DAVID J. MEYER
VICE PRESIDENT AND CHIEF COUNSEL FOR
REGULATORY & GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851
DAVID.MEYER@AVISTACORP.COM

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-17-01
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 14
AND NATURAL GAS CUSTOMERS IN THE	)	
STATE OF IDAHO	)	TARA L. KNOX

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED DECEMBER 31, 2016

				Production / Transmission					
	2018 Pro Forma Study								
							Accumulated	**Deferred**	**Deferred**
Line	Column	Description of Adjustment	(000's)	**Revenue**	**Expense**	**Plant**	**Depreciation**	**Debits/Credits**	**Tax**
1	1.00	Per Results Report		75,333	171,109	692,802	(257,787)	220	(93,326)
2	1.01	Deferred FIT Rate Base		-	-	-	-	-	(806)
3	1.02	Deferred Debits, Credits & Reg Amortizations		-	(48)	-	-	(149)	-
4	1.03	Restate Capital 2016 EOP		-	-	29,597	2,130	-	(6,126)
5	1.04	Working Capital		-	-	-	-	-	-
6	2.01	Eliminate B & O Taxes		-	-	-	-	-	-
7	2.02	Uncollectible Expense		-	-	-	-	-	-
8	2.03	Regulatory Expense		-	-	-	-	-	-
9	2.04	Injuries and Damages		-	-	-	-	-	-
10	2.05	FIT/DFIT ITC/PTC Expense		-	-	-	-	-	-
11	2.06	SIT/SITC Expense		-	-	-	-	-	-
12	2.07	Revenue Normalization		-	305	-	-	-	-
13	2.08	Miscellaneous Restating		-	(1)	-	-	-	-
14	2.09	Restate Incentives		-	-	-	-	-	-
15	2.10	ID PCA		-	(2,409)	-	-	-	-
16	2.11	Nez Perce Settlement Adjustment		-	(36)	-	-	-	-
17	2.12	Colstrip / CS2 Maintenance		-	(209)	-	-	-	-
18	2.13	2015 Storm 3-year Amortization		-	-	-	-	-	-
19	2.14	Restate Debt Interest		-	-	-	-	-	-
20	3.01	Pro Forma Power Supply		(55,833)	(46,531)	-	-	-	-
21	3.02	Pro Forma Transmission Rev/Exp		(741)	76	-	-	-	-
22	3.03	Pro Forma Labor Non-Exec		-	433	-	-	-	-
23	3.04	Pro Forma Labor Exec		-	-	-	-	-	-
24	3.05	Pro Forma Employee Benefits		-	(67)	-	-	-	-
25	3.06	Pro Forma IS/IT Costs		-	-	-	-	-	-
26	3.07	Pro Forma Property Tax		-	868	-	-	-	-
27	3.08	Planned Capital Add 2017 EOP		-	1,211	39,921	(10,836)	-	(7,586)
28	3.09	Pro Forma O&M Offsets		-	-	-	-	-	-
29	3.10	Pro Forma Underground Equip Inspection		-	-	-	-	-	-
30	2018 Pro Forma Total			18,759	124,701	762,320	(266,493)	71	(107,844)

Exhibit No. 14
Case No. AVU-E-17-01
T. Knox, Avista
Schedule 1, p. 1 of 4

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED DECEMBER 31, 2016

Proposed Production and Transmission Revenue Requirement
2018 Pro Forma Study
Calculation of Load Change Adjustment Rate

Line			($000's)	Debt Cost
1	Prod/Trans	Pro Forma Rate Base	388,054	
2	Cost of Capital	Proposed Rate of Return	7.810%	2.86%
3	Rate Base	Net Operating Income Requirement	$30,307	
4	Tax Effect	Net Operating Income Requirement (Rate Base x Debt Cost x -35%)	($3,884)	
5	Net Expense	Net Operating Income Requirement (Expense - Revenue)	105,942	
6	Tax Effect	Net Operating Income Requirement (Net Expense x -.35%)	($37,080)	
7	Total Prod/Trans	Net Operating Income Requirement	$95,285	
8	1 - Tax Rate	Conversion Factor (Excl. Rev. Rel. Exp.)	0.65	
9	Prod/Trans	Revenue Requirement	$146,592	
10	Test Year WA Normalized Retail Load MWh		2,953,031	
11	Prod/Trans Rev Requirement per kWh		$ 0.04964	
12	Cost of Service Energy Classified Production/Transmission Costs		$74,866	Company Case at Unity AVU-E-17-01
13	Cost of Service Total Production/Transmission Costs		$149,289	Company Case at Unity AVU-E-17-01
14	2018 Load Change Adjustment Rate per kWh (Line 11 * Line 12 / Line 13)		**$ 0.02489**	

