PUBLIC COUNSEL RESPONSES TO QUESTIONS POSED IN THE COMMISSION'S JULY 23 NOTICE OF OPPORTUNITY TO COMMENT REGARDING COST OF SERVICE STUDIES

I. QUESTIONS AFFECTING BOTH ELECTRIC AND NATURAL GAS COMPANIES

1. 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?

Public Counsel proposes the following minimum presentation requirements should be contained within a utility's base rate case filing as it relates to class cost of service studies.

Summary Rates of Return by Class showing at a minimum:

- Revenues
  - Current Base Rate Revenues
  - Current Other Rate Revenues (as applicable)
  - Current Miscellaneous Revenues
  - Total Current Revenues
- Expenses
  - Total O&M Expenses (Current Rates)
  - Total Depreciation & Amortization Expenses
  - Total Taxes Other Than Income
  - Total Income Taxes at Current Rates
  - Total Expenses
- Gross Plant in Service
  - Intangible Plant
  - Production Plant
  - Transmission Plant
  - Distribution Plant
  - General Plant
  - Total Gross Plant
- Accumulated Depreciation
  - Intangible Plant
  - Production Plant
  - Transmission Plant
  - Distribution Plant
  - General Plant
  - Total Depreciation
- Net Plant
- Working Capital
  - Materials & Supplies

  - Cash Working Capital
  - Other
  - Total Working Capital
- Accumulated Deferred Income Taxes
- Other Additions & Deductions to Rate Base
- Total Rate Base
- Rate of Return at Current Rates

The filing should also include each of the above items at Company proposed rates. In addition, the filing should include the Company's proposed increases to base rates by class along with proposed parity ratios.

Public Counsel also recommends that all class cost of service studies explicitly show the allocation of costs to each rate class by individual FERC account. The basis for allocation should be clearly shown and observable. Public Counsel believes that neither the proposed requirements relating to the allocation of costs by FERC account nor the basis for allocation for each account need to be provided in the Minimum Filing Requirement schedule or attached to a witness's testimony. Instead, Companies should be required to explicitly state in their filing where each may be found in the Company's workpapers.

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

Public Counsel recommends that the summary results be presented in a standardized presentation as recommended in response to Question 1, above. However, Public Counsel is cognizant that there are circumstances unique to each utility such that a one-size-fits-all format relating to the inner-workings of all cost of service studies across utilities is neither feasible nor advisable.

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

Public Counsel recommends that this decision be left to the individual experts evaluating and testifying on cost of service issues since some issues may be important to one party and not others. Furthermore, there may be instances in which a very detailed and small aspect within a cost of service study is at issue for a particular expert and not others. Experts and parties should not be required to rely only upon summary presentations. However, all parties should provide a summary of results as recommended in Question 1, above.

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?

Public Counsel recommends that all utility rate filings include a summary of cost of service results at present and proposed rates as stated in response to Question 1, above. Non-company witnesses should be free to present their case as they see fit to emphasize the issues important to their point of view. Not all parties will address revenue requirement, and certain parties may base their recommendations on an alternative revenue requirement. Flexibility is required to ensure that the Commission is presented with information that accurately reflects a party's advocacy.

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?

All allocation factors should be clearly identified and presented somewhere within the cost of service study. However, due to the complexity of the derivation of certain allocation factors, the calculations of individual factors may not need to be presented in the cost of service study but should be provided and incorporated into workpapers. Public Counsel believes that it is overly burdensome for a party to be required to explain or quantify how a particular allocation factor has changed from "inception." Finally, as discussed in response to Question 1, above, the allocation of costs to customer classes should show the basis for allocation for each FERC account. To the extent a particular cost of service study functionalizes, classifies, and then allocates grouped costs, the filed workpapers should clearly explain and show how costs are ultimately allocated to each FERC account.

2. 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.

Public Counsel strongly believes that utilities are the only parties realistically capable of conducting load studies, and, thus Staff, Public Counsel, and Intervenors should be exempt from any such requirement. With regard to requirements for utilities to conduct studies, Public Counsel supports the use of actual load studies with updates performed within a reasonable timeframe, which may vary from utility to utility. Indeed, some Washington utilities maintain ongoing load research and others may only periodically conduct or update their load studies. Public Counsel recommends that load studies be conducted every five years, at a minimum.

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?

By definition, all load studies should estimate class demands. At a minimum, these studies should measure (or estimate) class contributions to system coincident peak (CP) demand and class non-coincident peak (NCP) demands. In addition, all load studies should also measure (or estimate) the sum of individual customers' peak demands.[1] Furthermore, load studies should

[1] Class contributions to CP demands are coincident to total system loads. Class NCP demands reflect the maximum demands of a particular class regardless of when the class peak occurs. The sum of individual customer demands are an estimate of the sum of the maximum demands of individual customers.

measure (or estimate) the above referenced class demands on at least a monthly basis as well as several of the highest CP's and class NCP's occurring during a test year. As an illustration, load studies should provide class CP demands for each month of the test year, as well as class contributions to several of the system CPs. That is, if a standard is established to provide the highest 25 hours of system peak demands, and the 10 highest annual system peaks occurred during January with the next highest 15 highest system peaks occurring in February, class contributions to these 25 peak demands should be measured or estimated.[2] Due to the definitional framework of class NCP and sum of individual customer peak demands, Public Counsel believes that only a single annual peak observation by class is necessary.

With regard to the natural gas industry, in addition to actual class contributions to coincident peak day demands, utilities may also want to estimate class design day demands utilizing the same design day parameters as used for upstream gas supply planning purposes.

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?

In addition to Public Counsel's response to Question 2.a., above, all load studies should contain a narrative explanation regarding which class loads are developed based on actual interval metered data and which classes are estimated based on sampling techniques, algebraic formulas, weather sensitive load, etc. For those class loads that are estimated, this accompanying narrative should provide a detailed explanation of the methods and procedures used to estimate these class loads along with sample sizes and the procedures used to ensure that the selected samples reasonably reflect the characteristics of an entire class.

c. How frequently should companies perform load studies?

While some Washington utilities (such as Puget Sound Energy) maintain ongoing load research, others periodically conduct or update their load studies. Public Counsel recommends that load studies be conducted every five years, at a minimum.

