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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-21-01
OF AVISTA CORPORATION FOR THE	)	
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC SERVICE	)	EXHIBIT NO. 16
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, 2019

2021 and 2022 Pro Forma Study

						Production / Transmission			
Line	Column	Description of Adjustment	(000's)	**Revenue**	**Expense**	**Plant**	**Accumulated Depreciation**	**Deferred Debits/Credits**	**Accumulated Deferred Tax**
1	1.00	Per Results Report		53,368	162,832	788,042	(283,689)	(3,353)	(102,386)
2	1.01	Deferred FIT Rate Base		-	-	-	-	-	(3,020)
3	1.02	Deferred Debits, Credits & Reg Amortizations		-	(142)	-	-	(63)	-
5	1.03	Working Capital		-	-	-	-	-	-
4	1.04	Restate Capital 2019 EOP		-	473	11,398	(8,201)	-	(531)
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		-	(7,305)	-	-	-	-
13	2.08	Miscellaneous Restating		-	-	-	-	-	-
14	2.09	Restate Incentives		-	-	-	-	-	-
15	2.10	ID PCA		-	7,886	-	-	-	-
16	2.11	Nez Perce Settlement Adjustment		-	(35)	-	-	-	-
17	2.12	Colstrip / CS2 Maintenance		-	908	-	-	-	-
18	2.13	Restate Debt Interest		-	-	-	-	-	-
19	3.00P	Pro Forma Power Supply		(16,502)	(20,203)	-	-	-	-
20	3.00T	Pro Forma Transmission Rev/Exp		(765)	(234)	-	-	-	-
21	3.01	Pro Forma Labor Non-Exec		-	614	-	-	-	-
22	3.02	Pro Forma Labor Exec		-	-	-	-	-	-
23	3.03	Pro Forma Employee Benefits		-	(38)	-	-	-	-
24	3.04	Pro Forma IS/IT Costs		-	-	-	-	-	-
25	3.05	Pro Forma Property Tax		-	478	-	-	-	-
26	3.06	Pro Forma Insurance Expense		-	-	-	-	-	-
27	3.07	Pro Forma ARAM DFIT		-	-	-	-	-	-
28	3.08	Planned Capital Add 2020 EOP		-	1,573	28,938	(14,788)	-	(44)
29	3.09	Planned Capital Add 08.2021 EOP		-	630	12,623	(9,350)	-	96
30	3.10	Planned Capital Add 08.2022 AMA		-	(66)	27,647	(7,655)	-	(105)
31	3.11	Pro Forma O&M Offsets		-	(9)	-	-	-	-
32	3.12	Pro Forma Fee Free Amortization		-	-	-	-	-	-
33	3.13	Restate 2019 ADFIT		-	-	-	-	-	(8,612)
34	3.14	Pro Forma Colstrip Amortization		-	3	5,452	-	-	-
35	Rate Year September 1, 2021 - August 31, 2022			36,101	147,365	874,100	(323,682)	(3,416)	(114,602)
36	22.01	Planned Capital Add 08.2022 EOP		-	1,080	19,995	(8,200)	-	(302)
37	22.02	Planned Capital Add 08.2023 AMA		-	(119)	25,715	(8,534)	-	(175)
38	22.03	Pro Forma Property Tax		-	515	-	-	-	-
39	22.04	Pro Forma Labor Non-Exec		-	291	-	-	-	-
40	22.06	PF Colstrip / CS2 Maintenance		-	379	-	-	-	-
41	22.08	Pro Forma Wildfire Expenses		-	37	-	-	-	-
42	Rate Year September 1, 2022 - August 31, 2023			36,101	149,548	919,809	(340,416)	(3,416)	(115,079)

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED DECEMBER 31, 2019

Proposed Production and Transmission Revenue Requirement
2021 and 2022 Pro Forma Study
Calculation of Load Change Adjustment Rate