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED DECEMBER 31, 2016

	2019 Pro Forma Study					**Production / Transmission**			
							Accumulated	**Deferred**	**Deferred**
Line	Column	Description of Adjustment	(000's)	**Revenue**	**Expense**	**Plant**	**Depreciation**	**Debits/Credits**	**Tax**
1	1.00	Per Results Report		75,333	171,109	692,802	(257,787)	220	(93,326)
2	1.01	Deferred FIT Rate Base		-	-	-	-	-	(806)
3	1.02	Deferred Debits, Credits & Reg Amortizations		-	(48)	-	-	(149)	-
4	1.03	Restate Capital 2016 EOP		-	-	29,597	2,130	-	(6,126)
5	1.04	Working Capital		-	-	-	-	-	-
6	2.01	Eliminate B & O Taxes		-	-	-	-	-	-
7	2.02	Uncollectible Expense		-	-	-	-	-	-
8	2.03	Regulatory Expense		-	-	-	-	-	-
9	2.04	Injuries and Damages		-	-	-	-	-	-
10	2.05	FIT/DFIT ITC/PTC Expense		-	-	-	-	-	-
11	2.06	SIT/SITC Expense		-	-	-	-	-	-
12	2.07	Revenue Normalization		-	305	-	-	-	-
13	2.08	Miscellaneous Restating		-	(1)	-	-	-	-
14	2.09	Restate Incentives		-	-	-	-	-	-
15	2.10	ID PCA		-	(2,409)	-	-	-	-
16	2.11	Nez Perce Settlement Adjustment		-	(36)	-	-	-	-
17	2.12	Colstrip / CS2 Maintenance		-	(209)	-	-	-	-
18	2.13	2015 Storm 3-year Amortization		-	-	-	-	-	-
19	2.14	Restate Debt Interest		-	-	-	-	-	-
20	3.01	Pro Forma Power Supply		(55,833)	(46,531)	-	-	-	-
21	3.02	Pro Forma Transmission Rev/Exp		(741)	76	-	-	-	-
22	3.03	Pro Forma Labor Non-Exec		-	433	-	-	-	-
23	3.04	Pro Forma Labor Exec		-	-	-	-	-	-
24	3.05	Pro Forma Employee Benefits		-	(67)	-	-	-	-
25	3.06	Pro Forma IS/IT Costs		-	-	-	-	-	-
26	3.07	Pro Forma Property Tax		-	868	-	-	-	-
27	3.08	Planned Capital Add 2017 EOP		-	1,211	39,921	(10,836)	-	(7,586)
28	3.09	Pro Forma O&M Offsets		-	-	-	-	-	-
29	3.10	Pro Forma Underground Equip Inspection		-	-	-	-	-	-
30	19.01	Planned Capital Add 2018 AMA		-	179	9,431	(6,097)	-	(3,350)
31	19.02	Planned Capital Add 2018 EOP		-	464	24,768	(6,097)	-	(3,350)
32	19.03	Planned Capital Add 2019 AMA		-	130	6,735	(6,191)	-	(4,165)
33	19.04	Pro Forma Property Tax		-	410	-	-	-	-
34	19.05	Pro Forma Labor Non-Exec		-	244	-	-	-	-
35	2019 Pro Forma Total			18,759	126,128	803,254	(284,878)	71	(118,709)

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED DECEMBER 31, 2016

Proposed Production and Transmission Revenue Requirement
2019 Pro Forma Study
Calculation of Load Change Adjustment Rate

Line			($000's)	Debt Cost
1	Prod/Trans	Pro Forma Rate Base	399,738	
2	Cost of Capital	Proposed Rate of Return	7.810%	2.86%
3	Rate Base	Net Operating Income Requirement	$31,220	
4	Tax Effect	Net Operating Income Requirement (Rate Base x Debt Cost x -35%)	($4,001)	
5	Net Expense	Net Operating Income Requirement (Expense - Revenue)	107,369	
6	Tax Effect	Net Operating Income Requirement (Net Expense x -.35%)	($37,579)	
7	Total Prod/Trans	Net Operating Income Requirement	$97,008	
8	1 - Tax Rate	Conversion Factor (Excl. Rev. Rel. Exp.)	0.65	
9	Prod/Trans	Revenue Requirement	$149,243	
10	Test Year WA Normalized Retail Load MWh		2,953,031	
11	Prod/Trans Rev Requirement per kWh		$ 0.05054	
12	Cost of Service Energy Classified Production/Transmission Costs		$74,866	Company Case at Unity AVU-E-17-01
13	Cost of Service Total Production/Transmission Costs		$149,289	Company Case at Unity AVU-E-17-01
14	2019 Load Change Adjustment Rate per kWh (Line 11 * Line 12 / Line 13)		**$ 0.02534**	