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.

While the installation and implementation of true electric "smart" meters will provide the hardware necessary to measure individual customers' load on a discrete interval basis,

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[2] In the electric industry, peak demands are often measured at 15-minute intervals. Such a load interval may be acceptable instead of average loads over an entire hour. In the natural gas industry, peak loads are traditionally measured on a peak day rather than peak hour basis.

considerable computer hardware and software is required to collect, maintain, store, accumulate, and analyze the data obtained from individual customer meters. Although some utilities are moving forward with AMI installation, Public Counsel is not aware of whether all electric utilities in Washington have the hardware and software required to fully utilize customer load data for load studies. Therefore, Public Counsel does not, at this time, provide a recommendation or opinion as to how this may or may not reduce load study costs to ratepayers.

With regard to the natural gas industry, it is Public Counsel's understanding that only some of the residential and small commercial AMI meters currently deployed are capable of recording and transmitting usage (loads) on a daily basis. Therefore, and unless all natural gas utilities install meters capable of recording and transmitting individual customers' load on a daily basis, it is doubtful that the deployment of AMI meters for this industry will reduce the costs of conducting load studies.

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

Yes. Public Counsel does not support any rule requiring the removal of individual customer information when a single customer represents an entire class or is a special contract customer. There may be instances in which specific customer information is useful and relevant, particularly if a large customer has special contract rates or is an intervenor in rate cases that may recommend proposals specific to that customer. In these instances, it is useful to understand the impact of the proposals on and by the specific customer. Such information should be protected under the Commission's existing practices of confidentiality and protective orders.

a. If so, should confidential information be labeled in the same way as all other information identified as confidential under WAC 480-07-160?

Yes, companies should be allowed to submit confidential information under a protective order per the Commission's existing practices. See also response to 3, above.

b. What circumstances would require a party to provide a confidential version of a cost of service study?

There are a myriad of potential circumstances in which a utility (or party) may need to have certain aspects of a cost of service study deemed confidential. Public Counsel will not speculate as to every particular circumstance that could possible occur. However, Public Counsel's response to Question 3, above, points to instances in which only one customer makes up an entire class. Including that class's load data in a load study would make that customer's load data public if it is not designated confidential under the Commission's existing practices. To protect the confidentiality and rights of various parties, proposed confidential treatment should be subject to the existing Commission rules and practices.

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?

As indicated in response to Question 1, Public Counsel recommends that utility-sponsored cost of service studies provide revenues at current rates as well as at Company proposed rates. Billing determinants used to develop current and proposed rates are a rate design issue and are beyond the scope of class cost of service. Therefore, while Public Counsel supports a rule that all adjustments to test year revenues (including the impact on billing determinants) be included in a filing, this requirement should not be imposed upon the class cost of service study itself.

> **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?**

See response to Question 4, above.

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.

No, creating a rule that includes definitions of technical terms used in cost of service studies is unnecessary. Technical experts are familiar with the terms embedded within class cost of service studies.

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?

Public Counsel is not aware of the Commission ever relying upon marginal cost studies to evaluate class revenue responsibility. Indeed, for at least the last 25 years, the Commission has relied on embedded class cost of service studies as one of many tools in evaluating class revenue responsibility, but has consistently also considered other criteria such as gradualism, fairness, equity, economic conditions, and rate stability, as expressed in the Commission's order in Pacific Power's 2014 general rate case (Docket UE-140762). For example, the Commission stated:

> A utility performs a COSS to determine its cost to serve each class of customers. . . . As a general matter, it is appropriate from case to case to move the rates of each customer class closer to parity. Changes in rates to effect greater

> parity, however, must take into account "fairness, perceptions of equity, economic conditions in the service territory, gradualism, and rate stability.[3]

As the Commission indicated, class cost of service studies are indeed useful in measuring or estimating the cost to serve each customer class. However, cost of service studies are not the only tools or principles used to allocate costs among rate classes and set customer rates. Though gradually moving toward parity is among the Commission's aims, and many stakeholders share this goal, costs must be assigned and rates set with "principles the Commission has enunciated in prior orders," including those enumerated above.[4]

Public Counsel understands that these dockets were established to provide a mechanism for a collaborative effort of all parties to evaluate various aspects of class cost of service studies, which have always been based upon embedded, rather than marginal, costs.[5] If the Commission is considering relying upon marginal cost studies to establish class revenue responsibility (and/or rate design), this is a dramatic shift in the ratemaking process within Washington and is well beyond the scope of this docket.

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?

See Public Counsel's response to Question 6, above. Additionally, Public Counsel recommends that utilities should include an updated and current class cost of service study in all rate case filings, unless an the utility requests and the Commission grants an exemption.

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

Special contracts should reasonably pay for the services provided to these customers including those services provided and collected through pass-through riders. There are a multitude of pass-through riders approved for the Washington's electric and natural gas utilities. The cost responsibility of individual riders to individual special contract customers should be evaluated on a rider-by-rider basis and on a case-by-case basis.

8. 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

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[3] *WUTC v. Pacific Power & Light Co.*, Docket UE-140762, *et al. consolidated*, Order 08: Final Order, ¶ 197 (Mar. 25, 2015).
[4] *Id.*, ¶ 202.
[5] *WUTC v. Avista Corp*., Dockets UE-160228 & UG-160229, Order 06: Final Order, ¶ 100 (Dec. 15, 2016).

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.

