ALJ/KIM/pc *

Decision 90-05-037 May 4, 1990

ORIGINAL

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's own motion into implementing a rate design for unbundled gas utility services consistent with policies adopted in Decision 86-03-057.	I.86-06-005 (Filed June 5, 1986)
And Related Matters.	R.86-06-006 Application 87-01-033 Application 87-01-037 Application 87-04-040

O P I N I O N

This decision proposes guidelines for estimating long-run marginal costs (LRMC) for the gas operations of Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCal), and San Diego Gas and Electric Company. It also sets forth a schedule for consideration of LRMC and cost allocation issues.

Background

In Decision (D.) 90-01-021 we affirmed our commitment "...to implementing a program of long-run marginal cost-based rates as quickly as is reasonably feasible...." To that end, we directed the Commission Advisory and Compliance Division (CACD) to hold workshops with the utilities and interested parties. We also directed CACD to prepare a report on information received at the workshops. D.90-02-052 clarified our order to provide a 20-day period for the parties to comment on proposed LRMC study guidelines.

CACD held the workshops on February 6 through 9, 1990. The workshops were well-attended by representatives of utilities, ratepayer groups, and other interested parties. The workshop participants considered studies presented by SoCal, PG&E, and Southern California Edison Company including methodologies for determining LRMCs. After the workshops, the parties submitted comments stating their respective views on marginal cost methodologies.

On April 13, 1990, CACD issued its workshop report, which is attached to this decision. The report summarizes the parties' positions and recommends guidelines for the utilities' LRMC studies.

LRMC Study Guidelines

By this decision, we issue for comment the guidelines set forth in CACD's report for utility long-run marginal cost study methodologies. Specifically, LRMC studies should incorporate several general principles:

> System Components
> The system components which may be priced as products using LRMC include:
>
> o Customer-related
>
> o Distribution
>
> o Transmission: Interstate, Local, and "Backbone"
>
> o Storage: Seasonal and Peaking
>
> The utilities should, in developing their cost studies, choose the specific functions which best suit their respective systems. Permitting the utilities to determine appropriate system components recognizes that the utilities have built and operated their systems according to local geography and customer requirements.
>
> The cost studies should identify customer-related costs as those clearly associated with providing access to the gas system. Customer-related costs should be calculated using the "SRM" method proposed by DRA, which defines access costs as only those associated with the service line, regulator, and meter of each customer. The utilities should develop

customer LRMCs for each of the ACAP rate groups, annualize the costs with a real economic carrying charge, and add administrative and general and operating and maintenance expenses. In identifying the access costs of a "typical" customer, the utilities should use actual current cost information.

Expansion Costs
LRMC studies should apply engineering costs to estimate expansion costs, except for those associated with distribution. Distribution costs should be analyzed using regression analysis because of the difficulty of defining a "typical" distribution facility. LRMC studies should not employ the "optimized" system technique proposed by SoCal. In estimating expansion costs, the utilities should make explicit all assumptions used in determining "typical" investments.

Future Costs in Current Rates
Prices based on LRMC should recognize that some customers cause demand for system additions more than others, and some cause demand for additions sooner than others. To recognize these differences between customer groups, LRMC studies should incorporate an adjustment which takes into account the proximity or distance of actual, planned additions. The LRMCs used in revenue allocation and rate design should be low in times of capacity surplus, rising to full costs when capacity is constrained. The cost studies should employ the "present worth" method proposed by PG&E, which incorporates these effects.

Interstate Capacity
True system costs include the costs of interstate capacity as well as intrastate facilities. The cost studies should include the costs of building new pipeline capacity into California. The studies should use the estimated costs of a new pipeline as a proxy for the LRMC of expanding the existing system.

Storage/Transmission Equivalence
Storage and transmission capacity may be tradeoffs for one another to some extent. The

> utilities' cost studies may recognize this tradeoff. If they do, the utilities' assumptions should be explicit.

Consistent with CACD's recommendation, we do not propose to adopt different guidelines for different utilities. Although utility costs may differ, the methods for deriving them should not. As the CACD report states, the specific circumstances of individual gas utilities will not be ignored by a common methodology. To the contrary, a common methodology will allow utility costs to be compared so that their differences stand out. To promote consistency and simplicity, our final guidelines will apply to all three gas utilities.