Line			Rate Year 09.2021 - 08.2022 ($000's)	Debt Cost	Rate Year 09.2022 - 08.2023 ($000's)	Debt Cost
1	Prod/Trans	Pro Forma Rate Base	432,399		460,898	
2	Cost of Capital	Proposed Rate of Return	7.300%	2.35%	7.30%	2.35%
3	Rate Base	Net Operating Income Requirement	$31,565		$33,646	
4	Tax Effect	Net Operating Income Requirement (Rate Base x Debt Cost x -21%)	($2,134)		($2,275)	
5	Net Expense	Net Operating Income Requirement (Expense - Revenue)	111,264		113,447	
6	Tax Effect	Net Operating Income Requirement (Net Expense x -.21%)	($23,365)		($23,824)	
7	Total Prod/Trans	Net Operating Income Requirement	$117,330		$120,994	
8	1 - Tax Rate	Conversion Factor (Excl. Rev. Rel. Exp.)	0.79		0.79	
9	Prod/Trans	Revenue Requirement	$148,519		$153,157	
10	Test Year WA Normalized Retail Load MWh		2,966,810		2,966,810	
11	Prod/Trans Rev Requirement per kWh		$ 0.05006		$ 0.05162	
12	Cost of Service Energy Classified Production/Transmission Costs		$77,086		$77,086	Company Case at Unity AVU-E-21-01
13	Cost of Service Total Production/Transmission Costs		$150,038		$150,038	Company Case at Unity AVU-E-21-01
14	Load Change Adjustment Rate per kWh (Line 11 * Line 12 / Line 13)		**$ 0.02572**		**$ 0.02652**	

