BOARD STAFF RESPONSE TO
ENBRIDGE GAS DISTRIBUTION INC. #8

INTERROGATORY

ISSUE A1: Is Enbridge's proposal for a Customized IR plan for a 5 year term covering its 2014 through 2018 fiscal years appropriate?

Evidence Ref: ExhL/T1/S2

I.A1.Staff.EGDI.8

Preamble:
On page 5, PEG states: "The industry-specific inflation factor used in CEA's empirical research is unacceptable (as currently designed) because it excludes the rate of return on a utility's capital stock, as well as depreciation of that capital stock. These are large components of capital input prices, and any input price inflation measure that excludes them is not a credible measure of input prices for the gas distribution industry."

Request:

a. Please indicate whether PEG is aware of any North American regulator that has specifically incorporated the rate of return on a utility's capital stock and depreciation of capital stock in an I Factor for an incentive regulation program. Please provide the decision and page references.

b. Please indicate if PEG has taken a consistent approach to the inclusion of the rate of return on the utility's capital stock and depreciation of capital stock in its utility TFP studies and I factor recommendations. Please describe that approach.

c. Please produce the testimony and studies filed by PEG in Ontario and other jurisdictions where PEG has made recommendations for or comments upon the appropriate I factor to be used within an incentive regulation program.

d. Please provide copies of regulatory orders and decisions that adopted PEG's proposed I Factor that includes "the return on a utility's capital stock, as well as depreciation of that capital stock." Please indicate the page number that demonstrates reliance on PEG's I Factor analysis.

e. Please indicate if PEG is aware of alternative approaches for I factors (that did not specifically incorporate rate of return on a utility's capital stock and depreciation of capital stock) adopted by regulators in North American regulatory decisions. Please describe those approaches with citations to the decisions.

Witness: Dr. Lawrence Kaufmann, PEG

RESPONSE

a. PEG is aware of at least three instances where North American regulators have incorporated the rate of return on a utility's capital stock and the depreciation of its capital stock into an industry-specific inflation factor. These decisions with the associated page numbers describing the approach are presented below:

   i. Ontario, First Generation Incentive Regulation for Electricity Distributors, RP-1999-0034, pp. 33 -36
   ii. California, Southern California Gas, D. 97-07-054, p. 7 and 22-23
   iii. California, San Diego Gas and Electric, D. 99-05-030, pp. 23-26

   In addition, PEG is aware of an industry-specific inflation factor for Pacificorp's operations in California which we also believe incorporated a rate of return and depreciation on capital in the inflation factor, but we were unable to verify that this was the case.

b. PEG has used different measures of the "rate of return" and different approaches for measuring depreciation in our TFP and input price research. Our capital input price inflation measures have differed depending on data availability in a given jurisdiction, and our judgment regarding the merits of using simpler and more transparent measures versus more complex but potentially more accurate, or less volatile, measures. See the response to parts c) and d) of this question for some recent examples in PEG's work where we considered the tradeoff between complexity and other important objectives for inflation factors.

c. PEG rarely testifies in support of inflation factors, although we have done so in two recent cases.

   As part of our empirical research in support of 4th Generation Incentive Rate Setting for Electricity Distributors in Ontario, PEG was asked to recommend an inflation factor. The Board set out specific criteria that this inflation factor was to satisfy, and PEG endeavored to satisfy these criteria when developing our recommended inflation factor. Please see the response to I.A1.Staff.EGD.7 b) for a copy of the report providing this recommendation.

   PEG also recommended an inflation factor for gas distributors in the incentive regulation proceeding in Alberta. Please see the response to I.A.1.Staff.EGD.12 for a copy of the report providing this information.

d. The Board did not accept the inflation factor that PEG recommended in the report referenced in part c) of this question, largely because of its year to year volatility.

Witness: Dr. Lawrence Kaufmann, PEG

The Alberta Utilities Commission did not accept PEG's proposed inflation factor because it was considered too complex, primarily because it included a "triangularized weighted average (TWA)" of capital asset price indices when annual changes in capital input prices. This TWA was recommended to smooth volatility in capital input prices.

However, to avoid this complexity, PEG's recommended inflation factor to the Board did not include a TWA of capital asset prices.

e. Yes; PEG is well aware that incentive regulation plans can adopt alternate approaches for inflation factors, including economy-wide inflation factors rather than industry-specific inflation factors. Economy-wide inflation factors do not explicitly incorporate rate of return or depreciation rates. PEG has written frequently about the advantages and disadvantages of both economy-wide and industry-specific inflation factors. Please see a copy of our February 2008 report *Calibrating Rate Indexing Mechanisms for Third Generation Incentive Regulation in Ontario*, provided in response to .A1.Staff.EGD.7 b), for an example of such a discussion.