D.90-02-052 provided the parties with an opportunity to comment on these guidelines. We are interested in whether the parties believe the guidelines proposed by CACD are adequate and whether refinements to them should be adopted now. In formulating their comments, the parties should keep in mind several things. Of course we are concerned that cost studies be accurate, representing the true marginal costs of gas operations, to the extent practical. While we do not expect to develop a precise LRMC for every service, we recognize that accurate pricing promotes efficient use of resources. It is especially critical at this time because the utilities are considering major investments in additional gas plant.

At this point, we are very concerned that, in addition to having conceptual appeal, elements of our adopted costing methodology be simple and easy to implement. We favor proposals that do not require protracted debate or complex modeling because we hope to implement adopted costing methodologies soon.

Although we favor simplicity over sophistication at this point in time, we are concerned that reliability levels for gas system expansion have not been addressed. The specific solution we seek is one which determines the marginal costs for a system built to meet customers' desired level of service. This is the other half of the problem of determining marginal costs for gas. We therefore look to future proposals which address this problem. While we recognize the need to move toward more optimal approaches for this cost determination, the recommended CACD guidelines are sufficient to begin the process.

We believe CACD's proposed guidelines meet these objectives but welcome the parties' comments. Based on the parties' comments, we will also clarify the proposed guidelines and develop them in more detail where appropriate.

Procedures for Considering
LRMC and Cost Allocation

As set forth in D.90-02-052, the parties have 20 days from the effective date of this decision to submit their comments. Shortly after receiving the comments of the parties, we will issue a final decision on LRMC guidelines for methodologies. We will then hold hearings in September, 1990 to establish LRMC methodologies, using the adopted guidelines, and determine LRMCs by customer class for rate design and cost-allocation purposes. During the same set of hearings, we will consider the cost allocation issues identified in D.90-01-021 as part of Phase II of this proceeding. We anticipate the following schedule for considering these two issues:

July 9	Utility testimony due
August 6	DRA testimony due
August 20	Intervenor testimony due

If the proceeding goes forward according to schedule, we anticipate a final decision in early 1991. We direct the assigned Administrative Law Judge to schedule, as soon as possible, a prehearing conference to set forth in more detail the scope of the proceeding and address other procedural matters, including a final schedule for these hearings.

Findings of Fact

1. On April 13, 1990, CACD submitted its workshop report on LRMC study methodologies. The report summarizes the positions of the parties and suggests guidelines for LRMC cost studies.

2. D.90-02-052 provided the parties 20 days on which to comment on LRMC study guidelines proposed in this decision.

Conclusion of Law

The LRMC study guidelines proposed by CACD in its workshop report should be considered proposed rules upon which the parties may comment within 20 days of the effective date of this decision.

O R D E R

IT IS ORDERED that:

The parties may comment, within 20 days of the effective date of this decision, on the guidelines proposed in this decision for the development of long-run marginal gas costs. The parties' comments shall be filed in accordance with Rule 14.5 of the Rules of Practice and Procedure.

This decision is effective today.

Dated May 4, 1990, at San Francisco, California.

G. MITCHELL WILK
President
FREDERICK R. DUDA
STANLEY W. HULETT
JOHN B. OHANIAN
PATRICIA M. ECKERT
Commissioners

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

PB

I.86-06-005 et al.

ATTACHMENT A

NATURAL GAS
LONG RUN MARGINAL COST

WORKSHOP REPORT
April 13, 1990

Paul Clanon
Advisory Branch
Commission Advisory
and Compliance
Division

ATTACHMENT A

PURPOSE

On January 9, 1990 the Commission issued D. 90-01-021 directing the Commission Advisory and Compliance Division (CACD) to convene a workshop to consider long-run marginal cost (LRMC) methodologies for use in natural gas cost allocation and rate design. The Commission ordered CACD to report on this workshop.

HISTORY

The Commission's natural gas regulatory policies stem from two landmark decisions in December 1986. D. 86-12-010 unbundled transportation and procurement services; D. 86-12-009 adopted cost allocation and rate design methodologies based on the gas utilities' embedded costs of providing transportation. The Commission's use of embedded costs was explicitly interim, and was based at least partly on the lack of well-developed marginal cost studies, which the Commission ordered the utilities to prepare. Studies were submitted by Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCal), San Diego Gas and Electric Company (SDG&E), and Southern California Edison Company (Edison). Comments on these studies were filed by the Commission's Division of Ratepayer Advocates (DRA).