- **a. Is this a sound approach for providing consistency for the review of cost of service studies and their underlying methods?**
- **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?**
- **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?**
    - **i. Should the timeframe for re-evaluation be the same for all companies?**
    - **ii. Should baseline studies be established or reviewed outside of a general rate proceeding?**
    - **iii. Should the Commission consider re-evaluation simultaneously for all companies?**
- **d. Which metrics should be considered as the trigger for a formal re-evaluation of a baseline cost of service study?**

Establishment of a "baseline" cost of service study is not desirable for several reasons. First, class cost of service studies are only one of the many tools that are considered in establishing class revenue responsibility. Second, there is no absolute, correct class cost of service study based on the allocation of a utility's common and joint costs. Indeed, expert witnesses filing testimony in rate cases on cost of service studies often disagree on what should and should not be included in cost of service studies, how they are conducted, and how they are interpreted. Third, the implementation of a "baseline" study would effectively serve as being precedential. This shifts the burden of proof to any party proposing any type of cost of service study different from a precedent setting "baseline" study. Fourth, Public Counsel cautions against such rigidity due to the evolving nature of the electric and natural gas industries. There are several technological changes being confronted, realized, and advanced in the planning and operation of electric and natural gas utilities as well as evolving changes in the wholesale power and natural gas markets. As a result of these changes, alternative cost allocation methods may become more relevant or appropriate. In Public Counsel's opinion, the implementation of a "baseline" approach would stifle improvements or revisions as a result a utility's operational or planning changes.

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

The electric and natural gas industries are constantly evolving. Issues, topics, and controversies change with this evolution. It is impossible to provide an *a priori* list of all potential topics that should be considered as it relates to class cost of service studies. With that said, controversial issues should be decided upon on a case-by-case basis because each utility presents unique facts and circumstances.

II. QUESTIONS AFFECTING ELECTRIC UTILITY SERVICE ONLY

1. 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?

Public Counsel has the same concerns and recommendations with respect to use of marginal cost of service studies for special contract customers for both electric and natural gas service. While the use of marginal cost for establishing special (discounted) rate contracts has intuitive appeal from a theoretical standpoint, Public Counsel cautions against any rule or policy statement regarding the broad general term of marginal cost. Marginal costs can be defined as short-run marginal cost, long-run marginal cost, time differentiated marginal cost (particularly short-run), separately functionalized marginal cost between production, transmission, distribution, and perhaps sub-functionalized between various aspects of distribution-related costs; i.e., between demand and customer-related marginal cost.

Economic theory tells us that no customer should pay less than variable costs and no more than stand-alone costs.[6] Furthermore, recognition must be given to individual circumstances as it relates to the provision of firm or interruptible service.

Public Counsel strongly recommends that if an electric utility offers, or engages in, discounted rates below full Commission tariff rates, the discounted rates must be cost-justified based on a detailed analysis of a customer's stand-alone costs. In this way, the special contract customer will enjoy rates below full tariff rates while all other captive ratepayers will have assurances that the utilities are recovering as much revenue as possible from these customers, thereby, avoiding undue cross-subsidization to the special contract customers.

To the extent a special contract customer is able to unbundle its total electricity costs, the special contract customer should be required to pay full tariff rates for the services actually provided by the utility (e.g., distribution only) absent a stand-alone cost analysis. To the extent that a utility offers a discounted rate for unbundled service, a detailed stand-alone cost analysis should be required.

Finally, the burden of proof should rest on the utility to demonstrate that a discounted rate for a special contract customer is required in order to maintain that customer's load and energy usage, which will then provide some benefit to all remaining ratepayers.

[6] Stand-alone costs represents those costs that a customer would incur by providing the same service on its own.

2. How should cost of service studies allocate demand and energy costs?

Public Counsel interprets this question to relate only to utility-owned generation plant costs since Question 3 directly relates to fuel costs, purchased power costs, transmission, distribution, and other cost separations.

<u>Utility-Owned Generation Plant</u>
There are a myriad of approaches used throughout the country to allocate generation related capital (rate base) costs. Most experts agree that these costs should be allocated to classes based on the concept of "cost causation." However, experts disagree widely on the exogenous attributes of cost causation. Utilities are expected to plan and build their generation systems with a portfolio of assets that minimizes the total cost of providing service on an annual (or even long term) basis. In this regard, there is a clear tradeoff in generation alternatives between fixed capacity and variable energy costs relating to specific types of generation. While some types of generation require substantial amounts of investment per KW of capacity, these types of facilities are typically very efficient in that they operate with low energy costs per KWH of output. At the other extreme, peaker units are relatively inexpensive to build per KW yet operate at relatively expensive variable running costs per KWH of output. As a result, large baseload plants were planned, installed, and operated to meet the energy needs of its customers throughout the entire year, whereas peaker units are seldom dispatched and tend to operate for short durations in order to meet peak load requirements for a short period of time. Further, many alternative and renewable energy sources such as solar, wind, and sometimes hydro, have few, if any, related fuel costs, yet, at the same time, may not be totally reliable for peak load planning purposes.

Because of these realities in how generation plant costs are incurred, it is imperative that energy usage throughout the year be considered in allocating generation related plant. However, because all classes do not have the same load profiles and may contribute at varying degrees to a utility's need to meet peak load, some consideration should also be given to system coincident peak demands.

For more than 35 years, this Commission has had a general policy of preferring what it refers to as the Peak Credit method.[7] Although the Commission is very familiar with its long-standing use of the Peak Credit method, this approach is loosely based on the concept of short-run marginal cost wherein a peaker unit will serve as a surrogate for the short-run marginal cost of generation. As a result, the capacity costs of all generation are allocated based partially on system coincident peak demand and partially on energy usage.

[7] In a 1981 Pacific Power rate case, the Commission approved the Peak Credit method. *WUTC v. Pacific Power & Light Co.*, Cause No. U-81-17, Second Supplemental Order, at 17 (Dec. 16, 1981). Also, in a 1981 Puget Sound Power & Light Co. rate case, the Commission adopted the Peak Credit method. *WUTC v. Puget Sound Power & Light Co.*, Docket U-81-41, Sixth Supplemental Order, at 23 (Dec. 19, 1988). In 1982, the Commission directed Washington Water Power (now Avista) to prepare future studies using the Peak Credit method. *WUTC v. Wash. Water Power Co.*, Cause No. U-82-10, Second Supplemental Order (Dec. 30, 1982). In a 1984 Pacific Power rate case (Cause U-84-65), the Commission reiterated its support of the Peak Credit method. *WUTC v. Pacific Power & Light Co.*, Cause No. U-84-65, Fourth Supplemental Order, at 40 (Aug. 2, 1985).