Exhibit No. 16
Case No. AVU-E-21-01
T. Knox, Avista
Schedule 1, p. 2 of 2

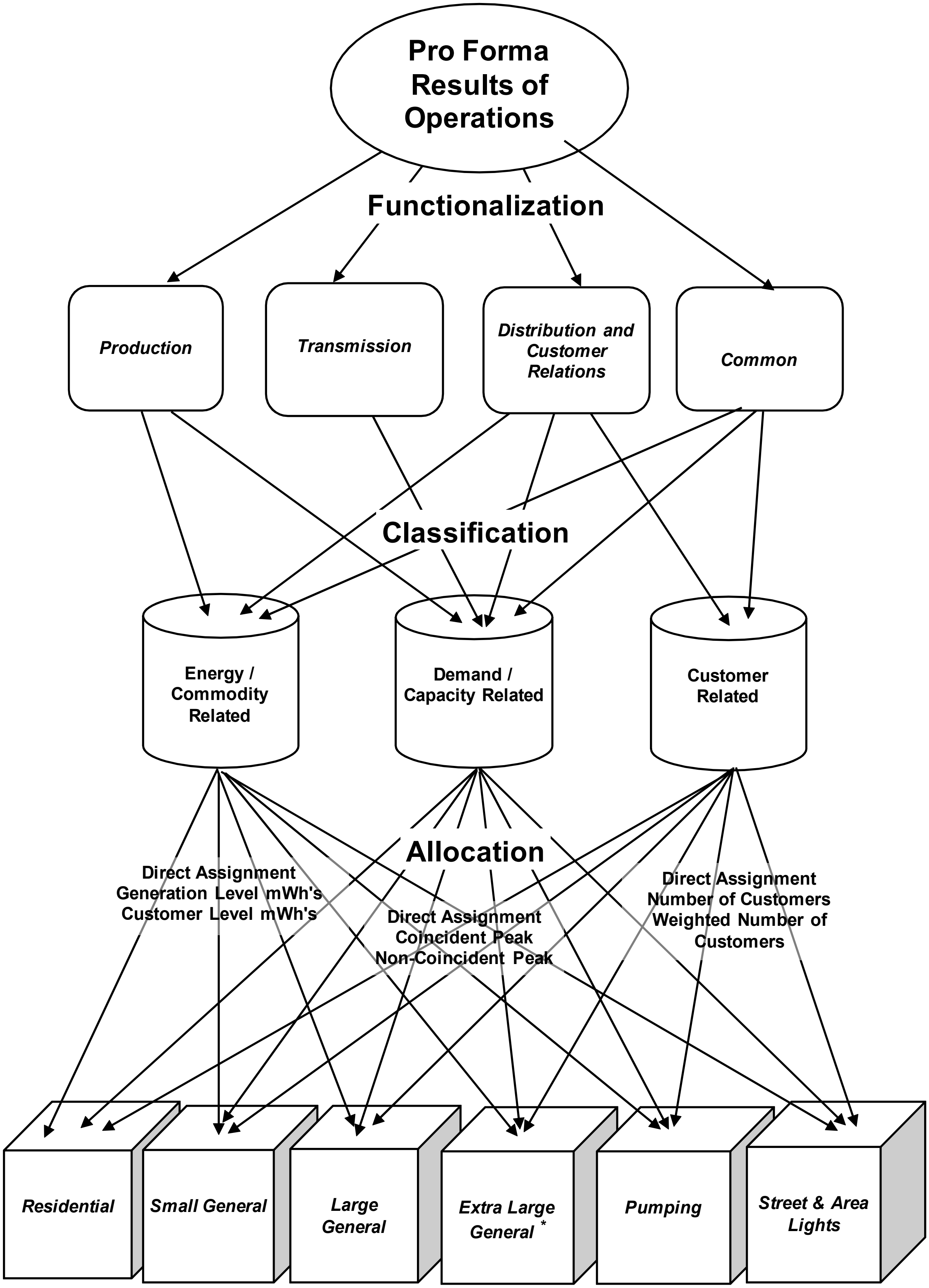
ELECTRIC COST OF SERVICE

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.

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 34.13% for the 2019 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.

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[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, demand and customer within the four-factor allocator applied to them. The four-factor allocator

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

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-21-01 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 AMI/MDM Software	D = Distribution	Customer	C01 All Customers unweighted
22	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			
23	Intangible	P/T/D/O	Follows Related Plant	S01/S02/C01/S23 Sum of Prod. Plant / Sum of Trans. Plant / All Cust. / Corp Cost Allocato
24	Production	P = Production	Follows Related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
25	Transmission	T = Transmission	Follows Related Plant	D01 Coincident Peak Demand (12CP)
26	Distribution	D = Distribution	Follows Related Plant	D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
27	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			
28	252 Customer Advances for Construction	D = Distribution	Customer	S13 Sum of Account 369 Services Plant
29	282/190 Accumulated Deferred Income Tax	P/T/D/O	Per Functional Analysis	S01/S02/S03/S04 Sums of Production / Transmission / Distribution / General Plant
30	Hydro Relicensing Related Settlements	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
31	Regultory Asset AFUDC	P/T/D/G	Demand/Energy/Customer as in related Plant	S06 Sum of Production, Transmission, Distribution, and General Plant
32	Colstrip Deferred Amortization	P = Production	Demand/Energy by Load Factor Peak Credit	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
33	Demand Side Management Investment	DSM	Demand/Energy by Load Factor Peak Credit	S01 Sum of Production Plant
34	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-21-01 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

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
8	928 Intervenor Funding	C = Customer Relations	Customer	C07/C08 Direct Assign to Residential and Small Commercial per IPUC Order
	Depreciation & Amortization Expense			
9	Intangible	P/T/D/O	Follows Related Plant	S01/S02/C01/S23 Sum of Prod. Plant / Sum of Trans. Plant / All Cust. / Corp Cost Allocato
10	Production	P = Production	Demand/Energy by Peak Credit as in related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
11	Transmission	T = Transmission	Demand	D01 Coincident Peak Demand (12CP)
12	Distribution	D = Distribution	Demand/Customer as in related Plant	D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
13	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	AFUDC Regulatory Deferral/Amortization	P/T/D/G	Demand/Energy/Customer as in related Plant	S06 Sum of Production, Transmission, Distribution, and General Plant
22	FISERVE (Fee Free) Deferral/Amortization	D = Distribution	Customer	C07 Direct Assign Residential
	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 | Filed

Scenario: AVU-E-21-01 Company Base Case | Cost of Service Basic Summary | Electric Utility | 01/29/21

