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VIA ELECTRONIC FILING
Mr. Mark L. Johnson
Executive Director and Secretary
Washington Utilities & Transportation Commission
1300 S. Evergreen Park Drive, S.W.
P.O. Box 47250
Olympia, WA 98504-7250

Re: Comments of Alliance of Western Energy Consumers on Rulemaking to Address Electric and Natural Gas Cost of Service
Dockets UE-170002 and UG-170003

Dear Mr. Johnson:

These comments are submitted on behalf of Alliance of Western Energy Consumers ("AWEC") in response to the Notice of Opportunity to File Written Comments, issued by the Washington Utilities and Transportation Commission (the "Commission") in the above referenced dockets on July 23, 2018. AWEC appreciates the opportunity to provide the comments on cost of service issues for Washington utilities.

These comments have been filed electronically via the Commission's web portal. Thank you for your assistance.

Very truly yours,

Chad M. Stokes

CMS:lms

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of	)	
	)	DOCKET NOS. UE-170002/UG-170003
WASHINGTON UTILITIES AND	)	
TRANSPORTATION COMMISSION	)	COMMENTS OF THE ALLIANCE OF
	)	WESTERN ENERGY CONSUMERS
Rulemaking to Address Electric and Natural	)	
Gas Cost of Service.	)	
	)	

I. INTRODUCTION

Pursuant to the Washington Utilities and Transportation Commission's ("Commission") July 23, 2018 Notice of Opportunity to File Written Comments ("Notice") in the above-referenced dockets, the Alliance of Western Energy Consumers ("AWEC") files these comments in response to the questions included in the Commission's Notice.

II. COMMENTS

AWEC's responses to the Commission's questions are below. Preliminarily, AWEC wishes to express its support for the Commission's and Staff's efforts to review utilities' cost of service methodologies and to coordinate them to the extent practical. As discussed in more detail below, AWEC believes that the traditional methods the utilities have used to determine cost of service in Washington, including the Peak Credit method for electric utilities and Peak and Average method for gas utilities, are not reflective of the true cost to serve customer classes, and AWEC is hopeful that this rulemaking ultimately will result in rates for customer classes that better align with the costs each class causes.

A. Questions affecting both electric and natural gas companies.

1. <u>To what degree should rules define the presentation (such as per class revenue and costs, parity ratios, revenue changes, billing determinants, etc.) of cost of service studies?</u>

AWEC supports the use of generalized rules that capture the requirements desired for information and presentation purposes but believes it should be left to each individual utility to develop the specific format for presenting the data. Where there is the need to compare data across utilities, then the presentation of the data should be prescribed such that when others summarize the data, such characterizations are accurate. For example, in per class average revenue per kWh, all data either should be weather normalized or non-weather normalized. Another example is whether the revenue per kWh data is inclusive of all applicable charges and fees or represents only base tariffs. Apples to apples comparisons are most useful to consumers and policy makers.

a. Are standardized presentation formats or templates an adequate way to enable comparisons of cost of service studies?

Yes. The benefit of standardized presentation formats is to make it easier for interested persons to compare multiple cost of service studies as well as to reduce the time required in analyzing the cost of service study. The question posed above should differentiate, though, between whether the comparison is between multiple years for the same utility or across the same year for different utilities. With respect to comparisons across utilities, the Bonneville Power Administration ("BPA") went to great lengths to develop a framework for reviewing average system cost filings and to create standardized procedures for developing average system cost values for utilities that choose to participate in the residential exchange program. The reason for this standardization is that there is, for all intents and purposes, a fixed set of residential exchange benefits available through 2028 that are to be allocated, by year, across investor-owned utilities ("IOUs"). The stream of annual values, which is in the hundreds of millions of dollars per year, does tend to increase over time, but the values themselves have been set by the BPA Administrator. To ensure an equitable and consistent treatment for the IOUs, a standardized set of rules apply which were developed by BPA in a formal comment and review process.

With respect to Commission regulation of utilities, however, it is not clear the same circumstance exists where a regulatory mechanism involves some allocation of benefit or costs across utilities. This begs the question whether the cost and effort utilities incur to adopt a new standardized format for cost of service presentation outweighs the benefit of aiding parties and the Commission in the ease of analysis and review. What would be beneficial is for all utilities to comply with specified standards and information requirements while leaving the exact details of how to meet those requirements to the utility.

Instead of making comparisons across utilities, Question 1(a) could also be read to mean across years for the same utility. Many of the questions posed in this rulemaking could be meant as informational requirements and should be applied across regulated utilities. There would be a significant benefit to parties to have standard requirements utilities must follow to facilitate review of utility costs. AWEC strongly supports such standardization while leaving to each utility discretion in the exact format of its cost of service study.

With respect to a single utility, there could be requirements that would allow for identifying how costs have changed over the years. That is, comparing that year's presentation to presentations provided in previous years. It would be good to know if the presentations have consistent recording practices in utility accounts. This would help the reviewer see that substantive changes in costs from year-to-year are not due to a change in where the costs are recorded, but rather a change in the level of costs for that component of costs. Having the presentations in the same format and cell and tab entry would allow for efficient review and analysis.

b. *To what degree should templates be relied upon for summary presentations versus underlying modeling and work papers?*

AWEC believes a template is sufficient for summary presentations and not necessary for underlying modeling or work papers. Utilities have different service territories and, therefore, different drivers for their costs of service. They should be allowed flexibility to operate within a broader standardized framework that balances the interest of Staff and intervenors in reviewing and comprehending a utility's cost of service with the interest of the utility in efficiently and accurately presenting its cost of service. Allowing flexibility in the presentation of modeling and workpapers would best strike that balance.

