Exhibit No. RRS-1TC
Dockets UE-160228/UG-160229
Witness: Robert R. Stephens
REDACTED

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. AVISTA CORPORATION, DBA AVISTA UTILITIES, Respondent.	)	DOCKETS UE-160228 and UG-160229 (*Consolidated*)

CONFIDENTIAL RESPONSE TESTIMONY OF ROBERT R. STEPHENS

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

(REDACTED VERSION)

AUGUST 17, 2016

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Robert R. Stephens. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. WHAT IS YOUR OCCUPATION?

A. I am a consultant in the field of public utility regulation and a Principal of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. These are set forth in Exhibit No. RRS-2.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU"), an association of large industrial businesses, some of whom are customers of Avista Corporation ("Avista" or the "Company"). Industrial customers generally take service from Avista under Extra Large General Service Schedule 25.

Q. WHAT IS THE PURPOSE OF YOUR RESPONSE TESTIMONY?

A. I will address Avista's electric cost of service study, revenue allocation ("rate spread"), and rate design issues. More specifically, with respect to cost of service, I will address alternatives to Avista's classification and allocation of production-related costs and transmission costs and its allocation of a portion of the costs of Avista's Advanced Metering Infrastructure ("AMI") program. I will also address Avista's proposed spread of its claimed revenue deficiency across rate schedules, and proposals for rate design.

The fact that I do not address any particular issue should not be interpreted as tacit approval of any position taken by Avista.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My response testimony can be summarized as follows:

1. The Company's electric cost of service study filed in this case is, in many respects, consistent with studies filed by Avista in the past. However, I have identified three significant changes that should be made in order for the embedded cost of service ("ECOS") study to more accurately measure the cost causation of the various customer rate schedules. These relate to the classification and allocation of production and transmission costs and the allocation of General and Intangible plant associated with AMI.

2. With respect to the classification and allocation of production plant costs, I discuss the significant shortcomings of the "Peak Credit" classification and recommend that it be discontinued. My recommendation is for production fixed costs to be allocated in the more traditional peak demand approach. If the Washington Utilities and Transportation Commission (the "Commission") decides to retain the Peak Credit classification approach, I strongly recommend that the demand allocator be modified to more accurately address capacity cost causation.

3. Whether or not the Peak Credit is retained, I recommend use of the "Summer and Winter Peak Method" utilizing coincident peaks in the summer and winter months as a better measure of the demand component for allocating production costs. This is a better method than Avista's proposed 12 Coincident Peak ("CP") measure, since Avista's load exhibits significant peaks in the summer and winter periods and much lower peaks in the spring and fall. The Summer and Winter Peak allocator is also more strongly supported in the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual ("NARUC Manual").

4. With respect to transmission system costs, I recommend use of the 12 CP demand allocation method rather than the Peak Credit method. 12 CP is a better measure of cost causation and is far more consistent with industry norms.

5. With respect to General and Intangible ("G&I") plant associated with AMI, I recommend that such plant values be allocated to the classes on the same basis as the meters themselves since, unlike other non-AMI G&I plant, these investments are closely associated with the AMI plant investments.

6. Adjustment of these three classification and allocation issues reveals significant class cost differences from the results of the Avista cost study. The differences are summarized and shown for each class rate schedule herein.

7. I support Avista's proposed rate spread for 2017, in part, if Avista's full revenue requirement is approved. If Avista does not receive its requested revenue requirement, then the reduction should flow to the rate schedules other than Schedule 1, since Schedule 1 customers are currently paying revenues well below their cost of service. Bringing Schedule 1 fully to cost of service, i.e., equalized rate of return, would require a 24.5% increase under Avista's ECOS study and a 30.1% increase under mine; so Avista's proposed increase for this class would represent only a modest step toward cost. Avista's proposed rate spread for 2018 should be modified to provide greater movement toward cost for Schedule 1 than proposed by Avista.

8. I recommend the application of Avista's Schedule 91, Demand Side Management ("DSM") Adjustment – Washington, be modified to reduce the current inequity of DSM collections from Schedule 25 customers generally and the largest ICNU member served by Avista, specifically.

9. Regarding Demand Response, I recommend Avista implement a demand response rate pilot program in a form matching, or similar to, my proposal.

III. ELECTRIC COST OF SERVICE STUDY

<u>Overview</u>

Q. PLEASE EXPLAIN THE BASIC STEPS FOR ESTABLISHMENT OF FAIR AND REASONABLE RATES.

A. The ratemaking process has three steps. First, we must determine the utility's total revenue requirement and whether an increase or decrease in revenues is necessary. Second, we must determine how the revenues are to be distributed among the various customer classes or schedules. A determination of how many dollars of revenue should be produced by each class is essential to obtaining the appropriate level of rates. This is called "revenue allocation" or "rate spread." Finally, individual tariffs must be designed to produce the required amount of revenues from each class of service and to send efficient price signals to customers.

The guiding principle at each step should be cost of service. In the first step – determining revenue requirements – it is widely agreed that the utility is entitled to a revenue increase only to the extent that its actual overall cost of service has increased. If current rate levels exceed the revenue requirement, a rate reduction is required. In short, rate revenues should equal a utility's actual cost of service. The same principle should apply in the last two steps. Each customer class should, to the extent practicable, produce revenues equal to the cost of serving that particular class. On some occasions, this may require a rate increase for some customer classes and a rate decrease for others. The standard tool for determining whether a class requires a rate increase or decrease is an ECOS study, which shows the rate of return for each class of service. Ideally, rate levels should be modified so that each customer class provides approximately the same rate of return.

Finally, in designing individual tariffs, the goal is to base the rate design on the cost of service, so that each customer's rate tracks, to the extent practicable, the utility's cost of providing that service to the customers on the tariff.

Q. HOW ARE LARGE INDUSTRIAL CUSTOMERS AFFECTED BY THE PRICE OF ENERGY?

A. For many industrial customers, energy is a primary component of their costs. For some, it may be the most critical component. As such, the overall cost of electricity prices is vital to the economic health of industrial customers in Washington – and to the economic health of Washington itself, as Washington industries compete in national and world markets. Furthermore, any cost of service study or rate design that misallocates costs to large customers will also result in unjust and unreasonable rates.

Q. WHAT IS THE BASIC PURPOSE OF A CLASS ECOS STUDY?

A. The basic purpose of a class ECOS study is an empirical determination of the utility's cost of serving classes of customers.[1/]

After determining the overall cost of service or revenue requirement, an ECOS study is used to ascertain the cost of service among customer classes (i.e., a cost of service study shows how each customer class contributes to the total system cost). For example, when a class produces the same rate of return as the total system, it is returning to the utility revenues sufficient to cover the costs incurred in serving it (including a reasonable authorized return on investment). If a class produces a below-average rate of return, it may be concluded that the revenues are insufficient to cover all relevant costs. On the other hand, if a class produces a rate of return above the average, it is paying revenues sufficient to cover the cost attributable to it and, in addition, is paying part of the cost attributable to other classes who produce a below average rate of return. The ECOS study is important because it shows the class revenue requirement as well as the rate of return under current and any proposed rates.

As a measurement or estimation tool, the ECOS study is not the step in which other factors, such as rate moderation or continuity, should be considered or allowed to influence the results. Those types of considerations are taken up in the revenue allocation and rate design steps.

1/ Despite occasional suggestions to the contrary, an ECOS study is not a service valuation or benefits valuation study. Such studies would be very difficult, if not impossible, to perform credibly and would likely be highly subjective, as one would need to know much more about individual customers, their preferences, and how much they value the utility services or benefits there from.

Q. PLEASE COMMENT ON THE PROPER FUNDAMENTALS OF A CLASS ECOS STUDY.

A. In all ECOS studies, certain fundamental concepts should be recognized. Of primary importance among these concepts is the functionalization of costs, as well as the classification of the nature of these costs as to whether they vary with the quantity of energy consumed, the demand placed upon the system, or the number of customers being served. Stated another way, functionalization is the classification and arrangement of costs according to major functions, such as production, transmission, and distribution.

Fixed costs are those costs which tend to remain constant over the short run irrespective of changes in output and are generally considered to be demand-related. Fixed costs include those costs which are a function of the size of the investment in utility facilities, and those costs necessary to keep the facilities "on-line." Variable costs, on the other hand, are those costs which tend to vary with output and are generally considered to be commodity-related. Customer-related costs are those which are closely related to the number of customers served, rather than the quantity of energy consumed or the peak demands placed upon the system. An understanding of these concepts is essential to the development of ECOS studies, as well as appropriate rate design.

<u>Review of Avista's Cost of Service Study</u>

Q. HAVE YOU REVIEWED THE COMPANY'S ECOS STUDY?

A. Yes. I have reviewed the Company's ECOS study that was submitted as part of Avista witness Tara Knox's direct testimony in this case.[2/]

[2/] Exh. No. TLK-1T.

Q. IS THE COMPANY'S ECOS STUDY REASONABLE TO USE AS A BASIS FOR REVENUE ALLOCATION AND RATE DESIGN IN THIS CASE?

A. Not entirely. The ECOS study filed in this case is, in many respects, consistent with studies filed by Avista in the past and is reasonable in certain ways. However, I have serious concerns with three aspects of its study. First, the study classifies production plant investment using a method that is based only in small part (37.93%) on the customers' contribution to peak demand for each month of the year and in much larger part (62.07%) on the basis of energy.[3/]

This method is improper because the classified plant investments include the cost of all production resources, and are dependent on the maximum capacities of those resources. Instead, production costs should be classified and allocated to the customer classes according to each class's demand during the peak months, when all of Avista's production resources are in use, and when those resources are most likely to be operating at their maximum capacities. It is Avista's system peak demands, which occur during winter and summer months, that drive the need for additional capacity. Demands during moderate-load times, whether time of day or month of year, do not cause new generating capacity to be built. Only variable costs, i.e., those which vary with the level of output of the units, such as fuel, should be classified as energy related and allocated on energy allocators.

