714,127	19,894,604	5,056,775	2,745,730
38	Net Income		49,255,000	17,333,407	9,083,722	12,357,512	4,097,815	4,218,776	1,215,115	948,654
39	Rate of Return		6.53%	4.86%	9.08%	7.75%	8.03%	8.01%	5.95%	6.59%
40	Return Ratio		1.00	0.74	1.39	1.19	1.23	1.23	0.91	1.01
41	Interest Expense		21,356,000	10,090,447	2,830,983	4,514,074	1,444,489	1,490,715	577,911	407,381
42	Revenue Related Operating Expenses		1,827,000	791,418	270,159	390,999	145,643	159,353	43,065	26,363

Sumcost
Scenario: AVU-E-16-03 Company Case
Load Factor Peak Credit
Transmission By Demand 12 CP

AVISTA UTILITIES
Revenue to Cost by Functional Component Summary
For the Twelve Months Ended December 31, 2015

Idaho Jurisdiction
Electric Utility

05/26/16

	(b) (c) (d) (e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Description	System Total	Residential Service Sch 1	General Service Sch 11-12	Large Gen Service Sch 21-22	Extra Large Gen Service Sch 25	Extra Large Service CP Sch 25P	Pumping Service Sch 31-32	Street & Area Lights Sch 41-49
	Functional Cost Components at Current Return by Schedule								
1	Production	116,851,559	45,167,744	15,050,262	25,849,817	12,696,284	15,370,943	2,276,421	440,088
2	Transmission	24,353,162	9,524,397	3,601,992	5,542,146	2,309,124	2,941,676	384,031	49,796
3	Distribution	58,884,114	27,956,788	10,574,011	13,504,892	1,951,305	360,767	2,128,438	2,407,914
4	Common	43,510,166	22,873,071	6,794,736	7,236,145	2,462,287	2,573,614	953,111	617,202
5	Total Current Rate Revenue	243,599,000	105,522,000	36,021,000	52,133,000	19,419,000	21,247,000	5,742,000	3,515,000
	Expressed as $/kWh								
6	Production	$0.03880	$0.03951	$0.04208	$0.03932	$0.03588	$0.03664	$0.03483	$0.03102
7	Transmission	$0.00809	$0.00833	$0.01007	$0.00843	$0.00653	$0.00701	$0.00588	$0.00351
8	Distribution	$0.01955	$0.02445	$0.02956	$0.02054	$0.00551	$0.00086	$0.03256	$0.16970
9	Common	$0.01445	$0.02001	$0.01900	$0.01101	$0.00696	$0.00614	$0.01458	$0.04350
10	Total Current Melded Rates	$0.08089	$0.09230	$0.10071	$0.07930	$0.05487	$0.05065	$0.08785	$0.24772
	Functional Cost Components at Uniform Current Return								
11	Production	116,053,088	47,695,059	13,919,524	24,883,864	12,117,559	14,678,911	2,318,965	439,207
12	Transmission	24,211,962	11,208,929	2,927,517	4,992,498	2,033,660	2,594,736	405,109	49,514
13	Distribution	59,480,435	31,504,005	8,979,518	12,309,924	1,743,697	319,913	2,226,885	2,396,494
14	Common	43,853,514	24,522,937	6,147,577	6,863,168	2,310,094	2,416,721	977,615	615,402
15	Total Uniform Current Cost	243,599,000	114,930,929	31,974,136	49,049,454	18,205,009	20,010,281	5,928,574	3,500,617
	Expressed as $/kWh								
16	Production	$0.03854	$0.04172	$0.03892	$0.03785	$0.03424	$0.03499	$0.03548	$0.03095
