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EXHIBIT: GAW-1T
ADMIT ☑ W/D ☐ REJECT ☐

BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILIITES AND TRANSPORTATION COMMISSION,

Complainant,

v.

AVISTA CORPORATION d/b/a AVISTA UTILITIES,

Respondent.

DOCKET NOS. UE-200900 and UG-200901

RESPONSE TESTIMONY OF GLENN A. WATKINS
ON BEHALF OF
WASHINGTON STATE OFFICE OF THE ATTORNEY GENERAL
PUBLIC COUNSEL UNIT

EXHIBIT GAW-1T

April 21, 2021

RESPONSE TESTIMONY OF GLENN A. WATKINS

DOCKET NOS. UE-200900 and UG-200901

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I. INTRODUCTION / SUMMARY

Q. Please state your name and business address.

A. My name is Glenn A. Watkins. My business address is 6377 Mattawan Trail, Mechanicsville, Virginia 23116.

Q. By whom are you employed and in what capacity?

A. I am President and Senior Economist with Technical Associates, Inc., which is an economics and financial consulting firm with offices in the Richmond, Virginia area.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Public Counsel Unit of the Washington Attorney General's Office ("Public Counsel").

Q. Please describe your professional qualifications.

A. During my 40-year career at Technical Associates, I have conducted hundreds of marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving electric, gas, water/wastewater, and telephone utilities throughout the United States and Canada. I have provided expert testimony in Alabama, Arizona, Delaware, Georgia, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. In addition, I have provided expert testimony before State and Federal courts as well as before State legislatures. A more complete description of my education and experience is provided in Exhibit GAW-2.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring Exhibit GAW-2 through Exhibit GAW-5.

Q. What is the purpose of your testimony in this proceeding?

A. Public Counsel retained Technical Associates to evaluate the accuracy and reasonableness of Avista Utilities ("Avista" or "Company") electric and natural gas class cost of service studies (CCOSS), proposed distribution of revenues by class ("rate spread"), and Residential rate designs. The purpose of my testimony, therefore, is to comment on Avista's proposals on these issues and to present my findings and recommendations based on the results of the studies I have undertaken on behalf of Public Counsel.

Q. Please summarize your findings and recommendations.

A. With regard to electric operations, I have concluded that no weight should be given to the Company's class cost of service study and agree with the Company's across-the-board (equal percentage) increases for class rate spread purposes. I also agree with the Company's proposal to not increase Residential customer charges.

With regard to natural gas operations, I have concluded that little, if any, weight should be given to the Company's class cost of service study and agree with the Company's across-the-board (equal percentage) increases for class rate spread purposes. I also agree with the Company's proposal to not increase General Service customer charges.

With regard to tax credits resulting from the Company's proposal to change from normalization to flow-through accounting practices, I concur that any approach and amounts approved by the Washington Utilities and Transportation Commission ("Commission" or WUTC) in this case should exactly offset any base rate increases authorized for both electric and natural gas services.

Q. Please explain how your direct testimony is structured.

A. In addition to this introduction, I have separated my direct testimony into two sections: Electric Operations and Natural Gas Operations. For each operational section, I have three subsections entitled: Class Cost of Service, Class Revenue Distribution (Rate Spread), and Residential Rate Design.

II. ELECTRIC OPERATIONS

A. Electric Cost of Service

Q. Please briefly explain the concept of a class cost of service study (CCOSS) and its purpose in a rate proceeding.

A. Generally, there are two types of cost of service studies used in public utility ratemaking: marginal cost studies and embedded, or fully allocated, cost studies. Consistent with the practices of the WUTC, Avista has utilized a traditional embedded cost of service study for purposes of establishing the overall revenue requirement in this case, as well as for class cost of service purposes.

Embedded class cost of service studies are also referred to as fully allocated cost studies because the majority of a public utility's plant investment and expenses are incurred to serve all customers in a joint manner. Accordingly, most costs cannot be specifically attributed to a particular customer or group of customers. To the extent that certain costs can be specifically attributed to a particular customer or group of customers, these costs are directly assigned to that customer or group in the CCOSS. Since most of the utility's costs of providing service are jointly incurred to serve all or most customers, they must be allocated across specific customers or customer rate classes.

It is generally accepted that to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although cost analysts strive to abide by this concept to the greatest extent practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors and must be subjectively assigned or allocated to customer rate classes. With regard to those costs which cost causation can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor (e.g., peak demand, energy usage, number of customers, etc.).

Q. Have the higher courts opined on the usefulness of cost allocations for purposes of establishing revenue responsibility and rates?

A. Yes. In an important regulatory case involving Colorado Interstate Gas Company and the Federal Power Commission (the predecessor to Federal Energy Regulatory Commission), the United States Supreme Court stated:

> But whereas here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science.[1]

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[1] *Colo. Interstate Gas Co. v. Fed. Power Comm'n*, 324 U.S. 581, 65 S. Ct. 829, 89 L. Ed. 1206 (1945).

Q. Does your opinion, and the findings of the U.S. Supreme Court, imply that cost allocations should play no role in the ratemaking process?

A. Not at all. It simply means that regulators should consider the fact that cost allocation results are not surgically precise and that alternative, yet equally defensible, approaches may produce significantly different results. In this regard, when all reasonable cost allocation approaches consistently show that certain classes are over or under contributing to costs and/or profits, there is a strong rationale for assigning smaller or greater percentage rate increases to these classes. On the other hand, if one set of reasonable cost allocation approaches show dramatically different results than another reasonable approach, caution should be exercised in assigning disproportionately larger or smaller percentage increases to the classes in question.

1. Generation costs

Q. Before you discuss specific cost allocation methodologies, please explain how generation and production-related costs are incurred. In doing so, please explain the cost causation concepts relating to generation and production resources.

A. Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. Because of this, and the physical laws of electricity, it is impossible to determine which facilities are serving which customers. As such, production facilities are joint costs, i.e., they are used by all customers. Because of this commonality, production-related costs are not directly known for any customer or customer group and must somehow be allocated.

If all customer classes used electricity at a constant rate (“load”) throughout the year, there would be no disagreement as to the proper assignment of generation-related costs. All analysts would agree that energy usage in terms of kilowatt-hour (KWh) would be the proper approach to reflect cost causation and cost incidence. However, such is not the case in that Avista experiences periods (hours) of much higher demand during certain times of the year and across various hours of the day. Moreover, not all customer classes contribute in equal proportions to these varying demands placed on the generation system.