Second, in addition to its misclassification and misallocation of production costs, the Company's ECOS study also improperly allocates the costs of transmission service.

[3/] *Id.* at 13.

Third, the Company's ECOS study should be modified to allocate AMI costs more closely with the cost incurrence.

Classified and Allocation of Production-Related Costs

Q. HOW HAS THE COMPANY CLASSIFIED AND ALLOCATED PRODUCTION-RELATED COSTS?

A. The Company's process is described at pages 11-14 of Avista witness Knox's direct testimony, and in additional detail at pages 3-4 of Exhibit No. TLK-2.

As described, Avista proposes to use the "Peak Credit" ratio to classify production and transmission resources. According to Ms. Knox, Avista proposes to apply a Peak Credit which utilizes the system load factor to determine the proportion of the production function that is demand-related. This classification yields a 37.93% proportion to be allocated on the basis of demand, with the remaining 62.07% to be allocated based on energy delivered. Avista performs this classification for both production fixed and variable costs and, as described below, to transmission plant. For the approximately 38% of costs that are classified as demand-related, Avista proposes to allocate on the basis of 12 CP, based on the average class contributions to the 12 monthly peaks for the year ended September 30, 2015.

Q. SETTING ASIDE THE VALIDITY OF THE PEAK CREDIT METHOD FOR THE MOMENT, WHY HAS AVISTA USED 12 CP TO ALLOCATE THE DEMAND-RELATED PRODUCTION COSTS IN ITS ECOS STUDY?

A. Avista witness Knox states as follows:

> 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.[4/]

Q. DO YOU FIND THIS EXPLANATION COMPELLING?

A. No, I do not. First, I do not necessarily agree with Ms. Knox that the Company is usually a winter peaking utility. While that may have been true in the past, in recent years, Avista has been trending toward becoming a summer peaking utility. This is illustrated clearly in Exhibit No. RRS-3, which shows a history of the monthly peak demands, stated as percentage of the system peak demand, for the last several years. As can be seen from that exhibit, summer month demands have grown significantly over time. Indeed, in two of the last four years, the system peaks occurred in the summer. Clearly, Avista has become a bi-modal utility system, with significant peaks in the summer and winter and much lower demands in the spring and fall seasons.

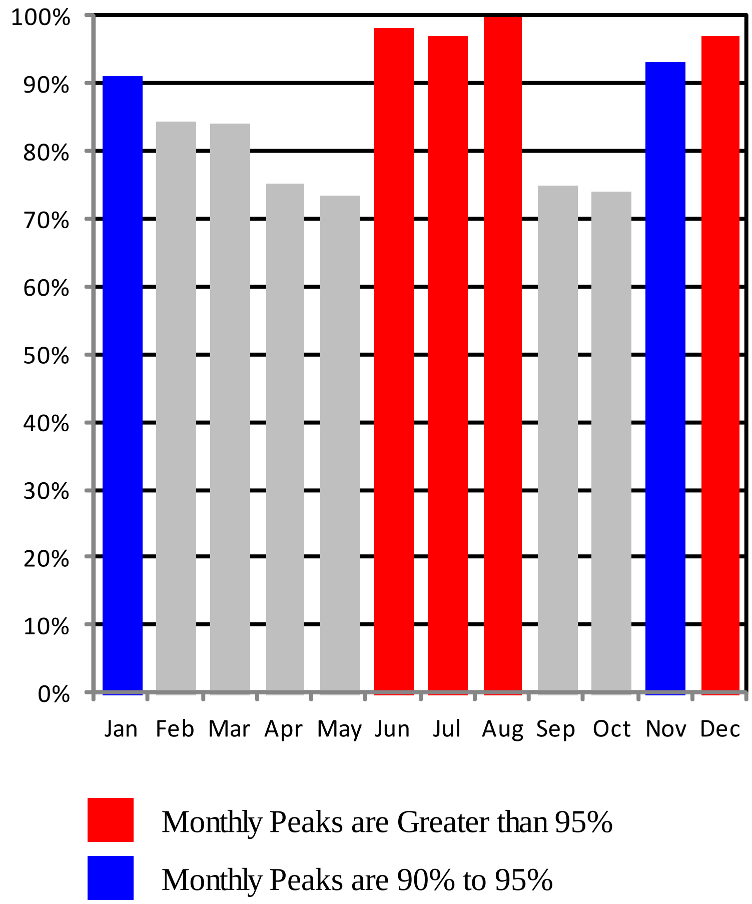
In the test year, 12 months ended September 2015, Avista experienced three high demand months in the summer and one in the winter, as shown in Figure 1, below, which is the same format as the calendar years shown in Exhibit No. RRS-3, but using the test year only.

4/ Exh. No. TLK-2 at 3.

Figure 1

Monthly Peak Demands as a Percent of the Annual System Peak

Test Year Ended September 30, 2015



A 12 CP method is more typically used when demands are relatively steady over the course of a year and do not exhibit significant peaks, which drive the need for new capacity. In addition, when 12 CP is used, it is typically when <u>all</u> production plant costs are allocated on the basis of demand, rather than when only a relatively small proportion (e.g., 38%) is allocated on demand.

Q. IS AVISTA'S USE OF 12 CP IN THIS MANNER WELL SUPPORTED IN INDUSTRY LITERATURE, SUCH AS THE NARUC MANUAL?

A. No. I cannot say that Avista's method of combining a peak credit classification with a 12 CP allocation is well-supported in industry literature. It certainly is uncommon. Rather, I find greater support for a more direct measure of system peak demand in the NARUC Manual for utility loads such as Avista's.[5/]

Q. WHY DO YOU BELIEVE THAT THE NARUC MANUAL DOES NOT SUPPORT THE USE OF 12 CP ALLOCATION FOR UTILITY LOADS LIKE AVISTA'S?

A. The same passage of the NARUC Manual that addresses the 12 CP method casts doubt on its use for Avista, when it states of the 12 CP method:

> This method is usually used when the monthly peaks lie within a narrow range; i.e., when the annual load shape is not spiky.[6/]

While the NARUC Manual does not define the word "spiky," it is clear that in cases where the need for production capacity (i.e., system demand) is substantially different across the months of the year, as with Avista, a 12 CP allocator is not appropriate.

Additional guidance is provided in the NARUC Manual where it describes conditions wherein multiple coincident peak demands may be warranted. In describing one of those conditions, the NARUC Manual states:

> Criteria for determining which hours to use include: (1) all hours of the year with demands within 5 percent or 10 percent of the system's peak demand.[7/]

5/ I note that the NARUC Manual lists the 12 CP method as one of the options for production allocation, but only in the context of a peak demand method not in conjunction with a Peak Credit classification approach, and generally not for utility loads such as Avista's.

6/ *NARUC Manual* at 46.

7/ *Id.* (emphasis added).

By considering only the hourly demands that are reasonably close to the annual system peak, the cost analyst recognizes that it is only during the highest system load hours that production capacity is most likely to be fully utilized. Consequently, a demand allocation method that is based on each class's contribution during these high demand periods will more fairly and reasonably recognize the classes' proportionate responsibility in causing the utility to incur those production investments. Therefore, in cases where the monthly peak loads fluctuate significantly (e.g., like the about 27% fluctuation in peak load in Avista's case),[8/] a method that considers only the annual system peak, or the average of monthly peaks that are near the system peak, is more appropriate.

Perhaps the most instructive guidance on the proper allocation method to be used in this case from the NARUC Manual, however, is the "Summer and Winter Peak Method" which is used to "reflect the effect of two distinct seasonal peaks on customer cost assignment."[9/] The NARUC Manual states:

> If the summer and winter peaks are close in value, [which is clearly the case for Avista,] and if both significantly affect the utility's generation expansion planning, this approach may be appropriate.[10/]

As I will demonstrate below, during the test year, Avista exhibited the summer and winter peak conditions described above. Under the Summer and Winter Peak method, either the single highest summer and single highest winter peaks are used (i.e., 2 CP) or a small number of summer and winter peak hours are used (e.g., 4 CP).

8/ The highest peak month, August, is nearly 27% higher than the lowest peak month, May.

9/ *NARUC Manual* at 45.

10/ *Id.*

To summarize, when monthly peak demands are quite similar during the entire year, a 12 CP method may be supported by industry literature. But when, as here, a substantial variation in peak demands is seen throughout the year, there is more support for production plant allocation based only on those peaks within a narrow range of the highest peak, or on the summer and winter peaks only. Thus, the use of 12 CP is not appropriate, with or without the peak credit classification.

Q. WHY ARE THE CUSTOMER LOADS DURING THE HIGHEST MONTHLY PEAK DEMANDS RELEVANT TO THE ALLOCATION OF PRODUCTION INVESTMENT?

A. The key factors that link customer loads at the time of the highest monthly peak demand to the allocation of production investments are the following:

1. Utilities typically bring all of their generating resources into operation in the hours leading up to their highest monthly peaks. This includes the base load, intermediate load and peaking plants, as well as the short-term and long-term power purchasing contracts. For many utilities in the United States, these peaks occur during the summer season. Avista exhibits peaks in both summer and winter.