Load Factor Peak Credit | For the Twelve Months Ended December 31, 2019

Transmission by Demand

	(b) Description	(c) (d) (e)	(f) System Total	(g) Residential Service Sch 01	(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
	Plant In Service									
1	Production Plant		520,389,000	218,009,144	68,106,556	108,986,679	53,086,894	61,076,540	9,622,574	1,500,614
2	Transmission Plant		326,847,000	150,467,273	42,918,674	68,140,630	29,784,469	30,290,300	4,841,524	404,129
3	Distribution Plant		656,851,000	343,933,575	98,972,601	136,380,070	20,945,469	3,050,218	23,621,054	29,948,013
4	Intangible Plant		104,175,000	56,003,260	14,835,493	16,749,189	6,871,630	7,063,588	1,992,600	659,242
5	General Plant		144,323,000	82,092,651	21,097,515	21,740,831	7,900,847	7,325,500	2,948,257	1,217,400
6	Total Plant In Service		1,752,585,000	850,505,903	245,930,839	351,997,399	118,589,308	108,806,145	43,026,008	33,729,398
	Accum Depreciation									
7	Production Plant		(236,976,000)	(99,277,531)	(31,014,528)	(49,630,617)	(24,174,838)	(27,813,182)	(4,381,951)	(683,353)
8	Transmission Plant		(88,090,000)	(40,553,109)	(11,567,204)	(18,364,887)	(8,027,346)	(8,163,675)	(1,304,861)	(108,919)
9	Distribution Plant		(263,227,000)	(141,573,294)	(40,685,218)	(52,221,683)	(7,075,420)	(826,795)	(9,311,619)	(11,532,971)
10	Intangible Plant		(40,825,000)	(22,802,737)	(5,912,242)	(6,267,232)	(2,398,954)	(2,329,942)	(808,582)	(305,311)
11	General Plant		(55,835,000)	(31,759,617)	(8,162,107)	(8,410,990)	(3,056,642)	(2,834,055)	(1,140,608)	(470,982)
12	Total Accumulated Depreciation		(684,953,000)	(335,966,288)	(97,341,299)	(134,895,408)	(44,733,200)	(41,967,649)	(16,947,621)	(13,101,536)
13	Net Plant		1,067,632,000	514,539,615	148,589,540	217,101,990	73,856,108	66,838,497	26,078,387	20,627,862
14	Accumulated Deferred FIT		(219,885,000)	(105,878,506)	(30,777,247)	(44,480,552)	(15,139,031)	(14,018,071)	(5,394,962)	(4,196,631)
15	Miscellaneous Rate Base		16,419,000	7,706,558	2,301,520	3,551,327	1,090,599	920,447	444,456	404,093
16	Total Rate Base		864,166,000	416,367,667	120,113,813	176,172,765	59,807,676	53,740,873	21,127,881	16,835,324
17	Revenue From Retail Rates		244,590,000	113,042,000	36,636,000	47,822,000	17,876,000	19,991,000	5,527,000	3,696,000
18	Other Operating Revenues		38,736,000	16,722,965	5,124,082	8,102,789	3,709,238	4,118,645	742,807	215,474
19	Total Revenues		283,326,000	129,764,965	41,760,082	55,924,789	21,585,238	24,109,645	6,269,807	3,911,474
	Operating Expenses									
20	Production Expenses		105,562,000	44,223,612	13,815,558	22,108,176	10,768,788	12,389,504	1,951,959	304,403
21	Transmission Expenses		11,562,000	5,322,682	1,518,220	2,410,430	1,053,606	1,071,500	171,266	14,296
22	Distribution Expenses		13,978,000	7,318,811	2,179,931	3,119,571	586,867	79,859	532,274	160,688
23	Customer Accounting Expenses		4,840,000	3,702,813	771,168	130,501	117,912	48,442	56,643	12,520
24	Customer Information Expenses		676,000	551,828	110,709	5,326	52	5	7,218	863
25	Sales Expenses		0	0	0	0	0	0	0	0
26	Admin & General Expenses		27,358,000	15,250,800	3,984,970	4,295,274	1,536,375	1,432,485	576,224	281,873
27	Total O&M Expenses		163,976,000	76,370,546	22,380,555	32,069,278	14,063,599	15,021,794	3,295,585	774,642
28	Taxes Other Than Income Taxes		12,555,000	5,713,611	1,712,159	2,621,056	1,015,111	1,030,113	283,790	179,161
29	Other Income Related Items		(418,000)	31,550	(60,388)	(159,524)	(100,870)	(129,787)	(6,944)	7,963
	Depreciation Expense									
30	Production Plant Depreciation		13,895,000	5,821,101	1,818,525	2,910,073	1,417,483	1,630,816	256,934	40,068
31	Transmission Plant Depreciation		7,135,000	3,284,668	936,905	1,487,495	650,189	661,231	105,689	8,822
32	Distribution Plant Depreciation		17,782,000	9,414,763	2,828,795	3,503,000	524,911	64,016	636,681	809,834
33	General Plant Depreciation		7,952,000	4,523,193	1,162,444	1,197,890	435,326	403,625	162,445	67,077
34	Amortization Expense		13,395,000	6,545,563	1,874,917	2,616,559	929,468	890,721	312,573	225,200
35	Total Depreciation Expense		60,159,000	29,589,289	8,621,587	11,715,017	3,957,375	3,650,408	1,474,323	1,151,001
36	Income Tax		2,550,000	788,977	599,076	528,084	118,656	312,167	69,270	133,771
37	Total Operating Expenses		238,822,000	112,493,972	33,252,989	46,773,912	19,053,871	19,884,695	5,116,023	2,246,538
38	Net Income		44,504,000	17,270,992	8,507,093	9,150,877	2,531,367	4,224,950	1,153,784	1,664,936
39	Rate of Return		5.15%	4.15%	7.08%	5.19%	4.23%	7.86%	5.46%	9.89%
40	Return Ratio		1.00	0.81	1.38	1.01	0.82	1.53	1.06	1.92
41	Interest Expense		20,308,000	9,784,688	2,822,688	4,140,080	1,405,487	1,262,917	496,508	395,632
42	Revenue Related Operating Expenses		1,176,000	543,511	176,148	229,930	85,949	96,118	26,574	17,771