Historically, there was a distinct energy/capacity trade-off relating to production costs. That is, utilities generally designed their mix of production facilities (generation and power supply) to minimize the total costs of energy and capacity, while also ensuring there was enough available capacity to meet peak demands. The cost trade-off occurred between the level of fixed investment per unit of capacity kilowatt (KW) and the variable cost of producing a unit of output (KWh). Large base load units such as coal and nuclear required high capital expenditures resulting in large investments per KW, whereas smaller units with higher variable production costs generally required significantly less investment per KW. Due to varying levels of demand placed on the system over the course of each day, month, and year there was a unique optimal mix of production facilities for each utility that minimizes the total cost of capacity and energy (i.e., its cost of service).

Q. In your previous answer, you discussed the planning process in the past tense. Has there recently been a material change in the manner in which electric utilities plan for their future energy and peak load requirements?

A. Yes. In Washington (as well as in several other states), there is a legislative mandate to reduce, and eventually eliminate, carbon emissions from electric generation. As a result, Washington utilities will eventually replace its fossil fuel-fired generators with various sources of so-called renewable energy resources.

This requirement causes numerous challenges and constraints that will be confronted by Washington electric utilities in that: (1) many carbon-free generation options are not truly "dispatchable" in nature, and therefore, cannot be relied upon to meet load requirements at any point in time; and (2) there is not a distinct capacity/energy cost trade-off between various types of carbon-free generation units (i.e., small carbon-free "peaker" units may not have lower fixed capacity costs than those of larger carbon-free units designed to primarily serve energy needs throughout the year). Therefore, Washington utilities will need to consider that many carbon-free alternatives do not have the dispatchable reliability to meet load requirements each and every hour the year, yet the utilities must have enough capacity available to meet peak load requirements.

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a. Renewable peak credit

Q. Does the movement away from fossil-fueled generation conflict with the UTC's historically preferred approach used to allocate generation-related costs?

A. Yes. Since the early-1980s, the Peak Credit method has been this Commission's preferred method to allocate production-related costs.[2] The Peak Credit method (which is a variant of the Equivalent Peaker method) is loosely based on forward-looking short-run marginal cost theory wherein: (1) increases in peak demand require the addition of peaking capacity only; and, (2) utilities incur the costs of more expensive intermediate and base load units because of the additional energy loads they must serve.[3] However, the most fundamental assumptions within the Peak Credit method are that: (1) there is a distinct capacity/energy cost trade-off between peaker units and base load units (i.e., the fixed capacity cost of a peaker unit are much lower than those of a base load unit, yet the peaker unit's variable running costs are more expensive than those of a base load unit); and, (2) both peaker and base load units must be dispatchable in nature.

With Washington's movement toward carbon-free generation, electric utilities' planning processes do not follow the historical, or traditional, generation

[2] In Cause U-78-05, the UTC first adopted the Peak Credit method. *In re Investigation into Rate Design and Rate Structures for Electrical Service, the Alterations, if any, that Should Be Ordered to such Rate Design and Rate Structures, and the Adequacy of Existing Rules Relating to Electrical Companies and Amendments or Additions Thereto that May Be Appropriate Regarding Master Metering, Information to Consumers, Advertising, and Termination of Service*, Docket No. U-78-05, Decision and Order, at 5 (Oct. 29, 1980). Then in Cause U-81-41, the Commission also accepted Puget Sound Energy's proposal to use the Peak Credit method to allocate generation-related costs. *WUTC v. Puget Sound Power & Light Co.*, Docket U-81-41, Sixth Supplemental Order at 23 (Dec. 1988). Then in Cause U-82-10, the Commission rejected Washington Water Power Company's (now Avista) proposal to use the Average & Excess method to allocate generation-related costs and directed WWP to prepare future studies using the Peak Credit method. *WUTC v. Wash. Water Power*, Docket No. U-82-10, Second Supplemental Order, at 36 (Dec. 29, 1985).

[3] NARUC, *Electric Utility Cost Allocation Manual*, at 53 (Jan. 1992).

expansion theories or practices simply because these replacements will not only be those required to meet incremental peak load requirements, but rather, to reduce carbon emissions resulting from the energy produced largely from the current stock of base load units. Furthermore, the two other fundamental assumptions required for the Peak Credit method (a capacity/energy cost trade-off between peakers and base load units as well as the requirement that generation resources must be reliably dispatchable) cannot be reasonably or accurately satisfied (at least with currently viable renewable generation options).

As such, the basic premises and foundations of the Peak Credit method do not hold in today's generation planning environment.

Q. Please explain this in detail.

A. First and foremost, it is important not to lose sight of the forest for the trees in selecting a reasonable and equitable method to allocate a utility's generation plant investment included in rate base. Under traditional ratemaking, the various customer classes are "allocated" portions of the embedded costs of generation plant that is included in rate base. The ultimate objective of such allocation is to fairly and equitably assign these embedded costs based on how the various customer classes utilize and require output from a utility's portfolio of generation resources. Any method that is based on speculative assumptions or that does not reflect current or near-term reality cannot be deemed reliable, or even reasonable, and therefore, should not be considered in the assignment of cost responsibility across classes.

While the Peak Credit method was at one time a reasonable allocation approach that was based on reasonably known generation expansion costs wherein a new peaking unit was a gas combustion turbine (with known costs) and a new base load unit was a gas combined cycle unit (with known costs), as discussed above, the situation is much different today.

Specifically, as it relates to Avista, the Company's proposed Peak Credit method was developed from data contained in its 2020 Integrated Resource Plan (IRP). With regard to Avista's forward-looking generation plan contained in its IRP, during the near-future (2021 through 2025), the Company's preferred resource strategy is to acquire Purchased Power Agreements (PPA) for wind generation along with upgrades to some of its existing hydro facilities. Then for the period 2026 through 2030 (with an assumed Colstrip plant closing in 2025), Avista will consider the addition of 175 MW of pumped hydro storage along with an additional 200 MW of wind resources. However, the Company's IRP is clear in that "at any time, if Avista believes pumped storage is not feasible or cost effective, Avista may pursue other alternatives including a natural gas-fired peaker."[4]

The following table reflects Avista's preferred resource strategy for the period 2021 through 2030:

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[4] Avista Corp., *2020 Electric Integrated Resource Plan*, at 11-3–11-5 ("Avista 2020 IRP").