2. The production costs that are allocated include the cost of base load, intermediate load and peaking plants, as well as the costs of short-term and long-term power purchase contracts.

3. The portion of the utility's highest monthly demand that is contributed by a customer class will provide a fair representation of the portion of production cost that the utility incurred to serve the class. For example, if a class constitutes 10% of the load at the times of system peak, it essentially represents 10% of the need for generation capacity and, thus, should be allocated 10% of fixed production capacity costs.

Q. PLEASE FURTHER DISCUSS AVISTA'S HISTORICAL SYSTEM PEAK LOAD DATA.

A. These load data shown on Exhibit RRS-3 are available in Avista's annual Federal Energy Regulatory Commission ("FERC") Form 1 filings. The charts of the historical load data for the last six calendar years, shown on Exhibit RRS-3, clearly indicate years with dominant winter peaks and, in 2012 and 2015, two to three high summer peak months. In 2013, only the monthly peak demands during January and July were within 10% of the December peak.[11/]

Avista's peak load data show significant peaks, not a steady load across the year, with only a small number of months close to the system peak. Table 1, below, summarizes the number of months in each of the last six calendar years that were within 5% and 10% of the system peak.

TABLE 1

Number of Months In Which Peak Demands Were Near Annual Peak Demands

Year	Within 5% of Peak	Within 10% of Peak
2010	0	3
2011	1	3
2012	2	5
2013	0	2
2014	0	3
2015	2	4
Test Year	3	5

As can be seen from Table 1, Avista has peak demands that are within 10% of the system peak in relatively few months each year, and even fewer are within 5% of the peak. This speaks further against the use of 12 CP for Avista.

The test year in this case is somewhat anomalous in that three of the highest four months were in the summer, not winter. A strict 4 CP allocator, which is often supported for allocating fixed production costs, would be reasonable (if not conservative) in this case. However, a 4 CP allocator would include June, July, August and December and, thus, would not equally represent the summer and winter peaks exhibited by Avista's

11/ In Exh. No. RRS-3, months within 5% of the peak (inclusive) are shown in red and months between 5% and 10% lower than the peak are shown in blue.

customers. Although this allocation method finds greater support in the NARUC Manual than does the 12 CP methodology used by Avista, as discussed previously, a strict application may not best reveal class costs in this case. Rather, the Summer and Winter Peak allocation method is likely a better measure, which I discuss in more detail later in my testimony.

Q. IS THERE PREVIOUS COMMISSION SUPPORT FOR A SUMMER AND WINTER-BASED ALLOCATION?

A. Yes, most recently in Pacific Power & Light Company's ("Pacific Power") 2014 general rate case.

Q. WHY IS THAT CASE SUPPORTIVE?

A. Despite testimony recommending otherwise, the Commission chose not to approve any modification to the "200 CP method" that Pacific Power had been using.[12/] While I may not agree with the total number of hours used, Pacific Power's 200 CP method implicitly recognizes the bi-modal nature of the utility load and gives equal weight to the summer and winter peaks, by specifying that 100 of the hours must come from the summer and the other 100 hours must come from the winter. Thus, I believe the Commission's determination in that case supports the Summer and Winter Peak allocator for Avista in the current proceeding, when compared to the Company's 12 CP proposal.

I also do not believe it refutes the use of four coincident peaks in the allocation, whether in the context of a Summer and Winter Peak allocation (as I propose here), or even as a strict 4 CP allocator.

12/ WUTC v. Pacific Power, Dockets UE-140762 *et al.*, Order 08 at ¶ 194 (Mar. 25, 2015).

Q. PLEASE EXPLAIN.

A. In the Pacific Power case, in comparison to the 200 CP method, the Commission found the 4 CP method to be "too narrow a range."[13/] For all practical purposes, however, there is no reason to believe that a 4 CP result would be any more dissimilar than the 200 CP result would be, in comparison to a 12 CP method, as we are lacking the data in this case to compute resulting 200 CP allocators. In fact, in my experience with another bi-modal peaking utility, a 200 CP allocator was closer to a 4 CP than a 12 CP in some years. Accordingly, I do not believe the Commission's determination in Pacific Power's 2014 general rate case would provide any more support for Avista's method, as compared to my recommended summer and winter peak method using 4 coincident peaks.

In the same order, the Commission explained that it approves an allocation methodology by "considering how the Company's resources are used to serve customers in Washington."[14/] As "PacifiCorp experiences both a summer and winter peak," the Commission determined that a method including 50% summer hours and 50% winter hours was appropriate in order "to determine peak demand," and specifically because this bi-modal method "recognizes how resources are used."[15/] In this sense, my recommendation for a Summer and Winter Peak demand allocator, with equal summer and winter weighting for peak demands, is in alignment with the Commission's determination, since recent data plainly demonstrate that Avista now experiences both summer and winter peaks, like Pacific Power. Conversely, as a generic averaging

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13/ *Id.* at ¶ 193. (quoting WUTC v. PacifiCorp, Docket UE-100749, Order 06 at ¶ 304 (Mar. 25, 2011)).

14/ *Id.* at ¶ 194.

15/ *Id.* at ¶ 193. (quoting Docket UE-100749, Order 06 at ¶ 304).

approach taking no account of seasonal differences, the 12 CP allocator proposed by Avista does not account for how the Company's resources are used to serve customers in Washington.

Finally, in Pacific Power's 2014 general rate case, the Commission cited concern about whether a 4 CP alone method might "produce volatility in results depending on the test period."[16/] I do not believe a 4 CP alone would produce volatility in results, and I see no evidence in this case to the contrary. My recommendation in this proceeding considers Avista's historic peak demands since 2010, which clearly show that a Summer and Winter Peak allocator as I propose to apply it would not be inappropriate for use in any of the years. Thus, the 4 CP method, and especially the Summer and Winter Peak method, should not be considered inferior to Avista's proposed 12 CP method.

Q. IS IT APPROPRIATE FOR THE COMMISSION TO CONSIDER DETERMINATIONS MADE FOR OTHER UTILITIES?

A. Sometimes, if the circumstances are similar enough to be constructive. Both Avista's Washington operations and Pacific Power are summer and winter peaking utilities. Thus, consideration of allocation determinations made for another summer and winter peaking utility in Washington, like Pacific Power, is appropriate.

Q. SHOULD A 200 CP METHOD BE ADOPTED FOR AVISTA IF THE COMMISSION AGREES THAT THE 12 CP METHOD DOES NOT RECOGNIZE SUMMER AND WINTER PEAKS?

A. No. First, for practical reasons, it cannot. Avista's demand study does not contain the data necessary to compute 200 CP allocation factors for each rate schedule.

Second, in 1993, the Commission accepted a top 200 hour proposal from another electric utility, Puget Sound Energy, Inc. ("PSE" or "Puget"), which the Commission

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16/ *Id.*

found to be “reasonably representative of the system peak and the actual resources put into place to serve that peak.”[17] However, the Commission did not state that using the top 200 hours was the only “reasonably representative” demand allocator. In fact, after this PSE determination, Pacific Power employed a 12 CP allocator *before* itself switching to 200 hour method.[18] Thus, it may not be appropriate in this case, even if the data were available.

Q. DO YOU HAVE ANY BASIS TO BELIEVE THE COMMISSION WOULD BE INTERESTED IN RECONSIDERING THE NUMBER OF HOURS USED FOR A SUMMER AND WINTER PEAKING UTILITY?

A. Yes. While not adopting my traditional 4 CP recommendation in Pacific Power’s 2014 general rate case, the Commission anticipated the consideration of alternative cost of service methodologies in Pacific Power’s next general rate case, “as well as the consideration of the number of hours that should be used within these methods.”[19] As I understand that the Commission has not had opportunity to fully consider such cost of service issues since that time, whether through settlement or lack of general rate case filings, further consideration of the appropriate number of demand allocation hours for a utility like Avista should be undertaken, either in this proceeding or taken up in a separate, more generic, proceeding.

Q. WITH THAT BACKGROUND, CAN YOU ILLUSTRATE THE DIFFERING CUSTOMER PROPORTIONS OF SYSTEM LOAD DURING PEAK MONTHS, AS OPPOSED TO NON-PEAK MONTHS?

