Re Methods for Estimating Marginal Cost of Service for Electric Utilities

UM 827
Order No. 98-374
188 PUR4th 455

Oregon Public Utility Commission
September 11, 1998

ORDER approving a stipulated change in the method used to reconcile the marginal cost of electric service with revenue requirement.

The stipulation provides that marginal cost and revenue requirement should be reconciled on a functional basis — i.e., separated into generation, transmission, and distribution components and then reconciled on a functional basis to calculate class revenue requirement responsibility. Historically, the commission has reconciled marginal cost and revenue requirement so that each customer class pays an equal percentage of marginal cost. The stipulation changes the allocation method to equal percentages of marginal cost by function.

Commission finds that the adopted reconciliation approach will improve its historical efforts to allocate cost responsibility to customer classes in ways that lead to more efficient price signals and more efficient use of electric service. It also determines that the new reconciliation approach will improve rate fairness by ensuring that the costs of one function (e.g. distribution) do not affect the allocation of the cost of another function (e.g., generation). Moreover, the commission finds that reconciliation on a functional basis will provide valuable information as to whether and how electric service should be provided on an unbundled basis.

Commission declines to require a single marginal cost approach for all utilities, noting that the calculation of marginal costs is as much an art as it is a science.

The facilities design and minimum system approaches are deemed reasonable methods for calculating marginal distribution costs.

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1. RATES, § 321

[OR.] Electric rate design — Allocation of cost responsibility to customer classes — Reconciliation of marginal cost and revenue requirement — Functional allocation. p. 458.

2. APPORTIONMENT, § 23

[OR.] Expenses and costs — Electric utilities — Allocation of cost responsibility to customer classes — Functional allocation. p. 458.

3. ELECTRICITY, § 1

[OR.] Industry restructuring — Rate unbundling — Allocation of cost responsibility to customer classes — Functional allocation. p. 458.

4. MONOPOLY AND COMPETITION, § 54

[OR.] Electric restructuring — Rate unbundling — Allocation of cost responsibility to customer classes — Functional allocation. p. 458.

5. APPORTIONMENT, § 23

[OR.] Expenses and costs — Electric utilities — Distribution costs — Methods of calculating marginal cost — Minimum system approach — Facilities design approach — Zero intercept approach. p. 458.

6. APPORTIONMENT, § 11

[OR.] Distribution costs — Methods of calculating marginal cost — Minimum system approach — Facilities design approach — Zero intercept approach — Electric utilities. p. 458.

7. RATES, § 262

[OR.] Cost elements — Marginal distribution cost methodologies — Minimum system approach — Facilities design approach — Zero intercept approach — Electric utilities. p. 458.

8. RATES, § 262

[OR.] Computation of marginal costs — Administrative and general expense — Loaders — Electric utilities. p. 463.

9. RATES, § 262

[OR.] Computation of marginal costs — Generation costs — Use of avoided cost methodologies — Electric utilities. p. 464.

10. RATES, § 262

[OR.] Computation of marginal costs — Transmission costs — Electric utilities. p. 464.

11. RATES, § 262

[OR.] Computation of marginal costs — No single approach required — Electric utilities. p. 465.

12. RATES, § 143

[OR.] Reasonableness — Cost of service — Calculation of marginal costs — Electric utilities. p. 465.

Before Eachus, chairman, and Hamilton and Smith, commissioners.

BY THE COMMISSION:

Executive Summary

In this order, the Commission:

1. Approves a stipulation that marginal costs and revenue requirement should be reconciled on a functional basis;

2. Approves the principles underlying the marginal cost studies presented by Portland General Electric Company (PGE), PacifiCorp, and Idaho Power Company (IPCO);

3. Approves the use of the facilities design approach for calculating marginal distribution costs;

4. Does not require a single marginal cost methodology; and

5. Requires utilities to study how variations in certain costs vary with demand, customer counts, and other factors.

Procedural History

On December 30, 1996, the Commission issued Order No. 96-337 initiating an investigation into "various methods for determining generation, transmission, and distribution marginal costs." We noted that studies submitted by Portland General Electric Company and PacifiCorp in recent rate cases indicated that residential customers pay a smaller share of the marginal cost of service than industrial customers. The Citizens' Utility Board challenged this result, arguing that the methods used to classify distribution costs as demand related or customer related assign too much cost to residential service. We also anticipated that this proceeding would result in an order adopting various methods for determining generation, transmission, and distribution marginal costs. We noted that utility-specific marginal cost estimates and rate spread and rate design decisions would be made in subsequent rate cases and other proceedings as needed.