TABLE 1
Avista 2020 Preferred Resource Strategy (2021–2030)[5]

Resource	In-Service Year	ISO Conditions (MW)	Equivalent Winter Peak Capacity (MW)	Capacity Factor
On-system wind	2022	100	5	37%
Montana wind	2022	100	40	48%
On-System wind	2023	100	5	37%
Kettle Falls modernization	2024	12	12	83%
Rathdrum CT upgrade	2026	24	24	92%
Long duration pumped hydro storage	2026	175	175	--
Post Falls modernization	2026	8	3.7	56%
Montana wind	2027	200	80	48%
Total		719	344.7	35%

In this regard, the Company's planned pumped hydro storage that may be considered in 2026 cannot be considered a "peaker" unit in that pumped hydro storage facilities operate throughout the year. Water is pumped uphill during low-cost evening and night hours and then used to generate electricity during the higher cost morning and daylight hours throughout the year; i.e., such facilities are not designed nor utilized simply to meet short-term peak load requirements. Furthermore, the capital costs per KW of a pumped hydro storage facility are significantly larger than those of a traditional peaker unit.[6]

In the mid-term planning horizon (2031 through 2035), Avista's preferred resource strategy is to acquire an additional 75 MW of regional hydro generation through a PPA along with a 68 MW upgrade to its current hydro facility at Long Lake.[7]

[5] Avista 2020 IRP, at 11-5, Table 11.1.
[6] For example, Avista's 2020 IRP estimates that the capital cost (2018 $) of a 100 mW pumped hydro storage facility is $2,850/kW as compared to a combustion turbine unit of $656/kW. Indeed, the estimated capital cost of pumped hydro storage are among the highest of all possible alternatives including those resources used to primarily meet energy needs throughout the year. Avista 2020 IRP, Appendix H.
[7] *Id.* at 11-7.

After 2035 through 2040, Avista anticipates that liquid air energy storage will be the economic choice to meet growing peak loads and to replace the likely retirement of the Northeast combustion turbine. The following table provides Avista's preferred resource strategy for the period 2031 through 2040:

TABLE 2
Avista 2020 Preferred Resource Strategy (2031–2040)[8]

Resource	Time Period	ISO Conditions (MW)	Equivalent Winter Peak Capacity (MW)	Capacity Factor
Regional hydro PPA	2031	75	75	45%
Long Lake upgrade/modernization	2035	68	68	34%
Liquid air energy storage (LAES)	2036	25	15	--
Liquid air energy storage (LAES)	2038	25	15	--
Liquid air energy storage (LAES)	2040	25	15	--
Total		218	188	26%

As can be seen above, Avista does not consider a true renewable peaker generation resource until at least 2036 (some 15 years from now).

Although Avista does not forecast resource additions beyond 20 years, its 2020 IRP does provide long-term potential additions required to meet both energy and capacity requirements as shown in the table below:

TABLE 3
Avista 2020 Preferred Resource Strategy (2041–2045)[9]

Resource	Time Period	Equivalent Winter Peak Capacity (MW)	Capacity Factor
Liquid air energy storage	2041	15	--
NW wind	2042	5	37%
4 hour storage (lithium-ion)	2042	3.75	--
NW wind	2043	5	37%
4 hour storage (lithium-ion)	2043	15	--
Solar	2043	0.1	26%
Solar w/storage (50 MW x 4 hours)	2044	8.5	24%
4 hour storage (lithium-ion)	2044	11.25	--
NW wind	2045	5	37%
4 hour storage (lithium-ion)	2045	15	--
Total		83.6	18%

[8] Avista 2020 IRP, at 11-7, Table 11.1.
[9] Avista 2020 IRP, at 11-8, Table 11.2.

While the above-referenced lithium-ion battery storage possibility may be considered a peaker unit, Avista has no plans to consider such technology for at least another 20-plus years. Furthermore, and as stated in the Company's IRP, the cost of a lithium-ion battery storage facility is not known with any level of certainty in that Avista assumed that the cost of such technology will decline over time and that the current cost was based on publicly available pricing forecasts as well as a review by Black & Veatch.

To summarize, it is apparent that Avista has no plans to add a carbon-free peaker unit for at least 15 years and that its near-term wind powered additions will be through PPAs and not Company-owned plant that would be included in rate base.[10] Therefore, there is no reasonable or reliable basis to apply the traditional Peak Credit method for cost allocation purposes. An incremental peaker unit will not be considered for many years into the future at a cost that is speculative at best and the incremental cost of a base load unit is considered to be wind generation, which is not dispatchable and only operates at approximately a 37 percent capacity factor. In addition, it is Avista's plan not to construct, own and operate wind generation for at least several years and additional wind generation will be met with PPAs. As a result, any energy/demand classification of generation plant derived from the Peak Credit method that only considers renewable resources is not based on reality, is based on speculative cost estimates, and is frankly a method lost in the forest due to the trees.

[10] The costs associated with PPAs are typically recovered through Avista's purchased power cost expenses.

Q. Did Avista classify generation plant based on its interpretation of a Renewable Peak Credit method?

A. Yes. Company witness Tara Knox sponsors the Company's class cost of service study and indicates that her study reflects her best efforts to comply with the Commission's recent rulemaking in Docket No. UE-170002, wherein it adopted WAC 480-85-060. In doing so, Ms. Knox attempted to apply a hypothetical Renewable Peak Credit method wherein she ultimately classified generation plant as 67 percent demand-related and 33 percent energy-related.[11]

Q. What parameters and assumptions did Ms. Knox utilize in developing her proposed Renewable Peak Credit classification of generation plant?

A. The Peak Credit method is based on the ratio of the levelized cost of an incremental peaker unit to the levelized cost of an incremental base load plus peaker unit. In this regard, the resulting ratio reflects the demand percentage classification while the residual (one minus the demand percentage) reflects the energy percentage classification.

With respect to her selection of an incremental renewable peaker unit, Ms. Knox assumed that the incremental peaker plant will be a 25 MW lithium-ion battery storage facility with an 8 MWh capability.[12] With respect to her selection of an incremental base load unit, Ms. Knox assumed that the incremental base

[11] Direct Testimony of Tara L. Knox, Exh. TLK-1T, 15:18–21.
[12] Ms. Knox's analysis utilized a fixed cost per KW of $384.55 (per her CCOSS Excel model, Tab "Renewable Future Peak Credit"). The source of this amount is from the Company's 2020 IRP Appendix H, Tab "Ownership Storage" which then refers to a 25 MW lithium-ion battery with 8 MWh capability (per Tab "Resource Options" in Appendix H to the 2020 IRP). See also Glenn A. Watkins, Exh. GAW-6, Avista response to Public Counsel Data Request No. 279(a).

load unit will be provided from a PPA that has a contractual cost of $38.15 per MWh.[13]

Q. Do you have any concerns and comments concerning the types of renewable generation units Ms. Knox selected within her analysis?