RP-1999-0034

IN THE MATTER OF a proceeding under sections 19(4), 57, 70, and 78 of the *Ontario Energy Board Act*, *1998* S.O. 1998, c. 15, Sched. B to determine certain matters relating to the Proposed Electric Distribution Rate Handbook for licensed electricity distributors.

BEFORE: George Dominy
Vice Chair and Presiding Member

Paul Vlahos
Member

Sally Zerker
Member

DECISION WITH REASONS

January 18, 2000

TABLE OF CONTENTS

1. INTRODUCTION

1.1 THE PROCEEDING

1.1.1 In anticipation of the passage of the *Energy Competition Act, 1998* (Bill 35), in October 1998 the Ontario Energy Board ("Board" or "OEB") stated its intent to implement new approaches to regulation and to consider the use of Performance Based Regulation ("PBR") wherever it is appropriate[1].

1.1.2 In view of the large number of electricity distribution utilities in the Province of Ontario, the Board determined that it would be expedient to establish a framework for guidelines on the application of PBR to the electricity distribution industry.

1.1.3 Board staff issued a document[2] in October 1998 and held educational seminars to familiarize stakeholders with the concept of PBR. Regional workshops were also held to obtain stakeholder input on the most appropriate approach to PBR for electricity distribution. An evaluation of the input received at the workshops was presented in a report[3] issued in December 1998 and was used to identify topics for further discussion.

[1] OEB Draft Policy on Performance Based Regulation. OEB. October 2, 1998.
[2] PBR Options for Electricity Distribution in Ontario. OEB Staff Report. October 16, 1998.
[3] Performance Based Regulation Framework for Electricity Distributors in Ontario. December 17, 1998.

1.1.4 Four task forces were established to address the following topics: cap mechanisms, yardstick mechanisms, implementation, and distribution rates. The efforts of the task forces were coordinated by Board staff. Technical expertise on PBR and industry restructuring was provided to the task forces by consultants retained by Board staff. The task forces consisted of 83 volunteer stakeholder members representing various electricity distributors, gas utilities, customer groups, and special interest groups. The task forces met from mid-January 1999 through April 1999. To address the diversity and large number of emerging issues on PBR and restructuring in general, working groups were formed within each of the task forces. The reports produced by the various working groups were compiled by Board staff into task force reports[4 5 6 7] and issued in mid-May, 1999. Individual task force member position papers were included as appendices to the task force reports.

1.1.5 A Board Web site provided updates on the process for the benefit of parties who were not participating in the task forces.

1.1.6 The Board staff Proposed Electric Distribution Rate Handbook ("the draft Rate Handbook") was distributed on June 30, 1999. This draft document contains a proposal for a regulatory framework for the Board to use in developing and administering electricity distribution rates in the Province. Regional seminars were held across Ontario to provide stakeholders with an understanding and clarification of the proposal.

1.1.7 The draft Rate Handbook contains proposed rate policies, guidelines and procedures to be used by the Board in the establishment and adjustment of electricity distribution rates in the Province of Ontario for a first generation PBR plan. The proposed plan has a three-year term for the period 2000-2002.

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[4] Report of the Ontario Energy Board Performance Based Regulation Cap Mechanism Task Force. May 18, 1999.

[5] Report of the Ontario Energy Board Performance Based Regulation Yardstick Task Force. May 18, 1999.

[6] Report of the Ontario Energy Board Performance Based Regulation Implementation Task Force. May 18, 1999.

[7] Report of the Ontario Energy Board Performance Based Regulation Distribution Rates Task Force. May 18, 1999.

1.1.8 The Board, on its own motion dated August 19, 1999, convened a proceeding under subsections 19(4), 57, 70, and 78 of the *Ontario Energy Board Act, 1998* S.O. 1998, c. 15, Sched. B (the "Act" or the "OEB Act") to determine certain matters relating to the draft Rate Handbook for licensed electricity distributors with respect to the distribution of electricity to end-use customers. The Board determined that a proceeding on the draft Rate Handbook was appropriate to provide the information necessary for the Board to finalize the draft Rate Handbook.

1.1.9 A technical workshop was held September 2-3, 1999 to deal with issues of data availability and analysis methodology relating to the proposal.