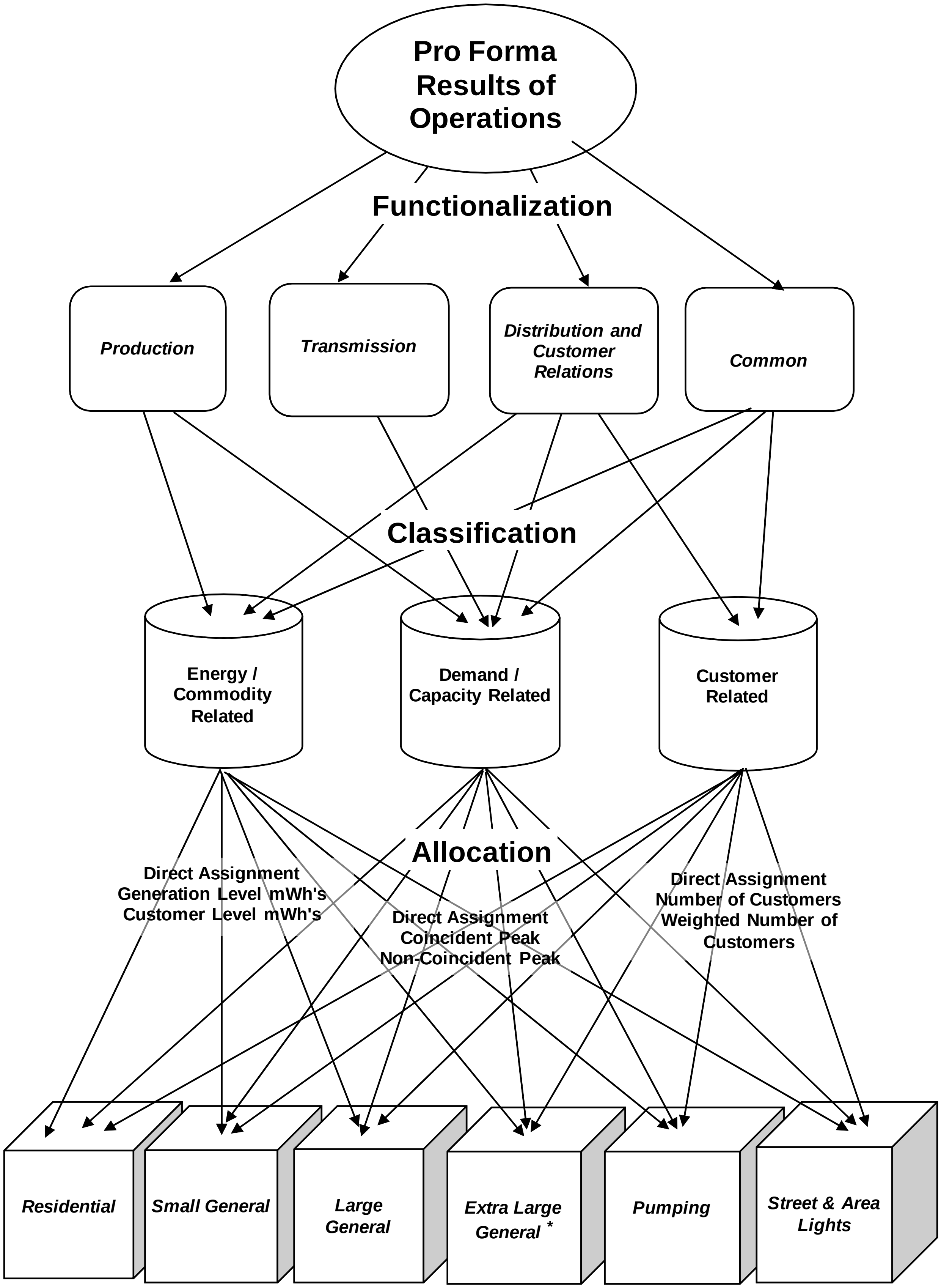
ELECTRIC COST OF SERVICE

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.

As shown in the flow chart below, there are three basic steps involved in a cost of service study: functionalization, classification, and allocation.

First, the expenses and rate base associated with the electric system under study are assigned to functional categories. The FERC 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 (capacity), or customer-related. Energy-related costs are allocated based on each rate schedule's share of commodity consumption. Demand-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.



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.

<u>BASE CASE COST OF SERVICE STUDY</u>

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 37.65% for the 2016 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.

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 (Schedules 41 – 49) are excluded from metering and meter reading expenses as their service is not metered.

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,

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

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.

