Cost of Service Analysis
For the
Electric and Natural Gas Industries

An Historical Review of Decisions by the

Washington Utilities and Transportation Commission

1978 - 2004

Prepared for:
Public Counsel Section
Office of the Attorney General

Jim Lazar -- Consulting Economist
1063 Capitol Way S. #202
Olympia, WA 98501
(360) 786-1822

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OVERVIEW

The Washington Utilities and Transportation Commission (WUTC or Commission) regulates three investor-owned electric utilities: Puget Sound Energy (Puget), Pacific Power and Light Company (Pacific), and Avista (formerly the Washington Water Power Company) (WWP). It also regulates four investor-owned gas utilities, Puget Sound Energy (formerly Washington Natural Gas Company) (WNG), Cascade Natural Gas (Cascade), Avista and Northwest Natural Gas (NWNG).

The Commission has considered the methodology and application of utility cost of service studies for a quarter-century, beginning with an electric "generic" proceeding in Cause U-78-05. In some proceedings, the Commission has rejected all cost of service analyses, in others it has accepted a study "for the purposes of this proceeding", and in many cases it has accepted some elements of a study but ordered changes in others.

In 1987, the Commission accepted a specific natural gas cost of service methodology, and revised the approved method in 1991. In 1993, the Commission accepted a specific electric cost of service methodology. While those methodologies are always subject to revision in future proceedings, the Commission has given increasingly clear guidance as to how costs should be classified between purposes and allocated between customer classes. Unlike some other commissions,[1] the WUTC has not adopted any administrative rules guiding the preparation of cost of service studies.

The methodologies accepted by the WUTC generally follow economic, rather than engineering, principles. Engineering-based approaches such as "fixed/variable" classification in which all fixed costs are treated as demand-related, "peak responsibility" approaches in which costs classified as demand-related are allocated on the basis of a single peak load measurement, and "minimum system" methods to classify significant portions of the distribution infrastructure as customer-related have been consistently rejected. Economic-based methodologies, including the Peak Credit method and Basic Customer method have been consistently favored.

The purpose of this exhibit is to identify the key elements of cost of service analysis, and track the history of Commission decision-making in each major area. It begins with a summary of the most recent cost of service methodologies accepted by the Commission, and then traces the history of major decisions which ultimately led to those methods.

There can be no certainty that past decisions will control future Commission actions, nor that decisions applied to one utility will be applied to other companies which may have different mixes of resources, costs, and customers. The Commission has generally not required that rates directly follow the results of cost studies, and has frequently cited other factors such as gradualism, perceptions of fairness, customer impact, and economic conditions in the service

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[1] See, e.g., Iowa Administrative Code, 199-20.10

territory as reasons to deviate from the results of cost of service studies in setting rates.[2]

For example, in 1984, the Commission specifically references a "composite" of varying studies which it found to set the parameters of "reasonableness." It further found that a 10% confidence range in the relative revenue to cost ratios for each class "seems sensible."[3]

ELECTRIC COST ALLOCATION PRINCIPLES

In 1991, the Commission directed Puget Power, the state's largest electric utility, to file a revenue-neutral cost of service and rate design proceeding.[4] Puget convened a collaborative of its residential, commercial, and industrial consumers, plus state agencies, low-income advocates and others prior to filing, but in spite of considerable progress toward consensus on some issues, ultimately the proceeding was hotly contested. The Commission made unambiguous decisions on major issues of cost allocation as follows:[5]

> **Production Plant:** Baseload generating plant and associated expenses were classified using the peak credit method, in which the ratio between costs of meeting peak demand and the total cost of a baseload facility determines the proportion of these costs to be classified as demand-related. The methodology resulted in 13% of baseload plant and expenses being classified as demand-related, and 87% being classified as energy-related.
>
> **Peak Definition:** The average contribution of each customer class to the highest 200 hours of system load was used to allocate the costs which are classified as demand-related.
>
> **Transmission:** All Transmission plant and expenses were classified in the same manner as baseload production plant and expenses: 87% were classified as energy-related and 13% as demand-related.
>
> **Distribution:** 100% of the cost of poles, conductors, and transformers were classified as demand-related, and allocated on the basis of class non-coincident demand. Classes are separated by voltage, and are allocated only those types of plant which provide service at the voltage at which they are served. Meters and service connections were classified as 100% customer-related, and allocated on the basis of customer count weighted by the typical cost of service connections for each class.