1.1.10 Interested parties were requested to file written submissions providing comment on the draft Rate Handbook by September 14, 1999.

1.1.11 A technical conference was held September 21-27, 1999 to provide the opportunity for clarification on the submissions filed.

1.1.12 From October 4 through October 7, 1999 parties made oral submissions before the Board and the Board sought clarification on participants' views. Participants had the option of providing the Board with final written submissions by October 22, 1999. A number of participants exercised this option.

Parties to the Proceeding

1.1.13 Below is a list of those parties who actively participated by filing submissions. Only the names of those parties who are mentioned in this Decision have been abbreviated.

<u>Combined Interventions - Electric Utilities</u>

Bracebridge Hydro, Brampton Hydro, Cambridge and North Dumfries Hydro, Guelph Hydro, Niagara Falls Hydro-Electric Commission, Oakville Hydro, Pickering Hydro, Richmond Hill Hydro-Electric Commission and Waterloo North Hydro ("The Coalition")

Hydro Mississauga, London Hydro, Oshawa PUC, Sarnia Hydro, St. Catharines Hydro, Whitby Hydro, Petrolia PUC, St. Thomas PUC, GPU Electric Inc./GPU Services Inc. and Collingwood PUC, ENERConnect ("Mississauga et al")

Halton Hills Hydro and Peterborough Hydro

Aurora Hydro, Georgina Hydro, Innisfil Hydro, Markham Hydro, Newmarket Hydro, North Bay Hydro, Orillia Water, Light and Power, Richmond Hill Hydro, Whitchurch-Stoufville Hydro ("Upper Canada Energy Alliance" or "Upper Canada")

<u>Individual Interventions - Electric Utilities</u>

Hydro-Electric Commission of the City of Nepean ("Nepean Hydro")

Municipality of Chatham-Kent Public Utilities Commission ("Chatham-Kent Hydro")

Ottawa Hydro Electric Commission ("Ottawa Hydro")

Public Utilities Commission of the City of Sault Ste. Marie ("Sault Ste. Marie Hydro")

Toronto Hydro Electric System Limited ("Toronto Hydro")

<u>Other</u>

Nova Scotia Holdings Inc., CanEnerco Energy Marketing Limited, Sunoco Inc., Flamborough Hydro Electric Commission, Lindsay Hydro-Electric System

Aiken & Associates

City of Nepean

City of Peterborough

Consumers' Association of Canada ("CAC")

Energy Probe Foundation ("Energy Probe")

Direct Energy Marketing Limited and Enershare Technology Corporation

Enbridge Consumers Gas ("Enbridge Consumers")

Energy Cost Management Inc. ("ECMI")

Federation of Ontario Cottagers' Associations Inc. ("FOCA")

Great Lakes Power Limited ("GLPL")

Green Energy Coalition ("GEC")

Independent Electricity Market Operator

The Heating, Ventilation, Air Conditioning Contractors Coalition Inc.

Metropolitan Separate School Board, and the Ontario Association of School Business Officials

Municipal Electric Association ("MEA")

Natural Resource Gas Limited

Ontario Energy Savings Corp.

Ontario Federation of Agriculture ("OFA")

Ontario Hydro Services Company (“OHSC”)

Ontario Natural Gas Association

Ontario Power Generation Inc.

Pollution Probe Foundation (“Pollution Probe”)

Power Workers Union (“PWU”)

PSEG Global Inc. (“PSEG”)

TransCanada PipeLines Limited

Vulnerable Energy Consumers Coalition (“VECC”)

1.1.14 Board staff were assisted by consultants from PHB Hagler Bailly.

1.1.15 The Board also received various letters of comment.

1.2 THE STRUCTURE OF THE DECISION/ISSUES

1.2.1 This Decision deals with certain issues raised by the parties. It also deals with certain issues not explicitly addressed in the draft Rate Handbook or where clarification was seen as necessary.

1.2.2 The structure of the Decision generally follows the sequence of the contents of the draft Rate Handbook. Chapter 2 deals with a general approach to PBR. Chapter 3 deals with establishing the initial rates. Chapter 4 discusses the annual rate adjustment mechanism. Chapter 5 deals with service quality performance under a PBR regime. Chapter 6 discusses Demand Side Management matters. The final chapter, Chapter 7, deals with implementation issues. This Decision should be read in conjunction with the draft Rate Handbook.