A. Yes. Figure 2 below shows the major Avista customer schedules’ contribution to jurisdictional peak load during the Company’s extreme (i.e., highest and lowest),

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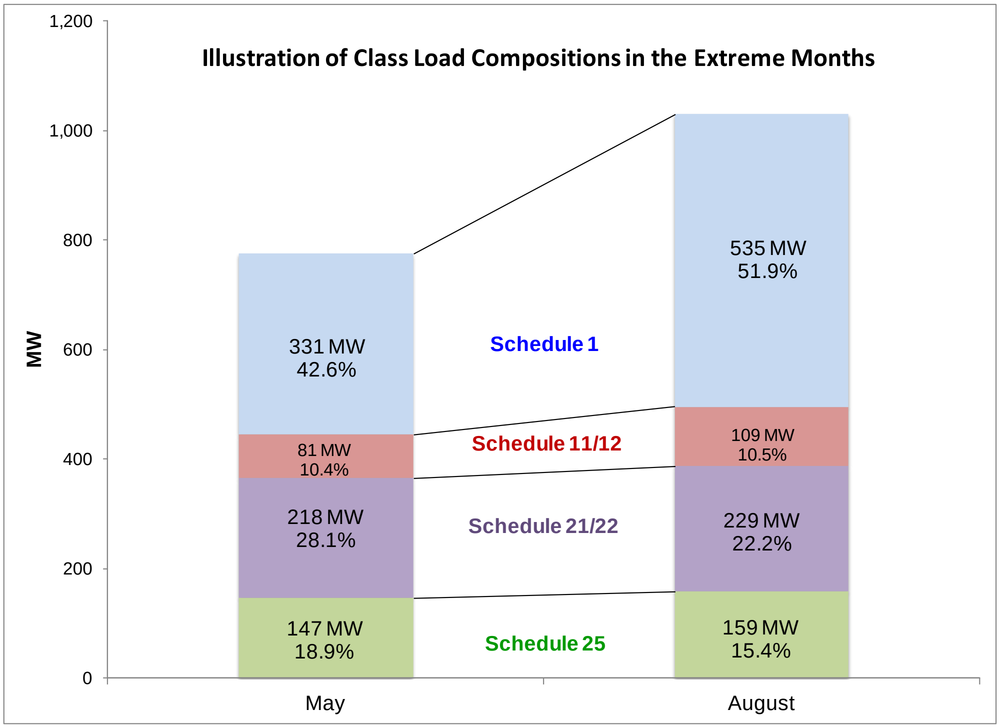
[17] WUTC v. PSE, Dockets UE-920433 *et al.*, 9th Suppl. Order at 12 (Aug. 17, 1993).
[18] Compare WUTC v. PacifiCorp, Docket UE-991832, Taylor, Exh. No.___(DLT-T) at 5, with WUTC v. PacifiCorp, Docket UE-032065, Taylor, Exh. No.___(DLT-1T) at 29-30.
[19] Dockets UE-140762 *et al.*, Order 08 at ¶ 191.

demand months of May and August, when its test year system loads are at the minimum and maximum, respectively.

Figure 2



As can be seen from Figure 2, peak loads of Schedule 1 and Schedule 11/12 customer classes are much higher in August than in May, undoubtedly due primarily to air conditioning, while Schedules 21/22 and 25 are relatively unchanged/flat, in August and May. It is these additional loads of the Schedule 1 and Schedule 11/12 customers that drive the peak loads of Avista and the need for generating capacity.

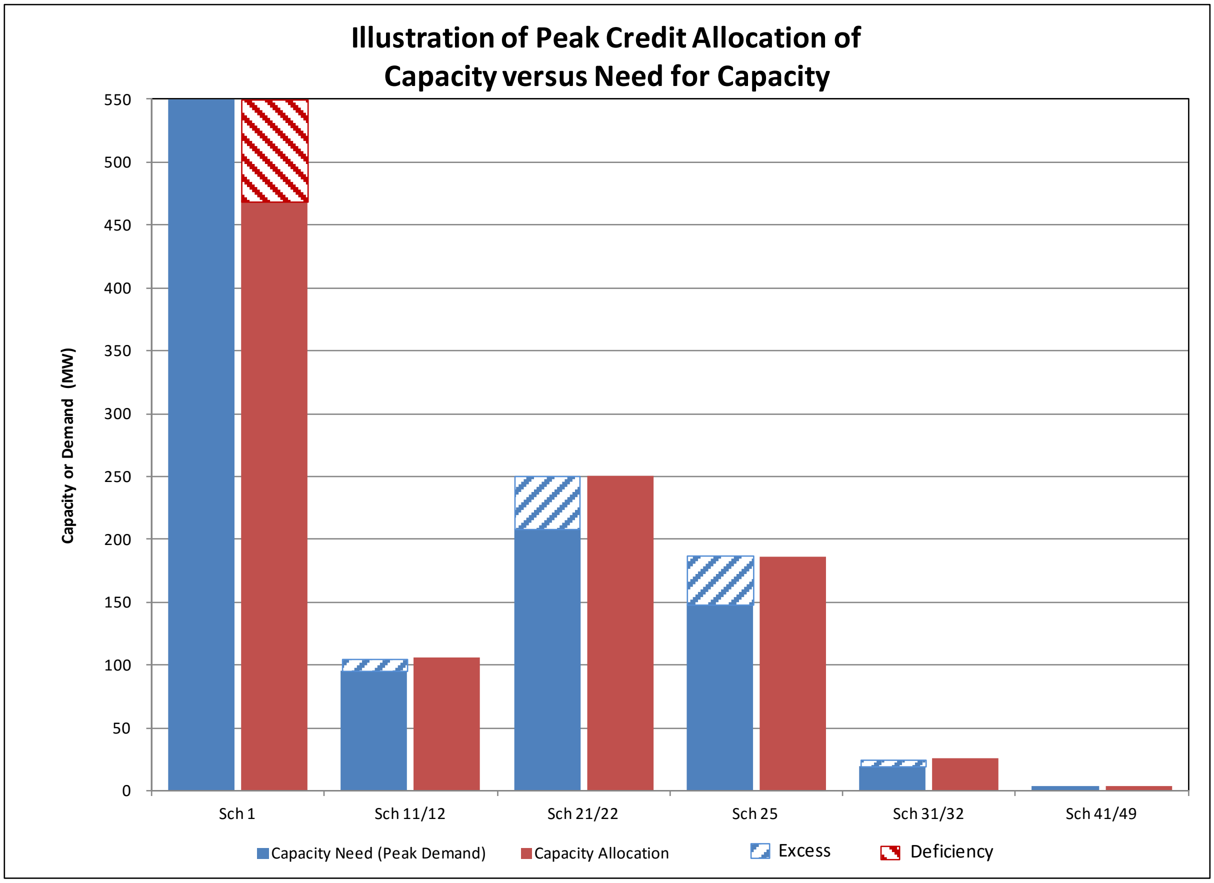
Q. PLEASE COMMENT ON THE PEAK CREDIT METHOD OF CLASSIFICATION OF PRODUCTION AND TRANSMISSION COSTS.

A. I do not agree with the Peak Credit method used to classify production and transmission costs between demand and energy components, as proposed by Avista. This approach is given little if any discussion in the NARUC Manual and is unusual in the industry. While I may not be intimately familiar with its use in all Avista cases, typically the use of a hybrid method of this type for classification or allocation of production costs is based on a perceived trade-off between capacity investment and fuel savings. In my opinion, this Peak Credit classification approach is not reflective of cost causation and, thus, inappropriately assigns far too much weight to energy usage as a basis for assigning production costs.

In considering how Avista classifies and allocates production and transmission plant, and considering the peak demands of the various rate schedules, it is clear that not enough production capacity is assigned to some of the rate schedules and too much is allocated to others. This is illustrated in Exhibit No. RRS-4, which shows the equivalent amount of capacity allocated to customer rate schedules, as compared to their peak demands.[20/] As shown in this exhibit, Schedule 25 is allocated considerably more capacity than its peak demand warrants, while Schedule 1, for example, is not assigned enough capacity to meet its capacity needs. Figure 3, below, graphically depicts the results of Exhibit No. RRS-4. This highlights a major weakness of the Peak Credit method.

20/ For peak demands, I have utilized the Summer and Winter Peak method, as discussed above. Had I used the actual peak or the single CP, the mismatches in results (shown by the hatched bars) would have been even more pronounced.

Figure 3



I think it would be highly reasonable and appropriate for the Commission to revisit the Peak Credit classification method used by Avista.

Q. WHY WOULD IT BE REASONABLE AND APPROPRIATE FOR THE COMMISSION TO CONSIDER AN ALTERNATIVE TO THE TRADITIONAL PEAK CREDIT METHODOLOGY USED BY AVISTA?

A. As an initial matter, I understand that the Commission has long rejected the notion that there is any "standard" cost of service methodology that must be used in Washington. The Commission stated as much in the same 1993 PSE Order mentioned previously. Specifically, in discussing the reasonability of the Peak Credit method, the Commission stated:

> The Commission does not, however, accept the Company's invitation to designate Puget's model to be used as the standard in future proceedings.

> As circumstances change, and theories evolve, other approaches to cost of service analysis may prove to be relevant.[21/]

Moreover, Pacific Power has been authorized to use the alternative Peak and Average method since 2013.[22/] As with the issue of allocation hours to be used in future ratemaking, the Commission also noted in Pacific Power's 2014 general rate case that "the parties raise sufficient concerns" so as to invite "more detailed justification for using an alternative approach" to the traditional Peak Credit method.[23/] I understand that this proceeding represents the Commission's first opportunity to consider alternatives in an electric general rate case setting since that determination was made.

Q. WHAT CLASSIFICATION METHOD DO YOU RECOMMEND FOR PRODUCTION INVESTMENT IN THIS CASE?

A. Because production investment is primarily incurred due to the need for and the size of the peak demands of customers, it should be assigned to customer classes exclusively, or at least primarily, on those classes' contribution to utility system peaks. Classification by this method has widespread support in the industry and is, in my view, a better reflection of cost causation than classification or allocation methods that utilize energy usage to any significant degree. Although energy costs typically and appropriately are taken into account in determining what kind of generating unit to build to meet the peak demand, it is the shrinking reserve margins over peak demand that typically cause new generation to be built. Furthermore, even when energy usage (as measured by average demand) is utilized, a far more appropriate and typical approach is the "average and excess demand" method.[24/] The average and excess demand method

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21/ WUTC v. PSE, Docket Nos. UE-920433 *et al.*, 9th Suppl. Order at 8 n.5 (August 17, 1993).
22/ Dockets UE-140762 *et al.*, Order 08 at ¶¶ 190-91.
23/ *Id.* at ¶ 191.
24/ *See NARUC Manual* at 49-52.

allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak demands.[25]

My understanding is that the Peak Credit method has been used in Avista cases for some time. Assuming the Commission is not constrained to utilize the Peak Credit method due to its prior use, I recommend it not be used in this case. On the other hand, if the Commission uses the Peak Credit method, I recommend that it be refined in its application.