A. Yes, I have several. First, it is important to understand that Ms. Knox based her calculations on data assumptions contained in the Company's 2020 IRP Appendix H. Specifically, the 2022 levelized carrying costs of her selected peaker and base load units came directly from the Company's 2020 IRP Appendix H. In this regard, and as discussed earlier in my testimony, Avista has no intentions of needing or acquiring any renewable peaker units in the foreseeable future. As a result, Ms. Knox's analysis is hypothetical at best and does not reflect the actual cost causation of Avista's generation plant in rate base nor does her analysis reflect the reality of any incremental peaker plant investments that Avista will be making in the foreseeable future. Indeed, even if the Commission were to consider Ms. Knox's hypothetical analysis, her calculations are rife with assumptions that are speculative in nature and/or not known with any degree of certainty.

Q. Please discuss your concerns with Ms. Knox's selected 8 MWh lithium-ion storage battery peaker plant.

A. First and foremost, Ms. Knox selected an 8 MWh lithium-ion battery storage facility as her forward-looking incremental peaker plant which is not even considered in Avista's planning horizon (as set forth in its 2020 IRP). In fact, the only lithium-ion battery storage even considered in the IRP is the possibility of a

[13] Per Watkins, Exh. GAW-6, Avista response to Public Counsel Data Request No. 279(e).

potential 4-hour lithium-ion storage facility that would not be constructed until at least the year 2042.[14] Although a 4-hour lithium-ion battery storage is not a reasonable proxy for an incremental peaker unit in today's world (or in the near future), it should be noted that the 2022 levelized capital cost of a 4-hour battery was calculated by Avista in its IRP to be $196.23 per KW as compared to Ms. Knox's selected 8 MWh 2022 levelized capital cost of $384.55 per KW (49 percent cheaper).[15]

Notwithstanding the concerns noted above, I then evaluated the basis for Avista's assumed costs of lithium-ion storage facilities. Remembering that Avista stated in its IRP that it does not forecast resource additions beyond 20 years and that no lithium-ion battery storage facilities are even anticipated for some 21-plus years into the future,[16] the Company's assumed future costs of lithium-ion battery storage facilities were based on "publicly available pricing and forecasts, as well as review by Black & Veatch."[17] In this regard, Avista's assumed installation costs (excluding AFUDC) for a 25 MW 8-hour lithium-ion battery storage facility is $2,818 per KW (in 2018 dollars). Similarly, Avista estimated the installation cost of a 25 MW 4-hour lithium-ion battery storage facility to be $1,438 per KW. Because Avista's estimates are not based on any specific knowledge of the cost of such technology, I then evaluated the reasonableness of the Company's assumed installation costs of such facilities.

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[14] Avista 2020 IRP, at 12-3, Table 12.1.
[15] Per Avista's 2020 IRP Appendix H, Tab "Ownership Storage."
[16] Avista 2020 IRP, at 11–7.
[17] *Id.* at 9–12.

In July 2020, the U.S. Department of Energy, Energy Information Administration published a report entitled: Battery Storage in the United States: An Update on Market Trends.[18] As noted on page 18 of this report, the installed cost of lithium-ion batteries has declined precipitously between 2015 and 2017 wherein the average installed cost of larger-scale battery storage facilities in 2017 was $1,587 per KW.[19] This compares to Avista's estimated 2018 cost for an 8-hour storage facility of $2,818 per KW. Therefore, and while Avista acknowledges that it does not have specific information concerning the cost of a future lithium-ion battery storage facility, it would appear that the Company's estimated cost in 2018 dollars is significantly overstated.[20]

My next concern regarding Ms. Knox's overall approach is that the levelized capital cost of her selected peaker unit (8 MWh lithium-ion battery) is $384.55 per KW while her calculated levelized capital cost of a base load unit (PPA wind turbine) is only $201.35 per KW.[21] As discussed earlier in my testimony, a fundamental assumption under the Peak Credit method is that on an incremental basis, a utility will install a relatively inexpensive (low capital cost) peaker unit to meet incremental load as compared to a more expensive base load unit. Under Ms. Knox's approach, we see that her calculated levelized fixed capital cost of a peaker unit is almost twice as expensive per KW as that of a base load unit.

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[18] U.S. Energy Information Administration, *Battery Storage in the United States: An Update on Market Trends*, U.S. DEP'T OF ENERGY (July 2020) available at https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf.

[19] Larger-scale units were defined with capacity of more than 1 MW of nameplate power capacity.

[20] Avista does assume future reductions to the installation cost of lithium-ion batteries such that by 2022 the assumed cost per KW for an 8-hour lithium-ion battery is $2,185 per KW.

[21] Per Tara L. Knox Workpaper CCOSS Excel titled "UE-20 Base Case Electric COS Model.xlsm", Tab "Renewable Future Peak Credit."

Q. Please discuss your concerns with Ms. Knox's selected PPA contract for a wind turbine.

A. First and foremost, the entire purpose of Ms. Knox's exercise is to develop a classification methodology that is used to ultimately allocate Avista's <u>owned</u> plant in service that is included in its rate base. However, Ms. Knox did not reflect the cost of owning an incremental base load unit, but rather, crafted a surrogate cost of a unit that would be contracted for under a PPA. The fundamental problem in Ms. Knox's approach is that power produced under a PPA is recovered as expenses and not reflected in rate base. Furthermore, Ms. Knox had to back into a surrogate cost per KW by using an assumed contractual variable energy PPA cost of $38.15 per MWh. In doing so, even though the PPA would be constructed on an energy basis, Ms. Knox was compelled to somehow convert this into a surrogate cost per KW.[22]

Ms. Knox did attempt to recognize that wind generation is not dispatchable and cannot be relied upon for each and every hour of the year by assuming a load factor of 60.3 percent and a capacity factor of 37.7 percent to arrive at an ultimate imputed fixed cost per KW from an energy-based PPA contract of $201.35 per KW. She then reduced this $201.35 amount by 5 percent to reflect the "relationship to the amount of MW of natural gas CTs [that] are displaced with wind from the northwest to equal the same Loss of Load

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[22] Ms. Knox calculated her surrogate fixed cost per KW of $125.89 as: $38.15 per MWh for a 100 MW facility operating at a 37.67 percent capacity factor; i.e., $38.15 x (100 MW x 8,760 hours x 37.67 percent CF) ÷ (100 MW x 1,000). Per Knox Workpaper CCOSS Excel titled "UE-20 Base Case Electric COS Model.xlsm", Tab "Renewable Future Peak Credit."