During the course of this proceeding, we granted intervenor status to the parties listed in Appendix A. Initial rounds of testimony were filed April 7, 1997. A protective order was issued

May 14, 1997. On May 30, 1997, Administrative Law Judge (ALJ) Thomas Barkin granted Staff's motion to delay the schedule in the proceeding until after the close of the legislative session. On July 9, 1997, ALJ Ruth Crowley denied a motion by Idaho Power Company to suspend discovery. In addition, she denied a motion by the Oregon Committee for Equitable Utility Rates, the Oregon Committee for Fair Utility Rates, and the Industrial Customer of Idaho Power of Oregon to vacate the docket.

On July 30, 1997, ALJ Barkin held a preheating conference. Several parties filed briefs on the Citizens' Utility Board's (CUB's) motion to expand the scope of the docket to include the impact of special contracts on allocation of costs. On August 7, 1997, ALJ Barkin issued a memorandum, ruling, and schedule for the initial stage of the proceeding. The ruling denied a renewed motion to vacate the proceeding.

On October 3, 1997, several of the parties met to identify the issues and propose a schedule. On November 10, 1997, ALJ Barkin adopted a pretrial order memorializing the parties' agreement that the following issues should be addressed in this proceeding:

1. Should reconciliation (comparing marginal cost and embedded cost or revenue requirement) be done on a functionalized basis?

2. How should unit marginal costs be developed?

In addition, the ALJ rejected CUB's and Northwest Conservation Act Coalition's (NCAC's) motion to consider the impact of special contracts on the allocation of costs between customer classes. The pretrial order also set forth a new schedule for filing additional testimony and hearings.

On April 14, 1998, based on the recommendations of the parties, ALJ Barkin issued a memorandum setting forth the procedure for the hearing. The hearing was held on April 21, 1998. The parties entered into the record a stipulation, all prefiled testimony, and the responses to certain of PGE's data requests.[1(1)] There were no requests for cross-examination. The evidence was received into the record. Briefing closed on June 6, 1998.

Reconciliation on a Functional Basis

[1-4] PGE, PacifiCorp, IPCO, Staff, CUB, NCAC, Pope & Talbot, Industrial Customers of Northwest Utilities (ICNU), and PG&E Energy Services (PG&E) stipulated that marginal costs and revenue requirement should be reconciled on a functional basis.[2(2)] That means that the marginal costs and revenue requirement should be separated into generation, transmission, and distribution components and then reconciled on a functional basis to calculate class revenue requirement responsibility. The stipulation is attached as Appendix B. Table 1 to the stipulation illustrates that allocating revenue requirement to recover equal shares of total marginal cost for bundled services versus equal shares of marginal cost by function can produce different results.

We have reviewed the stipulation and find it reasonable. Since 1974, the Commission has used marginal costs as one of the principal factors for spreading revenue requirement among customer classes. Order No. 74-658. Historically, we have reconciled the two so that each customer class pays an equal percentage of marginal costs. Adopting this stipulation will change the allocation method to equal percentages of marginal cost by function. This new approach will improve our historical efforts to allocate cost responsibility to customer classes in ways that lead to more efficient price signals for customers and efficient use of electrical service. It will also improve fairness in our rates by ensuring that the costs of one function (e.g., distribution) do not affect the allocation of the costs of another function (e.g., generation). Finally, adopting this stipulation will provide us valuable information when we consider whether and how electric service should be provided on an unbundled basis.

Development of Unit Marginal Costs

Marginal Cost Studies in the Proceeding

The parties generally agree that prices for electrical service should reflect marginal costs. According to PGE witness Hethie Parmesano:

> A marginal cost study should answer the question: How would the utility's costs change if it were to supply an additional kWh or kW at a particular time or service an additional customer? The study is forward looking and must take into account the practices and planning standards of the particular utility, as well as its incremental structure and cost of capital, regulatory constraints, tax liabilities, etc.

Ex. PGE 200 at 3.

Proper calculation of marginal costs provides proper price signals to customers, which, in turn, can lead to more efficient consumption.

PacifiCorp, IPCO, and PGE submitted marginal cost studies. Each study separates marginal costs into distribution, transmission, and generation marginal costs. The methodologies used in PacifiCorp's marginal cost study are essentially the same as those filed in UE 94, updated to reflect recent costs. The study was submitted by David L. Taylor, Cost of Service Manager, PacifiCorp. IPCO submitted the marginal cost study that it had submitted in UE 92, its most recent rate case. In addition, it submitted another study that included embedded cost information separated into power supply, transmission, and distribution categories. Both studies were submitted by Patricia Nichols, Senior Analyst, Resources Planning Department, IPCO. PGE submitted a marginal cost study prepared by Sara Cardwell, Manager of Tariff Administration, PGE, that was reviewed by Hethie Parmesano, Vice President, National Economic Research Associates, Inc. (NERA).