c. *How should a party sponsoring a cost of service study present the interface between a revenue requirement study and a cost of service study?*

Rules could be drafted to require the utility to provide a link, or links, between the revenue requirement study and the cost of service study with a "toggle" to allow the user to delink the two studies if desired. The location of the links should be clearly identified. The utility should also be required to provide a write-up and road map to aid the reviewer in understanding how the revenue requirements interface with the cost of service study, including identifying key tabs, cells and location of coding where applicable.

d. *Should parties present a list of all allocation factors, including how they are calculated, how the calculation method has changed from its inception, and where they are used?*

Yes. Utilities should be required to provide:

- A list of all allocation factors (both acronym and spelled out as applicable);
- A brief definition of the allocation factor and where it is used;
- How the factor is calculated;
- Whether the calculation method for the factor has changed from the utility's last filing with the Commission;
- The value of the factor in the present filing and the values for the last five years; and
- Where the factor has changed by more than ten percent from the prior-year's value, over any two consecutive years during the six-year period, a description of the reasons as to why the factor value changed.

2. <u>Should the Commission adopt rules requiring parties to conduct and present a load study when performing cost of service studies? Please explain why or why not.</u>

AWEC does not propose a new load study be required with each cost of service study. However, when a new study is not required, the utility should be required to provide its most recent study and note the date of the study and date of when a new load study would be provided.

Providing the load study and its "date-mark" is information that will aid parties in their review of the company's filing.

a. If the Commission were to require a load study in rule, what is an appropriate definition of a load study? Which parameters are necessary to include in a load study?

One possible definition of a load study is:

> The gathering and recording of energy use at a sufficient level of frequency, by class of customer or energy use level, or sample subset thereof, over a specified period of time, to study, analyze and represent class-level energy use patterns (hourly, daily, weekly, seasonally) with sufficient level of certainty through load factors and other energy use factors.

The parameters of a load study are typically terms that help represent a class's pattern of use and how that pattern of use drives the utility cost of supply. From that perspective, the ratio of the class average use to the use occurring at utility peak loads (coincidental peak load factor), the class average to the class peak demand (non-coincidental peak load factor), a substation level average use to substation peak use (substation non-coincidental peak demand), along with energy peak and total use by month are the minimum level of factors that should be provided.

Information regarding the number and type of customers at no less granularity than the substation level provides more precise information about (1) typical energy use profiles by type of energy user, and (2) the type of energy consumption—meaning what the energy is being used for. It would also be useful for analysis to know certain characteristics of customers. For example, whether the customer (residential or commercial) owns an electric car, the type of space-heating used, whether solar panels have been installed and at what kW capacity, and whether the customer has air conditioning.

For gas utilities, the load study should be designed to measure the utilities design day demands, reflecting losses, that establish customers' weather driven peak loads. This design day demand should reasonably reflect the system design days the utility uses for resource capacity planning reflecting both firm and interruptible/curtailable tariff services.

b. If a rule requires load studies, what level of specificity, in terms of measuring customer's loads, should the Commission require to be presented in load studies?

The level of specificity depends on the questions being answered. As noted in the proposed definition of a load study, customer electric loads should be measured no less frequently than intra-hour, on a daily basis, over a period of at least one full year to capture any hourly, monthly and seasonal customer use patterns. For gas service, the usage should be measured over a period that captures the design day demands that the system is expected to supply during extreme weather periods. The Commission should require a fairly granular level of customer use data to identify such energy use patterns. With the emergence of distributed generation and electric cars, it would be useful to know the load profiles of similarly-situated customers with and without such attributes.

c. How frequently should companies perform load studies?

Given that load studies play a critical role in the allocation of costs to retail customers, it is important to have up-to-date load studies. The cost of performing such studies, however, will have an impact on their frequency. Presumably the metering and collection of data would be lower if the utility has installed AMI equipment. While AWEC does not have a strong opinion on an exact level of frequency, AWEC does suggest that a frequency of no less than five years be the maximum period of time the Commission should consider. As noted in the next question, the cost of conducting a load study should impact the frequency of load studies.

d. How might emerging technologies, such as Advanced Metering Infrastructure (AMI), affect the timing and frequency of load studies? Please also explain whether and how selective deployment of AMI could minimize load study costs to ratepayers.

For utilities that have installed AMI, the utility should be required to provide load studies on a more frequent basis. In responding to subpart "c" above, the range of up to five years was provided in general applicability to all energy utilities. It is reasonable to require a load study update on a more frequent basis for utilities that have installed AMI.

Where AMI has been universally installed for customers, it may be possible for the load studies to be based on the entire class of customers rather than a sample subset of customers. The utility would need to gather and record energy use to the same granular level across the class of customers and identify customer location as well as the substation that serves the customer. Gathering this data would avoid the need of assuring the data represents the class of customers because the data is for the entire class of customers.

Where AMI is not yet universally installed, the utility should compare the ongoing cost of metering equipment currently used with the installation of AMI equipment. Furthermore, where the utility has decided to universally install AMI equipment, but has not yet installed the AMI, the Commission should require the utility to analyze advancing the installation date for a subset of classes of customers in order to have equipment to conduct load studies and begin installation of AMI for the subset of customers. The Commission should also require the utility to report on its analysis for review and comment by the Commission and interested parties. Advancing the installation of AMI for a subset of customers may yield cost savings as well as serve as a trial for installation and working with the AMI.

3. <u>Should the Commission allow parties to include confidential information in a cost of service study?</u>

AWEC does not have a strong opinion on this question at this time and will review the responses of other stakeholders.