Q. IF THE PEAK CREDIT CLASSIFICATION IS ADOPTED IN THIS CASE, HOW WOULD YOU RECOMMEND THAT THE APPROACH BE REFINED?

A. In that case, the heavy reliance on energy usage in assigning costs (62%) highlights the critical need to refine the demand allocator used for capacity costs. As mentioned, the Avista electric system exhibits a predominant winter peak and, recently, summer peak. Therefore, any method of cost allocation that considers loads in hours that do not contribute to the need for new generation, or any energy-based method,[26] does not adequately account for the dominant system peaks, fails to reflect the actual load characteristics of the Avista system, and fails to properly reflect class responsibility for production investment. Thus, for Avista, a Summer and Winter allocation is a more appropriate allocation method for demand-related production costs. This is true in the context of a full allocation of production investment or as used in conjunction with the Peak Credit classification approach.

25/ *Id.*

26/ Similarly, allocating costs on average demand is mathematically equivalent to a kWh allocation and ignores the distinctions between peak period usage and off-peak period usage.

Q. HOW WOULD YOU RECOMMEND THE SUMMER AND WINTER ALLOCATION METHOD BE APPLIED IN THIS CASE?

A. Because Avista is a bi-modal utility, I recommend equal weight (50%/50%) be given to summer and winter peak allocators, as was done in the Pacific Power case. Further, for the reasons previously explained, I recommend the peak demands that are within 5% of the system peak be used. As shown on Figure 1, above, these are the monthly peaks of June, July, August and December. Therefore, the winter demand allocator would be based on each class's demand during the December peak, and this would be given a 50% share in developing the overall allocator. For the summer allocator, I would average the class's proportionate shares of the system peaks during the months of June, July and August, and give these average shares the other 50% weight in the allocation method. Using this approach, each of the three summer peaks would be given a one-sixth weight in the overall allocator, while the December peak would be given a one-half weight. Although 4 coincident peaks are used in this method, it is not the same as a traditional 4 CP allocation approach, due to the variable weighting of the summer and winter demand values.

I believe this approach to be the most valid for developing a demand allocator for Avista, recognizing the bi-modal nature of the load, adopting the Summer and Winter Peak allocator, utilizing the available data (monthly peak values) and utilizing the monthly peaks within 5% of the system peak.

Q. HAVE YOU CALCULATED THE SUMMER AND WINTER ALLOCATION FACTORS NECESSARY TO APPROPRIATELY ALLOCATE DEMAND-RELATED PRODUCTION COSTS IN AVISTA'S ECOS STUDY?

A. Yes. These allocation factors, along with Avista's proposed 12 CP allocation factors for ease of comparison, are shown in Table 2, for each of the Avista rate schedules in the ECOS study.

TABLE 2

Production Allocation Comparison

Class	Summer/ Winter	12 CP
Sch 1	54.47%	50.24%
Sch 11/12	9.13%	9.48%
Sch 21/22	20.04%	22.25%
Sch 25	14.18%	15.81%
Sch 31/32	1.88%	2.02%
Sch 41/49	0.30%	0.20%
Total	100.00%	100.00%

Allocation of Transmission Costs

Q. HOW DOES AVISTA CLASSIFY TRANSMISSION COSTS IN ITS ECOS STUDY?

A. It uses the same peak credit methodology as is used for classifying production costs.

Q. HAS THIS CLASSIFICATION METHODOLOGY FOR TRANSMISSION COSTS BEEN APPROVED IN THE PAST?

A. Yes; although the Commission has also approved the Company's previous election to classify transmission plant as 100% demand-related,[27/] which is consistent with my

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27/ See WUTC v. the Washington Water Power Co., Cause No. U-83-26, Fifth Suppl. Order, 1984 WL 1022551 (Jan. 19, 1984).

proposed methodology and the industry standard. Thus, while I acknowledge that the Company has been allowed to classify transmission costs under the Peak Credit methodology, this is a highly unusual manner of classification with little to justify its continuation, and is not the only approach that has been used for the Company.

Q. WHY DO YOU BELIEVE THIS CLASSIFICATION METHOD IS HIGHLY UNUSUAL?

A. I am not aware of any case outside of Washington where a utility has classified or allocated traditional transmission costs on the basis of energy to <u>any</u> degree, let alone 68%. I see no justification for classifying transmission costs in this manner.

Q. WHY DO YOU BELIEVE THERE IS NO JUSTIFICATION FOR UTILIZING AN ENERGY COMPONENT IN CLASSIFYING OR ALLOCATING TRANSMISSION COSTS?

A. Unlike production, where parties sometimes claim there is a trade-off between fixed and variable costs that justify an energy component in the classification or allocation to reflect cost-causation, there is not even an arguable trade-off for transmission facilities.

I can illustrate this through a simple hypothetical. If a utility were to build a 1,000 MW generating unit in an area that is not adjacent to transmission facilities, additional transmission facilities would need to be constructed to connect the generating unit to the electrical grid. The capacity of the new transmission facilities would need to be designed to carry the maximum output of the generating unit. The capacity and cost of those new transmission facilities is not dependent on the fuel type or economics of the generating unit being constructed or how often it is run. Said another way, essentially the same transmission facilities would need to be built whether the 1,000 MW unit is a nuclear power plant, with a very high capacity factor producing 7.9 million MWh/year, or a natural gas-fired peaking plant with a much lower capacity factor producing 2.2 million MWh/year. The transmission facilities would be designed and constructed to meet the maximum capacity (1,000 MW) required over the lines.

Similarly, increased or decreased utilization of the transmission system, once it is built, does not impact the costs of the transmission assets. For example, higher cumulative energy flow without an increase in demand does not impact transmission costs. In addition, the vast majority of transmission costs are fixed, not variable. For these reasons, an energy classification or allocation of transmission costs is not justified.

Q. HAS THE COMPANY CONFIRMED THAT ITS TRANSMISSION SYSTEM IS CONSTRUCTED TO MEET THE PEAK DEMAND OF ITS CUSTOMERS?

A. Yes. Company witness Patrick Ehrbar states exactly that.[28/] He makes no mention of energy usage as a causal component in this regard. Further, my review of Avista's Transmission Planning Standards, Policies and Procedures reveals no reliance on energy flow as a planning criterion.

Q. ARE THERE OTHER REASONS FOR NOT UTILIZING THE PEAK CREDIT METHOD FOR CLASSIFICATION TRANSMISSION COSTS?

A. Yes, there are. In providing guidance to utilities in billing for network transmission service, FERC utilizes 12 CP, without regard to the amount of energy flowed across the lines over time.[29/] Further, in billing for transmission service separate from bundled service, Avista itself utilizes a 12 CP billing method for network transmission service as specified in Sections 34.1 and 34.2 of Avista's current Open Access Transmission Tariff.[30/] An excerpt of Section 34 of that tariff is attached as Exhibit No. RRS-7.

28/ Exh. No. PDE-1T at 13.

29/ Generally, FERC Orders 888 and 889 dealt with these matters.

30/ "Avista Corporation FERC Electric Tariff Volume No. 8," generated on 5/12/2016.

Q. BESIDES 12 CP, ARE THERE ANY OTHER REASONABLE OPTIONS FOR ALLOCATION OF TRANSMISSION COSTS?

A. Yes, considering that the transmission system is built to meet the peak demands on the system (as opposed to times of relatively low demands), it would not be unreasonable to use a 1 CP, 4 CP or the Summer and Winter Peak measure. Indeed, some Regional Transmission Organizations effectively use a 1 CP or 5 CP for billing for transmission service.

However, although 12 CP may not be the truest measure of transmission cost-causation, as it overemphasizes demands in non-peak seasons, given its widespread use by other utilities around the country and by FERC, it is reasonable (though conservative) for use in this case.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that transmission system costs not be classified using the peak credit method at all. Rather, the 12 CP demand measure should be used for 100% allocation of transmission costs.

Q. CAN YOU PROVIDE A COMPARISON OF THE TRANSMISSION ALLOCATION FACTORS THAT YOU RECOMMEND TO THOSE USED BY AVISTA?

A. Yes, I can. The resulting effective transmission allocation factors are shown in Table 3.

TABLE 3

Comparison of
Transmission Allocation Factors

Rate Schedule	Avista	ICNU
Sch 1	45.10%	50.24%
Sch 11/12	10.13%	9.48%
Sch 21/22	24.05%	22.25%
Sch 25	17.90%	15.81%
Sch 31/32	2.46%	2.02%
Sch 41/49	0.36%	0.20%
Total	100.00%	100.00%

Allocation of AMI General and Intangible Plant

Q. HOW DOES AVISTA ALLOCATE PLANT COSTS ASSOCIATED WITH AMI?

A. Avista detailed this information in response to a data request from Public Counsel/Energy Project ("PC/EP"), specifically PC/EP – 040.[31/] In this response, Avista shows four main categories of Plant, each with a different allocation factor. The first category is Distribution Plant, which is the advanced meters and associated tangible equipment. Avista proposes to allocate the costs of this category on "Meter Investment Allocation Ratio." The second category, Intangible Plant, is related to computer software and is allocated on Avista's "Computer Software Investment Allocation Ratio." The third category, General Plant, is related to AMI communications and is allocated on "Communication Equipment Investment Allocation Ratio." Finally, the fourth category is Accumulated Deferred Income Tax and is allocated on "AMI - Accumulated Deferred Income Tax Allocation Ratio."