Sumcost
Scenario: AVU-E-21-01 Company Base Case
Load Factor Peak Credit
Transmission by Demand

AVISTA UTILITIES
Revenue to Cost by Functional Component Summary
For the Twelve Months Ended December 31, 2019

Idaho Jurisdiction
Electric Utility

Filed
01/29/21

	(b)	(c) (d) (e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Description		System Total	Residential Service Sch 01	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		110,630,031	45,177,900	15,098,134	23,146,910	11,023,260	13,774,106	2,056,311	353,411
2	Transmission		27,183,964	11,502,124	4,143,779	5,697,336	2,294,049	3,086,230	413,654	46,791
3	Distribution		57,909,065	30,278,911	9,942,776	10,923,868	1,779,538	320,926	1,991,238	2,671,808
4	Common		48,866,940	26,083,064	7,451,311	8,053,886	2,779,153	2,809,738	1,065,797	623,990
5	Total Current Rate Revenue		244,590,000	113,042,000	36,636,000	47,822,000	17,876,000	19,991,000	5,527,000	3,696,000
	Expressed as $/kWh									
6	Production		$0.03729	$0.03843	$0.03907	$0.03725	$0.03420	$0.03534	$0.03409	$0.03198
7	Transmission		$0.00916	$0.00978	$0.01072	$0.00917	$0.00712	$0.00792	$0.00686	$0.00423
8	Distribution		$0.01952	$0.02576	$0.02573	$0.01758	$0.00552	$0.00082	$0.03301	$0.24174
9	Common		$0.01647	$0.02219	$0.01928	$0.01296	$0.00862	$0.00721	$0.01767	$0.05646
10	Total Current Melded Rates		$0.08244	$0.09616	$0.09481	$0.07695	$0.05546	$0.05129	$0.09162	$0.33440
	Functional Cost Components at Uniform Current Return									
11	Production		110,408,115	46,253,819	14,449,799	23,123,113	11,263,159	12,958,279	2,041,569	318,377
12	Transmission		27,228,879	12,535,086	3,575,457	5,676,641	2,481,276	2,523,416	403,336	33,667
13	Distribution		57,934,108	32,091,701	8,941,707	10,890,782	1,894,329	265,201	1,951,822	1,898,567
14	Common		49,018,897	26,795,001	7,090,691	8,044,725	2,846,683	2,625,406	1,057,284	559,107
15	Total Uniform Current Cost		244,590,000	117,675,607	34,057,654	47,735,261	18,485,447	18,372,302	5,454,012	2,809,718
	Expressed as $/kWh									
16	Production		$0.03721	$0.03935	$0.03740	$0.03721	$0.03495	$0.03325	$0.03384	$0.02881
17	Transmission		$0.00918	$0.01066	$0.00925	$0.00913	$0.00770	$0.00647	$0.00669	$0.00305
18	Distribution		$0.01953	$0.02730	$0.02314	$0.01752	$0.00588	$0.00068	$0.03236	$0.17178
19	Common		$0.01652	$0.02279	$0.01835	$0.01294	$0.00883	$0.00674	$0.01753	$0.05059
20	Total Current Uniform Melded Rates		$0.08244	$0.10011	$0.08814	$0.07681	$0.05736	$0.04714	$0.09041	$0.25422