4. Should the Commission adopt rules that require parties to include in cost of service studies the reconciliation between test year billing determinants and billing determinants used in the cost of service model?

Yes. The requirement should include a discussion of the reconciliation process between test-year billing determinants, the billing determinants used in the cost of service study and an excel spreadsheet with cell formulae intact that undertakes such reconciliation. The utility should also describe any changes in its reconciliation process if such process has changed from the previous version most recently submitted to the Commission.

a. Similarly, should the Commission require cost of service studies to include a reconciliation for unadjusted and pro forma revenues and the resulting cost of service models?

Yes. The requirement should include a discussion of the reconciliation process for unadjusted and pro forma revenues as well as an excel spreadsheet with cell formulae intact that undertakes such reconciliation. The utility should also describe any changes in its reconciliation process if such process has changed from the previous version most recently submitted to the Commission.

5. Should the Commission include in a rule on cost of service studies definitions of specific terms used in cost of service studies? Please include specific technical terms that should be defined.

AWEC could support defining a few well-established and common terms used in cost of service studies but has concerns with getting too granular with rules in this area. New terms appear over time as technological advances yield new products and services. If a new term appeared, it could be administratively burdensome to update the definitions. One alternative suggestion is for the rules to require the utility to define the terms it uses in its cost of service study. While this could result in the same term being defined in different ways by different utilities, it would at least assure a common understanding of that term within the confines of a particular proceeding.

6. There are several overall methods upon which cost of service studies rely, e.g., marginal, total service, long run, incremental or embedded cost studies. Should the Commission rely principally upon a single method?

The appropriateness of any particular method ultimately depends on whether the service being provided is gas or electric, the particulars of the service, and a host of other factors. Accordingly, AWEC recommends that the Commission not rely principally on a single method for all services and all utilities. AWEC supports the traditional embedded cost of service approach for gas and electric utilities with the modifications discussed in these Comments.

a. *If so, what parameters should the method include? Is it necessary for the Commission or parties sponsoring a study to conduct periodic revisions of the method? What would prompt such a revision?*

A general rate case is the appropriate venue to review a cost of service study methodology. While rulemaking policy dockets such as this are useful in establishing principles that might be applied, it is difficult to consider the reasonableness of any particular alternative in the absence of a specified cost of service proposal.

7. <u>How should special contract customers be treated with regard to pass-through costs (i.e., separate riders identifying and recovering specific types of costs)?</u>

Special contracts are unique because they are both a rate approved by the Commission and a bilateral contract between the utility and a customer. These contracts are intended to provide comprehensive terms for recovery of costs. Adding a rider or surcharge to these contract rates would upset the contractual agreement between the utility and the customer, which would seriously undermine the value of the special contract program.

Because special contracts are intended to allow utilities to compete against alternative service providers, it is essential that utilities retain flexibility to negotiate terms that are attractive to their customers. These contracts must also provide benefits to the utility and other customers because special contracts must "recover all costs resulting from providing the service" and "provide a contribution to [the utility's] fixed costs." WAC 480-80-143(5)(c). The theory justifying the special contract program is that all customers are better off if customers with a credible bypass option remain on the utility's system and provide at least some contribution to fixed costs (thus lowering the total amount of fixed costs to be recovered from other ratepayers). This arrangement only works if utilities can offer terms competitive with those of alternative service providers. The market can provide customers with long-term, fixed-cost energy and transportation/transmission. If utilities cannot guarantee similar terms, they will be at a significant competitive disadvantage – adding a rider to recover pass-through costs applicable to customers paying tariffed rates would essentially eliminate the possibility of a cost-certain contract.

Further, special contracts are not necessarily intended to recover pass-through costs, unless specifically addressed in the contract. As noted above, these rates must recover the utility's incremental cost of service and make some contribution to the utility's fixed costs. If the rate charged under the special contract does not meet this requirement, the Commission may not approve it. WAC 480-80-143. To the extent that pass-through costs are unrelated to a utility's incremental cost of service in serving the special contract customer or the utility's fixed costs, there is no need to recover from special contract customers. Again, the fact that special contract customers are paying less for service than others is not surprising, and nor should it be controversial: all ratepayers benefit if the special contract customers continue to take utility service and contribute to shared costs when they have an alternative that would eliminate any contribution they make to these costs.

Finally, AWEC would be very concerned by any effort to impose riders on existing special contracts, or otherwise modify special contract rates. As discussed above, such a move would upset the fundamental expectation of all parties and could have serious consequences for customers and the utilities. A change of policy going forward would be no less disruptive: utilities would almost certainly lose customers with competitive alternatives, leaving fewer ratepayers to cover the fixed costs.

It is worth noting that pass-through costs should be treated the same as pass-through *benefits*, and for the same reasons. Special contract customers value the certainty that long-term contracts can deliver. In other words, they are willing to forgo the potential benefit of falling rates to avoid the risk of rising rates. Recent Commission decisions illustrate this principle: In the Cascade Natural Gas Corporation rate proceeding, while most customers saw a reduction in rates due to the Tax Cuts and Jobs Act, special contracts customers did not receive lower rates.[1]

8. <u>The Commission is considering rules that require a baseline cost of service study for each Company. One option for such a process would require a company to submit an initial baseline cost of service study for the Commission to review and approve. This would happen in the next general rate case each company files after the Commission adopts rules requiring such a baseline. The Commission would consider this baseline the standard approach for that company to allocate costs, inclusive of future updates with Commission approval. Thereafter, a company would be required to present adjustments to the cost of service method in comparison to the latest Commission-approved baseline.</u>

a. Is this a sound approach for providing consistency for the review of cost of service studies and their underlying methods?