With advances in technology, most electric utilities are now able to determine how individual class usage patterns (loads) vary not only by season or on an annual basis, but on an hour-by-hour basis throughout the year. Furthermore, electric utilities are able to maintain records of the hourly output of its generation resources by unit. With this information, electric utilities can reasonably determine how its generation plant is utilized by individual classes throughout the year. Actual utilization of the utility's resources determines a proper allocation of generation plant. An hour-by-hour analysis is the most technically correct method to allocate generation plant investment. The Probability of Dispatch method accurately measures and appropriately allocates costs on an hour-by-hour basis.

However, class hourly loads and hourly generation output by unit are not always available. In these instances, less rigorous methods can (and should) be utilized to reflect the fact that a portion of generation plant should be allocated based on a portion of coincident peak demands and a portion on annual energy usage. These less rigorous methods include the Peak Credit, Base-Intermediate-Peak, and Peak & Average methods.[8]

Public Counsel filed a discussion of the advantages and disadvantages of various allocation methods used to assign generation plant to classes in the Direct Testimony of Glenn A. Watkins in the recent Puget Sound Energy general rate case (Docket Nos. UE-170033 and UG-170034) at pages 5 through 16. Mr. Watkins' background and experience is provided in Appendix A to these comments, and a true and accurate copy of Mr. Watkins' testimony from the Puget rate case is provided in Appendix B to these comments.

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

Public Counsel cautions against any assertions that there should be a one-size-fits-all cost of service approach or that there is only one absolutely correct method to reasonably allocate generation related costs. Further, the United States Supreme Court stated regarding the accuracy and reasonableness of public utility cost allocations: "But where as here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science."[9]

Public Counsel agrees with the findings of the U.S. Supreme Court in that no fully allocated cost of service study can be considered surgically precise. However, some methods that have

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[8] The Peak & Average method should not be confused with the Average & Excess method as these are totally different approaches. The Average & Excess method is rarely a reasonable approach to allocate generation plant investment as it utilizes class non-coincident peak demands instead of coincident peak demands. Non-coincident peak demands have no causal relationship to how generation assets are planned, installed, or operated since it is total system loads that are important when evaluating generation assets as opposed to diversified individual class peak demands (NCPs). Furthermore, the Average & Excess approach tends to over-allocate costs to low load factor customers even though the majority (or significant amount) of usage occurs during off-peak periods.

[9] *Colo. Interstate Gas Co. v. Fed. Power Comm'n*, 324 U.S. 581, 589, 65 S. Ct. 829 (1945).

historically been advocated by industrial and large commercial interests are clearly biased against residential and small commercial customers and are not consistent with cost causation. These inappropriate methods generally only consider class peak demands. In any event, multiple reasonable cost studies could be considered in evaluating class contributions to costs and profitability.

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

See response to 2.a, above.

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

Yes. The Commission should not consider any method that considers only class peak demands to allocate generation plant related costs. For the reasons discussed in response to Question 2, above, a utility's generation plant investment is incurred to meet energy needs throughout the year as well as meet peak loads such that a portfolio of various types of generation assets are employed to minimize a utility's total cost of service. For a complete discussion of this issue, please refer to Appendix A (Mr. Watkins' direct testimony in Docket Nos. UE-170033 and UG-170034 at pages 5 through 16).

In addition, and as noted in Footnote 8, the Average & Excess method should not be considered as an approach to allocate generation plant related costs as it bears no resemblance as to how costs are incurred or caused across classes. Indeed, the Commission explicitly rejected the Average & Excess method in 1982.[10]

3. How should cost of service studies classify and allocate:

a. Transmission and distribution assets?

<u>Transmission</u>
There are two general philosophies relating to the proper allocation of transmission-related plant. The first philosophy is based on the premise that transmission facilities are nothing more than an extension of generation plant in that transmission facilities simply act as a conduit to provide power and energy from distant generating facilities to a utility's load center (specific service area). That is, generation facilities are often located well away from load centers and near the resources required to operate generation facilities. For example, natural gas generators must be located in close proximity to large natural gas pipelines.

The second philosophy relates to the physical capacity of transmission lines. That is, transmission facilities have a known and measurable load capability such that customer contributions to peak load should serve as the basis for allocating these transmission costs.

[10] *WUTC v. Wash. Water Power Co.*, Cause No. U-82-10, Second Supplemental Order (Dec. 30, 1982).

While there is no doubt that any given electricity conductor (i.e., a transmission line) has a physical load carrying capability, this rationale fails to recognize cost causation in three regards.

First, an allocation based simply on contributions to a few hours of peak load fails to recognize the fact that transmission facilities are indeed an extension of generation facilities and are used to move the energy produced by the generators from remote locations to where customers actually consume electricity. Second, and similar to the concept of base load units producing energy to serve customers throughout the year, a peak responsibility approach based on one or only a few hours of maximum demand fails to recognize that transmission facilities are used virtually every hour of an entire year and not just during periods of peak load. Third, any assumption that transmission costs are related to peak load implies that there is a direct and linear relationship between cost and load. In other words, one must assume that if load increases, the cost of transmission facilities increases, in a direct and linear manner. This is simply not the case since there are significant economies of scale associated with high voltage transmission lines.

Since at least the early-1990s, this Commission has consistently found that transmission facilities are an extension of generation facilities, and has consistently ruled that transmission facilities should be classified as partially energy related and partially demand-related. Traditionally, Washington electric utilities have utilized the same demand/energy classification for transmission plant as they do for generation plant.

Public Counsel supports the continued policy of classifying and allocating transmission plant in the same manner as generation plant.

<u>Distribution</u>
While the classification of distribution plant (between customer and demand) can be controversial in some jurisdictions, once distribution plant is classified, the allocation of this plant is generally less contentious.

Classification of Distribution Plant
For many years, all investor-owned electric utilities in Washington have classified distribution plant Accounts 364-368 as 100 percent demand-related. These accounts encompass poles, overhead conductors, underground conduit, underground conductors, and line transformers. The rationale behind this practice is that these distribution costs are incurred to meet the collective loads of customers such that maximum demands reflect a reasonable proxy for cost causation.

Some cost of service experts and analysts are of the opinion that there should be a "customer" component relating to each of these accounts because a utility must incur some level of costs to connect customers to the system. Furthermore, some experts even argue that distribution costs are a direct function of number of customers. Unfortunately, advocates of the customer/demand component of these distribution plant accounts invariably make an *a priori* assumption that there must somehow be a customer component associated with these plant investments.