21	**Revenue to Cost Ratio at Current Rates**		1.00	0.96	1.08	1.00	0.97	1.09	1.01	1.32
	Functional Cost Components at Proposed Return by Schedule									
22	Production		117,414,966	47,838,313	16,031,638	24,476,293	11,735,810	14,795,281	2,169,434	368,198
23	Transmission		33,056,662	14,055,742	4,961,911	6,853,242	2,850,038	3,790,590	492,809	52,329
24	Distribution		66,719,121	34,760,550	11,383,920	12,771,821	2,120,428	390,667	2,293,639	2,998,096
25	Common		52,182,251	27,843,395	7,970,530	8,565,645	2,979,724	3,040,462	1,131,118	651,377
26	Total Proposed Rate Revenue		269,373,000	124,498,000	40,348,000	52,667,000	19,686,000	22,017,000	6,087,000	4,070,000
	Expressed as $/kWh									
27	Production		$0.03958	$0.04070	$0.04149	$0.03938	$0.03641	$0.03796	$0.03596	$0.03331
28	Transmission		$0.01114	$0.01196	$0.01284	$0.01103	$0.00884	$0.00973	$0.00817	$0.00473
29	Distribution		$0.02249	$0.02957	$0.02946	$0.02055	$0.00658	$0.00100	$0.03802	$0.27126
30	Common		$0.01759	$0.02369	$0.02063	$0.01378	$0.00925	$0.00780	$0.01875	$0.05893
31	Total Proposed Melded Rates		$0.09080	$0.10591	$0.10442	$0.08475	$0.06108	$0.05649	$0.10091	$0.36824
	Functional Cost Components at Uniform Requested Return									
32	Production		117,027,243	49,026,803	15,316,086	24,509,378	11,938,402	13,735,146	2,163,965	337,464
33	Transmission		33,010,646	15,196,780	4,334,668	6,882,016	3,008,149	3,059,237	488,981	40,816
34	Distribution		66,994,288	36,763,007	10,279,064	12,817,821	2,217,368	318,254	2,279,015	2,319,758
35	Common		52,340,823	28,629,821	7,572,523	8,578,382	3,036,751	2,800,930	1,127,959	594,457
36	Total Uniform Cost		269,373,000	129,616,411	37,502,341	52,787,597	20,200,670	19,913,567	6,059,919	3,292,495
	Expressed as $/kWh									
37	Production		$0.03945	$0.04171	$0.03964	$0.03944	$0.03704	$0.03524	$0.03587	$0.03053
38	Transmission		$0.01113	$0.01293	$0.01122	$0.01107	$0.00933	$0.00785	$0.00811	$0.00369
39	Distribution		$0.02258	$0.03127	$0.02660	$0.02062	$0.00688	$0.00082	$0.03778	$0.20989
40	Common		$0.01764	$0.02436	$0.01960	$0.01380	$0.00942	$0.00719	$0.01870	$0.05378
41	Total Uniform Melded Rates		$0.09080	$0.11026	$0.09706	$0.08494	$0.06268	$0.05109	$0.10046	$0.29790
42	**Revenue to Cost Ratio at Proposed Rates**		1.00	0.96	1.08	1.00	0.97	1.11	1.00	1.24
43	**Current Revenue to Proposed Cost Ratio**		**0.91**	**0.87**	**0.98**	**0.91**	**0.88**	**1.00**	**0.91**	**1.12**
44	**Target Revenue Increase**		**24,783,000**	**16,574,000**	**866,000**	**4,966,000**	**2,325,000**	**(77,000)**	**533,000**	**(404,000)**