AWEC appreciates the concept put forth for a baseline to be established whereby any changes in the baseline must be clearly identified and explained. Standardization and streamlining of reviews are worthy objectives. However, AWEC has substantive concerns regarding using a baseline concept that very likely outweigh potential benefits. The concerns involve placing significance on a study to be a baseline, establishing a baseline in the midst of significant changes in the industry and technology, and legal concerns about a baseline concept. Each of these concerns is discussed below.

The significance of a baseline: From the text above it appears that once a baseline is established, it is the Commission-approved approach and presumptive standard for which changes in approach must be well justified. Thus, in the utility baseline filing, parties would be required to review and analyze all components of the baseline and address them substantively as the Commission adoption/order will be presumed the ongoing standard. All parties, including Staff, have a limited set of resources. Typically, parties focus on matters of increased significance, as well as overall workload, and prioritize scarce resources. Utilities filing at

[1] *WUTC v. Cascade Natural Gas Corporation*, Docket UG 170929, Partial Settlement Agreement (May 17, 2018) at p. 9.

different times will face varying scrutiny based on the level of other regulatory matters before the Commission. One item to note is that parties are not immune to over-looking topics or identifying adjustments and corrections. There is asymmetric information. The utility is most familiar with its functions and costs and this leads to an advantage to the utility that parties must overcome. This means that a party might not identify an adjustment in one case but given time and discovery may uncover the issue in a subsequent case. To have a cost of service study "locked-in" would seem to be to the detriment of other parties as presumably they would not have the opportunity to re-visit the issue during the effective term of the cost of service study.

Technological advances and industry trends: Technological advances are underway in both informational data management as well as energy resource supply. These changes may lend themselves to changes in how costs are allocated. A baseline concept creates a hurdle for parties and the utility to overcome that may make it difficult to keep pace with technological and industry changes.

Legal concerns: In the review of a utility general rate filing, the approach or standard of the case from a legal context is "de novo". That is, decisions made should be based on the record in that case. If a party decides to challenge an allocation or assumption within the cost of service study, it should not be sufficient for the utility to note the assumption was established in the baseline (or in a prior general rate case) and is therefore immune from review. The utility would presumably need to show that the set of circumstances and facts in the case justify and support the cost of service factor or assumption. It seems that given that legal standard of review, the cost of service study would be applicable for: (a) that general rate filing; (b) compliance or tracking adjustments; and (c) perhaps for an attrition or indexing mechanism if the Commission establishes a multi-year general rate case format. In this context, as will be seen in the comments below, baselines should be established in a general rate case.

In sum, while the format of, and informational requirements for, a cost of service study could apply across several general rate case filings, the factors and data within the cost of service study should be specific to the general rate case filing at that time.

b. What specific topics or aspects of a cost of service study should or should not be included as a part of a baseline study?

Given the concerns raised above, if the Commission adopts a baseline approach, it should be limited to the format of the study and the informational requirements in it. The specific factors and data that are included in the cost of service study should be allowed to change over time. As mentioned above, rules could require that utilities identify and explain significant changes in costs, but that should not alone be a reason to reject the change as a deviation from the "baseline."

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c. *Should there be a defined timeframe for the effective period of a baseline cost of service study before formal re-evaluation of the baseline would be required?*

If the Commission adopts the baseline concept, there should be a defined timeframe for the effective period. As noted in other responses herein, each utility could have its baseline adopted by the Commission at different times. This would be clearly the case if the Commission adopts the proposal that the baseline be established as part of a general rate filing. Therefore, the timeframe for reevaluation with regards to a specific date would be different across companies.

i. Should the timeframe for re-evaluation be the same for all companies?

The generic timeframe for an effective period could be different across industries depending on the industry type. For example, while not specific AWEC recommendations but rather for illustrative purposes, the effective timeframe could be three years for electric and five years for natural gas. For joint natural gas/electric utilities, the effective period would default to the shortest effective period applicable. If there is an effective time period for a cost of service study, the utility should be required to file a new cost of service study no less than twelve months prior to the end of the effective time period to allow parties and Commission sufficient time for review and issuance of order.

ii. Should baseline studies be established or reviewed outside of a general rate proceeding?

AWEC recommends that if the Commission decides to go forward with the baseline concept that the baseline be established in a general rate proceeding. The cost of service study would affect rates and rates are set in a general rate proceeding. Since the paramount importance of a cost of service study is in setting rates, it seems most efficient to conduct that review in the context of a general rate proceeding. Also, parties and the Commission would likely be interested in the rate impacts of differing factors, which would depend on the specific circumstances at that time. This reinforces the view that a general rate proceeding is the most practical time to establish a baseline. As noted elsewhere, the format and requirements of a baseline study, while broad and generic in nature, could be set forth outside of a general rate proceeding.

iii. Should the Commission consider re-evaluation simultaneously for all companies?

The need for simultaneous re-evaluation for all utilities would depend on the facts and circumstances triggering the event. If the need for re-evaluation is based on factors or forces that affect all utilities simultaneously then perhaps a simultaneous re-evaluation would be necessary. However, the factor causing the Commission to consider re-evaluation may be utility specific. In this case, there would be no need to require all utilities cost of service studies to be re-evaluated. Therefore, it seems unlikely to establish a policy that requires re-evaluation of cost of service studies for all utilities simultaneously.

A further comment on this topic is that simultaneous review of all utility cost of service studies would place enormous demand on the resources of parties to actively participate in the review of the cost of service studies and would likely be a significant burden on parties.

d. Which metrics should be considered as the trigger for a formal re-evaluation of a baseline cost of service study?