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[2] See, e.g., Cause U-78-05, Cause U-89-2688-T, Cause U-86-100

[3] Cause U-84-65, Third Supp. Order, P. 46

[4] Docket UE-901183, Third Supplemental Order

[5] Docket No. UE-920499, Ninth Supplemental Order

Administrative and General: Administrative costs related to labor, such as pensions and benefits, were allocated on the basis of allocated labor costs. Other administrative costs were allocated on the basis of total allocated O&M cost, including fuel and purchased power. [2004 note: this issue may be due for revisitation with the advent of retail wheeling service]

ELECTRIC COST OF SERVICE -- TOPICAL HISTORY

This section deals with the evolution of electric cost of service methodologies by type of plant or expense. It is intended to convey a sense of the periodic refinement of cost allocation methodologies by the Commission.

The Commission did not use cost of service studies prior to 1981. In a generic investigation of electric ratemaking begun in 1978 and concluded in 1980, the Commission considered whether to rely on **marginal** or **embedded** cost of service analyses. Commission Staff, Puget, Pacific, and the low-income intervenors advocated several different marginal cost methods, while WWP, Industrial Customers, and consumer intervenors advocated various embedded cost methods. The Commission decided in favor of the use of an approach relying on "forward-looking embedded costs" as the basis for future cost allocation decisions.[6] It has subsequently defined this concept in an evolving manner, considering evidence in numerous proceedings.

Production Costs

The major issue in allocation of production costs is the classification method used for the fixed costs, that is, what part of the costs are treated as energy-related versus demand-related. The more that costs are classified as energy-related, the smaller the proportion of costs allocated to the residential and other lower load-factor classes. A second issue has been determining which measure of demand should be used to spread the demand-related costs. Using multiple peaks (either multiple hours during the peak season, or the highest peak demand in each of multiple months) results in more costs being allocated to steady-load industrial customers than would use of a single peak.

The first consideration of a cost of service study following the generic decision in 1980 was in a Pacific Power proceeding in 1981. There, the Company proposed use of the Peak Credit methodology based on the ratio between new peaking and baseload power plants. The Commission found the Company method for classifying production costs to be "responsive" and "acceptable" but clearly left the door open to other methods.[7]

[6] Cause U-78-05, Decision and Order, P. 5

[7] Cause U-81-17, Second Supplemental Order, P. 17

Later that year, in a Puget proceeding, the Commission also accepted a study using the Peak Credit method. However, in response to a proposal by Intervenor Navy, the Commission clarified that the demand-related portion of fixed production costs should be allocated based on multiple peaks, rather than a single peak. While it accepted the average of the five winter months peak demand proposed by the Navy, it did not preclude other multiple peak methods.[8]

In 1982, WWP proposed classifying all production fixed costs as demand-related, and allocating those costs using the "average and excess demand" method. The Commission rejected this method, finding that:

> *The use of a fixed/variable cost distinction simply fails to account for the power supply needs of the company, which are predominantly energy rather than capacity.*[9]

The Commission directed WWP to prepare future studies using the Peak Credit method.

Later in 1982, Pacific Power again proposed use of the Peak Credit method. It was opposed by industrial intervenors. The Commission ruled in favor of the Peak Credit method, stating:

> *Mr. Schoenbeck's proposed allocation on a fixed/variable approach is rejected because it fails to recognize whether generation is constructed for baseload or peaking.*[10]

The next refinement of production cost allocation methods came in a 1983 WWP proceeding, where the Company complied with the Commission's directives in previous cases to use the Peak Credit method and to allocate demand-related costs based on multiple peaks. WWP classified 80% of fixed costs as energy-related, and allocated the 20% classified as demand related based on the average of the 12 monthly peaks by class. The Commission affirmed the Company's application of the Peak Credit method.[11]

In a 1984 Pacific proceeding, the Commission recapitulated all of its previous cost of service decisions, reiterated its support of the Peak Credit method and rejection of fixed/variable methods, and restated its preference for multiple peaks for allocation of demand-related costs.[12]

In a 1985 Puget proceeding, the Commission accepted a company study using the Peak Credit

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[8] Cause U-81-41, Sixth Supp. Order, P. 23

[9] Cause U-82-10, Second Supp. Order, P. 36

[10] Cause U-82-12, Fourth Supp. Order, P. 34

[11] Cause U-83-26, Fifth Supp. Order, P. 33

[12] Cause U-84-65, Third Supp. Order, P. 40

method.[13]

In a 1986 Pacific case, the Peak Credit method was not contested. Testimony focussed on the allocation method for costs classified as demand-related. The Commission ordered future examination of a non-coincident peak method for allocating the demand-related costs in light of Pacific's large off-peak seasonal irrigation load.[14] There has not been a fully litigated Pacific general rate case since 1986.