Sumcost
Scenario: AVU-E-21-01 Company Base Case
Load Factor Peak Credit
Transmission by Demand

AVISTA UTILITIES
Revenue to Cost By Classification Summary
For the Twelve Months Ended December 31, 2019

Idaho Jurisdiction
Electric Utility

Filed
01/29/21

	(b)	(c) (d) (e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Description		System Total	Residential Service Sch 01	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		83,681,704	32,366,378	11,393,532	17,526,821	8,784,335	11,550,448	1,713,647	346,544
2	Demand		132,568,360	60,637,538	20,404,549	29,913,490	8,972,532	8,428,379	3,454,025	757,848
3	Customer		28,339,935	20,038,084	4,837,919	381,690	119,133	12,173	359,328	2,591,608
4	Total Current Rate Revenue		244,590,000	113,042,000	36,636,000	47,822,000	17,876,000	19,991,000	5,527,000	3,696,000
	Expressed as Unit Cost									
5	Energy	$/kWh	$0.02821	$0.02753	$0.02949	$0.02820	$0.02726	$0.02964	$0.02841	$0.03135
6	Demand	$/kW/mo	$10.28	$7.95	$12.50	$18.87	$12.58	$9.34	$8.58	$24.52
7	Customer	$/Cust/mo	$17.56	$15.21	$18.30	$30.01	$960.75	$1,014.41	$20.85	$1,258.06
	Cost Classifications at Uniform Current Return									
8	Energy		83,402,593	33,150,107	10,896,621	17,508,508	8,978,706	10,855,805	1,701,163	311,685
9	Demand		133,207,119	63,915,816	18,562,585	29,845,462	9,386,661	7,504,609	3,396,370	595,616
10	Customer		27,980,288	20,609,684	4,598,448	381,291	120,080	11,888	356,479	1,902,417
11	Total Uniform Current Cost		244,590,000	117,675,607	34,057,654	47,735,261	18,485,447	18,372,302	5,454,012	2,809,718
	Expressed as Unit Cost									
12	Energy	$/kWh	$0.02811	$0.02820	$0.02820	$0.02817	$0.02786	$0.02785	$0.02820	$0.02820
13	Demand	$/kW/mo	$10.33	$8.38	$11.37	$18.83	$13.16	$8.32	$8.43	$19.27
14	Customer	$/Cust/mo	$17.33	$15.64	$17.39	$29.98	$968.39	$990.68	$20.68	$923.50
15	**Revenue to Cost Ratio at Current Rates**		1.00	0.96	1.08	1.00	0.97	1.09	1.01	1.32
	Cost Classifications at Proposed Return by Schedule									
16	Energy		88,915,463	34,304,286	12,109,005	18,549,878	9,361,654	12,419,933	1,809,451	361,257
17	Demand		150,021,400	68,742,313	23,056,288	33,713,192	10,202,398	9,584,537	3,896,362	826,310
18	Customer		30,436,137	21,451,401	5,182,707	403,930	121,948	12,530	381,188	2,882,434
19	Total Proposed Rate Revenue		269,373,000	124,498,000	40,348,000	52,667,000	19,686,000	22,017,000	6,087,000	4,070,000
	Expressed as Unit Cost									
20	Energy	$/kWh	$0.02997	$0.02918	$0.03134	$0.02985	$0.02905	$0.03187	$0.03000	$0.03269
21	Demand	$/kW/mo	$11.64	$9.01	$14.12	$21.27	$14.30	$10.62	$9.67	$26.74
22	Customer	$/Cust/mo	$18.85	$16.28	$19.60	$31.76	$983.45	$1,044.13	$22.11	$1,399.24
	Cost Classifications at Uniform Requested Return									
23	Energy		88,484,495	35,170,015	11,560,576	18,575,339	9,525,798	11,517,272	1,804,818	330,677
24	Demand		150,689,939	72,363,591	21,023,357	33,807,773	10,552,125	8,384,135	3,874,970	683,989
25	Customer		30,198,565	22,082,806	4,918,408	404,484	122,748	12,159	380,131	2,277,829
26	Total Uniform Cost		269,373,000	129,616,411	37,502,341	52,787,597	20,200,670	19,913,567	6,059,919	3,292,495
	Expressed as Unit Cost									
27	Energy	$/kWh	$0.02982	$0.02992	$0.02992	$0.02989	$0.02956	$0.02955	$0.02992	$0.02992
28	Demand	$/kW/mo	$11.69	$9.49	$12.88	$21.33	$14.79	$9.29	$9.62	$22.13
29	Customer	$/Cust/mo	$18.71	$16.76	$18.60	$31.80	$989.90	$1,013.29	$22.05	$1,105.74
30	**Revenue to Cost Ratio at Proposed Rates**		1.00	0.96	1.08	1.00	0.97	1.11	1.00	1.24
31	**Current Revenue to Proposed Cost Ratio**		**0.91**	**0.87**	**0.98**	**0.91**	**0.88**	**1.00**	**0.91**	**1.12**
32	Annual Consumption (mWh's)		2,966,810	1,175,515	386,398	621,476	322,296	389,749	60,324	11,052
33	Estimated Annual Billing Demand (kW)		12,893,861	7,627,031	1,632,488	1,585,042	713,235	902,420	402,738	30,907
34	Monthly Average Number of Customers		134,526	109,816	22,031	1,060	10	1	1,436	172

Exhibit No. 16
Case No. AVU-E-21-01
T. Knox, Avista
Schedule 3, p. 3 of 4

Sumcost		AVISTA UTILITIES			Idaho Jurisdiction			Filed
Scenario: AVU-E-21-01 Company Base Case		Customer Cost Analysis			Electric Utility			01/29/21
Load Factor Peak Credit		For the Twelve Months Ended December 31, 2019						
Transmission by Demand								