If the Commission adopts the baseline approach, then one metric would be time. A baseline should be updated after a specified number of years. Another metric could be a change in a utility's organizational structure such as the formation of new affiliates or a utility merger/acquisition. Such activities could lead to changes in cost of service studies through allocations and hence require a re-evaluation. Whether a new baseline is required would depend on the specific facts and circumstances. No other metrics are offered at this time.

9. <u>What other topics should the Commission consider in adopting rules governing cost of service studies?</u>

AWEC does not have any other topics to offer at this time. After reviewing other parties' comments, AWEC may have topics to suggest.

B. Questions affecting electric utility service only.

1. <u>Should the Commission require marginal cost studies for special contract customers that rely upon a utility for electric generation, transmission, distribution, or a sub-set of these components?</u>

Please see AWEC's response to Question C.1 for its general position on this question. With respect to electric customers specifically, while there may be some legacy special contracts, AWEC is aware of only one customer with a special contract, which was the tool utilized to allow Microsoft to opt-out of Puget Sound Energy's bundled service. Not only is that special contract not yet in effect, it is also unique in the requirements it imposes on Microsoft and the manner in which it recovers costs to serve Microsoft. These requirements were developed through a comprehensive stipulation that included all parties to the case and was approved by the Commission. Thus, AWEC would have serious concerns with the development of new rules that effectively modify that settlement and special contract. Moreover, because this appears to be one of if not the only electric special contract in existence, there does not appear to be a pressing need to modify how the Commission treats special contracts for electric customers at this time.

2. <u>How should cost of service studies allocate demand and energy costs?</u>

AWEC shares the view that the next ten years in the electric services industry in the West have the potential to be more transformative than the past one hundred years. Accordingly, as the Commission considers the electric services portion of this docket, particular attention should be given to the fast pace of change taking place in the industry. Many of the mantras that have been commonplace through the industry might not apply in a world with high volumes of low cost renewables.

Before considering the specific allocators used in the cost allocation formula, it is appropriate for the Commission to consider the methodology used to classify production costs between demand-related and energy-related cost components. Often this classification can be overlooked and thought of in terms of a blended production cost allocator, as with the Peak Credit method. Notwithstanding, classification is inherently part of, and an important consideration for developing, any production cost allocation system. Thus, before arriving at specific allocators, AWEC believes it is appropriate for the Commission to reevaluate its use of the Peak Credit methodology and consider other acceptable methods that might be used to determine the portion of production costs to allocate as demand and energy.

Further, in considering demand and energy costs, it is important to recognize that many cost functions other than production may be classified as demand-related and energy-related cost classifications. AWEC's response to this question generally focuses on production costs, although the other cost functions are considered in response to other questions.

a. Is a single method or a set of methods the most balanced and fair to all parties involved?

When considering the reasonableness of any particular cost allocation methodologies, one inherently must establish and balance a set of competing principles, which may be reasonably applied to varying degrees depending on the circumstances. With respect to mathematics, Gödel proved that there can be no single axiomatic system universally applicable to all mathematics,[2] and a similar inference can be extended to the field of cost allocation. There is no single cost allocation system that provides a common solution for all issues of cost allocation that might arise. As stated in the Electric Utility Cost Allocation Manual "no single Costing methodology will be superior to any other, and the choice of methodology will depend on the unique circumstances of each utility"[3] Thus, the axiom "ratemaking is more an art than science."

That is not to say, however, that a common set of principles should not be established and applied in a manner that is consistent and rational. Certainly, a great deal of thought has been given through the years on establishing these sorts of principles. Dr. Bonbright's treatise on the topic does an excellent job in defining and describing the many competing principles that are often involved with cost allocation and rate design. Although it's not clear if one might be able to offer an exhaustive list of each and every factor one might consider when evaluating the reasonableness of an electric cost allocation proposal, Dr. Bonbright's analysis is an excellent standard that is applicable in today's complex energy environment. In addition, the NARUC Electric Utility Cost Allocation Manual is another good source of cost allocation principles that may be applied for electric utilities. Another relevant source of cost allocation principles may be found in FERC Order 1000.

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[2] On Formally Undecidable Propositions of "*Principia Mathematica*" and Related Systems

[3] National Association of Regulatory Utility Commissioners ("NARUC"), Electric Utility Cost Allocation Manual at p. 22 (Jan. 1992).

In consulting these sources, AWEC has identified the following principles that it recommends the Commission consider when evaluating the reasonableness of a cost allocation system.

1. Cost should be allocated in proportion to the benefit received.
2. Allocation should send proper price signals.
3. Pricing should encourage smart consumer rationing.
4. Where possible conform with FERC methodologies.
5. The allocation of costs should be equitable among customers in consideration of the reasons for justifying the resource addition.

b. Should the Commission establish a preference for a particular method? Please explain your response.

With respect to production plant costs, the Commission has had a general preference for using the Peak Credit methodology for determining the classification of production costs between demand and energy cost components. AWEC has concerns regarding the continued validity of that method and has in the past supported using the Average and Excess methodology.

Use of the Peak Credit methodology has its foundation in marginal cost theory. The method uses the cost relationship of a marginal peaker and base load resources to determine which fixed production costs ought to be functionalized as demand and which costs ought to be functionalized as energy. Mr. Ball's March 5, 2018, memoranda filed in this docket describes the method in more detail.

In contrast to the use of the Peak Credit methodology, it was once the case that the prevailing view among utility analysts was that "fixed production plant costs were driven only by system maximum peak demands."[4] This view can be thought of as a very short-term marginal cost allocation methodology, where 100% of fixed costs are considered unavoidable and thus allocated on the basis of demand. This sort of approach is not used in Washington and many states for cost allocation purposes, however, in recognition of the fact that, in the long-term, a portion of fixed production costs may be reasonably viewed as being energy-related.