1.2.3 Copies of all the documents and submissions filed in the proceeding, together with a verbatim transcript of the hearing, are available for review at the Board's offices. While the Board has considered all of the documents and submissions, the Board has cited these only to the extent necessary to clarify specific issues on which it has made findings.

1.2.4 The Board has not amended Board staff's draft Rate Handbook as part of this Decision. The next version of the Rate Handbook, which will reflect the Board's findings, will be distributed following the issuance of the Decision.

1.2.5 In addition to revisions necessary as a result of this Decision, the Rate Handbook may in the future be revised to address Board policies, Codes, and guidelines which affect rates. Compliance with the Rate Handbook will be a condition of licences issued to electricity distributors.

GENERAL APPROACH TO PBR

2.

2.1.1 The following are extracts from the draft Rate Handbook regarding the objectives of PBR:

> *PBR provides the distribution utilities with incentives to operate efficiently and innovate. It also gives consumers appropriate price signals, and allows the sharing in the gains from more efficient production, consumption and innovation.*
>
> *PBR is a framework that permits greater pricing flexibility and allows the potential for higher profits based on superior performance than would a traditional regulatory framework such as cost-of-service...*
>
> *...PBR decouples the price that the utility charges for its service from its cost. Since price adjusts according to a simple formula, if the utility can reduce its costs by more than its consumer dividend, it can keep the cost savings in the form of higher operating profits. Thus, PBR provides strong incentives for utilities to find efficiencies in their operations, some of which are recaptured in the form of lower rates when the plan is revised...*

... to discourage utilities sacrificing service quality in pursuing the economic incentives, service quality performance measures are included in the PBR plan.

2.1.2 The draft Rate Handbook proposes a three-year first generation transition PBR plan with price caps for all Ontario electricity distribution utilities. It is also proposed that a mid-term review be held to design the second generation of PBR. While the regulatory mechanism would be reviewed at that time, it is proposed that the Board would also conduct a re-basing study to identify the level at which rates should be established for second generation PBR.

Positions of the Parties

2.1.3 In general, the adoption of PBR was acknowledged by parties to be the appropriate direction for the regulation of the restructured electricity distribution utilities in Ontario. OFA did not believe that regulation by the province of the electrical distribution utilities was necessary. Some parties (most notably Upper Canada and CAC) proposed that the implementation of PBR be delayed. CAC was concerned about getting the initial rates correct, while Upper Canada felt that PBR was not needed at this point as the distribution utilities are already efficient, implementation of a market-based rate of return and transition costs would dwarf PBR gains, and utilities are already in a period of volatility and transition. Upper Canada proposed suspending the implementation of PBR for two or three years.

2.1.4 With respect to the price cap proposal, while most parties did not object to its use some parties proposed alternatives. Frontier Economics on behalf of Mississauga et al argued that, for industries where there are many participating businesses, the use of a yardstick regulation mechanism would give greater incentive for efficiency. In addition, Frontier Economics held that the price cap mechanism, as proposed, gives no consideration to the circumstances of particular utilities. Sault Ste. Marie Hydro suggested that the price cap adjustment mechanism incorporate a growth factor to account for increased system demand. It was generally agreed by parties that a yardstick regulation mechanism be a goal of the second generation PBR plan.

2.1.5 Certain parties suggested that the proposed three-year term was too short to provide incentives to distribution utilities to achieve maximum productivity. Others commented that, because of the lack of experience with PBR, the three-year term would help limit possible "bad outcomes", that is either excessive earnings or financial hardship. Parties also asked the Board to provide further elaboration on second generation PBR with respect to both re-basing and service quality matters.

Board Findings

2.1.6 The Board notes that some parties questioned the purpose of embarking on a PBR regime. In its policy document on the electricity industry restructuring, Direction for Change, 1997, the Government proposed "to direct the Board to examine, advise on, and subsequently implement a performance-based approach to regulation that ensures efficiencies are achieved in the monopoly parts of the industry and results in benefits to customers. The Government's goal is tariffs that are as low as possible on a sustainable basis".

2.1.7 In its draft policy on Performance Based Regulation in October 1998, the Board stated its rationale for developing a PBR mechanism:

- With the passage of Bill 35, the Board will have the task of regulating a large number of diverse utilities within the province. Since PBR has the potential to provide an expedient mechanism for adjusting rates over time as circumstance change, it is expected to result in fewer rate reviews before the Board and, hence, a lesser regulatory burden.