IPUC Case No. AVU-E-17-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

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

IPUC Case No. AVU-E-17-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

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 Cus
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-17-01 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
22	Storm Cost Amortization	D=Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
	Operating Revenues			
23	Sales of Electricity- Retail	R = Revenue from Rates	Revenue	Input Pro Forma Revenue per Revenue Study
24	Sales for Resale (447)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
25	Misc Service Revenue (451)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
26	Sales of Water & Water Power (453)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
27	Rent from Production Property (454)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
28	Rent from Transmission Property (454)	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
29	Rent from Distribution Property (454)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
30	Other Electric Revenues - Generation (456)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
31	Other Electric Revenues - Wheeling (456)	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
32	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			
33	Production Total	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
34	Transmission Total	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
35	Distribution Total	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
36	Customer Accounts Total	C = Customer Relations	Customer	S18 Sum of Other Customer Accounts Expenses Excluding Uncollectibles
37	Customer Service Total	C = Customer Relations	Customer	C01 All Customers unweighted
38	Sales Total	C = Customer Relations	Energy	E02 Annual Generation Level Consumption
39	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
40	Interest Expense (allocation factor input)	R = Revenue Conversion	Demand/Energy/Customer from Rate Base components	S07 Total Rate Base

Sumcost | AVISTA UTILITIES | Idaho Jurisdiction
Scenario: AVU-E-17-01 Company Case | Cost of Service Basic Summary | Electric Utility | 06/09/17
Load Factor Peak Credit | For the Twelve Months Ended December 31, 2016
Transmission By Demand 12 CP

	(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
	Plant In Service									
1	Production Plant		480,244,000	197,473,909	58,140,608	104,522,472	53,855,677	55,510,682	9,019,849	1,720,803
2	Transmission Plant		251,948,000	112,611,439	29,185,706	53,642,606	25,212,607	26,796,571	3,995,633	503,439
3	Distribution Plant		557,747,000	281,521,386	81,436,351	122,639,659	18,493,633	2,838,141	20,976,158	29,841,672
4	Intangible Plant		94,523,000	47,868,656	12,557,058	16,835,030	7,379,463	7,137,696	1,889,315	855,782
5	General Plant		127,102,000	71,470,557	17,824,792	19,525,473	7,456,807	6,685,021	2,628,498	1,510,852
6	Total Plant In Service		1,511,564,000	710,945,948	199,144,515	317,165,240	112,398,187	98,968,110	38,509,453	34,432,548
	Accum Depreciation									
7	Production Plant		(193,329,000)	(79,495,909)	(23,405,322)	(42,076,996)	(21,680,363)	(22,346,608)	(3,631,068)	(692,734)
8	Transmission Plant		(73,831,000)	(32,999,727)	(8,552,598)	(15,719,463)	(7,388,318)	(7,852,484)	(1,170,883)	(147,528)
9	Distribution Plant		(204,995,000)	(105,213,826)	(30,096,047)	(43,663,546)	(5,722,966)	(729,059)	(7,577,970)	(11,991,586)