Probability target of 5%."[23] Ultimately, Ms. Knox calculated a fixed cost of $191.29 per KW.[24]

Q. What are your conclusions regarding Ms. Knox's Renewable Peak Credit analysis wherein she ultimately classified the Company's generation plant investment as 67 percent demand-related and 33 percent energy-related?

A. I appreciate Ms. Knox's attempt to comply with the Commission's new regulations that mandate a preferred (if not required) methodology to classify and allocate Avista's generation plant in service. However, for the reasons discussed above as well as earlier in my testimony, the analysis and findings are meaningless and in no way relate to how Avista's current portfolio of generation assets are planned and utilized nor does it relate to how the Company's future generation assets will be configured as set forth in its IRP.

b. Class peak demands

Q. Have you examined Ms. Knox's estimation of class coincident peak (CP) demands?

A. Yes. Ms. Knox's workpapers used to develop her estimated class contributions to monthly CP demands were provided in electronic format.[25] As noted in Ms. Knox's testimony, the Company has not developed class CPs based on AMI data but rather has relied on estimates from a previous load study. In this regard, Ms. Knox claims that her class estimated peak demands were based on a 2014 Load

[23] Watkins, Exh. GAW-6, Avista Response to Public Counsel Data Request No. 279(i).
[24] Per Knox Workpaper CCOSS Excel titled "UE-20 Base Case Electric COS Model.xlsm", Tab "Renewable Future Peak Credit."
[25] Knox Workpaper titled "System and Distribution Demand 12CP 12.2019.xlsm".

Study.[26] However, it appears that this representation is not entirely accurate. This is because Ms. Knox first calculates each weather-sensitive class's total usage on each month's peak day and then applies each class's profile of hourly usage from the Company's 2009 Load Study database.[27] In other words, Ms. Knox first estimates each weather-sensitive class's peak day usage based on regression analysis of usage during the monthly peak days of the test year. The estimated peak day usage by class is then multiplied by each class's hourly load profile wherein the hourly load profile is each hour of the day's percentage of total use during a given day. To further explain, each hour of the day is assigned a percentage such that the sum of all 24 hours in a day equals 100 percent. As an example, the Residential class's hourly load profile in the month of January for 8:00 a.m. is 3.984 percent of that class's daily usage.[28]

Q. Do you have any concerns regarding Ms. Knox's estimates of monthly class CPs?

A. Yes. While total system and total Washington monthly CPs are relatively known with certainty, I have analyzed the monthly forecasted CP errors for the Residential class as well as for the sum of all individual classes and have determined that there are unreasonably high forecast errors across classes. The details of this analysis are provided in my Exhibit GAW-3 while a summary of the forecasted percentage errors are provided in the table below:

[26] Knox, Exh. TLK-1T, 13:23–14:2.
[27] *See* Knox Workpaper titled "System and Distribution Demand 12CP 12.2019.xlsm", tab "Notes".
[28] Per Knox Workpaper titled "System and Distribution Demand 12CP 12.2019.xls", Tab "Load Shape."

TABLE 4

Summary of Avista Washington Jurisdictional Coincident Peak Forecast Percentage Errors

Month	Sum of Individual Classes	Residential Class
January	-0.91%	1.10%
February	-3.12%	3.76%
March	**12.55%**	**-12.82%**
April	2.79%	-3.30%
May	**-14.59%**	**21.60%**
June	**-9.69%**	**13.03%**
July	0.22%	-0.25%
August	4.07%	-4.54%
September	**-13.71%**	**19.46%**
October	**-7.24%**	**9.37%**
November	**-13.24%**	**18.57%**
December	-2.81%	3.42%

As can be seen in the table above, in half of the months (6 out of 12), the forecast errors for the sum of all classes as well as the Residential class was greater than +/- 5 percent. With regard to the Residential class, the forecast errors were greater than +/- 10 percent in 5 of the 12 months.

This causes significant concern since Ms. Knox's allocation of the demand portion of the Peak Credit method is based on her estimated 12-CP demands, yet in half of the months there are significant forecast errors which are largely based on an outdated load profile study that is 12 years old (2009).

2. AMI costs and benefits

Q. Has Avista reflected all of its proposed AMI costs within its class cost of service study?

A. Yes. As set forth in her Exhibit TLK-3, Ms. Knox has included all of the Company's proposed cost associated with AMI. This includes $111.6 million of

AMI rate base[29] and $14.0 million in AMI-related expenses.[30] At the Company's proposed rate of return (ROR), these AMI-related costs equate to a revenue requirement of $24.890 million. The following table presents Ms. Knox's allocation of the $24.890 million revenue requirement associated with the Company's proposed AMI-related costs:

TABLE 5
Avista's Allocation of Proposed Electric AMI-related Costs
($ Millions)

Class	Rate Base	Expenses	Revenue Requirement
Residential	$89.076	$11.273	$19.939
General Service	$16.996	$2.033	$3.682
Large General Service	$2.907	$0.383	$0.666
Extra Lg. General Service	$0.936	$0.135	$0.227
Pumping	$1.595	$0.187	$0.342
Street & Area Lighting	$0.113	$0.022	$0.034
Total	$111.624	$14.034	$24.890

Q. Did Ms. Knox also allocate benefits associated with the Company's proposed AMI program?

A. Yes and no. That is, in her Exhibit TLK-3, Ms. Knox did allocate the Company's total anticipated AMI benefits during the rate period to individual classes for informational purposes only. However, her class cost of service study (which ultimately reflects class RORs and parity ratios) does not include or reflect any of the estimated AMI-related benefits. In other words, the Company's proposed overall revenue requirement and Ms. Knox's attendant class cost allocations

[29] Includes $13.6 million in AMI Software, $49.6 million in AMI Meters, $1.4 million in AMI Office Equipment, $0.1 million in AMI Laboratory Equipment, $10.2 million in AMI Communications Equipment and $36.7 million in AMI Regulatory Assets net of ADIT.
[30] Reflects depreciation and amortization of AMI investment cost.

reflect all of the costs associated with the proposed AMI program but none of the benefits that will accrue during the rate period.