Marginal Distribution Cost Methodologies

Overview

[5-7] The parties presented three approaches for calculating the marginal cost of certain distribution facilities. PGE uses the facilities design approach. ICNU and Pope & Talbot support this approach. PacifiCorp and IPCO presented marginal cost studies based on the minimum system and zero-intercept approaches. CUB recommended the Commission adopt the zero-intercept approach.

In this order, the Commission concludes that the facilities design approach and the minimum system approach are reasonable methodologies for calculating marginal distribution costs. The zero-intercept approach can be used in limited circumstances, but is not sufficiently robust to be used for all distribution cost calculations.

Minimum system approach

PacifiCorp uses the minimum system approach for calculating the marginal cost of poles and conductors. The minimum system approach is based on a hypothetical system where equipment is of the minimum size necessary to meet the load. Distribution costs are classified into demand related (dollars per kW/year) and customer related (dollars per customer/year). Demand-related costs include the additional costs of larger poles and conductors with sufficient capacity to serve the level of demand a customer class places on the system over different time periods. Customer costs include commitment-related and billing-related costs. Commitment costs consist of the costs of transformers, poles, and conductors that are not determined by the level of customer demand. Billing costs include the costs of meters, service drops, and customer accounting functions.

PacifiCorp's minimum system approach employs a hypothetical Distribution Feeder Model, which considers customer characteristics, such as density, size, usage, and customer location on the feeder. Pole and conductor marginal costs are split between demand and commitment.[3](3) Marginal substation costs are all classified as demand related. The costs are developed based upon the historical ratio of substation investment to pole and conductor investment. Billing-related costs include the marginal and operations and maintenance (O&M) costs of the service drop and metering, and customer accounting and informational expenses.

Facilities design approach

PGE's marginal cost study recognizes three categories of distribution costs: customer, demand, and design demand. Customer marginal costs include the carrying costs of the meter and service drop, O&M expenses, and other customer-related costs.[4](4) Demand-related costs are primarily comprised of the carrying costs of distribution substations and associated O&M costs, which increase as actual load grows.

The design demand category recognizes a unique category of distribution costs that are neither customer related nor (metered) demand related. The facilities design approach, as used by PGE, attempts to track the utility's actual distribution planning process in the marginal cost study. To calculate marginal costs, the investigator asks distribution planners how they design the system, what criteria they use, and what the costs are of components they specify in the plans. The facilities design approach is used to calculate the cost of distribution elements that are sized to serve maximum expected loads (design demand) of the customers in the area over the life of the equipment. According to PGE, the planners' expectation is that these components will not be changed even if a customer's actual load grows. ICNU and Staff point out that the costs of conductors, poles, and transformers do not vary with the number of customers or actual usage. The design standards used by the planners include enough reserve capacity to accommodate changes in actual loads.

The facilities design approach includes primary and secondary lines, utilization transformers and associated carrying costs, and O&M expenses. PGE calculates marginal costs by dividing the investment in typical feeders by the design demand on those feeders, annualizing the cost per kilowatt (kW) or per kilovolt-ampere (kVa), and adding O&M, administrative and general (A&G), and general plant expenses. In the study, the costs are expressed in dollars per kVa of design demand, not per customer. Marginal revenues are calculated by multiplying the unit design demand cost by the sum of the total design demands for a customer class.[5(5)]

Pope & Talbot supports using the facilities approach as long as the actual changes in the customer makeup and the system occurring over time are included.

ICNU listed a number of factors that it claims should be included in a facilities design study. It claims that the costs should be based on the basic system, as opposed to more costly components used to serve a few customers. For example, overhead feeder service should be considered the basic system. Underground facilities should be considered separately. CUB agrees that, if the Commission adopts the facilities approach, it should require PGE to base its calculations on a basic system. It asserts that utilities should not be allowed to assign costs of expensive alternative facilities to customers who neither desire nor use them.

PGE observes that the reference to the basic system is ill defined. Underground service is a part of the basic service that utilities usually address in line extension policies. Furthermore, ICNU's proposal presupposes a particular system configuration. PGE points out that it is inaccurate to assume that the majority of new distribution lines are being built overhead and not underground. Such an assumption would misstate the PGE building practices that the facilities design approach is intended to emulate.