The Peak Credit methodology assumes that there is a fundamental planning dichotomy between building a "peaker" resource and building a "baseload" resource. The peaker resource was typically less expensive from a fixed cost perspective but carried a higher energy cost. In contrast, the baseload resource may have had a higher capital cost, but lower fuel costs. As a result, a portion of the investment in the baseload resources can be thought of as a fixed investment made to reduce fuel costs or "capitalized energy," the cost of which is reasonably considered energy-related. From a marginal cost perspective, the Peak Credit methodology can also be thought of as establishing shadow prices for capacity versus energy services.

AWEC sees at least two reasons to move away from using the Peak Credit methodology.

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[4] NARUC Electric Utility Cost Allocation Manual at p. 39.

First, in recent years, combustion turbine technologies have advanced significantly. New combined cycle combustion turbines ("CCCT") and single cycle combustion turbines ("SCCT") technologies have become much closer both in terms of cost and capability. PSE's resource assessment currently under development for PSE's 2019 Integrated Resource Plan, for instance, estimated that the cost of a CCCT has declined by about 12%, relative to PSE's 2018 Integrated Resource Plan.

This phenomenon can also be seen in Avista's 2017 IRP on page 9-5. While the cost of "Frame" SCCT resources continues to be below the cost of a CCCT, the per kilowatt cost of more flexible SCCT resources such as the hybrid or aeroderivative resource are comparable to the cost of a combined cycle.

Frame SCCT resources have high heat rates and limited flexibility, making them less suitable resources for maintaining the level of reliability required to meet incremental peak loads. This is probably the reason why the only peaker resources that have been built in the region since 2010 have been based on aeroderivative technology, or reciprocating engines.[5] From that perspective, AWEC's position is that a Frame SCCT is not a suitable option to be used in a Peak Credit calculation.

Notwithstanding, in comparison to the types of flexible peaker resources that have actually been built in recent years, it is apparent that the cost of a flexible peaker resource has exceeded, or at a minimum is very close to exceeding, the cost of the capacity from a CCCT. As shown in Avista's 2017 IRP, the cost of a Hybrid SCCT was $1,042/kW, compared to $1,148/kW for the CCCT. After considering the value of lower fuel cost, the CCCT is more and more becoming a preferred option both in terms of a baseload, energy resource and in terms of a peaker capacity resource.

Second, utility planning is transitioning away from planning on the basis of a peaker versus a base load resource. While it was once the case that, to get low cost energy, the utility would have to build a more expensive base load plant, that dynamic no longer exists. The cost of energy is at historical lows due to a combination of low gas prices and the availability of low-cost renewables.

Thus, from a planning perspective, the planning dichotomy is transforming into one that is more oriented towards building renewables for energy and maintaining enough capacity to augment the energy and capacity provided by the renewables.

Given these changes, AWEC sees at least two options. The Commission could transition to a deterministic method for determining the demand energy split, such as on the Average and Excess methodology, which does not rely on complicated planning assumptions to determine the classification of production costs.

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[5] Culbertson and Dave Gates are two aeroderivative turbines built in 2010 and 2011 in Montana. Similarly, Portland General electric built the Port Westward II reciprocating facility in 2014.

As another option, the Commission could modify the Peak Credit methodology to take into consideration the realities of the current environment. This might involve considering solar to be the marginal energy resource and a CCCT as the capacity resource.

With respect to the allocation factor used for costs classified as demand-related costs, AWEC's supports having different methods for different utilities that take into consideration the unique aspect of the utility's electric loads. Notwithstanding, AWEC's position is that the measure of demand should consider the increasingly dual peaking nature of utilities in the Northwest. Thus, AWEC supports methodologies that focus on the top summer and winter peaking hours of the utilities, i.e. the "Summer and Winter Peak Method" described in the NARUC Electric Utility Cost Allocation Manual.

c. Are there specific methods that should not be considered by the Commission? For what reason should the Commission not consider specific methods?

With respect to the demand allocator applied to production plant, AWEC does not support using 12-CP to measure demand for production plant. The 12-CP measurement uses the coincident peak measurements for each month of the year. Given the dual peaks of the utilities in the Northwest, a 12-CP measurement more closely resembles a measurement of energy consumption than peak demand.

3. <u>How should cost of service studies classify and allocate:</u>

a. Transmission and distribution assets?

The current practice of the Commission with respect to transmission costs is to classify such costs using the same percentages that are applied to generation. AWEC disagrees with this treatment and recommends that transmission costs be allocated on the basis of 12-CP, which is a better measure of beneficial use of the system and more consistent with industry norms. Use of 12-CP also generally conforms with the FERC cost allocation.

Some utility analysts argue that transmission may serve as a substitute for generation, and therefore, that a portion of the transmission investment might be reasonably classified as energy-related. AWEC does not necessarily disagree with this argument. AWEC does, however, disagree with the premise that transmission costs ought to receive the same demand/energy weighting as fixed production costs. By applying the same demand/energy weightings as production costs, the current transmission allocation method assumes that <u>all</u> transmission is a substitute for generation. The amount of transmission that may reasonably be considered a substitute for generation must be a small subset of overall transmission costs, since the majority of the utilities' transmission investments have been for reliability purposes not generation interconnections. AWEC supports using 12-CP for transmission because it is not purely a measurement of peak demand and has an element of energy due to the fact that it is measured over the 12 months of the year.