Q. How did Ms. Knox allocate the Company's total estimated AMI benefits across classes?

A. For informational purposes, Ms. Knox allocated the total Company's estimated $7.092 million in AMI O&M benefits to classes based on her "4-Factor" allocator.[31] This 4-Factor allocator is comprised of the average class allocators for total production/transmission/distribution plant in service, O&M expenses (excluding fuel, labor and A&G), labor (excluding A&G labor), and number of customers.

Q. What are the results of Ms. Knox's allocation of total Company AMI benefits using her 4-Factor approach?

A. The following table provides a summary of Ms. Knox's allocation of the Company's proposed AMI revenue requirement (costs) along with her allocation of rate period AMI benefits to individual classes:

TABLE 6
Avista's Allocation of Electric AMI Costs and Benefits
($ Millions)

Class	Revenue Requirement	Benefits	Net Benefits
Residential	$19.939	$4.295	($15.644)
General Service	$3.682	$0.864	($2.818)
Large General Service	$0.666	$1.124	$0.458
Extra Lg. General Service	$0.227	$0.607	$0.380
Pumping	$0.342	$0.137	($0.205)
Street & Area Lighting	$0.034	$0.065	$0.031
Total	$24.890	$7.092	($17.798)

[31] Per Knox Workpaper to Knox, Exh. TLK-3, which is included in Knox's Workpaper CCOSS Excel titled "UE-20 Base Case Electric COS Model.xlsm", Tab "AMI Costs and Benefits."

Q. Does Ms. Knox's calculated AMI benefits reflect all of the expected AMI benefits reported by Company witness Joshua DiLuciano in his updated Advanced Metering Infrastructure Project Report?

A. No. Mr. DiLuciano updated the Company's projected AMI costs and expected benefits in October 2020 wherein he itemized each expected benefit by year. Mr. DiLuciano's updated total (electric and gas) AMI savings for 2021 and 2022 are $14.517 million and $15.489 million, respectively.[32] According to Ms. Knox's AMI costs and benefits workpaper, the total AMI savings were based on a September 2020 update wherein total 2021 and 2022 savings are $8.700 million and $9.153 million, respectively.[33]

Q. Have you calculated the Company's expected rate period AMI savings based on Mr. DiLuciano's updated analysis?

A. Yes. My Exhibit GAW-4 shows the estimated rate period AMI savings based on Mr. DiLuciano's October 2020 updated report. As shown in this Exhibit, I have also calculated the expected rate period AMI benefits accruing to the Residential class. Utilizing Mr. DiLuciano's calculated AMI savings, the total Company (electric and gas) rate period AMI savings are expected to be $15.246 million wherein the electric Residential savings are expected to be $7.198 million as shown on Line (14) of Exhibit GAW-4. This compares to Ms. Knox's calculated rate period electric Residential AMI savings (benefits) of $4.295 million.[34]

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[32] Per Joshua D. DiLuciano Workpaper titled "New-AVA-JDD-WP-AMIBenefits-10-30-20.xlsx", Tab "Summary_RealizationSchedule."

[33] In addition, Ms. Knox's "benefits" amounts only reflect O&M savings. Per Knox Workpaper to Exh. TLK-3, which is included in Knox's Workpaper CCOSS Excel titled "UE-20 Base Case Electric COS Model.xlsm", Tab "AMI Costs and Benefits."

[34] Per Knox, Exh. TLK-3.

Q. Earlier you indicated that Ms. Knox's class cost allocation study reflects all of the costs associated with Avista's AMI program but does not include or reflect any of the expected benefits that will be realized from the AMI program. Does this mismatch of costs and benefits distort Ms. Knox's calculated class parity ratios?

A. Absolutely. Remember that class parity ratios reflect the relative percentage of each class's revenue-to-cost ratio. In this regard, Avista expects considerable cost savings during the rate period associated with the implementation of its AMI program. Ms. Knox's class cost allocation study does not reflect any of the expected cost savings associated with the AMI program, and importantly, during the rate period, the majority of these savings (68 percent) will accrue to the Residential class relative to all other classes. As such, while Avista expects its costs of providing service to decline more for the Residential class than for all other classes combined during the rate period, Ms. Knox's calculated "costs" to serve the Residential class are overstated relative to other classes. Therefore, Ms. Knox's so-called parity ratios are understated for the Residential class and overstated for other classes.

Q. What are your conclusions regarding the reliability and usefulness of Ms. Knox's class cost of service study in this case?

A. For the reasons discussed in this testimony, Avista's class cost of service study should not be relied upon as any reasonable measure of class cost responsibility such that any overall revenue increase should be spread across customer classes on an equal percentage of base rate revenues.

B. Electric Rate Spread

Q. How does Avista propose to spread its overall requested revenue increase across individual rate schedules?

A. Company witness Joseph Miller recommends that the Company's requested overall $44.185 million increase be spread across individual rate classes on an equal percentage of base rate revenues currently in effect.[35] In addition, Mr. Miller recommends that its Tax Customer Credit Offset (Proposed Schedule 76) which is the result of the Company converting from normalization to flow-through accounting exactly offset individual class billing rate increases such that the net effect on all classes is no change in revenue responsibility.[36]

Q. Does Mr. Miller recommend a caveat to his proposed rate spread recommendation in the event the Commission orders an overall revenue increase less than that requested by the Company?

A. Yes. Mr. Miller recommends that if the Commission orders a lower revenue requirement than that requested, the Residential class should receive the same increase as that proposed under the Company's primary recommendation; i.e., an 8.3 percent increase in base rates. He also recommends that the Extra Large General Service (Schedule 25), Pumping Service (Schedule 31/32) and Street/Area Lighting Schedules (Schedule 41-48) receive an equal percentage of the overall revenue increase. Finally, Mr. Miller recommends that any remaining revenue increase should be applied equally to General Service (Schedule 11/12) and Large General Service (Schedule 21/22).[37]

[35] Direct Testimony of Joseph D. Miller, Exh. JDM-1T, at 5; Miller, Exh. JDM-4.
[36] *Id.*
[37] Miller, Exh. JDM-1T, at 6:23–7:6.

However, Mr. Miller does not explain or discuss how the proposed Tax Customer Credit Offset (Proposed Schedule 76) would be adjusted in the likely event the Commission orders an overall increase less than that requested by Avista.