Between 1986 and 1993, the Commission did not render any substantive orders dealing with electric production cost allocation. A 1987 Pacific filing was withdrawn, several cases were settled by stipulation, and a 1989 Puget decision discussed later addressed only distribution cost allocation.
In 1992, however, following a year-long collaborative effort, the Commission heard a revenue-neutral rate design proposal by Puget. This filing was ultimately consolidated with a general rate increase filing, but the Commission issued an interlocutory order in 1993 specifically addressing technical issues of cost allocation, and gave very specific direction to the parties on classification and allocation of production costs.

The Peak Credit method was to be calculated using a factor developed by using one-half of the fixed costs of a simple-cycle combustion turbine plus expected operating costs for 200 hours as the numerator, and the total fixed and variable cost of a baseloaded combined-cycle generating plant as the denominator, in recognition that even a simple-cycle turbine can be used for seasonal capacity exchanges, hydrofirming, and other non-peak purposes. The Commission agreed that the highest 200 peak hours of the year was to be used to determine the contribution of each customer class to peak demand.[15]

The WUTC rejected proposals by industrial customers to attribute 100% of the cost of a simple-cycle combustion turbine to demand, and to focus on a narrower definition of peak than 200 hours/year.

Transmission Costs

In the early years of electric cost of service analysis in Washington (1981-83), transmission costs were heavily contested. The Commission seemed to resolve this issue in favor of the concept that transmission costs should be allocated on the same basis as production costs. Compared with 100% demand-based allocation of transmission costs, classifying a significant portion of

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[13] Cause U-85-53, Second Supp. Order, P. 59

[14] Cause U-86-02, Second Supp. Order, P. 39

[15] Docket No. UE-920499, 9th Supp. Order on Rate Design, P. 12

transmission costs as energy-related shifts costs away from low load-factor classes onto higher load-factor and off-peak classes. A 1985 Puget study which deviated from this approach was accepted by the Commission, and caused uncertainty as to the Commission's perspective. As discussed later in this section, this issue was decisively resolved in the 1992 Puget proceeding.

In a 1981 Puget proceeding, the Commission stated that:

> *Transmission costs should not be fully allocated to demand, but should be allocated to both energy and to demand.*[16]

The decision did not provide any more specific guidance on how such an allocation should be performed.

In the 1982 WWP proceeding, the Commission was more specific, stating that:

> *Classification of transmission system cost should be applied using the same principles as for production plant....The appropriate distinction between energy and capacity classification is remote production plant. Construction of baseload energy facilities at remote locations creates a need for transmission facilities which are energy rather than capacity cost related, and the classification should be so applied.*[17]

In 1982, Pacific proposed a 100% demand-based allocation of transmission costs in 1982, and was given the same general directive as WWP.[18]

This direction, however, was soon clarified. In 1982, Puget filed a proceeding in which "generation-related" transmission costs were classified on the same basis as production plant, using the Peak Credit method, while "local network" transmission costs were classified as 100% demand. Citing and affirming its previous positions, the Commission stated:

> *The Company is ordered in its next rate case to present a cost of service study that complies literally with the Commission's directive related to the allocation of transmission costs. The Commission does not intend that remote transmission costs should be allocated differently than total transmission costs.*[19]

This same directive was repeated in a WWP decision in 1983.[20]

16 Cause U-81-41, Sixth Supp. Order, P. 23

17 Cause U-82-10, Second Supp. Order, P. 37

18 Cause U-82-12, Fourth Supp. Order, P. 34

19 Cause U-82-38, Third Supp. Order, P. 31

20 Cause U-83-26, Fifth Supp. Order, P. 33

In a 1984 Pacific proceeding, the Commission reiterated that transmission costs should be classified on the same basis as production costs, and that remote transmission costs should not be treated differently from other transmission costs.[21]

In 1985, the Commission may have reversed itself inadvertently on this issue. Puget presented a study in which remote transmission costs were classified using the peak credit method, while network transmission were classified as 100% demand-related. The Commission accepted the Company's cost of service study for the purposes of that proceeding, although it made no direct reference to any specific treatment of transmission costs.[22]

A 1989 Puget proceeding also offered little guidance with respect to transmission costs. Puget again filed a study treating remote and network transmission differently, but the Commission declined to accept any of the cost of service studies presented. The only directive in the Commission’s order related to distribution costs.[23]

Most recently, in the 1992 Puget revenue-neutral cost allocation and rate design proceeding, the Commission gave very specific direction with respect to transmission cost allocation, stating:

> *Commission Staff's position conforms with our continuing belief that "distribution-related" transmission lines are constructed to deliver energy as well as to meet peak demand. Thus, we reaffirm that transmission network costs should be classified as partly driven by demand and partly by energy, using the approved Peak Credit ratio.*[24]

Transmission cost allocation has not been contested in proceedings since 1992.