The Commission's attention over the past three years has focused on implementing the new regulatory structure. On November 1, 1989 the Commission held an en banc hearing to evaluate the success of the program and to consider further evolution. One outgrowth of that hearing was renewed resolution to develop a long-run marginal cost-based revenue allocation and rate design to replace the interim embedded cost-based rates. In D. 90-01-021 the Commission formalized this resolve by ordering an LRMC workshop and proposing an ambitious procedural schedule to develop an "on the shelf" LRMC rate methodology ready for use when the allocation restrictions codified in Section 739.6 of the Public Utilities Code expire on January 1, 1991.

THE WORKSHOP

Introduction

The workshop, moderated by CACD, took place at the Commission's offices February 6 through February 9. Attendees are listed in Appendix A, and the working agenda is contained in Appendix B. Each of the four daily sessions was well attended by representatives of utilities, ratepayer groups, industrial organizations, and other interested parties.

The studies had been completed and commented on several months before and had not yet been discussed in a Commission-sponsored forum. Accordingly, the workshop agenda called for presentations by each of the utilities on their proposed methods and by DRA on DRA's assessment of the proposals. Each presenter was then available for questions from workshop participants. The following summaries are based on presentations made at the workshop, in some cases expanded by information from earlier filings or from draft workshop comments provided to the Moderator by several parties after the conclusion of the workshop.

PG&E Proposal

PG&E proposes to derive LRMCs from system expansion plans based on forecast new loads and constrained by chosen levels of reliability. PG&E would choose the standard of providing a system capable of providing the maximum level of service with minimal operating constraints at the lowest cost. PG&E explicitly rejects the notion of basing LRMCs on an optimized system[1], and argues instead for using planned additions to the existing system, even though the existing system may, because of its history and changes in load patterns and planning criteria, not be optimal.

PG&E considers two kinds of marginal costs: (1) customer-related, which vary by customer class according to the costs of providing access, and (2) demand-related, which vary according to demands placed on different segments of the system (storage, distribution, local transmission, and backbone transmission). PG&E would further separate each kind of marginal cost into variable and non-variable (generally, capacity) components.

The variable costs associated with PG&E's functions, both customer- and demand-related, are operating and maintenace (O&M) and administrative and general (A&G) costs. There was little discussion of these variable costs at the workshop.

To estimate the non-variable components, PG&E would first identify a specific system addition to be made at some future time, then make an engineering estimate of the costs of building the expansion. In order to account for this addition's being in the future, PG&E would calculate the net present value of deferring that addition by one unit of time (or demand). By the nature of the calculation, this value would be relatively low in time of excess capacity, rising toward the full engineering cost estimate at the moment when capacity addition becomes necessary. This "Present Worth" (PW) method is intended by PG&E to send an increasing-cost signal to customers when capacity additions are imminent.

PG&E emphasized its preference for flexibility in methodology across utilities, arguing that fundamental differences exist among the gas utilities both in physical conditions and in

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1. That is, a system perfectly designed to provide a level of service meeting some list of criteria, usually economic and operational.

planning processes. PG&E believes that each utility's customers should be given price signals accurately reflecting that utility's costs, and PG&E believes that a single methodology will not meet this goal.

SDG&E Proposal

SDG&E proposes (1) to mirror the existing LRMC methodology used by the Commission for setting electricity rates, and (2) to reflect the company's actual planning criteria in the methodology. SDG&E proposes its methodology for use on SDG&E's own system, not necessarily on PG&E's or SoCal's.

SDG&E explained its current system planning process, which is based on a Recurrence Interval Study (RIS) performed every few years. Using monte carlo simulations of probable outcomes, the RIS optimizes, over a 20-year horizon, the interplay between the costs of expanding the system and the costs of not expanding the system; that is, of accepting the revenue loss and customer shortage costs associated with gas curtailments.

Using the system additions suggested by the RIS, SDG&E makes engineering estimates of the costs of additions. For calculating the LRMC of transmission, SDG&E regresses a twenty-year future stream of these costs against time, ending with a single estimate of the cost of expanding the system. This estimate is annualized over the life of each investment by a real economic carrying charge (RECC), which may be thought of as the rental charge for capital additions, adjusted for inflation.