31/ Exh. No. RRS-11C (Avista Response to PC/EP Data Request ("DR") 040, Attachment A).

Associated depreciation and amortization expenses are allocated accordingly.

These allocation ratios correspond to associated total investments in Avista's ECOS study.[32/] For the G&I plant, this essentially means that AMI-related G&I plant investments are allocated the same as non-AMI G&I investments.

Q. IS THE AMI PROGRAM APPLYING TO ALL CUSTOMER CLASSES?

A. No. At this time, Avista will continue to use the existing metering system (MV-90) for Schedule 25 customers.[33/] The AMI equipment will be used only for classes other than Schedule 25.

Q. DO YOU EXPECT THAT SCHEDULE 25 CUSTOMERS WILL BENEFIT IN ANY SIGNIFICANT WAY FROM THE DEPLOYMENT OF AVISTA'S AMI SYSTEM?

A. No, at least not directly. The direct benefits of the AMI program will flow to the customers who receive the advanced meters and functionality, i.e., customers other than Schedule 25 customers. Avista witness Heather L. Rosentrater lists such benefits to participants in her testimony.[34/] If there is any benefit to Schedule 25 customers at all, it will be primarily, if not exclusively, indirect benefits.

Some may argue that the existence of AMI will benefit all customers and, accordingly, all customers should pay for the system. While such an argument is superficially appealing, it does not properly reflect cost causation and does not adequately quantify, or even estimate, the relative benefits enjoyed by the classes. Schedule 25 customers are larger, more energy-intensive customers than customers in other customer classes. They have had sufficient metering for years that allow them to

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32/ *Id.* (Avista Supplemental Response to ICNU DR 075).
33/ *Id.* (Avista Response to ICNU DR 088).
34/ Exh. No. HLR-1T at 18-19.

know their usage information on a much more granular basis than other customers and to alter their loads, through conservation or load shifting, as economically warranted.

In addition, Schedule 25 customers tend to take service at higher voltages than most customers in other classes. Thus, purported benefits of AMI on lower voltage parts of the system, e.g., distribution outage recovery, are of no benefit to customers at higher voltages.

The most difficult claim of indirect benefit to substantiate, in my opinion, is lower overall energy costs to the system due to customer usage changes enabled by AMI. Even this cross-schedule benefit claim fails to justify imposition of additional costs on Schedule 25 customers, however, as their existing metering system has enabled them to provide such benefits to other customer classes for years, without associated compensation from the other classes.

Q. ARE YOU RECOMMENDING THAT SCHEDULE 25 CUSTOMERS BE RELIEVED OF ALL AMI COST RESPONSIBILITY IN THE ECOS STUDY?

A. No; although such a recommendation would not be unreasonable, for the reasons discussed above. As a practical matter, Schedule 25 customers are allocated a relatively low share of the total AMI-related Distribution Plant, 0.14%.[35/] At such a level, elimination of Schedule 25's AMI-related Distribution Plant cost (about $23,000) would not make a significant difference in the overall ECOS study results.

However, Schedule 25 customers are being assigned an unreasonable share of the G&I plant associated with AMI. According to Avista's response to PC/EP – 040, Schedule 25 customers are being allocated 11.66% and 9.80% of the costs of Intangible and General Plant, respectively. The associated costs are about $478,000 and $410,000,

[35/] Exh. No. RRS-11C (Avista Response to PC/EP DR 040, Attachment A).

respectively, totaling about $900,000. Schedule 25 customers, who will not be using the AMI system, should not have to pay such a large share of the computer software and communications costs.

Q. HOW DO YOU RECOMMEND AMI-RELATED G&I PLANT COSTS BE ALLOCATED IN THE ECOS STUDY?

A. I recommend they be allocated on the same basis as the Total AMI-Related Distribution Plant. These costs are for assets that are closely associated with and support the AMI metering function and should be allocated accordingly. Associated depreciation and amortization expenses should follow the plant allocators as well.

I have made these modifications in all of the ECOS study scenarios that I will report below. I have not made such a modification to Avista's original study, but I recommend it be made, if Avista's study is adopted.

ECOS Study Results

Q. HAVE YOU MODIFIED THE AVISTA ECOS STUDY SO THAT PRODUCTION-RELATED COSTS ARE ALLOCATED USING YOUR RECOMMENDED SUMMER AND WINTER ALLOCATOR, RATHER THAN THE 12 CP METHOD?

A. Yes. I have calculated the ECOS study for the recommended summer and winter demand allocation method under both a 100% demand allocation of production capacity costs, and in the context of Avista's Peak Credit classification (38% demand, 62% energy).[36/] For the 100% demand summer and winter allocation, I calculate the ECOS results as if the peak credit method for classification is not used at all and, instead, production fixed costs are allocated on the basis of the Summer and Winter Peak Method alone. Disuse of the Peak Credit method altogether requires some modifications to the

36/ And I have allocated AMI-related G&I plant and expenses as described hereinabove.

allocation of production variable costs and transmission costs. For simplicity, I have conservatively used a 100% energy allocator for variable production costs, and a 100% 12 CP allocator for transmission costs. The results of this allocation method are shown in Exhibit No. RRS-5. As shown, for some rate schedules, the change in production cost allocator makes a significant difference in the cost of service.

I have also modified the Avista ECOS study to adopt a summer and winter demand measure in the context of the Peak Credit classification approach, should the Commission utilize that method. For this version of the ECOS study, no other changes were made as compared to Avista's proposed study, other than the allocation of AMI-related G&I plant. The results of this modification are shown in Exhibit No. RRS-6. As with my primary recalculation shown in Exhibit No. RRS-5, the change in the demand measure makes a significant difference in the schedules' overall cost of service.

Q. CAN YOU PROVIDE THE RESULTS OF APPLYING THE 12 CP ALLOCATION OF TRANSMISSION COSTS TO THE MODIFIED PEAK CREDIT ALLOCATION OF PRODUCTION COSTS?

A. Yes. This information is provided in Exhibit RRS-8. This exhibit differs from Exhibit No. RRS-6 in that transmission costs are 100% allocated on 12 CP. As mentioned, if the Peak Credit is retained at all, it should only be retained for production costs.

<u>Overall Cost of Service Results</u>

Q. CAN YOU PLEASE PROVIDE A SUMMARY OF THE RESULTS OF THE ECOS STUDIES MODIFIED FOR YOUR RECOMMENDATIONS FOR PRODUCTION AND TRANSMISSION COST CLASSIFICATION AND ALLOCATION OF AMI-RELATED G&I PLANT AND EXPENSES?

A. Yes. This information is provided in Table 4, below, which provides the rate schedule returns under Avista's ECOS study, my preferred ECOS study, from Exhibit No. RRS-

5 and the modified Peak Credit (production-only) ECOS study, from Exhibit No. RRS-8.

TABLE 4

Summary Comparison of Cost of Service Study Results

Schedule	Avista ECOS Study Rate of Return	Avista ECOS Study Index	Exhibit (RRS-5) Recommended ECOS Study Rate of Return	Exhibit (RRS-5) Recommended ECOS Study Index	Exhibit (RRS-8) Modified Peak Credit ECOS Study Rate of Return	Exhibit (RRS-8) Modified Peak Credit ECOS Study Index
Sch 1	3.30%	0.55	2.75%	0.46	2.76%	0.46
Sch 11/12	11.92%	1.98	12.43%	2.06	12.16%	2.02
Sch 21/22	8.96%	1.49	10.09%	1.68	9.72%	1.62
Sch 25	6.23%	1.03	8.01%	1.33	7.46%	1.24
Sch 31/32	5.01%	0.83	5.77%	0.96	5.56%	0.92
Sch 41/49	5.32%	0.88	5.44%	0.90	5.39%	0.90
Total	6.02%	1.00	6.02%	1.00	6.02%	1.00

Notes:

	Avista ECOS Study	Exhibit (RRS-5) Recommended ECOS Study	Exhibit (RRS-8) Modified Peak Credit ECOS Study
Production (fixed)	12 CP, Peak Credit	Summer and Winter, No Peak Credit	Summer and Winter, Peak Credit
Production (variable)	12 CP, Peak Credit	Generation Energy 100%	Summer and Winter, Peak Credit
Transmission	12 CP, Peak Credit	12 CP 100%	12 CP 100%
AMI-Related G&I	Total G&I	AMI Dist. Plant	AMI Dist. Plant

As Table 4 shows, the cost returns vary significantly from Avista's calculation. For example, rather than a rate of return index of 1.03 for Schedule 25, under my adjusted measure of cost of service, the rate of return index is 1.33, meaning that Schedule 25 customers actually are providing revenues to produce a return significantly higher than the system average, i.e., indicating that Schedule 25 is currently providing revenues well above cost of service.

IV. ELECTRIC REVENUE ALLOCATION ("RATE SPREAD")

Q. PLEASE DISTINGUISH THE REVENUE ALLOCATION STEP IN THE PROCESS FROM THE COST OF SERVICE ANALYSIS.

A. As previously mentioned, the cost of service analysis is an empirical analysis of the costs caused by the various customer schedules. In itself, it does nothing to change customers' rates. Rather, determining how much of the revenue requirement should be borne by each rate schedule is the step known as revenue allocation or rate spread.