Distribution Costs

The major contested issue in distribution plant allocation has been over the method used to classify and allocate the basic distribution infrastructure – poles, primary and secondary distribution lines, and line transformers. On several occasions, utilities and intervenors representing large users have advocated the "Zero-Intercept" or "Minimum-System" methods, by which 50% or more of these costs are classified as customer-related. The Commission has repeatedly rejected this approach, instead adopting the "Basic Customer" method by which only service drops and meters are classified as customer-related, and the remaining distribution

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[21] Cause U-84-65, Third Supp. Order, P. 41

[22] Cause U-85-53, Second Supp. Order, P. 61

[23] Cause U-89-2688-T, Third Supp. Order, P. 71

[24] Docket No. UE-920499, Ninth Supplemental Order on Rate Design, P. 10

infrastructure is classified as demand-related.

In Cause U-78-05, the generic rate design proceeding, WUTC staff proposed a marginal cost of service methodology which would entirely ignore so-called "customer costs," including those associated with the distribution infrastructure. The logic at that time was that marginal energy costs were so much higher than average energy costs, and were avoidable if customers used less energy, that rates should be designed to focus first on moving energy rates up to marginal cost. That proposal was rejected in favor of the use of embedded cost of service analysis.[25]

Beginning in 1982, the Commission began examining the distribution infrastructure. In a WWP proceeding that year, the Company advocated use of the minimum system method. Relying in part on Bonbright's rejection of the minimum system and zero-intercept methods[26], a low-income intervenor recommended that the distribution infrastructure be treated as "unallocable" and distributed among classes on the basis of energy usage. Both methods were rejected, but the Commission stated:

> *Although the Commission rejects the approach suggested by POWER, it is not persuaded that the minimum distribution system method presented by the company is totally correct. In the company's next study, the Commission will require further evidence concerning the methodology for allocating and classifying customer cost.*[27]

Also in 1982, in a Pacific Power proceeding, a different witness for the same consumer intervenor proposed consideration of the Basic Customer methodology. The Commission stated:

> *After extensive presentations, the Commission is aware there are reservations about the validity of each of the methodologies, but desires the opportunity to examine applications of both methods in similar circumstances to determine which may be the appropriate method for ratemaking purposes.*[28]

In this proceeding, the Commission first utilized a “range of reasonableness” in evaluating multiple cost of service studies – ordering a uniform adjustment to rates if one or more studies showed a customer class within a range of “parity,” and only ordering a differentially larger or smaller increase if multiple studies showed the class to be outside the range of reasonableness.

The Commission considered more detailed presentations on the proper way to classify and allocation distribution infrastructure costs in subsequent proceedings. In a 1983 WWP

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[25] Cause U-78-05, Decision and Order, P. 5

[26] Bonbright, Principles of Public Utility Rates, 1961, P. 347

[27] Cause U-82-10, Second. Supp. Order, P. 37

[28] Cause U-82-12, Fourth Supp. Order, P. 35

proceeding, the Commission decisively rejected the zero-intercept and minimum system methods:

> *The Commission rejects the company's use of the zero-intercept method. The minimum system method, of which the zero-intercept method is a variant, is also rejected. Both methods are likely to lead to the double allocation of costs to residential customers and over allocation of costs to low use customers.*[29]

Between 1984 and 1992 there were a number of proceedings in which the Commission rejected all cost of service studies, accepted settlements on rate spread between classes, or made rate spread decisions based on the range of studies presented. This was a period when there were major revenue and policy issues before the Commission including recovery of abandoned project costs (e.g., Skagit, WNP-3), and restructuring of power cost recovery mechanisms.