For distribution additions, SDG&E uses ten years of historic data and five years of forecast in performing the regression. Customer-related costs are excluded from both historical and forecast distribution additions.

For customer-related costs, SDG&E proposes the SRM (service line -- regulator -- meter) method, based on average installations and including O&M. Again, SDG&E would apply a real economic carrying charge. The company estimates customer accounting and collection expenses based on ten years of recorded data.

In response to questions, SDG&E noted that SoCal Gas' system costs (all of SDG&E's supplies are delivered to SDG&E by SoCal) and interstate pipeline costs were not included in SDG&E's LRMC estimates, and that SDG&E has no current plans to add storage to its own system.

Although SDG&E had hoped a consensus would emerge at the workshop around a single LRMC methodology, the company believes that no such consensus arose and that the Commission has insufficient information to establish a single methodology now.

SoCal Proposal

SoCal's proposal is centered on the development of an optimal system through a series of investments, each made at the moment in time when they become most cost-effective. SoCal's methodology for determining that right time is based on several engineering and economic models that together provide a system planning tool. Using forecasts of demand, supply, the prices of alternate fuels, and the costs of system additions, SoCal's models derive the needed system additions and predict the best time to make the investments. A key feature of SoCal's proposal, and the feature that most separates SoCal's from the other parties' proposals, is SoCal's reliance on the value of service provided to customers as an indicator of the need for new capacity. SoCal would build new capacity only when the value of the new capacity is greater than its cost.

Once the investment decision is made, SoCal would calculate the unit cost of the investment for use in LRMC rate design.

SoCal believes that many of the components of LRMC lend themselves to a common statewide methodology, but that some costs -- in particular mainline transmission and storage -- require different methodologies among the different utilities. SoCal opposes the use of an energy reliability index, believing that the use of an ERI would distort its customers' decision-making.

SoCal excludes A&G and general plant from its study.

Edison Proposal

Edison presented a wellhead-to-customer methodology using a mix of engineering estimates and statistical analyses of investments for different segments of the gas systems. Edison concentrated discussion on the reliability standards adopted by the utilities in planning their systems, and noted that these reliability standards are a precursor to identifying LRMCs. Edison believes that LRMCs should be measured by adopting a reliability standard and determining the investment costs necessary to maintain that standard given an increase in load. In its study Edison adopted a reliability standard equal to serving all customers' demands in an average year.

Edison has developed its own modeling techniques to indicate stressed points on SoCal's system and identify the need for system expansion.

CGPA Comments

The California Gas Producers Association (CGPA) is concerned about the theoretical justification for discounting lumpy future investments, and argues that large customers should be given short-run marginal cost price signals. CGPA particularly questions PG&E's PW method and considers it "conjectural".

CGPA favors the use of one LRMC methodology statewide, and believes some distribution costs not to be common to residential and large customers, but to be allocable directly to one or the other. CGPA also questions the use of customers' opportunity costs of curtailment in determining LRMCs, because doing so begs the question of the actual cost of the system addition.

CIG Comments

The California Industrial Group (CIG) emphasizes that although marginal cost pricing is recognized to be more efficient than embedded cost pricing, the final rates themselves, whether based on the one or the other, must be reasonable and just. CIG urges the Commission to remember that no matter what the accuracy of the LRMC estimates, they must still be adjusted to recover the revenue requirement, to ensure cogenerator rate parity, and to comply with a number of other Commission and statutory mandates. CIG believes that because of the uncertainty in forecasting future costs LRMC rates will inherently be more controversial than embedded cost rates. CIG urges the Commission to reconsider its decision to develop a gas LRMC rate design in 1990.

If the Commission does not change its policy, CIG considers it essential for one methodology to apply statewide. CIG notes the substantial differences among the utilities' studies and the utilities' desire to continue refining the methodologies. CIG believes that consensus was reached at the workshop that replacement costs are not an adequate proxy for LRMCs.

HESI Comments

Henwood Energy Services, Inc (HESI) urges the Commission to include the concept of value of service in developing LRMCs, and points to SoCal's proposal as an example of using that information to help design the optimal system. HESI also believes that the Commission should acknowledge that gas utilities are designed to serve not just core loads, but non-core as well.