17	Transmission	$0.00804	$0.00980	$0.00818	$0.00759	$0.00575	$0.00619	$0.00620	$0.00349
18	Distribution	$0.01975	$0.02756	$0.02510	$0.01872	$0.00493	$0.00076	$0.03407	$0.16890
19	Common	$0.01456	$0.02145	$0.01719	$0.01044	$0.00653	$0.00576	$0.01496	$0.04337
20	Total Current Uniform Melded Rates	$0.08089	$0.10053	$0.08939	$0.07461	$0.05144	$0.04770	$0.09070	$0.24671
21	Revenue to Cost Ratio at Current Rates	1.00	0.92	1.13	1.06	1.07	1.06	0.97	1.00
	Functional Cost Components at Proposed Return by Schedule								
22	Production	121,537,987	47,376,329	15,510,677	26,775,086	13,136,731	15,905,296	2,375,831	458,037
23	Transmission	27,159,385	10,996,705	3,876,683	6,068,743	2,518,809	3,209,617	433,292	55,535
24	Distribution	64,430,844	31,057,030	11,223,373	14,649,729	2,109,336	392,317	2,358,505	2,640,555
25	Common	45,903,784	24,314,937	7,058,267	7,593,443	2,578,124	2,694,769	1,010,371	653,873
26	Total Proposed Rate Revenue	259,032,000	113,745,000	37,669,000	55,087,000	20,343,000	22,202,000	6,178,000	3,808,000
	Expressed as $/kWh								
27	Production	$0.04036	$0.04144	$0.04336	$0.04073	$0.03712	$0.03792	$0.03635	$0.03228
28	Transmission	$0.00902	$0.00962	$0.01084	$0.00923	$0.00712	$0.00765	$0.00663	$0.00391
29	Distribution	$0.02140	$0.02717	$0.03138	$0.02228	$0.00596	$0.00094	$0.03608	$0.18610
30	Common	$0.01524	$0.02127	$0.01973	$0.01155	$0.00729	$0.00642	$0.01546	$0.04608
31	Total Proposed Melded Rates	$0.08602	$0.09949	$0.10531	$0.08379	$0.05749	$0.05293	$0.09452	$0.26837
	Functional Cost Components at Uniform Requested Return								
32	Production	120,818,534	49,653,543	14,491,096	25,905,661	12,615,138	15,281,665	2,414,188	457,242
33	Transmission	27,032,156	12,514,538	3,268,512	5,574,021	2,270,540	2,896,969	452,296	55,281
34	Distribution	64,968,259	34,253,219	9,785,626	13,574,174	1,922,223	355,502	2,447,263	2,630,253
35	Common	46,213,050	25,801,534	6,474,726	7,257,737	2,440,956	2,553,384	1,032,464	652,249
36	Total Uniform Cost	259,032,000	122,222,834	34,019,960	52,311,594	19,248,856	21,087,520	6,346,211	3,795,025
	Expressed as $/kWh								
37	Production	$0.04012	$0.04343	$0.04051	$0.03940	$0.03565	$0.03643	$0.03693	$0.03222
38	Transmission	$0.00898	$0.01095	$0.00914	$0.00848	$0.00642	$0.00691	$0.00692	$0.00390
39	Distribution	$0.02157	$0.02996	$0.02736	$0.02065	$0.00543	$0.00085	$0.03744	$0.18537
40	Common	$0.01535	$0.02257	$0.01810	$0.01104	$0.00690	$0.00609	$0.01580	$0.04597
41	Total Uniform Melded Rates	$0.08602	$0.10691	$0.09511	$0.07957	$0.05439	$0.05027	$0.09709	$0.26746
42	Revenue to Cost Ratio at Proposed Rates	1.00	0.93	1.11	1.05	1.06	1.05	0.97	1.00
43	Current Revenue to Proposed Cost Ratio	0.94	0.86	1.06	1.00	1.01	1.01	0.90	0.93
44	Target Revenue Increase	15,433,000	16,700,000	(2,001,000)	179,000	(170,000)	(159,000)	604,000	280,000