One important methodological decision on distribution plant cost allocation was incorporated in a decision in a 1989 Puget proceeding:

> *In this case, the only directive the Commission will give regarding future cost of service studies is to repeat its rejection of the inclusion of the costs of a minimum-sized distribution system among customer-related costs. As the Commission stated in previous orders, the minimum system method is likely to lead to the double allocation of costs to residential customers and over-allocation of costs to low-use customers. Costs such as meter reading, billing, the cost of meters and service drops, are properly attributable to the marginal cost of serving a single customer. The cost of a minimum sized system is not. The parties should not use the minimum system approach in future studies.*[30]

In light of this decision, in 1992 Puget proposed using the Basic Customer method to treat poles, towers, fixtures, conduit and transformers as demand-related (an approach the Commission had rejected when proposed by an intervenor in 1982), and to classify service drops and meters as customer-related. Puget indicated that, while it preferred the minimum system method, it considered the Basic Customer method reasonable given the development of a mechanism which decoupled Puget's profit margins from sales volumes in a 1990 proceeding.

Despite the unambiguous direction in the 1989 Puget proceeding against use of a minimum system method, parties representing large-volume users did advocate the use of the minimum system method in the 1992 Puget cost of service and rate design proceeding. The Commission again rejected this approach, with even greater emphasis:

> *The Commission finds that the Basic Customer method represents a reasonable*

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[29] Cause U-83-26, Fifth Supp. Order, P. 33

[30] Cause U-89-2688-T, Third Supp. Order, P. 71

> *approach. This method should be used to analyze distribution costs, regardless of the presence or absence of a decoupling mechanism. We agree with Commission Staff that proponents of the Minimum System approach have once again failed to answer criticisms that have led us to reject this approach in the past. We direct the parties not to propose the Minimum System approach in the future unless technological changes in the utility industry emerge, justifying revised proposals.*[31]

In this case, having classified the bulk of the distribution infrastructure as demand-related, the Commission then approved (without comment) a methodology which allocated these distribution demand-related costs based on the non-coincident demand of each class using plant at the relevant voltage levels.[32]

Distribution cost allocation has not been contested in proceedings since 1992.

Administrative and General Costs

Allocation of administrative and general (A&G) costs has been contested on numerous occasions before the Commission, in proceedings from 1982 forward. The author was unable to identify a single decision in which the Commission made specific findings regarding the appropriate method to allocate these costs.

The only decision which can be construed as providing guidance in this regard is the acceptance in 1993 of Puget's cost of service methodology with specific modifications requested by the Commission. In that proceeding, Puget proposed (and the study requested by the Commission did not modify) an allocation of most A&G accounts on the subtotal of O&M expense, except purchased power and fuel. Certain accounts were allocated differently: Property Insurance was allocated on the subtotal of Plant in Service; Injuries & Damages and Pensions & Benefits were allocated on the subtotal of labor expense; Franchise Requirements were allocated on an energy basis; and Regulatory Commission Expense was allocated on the basis of revenue.[33] This issue may be ripe for revisitation, given the emergence of retail wheeling as a separate class of service; when this type of service was introduced by natural gas utilities, the Commission redefined the method for allocating A&G expenses to recognize this change.

GAS COST ALLOCATION PRINCIPLES

There is not nearly the lengthy history for gas cost allocation as is presented above for electric

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[31] Docket No. UE-920499, Ninth Supp. Order on Rate Design, P. 11

[32] Docket No. UE-920499, Ninth Supp. Order on Rate Design, P. 12

[33] Docket No. UE-921262, Revised Response to Bench Request No. 515-e

cost allocation, as there are only three decisions by the Commission setting forth guidance for acceptable cost allocation methods. The first is the 1986 Cascade proceeding, Cause U-86-100, where the Commission adopted the methodology set forth by Staff in an exhibit of consultant Kimberly Herbig (modified to reflect a 100% commodity allocation of pipeline demand charges proposed by Public Counsel). The second is a WWP proceeding, Docket UG-901459, where the Commission adopted the methodology set forth by Staff in an exhibit of John Bushnell. The final case is WNG (now PSE), Docket UG-940814, in which the Commission revised it's approach to some distribution costs and to the definition of the peak period.

In 1986, Cascade Natural Gas Company filed a general rate increase. The parties settled the revenue requirement portion of the proceeding, but could not agree on cost allocation principles. The Company proposed a peak responsibility / minimum system method. Staff and industrial intervenors proposed a method which was commodity-weighted except for fixed charges from the pipeline. Public Counsel proposed a method similar to that advocated by Staff, but with a commodity-based allocation of pipeline fixed charges as well. After extensive hearings, the Commission adopted the methodology proposed by staff, with the modification to pipeline fixed costs proposed by Public Counsel.[34]

In 1990, the Washington Water Power Company filed a gas cost allocation proceeding as part of a proceeding in which it reconfigured gas transportation service. In that proceeding, the Commission approved a modification to the methodology it had relied on in Cascade, by which it specifically separated "upstream" gas supply costs from "downstream" distribution costs.[35]

In many ways the WWP decision was a refinement of the Cascade methodology. Changes were made to the allocation of baseload gas supply costs, storage costs, and administrative & general costs.