- PBR can provide greater incentives for cost reduction and productivity gains compared to those available under traditional cost of service regulation while protecting the interests of customers.

- PBR would allow the Board to establish minimum service quality and reliability standards and require compliance with these standards.

2.1.8 The Board has broad discretion under the Act to employ any method or technique in discharging its responsibilities to set just and reasonable rates.

2.1.9 The Board confirms its position that PBR is the appropriate mechanism to be used in bringing the electricity distribution utilities under the authority of the Ontario Energy Board.

2.1.10 With respect to the arguments regarding the use of price cap for all the distribution utilities, while there may be alternative PBR mechanisms that may hold promise, the Board notes that the task forces indicated that, at this time because of lack of consistent data, insufficient time, and insufficient resources, it was not possible to pursue other mechanisms, such as the yardstick mechanism that was the preference of many parties. Further, the Board is of the opinion that price cap regulation for all the electricity distribution utilities represents a simple approach that will provide incentives for efficiency improvements and will at the same time provide the ability to maintain service quality over the course of the first generation PBR plan. The Board therefore adopts the price cap mechanism for first generation PBR.

2.1.11 With respect to the suggestion by some parties that the initial term ought to be longer than three years, the Board finds that the three-year term provides a fair balance of the risks of potential "bad outcomes" and sufficient time for the distribution utilities to gain experience with PBR. In addition, the three-year term would allow the collection of sufficient data for the Board and the industry to assess the various mechanisms and will establish a baseline for second generation PBR. The Board therefore concludes that a three-year first generation transition PBR term for years 2000-2002 is appropriate. Given the relatively short period of first generation PBR, the Board does not envisage the need to include any provision to allow utilities to exit the plan, commonly known as "off-ramp".

2.1.12 On the issue of whether a growth factor should also be included in the price cap mechanism, the Board accepts Dr. Bauer's testimony that a growth allowance is implicit in a price cap PBR regime and therefore explicit inclusion of a growth factor in the price cap formula is unnecessary.

2.1.13 The Board is not prepared at this time to elaborate on details for the second generation PBR plan, such as re-basing of rates, except to reiterate what is stipulated in the draft Rate Handbook that the utilities will be required to undertake cost allocation studies[8] to better align rates among customer classes with cost causation in second generation PBR. Further, the Board confirms the proposal in the draft Rate Handbook that Board staff should initiate a mid-term review to design the next generation of PBR.

2.1.14 By way of commentary, the Board observes that PBR is not just light-handed cost of service regulation. For the electricity distribution utilities in Ontario, PBR represents a fundamental shift from the historical cost of service regulation. It provides the utilities with incentive for behaviour which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies. Customers and shareholders alike can gain from efficiency enhancing and cost-minimizing strategies that will ultimately yield lower rates with appropriate safeguards for service quality. Under PBR, the regulated utility will be responsible for making its investments based on business conditions and the objectives of its shareholder within the constraints of the price cap, and subject to service quality standards set by the Board.

[8] The Board distinguishes the terms ‘cost of service’ and ‘cost allocation’ studies in the following manner. Cost of service studies pertain to the determination of a total revenue requirement. Cost allocation studies deal with the allocation of the revenue requirement among customer rate classifications.

INITIAL RATES

3.

3.1.1 This chapter deals with the determination of the initial rates to be used in the first year (year 2000) of the PBR plan and to which the price adjustment mechanism will apply in the subsequent two years (years 2001 and 2002).

3.2 UNBUNDLING

3.2.1 As the starting point for unbundling the existing distribution utilities' rates into distribution and cost of power rates, the draft Rate Handbook assumes that existing rates appropriately recover costs from each of the rate classes. With this premise, a simplified method of allocating the cost of power to each rate class is presented in the draft Rate Handbook so that an initial class revenue requirement can be constructed that preserves rate class revenue neutrality.

3.2.2 The draft Rate Handbook acknowledges that, ideally, cost allocation studies would be available to guide the unbundling process. However, the draft Rate Handbook also acknowledges that there is only a short time available before market opening and therefore new cost allocation studies may not be feasible. In such circumstances, the draft Rate Handbook presents a simplified model of cost allocation as a default. The draft Rate Handbook allows distribution utilities that have their own studies to use them as the basis for setting initial rates.