TURN Comments

Toward Utility Rate Normalization's (TURN) largest concern is consistency of methodology across the range of system components, both in the size of the planning horizon and in any adjustments to account for scarcity of capacity. TURN comments that if any element of LRMC is adjusted to account for the scarcity or plenty of capacity at any given time (an adjustment TURN supports in principle), all elements should be adjusted, and in particular TURN believes that marginal customer costs should take into account the stock of existing, partly-depreciated customer access plant in the same way that marginal transmission costs, for instance, might be calculated based on a system addition that assumes an existing transmission network.

TURN believes the SoCal proposal to be a sophisticated system planning tool and encourages its use for that purpose, but thinks the mass of data needed makes the method poorly suited to ACAPs. TURN supports instead something more like PG&E's present worth method.

TURN believes strongly that the costs of an actual new interstate pipeline should be used in developing interstate transmission marginal costs, rather than estimates of the likely change in interstate demand charges if existing pipelines were to be expanded.

CSC Comments

The Cogenerators of Southern California (CSC) note the lack of consensus at the workshop on a common methodology, and urge the Commission to consider the differences in the service provided core and non-core customers. CSC believes that an LRMC methodology should be based on the utilities' actual planning processes and on actual, as opposed to optimized, systems. CSC argues that the Commission should include interstate capacity in its LRMCs, should differentiate between local and backbone transmission, and should include some distribution main costs in its adopted customer-related LRMCs.

CCC Comments

The California Cogeneration Council's (CCC) primary concern is that rate parity between cogenerators and utility power plants be maintained under any adopted LRMC method.

DRA Comments

The Commission's Division of Ratepayer Advocates (DRA) supports the resource planning approach to developing LRMCs, rather than the estimation of LRMCs by replacement costs. DRA notes a number of important differences among the utilities' proposals, and argues the need for a single statewide methodology capable of implementation in ACAPs. DRA suggests that the utilities have not shown any differences in the design or operation of their systems that would warrant the use of different LRMC methodologies.

DRA recommends that the Commission divide the gas systems into customer-related, distribution, transmission, storage, and commodity functions for purposes of costing, and that interstate transmission be kept separate from intrastate transmission.

DRA recommends that customer costs be calculated using the SRM method, assuming the lowest installation costs absent a utility showing that the assumption is incorrect. DRA would calculate distribution costs by engineering estimates made of costs where the distribution system is expanding rather than by regression techniques. DRA believes that regression techniques, based on the entire distribution system, are not representative of current conditions, when only certain parts of the distribution systems are expanding.

DRA recommends that the storage and transmission models be simplified for use in calculating LRMCs, and that a uniform system reliability level be set for all utilities.

DISCUSSION

Introduction

The Commission's decision to move forward with a gas revenue allocation and rate design based on marginal costs was reached partly on the understanding that resource additions (particularly interstate pipeline capacity and attendant intrastate expansions) are imminent for California's gas utilities. Accurate price signals are always important; they are most critical when system planners are actively considering committing large sums of shareholder (and ultimately ratepayer) money to meet expected loads that, to a degree, are the products of the rate design.

The Commission's adopted LRMC rate design should therefore have two primary features: accuracy and timeliness. A new rate design implemented tomorrow but sending the wrong price signals will bring no benefits to ratepayers; nor will a perfect methodology whose development takes years and which can't be implemented until after the next generation of planning decisions is made. The task is to develop a methodology for calculating LRMC that (a) promises reasonable accuracy and (b) can be implemented soon. These two requirements are helpful in considering the proposals of the parties.

A number of parties expressed at the workshop their belief that a common methodology should not be adopted for all utilities, instead arguing that each utility should be allowed to use its own methodology. Beyond the obvious technical and procedural difficulties inherent in the Commission's adopting several different methodologies to measure the same thing -- namely, the cost involved in providing gas service -- the Commission should remember that LRMC is only a measuring tool. The specific circumstances of the gas utilities will not be ignored by a common methodology. To the contrary, a common methodology will allow the utilities to be compared so that their differences stand out.

All LRMC proposals thus far submitted attempt to answer essentially the same three questions: (1) How should the systems be divided into components for costing purposes? (2) How much would it cost to expand the size of the various components of the systems? (3) How should future expansion costs be treated in current rates?