ICNU also asserts that a facilities design study should account for variations in customer classes, including geographic and load profile differences. PGE notes that ICNU has not provided evidence showing that geographic profiles beyond what is reflected in the facilities design and minimum system approaches would affect cost allocations in marginal cost studies.

In addition, ICNU asks that historic, weather adjusted data be used to reflect system peaks. PGE believes that consideration of historical costs would violate the Commission's requirement that the company use future test years. Further, PGE notes that ICNU has not described how weather conditions would be factored into a marginal cost study. Finally, ICNU asks that the full marginal impact of changing and maintaining existing facilities should be considered.

CUB's objections

CUB objects to the treatment of customer costs in the minimum system and facilities design approaches. CUB asks the Commission to prohibit utilities from using the facilities design approach. CUB also asks for limited use of the minimum system method because some demand-related costs are included in the customer component. CUB is concerned that customer-related costs not include any costs that vary with usage. It believes that the minimum system approach includes fewer demand-related costs in the customer component than the facilities design approach.

CUB claims that some of the costs included in the customer component are sunk costs and should not be included in a marginal cost study. CUB argues that marginal customer costs are only relevant to new customers. If such costs are considered marginal costs, CUB argues that the marginal cost should be lower than the cost of new meter and service drops, since existing customers did not buy their meter and service drops at current costs.

PGE and PacifiCorp disagree with CUB's assertion that the carrying costs of existing meters and service drops are sunk costs. According to PGE and PacifiCorp, these costs were marginal when first installed. Because the costs were not recovered at the time of installation, but were expected to be recovered over time, they should be included in marginal costs. PGE notes that the implication of adopting CUB's proposal is that utilities should collect the costs of meters and service drops up front. Such a proposal would impose sizable new costs on new customers and would increase the gap between marginal cost revenues and the utility's revenue requirement to be dealt with in the rate design.

PGE and PacifiCorp also point out that O&M and replacement costs of existing facilities are marginal. If a customer discontinues service, the utility can avoid a host of costs, including the cost of operating and maintaining the meter and drop, repairing the facilities, and billing, collecting, and meter reading. ICNU notes that, if existing facilities were not accounted for, this would suggest that the utility does not incur expenses to repair and maintain the facilities.

In addition, PGE notes that some of the local distribution facilities, such as meters and transformers, can be reused for new customers once an existing customer discontinues service. This means that a customer's decision to remain on the system imposes an opportunity cost. The utility has to purchase additional equipment for a new customer rather than reusing the equipment of an existing customer. Finally, if a customer's design demand does increase, the utility will likely have to provide additional distribution facilities. These costs are marginal and proper pricing requires that the costs be reflected in the portion of the rates that varies with design demand.

CUB is concerned that if the Commission does not expressly conclude that design demand-related costs are fundamentally demand related, there will be pressure to treat demand design costs as customer costs. CUB asks that, if costs computed under the facilities design approach are included in marginal cost studies, the costs should be recovered on a usage-related basis, not a fixed charge.

Staff disagrees with CUB's analysis. Staff's explains:

> ... Design demand is not the same as measured demand (which reflects actual usage). It looks like a customer cost because it does not vary with usage, but it is different for different types of customers (e.g., residential customers with and without space heat). CUB considers costs caused by design demands to be customer costs because it claims they are treated like customer costs in calculating `marginal revenues' (revenues collected at marginal costs prices). As a result, CUB concludes that the facilities approach shifts demand-related costs into the customer component.
>
> CUB is incorrect about the treatment of costs related to design demand. PGE expresses the facilities costs in terms of \$/kW of design demand (not \$/customer) and multiplies them by the total design demands for each class (not the number of customers) to obtain marginal revenues for the class. PGE properly relates the costs of distribution lines and transformers to design demands instead of assigning them to the customer or (measured) demand components. The facilities approach should be preferred to the minimum system and zero-intercept approaches, which do not directly link line and transformer costs to the characteristic that determines those costs — design demand. *Citations omitted.*
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> Staff Opening Brief, at 1-2.

CUB also recommends that the Commission require utilities to conduct an analysis that does not include marginal customer costs and compare the results of any analysis that does. It proposes that the Commission give weight to both results in setting class revenue requirements. CUB proposes this study so the Commission will be fully aware of the influence the facilities approach has on increases in customer costs, and potentially, customer charges.

Staff and PacifiCorp oppose this proposal. PacifiCorp notes this would inappropriately shift costs from small to large customers. PacifiCorp points out that customer costs must be recovered in the revenue requirement under any circumstances. CUB's proposal would send the wrong price signals by including customer costs in rates based on usage.