With respect to distribution costs, the electric utilities currently use varying methods for allocating distribution costs and AWEC does not have a preference for one at this time but reserves its right to support a particular methodology as this rulemaking progresses.

b. Fuel costs and purchased power?

AWEC recommends that fuel and purchased power cost be considered in the classification of production costs between demand and energy components, whether that is done through the Peak Credit method, or some other way. Just as a portion of fixed costs might be considered variable, a portion of fuel and purchased power costs is appropriately considered to be demand-related. For example, many power purchase agreements contain capacity payments, which are appropriately considered demand-related costs. Similarly, even market purchases may be thought of to include a capacity component, to the extent there is an additional premium embedded in market prices to transact at a fixed price in the future.

Accordingly, if a high-level methodology is to be used to classify production costs between energy and demand components, it would appropriately apply to all production costs.

c. Common and joint costs?

While AWEC is not entirely certain about what types of costs that the Commission might consider common or joint costs in this context, AWEC's view is that the functionalization of such costs is typically of greater concern than the allocation. Determining which portion of an accounting department, for instance, to functionalize as a distribution cost versus production costs, is typically more impactful than the specific allocator that is used to allocate costs.

d. Administrative and general costs?

As noted with respect to common and joint costs above, these costs are typically functionalized to other functional cost groups and then allocated accordingly. AWEC is generally fine with this approach.

e. Poles, conductors, and line transformers?

As with distribution costs, the utilities have varying methods for allocating poles, conductors and line transformers. At this time AWEC does not have a proposal for these costs.

4. <u>Are there any other costs that cost of service studies should classify and allocate in a specific way?</u>

For the costs of meters and services, AWEC is generally not opposed to the methodology utilities are using today, which takes the average installed costs for new meters and services and multiplies by the customer count. Notwithstanding, to the extent utilities are upgrading their metering infrastructure for AMI or other similar technology, the costs of the upgrades are most appropriately assigned to the classes receiving and benefiting from the upgraded meters.

C. Questions affecting natural gas service only.

1. Should the Commission adopt rules requiring marginal cost of service studies for special contract customers that rely upon a utility for natural interstate pipeline connections, localized distribution, or a sub-set of these components?

AWEC believes that a load retention marginal cost analysis (which is different from a marginal class cost of service study) is already required by WAC 480-80-143, and therefore no change to the rule is required. The load retention marginal cost analysis gives all the information required to determine whether it is in the public interest to approve a special contract. WAC 480-80-143 allows a utility, upon Commission approval, to contract for the retail sale of regulated utility services with customers directly. Importantly, Commission rules clearly require that special contracts: "[d]emonstrate, at a minimum, that the contract charges recover all costs resulting from providing the service during its term, and, in addition, provide a contribution to the gas, electric, or water company's fixed costs." WAC 480-80-143(5). In order to perform that analysis, a load retention marginal cost analysis is required, showing, among other things, that all the variable or incremental costs to serve the customer are being covered by the special contract rate, and that there is some contribution to the LCD's fixed cost to benefit other customers. When there is a contribution to fixed cost, it is in the best interest of all customers and the utility to prevent the special contract customer from leaving the system.

By way of background, the purpose of a special contract is to address the unique situation where a customer has a competitive alternative to service from a regulated utility. In the gas context, this usually arises when the customer can bypass the LDC's system and connect directly to the interstate pipeline. By offering a discount from tariff service to keep the customer on the system and ensuring that there is a contribution to fixed costs, the rule recognizes the public benefit that will accrue to the LDC and the remainder of its customers. That benefit is largely in the form of the contribution to the utility's fixed costs, because the LDC would otherwise recover those costs from the rest of the customers on its system.

In deciding whether to exercise its right to bypass the LDC, the rate and terms of the special contract are important factors for the customer's decision. If the rate can be adjusted during the term of the agreement based on an updated cost of service study, that adjustment would occur in part because of factors that were unforeseeable at the time the original contract was executed. Rather than face that uncertainty, a customer would be more likely to permanently leave the system, which is harmful to both the utility and other customers. Further, a customer's ability to bypass the LDC may diminish over time. A special contract customer may be willing to give up the economic advantage of a bypass, but only if there is a corresponding certainty in the rates it will continue to receive from the LDC. The loss of both the benefit of a bypass and the benefit of rate certainty would undermine the purpose of the rule. Accordingly, during the term of a special contract, further cost studies and analysis are unnecessary and inappropriate.

A load retention marginal cost of service analysis for special contract customers is appropriate during the approval process, and any renewal of the special contract, but this is very different than a marginal class cost of service study. To be clear, substantial portions of a utility's costs are not marginal. Utility rates include recovery of costs for investments made long ago and over a long period of time. As a result, a utility's rates are typically based on average embedded costs. However, average embedded costs typically do not give correct pricing signals for serving new or incremental customer load. A marginal cost analysis may be more reflective of the economic considerations in the pricing for serving new or incremental customer loads.

Because marginal costs are typically lower than a utility's average embedded costs, a special contract priced at marginal costs could be interpreted as being subsidized by other customers when using standard tariff pricing based on embedded costs as a measure of the reasonableness of the special contract pricing. However, as long as a special contract exceeds variable costs, then the contract benefits other customers by providing a contribution to a utility's fixed costs, which makes existing customers better off with the contract than without it.

a. To what extent should these contracts be subject to scrutiny regarding the impact on other customers of the cost assignment to special contracts?