3.2.3 The draft Rate Handbook indicates that the distribution (wires only) rates must be separated (unbundled) from the cost of power rates. The cost of power rates prior to market opening will cover both the transmission and commodity costs, since these are currently both included in current wholesale rates. With market opening, a transmission charge and a commodity charge will replace the cost of power charge. In order to unbundle existing rates, the revenue requirement for each customer class must first be separated into distribution and cost of power revenue requirements. In unbundling the rates, the cost of distribution system losses are separated as well. Prior to market opening, the distribution system losses will be included in the cost of power. With market opening, the distribution system losses will be recovered through a separate charge.

3.2.4 The proposal regarding the distribution rate structure in the draft Rate Handbook is a two-part distribution rate: a monthly service charge ($/month) plus a variable or volumetric charge ($/kWh or $/kW). The intent of the volumetric rate is to provide intra-class equity related to differences in system usage. The proposed design uses the incremental distribution cost (“IDC”) included in existing rates, net of system losses, to set the level of the volumetric charge.

3.2.5 The volumetric rate is based on the incremental distribution cost of $0.0062/kWh derived for residential customers in the 1980s. Appendix A to the draft Rate Handbook requires that distribution system losses be deducted from the IDC.

Positions of the Parties

3.2.6 Some parties questioned whether the current rates correctly reflect costs and whether they are therefore the appropriate starting point for the PBR regime.

3.2.7 Several parties (MEA, Upper Canada, OHSC, ECMI, FOCA, GEC, CAC) expressed concern that the unbundling model proposed in the draft Rate Handbook could cause undue rate impact within each customer rate class. This concern is related to the fact that a significant portion of distribution revenue will be recovered through the fixed service charge, rather than the volumetric charge. Additional concerns were raised about the validity of the IDC.

3.2.8 There was debate among parties as to whether losses were included or excluded from the $0.0062/kWh IDC rate. MEA commented that the proposed approach in the draft Rate Handbook of deducting losses from the IDC may amplify deficiencies in the IDC in the case of lower density/higher loss networks. That is, their true IDC would be higher than the $0.0062 value, yet deducting higher losses would further reduce this rate. MEA therefore suggested that the $0.0062 value be treated as a floor that could be raised by a certain percentage to reflect local costs. GEC suggested that losses were never included in the IDC so that it is inappropriate to deduct them.

3.2.9 GEC's consultant suggested that the IDC should at least be adjusted for inflation. Also, FOCA's consultant submitted analysis that suggested that the IDC used to determine the provincial average residential end rate could be almost twice the $0.0062/kWh rate.

3.2.10 Some parties expressed concern with the use of the residential IDC to establish volumetric rates for the remaining customer classes (general service, street lighting, sentinel lighting, and large use customer classes) since the $0.0062/kWh rate was derived for the residential class.

3.2.11 ECMI provided rate comparisons showing that low use customers in residential and general service classes would be subject to large rate impacts if a large proportion of the distribution revenue is collected in the form of a fixed service charge.

3.2.12 Certain parties (GEC, FOCA, Pollution Probe) were concerned about the environmental and energy efficiency effects of collecting a substantial amount of the distribution rate as a fixed service charge. These parties argued this rate structure would discourage energy conservation.

3.2.13 FOCA recommended that the monthly service charge reflect only customer specific charges such as meter reading, billing, and collection, and that all other costs be recovered in the volumetric component.

Board Findings

3.2.14 The Board is aware that the existing rates of the municipally-owned distribution utilities, as previously regulated by Ontario Hydro, are based on a utility average cost allocation model. The Board understands that, as a result of the use of the average cost allocation model, few, if any, distribution utilities have conducted their own cost allocation studies. The Board also recognizes the need for the distribution utilities to have unbundled rates in place by market opening and that this constraint makes it unrealistic to expect utilities to complete cost allocation studies prior to market opening. Therefore, the Board agrees that, as a default, the distribution utilities should be allowed to base their initial rates on existing rates.

3.2.15 However, the Board also recognizes the need for the distribution utilities to carry out cost allocation studies in order to ensure that rates for second generation PBR are based on cost causation principles. The Board therefore expects utilities to be prepared for a review of their individual cost allocation studies at the time of the mid-term review leading to the development of second generation PBR.

3.2.16 The Board notes that, while parties expressed concern with the use of a dated 1980s load research model as the default, no alternative study was available or prepared for the purposes of this proceeding. The Board notes that the two alternative approaches to unbundling existing distribution utility rates are to use utility-specific load research information or to use the 1980s load research model. To the extent that some utilities may choose to use their own load research information, the Board expects them to include such information in their filings with the Board.