In order to test whether it may be appropriate and equitable to classify and allocate a portion of distribution plant Accounts 364-368 as partially customer-related, analyses should first be performed to determine if such a classification is at all necessary or preferred.

The only salient reason to consider number of customers within the classification/allocation of distribution plant is that there may be considerable differences in both customer densities and the mix of customers throughout a utility's service area. As a hypothetical, suppose a utility serves both an urban area and a rural area. In this situation, many customers' electrical needs are served with relatively few miles of conductors, few poles, etc. in the urban area, while many more miles of conductors, more poles, etc. are required to serve the requirements of relatively few customers in the rural area. If the distribution of classes of customers (class customer mix) is relatively similar in both the rural and urban areas, there is no need to consider customer counts (number of customers) within the allocation process, because all classes use the utility's joint distribution facilities proportionately across the service area. However, if the customer mix is such that commercial and industrial customers are predominately clustered in the urban area, while the rural portion of the service territory consists almost entirely of residential customers, it may be unreasonable to allocate the total company's investment based only on demand; i.e., a large investment in many miles of line is required to serve predominately residential customers in the rural area while the commercial and industrial electrical needs are met with much fewer miles of lines in the urban area. Under this circumstance, an allocation of costs based on a weighting of customers and demand can be considered equitable and appropriate.

With today's technology, GPS mapping, and a multitude of computerized data sources, such an analysis of distribution of customers classes relative to the density of customers is certainly possible such that if a utility (or other party) proposes a customer/demand classification of distribution plant, it should be incumbent upon that party to show a factual and definite need to classify and allocate a portion of plant Accounts 364-368 based partially on number of customers. Furthermore, electric distribution systems are sub-functionalized between primary voltage and secondary voltage systems. Public Counsel recommends that if any party recommends a customer/demand split of distribution plant, that the customer density/mix analysis be bifurcated between the primary and secondary subsystems.

Allocation of Distribution Plant

Once the classification aspect is determined, there tends to be little controversy with regard to the actual allocation factors used to assign distribution plant investment across classes. Typically, distribution plant accounts are allocated to customer classes based on the following criteria:

- Account 360 – Land & Land Rights: class NCPs
- Account 361 – Structures & Improvements: class NCPs
- Account 362 – Station Equipment: class NCPs
- Account 363 – Storage Battery Equipment: class NCPs
- Account 364 – Poles
    - Demand
        - Primary Voltage: primary plus secondary class NCPs

        - Secondary Voltage: secondary class NCPs or sum of individual customers' demands
    - Customer
        - Primary Voltage: primary plus secondary number of customers
        - Secondary Voltage: secondary number of customers
- Account 365 – OH Conductors
    - Demand
        - Primary Voltage: primary plus secondary class NCPs
        - Secondary Voltage: secondary class NCPs or sum of individual customers' demands
    - Customer
        - Primary Voltage: primary plus secondary number of customers
        - Secondary Voltage: secondary number of customers
- Account 366 – UG Conduit
    - Demand
        - Primary Voltage: primary plus secondary class NCPs
        - Secondary Voltage: secondary class NCPs or sum of individual customers' demands
    - Customer
        - Primary Voltage: primary plus secondary number of customers
        - Secondary Voltage: secondary number of customers
- Account 367 – UG Conductors
    - Demand
        - Primary Voltage: primary plus secondary class NCPs
        - Secondary Voltage: secondary class NCPs or sum of individual customers' demands
    - Customer
        - Primary Voltage: primary plus secondary number of customers
        - Secondary Voltage: secondary number of customers
- Account 368 – Line Transformers
    - Demand
        - Primary Voltage: primary plus secondary class NCPs
        - Secondary Voltage: secondary class NCPs or sum of individual customers' demands
    - Customer
        - Primary Voltage: primary plus secondary number of customers
        - Secondary Voltage: secondary number of customers
- Account 369 – Services
    - Weighted Customers
- Account 370 – Meters
    - Weighted Meters Costs
- Account 371 – Installation on Customer Premises
    - Direct Assignment or Number of Customers
- Account 372 – Lease Property on Customer Premises

  - Direct Assignment or Number of Customers
- Account 373 – Street Lighting & Signal Systems
  - Direct Assignment

Whether class NCPs or the sum of individual customer demands should be used as a demand allocator for secondary subsystems varies depending upon the analyst's opinions and data availability. Generally, the sum of individual customer demands are the preferred allocator for secondary voltage demand costs while NCPs are the preferred allocator for primary voltage demand costs.

b. Fuel costs and purchased power?

<u>Fuel Costs</u>
There is no doubt that fuel costs vary directly with kilowatt hour (energy) usage. However, because fuel costs vary hour-by-hour depending upon the dispatch of generation units, time-differentiated fuel cost analyses may be appropriate. In this regard, hour-by-hour generation output is required along with good approximations of fuel costs per KWH by individual generation unit. Furthermore, if a true time differentiated fuel cost is conducted, hourly class loads are also required. While an hour-by-hour analysis is the most preferred approach, compromises can be made due to data available such that fuel costs are sometimes differentiated only by season and/or off-peak/on-peak diurnal time periods.

In the recent PSE general rate case (Docket Nos. UE-170033 and UG-170034), Public Counsel conducted a detailed hour-by-hour fuel cost analysis and determined that there was little variation in incurred fuel costs across classes such that an allocation of annual fuel costs based simply on annual energy (KWH) usage was reasonable. *See* Appendix B, Testimony of Glenn A. Watkins, Exh. GAW-1T at pages 27 through 33. Under no circumstances should fuel costs be allocated based on peak demands or any other demand-type allocator.

<u>Purchased Power Costs</u>
Purchased power costs varies considerably across utilities. While some utilities have reserved capacity (KW) for certain purchased power coupled with provisions for fuel costs, other contracts may be priced based on spot wholesale market prices. A detailed analysis of purchased power costs should be conducted on a utility-by-utility basis because a one-size-fits-all approach may not be appropriate.

c. Common and joint costs?