10	Intangible Plant		(21,030,000)	(11,172,163)	(2,861,228)	(3,512,864)	(1,465,237)	(1,381,361)	(424,925)	(212,222)
11	General Plant		(44,726,000)	(25,149,818)	(6,272,377)	(6,870,831)	(2,623,980)	(2,352,396)	(924,944)	(531,655)
12	Total Accumulated Depreciation		(537,911,000)	(254,031,443)	(71,187,571)	(111,843,701)	(38,880,864)	(34,661,908)	(13,729,789)	(13,575,724)
13	Net Plant		973,653,000	456,914,505	127,956,943	205,321,539	73,517,323	64,306,202	24,779,663	20,856,824
14	Accumulated Deferred FIT		(206,421,000)	(96,908,122)	(27,121,695)	(43,240,418)	(15,579,356)	(13,851,401)	(5,191,407)	(4,528,601)
15	Miscellaneous Rate Base		29,377,000	13,221,458	3,819,527	6,530,647	2,290,281	2,003,701	781,037	730,349
16	Total Rate Base		796,609,000	373,227,841	104,654,776	168,611,768	60,228,248	52,458,502	20,369,293	17,058,572
17	Revenue From Retail Rates		246,583,000	108,991,000	37,312,000	52,070,000	19,946,000	19,145,000	5,494,000	3,625,000
18	Other Operating Revenues		20,780,000	8,899,571	2,541,872	4,505,215	2,114,756	2,135,888	414,754	167,944
19	Total Revenues		267,363,000	117,890,571	39,853,872	56,575,215	22,060,756	21,280,888	5,908,754	3,792,944
	Operating Expenses									
20	Production Expenses		88,064,000	36,211,472	10,661,444	19,166,647	9,875,701	10,179,185	1,654,001	315,550
21	Transmission Expenses		10,865,000	4,856,253	1,258,604	2,313,283	1,087,268	1,155,575	172,308	21,710
22	Distribution Expenses		10,940,000	5,596,406	1,681,063	2,402,126	443,469	93,011	417,523	306,403
23	Customer Accounting Expenses		4,918,000	3,624,223	785,556	232,498	117,416	76,463	63,922	17,922
24	Customer Information Expenses		570,000	464,785	93,221	5,045	49	4	6,235	661
25	Sales Expenses		0	0	0	0	0	0	0	0
26	Admin & General Expenses		23,837,000	13,147,254	3,331,078	3,812,614	1,437,861	1,287,549	505,435	315,209
27	Total O&M Expenses		139,194,000	63,900,393	17,810,966	27,932,212	12,961,764	12,791,788	2,819,424	977,454
28	Taxes Other Than Income Taxes		12,110,000	5,382,896	1,541,234	2,633,062	1,057,312	995,859	286,399	213,238
29	Other Income Related Items		764,000	434,894	110,560	123,919	33,316	22,962	19,573	18,776
	Depreciation Expense									
30	Production Plant Depreciation		10,270,000	4,222,972	1,243,335	2,235,209	1,151,702	1,187,094	192,889	36,799
31	Transmission Plant Depreciation		4,526,000	2,022,955	524,293	963,637	452,920	481,374	71,778	9,044
32	Distribution Plant Depreciation		16,423,000	8,476,365	2,540,928	3,468,209	480,167	48,535	617,669	791,126
33	General Plant Depreciation		15,215,000	8,555,527	2,133,753	2,337,336	892,632	800,244	314,650	180,860
34	Amortization Expense		1,923,000	801,669	233,817	417,332	209,351	214,465	36,838	9,528
35	Total Depreciation Expense		48,357,000	24,079,488	6,676,125	9,421,723	3,186,771	2,731,713	1,233,823	1,027,357
36	Income Tax		16,103,000	4,893,661	3,910,183	4,245,753	1,130,207	1,180,967	352,648	389,581
37	Total Operating Expenses		216,528,000	98,691,332	30,049,068	44,356,669	18,369,369	17,723,289	4,711,867	2,626,406
38	Net Income		50,835,000	19,199,240	9,804,803	12,218,546	3,691,387	3,557,598	1,196,887	1,166,538
39	Rate of Return		6.38%	5.14%	9.37%	7.25%	6.13%	6.78%	5.88%	6.84%
40	Return Ratio		1.00	0.81	1.47	1.14	0.96	1.06	0.92	1.07
41	Interest Expense		22,783,000	10,674,308	2,993,124	4,822,293	1,722,527	1,500,312	582,561	487,875
42	Revenue Related Operating Expenses		1,507,000	666,102	228,033	318,227	121,901	117,005	33,577	22,154