Finally, in 1994, a Washington Natural Gas proceeding resulted in a refinement of some of the principles adopted.[36]

The major issues resolved in these proceedings were as follows:

> **Production:** All baseload gas supply fixed costs in **Cascade** were treated as commodity-related costs; in **WWP** this was refined to 90% commodity and 10% demand. Peak demand is measured by a multi-year average of multiple days of peak demand.
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> **Transmission:** Neither Cascade nor WWP have any significant amount of plant in the transmission accounts. In **Cascade**, the only transmission plant was directly assigned to

[34] Cause U-86-100, Fourth Supplemental Order, P. 11

[35] Docket No. UG-901459, Third Supp. Order

[36] Docket UG-940814, Fifth Supplemental Order

an individual class. In **WWP**, it was included in the distribution plant accounts. In **WNG**, the Commission used the Peak and Average method, allocating transmission on the same basis as large-diameter distribution mains.

Distribution Mains: In both **Cascade** and **WWP**, investment in distribution mains was classified as 25% coincident demand-related, 25% non-coincident demand-related, and 50% commodity-related. In **Cascade**, actual peak demand for the test year was used to allocate demand-related costs. In **WWP**, the demand-related costs were allocated based on the 3-year average of 5-day sustained peak demand. In **WNG**, a "Peak and Average" method was utilized for classifying mains.

Meters and Services: In both the **Cascade** and **WWP** proceedings, meters and services were classified as 50% customer-related, 25% demand-related, and 25% commodity-related. Proposals by the companies to classify these as 100% customer-related were rejected. In **WNG**, meters and services were classified as 100% customer-related by the Staff, and that study was accepted by the Commission without specific comment.

Administrative and General Costs: In **Cascade**, A&G costs were allocated based on total expenses by class, including the cost of gas for all classes (sales and transportation). In **WWP** this was refined to reflect the availability of transportation service. Labor-related A&G costs (pensions and benefits) were allocated based on directly allocated labor expense; plant-related A&G costs (property insurance) were allocated based on directly-allocated plant costs; all other A&G accounts were allocated 50% based on throughput, and 50% based on O&M expense other than purchased gas cost. This method was retained in WNG.

Three other proceedings considered -- but did not resolve -- cost of service issues. In a 1986 WNG tracker, the Company proposed a reallocation of costs based on a cost of service study. The Commission rejected the concept of reallocation in a tracker without addressing specific issues of cost allocation.[37] A 1988 WWP proceeding included a Company cost of service study using a methodology different than the Cascade methodology. The Commission rejected that methodology, reaffirming the Cascade decision.[38] Finally, in a 1992 WNG proceeding the Commission rejected all of the cost of service studies. It also rejected a rate spread approach based upon a Company-advocated cost of service methodology, and accepted the Staff's rate spread proposal which in turn was based upon the Cascade/WWP methodologies.[39]

[37] Cause U-86-117, Third Supplemental Order, P. 6

[38] Cause U-88-2380-T, Third Supplemental Order, P. 35

[39] Docket No. UG-920840, Fourth Supp. Order, P. 34; P. 42-44

GAS COST OF SERVICE -- TOPICAL HISTORY

The only differences between Cascade and WWP related to the treatment of baseload gas supply costs, the inclusion of storage as a separate category of costs, and the method used for allocating administrative and general costs. However, the methods proposed originally by the two utilities were very different, and the manner in which the Commission addressed those proposals is perhaps of greater importance than the minor changes in the results.

Production Costs

In the 1986 Cascade proceeding, the Company proposed to classify pipeline ODL-1 D-1 demand charges as demand-related, while D-2 and commodity charges were classified as commodity-related and allocated on a throughput basis. At that time, separate transportation service was not generally available. Public Counsel argued that the Company was in capacity surplus and that therefore all baseload gas supply fixed costs (at that time, ODL-1 Demand Charges) should be classified as commodity-related and allocated over all throughput volumes <u>including transportation.</u> The Commission stated:

> *After a review of the cost of service studies submitted, the Commission finds most reasonable the [Staff] Johnson/Herbig study, with one modification. The treatment of D-1 costs should be modified to conform with the position of Public Counsel. That is, D-1 costs should be shared by all classes that use gas delivered through the pipeline, including interruptible customers.*[40]

Circumstances were different in the 1990 WWP proceeding, as WWP had reduced its peak demand on the pipeline, and did not attempt to include excess capacity in the overall cost allocation scheme. However, WWP did propose to classify those pipeline demand charges it did include in rates as 100% demand-related.