Public Counsel interprets this question to relate to those costs typically referred to as "overhead" costs. That is, the vast majority of all electric utility costs are common or incurred in a joint manner to serve all customers.

Because of their very nature, overhead costs are incurred to serve the overall business operations of an electric utility. There are no true cost causative metrics to measure overhead cost incidence such that the selected allocation approach to assign these overhead costs often varies by expert. For example, general plant is often assigned based on previously assigned production, transmission, and distribution plant since this general plant serves as support for the plant in service actually devoted to producing, transmitting, and delivering electricity to customers. Other experts prefer to allocate general plant based upon labor expenses since most of general plant is utilized to support personnel. Public Counsel does not have a strong position or preference as it relates to the allocation of general plant

d. Administrative and general costs?

With regard to administrative and general expenses, consideration should be given to individual accounts. That is, many A&G expense accounts are directly labor-related, while others may be either revenue-related or plant-related. One important caveat relates to expense Account 923 (Outside Services). All three of the major investor-owned electric utilities in Washington are either multi-jurisdictional or offer services other than electricity under its overall corporate umbrella. As a result, affiliate transactions are often booked under Account 923 with no regard to the individual components embedded within these affiliate transactions. Therefore, instead of Account 923 being a catchall for the collective amount of affiliate transactions or other outside services, s separate analysis should be conducted regarding the various types of services included within this account.

e. Poles, conductors, and line transformers?

Allocating distribution plant costs is relatively non-controversial after costs are classified as customer or demand related. See response to 3.a. Distribution, above, for additional detail.

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

There often may be additional costs that are not specifically addressed in these questions. These additional costs should be identified and addressed as they specifically relate to an individual utility. In other words, the Commission should consider the utility-specific factors in classifying and allocating costs, rather than adopting a blanket approach for all Washington utilities.

III. 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?

Public Counsel has the same concerns and recommendations with respect to use of marginal cost of service studies for special contract customers for both electric and natural gas service. While the use of marginal cost for establishing special (discounted) rate contracts has intuitive appeal from a theoretical standpoint, Public Counsel cautions against any rule or policy statement regarding the broad general term of marginal cost. As noted in Public Counsel's comments addressing electric service, marginal costs can be defined as short-run marginal cost, long-run marginal cost, time differentiated marginal cost (particularly short-run), separately functionalized marginal cost between storage, transmission, distribution, and perhaps sub-functionalized between various aspects of distribution-related costs; i.e., between demand and customer-related marginal cost.

Economic theory tells us that no customer should pay less than variable costs and no more than stand-alone costs.[11] Furthermore, recognition must be given to individual circumstances as it relates to the provision of firm or interruptible service.

Public Counsel strongly recommends that if a natural gas utility offers, or engages in, discounted rates below full Commission tariff rates, these discounted rates must be cost justified based on a detailed analysis of a customer's stand-alone costs. In this way, the special contract customer will enjoy rates below full tariff rates while all other captive ratepayers will have assurances that the utilities are recovering as much revenue as possible from these customers, thereby, avoiding undue cross-subsidization to the special contract customers.

To the extent a special contract customer is able to unbundle its total gas costs, the special contract customer should be required to pay full tariff rates for the services actually provided by the utility (e.g., distribution only) absent a stand-alone cost analysis. To the extent that a utility offers a discounted rate for unbundled service, a detailed stand-alone cost analysis should be required.

Finally, the burden of proof should rest on the utility to demonstrate that a discounted rate for a special contract customer is required in order to maintain that customer's load and gas throughput, which will then provide some benefit to all remaining ratepayers.

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

[11] Stand-alone costs represents those costs that a customer would incur by providing the same service on its own.

See response to Question 1, above. Additionally, to the extent that a natural gas utility engages in special contracts at rates below full tariff rates, the utility should be required to maintain detailed records supporting the need for, and cost benefits to, ratepayers associated with the offering of discounted rates to selected customers; i.e., detailed records supporting stand-alone cost analysis. Additional studies and analyses supporting any discounted rates due to contract renewals or renegotiations should also be required to be updated.

2. How should cost of service studies allocate demand and throughput?

Public Counsel interprets this question to relate to non-gas costs relating to natural gas distribution companies' (NGDCs) base rates. In this regard, because NGDCs are generally able to pass through their purchased gas costs (including transportation) through riders, cost of service studies should exclude costs and revenues associated with purchased gas costs.

Allocation of plant and expenses for storage and mains tend to be controversial as it relates to whether these should be allocated on demand, throughput, or a combination of the two.

With regard to storage-related costs, the most preferred approach for accuracy is a detailed analysis of storage withdrawals evaluating such withdrawals on a daily basis compared to individual class throughputs on these days. In reality, few utilities maintain accurate records or estimates of all classes' throughputs on a daily basis. A second best approach is to evaluate withdrawals and class throughputs on a monthly basis while a third option is to allocate storage-related costs based on winter months' throughput. Public Counsel does not agree that simply allocating storage-related costs on some measure of only a single day (or a few days) of peak demand is appropriate as storage facilities are typically used throughout the winter months.

With regard to mains-related costs, these costs should be allocated based on a combination of peak day demand and annual throughput (average day demand). Washington has used this approach for many years and reasonably reflects cost causation in that mains are sized to meet peak load requirements but at the same time, serve customers throughout the year. While some cost of service experts believe that peak demand should be the only criteria considered, Public Counsel notes that if a customer (or group of customers) utilized an NGDC system for only one day a year (peak day), the system would not be economical and would not be built such that the revenue contributed from annual throughput reduces the costs paid by all ratepayers.

Common methods for allocating mains-related costs in a cost of service study include:

<u>Peak & Average</u>
The Peak and Average (also referred to as Demand/Commodity) method is the most fair and equitable method to assign natural gas distribution mains costs to the various customer classes. This method recognizes each class's utilization of the Company's facilities throughout the year yet also recognizes that some classes rely upon the Company's facilities (mains) more than others during peak periods.