Zero-intercept approach

CUB recommends the zero-intercept approach. This model is a linear regression model that calculates the customer-related portion of the marginal distribution costs when demand is zero. The demand portion is based on the slope of a line that represents the change in the cost for distribution facilities as demand increases. One of the limitations of the zero-intercept model is that data are not always available. However, CUB witness John Stutz argues that whenever data are available, or can be developed, the zero-intercept approach should be used. CUB recommends that the Commission require the minimum system approach when the zero-intercept approach cannot be used for lack of data or other reasons.

PacifiCorp uses the zero-intercept approach when calculating the marginal cost of distribution line transformers. However, PacifiCorp concludes that broader application is not justified because necessary data are not always available and the results do not necessarily make economic sense. For example, the zero-intercept approach sometimes yields results indicating a utility has negative customer costs. PacifiCorp also notes that CUB's recommendation to use the zero-intercept approach has the potential of shifting customer-related costs to the demand component.

ICNU argues that the zero-intercept approach is theoretically incorrect and too limiting. It complains that this method does not allow for inclusion of certain costs borne by the utility which are customer related, such as the cost of maintaining existing systems. ICNU also notes that the method reflects only very short-term impacts and does not include a utility's general and overhead expenses that vary directly based on the number of customers. The approach would not include the costs associated with hiring additional employees to read meters or process bills. Because data are not always available, ICNU notes that utilities would be required to maintain two different marginal cost systems.

Commission Decision

We conclude that the facilities design and minimum system approaches are reasonable methods for calculating marginal distribution costs. The minimum system and facilities design approaches categorize the costs of the distribution system that are dedicated to specific groups of customers at the time of installation. These costs are not affected by actual usage and do not benefit from the diversity of system-wide or feeder-wide load. The minimum system approach identifies these costs as a function of the number of customers on the system. In contrast, the facilities approach identifies these costs as a function of the expected peak demand of the customers to be served. Regardless of the approach, dedicated facilities are matched to the requirements of the specific customers.

The minimum system approach has been used in Oregon for many years. The evidence in this record has not convinced us that we should abandon this approach or limit its applicability. As for the facilities design approach, PGE makes a compelling argument that distribution marginal costs should be based on the decisions of system planners who design the distribution system. This is a reasonable way to allocate costs based on cost causation. Furthermore, we reject CUB's assertion that design demand costs are usage related. The costs do not vary with the number of customers or with actual usage.

We also reject CUB's argument that metering and billing costs are sunk and, therefore, should not be included in a marginal cost study. PGE and PacifiCorp demonstrated that the costs of these components should be considered in a marginal cost study. There are repairs, maintenance, upgrades, and opportunity costs that require expenditures at the margin by the utility. These costs are appropriately included in the marginal cost study.

We agree with PGE's recommendation to reject ICNU's proposals to modify the facilities design approach. ICNU's proposals regarding the base system, geographic and load profiles, and historic and weather data are too vague to be incorporated into a marginal cost analysis without considerable study. At this point, we do not have a reasonable basis for requiring PGE to undergo extensive studies to determine whether these additional variables actually impact distribution system planning. We assume that Pope & Talbot's concerns about considering actual changes in the customer makeup and the system over time are incorporated into the facilities design approach. These factors would appear to be relevant to system planners, as long as they are considered on a forward-looking basis. These parties may raise these issues in rate cases where the facilities design approach is used.

We will not require utilities to use the zero-intercept approach. The approach is appropriate for some purposes, such as distribution line transformers, but cannot be applied broadly. CUB itself admits that data are not always available. Furthermore, the zero-intercept approach does not fully consider the costs that customers impose for distribution systems.

Furthermore, we will not require utilities to conduct studies excluding marginal customer costs. CUB's proposal reflects concern over the impact of particular approaches on cost allocations between classes. Its proposal suggests that our decision on marginal cost methods should be result oriented. We reject that proposition. Marginal cost studies should be designed to measure as accurately as possible the costs associated with providing service. Possible adverse impacts on customer classes from cost allocations based on those marginal cost studies should be addressed in the rate design phase of a rate case. CUB may raise its concerns in a future rate proceeding.

PGE recommends the Commission strike Pope & Talbot's initial comments that included an example of changes in utility service territory. We see no harm in the example and will not grant PGE's motion.