The rate spread should be based on the results of the cost of service study, since cost-based rates tend to be the fairest and most economically efficient. However, the rate spread can be influenced by other principles, such as rate continuity, rate moderation and avoidance of rate shock.

Q. WHAT IS AVISTA'S PROPOSAL REGARDING RATE SPREAD?

A. Avista's proposed rate spread for 2017 is shown in Table 2 of Company witness Patrick Ehrbar's testimony.[37/] As shown in the table, the Company has requested a system average base rate increase of 7.8% over current rates. Under the Company's proposal, Residential, Pumping Service, and Lighting customers will receive above system average increases, while General Service customers will receive below system average increases.

The proposed base rate spread for 2018 is shown in Table 4 of Mr. Ehrbar's testimony.[38/] Avista has requested an additional increase of 3.9% over proposed 2017

37/ Exh. No. PDE-1T at 6.

38/ *Id.* at 8.

rates. As in 2017, Residential, Pumping Service, and Lighting customers will receive increases that are above the system average, while the remaining customers will receive increases below the system average. However, in billing rates, the increase in base rates is offset by the Energy Recovery Mechanism rebate, yielding no change in billing rates (and no further movement to cost of service).

Q. IS AVISTA'S PROPOSAL REASONABLE?

A. Avista's proposed rate spread for 2017 rates is reasonable in some respects. It is based on the results of Avista's cost of service study showing that certain classes to varying degrees are currently over-paying or under-paying, as evidenced by the present relative rate of return, as shown on Table 3 of Mr. Ehrbar's direct testimony.[39/]

However, Mr. Ehrbar's proposal provides very little movement toward cost of service for Schedule 1, which is far below cost of service under any of the ECOS study results shown in Table 4, above, or in Mr. Ehrbar's testimony. This is indicated by the rate of return indices which range from 0.54 to 0.63, when the system average is 1.0. Bringing Schedule 1 fully to cost of service, i.e., equalized rate of return, would require a 24.5% increase under Avista's ECOS study and a 30.1% increase under mine. While full movement to cost is not feasible in a single step for this class,[40/] much greater movement toward cost of service for this class is justified from a cost of service view. Mr. Ehrbar's proposed increase of 8.4% in 2017 only modestly brings Schedule 1 closer to cost. Even with an 8.4% increase, Schedule 1 would provide rate of return indices of only 0.54 under my recommended ECOS study and 0.63 under Avista's ECOS study.

39/ *Id.* at 7.

40/ Due to rate moderation criteria.

Q. WHAT DO YOU RECOMMEND FOR RATE SPREAD?

A. Avista's rate spread is generally acceptable in this case, if Avista receives its full revenue request. However, if Avista's approved revenue requirement is lower than proposed by Avista, the increase for Schedule 1 should not be reduced, as this schedule is so far below cost of service. Rather, those savings should accrue to the other classes, in proportion to Avista's proposed increase amounts. For example, if Avista received only one half of its requested increase, I would suggest the rate spread shown in Table 5, below.

TABLE 5

Recommended Rate Spread Based on
Avista Receiving 50% of Requested Increase

		Company		50% of	
	Current	Proposed Increase		Requested Increase	
Schedule	Revenue	Amount	Percent	Amount	Percent
Sch 1	$ 211,070,000	$17,730,000	8.4%	$17,730,000	8.4%
Sch 11/12	70,975,000	4,948,000	7.0%	368,999	0.5%
Sch 21/22	129,105,000	9,708,000	7.5%	723,977	0.6%
Sch 25	64,450,500	4,386,500	6.8%	327,125	0.5%
Sch 31/32	12,510,500	1,082,500	8.7%	80,728	0.6%
Sch 41/49	6,953,000	713,000	10.3%	53,172	0.8%
Total	$ 495,064,000	$38,568,000	7.8%	$19,284,000	3.9%

For 2018 rates, I recommend the same approach. However, Schedule 1 rates should be adjusted by something more than 4.2% if significant movement toward cost is to be achieved. I recommend at least a 6% increase, as a step toward cost of service, with savings allocated to other classes in the same fashion as I propose for 2017 rates.

Q. DO YOU HAVE ANYTHING TO ADD ON RATE SPREAD?

A. Yes. I recognize that the Commission has found that increases of 114% of the system average to certain rate classes were too extreme, while approving a 112% increase for the residential rate class.[41/] However, I do not believe that the rate increases that I have proposed will be unduly burdensome to Schedule 1 customers. This is because I am only proposing increases for Schedule 1 of 8.4% and 6% for 2017 and 2018, respectively, while the Commission's finding regarding a 114% increase above the system average was made in the context of a *much larger* 17.85% overall rate increase.[42/]

Notwithstanding, if the Commission were to apply a rate increase cap, then I recommend that the Commission approve a Schedule 1 rate increase limit of no less than 112% of the system average, but with a lower bound of 3%, even if the increase is minimal or negative. Significant movement must be made to bring Schedule 1 closer to parity, in order to achieve a fair and equitable outcome for other customers who have long subsidized the residential rate class.

V. ELECTRIC RATE DESIGN

Q. WHAT IS AVISTA'S OVERALL PROPOSAL AS IT RELATES TO RATE DESIGN?

A. According to Company witness Mr. Ehrbar, the Company is not proposing any changes to the existing rate structures within its rate schedules except for changes in rate components.[43/]

41/ Dockets UE-140762 *et al.*, Order 08 at ¶ 202 (citing Docket UE-100749, Order 06 at ¶ 316).
42/ Docket UE-100749, Order 06 at ¶ 311.
43/ Exh. No. PDE-1T at 10.

For Extra Large General Service Schedule 25, the current rate consists of a two-tiered demand charge: (1) $21,000 for the first 3,000 kVA or less; and (2) an additional demand charge of $6.00 per kVA for monthly demand in excess of 3,000 kVA. Energy charges are broken into three blocks: the first 500,000 kWh, 500,000 through 6,000,000 kWh, and all over 6,000,000 kWh. The rates per kWh are $0.05505, $0.04953, and $0.04235, respectively. Avista proposes to maintain the demand charge for the first 3,000 kVA at $21,000 and increase the charge to $6.50 per kVA for demand above 3,000 kVA.[44/] The energy charges for the same blocking structure are proposed to be $0.05896, $0.05305, and $0.04536, respectively. In addition to these demand and energy charges, there are service voltage discounts on these demand charges, which Avista does not propose to change.

Q. DO YOU HAVE ANY RATE DESIGN RECOMMENDATIONS?

A. Yes, I do. The first is related to Avista's collection of demand-side management costs under Schedule 91. The second is related to implementing a viable demand response pilot program for Schedule 25 customers.

<u>Schedule 91 Collections</u>

Q. PLEASE DESCRIBE SCHEDULE 91.

A. Schedule 91, Demand-Side Management Rate Adjustment-Washington is applicable to all six major rate classes, although the charge is different for each class. The Schedule 91 rate adjustment was designed to recover costs incurred by Avista associated with providing demand-side management services and programs to customers. For Schedule

[44/] Exh. No. PDE-4 at 4.

25 customers, Avista has recently increased the Schedule 91 surcharge to $0.00172 per kWh.

Q. WHAT IS YOUR CONCERN WITH AVISTA'S SCHEDULE 91?

A. There is a clear disparity among the rate classes in the relationship of benefits to costs associated with the Schedule 91 collections. Customers in the Schedule 25 class receive direct incentives far below the level of their contributions under Schedule 91. Said alternatively, the customers are paying much more than they are receiving in direct incentives. This inequitable disparity is detailed in Confidential Exhibit No. RRS-9C, which was created to provide an overview of ICNU's DSM proposal, supported by quantitative analysis obtained through discovery.

For instance, the Company recently reported that direct incentives returned to customers have constituted 64% of the contributions paid on a total-customer, Washington basis.[45/] For Schedule 25, however, the same measure indicates these customers have received only 38% in returned direct incentives since 2005, as compared to their level of contributions.[46/] Further, the largest ICNU member represented in this case has a much lower benefit to cost ratio, receiving only about [redacted] of its contributions as direct incentives.[47/] Consequently, there exists a broad inequity between that particular ICNU member, Schedule 25 and the Company as a whole. This inequity should be addressed in this case.

[45/] Exh. No. RRS-9C at 3, line 2, column 3 (citing Re Avista, Docket UE-152076, Biennial Conservation Plan for 2016-2017, App. B: Rev. 2016 DSM Business Plan at 29, Table 4).

[46/] *Id.* at 3, line 1.

[47/] *Id.* at 3, line 3.

Q. HAS THIS ISSUE BEEN RAISED BY ICNU BEFORE?

A. Yes, this issue has been discussed in the conservation/DSM Advisory Group formed by the Company to address issues with Avista's conservation programs.[48/] However, as the issue has not been resolved in that forum, ICNU has elected to bring its concerns to the Commission in conjunction with other rate design considerations affecting Schedule 25.

Q. WHAT ALTERNATIVES EXIST TO CORRECT THE INEQUITY AS RELATES TO SCHEDULE 25 CUSTOMERS AND/OR THE LARGEST ICNU MEMBER SERVED BY AVISTA?