Q. Do you agree with Mr. Miller's recommended class rate spread?

A. In part, yes. That is, I agree with Mr. Miller's recommended equal percentage increase in base rate revenues for all classes with an equal Tax Customer Credit Offset by individual rate schedule. However, I do not agree with Mr. Miller's secondary recommendation in the event the Commission authorizes an overall base rate increase less than that requested by Avista. The primary reason for Mr. Miller's secondary recommendation is based on the class cost of service results presented by Ms. Knox. As explained earlier, it is my opinion that Avista's electric class cost of service study cannot be relied upon for evaluating class revenue responsibility.

C. Residential Electric Rate Design

Q. How does Avista propose to design Residential rates to reflect the Company's proposed increase in base rates as well as to reflect the Tax Customer Credit Offset?

A. Company witness Joseph Miller sponsors the Company's rate design proposals. Mr. Miller proposes to hold the current Residential customer charge of $9.00 per month at its current rates such that the base rate revenue increase assigned to the Residential class will be collected from energy charges. Avista's Residential energy charges are comprised of an inverted three-block rate structure. Mr. Miller proposes equal percentage increases to each of the three energy blocks.[38]

With regard to the proposed Tax Customer Credit Offset (Proposed Schedule 76), Mr. Miller proposes that this credit will be given to customers based on energy usage with proportional credits based on the base rate energy charges for each usage block. The details of Mr. Miller's Residential rate design are provided in his Exhibit JDM-4.[39]

Q. Do you support Avista's proposal to not increase customer charges such that any overall revenue increase assigned to the Residential class be collected from energy charges?

A. Yes. Avista's current Residential customer charge of $9.00 per month reasonably reflects the direct costs to connect and maintain a customer's account.

Q. How should Public Counsel's recommended treatment of Tax Customer Credit Offsets be reflected in the design of Residential rates?

A. I concur with Mr. Miller's concept that the Tax Customer Credit Offsets should eliminate any base rate increases and that these Tax Customer Credit Offsets should be designed on an energy usage basis. Specifically, Public Counsel witness Crane's recommended credits should be assigned to the Residential class based on base rate revenues and that the Residential credits be designed based on the energy inverted-block rates; i.e., under the same concept as proposed by witness Miller.

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[38] Miller, Exh. JDM-1T, at 8:7–8.
[39] Miller, Exh. JDM-4, at 3.

III. NATURAL GAS OPERATIONS

A. Natural Gas Cost of Service

Q. Have you examined Avista's natural gas class cost of service study filed in this case?

A. Yes. The Company's natural gas class cost of service study is sponsored by Joel Anderson. My examination included a detailed review of Mr. Anderson's classification and allocation procedures particularly as they relate to the assignment of those costs that tend to be the most controversial in natural gas cost allocations; i.e., the classification and allocation of storage and mains-related costs. In these regards, I have concluded that Mr. Anderson's study reasonably reflects cost causation and is in accordance with the Commission's new rules regarding cost allocations.[40]

Q. Please summarize Avista's natural gas class cost of service study results.

A. The following table presents each class's parity ratios as calculated within Mr. Anderson's cost of service study:

TABLE 7
Avista CCOSS Results
Parity Ratios At Current & Proposed Rates

Class	Parity Ratio
General Service (Sch. 101)	91%
Large General Service (Sch. 111)	170%
Interruptible (Sch. 131)	140%
Transportation (Sch. 146)	91%
Total Company	100%

[40] I am aware that Avista has not conducted a true load study for purposes of this case but has utilized design day demands as a proxy for peak load responsibilities.

Q. What are your conclusions regarding Mr. Anderson's class cost allocation study?

A. While I agree with Mr. Anderson's procedures to allocate Avista's pro forma costs, I do share the same concerns that I have with the Company's electric cost allocation study wherein all of the AMI costs are reflected but none of the AMI benefits that will accrue as a result of the deployment of AMI for Avista's natural gas operations are reflected. This is important for evaluating class revenue responsibility because the reduced costs due to the deployment of AMI is not proportional across all classes such that, on a going-forward basis, the parity ratios reflected in Mr. Anderson's study are distorted.

Q. Did Mr. Anderson estimate AMI benefits by class as part of his studies?

A. Yes. In his Exhibit JCA-3, Mr. Anderson did allocate the Company's total anticipated AMI benefits during the rate period to individual classes for informational purposes only.[41] However, as indicated earlier, his cost of service study does not include or reflect any of the AMI-related benefits but only reflects the Company's proposed AMI-related costs.

Q. How did Mr. Anderson allocate the Company's total AMI benefits across the natural gas classes?

A. Similar to Ms. Knox's approach, Mr. Anderson allocated the total Company's estimated $2.260 million in AMI O&M benefits to classes under his "4-Factor" allocator.[42]

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[41] Joel C. Anderson, Exh. JCA-3.

[42] Per Anderson Workpaper to Anderson, Exh. JCA-3, which is included in Anderson's Workpaper CCOSS Excel titled "2019 Avista - WA Cost of Service (NG) - Base Case.xlsm", Tab "AMI Costs and Benefits."

Q. What are the results of Mr. Anderson's allocation of total Company AMI benefits using his 4-Factor approach?

A. The following table provides a summary of Mr. Anderson's allocation of the Company's proposed AMI revenue requirement (costs) along with his allocation of rate period AMI benefits to individual classes:

TABLE 8
Avista's Allocation of Natural Gas AMI Costs and Benefits
($ Millions)

Class	Revenue Requirement	Benefits	Net Benefits
General Service (Sch. 101)	$13.863	$2.068	($11.795)
Large General Service (Sch. 111)	$1.437	$0.224	($1.213)
Interruptible (Sch. 131)	$0.016	$0.003	($0.014)
Transportation (Sch. 146)	$0.270	$0.068	($0.201)
Total	$15.586	$2.363	($13.222)

Q. Does Mr. Anderson's calculated natural gas AMI benefits reflect all of the expected AMI benefits reported by Company witness Joshua DiLuciano in his updated Advanced Metering Infrastructure Project Report?