Sumcost
Scenario: AVU-E-16-03 Company Case
Load Factor Peak Credit
Transmission By Demand 12 CP

AVISTA UTILITIES
Revenue to Cost By Classification Summary
For the Twelve Months Ended December 31, 2015

Idaho Jurisdiction
Electric Utility

05/26/16

	(b)	(c) (d) (e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
				Residential	General	Large Gen	Extra Large	Extra Large	Pumping	Street &
			System	Service	Service	Service	Gen Service	Service CP	Service	Area Lights
	Description		Total	Sch 1	Sch 11-12	Sch 21-22	Sch 25	Sch 25P	Sch 31-32	Sch 41-49
	Cost Classifications at Current Return by Schedule									
1	Energy		84,102,238	30,028,997	10,780,683	18,976,884	10,134,211	12,001,444	1,782,214	397,805
2	Demand		131,136,857	55,312,644	19,803,858	32,648,620	9,233,514	9,240,423	3,562,974	1,334,824
3	Customer		28,359,906	20,180,359	5,436,460	507,496	51,275	5,132	396,812	1,782,371
4	Total Current Rate Revenue		243,599,000	105,522,000	36,021,000	52,133,000	19,419,000	21,247,000	5,742,000	3,515,000
	Expressed as Unit Cost									
5	Energy	$/kWh	$0.02793	$0.02627	$0.03014	$0.02886	$0.02864	$0.02861	$0.02727	$0.02804
6	Demand	$/kW/mo	$10.41	$7.71	$12.90	$18.18	$13.65	$9.85	$8.17	$33.64
7	Customer	$/Cust/mo	$18.56	$16.20	$21.82	$36.73	$388.45	$427.71	$23.64	$1,024.35
	Cost Classifications at Uniform Current Return									
8	Energy		83,271,618	31,777,603	9,942,002	18,241,550	9,655,349	11,441,308	1,816,828	396,978
9	Demand		131,145,628	61,638,343	17,083,999	30,325,480	8,499,634	8,563,984	3,705,490	1,328,698
10	Customer		29,181,754	21,514,983	4,948,134	482,423	50,026	4,989	406,256	1,774,941
11	Total Uniform Current Cost		243,599,000	114,930,929	31,974,136	49,049,454	18,205,009	20,010,281	5,928,574	3,500,617
	Expressed as Unit Cost									
12	Energy	$/kWh	$0.02765	$0.02780	$0.02780	$0.02775	$0.02728	$0.02728	$0.02780	$0.02798
13	Demand	$/kW/mo	$10.41	$8.59	$11.13	$16.89	$12.57	$9.13	$8.50	$33.48
14	Customer	$/Cust/mo	$19.10	$17.27	$19.86	$34.92	$378.99	$415.76	$24.20	$1,020.08
15	Revenue to Cost Ratio at Current Rates		1.00	0.92	1.13	1.06	1.07	1.06	0.97	1.00
	Cost Classifications at Proposed Return by Schedule									
16	Energy		87,570,893	31,557,092	11,122,182	19,681,256	10,498,659	12,433,958	1,863,094	414,652
17	Demand		141,537,506	60,841,200	20,911,510	34,874,231	9,792,116	9,762,799	3,896,025	1,459,626
18	Customer		29,923,602	21,346,707	5,635,308	531,514	52,225	5,243	418,881	1,933,722
19	Total Proposed Rate Revenue		259,032,000	113,745,000	37,669,000	55,087,000	20,343,000	22,202,000	6,178,000	3,808,000
	Expressed as Unit Cost									
20	Energy	$/kWh	$0.02908	$0.02760	$0.03109	$0.02994	$0.02967	$0.02964	$0.02850	$0.02922
21	Demand	$/kW/mo	$11.24	$8.48	$13.62	$19.42	$14.48	$10.41	$8.93	$36.78
22	Customer	$/Cust/mo	$19.59	$17.13	$22.62	$38.47	$395.65	$436.93	$24.96	$1,111.33
	Cost Classifications at Uniform Requested Return									
23	Energy		86,822,474	33,132,659	10,365,948	19,019,404	10,067,071	11,929,187	1,894,300	413,906
24	Demand		141,545,703	66,540,916	18,459,025	32,783,243	9,130,686	9,153,219	4,024,515	1,454,099
25	Customer		30,663,822	22,549,258	5,194,987	508,947	51,100	5,114	427,396	1,927,020
26	Total Uniform Cost		259,032,000	122,222,834	34,019,960	52,311,594	19,248,856	21,087,520	6,346,211	3,795,025
	Expressed as Unit Cost									
27	Energy	$/kWh	$0.02883	$0.02898	$0.02898	$0.02893	$0.02845	$0.02844	$0.02898	$0.02917
28	Demand	$/kW/mo	$11.24	$9.28	$12.02	$18.26	$13.50	$9.76	$9.23	$36.64
29	Customer	$/Cust/mo	$20.07	$18.10	$20.85	$36.84	$387.12	$426.16	$25.46	$1,107.48
30	Revenue to Cost Ratio at Proposed Rates		1.00	0.93	1.11	1.05	1.06	1.05	0.97	1.00
31	Current Revenue to Proposed Cost Ratio		0.94	0.86	1.06	1.00	1.01	1.01	0.90	0.93
32	Annual Consumption (mWh's)		3,011,312	1,143,267	357,685	657,454	353,879	419,474	65,364	14,189
33	Estimated Annual Billing Demand (kW)		12,593,635	7,172,180	1,535,420	1,795,626	676,382	938,250	436,092	39,685
34	Monthly Average Number of Customers		127,305	103,838	20,761	1,151	11	1	1,399	145