A. As least three alternatives have been considered. The first of these is to implement an opt-out process for Schedule 25 customers, or at least the ICNU member most egregiously affected. Under an opt-out approach, large customers are relieved of the requirement for DSM contributions and in return are not eligible to receive any direct benefits. In addition, the loads of such customers who have opted-out are not counted against a utility's requirement for DSM programs or energy savings. Opt-out programs make good sense, because large industries, especially those which are energy-intensive, already have adequate incentives to pursue cost beneficial energy efficiency measures. Further, their energy-using systems are complex enough that they do not readily conform to standard utility-supplied programs.

The second alternative considered is a Self-Direct option. Under a Self-Direct option, customers either on their own, or through the utility, establish reserve accounts where they periodically deposit funds that can only be withdrawn and used for energy efficiency or demand-side management measures. This provides an additional strong

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48/ Exh. No. RRS-9C is very similar to a presentation document provided by ICNU to multiple Avista Conservation/DSM Advisory Group members.

incentive to invest in energy efficiency. Although such an incentive arguably is not needed, a Self-Direct approach provides an even larger incentive for customers to pursue DSM programs because their capital otherwise is tied up and not available for operations, which is significant. Under this approach, customers typically are relieved from making normal DSM contributions to the utility and the utility is relieved of providing direct incentives to the customer and an obligation for energy savings associated with the customers' loads.

The third option is a modest change in application of the Schedule 91 collection mechanism for Schedule 25 energy charges, to reduce the funding requirement from these customers. Ultimately, ICNU believes that both the second and third options should be approved. The Self-Direct program may provide a long-term solution, but it would be highly unlikely that a properly designed program could be implemented within the confines of the current proceeding. Conversely, Schedule 91 could easily be modified within this rate case, providing a near-term solution that will at least somewhat correct the longstanding interclass inequity issue.

Q. PLEASE DESCRIBE THIS NEAR-TERM SOLUTION IN GREATER DETAIL.

A. Under this approach, I recommend that Schedule 91 DSM funding charges apply to blocks 1 and 2 energy charges of Schedule 25 only. The third energy block charge would not be subject to the DSM component. While this solution does not fully bridge the funding inequity between Schedule 25 and other classes, I believe this solution is a reasonable compromise in order to minimize the overall rate impact. Specifically I recommend that all other rate schedules, including Blocks 1 and 2 of Schedule 25, would have Schedule 91 collections increased on a uniform percentage basis, considering current DSM contribution levels. ICNU estimates that such increase in funding would be approximately 5.1% for these other schedules and Blocks 1 and 2 of Schedule 25.[49]

Q. WOULD THIS PROPOSAL EQUALIZE THE DIRECT INCENTIVES AS A PERCENTAGE OF CONTRIBUTIONS AMONG THE RATE CLASSES?

A. No. Schedule 25 would still be receiving a lower benefit to cost ratio than the system average and the largest ICNU member served by the Company would still be receiving a much lower percentage, around [redacted].[50] However, this approach is a step in the right direction and would make a modest reduction in the current rate inequities. Eventually, the Commission should work toward an opt-out or Self-Direct solution.

Q. IS YOUR RECOMMENDATION FOR APPLICATION TO SCHEDULE 91 CONSISTENT WITH ANY OTHER RATE SCHEDULES?

A. Yes. It is consistent with the approach used for Schedule 92.

Q. HAS AVISTA PROVIDED AN OPINION RELATED TO THESE DSM FUNDING OBJECTIVES?

A. Yes. In response to ICNU Data Request 119, Avista states as follows:

> Among the objectives of the Company in designing programs such as the DSM program, including funding for the program, is for the program to be fair and reasonable. There can be a range of designs and outcomes that could be considered to meet those objectives based on specific circumstances.[51]

<u>Demand Response</u>

Q. WHAT IS DEMAND RESPONSE?

A. A usable definition is shown below.

> Demand response provides an opportunity for consumers to play a significant role in the operation of the electric grid by reducing or shifting their electricity usage during peak periods in response to time-based rates or other forms of financial incentives. Demand response programs are

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49/ Exh. No. RRS-9C at 6, column 4.
50/ *Id.* at 7, line 3.
51/ Exh. No. RRS-11C (Avista Response to ICNU DR 119).

> being used by electric system planners and operators as resource options for balancing supply and demand.[52]

The form of demand response that I would like to address is utility interruptible load. Properly used, interruptible load is a valuable resource for utilities for both avoiding construction or purchase of expensive generating capacity and can be used to avoid high cost energy generation or purchase. Both are valuable to Avista and its customers

Q. HOW CAN INTERRUPTIBLE LOAD BE USED TO HELP AVOID CAPACITY ADDITIONS?

A. Utilities typically plan system expansion to meet only the firm loads of their customers. By having some load designated as interruptible, the utility can build or acquire less generating capacity. This is a concept that has been used for decades and is well established in the industry. Interruptible load is often treated in utility integrated resource plans on equivalent, or near equivalent, footing as "assets in the ground" generation.

When system supply conditions are tight, interruptible load is taken off the system first, leaving more capacity to serve firm load. The value of this was exhibited plainly in 2014, during the "polar vortex" in the eastern interconnection of the U.S., when many utilities curtailed their interruptible customers and, in doing so, were able to avoid blackouts to firm customers.

Q. HOW CAN INTERRUPTIBLE LOAD CAUSE A UTILITY TO INCUR LESS GENERATION ENERGY COSTS?

A. Except in the case of utility real-time pricing or hourly index programs, retail energy rates tend to be fixed by tariff. However, a utility's cost of generating power varies each hour, according to the generating mix present at the time and the impact of off-system

[52] From http://energy.gov/oe/services/technology-development/smart-grid/demand-response.

purchases. In hours where the retail energy price is 5¢ per kWh, for example, but the utility's cost of generation is 10¢ per kWh, the utility loses money on every kWh sold. During those hours when the cost of supply is higher than the retail rate, a utility will benefit if customers interrupt their load.

Thus, interruptible load can provide both reliability benefits to the system and economic benefits to the utility.

Q. HOW ARE INTERRUPTIBLE RATES TYPICALLY STRUCTURED TO REFLECT THE RELIABILITY AND ECONOMIC BENEFITS THAT YOU MENTIONED?

A. Properly designed interruptible rates typically offer a credit on the demand charge associated with the portion of the customer's total load which is interruptible. Effectively, the utility "reserves" a certain amount of capacity that it can call upon if needed. Because this reserved capacity is available each month, capacity credits are payable to customers even in months where no interruption events occur.

Q. HOW ARE ECONOMIC BENEFITS NORMALLY TREATED?

A. For economic interruptions, the utility will generally compensate the customer only for times interruption events occur, and then only to the extent that costs are avoided. This form of compensation can be detailed and can take numerous different forms.

Q. DOES AVISTA HAVE A TARIFF INTERRUPTIBLE RATE?

A. No.

Q. DO ANY OTHER WASHINGTON UTILITIES HAVE INTERRUPTIBLE RATES?

A. Although I have not conducted an exhaustive search, I am aware of industrial demand response programs for some municipal utilities and PSE.[53/]

53/ PSE Schedule 46-High Voltage Interruptible Service.

Q. WHAT ARE TYPICAL DEMAND CHARGE REDUCTIONS OR CREDITS ASSOCIATED WITH INTERRUPTIBLE LOAD?

A. These amounts vary from time-to-time as circumstances change, but in my recent experience, the credits range from around $3 to $7 per kW-month. However, much higher credits could be justified based on the cost of new generation that can be avoided by greater use of interruptible resources. For example, in Washington, in the analytical methodology used by the Northwest Power Conservation & Council to evaluate the cost effectiveness of energy efficiency and demand response resources, the cost of new natural gas-fired generating units are used. Table 13-2 of the Seventh Northwest Conservation and Electric Power Plan, released February 25, 2016, provides capital costs and levelized fixed costs of various natural gas-fired generating resources. The levelized fixed costs range from $148 per kW-year to $214 per kW-year. Even at the lowest value, $148 per kW-year when adjusted for reserve margin losses and coincidence factor, would result in monthly costs of around $13 per kW-month. Thus, the value of avoiding new capacity additions is significant.

Q. ARE THERE OTHER CONSIDERATIONS TO BE TAKEN INTO ACCOUNT WHEN DESIGNING AN INTERRUPTIBLE RATE?

A. Yes. In addition to the proper capacity credits and avoided energy rates, a number of operational terms must be defined. These include matters such as notice time for interruption, duration and frequency of interruptions, total interruptions in a year, periods between interruptions, communication mechanisms, etc.

Q. WHAT IS YOUR RECOMMENDATION IN THIS REGARD?

A. I recommend that the Commission direct Avista to begin utilizing demand response resources in a way that can benefit both the utility system and customers. Because of the complexities of developing a fully functional demand response program, I recommend Avista begin with a pilot program, to be made available to large Schedule 25 customers.

Toward this end, I have developed an example Schedule 78-Large Customer Demand Response Pilot Program. The details of my initial proposal are shown in Exhibit No. RRS-10.

Q. IS EXHIBIT NO. RRS-10 THE ONLY FORM OF DEMAND RESPONSE PILOT PROGRAM THAT ICNU WOULD FIND ACCEPTABLE?

A. Not necessarily. Avista or other parties may have suggestions for enhancements that should be considered. Hopefully, this exhibit will provide a reasonable framework for going forward discussions, with the goal of a reasonable demand response pilot program coming out of this rate case, which can be evaluated for effectiveness and potential modification or expansion in the future, as needed.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR RESPONSE TESTIMONY?

A. Yes, it does.

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