A. No. Mr. DiLuciano updated the Company's projected AMI costs and expected benefits in October 2020 wherein he itemized each expected benefit by year. Mr. DiLuciano's updated total (electric and gas) AMI savings for 2021 and 2022 are $14.517 million and $15.489 million, respectively.[43] According to Mr. Anderson's AMI costs and benefits workpaper, the total AMI savings were based

[43] Per DiLuciano Workpaper Excel, "New-AVA-JDD-WP-AMIBenefits-10-30-20.xlsx", Tab "Summary_RealizationSchedule."

on a September 2020 update wherein total 2021 and 2022 savings are $8.700 million and $9.153 million, respectively.[44]

Q. Have you calculated the Company's expected rate period AMI savings based on Mr. DiLuciano's updated analysis?

A. Yes. My Exhibit GAW-5 shows the estimated rate period AMI savings based on Mr. DiLuciano's October 2020 updated report. As shown in this Exhibit, I have also calculated the expected rate period AMI benefits accruing to the Residential class. Utilizing Mr. DiLuciano's calculated AMI savings, the total Company (electric and gas) rate period AMI savings are expected to be $15.246 million wherein the natural gas Residential savings are expected to be $4.510 million as shown on Line (15) of Exhibit GAW-5. This compares to Mr. Anderson's calculated rate period natural gas Residential AMI savings (benefits) of $2.260 million.

Q. Earlier you indicated that Mr. Anderson's class cost allocation study reflects all of the costs associated with Avista's natural gas AMI program but does not include or reflect any of the expected benefits that will be realized from the AMI program. Does this mismatch of costs and benefits distort Mr. Anderson's calculated class parity ratios?

A. Absolutely. Remember that class parity ratios reflect the relative percentage of each class's revenue-to-cost ratio. In this regard, Avista expects considerable cost savings during the rate period associated with the implementation of its AMI program. Mr. Anderson's class cost allocation study does not reflect any of the

[44] In addition, Mr. Anderson's "benefits" amounts only reflect O&M savings. Per Anderson Workpaper to Anderson, Exh. JCA-3, which is included in Anderson's CCOSS Excel titled "2019 Avista - WA Cost of Service (NG) - Base Case.xlsm", Tab "AMI Costs and Benefits."

expected cost savings associated with the AMI program, but, during the rate period, the majority of these savings (93 percent) should accrue to the Residential class relative to all other classes. As such, while Avista expects its costs of providing service to decline more for the Residential class than for all other classes combined during the rate period, Mr. Anderson's calculated "costs" to serve the Residential class are overstated relative to other classes. Therefore, Mr. Anderson's so-called parity ratios are understated for the Residential class and overstated for other classes.

Q. What are your conclusions regarding the reliability and usefulness of Mr. Anderson's class cost of service study in this case?

A. Although I agree with Mr. Anderson's procedures to allocate the Company's total costs reflected in its rate application, his studies do not reasonably reflect how costs will be incurred going forward particularly due to savings that are expected to result from the deployment of AMI. As such, little, if any, weight should be given to the parity ratios calculated by Mr. Anderson in this case.

B. Natural Gas Rate Spread

Q. How does Avista propose to spread its overall requested natural gas revenue increase across individual rate schedules?

A. Company witness Joseph Miller recommends that the Company's requested overall $12.790 million increase be spread across individual rate classes on an equal percentage of distribution (margin or non-gas) revenues currently in effect.[45] In addition, Mr. Miller recommends that its Tax Customer Credit Offset

[45] Miller, JDM-1T, at 15.

(Proposed Schedule 176) which is the result of the Company converting from normalization to flow-through accounting exactly offset individual class billing rate increases such that the net effect on all classes is no change in revenue responsibility.[46]

Q. Does Mr. Miller recommend a caveat to his proposed rate spread recommendation in the event the Commission orders an overall revenue increase less than that requested by the Company?

A. Yes. Mr. Miller recommends that if the Commission orders a lower revenue requirement than that requested, the General Service and Transportation classes should receive the same increase as that proposed under the Company's primary recommendation; i.e., a 12.4 percent increase in distribution rates. Then, any remaining revenue increase should be applied equally to Large General Service and Interruptible Sales Service.[47]

However, Mr. Miller does not explain or discuss how the proposed Tax Customer Credit Offset (Proposed Schedule 176) would be adjusted in the likely event the Commission orders an overall increase less than that requested by Avista.

Q. Do you agree with Mr. Miller's recommended class rate spread?

A. In part, yes. That is, I agree with Mr. Miller's recommended equal percentage increase in distribution revenues for all classes with an equal Tax Customer Credit Offset by individual rate schedule. However, I do not agree with Mr. Miller's secondary recommendation in the event the Commission authorizes an overall increase less than that requested by Avista. The primary reason for Mr. Miller's

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[46] *Id.*
[47] Miller, JDM-1T, at 16:18–22.

secondary recommendation is based on the class cost of service results presented by Mr. Anderson. As explained earlier, Mr. Anderson's natural gas cost allocation study does not reflect the forward-looking cost savings that are expected to occur as a result of AMI deployment wherein the majority of the expected cost savings will be realized by the Residential class.

C. General Service Natural Gas Rate Design

Q. How does Avista propose to design General Service rates to reflect the Company's proposed increase in distribution rates as well as to reflect the Tax Customer Credit Offset?

A. Company witness Joseph Miller also sponsors the Company's natural gas rate design proposals. Mr. Miller proposes to hold the current General Service customer charge of $9.50 per month at its current rates such that the distribution revenue increase assigned to the General Service class will be collected from volumetric usage charges.[48] Avista's General Service volumetric usage charges are comprised of an inverted two-block rate structure. Mr. Miller proposes equal percentage increases to the two volumetric usage blocks.

With regard to the proposed Tax Customer Credit Offset (Proposed Schedule 176), Mr. Miller proposes that this credit will be given to customers based on usage with proportional credits based on the volumetric distribution charges for each usage block. The details of Mr. Miller's General Service rate design are provided in his Exhibit JDM-7.[49]

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[48] Miller, JDM-1T, at 18:8–16; Miller, Exh. JDM-7.
[49] Anderson, Exh. JCA-7, at 3.

Q. Do you support Avista's proposal to not increase customer charges such that any overall revenue increase assigned to the General Service class be collected from volumetric usage charges?

A. Yes. Avista's current General Service customer charge of $9.50 per month reasonably reflects the direct costs to connect and maintain a customer's account.

Q. How should Public Counsel's recommended treatment of Tax Customer Credit Offsets be reflected in the design of General Service rates?

A. I concur with Mr. Miller's concept that the Tax Customer Credit Offsets should eliminate any base rate increases and that these Tax Customer Credit Offsets should be designed on a commodity usage basis. Specifically, Public Counsel witness Crane's recommended credits should be assigned to the Residential class based on base rate revenues and that the Residential credits be designed based on the inverted-block usage rates; i.e., under the same concept as proposed by witness Miller.

Q. Does this complete your testimony?

A. Yes.