Sumcost
Scenario: AVU-E-17-01 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, 2016

Idaho Jurisdiction
Electric Utility

06/09/17

	(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	114,635,668	45,109,599	15,238,783	25,627,781	12,725,155	13,404,982	2,113,042	416,325
2	Transmission	25,784,512	10,259,619	3,789,987	5,921,695	2,524,804	2,843,866	390,850	53,691
3	Distribution	58,928,436	28,583,759	10,803,750	12,761,793	1,900,334	319,343	2,016,900	2,542,558
4	Common	47,234,384	25,038,023	7,479,479	7,758,730	2,795,707	2,576,809	973,209	612,426
5	Total Current Rate Revenue	246,583,000	108,991,000	37,312,000	52,070,000	19,946,000	19,145,000	5,494,000	3,625,000
	Expressed as $/kWh								
6	Production	$0.03882	$0.03939	$0.04174	$0.03948	$0.03562	$0.03697	$0.03499	$0.03120
7	Transmission	$0.00873	$0.00896	$0.01038	$0.00912	$0.00707	$0.00784	$0.00647	$0.00402
8	Distribution	$0.01996	$0.02496	$0.02959	$0.01966	$0.00532	$0.00088	$0.03340	$0.19052
9	Common	$0.01600	$0.02186	$0.02049	$0.01195	$0.00782	$0.00711	$0.01611	$0.04589
10	Total Current Melded Rates	$0.08350	$0.09518	$0.10219	$0.08021	$0.05583	$0.05280	$0.09097	$0.27164
	Functional Cost Components at Uniform Current Return								
11	Production	114,439,416	47,056,910	13,854,576	24,907,111	12,833,502	13,227,880	2,149,379	410,058
12	Transmission	25,813,581	11,537,716	2,990,250	5,496,006	2,583,183	2,745,469	409,376	51,580
13	Distribution	58,876,824	31,296,565	8,887,942	11,898,600	1,941,784	308,273	2,102,163	2,441,497
14	Common	47,453,179	26,413,447	6,627,987	7,458,088	2,828,310	2,530,799	996,148	598,400
15	Total Uniform Current Cost	246,583,000	116,304,639	32,360,756	49,759,805	20,186,778	18,812,421	5,657,066	3,501,536
	Expressed as $/kWh								
16	Production	$0.03875	$0.04109	$0.03795	$0.03837	$0.03592	$0.03648	$0.03559	$0.03073
17	Transmission	$0.00874	$0.01008	$0.00819	$0.00847	$0.00723	$0.00757	$0.00678	$0.00387
18	Distribution	$0.01994	$0.02733	$0.02434	$0.01833	$0.00543	$0.00085	$0.03481	$0.18295
19	Common	$0.01607	$0.02307	$0.01815	$0.01149	$0.00792	$0.00698	$0.01649	$0.04484
20	Total Current Uniform Melded Rates	$0.08350	$0.10156	$0.08863	$0.07665	$0.05650	$0.05189	$0.09367	$0.26238
21	**Revenue to Cost Ratio at Current Rates**	1.00	0.94	1.15	1.05	0.99	1.02	0.97	1.04
	Functional Cost Components at Proposed Return by Schedule								
22	Production	120,307,023	47,365,508	15,988,277	26,890,510	13,351,062	14,064,209	2,217,325	430,132
23	Transmission	29,205,631	11,740,371	4,223,042	6,667,622	2,862,078	3,210,156	444,023	58,340
24	Distribution	65,369,327	31,726,668	11,841,142	14,274,347	2,139,803	360,555	2,261,609	2,765,203
25	Common	50,272,019	26,631,454	7,940,540	8,285,521	2,984,056	2,748,080	1,039,043	643,325
26	Total Proposed Rate Revenue	265,154,000	117,464,000	39,993,000	56,118,000	21,337,000	20,383,000	5,962,000	3,897,000
	Expressed as $/kWh								
27	Production	$0.04074	$0.04136	$0.04379	$0.04142	$0.03737	$0.03879	$0.03672	$0.03223
28	Transmission	$0.00989	$0.01025	$0.01157	$0.01027	$0.00801	$0.00885	$0.00735	$0.00437
29	Distribution	$0.02214	$0.02771	$0.03243	$0.02199	$0.00599	$0.00099	$0.03745	$0.20721
30	Common	$0.01702	$0.02326	$0.02175	$0.01276	$0.00835	$0.00758	$0.01720	$0.04821
31	Total Proposed Melded Rates	$0.08979	$0.10258	$0.10954	$0.08644	$0.05972	$0.05622	$0.09872	$0.29202
	Functional Cost Components at Uniform Requested Return								
32	Production	120,073,209	49,373,498	14,536,630	26,133,275	13,465,288	13,879,082	2,255,192	430,245
33	Transmission	29,215,601	13,058,293	3,384,341	6,220,335	2,923,625	3,107,300	463,329	58,378
34	Distribution	65,373,329	34,524,006	9,831,995	13,367,357	2,183,503	348,982	2,350,461	2,767,024
35	Common	50,491,861	28,049,737	7,047,562	7,969,624	3,018,428	2,699,985	1,062,948	643,577
36	Total Uniform Cost	265,154,000	125,005,533	34,800,528	53,690,592	21,590,844	20,035,348	6,131,930	3,899,225
	Expressed as $/kWh								
37	Production	$0.04066	$0.04312	$0.03981	$0.04026	$0.03769	$0.03828	$0.03734	$0.03224
38	Transmission	$0.00989	$0.01140	$0.00927	$0.00958	$0.00818	$0.00857	$0.00767	$0.00437
39	Distribution	$0.02214	$0.03015	$0.02693	$0.02059	$0.00611	$0.00096	$0.03892	$0.20734
40	Common	$0.01710	$0.02449	$0.01930	$0.01228	$0.00845	$0.00745	$0.01760	$0.04823
41	Total Uniform Melded Rates	$0.08979	$0.10916	$0.09531	$0.08270	$0.06043	$0.05526	$0.10153	$0.29218
42	**Revenue to Cost Ratio at Proposed Rates**	1.00	0.94	1.15	1.05	0.99	1.02	0.97	1.00
43	**Current Revenue to Proposed Cost Ratio**	**0.93**	**0.87**	**1.07**	**0.97**	**0.92**	**0.96**	**0.90**	**0.93**
44	**Target Revenue Increase**	**18,571,000**	**16,014,000**	**(2,511,000)**	**1,621,000**	**1,645,000**	**890,000**	**638,000**	**274,000**