3.2.17 GEC suggested that the IDC value of $0.0062/kWh does not include system losses. The Board notes that Ontario Hydro's Regulatory Application Guidebook describes local costs to include losses, incremental distribution costs and maintenance. It would appear that, in preparing the draft Rate Handbook, Board staff had incorrectly assumed that losses were included in incremental distribution costs.

3.2.18 The Board accepts that the use of a two-part rate structure consisting of a monthly service charge and a volumetric charge provides some revenue certainty for the distribution utility and, to the extent that IDC charges represent a reasonable reflection of the incremental cost of providing additional service, intra-class equity.

3.2.19 The Board however shares the concerns expressed by some parties as to the appropriateness of the proposed IDC value of $0.0062/kWh. For the purposes of first generation PBR, the Board concludes that it would be appropriate for the residential class to allow utilities to use their specific IDC level. The utility wishing to propose its own IDC level will be required to file appropriate justification. In the absence of a utility specific IDC level, the Board concludes that the proposed IDC value of $0.0062/kWh be used as the default value.

3.2.20 In either case, the volumetric charge (which is the same as the IDC in the absence of any other considerations) to be included in rates will have to consider the rate impact resulting from rate restructuring and the adjustments to the existing rates for purposes of establishing the initial rates for the first generation PBR plan. The Board's comments regarding mitigation of rate impact are set out later in this section.

3.2.21 The Board notes that the existing rates for the other (non-residential) rate classes were derived using this IDC value of $0.0062/kWh. The Board shares parties' concerns that this value may not be appropriate for these classes. Further, Board staff have alerted the Board that using the $0.0062/kWh value as the volumetric charge may result in revenue recovery in excess of 100 percent of the general service revenue requirement. In the absence of a utility-specific study, to provide for a consistent approach in designing a two-part rate structure among the various classes the Board has asked Board staff to explore the use of the ratio of the monthly service charge revenue to volumetric rate revenue for residential customers as a guide to determining the split between the revenue to be generated from the volumetric charge and the monthly service charge for the remaining customer classes. The method developed to address the above will be included in the Rate Handbook.

3.2.22 The Board also shares the concerns expressed by some parties about using a single monthly service charge level for all customers in the general service class regardless of customer size. To address this concern, the Board will include in the Rate Handbook a method for differentiation of monthly service charges for general service customers for three sub-groups: up to 50 kW (non-demand metered), equal to or greater than 50 kW, and intermediate use which is an optional rate classification for general service customers with demand greater than 3000 kW. The rate design should ensure revenue neutrality for each of these general service sub-groups.

3.2.23 The Board anticipates that the utilities will tend to set the volumetric charge at the minimum possible level and the monthly service charge at a higher level to minimize the risk of revenue shortfall. The Board shares certain parties' concerns regarding rate impact from moving to a rate structure with the proposed levels of monthly service charges. The Board observes that the rate impact could be large for low use customers. The Board expects that distribution utilities should take these impacts into consideration when setting the service charge and volumetric charge levels. The Board will require utilities to employ appropriate measures to mitigate the impact on low use consumers in each customer sub-group/rate class (for example, residential customers consuming less than 250 kWh per month). As a guideline, the increase in the total electricity bill resulting from rate restructuring for these customer groups should not exceed 10% on an annualized basis. For purposes of calculating the rate impact, the utilities shall use the current wholesale cost of power rates to determine the commodity component of the total customer bill amount.

3.2.24 Some parties expressed concern that a variable rate based on an IDC level of $0.0062/kWh is too low to provide an incentive for energy efficiency. The Board notes that there is insufficient evidence to determine the impact that the rate redesign will have on energy efficiency activity. In any event, the Board notes that the delivery component charges are not the major components of the total bill (distribution plus cost of power). Further, the Board's findings will likely result in higher volumetric charges than those proposed in the draft Rate Handbook.

3.2.25 The Board understands that revenues from miscellaneous distribution related service charges, such as disconnection and reconnection charges, non-payment of account charges, and rental fees are excluded from existing distribution service rates and are collected through separate charges. As such, these charges are not covered by the price cap mechanism and any changes to these charges will require explicit Board approval.

Minimum Bill Provision

3.2.26 The draft Rate Handbook makes no reference to minimum bill provisions. In their opening remarks in the oral phase, Board staff noted the need for minimum bill provisions in the Rate Handbook and referenced the existing Standard Application of Rates ("SAR") document for guidance on the development of minimum bill provisions.