Staff proposed instead to use the equivalent of the Peak Credit method long used in the electric industry to classify these demand charges, whereby only the portion of demand charges equal to the fixed costs associated with a peaking resource would be treated as demand-related. It proposed that 90% of these costs be classified as commodity-related.

WWP proposed to allocate pipeline demand charges based on the single cold-day peak experienced on February 2, 1989. Public Counsel objected to the single-day peak determination, arguing for a multi-day definition of peak demand.

The Commission accepted the staff cost of service approach, but ordered the use of a 5-day sustained peak, averaged over three years, as the basis for assignment of those costs which were determined to be peak-related, stating:

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[40] Cause U-86-100, Fourth Supp. Order, P. 11

> *The Commission rejects the company's proposal to allocate demand-related costs on the basis of a single peak day. A figure averaging several days for several years is more likely to avoid wide swings from year to year due to unusual weather conditions that are unlikely to occur frequently.*[41]

In 1994, the Commission revised this from using the five-day period with the highest demand in each of the past three years to using the five highest days, whether consecutive or not. It again rejected the use of "design day" criteria. In doing to, it recognized that this would, at times, use data that did not include extreme weather, stating:

> *The average peak proposed will vary over time, but will reflect customer class growth and changing real-world usage patterns including test-year weather. The proposed averaging will moderate wide swings. This proposal best reflects various classes' actual peak usage of the WNG system.*[42]

In WNG, this was further refined, using a "Base-Intermediate-Peak" methodology. This approach treats all baseload production costs (both pipeline service and gas supply costs) as predominantly commodity-related, intermediate resources such as seasonal storage are classified more significantly to demand, and peaking resources such as LNG and Propane-Air facilities are treated as peak-demand related. This approach has been used in tracking proceedings for all utilities since the mid-1990's.

Storage Costs

Cascade did not own any storage plant at the time of the 1986 proceeding, but did own some propane-air facilities; these were excluded from rates as part of the revenue requirement settlement in U-86-100. The amounts were small and did not materially affect the results.

WWP (now Avista) owns one-third of the Jackson Prairie storage facility, and indicated that it used that plant for balancing, seasonal cost-shaving, and other purposes. In the WWP case, the costs of storage were classified by the Company as 22.73% demand-related and 77.27% commodity-related based on the ratio between the average number of days of expected interruption of interruptible customers and the storage capacity of the field at maximum daily dispatch. Staff supported this classification, but for different reasons. The methodology was accepted without specific comment by the Commission.

The demand-related portion of storage costs were allocated by WWP solely to firm sales customers; the commodity-related portion was allocated to all sales service but not to transportation customers. With the exception of the definition of "peak" discussed above under

[41] Docket No. UG-901459, Third Supp. Order, P. 8

[42] Docket UG-940814, Fifth Supplemental Order, P. 8

Production, this was also accepted by the Commission without comment as well. In WNG, a portion of storage costs was allocated to transportation customers, reflecting the costs associated with providing balancing service to these customers.

Distribution Costs

In Cascade, the Company proposed to use the minimum-system method to classify distribution mains between demand and customer, resulting in 53% of these costs classified as demand-related and 47% classified as customer-related. Staff proposed classification 25% on the basis of coincident peak, 25% on non-coincident peak, and 50% commodity. For meters and services, the Company proposed a 100% customer classification. Staff proposed classifying meters and services 25% commodity, 25% non-coincident peak, and 50% customer-related. The Commission accepted the staff study without specific comment on this issue.

In WWP, the Company proposed direct assignment of distribution plant to large volume customers, with the balance classified as demand-related, and allocated on the cold-day peak methodology described above under Production. Staff proposed continuation of the Cascade methodology.