Loaders

[8] Loaders are factors used to include A&G expenses and general plant costs as part of the computation of marginal costs. A&G costs include managers' salaries, office supplies and equipment, injuries and damages, employee pensions and benefits, social security and employment taxes, property insurance, regulatory expenses, and maintenance of general plant. General plant includes such expenses as office space, cars and trucks, computers, and office furniture. PGE, PacifiCorp, and IPCO include loaders in the calculation of their marginal customer cost calculations. Pope & Talbot and ICNU agree that loaders should be included in the calculation of marginal costs.

Most items included in the calculation of marginal cost relate to supplying an additional kWh, meeting an additional kW of demand, or adding an additional customer to the utility's system. CUB claims that loaders reflect costs not directly related to energy usage, demand, or the number of customers.

CUB argues that the Federal Energy Regulatory Commission (FERC) accounts for loader type costs do not identify the costs as customer related. In addition, it claims that these accounts are designed to capture costs that cannot be assigned to other accounts. CUB contends that there is no reason to assume these costs are customer related.

CUB asks the Commission to require each utility to demonstrate the marginal nature of the costs included in its loaders, before it is permitted to use the loaders in its marginal cost study. CUB wants the utilities to show how successive annual differences in each of the costs included in their loaders vary directly with the successive annual differences in the number of customers over a period of years. ICNU argues that the analysis proposed by CUB would not capture the indirect and longer run impacts of changes in usage or customer count.

PGE disagrees with CUB's reading of the FERC accounts. It notes that studies of other utilities show that loader costs are marginal. PGE also explains that the number of customers determines the number of meters to be read and, therefore, the costs, in terms of employees and the associated overhead, of reading the meters. PacifiCorp has conducted its own study indicating that general plant and A&G expenses increase over time along with customer and load growth. However, PGE does not object to conducting further studies.

PacifiCorp and IPCO assert that loaders do not significantly affect cost allocation, because the loaders are applied as a percentage of investment. They claim that costs increase uniformly for all customer classes. Staff points out that PacifiCorp included loaders for its plant and nonplant costs. It notes that applying different loading factors will affect the relative marginal costs of different customer classes if the classes do not have the same proportions of plant and nonplant costs. These differences would affect rate spread.

IPCO ask the Commission to consider the costs and benefits of requiring the studies that CUB proposes. IPCO argues that its limited presence in Oregon should be considered in the Commission's determination of the need for, and degree of, complexity demanded for the loader studies.

Staff agrees with CUB that utilities should examine this issue further. Logical arguments about the effects of A&G and general plant costs are not sufficient. Staff also agrees with ICNU on the importance of recognizing indirect and long run impacts in the analysis. Staff proposes that all utilities be required to conduct studies of how loaders and A&G expenses should be used in marginal cost studies. Specifically, it recommends that utilities submit studies demonstrating how variations in A&G and general plant costs follow variations in demand, customer counts, and other factors, including long run or indirect impacts. These studies should be included in the utility's next marginal cost study. PGE does not oppose reviewing alternative methodologies for determining marginal A&G and general plant costs in order to fine-tune its cost studies.

Commission Decision

Regarding the use of loaders in marginal cost studies, we agree with Staff and CUB that PGE, PacifiCorp, and IPCO should conduct more extensive studies to determine whether usage and other factors affect changes in A&G and general plant expenses. As Staff points out, the effect of loaders on cost allocation is not necessarily neutral, as PacifiCorp and IPCO claim.

Customer classes that use different proportions of plant and nonplant will be allocated different proportions of the loader costs. We agree with Staff's conclusion that if marginal costs are used to allocate embedded costs or revenue requirement (rate spread), the result may well be affected by the use of loaders.

Marginal Generation Costs

[9] PGE, PacifiCorp, and IPCO use their avoided cost methodologies to determine marginal generation costs. Avoided costs are usually reviewed and approved by the Commission following acknowledgement of a company's least cost plan. PacifiCorp's method for estimating marginal generation costs in this docket varies only slightly from the method used in its currently filed avoided cost study. PGE argues that using avoided costs recognizes the competitive nature of the generation industry. It explains that market price, avoided cost, and marginal cost are nearly equivalent terms in a deregulated and commodity-oriented electricity market.

ICNU proposes using information from Northwest nonfirm markets to develop energy costs on a time-of-day basis. PGE characterizes this as a suggestion to use a facilities design approach for generation. PGE notes that, contrary to ICNU's suggestion, PGE's marginal generation cost proposal is not based on a facilities approach, but is a market price determination of costs. PGE's facilities approach is designed for the distribution system, not for transmission or generation. The distribution system costs do not vary with time-of-day changes in load.

Commission Decision

We conclude that using avoided costs for marginal generation costs is appropriate in an increasingly competitive generation market. Further, there is not enough information in the record to conclude that PGE should include time-of-day information in the calculation of generation marginal costs.