While it is appropriate to consider and reflect class peak demands when allocating distribution mains, it should not be the only criteria. A NGDC system is constructed and is in existence in order to serve the natural gas energy needs of its customers throughout the year. As noted above, if a NGDC's customers only demand gas for one day of the year (the so-called peak day), the costs to deliver gas throughout the system would be prohibitively high such that a system would never exist. In other words, customers' demand and utilize natural gas every day of the year, not just one day out of 365 days. If by chance, a customer did require gas for only one day a year, it would be prohibitively expensive to the NGDC (and ultimately the customer) to provide service as the investment in mains would therefore be required to be recovered from a very small amount of natural gas energy (usage) and would be economically unfeasible.

Furthermore, the Peak & Average is consistent with virtually every NGDC's mains extension policy and tariff in that when a NGDC evaluates a mains extensions project, it considers the maximum load that will be placed on the extension as well as the annual usage of the mains extension in determining the feasibility of the project as well as any customer contribution requirements (e.g., Contribution In Aid of Construction).

<u>Peak Responsibility</u>
As noted in earlier questions, some CCOSS experts are of the opinion that mains should be allocated solely on the basis of peak day demands. However, there is not a direct and linear relationship between loads (capacity requirements) and costs. For example, if the peak load on one line segment of mains is double that of another line segment, the cost of mains for the higher capacity pipe may be higher but is not double that of the lower capacity pipe. This reality reflects the major shortcoming of the Peak Responsibility method (which allocates mains entirely on peak day demand). The Peak Responsibility method is premised on the incorrect assumption that there is a direct and perfectly linear relationship between peak loads, system capacity, and costs. With regard to system capacity, the amount of gas that can be delivered throughout a NGDC system is not only a function of the size of pipe(s) but also pressurization of gas within these pipes, and, as well, the presence or absence of looping various segments of the distribution system. All else constant, the *capacity* of pipes increase by a factor of exactly 4 to 1 as the *diameter* of pipe increases.[12] Therefore, if the size of pipe is doubled, the capacity of the pipe increases by a factor of four. At the same time, the cost of this additional capacity is far less than four times greater.[13]

In addition, and as important as the geometric capacity of pipe at a given pressure, the amount of gas required to be pushed through a distribution system can be met with larger pipes at lower pressures or smaller pipes at higher pressures.

[12] The volume of a cylinder (pipe) is equal to pi (3.14159) x Radius^2 x length. Therefore, as the diameter doubles, the area (volume) of the pipe increases by four times that of the smaller pipe.

[13] The cost of Mains investment reflects the cost of capitalized labor to install the main plus the cost of materials (the piping). Although the labor cost of installing pipe increases somewhat with larger size pipe, these additional labor costs tend to be much smaller than the capacity added. Similarly, the materials cost of the pipe also increases but by a much smaller percentage than the capacity added.

Customer/Demand

There is a third allocation method that is also advocated by some experts in which mains are classified and allocated partially based on number of customers and partially on contributions to peak demands. I am aware of two rationales used to advocate the allocation of natural gas distribution mains based partially on number of customers.

The first rationale used by some analysts is that, because every customer (regardless of size) must be physically connected to the utility's distribution network, there is some minimum level of investment required to simply connect customers to the distribution system. It is certainly true that, unless natural gas is delivered in a portable tank or cylinder, some form of a physical "plumbing" is required to deliver natural gas to each and every end-user.[14] Indeed, this is the very purpose of the distribution system. However, no customer connects to a NGDC system simply to be connected but never utilize natural gas, nor do NGDC's haphazardly install natural gas mains where no usage is present or anticipated. Because there is no economic utility (benefit) derived from simply being connected to a system, there is no economic (or cost causative) basis for assigning some value of a NGDC's distribution mains required to simply connect customers.

The second rationale used to consider number of customers within the allocation of mains relates to customer densities and differences in the mix of customers (by class) throughout a utility's service area. Unlike electric utilities, NGDC's distribution systems are not configured or installed to serve virtually every potential household or business within their service areas. That is, NGDC's distribution systems are typically limited to areas with sufficient customer density to justify the costs of building and maintaining distribution mains. Virtually every NGDC has economic tests in place to evaluate project feasibilities and to determine required customer contributions in the event that a mains extension is not considered to be "economic" absent a customer contribution. Additionally, customer densities relative to the distribution of customers by class tend to be very similar for NGDCs. As a result, this rationale has little, to no, merit in the natural gas industry.

Bifurcation (Skeletonization) of Mains

Another method commonly advocated by experts is to skeletonize a utility's distribution system between various sizes of mains (most commonly between large mains and small mains). Under this approach, small volume customers, such as residential and small commercial, are responsible for the costs associated with all distribution mains (small and large). Large volume customers such as large commercial and industrial are then only responsible for a portion of large diameter mains; i.e., they share no cost responsibility associated with small diameter mains.

This approach to skeletonize a NGDC's distribution system by size of pipe is improper for several reasons. Importantly, a NGDC's network of distribution mains is a system of commonly used facilities. However, proposals to skeletonize distribution mains would result in nothing more than enabling large volume customers to skim the cream off the top of the cost assignment

[14] If natural gas was delivered to end-users in tanks (such as done with propane), there would be no distribution system, or mains to allocate.

process. That is, for large volume customers, this approach would reflect the advantages of being part of a network, or system of commonly used facilities, but then not share in a reasonable proportion of the costs associated with the system. Each customer served by a NGDC enjoys significant savings as a result of the economies of scale made possible with a large commonly used distribution system. Each customer's savings are brought about not only as a result of not having to build their own facilities to deliver gas to their individual facility from a transmission pipeline, but also due to the sharing of investment and operational costs of a joint use distribution system. Under this skeletonization approach, large volume customers would each enjoy the economies of scale benefits associated with being part of a NGDC system, but nonetheless share only a small portion of the joint costs.

Further, this approach is unreasonable based on the "beginning of the road versus end of the road" rationale of cost allocation. This rationale relates to an analogy of a dedicated private lane that enables homeowners access to public roads and streets. If some residents argued that each should only be responsible for those costs from the termination of the public road to their respective driveway, others might argue that the proximity to the public road is nothing more than luck of the draw in that an alternative route for the lane would have yielded an entirely different result. Proper cost allocation procedures dictate that unless there are dedicated facilities to serve a particular customer, all customers should share (in a rational and equitable manner) in the benefits ***and costs*** associated with joint use facilities.