<u>System Components</u>

The first step in deriving marginal costs is identifying the products being priced. The workshop participants reached consensus on these system components:

1. Customer-Related

2. Distribution

3. Transmission

   Local

Backbone

4. Storage

Seasonal

Peaking

5. Interstate Transmission

This functionalization was agreed to as an inclusive list, but not every gas utility thought each of the definitions necessary for its system. For instance, because SoCal's transmission system delivers gas over main lines directly to the distribution network, the separation between backbone and local transmission is of uncertain value. SDG&E likewise may not need a distinction between the two types of transmission, and may for that matter need no storage functionalization at all.

The most controversial functionalization decision is the separation of distribution from customer-related costs -- a separation that is equally controversial in the Commission's electric marginal cost methodology. The separation is critical because of the implications for revenue allocation: assigning too much cost to the customer function and too little to the distribution function, for instance, might cause the Commission's final allocation to be weighted heavily to small, especially residential, customers.

At the workshop DRA tried with some success to develop consensus on the SRM method, which would define access costs to be only those costs associated with the service line, regulator, and meter of each customer (as opposed, for instance, to including some distribution mains). DRA would develop customer LRMCs for each of the current ACAP rate groups, annualize the costs with a real economic carrying charge, and add administrative and general (A&G) and operating and maintenance (O&M) expenses. Workshop participants discussed and were unable to agree on the precise parameters for developing the SRM costs. For instance, the definition of "typical" customer-related investment may include differing assumptions about the amount of trenching required to hook up a new customer.

CACD RECOMMENDATION. The Commission should adopt the system components listed above, but each utility should choose the specific functions from the list that best suit that utility's system. PG&E, SoCal Gas, and SDG&E have built and operated their systems in markedly different ways, driven by geography and by the needs of their customers. If because of PG&E's circumstances the backbone and local transmission systems can be logically separated for costing purposes, that is no proof that similar circumstances prevail on the SoCal system.

The separation of customer-related from distribution costs should be based on DRA's proposal, and should hinge on the principle that only those costs clearly associated with providing access to the gas system should be considered customer-related. By its nature the customer/distribution split can never be theoretically satisfying: common costs are common costs, and any one party's proposal can never be proven accurate. The SRM proposal has the advantage of comparability with the Commission's adopted T-S-M (transformer, service drop, meter) methodology for marginal customer costs in electricity, a methodology developed after many years of debate and litigation. The Commission should concentrate its attention on the utilities' definitions of "typical" access costs by customer class. Those definitions should be representative of actual investments currently being made.

Expansion Cost

Regression vs. Engineering Estimate. SDG&E and SCE both propose to use statistical regressions to estimate the LRMC of certain system components. Using some mix of recorded and forecast expansions and related costs, this technique derives a statistical best fit for the cost of expanding the system. For instance, to calculate a distribution LRMC SDG&E would first exclude customer-related costs from the distribution accounts, then regress ten years of recorded and five years of forecast expansion costs against the past and future expansions. The slope of the resulting line gives an estimate of the cost of expanding the existing distribution system by one unit.

Engineering estimates begin by choosing a particular expansion project thought to be typical, then determining the cost of that typical expansion; that is, the actual expected costs of labor, materials, design, and so on for that engineering project.

Each method came under criticism during the workshop, the regression technique because of its reliance on recorded and averaged data to calculate a future incremental cost, and the engineering method because of its sensitive dependence on the assumptions made about the "typical" project. For instance, the regression technique would base distribution LRMC partly on expansions and costs that took place up to ten years ago -- an obvious dilution of the forward-looking nature of marginal costs. An engineering estimate would avoid this problem, but might be highly influenced by difficult judgments about whether the typical system addition would, for instance, be rural, semi-urban, or urban.

The Commission's adopted electricity marginal costs have relied on regressions for the distribution and transmission functions and engineering estimates (the combustion turbine proxy) for generation. Neither method can be said to have been free of controversy.