Marginal Transmission Costs

[10] PGE, PacifiCorp, and IPCO incorporate system planning for new loads into the calculation of marginal transmission costs. For PacifiCorp, transmission costs are based on a 10-year analysis of historical and planned additions to the system. Except for bulk power lines, all growth-related costs are classified to demand. Bulk power lines are classified to energy and demand in the same proportions as 20-year marginal generation costs are allocated.

System planning information should be used, according to PGE, because transmission systems are constantly being adjusted to handle expected near-term loads. PGE uses the typical cost to supply additional transmission at times when capacity is strained. PGE looks at the costs related to building an "optimum" transmission system necessary to serve all customers at the end of the study period (2001) and divides that investment by the average or the highest winter and summer system peak loads in 2001.

ICNU proposes using the facilities approach to compute marginal transmission costs. PGE objects to that proposal. PGE contends that there is a significant difference in the demands a distribution system is designed to accommodate and the demands a transmission system is designed to handle. Local distribution systems are designed to handle the entire load they will ever be expected to carry over their lives. Transmission systems are constantly being adjusted to handle peak loads that may vary on a day-to-day basis.

Commission Decision

We are satisfied with the transmission marginal cost analyses presented by the utilities. As PGE points out, the facilities design approach is not appropriate for calculating transmission marginal costs. Transmission planners must anticipate constant variations in peak loads. The facilities design approach is more appropriate for less dynamic functions of the system.

Desirability of a Single Marginal Cost Methodology

[11, 12] PGE, IPCO, and PacifiCorp argue that the Commission should not adopt a single marginal cost methodology that would apply to all utilities. PacifiCorp points out that its methodology is well suited to its largely rural distribution system. PGE contends that PacifiCorp's methodology would not be as well suited to PGE's urban distribution system. PGE points out that the marginal cost methods used for a particular utility should reflect as closely as possible the practices and planning criteria of that utility, the structure of the utility's service territory, and the utility's situation.

IPCO is concerned that a restrictive policy requiring a single marginal cost methodology could discourage the introduction of different and innovative approaches to analyzing the costs of serving different customer classes. The Idaho legislature required IPCO, and all other electric utilities in that state, to begin a process of unbundling their costs of supplying energy to their customers. IPCO intends to refine and improve its process as it gains more experience with the new concepts. IPCO recognizes that unbundling and marginal cost analyses are quite different. However, it hopes to be able to use the results of its Idaho studies in Oregon. It asks the Commission not to require it to perform overlapping and redundant cost analyses.

Pope & Talbot argues that the facilities approach should be required for all utilities. It asserts that utility specific data should be used for a specific utility using a standard methodology. A different approach should be considered only when a utility has an innovative approach to analyzing the costs of serving customer classes and the utility can demonstrate that the approach accurately allocates such costs. In such a case the Commission should consider whether the approach should be included as part of the standard methodology or whether the utility specific situation warrants a modification of the standard policy.

Commission Decision

We will not require a single marginal cost approach for all utilities. Calculating marginal costs is as much of an art as it is a science. Allowing utilities to address the issue of calculating marginal costs in different ways has led to significant and productive new approaches to efficient pricing and costing of electrical service. We do not believe that mandating a single approach will advance the art of marginal cost analysis, and it could significantly impede progress.

Furthermore, utilities should be allowed to choose approaches that best fit the particular circumstances of their systems and nature of their customers. We do not believe that we are capable of identifying a single approach that will satisfy the needs of every utility and its respective customers.

ORDER

IT IS ORDERED that:

1. Marginal costs and revenue requirement should be reconciled on a functional basis;

2. The principles underlying the marginal cost studies presented by PGE, PacifiCorp, and IPCO are approved;

3. The facilities design approach may be used to calculate marginal distribution costs;

4. No single approach to calculating marginal costs is required; and

5. PGE, PacifiCorp, and IPCO shall provide, with their next marginal cost studies, an analysis showing how variations in administrative and general plant costs vary with demand, customer counts, or other factors.

Made, entered, and effective SEP 11 1998

APPENDIX A — Intervenors

Citizens' Utility Board (CUB) Enron Corp. Eugene Water & Electric Board Idaho Power Company (IPCO) Industrial Customers of Idaho Power of Oregon (ICIP/O)* Industrial Customers of Northwest Utilities (ICNU) Lloyd Marbet Northwest Conservation Act Coalition (NCAC) Northwest Industrial Gas Users (NWIGU) Northwest Natural Gas Company (NNG) Oregon Committee for Equitable Utility Rates (OCEUR)* Oregon Committee for Fair Utility Rates (OCFUR)* Oregon Energy Coordinators Association, Inc. (OCEA) Oregon Office of Energy PacifiCorp PG&E Energy Services (PG&E) Portland General Electric (PGE) Utility Reform Project (URP)

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*Intervention withdrawn on December 24, 1997.