Sumcost | AVISTA UTILITIES | Idaho Jurisdiction
Scenario: AVU-E-16-03 Company Case | Customer Cost Analysis | Electric Utility | 05/26/16
Load Factor Peak Credit | For the Twelve Months Ended December 31, 2015
Transmission By Demand 12 CP

	(b) Description	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 1	(h) General Service Sch 11-12	(i) Large Gen Service Sch 21-22	(j) Extra Large Gen Service Sch 25	(k) Extra Large Service CP Sch 25P	(l) Pumping Service Sch 31-32	(m) Street & Area Lights Sch 41-49
	Meter, Services, Meter Reading & Billing Costs by Schedule at Requested Rate of Return											
	Rate Base											
1	Services				51,737,000	42,260,767	8,449,366	457,591	0	0	569,276	0
2	Services Accum. Depr.				(23,577,000)	(19,258,598)	(3,850,449)	(208,528)	0	0	(259,424)	0
3	Total Services				28,160,000	23,002,169	4,598,916	249,063	0	0	309,852	0
4	Meters				22,152,000	14,228,811	5,860,337	1,298,419	25,926	4,411	734,096	0
5	Meters Accum. Depr.				(6,906,000)	(4,435,905)	(1,826,990)	(404,789)	(8,083)	(1,375)	(228,858)	0
6	Total Meters				15,246,000	9,792,906	4,033,346	893,630	17,843	3,036	505,238	0
7	Total Rate Base				43,406,000	32,795,075	8,632,263	1,142,693	17,843	3,036	815,090	0
8	Return on Rate Base @ 7.78%				3,376,948	2,551,427	671,582	88,901	1,388	236	63,413	0
9	Tax Benefit of Interest				(429,932)	(324,832)	(85,502)	(11,318)	(177)	(30)	(8,073)	0
10	Revenue Conversion Factor				0.61272	0.61272	0.61272	0.61272	0.61272	0.61272	0.61272	0.61272
11	Rate Base Revenue Requirement				4,809,765	3,633,982	956,530	126,620	1,977	336	90,319	0
	Expenses											
12	Services Depr Exp				1,393,000	1,137,856	227,496	12,320	0	0	15,328	0
13	Meters Depr Exp				1,688,000	1,084,247	446,562	98,941	1,976	336	55,939	0
14	Services Operations Exp				280,000	228,715	45,728	2,476	0	0	3,081	0
15	Meters Operating Exp				399,000	256,288	105,556	23,387	467	79	13,222	0
16	Meters Maintenance Exp				6,000	3,854	1,587	352	7	1	199	0
17	Meter Reading				374,000	283,109	56,603	3,139	25,057	2,278	3,814	0
18	Billing				3,129,000	2,550,917	510,015	28,284	1,704	155	34,362	3,562
19	Total Expenses				7,269,000	5,544,986	1,393,548	168,899	29,211	2,850	125,944	3,562
20	Revenue Conversion Factor				0.992672	0.992672	0.992672	0.992672	0.992672	0.992672	0.992672	0.992672
21	Expense Revenue Requirement				7,322,660	5,585,919	1,403,835	170,146	29,426	2,871	126,874	3,588
22	Total Meter, Service, Meter Reading, and Billing Cost				**12,132,426**	**9,219,901**	**2,360,365**	**296,767**	**31,404**	**3,207**	**217,193**	**3,588**
23	Total Customer Bills				1,527,664	1,246,051	249,128	13,816	132	12	16,785	1,740
24	Average Unit Cost per Month				$7.94	$7.40	$9.47	$21.48	$237.91	$267.25	$12.94	$2.06
	Distribution Fixed Costs per Customer											
25	Total Customer Related Cost				30,663,822	22,549,258	5,194,987	508,947	51,100	5,114	427,396	1,927,020
26	Customer Related Unit Cost per Month				$20.07	$18.10	$20.85	$36.84	$387.12	$426.16	$25.46	$1,107.48
27	Total Distribution Demand Related Cost				60,204,081	28,883,810	8,623,848	16,010,630	2,298,476	436,040	2,663,524	1,287,754
28	Dist Demand Related Unit Cost per Month				$39.41	$23.18	$34.62	$1,158.85	$17,412.69	$36,336.64	$158.68	$740.09
29	Total Distribution Unit Cost per Month				**$59.48**	**$41.28**	**$55.47**	**$1,195.68**	**$17,799.81**	**$36,762.80**	**$184.15**	**$1,847.57**