Through application of the existing rule, all customers are better off if a special contact customer remains on the system. To assess the impact on other customers, the comparison must be between having the special contract customer on the system and having the special contract customer leave the system at the time the contract is executed when variable and fixed costs are known. A comparison of the special contract rate to the tariff rate or embedded cost of service after that time is inappropriate. WAC 480-80-143(5)(c) expressly requires a showing that some (therefore not all) fixed costs will be recovered in a special contract, and it requires the Commission to acknowledge that fact by approving a contract. Specifically, the Commission must find that the contract demonstrates, "at a minimum, that the contract charges recover all costs resulting from providing the service during its term, and, in addition, provide a contribution to the gas, electric, or water company's fixed costs." WAC 480-80-143(5)(c). A load retention marginal cost analysis is appropriate for this analysis.

2. <u>How should cost of service studies allocate demand and throughput?</u>

AWEC supports a class cost of service study method that allocates demand-related costs based on customers' peak load characteristics. Appropriate class cost of service study methods that allocate demand classified costs based on customers' peak load characteristics would include the Design Day Demand method and the Average and Excess method. The costs a utility incurs developing its system are driven by the design of the system and not its actual use. Because utilities design their transmission and distribution systems to meet the coincident peak demand of their customers and do not design the system capacity of the gas transmission and distribution systems to meet annual throughput, a cost of service study that allocates capacity costs based on customers' peak load characteristics most accurately reflects cost causation.

Regardless of the class cost of service method used to allocate demand-related costs, a portion of mains should be classified and allocated based on the number of customers. Because utilities also design their systems in order to connect customers to its system, there is a cost of mains that is associated with the length of the main. Therefore, a portion of mains should be classified and allocated based on the number of customers. This will best reflect cost causation.

a. Is a single method or a set of methods the most balanced and fair to all parties involved?

All classes of cost of service studies should include consideration and incorporation of peak use characteristics, as that prescribes the size of the facilities that are built to meet customer demands.

As described in Section (b) below, to the extent a class cost of service study method that allocates demand-related costs on class peak load characteristics is not accepted by the Commission, then AWEC would support a range of class cost of service studies be filed by the utility and used to determine a range of reasonableness with respect to class cost of service.

b. Should the Commission establish a preference for a particular method?

As noted above, AWEC believes the Commission should use the Design Day Demand or Average and Excess methods because these methods best reflect class cost causation.

If the Design Day Demand or Average and Excess methods are not used to determine class cost of service, AWEC would recommend studies that use similar principles. A compromised approach would be to require three class cost of service studies be performed for determining a range of reasonableness for class cost of service: Design Day Demand, Average and Excess, and Peak and Average. It is AWEC's opinion that performing three class cost of service studies is not a burden to the utility. Reasonable variations of Design Day Demand, Average and Excess, and Peak and Average could also be acceptable in determining class cost of service.

c. Are there specific methods that should not be considered by the Commission? For what reason should the Commission not consider specific methods?

AWEC recommends that the Peak and Average method not be used to allocate costs to classes because it is AWEC' s opinion that this method does not best reflect class cost of service. The Peak and Average method double counts average demand in the cost allocation, which unnecessarily skews the results to allocate more costs to higher volume users even though their demand is more consistent. In other words, the difference in the design of the system to serve peak loads and the design of the system to serve average loads is the result of smaller volume users that have wider variations in their use of the system throughout the year. The Peak and Average method dampens that distinction and therefore does not best reflect class cost causation.

3. <u>How should a cost of service study address the allocation of mains?</u>

As stated in the previous response, AWEC supports a class cost of service study that allocates demand related costs based on customers' peak load characteristics. Appropriate class cost of service studies that allocate demand classified costs, such as the costs of mains, based on the peak load characteristics of customer classes include the Design Day Demand method and the Average and Excess method. Because utilities design their systems to meet the peak demands of their customers and do not design their systems to meet annual throughput, a class cost of service study that allocates costs based on customers' peak loads better reflects cost causation.

a. What is the appropriate balance of demand with throughput?

AWEC recommends that demand classified costs be allocated on the peak load characteristics of its customer classes and not on throughput. Utilities design the capacity of the transmission and distribution mains to meet the design day demands and not annual throughput. Because utilities also design their systems in order to connect customers to its system, there is a cost of mains associated with the length of the mains. Therefore, a portion of mains should be classified and allocated based on the number of customers.

b. Is it appropriate for the Commission to establish or allow different companies to use different methods?

AWEC recommends that all utilities provide results for review that use the same common class cost of service methods. Reasonable variations of these methods (Design Day Demand, Average and Excess, and Peak and Average) would be acceptable.

c. Should the Commission allow a cost of service study to exempt specific customer classes from an identified methodology?

To the extent costs can be identified for a particular class, it would be appropriate to directly assign these costs to that class. In addition, it may be appropriate to modify a class cost of service study to take into account the load profiles of seasonal or interruptible customers.

4. <u>How should cost of service studies classify and allocate:</u>

a. Common and joint costs?

To the extent this question is asking how common and joint plant costs should be allocated, AWEC would support the allocation of common and joint plant costs based on labor operating ratios. These costs are generally related to employees and the labor they perform. In performing a cost of service study, O&M costs for production, transmission, distribution, and customer functions have already been functualized, classified, and allocated. As a result, the amount of labor, wages, and salaries assigned to each function is known, and a set of labor expense ratios is available for use in allocating accounts such as transportation equipment, communications equipment, and general office space.

b. Administrative and general costs?

AWEC would support the allocation of administrative and general costs on the basis of the sum of the other operating and maintenance expenses (excluding gas cost).

5. Are there any other costs that cost of service studies should classify and allocate in a specific way?

To the extent a particular cost can be identified and attributed to a specific customer class such as, for example, the cost associated with a dedicated distribution main, it would be appropriate to directly assign that cost to the customer class.

Dated this 31st day of August 2018.

Respectfully submitted,

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