Sumcost | AVISTA UTILITIES | Idaho Jurisdiction
Scenario: AVU-E-17-01 Company Case | Revenue to Cost By Classification Summary | Electric Utility | 06/09/17
Load Factor Peak Credit | For the Twelve Months Ended December 31, 2016
Transmission By Demand 12 CP

	(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
	Cost Classifications at Current Return by Schedule									
1	Energy		81,602,941	30,328,970	11,155,245	18,477,459	9,630,304	9,993,684	1,642,061	375,218
2	Demand		135,017,624	57,183,030	20,433,259	33,095,991	10,243,225	9,144,227	3,445,939	1,471,953
3	Customer		29,962,435	21,479,000	5,723,496	496,550	72,472	7,088	406,000	1,777,829
4	Total Current Rate Revenue		246,583,000	108,991,000	37,312,000	52,070,000	19,946,000	19,145,000	5,494,000	3,625,000
	Expressed as Unit Cost									
5	Energy	$/kWh	$0.02763	$0.02649	$0.03055	$0.02846	$0.02695	$0.02756	$0.02719	$0.02812
6	Demand	$/kW/mo	$10.95	$8.17	$13.62	$19.83	$14.06	$9.29	$8.48	$39.58
7	Customer	$/Cust/mo	$19.42	$17.07	$22.68	$36.36	$549.03	$590.70	$24.05	$993.76
	Cost Classifications at Uniform Current Return									
8	Energy		81,348,717	31,693,170	10,105,101	17,937,603	9,715,621	9,856,422	1,671,453	369,346
9	Demand		134,893,230	62,089,071	17,122,054	31,342,856	10,398,396	8,948,960	3,571,295	1,420,599
10	Customer		30,341,053	22,522,398	5,133,601	479,346	72,761	7,039	414,318	1,711,590
11	Total Uniform Current Cost		246,583,000	116,304,639	32,360,756	49,759,805	20,186,778	18,812,421	5,657,066	3,501,536
	Expressed as Unit Cost									
12	Energy	$/kWh	$0.02755	$0.02768	$0.02768	$0.02763	$0.02719	$0.02718	$0.02768	$0.02768
13	Demand	$/kW/mo	$10.94	$8.87	$11.41	$18.78	$14.28	$9.09	$8.79	$38.20
14	Customer	$/Cust/mo	$19.66	$17.90	$20.34	$35.10	$551.22	$586.58	$24.55	$956.73
15	**Revenue to Cost Ratio at Current Rates**		1.00	0.94	1.15	1.05	0.99	1.02	0.97	1.04
	Cost Classifications at Proposed Return by Schedule									
16	Energy		85,798,968	31,909,367	11,723,858	19,423,377	10,123,179	10,504,621	1,726,413	388,154
17	Demand		147,662,622	62,866,869	22,226,236	36,167,929	11,139,679	9,871,107	3,805,714	1,585,089
18	Customer		31,692,410	22,687,764	6,042,906	526,695	74,142	7,273	429,873	1,923,757
19	Total Proposed Rate Revenue		265,154,000	117,464,000	39,993,000	56,118,000	21,337,000	20,383,000	5,962,000	3,897,000
	Expressed as Unit Cost									
20	Energy	$/kWh	$0.02905	$0.02787	$0.03211	$0.02992	$0.02833	$0.02897	$0.02859	$0.02909
21	Demand	$/kW/mo	$11.98	$8.98	$14.81	$21.67	$15.30	$10.03	$9.36	$42.62
22	Customer	$/Cust/mo	$20.54	$18.03	$23.95	$38.57	$561.68	$606.05	$25.47	$1,075.33
	Cost Classifications at Uniform Requested Return									
23	Energy		85,514,322	33,316,075	10,622,551	18,856,130	10,213,127	10,361,138	1,757,043	388,260
24	Demand		147,497,955	67,925,783	18,753,707	34,325,844	11,303,270	9,666,990	3,936,346	1,586,015
25	Customer		32,141,723	23,763,675	5,424,270	508,618	74,447	7,221	438,541	1,924,951
26	Total Uniform Cost		265,154,000	125,005,533	34,800,528	53,690,592	21,590,844	20,035,348	6,131,930	3,899,225
	Expressed as Unit Cost									
27	Energy	$/kWh	$0.02896	$0.02909	$0.02909	$0.02905	$0.02859	$0.02858	$0.02909	$0.02909
28	Demand	$/kW/mo	$11.96	$9.70	$12.50	$20.57	$15.52	$9.82	$9.68	$42.65
29	Customer	$/Cust/mo	$20.83	$18.89	$21.49	$37.24	$563.99	$601.74	$25.98	$1,075.99
30	**Revenue to Cost Ratio at Proposed Rates**		1.00	0.94	1.15	1.05	0.99	1.02	0.97	1.00
31	**Current Revenue to Proposed Cost Ratio**		**0.93**	**0.87**	**1.07**	**0.97**	**0.92**	**0.96**	**0.90**	**0.93**
32	Annual Consumption (mWh's)		2,953,031	1,145,126	365,114	649,193	357,288	362,573	60,392	13,345
33	Estimated Annual Billing Demand (kW)		12,328,719	7,002,866	1,500,584	1,668,724	728,287	984,630	406,438	37,190
34	Monthly Average Number of Customers		128,591	104,855	21,031	1,138	11	1	1,407	149