	(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 01	Sch 11-12	Sch 21-22	Sch 25	Sch 25P	Sch 31-32	Sch 41-49

Meter, Services, Meter Reading & Billing Costs by Schedule at Requested Rate of Return

	Description	System Total	Residential Service Sch 01	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
	Rate Base								
1	Services	60,394,000	49,376,424	9,905,979	465,741	0	0	645,856	0
2	Services Accum. Depr.	(30,433,000)	(24,881,159)	(4,991,699)	(234,691)	0	0	(325,452)	0
3	Total Services	29,961,000	24,495,265	4,914,280	231,051	0	0	320,404	0
4	Meters	23,136,000	15,022,919	6,057,985	1,278,780	29,078	4,456	742,783	0
5	Meters Accum. Depr.	(15,088,000)	(9,797,104)	(3,950,677)	(833,949)	(18,963)	(2,906)	(484,401)	0
6	Total Meters	8,048,000	5,225,815	2,107,307	444,832	10,115	1,550	258,382	0
7	Total Rate Base	38,009,000	29,721,080	7,021,588	675,882	10,115	1,550	578,786	0
8	Return on Rate Base @ 7.30%	2,774,652	2,169,635	512,575	49,339	738	113	42,251	0
9	Tax Benefit of Interest	(312,626)	(244,457)	(57,753)	(5,559)	(83)	(13)	(4,761)	0
10	Revenue Conversion Factor	0.749719	0.749719	0.749719	0.749719	0.749719	0.749719	0.749719	0.749719
11	**Rate Base Revenue Requirement**	**3,283,930**	**2,567,864**	**606,656**	**58,395**	**874**	**134**	**50,006**	**0**
	Expenses								
12	Services Depr Exp	1,341,000	1,096,364	219,954	10,341	0	0	14,341	0
13	Meters Depr Exp	2,009,000	1,304,506	526,041	111,042	2,525	387	64,499	0
14	Services Operations Exp	321,000	262,441	52,651	2,475	0	0	3,433	0
15	Meters Operating Exp	410,000	266,226	107,355	22,662	515	79	13,163	0
16	Meters Maintenance Exp	9,000	5,844	2,357	497	11	2	289	0
17	Meter Reading	398,000	255,041	51,167	2,461	78,407	7,588	3,336	0
18	Billing	3,805,000	3,104,520	622,834	29,962	2,027	196	40,608	4,853
19	Total Expenses	8,293,000	6,294,941	1,582,360	179,441	83,485	8,251	139,668	4,853
20	Revenue Conversion Factor	0.995006	0.995006	0.995006	0.995006	0.995006	0.995006	0.995006	0.995006
21	**Expense Revenue Requirement**	**8,334,623**	**6,326,536**	**1,590,302**	**180,342**	**83,904**	**8,293**	**140,369**	**4,877**
22	**Total Meter, Service, Meter Reading, and Billing Cost**	**11,618,553**	**8,894,400**	**2,196,958**	**238,737**	**84,778**	**8,427**	**190,376**	**4,877**
23	Total Customer Bills	1,614,317	1,317,789	264,377	12,718	124	12	17,237	2,060
24	**Average Unit Cost per Month**	**$7.20**	**$6.75**	**$8.31**	**$18.77**	**$683.69**	**$702.23**	**$11.04**	**$2.37**

Distribution Fixed Costs per Customer

	Description	System Total	Residential Service Sch 01	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
25	Total Customer Related Cost	30,198,565	22,082,806	4,918,408	404,484	122,748	12,159	380,131	2,277,829
26	Customer Related Unit Cost per Month	$18.71	$16.76	$18.60	$31.80	$989.90	$1,013.29	$22.05	$1,105.74
27	Total Distribution Demand Related Cost	63,553,859	32,170,224	9,556,936	15,590,948	2,659,732	384,050	2,567,289	624,681
28	Dist Demand Related Unit Cost per Month	$39.37	$24.41	$36.15	$1,225.90	$21,449.45	$32,004.20	$148.94	$303.24
29	**Total Distribution Unit Cost per Month**	**$58.08**	**$41.17**	**$54.75**	**$1,257.70**	**$22,439.35**	**$33,017.49**	**$170.99**	**$1,408.99**