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

Public Counsel cautions against any assertions that there should be a one-size-fits-all cost of service approach or that there is only one absolutely correct method to reasonably allocate distribution-related costs (particularly storage and mains). Further and as noted in our comments related to electric service, the United States Supreme Court stated regarding the accuracy and reasonableness of public utility cost allocations: "But where as here several classes of services have a common use of the same property, difficulties of separation are obvious. Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science."[15]

Public Counsel agrees with the findings of the U.S. Supreme Court in that no fully allocated cost of service study can be considered surgically precise. However, some methods that have historically been advocated by industrial and large commercial interests are clearly biased against residential and small commercial customers and are not consistent with cost causation. These inappropriate methods generally: classify and allocate mains partially on number of customers; allocate mains based only on peak day demands; or attempt to skeletonize an NGDCs distribution system by assigning only larger diameter mains to large commercial/industrial customers while residential and small commercial classes absorb a portion of large diameter mains plus all costs associated with small diameter mains. With this being said, multiple

[15] *Colo. Interstate Gas Co.*, 324 U.S. at 589, 65 S. Ct. 829.

reasonable cost studies could be considered in evaluating class contributions to costs and profitability. See also response to Question 2, above.

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

Public Counsel cautions against applying a one-size-fits-all solution, but recognizes that multiple cost of service study methodologies can result in reasonable cost allocation. See response to Question 2.a. above.

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

Yes. See response to Questions 2 and 2.a., above.

3. How should a cost of service study address the allocation of mains?

See the allocation methods described in Question 2, above. Methods include Peak & Average, Peak Responsibility, Customer/Demand, and Bifurcation/Skeletonization. That analysis explains why Peak & Average is the most reasonable approach to allocation of mains.

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

An equal weighting between demand and throughput strikes an appropriate balance under the Peak & Average method. While some experts may prefer to use system load factor as a basis to weight between peak (demand) and average (throughput), such an approach does not reasonably relate to cost causation for NGDCs. This is because the annual system load factor for a NGDC tends to be fairly low due to the fact that there is little natural gas consumption by residential and small commercial customers in the non-heating months. As such, the use of a load factor to weight between demand and throughput places too much weight on demand and not enough on throughput.

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

As a general framework, Public Counsel believes that the Peak & Average method is appropriate for all NGDCs as it relates to the allocation of distribution mains. However, there may be some differences in the measurement of peak day demands as well as how non-firm (interruptible) customers' usage and load characteristics are measured across utilities.

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

Public Counsel believes this question generally refers to non-firm (interruptible) and/or special contract customers.

Interruptible customers should be allocated costs and treated as a separate class of customer. Service provided to interruptible customers is different enough from firm service such that interruptible load and customers should not be included within a class that also includes firm service. With regard to how and what level of costs should be assigned to interruptible customers, this should be evaluated on a case-by-case basis depending on the terms and conditions for curtailment as well as the historical frequency and duration of curtailments. To the extent that interruptible customers are realistically subject to curtailment, these customers should not enjoy a free ride as it relates to the allocation in mains. The interruptible class should be assigned some level of mains-related costs, but cost allocation should recognize that this is of a lesser quality than firm service. Public Counsel believes that a reasonable method to assign mains-related costs to interruptible customers under the Peak & Average method is to develop a mains allocator in which the interruptible class is assigned no "peak" portion but is responsible for the "average" (throughput) portion of this method.

Regarding special contract customers, it seems illogical to fully allocate costs to these customers since it is known that these special contract customers are not expected to pay fully allocated cost of service, assuming that these customers benefit from rates below full tariff rates that are fully supported by cost analysis and threat of bypass. One approach often used for special contract customers is to simply credit the rate revenues from special contracts back to all other classes. However, this approach provides little insight as to what these customers should pay absent a negotiated special contract. For very large special contract customers served with a dedicated spur, it is often possible to correctly assign mains, service lines, and meters cost to these customers and then allocate a portion of overhead and administrative costs. Public Counsel believes that, due to the significant variability in circumstances surrounding special contract customers, as well as the actual facilities that these customers utilize, this issue is best addressed on a case-by-case basis.

4. How should cost of service studies classify and allocate:

a. Common and joint costs?

Public Counsel interprets this question to relate to those costs typically referred to as "overhead" costs. That is, the vast majority of all NGDC utility costs are common or incurred in a joint manner to serve all customers.

Because of their very nature, overhead costs are incurred to serve the overall business operations of a NGDC. There are no true cost causative metrics to measure overhead cost incidence such that the selected allocation approach to assign these overhead costs often varies by expert. For example, general plant is often assigned based on previously assigned storage, transmission, and distribution plant since this general plant serves as support for the plant in service actually devoted to delivering natural gas to customers. Other experts prefer to allocate general plant based upon labor expenses since most of general plant is utilized to support personnel. Public Counsel does not have a strong position or preference as it relates to the allocation of general plant.

b. Administrative and general costs?

When classifying and allocating administrative and general expenses, consideration should be given to individual accounts. That is, many A&G expense accounts are directly labor-related, while others may be either revenue-related or plant-related. One important caveat relates to expense Account 923 (Outside Services). All of the major investor-owned NGDCs in Washington are either multi-jurisdictional or offer services other than natural gas under their overall corporate umbrella. As a result, affiliate transactions are often simply booked under Account 923 with no regard to the individual components embedded within these affiliate transactions. Therefore, instead of Account 923 being a catchall for the collective amount of affiliate transactions or other outside services, a separate analysis should be conducted regarding the various types of services included within this account.

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

There may be additional costs that are not specifically addressed in the questions posed in the Commission's Notice. These additional costs should be identified and addressed as they specifically relate to an individual utility, rather than applying a one-size-fits-all methodology.

IV. CONCLUSION

Public Counsel appreciates the opportunity to address the questions contained in the Commission's Notice. We look forward to engaging collaboratively with stakeholders on issues that are often controversial in litigated matters, and we look forward to participating in future rounds of comments and workshops in this rulemaking where the issues can be further refined. The Public Counsel team, and their contact information, is listed below.

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