Sumcost | AVISTA UTILITIES | Idaho Jurisdiction
Scenario: AVU-E-17-01 Company Case | Customer Cost Analysis | Electric Utility | 06/09/17
Load Factor Peak Credit | For the Twelve Months Ended December 31, 2016
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		53,388,000	43,596,354	8,744,023	462,796	0	0	584,827	0
2	Services Accum. Depr.		(24,233,000)	(19,788,538)	(3,968,943)	(210,065)	0	0	(265,455)	0
3	Total Services		29,155,000	23,807,816	4,775,081	252,731	0	0	319,372	0
4	Meters		22,603,000	14,525,276	5,972,269	1,324,309	26,468	4,504	750,174	0
5	Meters Accum. Depr.		(8,495,000)	(5,459,108)	(2,244,588)	(497,722)	(9,948)	(1,693)	(281,942)	0
6	Total Meters		14,108,000	9,066,168	3,727,681	826,587	16,521	2,811	468,232	0
7	Total Rate Base		43,263,000	32,873,984	8,502,762	1,079,318	16,521	2,811	787,604	0
8	Return on Rate Base @ 7.81%		3,378,831	2,567,451	664,064	84,295	1,290	220	61,512	0
9	Tax Benefit of Interest		(433,062)	(329,068)	(85,113)	(10,804)	(165)	(28)	(7,884)	0
10	Revenue Conversion Factor		0.612771	0.612771	0.612771	0.612771	0.612771	0.612771	0.612771	0.612771
11	**Rate Base Revenue Requirement**		**4,807,290**	**3,652,885**	**944,808**	**119,931**	**1,836**	**312**	**87,517**	**0**
	Expenses									
12	Services Depr Exp		1,437,000	1,173,446	235,356	12,457	0	0	15,741	0
13	Meters Depr Exp		1,722,000	1,106,602	454,995	100,892	2,016	343	57,152	0
14	Services Operations Exp		326,000	266,210	53,393	2,826	0	0	3,571	0
15	Meters Operating Exp		410,000	263,477	108,332	24,022	480	82	13,608	0
16	Meters Maintenance Exp		9,000	5,784	2,378	527	11	2	299	0
17	Meter Reading		379,000	275,057	55,168	2,985	38,592	3,508	3,690	0
18	Billing		3,397,000	2,768,573	555,286	30,050	1,847	168	37,139	3,936
19	Total Expenses		7,680,000	5,859,148	1,464,908	173,759	42,947	4,103	131,199	3,936
20	Revenue Conversion Factor		0.993979	0.993979	0.993979	0.993979	0.993979	0.993979	0.993979	0.993979
21	**Expense Revenue Requirement**		**7,726,521**	**5,894,640**	**1,473,781**	**174,812**	**43,207**	**4,128**	**131,994**	**3,960**
22	**Total Meter, Service, Meter Reading, and Billing Cost**		**12,533,811**	**9,547,525**	**2,418,590**	**294,743**	**45,043**	**4,440**	**219,511**	**3,960**
23	Total Customer Bills		1,543,093	1,258,258	252,366	13,657	132	12	16,879	1,789
24	**Average Unit Cost per Month**		**$8.12**	**$7.59**	**$9.58**	**$21.58**	**$341.23**	**$370.01**	**$13.00**	**$2.21**
	Distribution Fixed Costs per Customer									
25	Total Customer Related Cost		32,141,723	23,763,675	5,424,270	508,618	74,447	7,221	438,541	1,924,951
26	Customer Related Unit Cost per Month		$20.83	$18.89	$21.49	$37.24	$563.99	$601.74	$25.98	$1,075.99
27	Total Distribution Demand Related Cost		60,647,087	29,106,657	8,692,885	15,834,303	2,612,045	429,745	2,558,982	1,412,471
28	Dist Demand Related Unit Cost per Month		$39.30	$23.13	$34.45	$1,159.43	$19,788.22	$35,812.07	$151.61	$789.53
29	**Total Distribution Unit Cost per Month**		**$60.13**	**$42.02**	**$55.94**	**$1,196.67**	**$20,352.21**	**$36,413.81**	**$177.59**	**$1,865.52**