The Commission rejected the direct assignments proposed by the Company, stating:

> *Removing and directly assigning plant only for a select group of customers with lower costs is not consistent with the embedded cost class allocations underlying the rest of the company study. As described by Public Counsel on brief, direct assignment could be considered to be cost-based only if it were applied to the entire utility rather than to one customer with competitive alternatives.*[43]

In accepting the Cascade methodology for allocation of distribution plant a second time, the Commission took notice of one piece of testimony which it footnoted:

> *As discussed by company witness Mr. Mitchell on cross-examination, increasing the size of a main by 100 times increases the cost by a factor of less than three times.*[44]

In the body of the decision, the Commission then stated:

> *Although the company provided engineering testimony about the design of distribution systems, this information does not lead automatically to the company's conclusions. The cost of a main does not increase proportionally as the size of the main is increased. The system was built to deliver gas daily. Cost-of-service analysis thus should reflect the fact*

[43] Docket No. UG-901459, Third Supp. Order, P. 7

[44] Cause UG-901459, Third Supp. Order, P. 8

that fixed costs are incurred for the company to deliver gas year-round, not just on a peak day. The Staff's allocation proposal recognizes this.[45]

In Cascade and WWP, the Commission accepted the methodology for allocation of distribution costs proposed by Staff. In a 1992 WNG proceeding which was proposed as a rate increase, but ultimately resulted in an overall rate decrease, Staff proposed the same methodology, while the Company presented a peak responsibility / minimum system based study. Public Counsel supported the Staff methodology, but presented a separate study on calculation of customer costs, which included 50% of meters, services, meter reading, billing, and associated A&G expenses as customer-related.

The Commission rejected all of the studies in the proceeding, in large part because they did not separate transportation costs from gas supply costs, but then spread rates between classes based generally on the approach proposed by Staff. The Commission did provide guidance on one issue in the WNG proceeding, the determination of the level of customer-related costs:

The reduction to residential rates should be equal to the system average, with the reduction first applied to reduce the customer charge from $4.51 to $4.00, on the basis of Public Counsel's cost analysis. Any further reduction should be applied to the commodity rate.[46]

Administrative and General Costs

Administrative and general costs were heavily contested in both the Cascade and WWP cases. In both proceedings, the Commission decided to allocate about half of A&G expenses on the basis of throughput, and about half on the subtotal of non-gas O&M costs, but used different methods to reach the same end.

At the time of the Cascade case, cost of service for all classes was computed in a manner which included gas supply costs. The Company proposed to allocate A&G costs on the subtotal of all O&M expense for each class, less purchased gas cost. Given the Company's minimum-system distribution plant classification methodology, this effectively resulted in the classification of these costs as about 4% commodity-related, 20% demand-related, and 76% customer-related. Staff proposed that A&G costs be allocated on the basis of the subtotal of all O&M expenses <u>including</u> gas costs; the net effect of this is to classify these costs as about 70% commodity-related, 15% demand-related, and 15% customer-related. The Commission accepted the Staff proposal without specific comment on this issue.

In WWP, gas costs were not included in the calculation of cost of service for the transportation

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[45] Docket No. UG-901459, Third Supp. Order, P. 8

[46] Docket No. UG-920840, Fourth Supp. Order, P. 42

customers. The Company proposed a different approach from either that advocated by Cascade or adopted by the Commission, allocating most A&G costs on the basis of the subtotal of labor expenses allocated to each class. Since the largest component of labor on a gas system is meter reading and billing, this approach also resulted in the vast majority of A&G expenses being effectively classified as customer-related. Staff proposed that the Company's labor method be used for those A&G costs which are directly labor-related (pensions and benefits), that property insurance be allocated on the basis of allocated plant, and that franchise and regulatory expenses be allocated on the basis of revenue. Staff allocated the remaining items, which constitute the majority of A&G expenses, 50% on the basis of throughput, and 50% on the basis of total O&M less cost of gas by class. Since gas costs were about 50% of total O&M on the Cascade system, this method produces very similar results to the method accepted by the Commission in Cascade. The Commission accepted the Staff proposal without specific comment on this issue, and it has been used since that time.

SUMMARY

The discussion above seeks to capsulize twenty-five years of Commission decisions on electric and gas cost allocation. By doing so, major elements of testimony and exhibits contributing to those decisions has been passed over very lightly. In these decisions, the Commission has been fairly consistent on several issues. First, "cost of service" is only one of many considerations which go into rate spread and rate design decisions; issues such as customer impact, gradualism, perceptions of equity and fairness and other factors are given weight as well. Second, facilities used throughout the year are to be allocated among the classes primarily on measures of annual usage. Third, the definition of "customer costs" should be very narrow, dealing only with costs such as meters and meter reading which rise and fall with the number of customers, and do not include the distribution infrastructure for either electric or gas distribution systems.

The author has attempted to be objective in presenting the results of these proceedings, and any subjective comment or selective citation is solely the responsibility of the author. The full testimony, exhibits, and briefs for each of these cases are available for review in the WUTC archives. The full text of each order is available from the Commission Records Center (P.O. Box 47250, Olympia, WA 98504).