Optimized vs. Existing System. Should LRMCs be developed assuming that additions are made to the systems as they currently exist, or assuming that the systems have been "optimized"? SoCal, for instance, has developed a series of models intended to make serial investment decisions throughout an extended planning horizon until an optimized system is in place. SoCal would calculate an LRMC by assuming a small increase in demand at the future time when that notional, optimized system would be in place and measuring the cost imposed on customers by the added curtailment. Most other parties would develop the marginal costs of the existing systems, even though their design has been dictated as much by history as by strict cost-effectiveness analysis.

At the workshop, objections were raised to both techniques. Since the current system might, for instance, be expandable cheaply because of over-capacity in one or more segments, the current-system approach could underestimate LRMCs. The optimization method, though, clearly requires more data and greater analysis, and may be unworkable for limited proceedings like ACAPs.

CACD RECOMMENDATION

The Commission should direct the utilities to use engineering estimates for all components except distribution, and the utilities should make explicit all assumptions used in determining "typical" investments. The optimized system technique should not be part of the initial methodology, though it may be useful as a future refinement.

Engineering estimates are conceptually more appealing than regressions because they attempt to measure the cost of an incremental addition in a straightforward way. Engineering estimates do not rely on averaged, recorded data that dilute the information given about the costs of expanding the system. Engineering estimates do inspire controversy over the definition of a "typical" addition, and the Commission should signal its intention to look carefully at the assumptions underlying the utilities' choice of particular additions in developing LRMCs.

Engineering estimates are poorly suited to calculating the LRMC of one system component: distribution. Expansions of a distribution system increase capacity only for a local area, and not for the system as a whole. To define a "typical" addition to such a disparate thing as a gas distribution system, with its large pipes and small pipes, urban customers and suburban, would require a process, whether explicit or implicit, of averaging. Developing an engineering estimate for this typical expansion would likewise be once removed from an actual estimate for an actual addition.

These limitations argue for the use of an averaging technique that makes use of known information about the costs of distribution expansions; in other words, for the regression method of estimating LRMCs.

An optimized system approach along the lines of the SoCal proposal is an excellent planning tool for system additions, and the models SoCal has developed are very promising. Several parties, including DRA, were especially concerned about the data and analysis requirements of the models, and argued that ACAPs, because of their already-tight schedules and inherent time limits, would be overburdened by the use of such models. Since the Commission is in the beginning stages of developing an LRMC methodology, SoCal should be encouraged to continue developing its optimization techniques, but the Commission's proposed LRMC methodology should be based on additions to the existing systems.

FUTURE COSTS IN CURRENT RATES

The purpose of marginal cost pricing is to signal to customers the costs their demands place on systems that are dynamic over time. Customers whose loads cause expensive system additions in the future should pay higher rates than customers whose loads don't force additions, and customers whose loads force additions soon should pay more than customers whose loads won't force additions for some longer time.

A great deal of discussion at the workshop centered on the method for reflecting this temporal element of cost. The parties generally agreed with one or the other of two proposals: PG&E's Present Worth (PW) method, or a variant of the Energy Reliability Index (ERI) adopted by the Commission for electric utility marginal costs.

The PW method is an attempt by PG&E to measure the present worth of an investment deferred in the future. If, for instance, a forecast decrease in loads would cause a pipeline investment to be put off for a year, the system realizes a net decrease in cost. If the need for new investment is far off in time, the present worth of deferring that investment is small; the present worth of a deferral rises sharply as the time of planned expansion approaches. PG&E's proposal would exhibit the features common sense expects: Costs would go up as system capacity became constrained, and would fall when system capacity was ample.

The Energy Reliability Index as implemented in electricity generation marginal costs exhibits the same feature, starting small and rising toward 1.0 as generation capacity begins to run out and additions are planned. No party has actually developed a gas capacity equivalent to the ERI.

TURN argued at the workshop that if reliability adjustments are made to the LRMCs of system components like transmission and storage similar adjustments should be made to customer-related LRMCs to reflect the need for access.

CACD RECOMMENDATION. LRMC studies should incorporate an adjustment to take into account the proximity or distance of actual planned additions. The LRMCs used in revenue allocation and rate design should be low in times of capacity surplus, rising to full costs when capacity is constrained. PG&E's PW method, because it incorporates this adjustment and is relatively simple, should be adopted as the standard adjustment until further work can be done in developing a gas equivalent of the ERI. Parties wishing to develop ERIs should be put on notice that the Commission will require strong theoretical and practical evidence that an ERI would give better price signals than the PW method.