APPENDIX B

STIPULATION

The parties executing this Stipulation agree as follows:

1. The second issue identified in the parties' Pretrial Order and adopted in the Memorandum and Ruling dated November 10, 1997, was `Should reconciliation (comparing marginal costs and embedded costs or revenue requirement) be done on a functionalized basis?' This Stipulation is designed to resolve this issue among the parties to the Stipulation.

2. Reconciliation is the process of comparing marginal cost to revenue — at specific rates (in effect or proposed) — for different customer classes. The Commission has used the results of reconciliation as one factor in its rate spread decisions in recent rate cases, i.e., by allocating changes in overall revenue requirement so as to move the different customer classes closer to recovering the same share of marginal cost.

3. Reconciliation should be done on a functionalized basis in electric utility rate cases. The functions used should be those that support services to be offered separately (unbundled) by the utility in the future, such as generation, transmission, and distribution.

4. The attached Table 1 illustrates that allocating revenue requirement to recover equal shares of total marginal cost (for bundled service) versus equal shares of marginal cost by function can produce different results. The parties take no position on the specific marginal cost estimates or functionalized revenue requirements used in this illustration.

5. By entering into this Stipulation, no party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other party conducting marginal cost studies or analysis in this proceeding.

6. This Stipulation will be entered into the record of this proceeding as evidence pursuant to OAR 860-14-0085(1), and the parties to this Stipulation agree to waive cross-examination of one another at the hearing on the issue addressed in the Stipulation. The parties agree to support this Stipulation throughout the proceeding and any appeal and recommend that the Commission enter an order adopting the settlement contained herein.

Respectfully submitted this 21st day of April, 1998.

[TO BE SHOT - MS. P. 3]

The signature of the representative of the party identified below shows the agreement of the party to the April 21, 1998, Stipulation in Docket UM 827 on the second issue listed in the parties' Pretrial Order and adopted in the Memorandum and Ruling dated November 10, 1997.

Signature: Paul A. Graham
Party: PUC Staff

Date: 4/21/98

Signature: James C. Paine
Party: PacifiCorp
Date: 4-21-98

Signature: Bart Kline
Party: Idaho Power Co.
Date: 4-21-98

Signature: Jason Eisdorfer
Party: Citizens' Utility Board
Date: 4/20/98

Signature: Steven D. Weiss
Party: NW Energy Coalition
Date: 4/17/98

Dated this 21st day of April, 1998
Pope and Talbot, Inc
By Ann L. Fisher, Esq.
2005 SW 71st Avenue
Portland, Oregon 97225

Signature: Melinda J. Horgan
Party: ICNU
Date: 4/21/98

Signature: Mary C. Hain
Party: PGE
Date: 4/24/98

Signature: Paul M. Murphy
by Andrew K. Soto
Party: PG&E Energy Services
Date: 4/21/98

FOOTNOTES

[1]ICNU's objections to PGE's data requests are denied.

[2]Reconciliation is the process of using marginal costs to determine a preliminary allocation of revenue requirement among customer classes. For example, if residential customers account for a specified percentage of marginal costs, then the same percentage of revenue requirement would be allocated to that class. Other factors, such as rate shock, would be considered in setting the final rate spread.

[3]PacifiCorp also uses the zero-intercept approach for splitting transformer costs between commitment and demand costs.

[4]O&M expenses include the costs of meter reading and billing.

[5]Marginal revenues are equal to the total marginal cost for a customer class, used in reconciliation.

Endnotes

1 (Popup)

[1]ICNU's objections to PGE's data requests are denied.

2 (Popup)

[2]Reconciliation is the process of using marginal costs to determine a preliminary allocation of revenue requirement among customer classes. For example, if residential customers account for a specified percentage of marginal costs, then the same percentage of revenue requirement would be allocated to that class. Other factors, such as rate shock, would be considered in setting the final rate spread.

3 (Popup)

[3]PacifiCorp also uses the zero-intercept approach for splitting transformer costs between commitment and demand costs.

4 (Popup)

[4]O&M expenses include the costs of meter reading and billing.

5 (Popup)

[5]Marginal revenues are equal to the total marginal cost for a customer class, used in reconciliation.