TURN's proposal to adjust customer-related costs by a reliability factor should not be adopted now, but the Commission should allow TURN to develop its proposal more fully during the allocation phase of this proceeding.

OTHER ISSUES

Interstate Capacity. There was disagreement at the workshop over the proper method for including the marginal cost of interstate capacity in the LRMC methodology; in fact, some participants, notably PG&E, would not include interstate costs at all. PG&E argued the infeasibility of conducting a marginal cost study of El Paso Natural Gas Company solely for the purpose of allocating the costs passed on to PG&E by El Paso. Most participants disagreed with PG&E, and argued that improper price signals would be sent if the ultimate rate design failed to include such a major cost element.

Among the parties supporting the inclusion of interstate pipeline marginal costs there was disagreement over quantification methods. SoCal would analyze the change in demand charges charged to SoCal by the FERC brought about by increases in SoCal demand. Edison would measure investment costs at the interstate level more directly. TURN agreed with Edison that using pipeline demand charges as a proxy for LRMC distorts the price signal by introducing embedded costs (and FERC rate design) into the determination of marginal cost.

<u>CACD RECOMMENDATION</u>. Utility LRMC estimates should include interstate LRMC, which should be based on the cost of building new pipeline capacity into California. As the Commission well knows, the cost of expanding interstate capacity into California is significant, and for an LRMC-based rate design to have its desired effect -- that is, signaling customers the real costs they impose -- the marginal cost of interstate capacity must be included. Of the competing proposals to quantify the LRMC of interstate capacity, the most conceptually appealing is the use of a new-pipeline proxy -- that is, using the estimated costs of a planned new pipeline as a proxy for the LRMC of expanding the existing system. The Commission's continuing work in the development of policies on new interstate capacity has given the Commission a great deal of information and expertise regarding the siting, design, and cost of new pipelines, making the cost of a new pipeline an attractive proxy for the LRMC of interstate capacity.

SoCal's proposal to model the effect on SoCal's own demand charges when load grows is straightforward and simple to implement, but because those interstate demand charges are based on embedded costs and are subject to changes in the FERC rate design the price signals sent by the use of that proposal could vary markedly from those sent by a true marginal cost-based rate design.

Storage/Transmission Equivalence. Both in its study and at the workshop, Edison discussed its view that transmission capacity and storage capacity are substitutes for one another, at least to some degree. In order to meet a forecast peak load, a system planner might be required to design additions to both the transmission and the storage systems, with a larger transmission addition making possible a smaller storage investment and vice versa.

This equivalence was discussed at the workshop, and no consensus was reached on the proper way of intergrating this fact into the LRMC methodology.

CACD RECOMMENDATION. The Commission should recognize that definitions of "typical" system additions may include a tacit design decision on the part of the utilities about the optimal tradeoff between transmission and storage. If so, the utilities should make explicit their assumptions.

CONCLUSION

Although the LRMC workshop was not characterized by consensus, the Commission has now focused attention on its desire to implement an LRMC rate design, and the work done to date by the utilities and other parties is sufficient for the Commission to adopt in principle a beginning methodology. The Commission should not expect any methodology adopted now to remain unchanged; the state of knowledge about the marginal costs of gas systems is low, and evolution of the methodology can be expected as the Commission and the parties gain experience.

The utilities should be commended for the quality of thinking their proposals have shown, and the Commission should encourage them to continue integrating marginal cost analysis into their system planning.

(END OF ATTACHMENT A)

APPENDIX A

LONG-RUN MARGINAL COSTS WORKSHOP
February 6 through 9, 1990

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APPENDIX A

AGENDA
Long Run Marginal Cost Workshops
February 6-9, 1990

February 6

Introduction
Presentation by PG&E of its proposed LRMC methodology
    Question and Answer
Presentation by SoCalGas of its proposed LRMC methodology
    Question and Answer

February 7

Presentation by DRA of its proposed LRMC methodology
    Question and Answer
Presentation by other parties of proposed methodologies
    Question and Answer

February 8

Critique proposals
Compare and contrast proposals
Identify major issues

February 9

Identify areas of agreement and controversy
Identify options for recommendations to Commission
Parties summarize final positions

(END OF APPENDIX A)