3.2.27 The SAR states that minimum bills should be established according to existing guidelines developed by Ontario Hydro. The existing guidelines on minimum bills require the level for the residential class and non-demand metered general service customers to be established so that it does not exceed 25 percent of the residential bill at a consumption of 250 kWh. For general service customers with demand meters, the minimum bill is either equal to the residential minimum bill plus the allowance for transformers supplied at less than 115 kV per kW applied to the maximum kW in excess of 50 kW in the previous eleven months, or the transformer allowance per kW of the maximum demand created in the previous eleven months. The existing guidelines state that the existing minimum bill provision is based on the avoided cost of supply to the average customer, including the cost of the meter, meter reading, and carrying costs of any utility-supplied service drop normally dedicated to one customer. Even if a customer takes no power at all, the minimum bill applies.

3.2.28 The Board questions whether the provision for a minimum bill is required under a two-part rate structure with a fixed charge and a volumetric charge, given an appropriate degree of flexibility setting the levels of these charges. The Board is prepared to accept the use of a minimum bill for distribution services for first generation PBR for those utilities that currently have a minimum bill provision, where the utility believes it is necessary to retain such a provision in order to mitigate the rate impact on customers. However, any such requests must reflect the separation of distribution rates from cost of power. The Board expects that the need to have a minimum bill provision in a two-part rate structure will be reviewed for second generation PBR.

Unbundling and Rate Design Model

3.2.29 Appendix A of the draft Rate Handbook includes an illustration of the unbundling and rate design methodologies proposed by Board staff.

3.2.30 The availability of a spreadsheet model for unbundling and rate design could be of assistance to utilities in developing their proposed initial rates. In that regard, the Board understands Board staff are already in the process of developing such a model. The Board expects Board staff to ensure that the model reflects the Board's findings in this Decision, including the Board's concerns regarding rate impact.

3.3 ADJUSTMENTS TO UTILITY REVENUE REQUIREMENT

3.3.1 In establishing initial rates, the draft Rate Handbook stipulates that certain adjustments to current rates may be warranted, such as an allowance for market-based returns, which includes payment in lieu of income taxes, or proxy taxes, and for prudently incurred costs associated with the transition to the new market structure.

Market-based Return

3.3.2 The draft Rate Handbook proposes that distribution utilities would fall into four categories for the purpose of establishing a deemed capital structure. The draft Rate Handbook identified four levels of risk classification based on rate base size.

3.3.3 In order to calculate the market-based return, a rate base has to be determined. The total rate base equals total deemed capitalization of the utility. The cost associated with the debt component of the deemed capital structure is included in the draft Rate Handbook as part of the market-based rate of return revenue requirement ("MBRR") formula. The cost rate associated with the common equity component that was used in the draft Rate Handbook was 9.75 percent. The illustrative values for the cost of debt and common equity were based on a forecast that long-term Canada bond yields would average between 5.95 percent and 6.0 percent during year 2000, implying an equity risk premium of 375-380 basis points.

3.3.4 The methodology for determining the initial rate of return on common equity and the annual setting of Return on Common Equity ("ROE") is based on the methodology used by the Board in regulating natural gas utilities and was also applied in setting the transitional rates for OHSC (RP-1998-0001). The actual values of both the debt rate and the return on common equity will be calculated by the Board using data from December 1999.

3.3.5 The Board notes that certain parties submitted that the implied equity risk premium that underpins the 9.75 percent[9] rate of return used in the draft Rate Handbook is inadequate. The Board has not been persuaded that the implied equity risk premium contained in the 9.75 percent proposal is unreasonable. In finding so, the Board has considered the authorized rates of return for the gas utilities in Ontario as well as the authorized rate of return for OHSC. As for the argument by Enbridge Consumers that the single risk premium may not adequately compensate the higher risk faced by a smaller electric utility, the Board notes that the differentiation in the capital structure contained in the draft Rate Handbook based on rate base size makes allowance for the perceived differences in risk.

3.3.6 To determine the level of return, an initial rate base must be established. Such rate base must be related to the "wires only" activities. The Board is aware that some distribution utilities have already been incorporated and therefore have

[9] The updated rate of return on common equity to be used in establishing the initial rates may change to reflect the forecast values of the long-term Canada bond yields based on data for December 1999.

established their "wires only" activities, others have not. In either case the Board needs the information to establish the "wires only" rate base.

3.3.7 If the utility has undergone incorporation and separation of regulated and competitive activities when an application for initial rates is filed, the establishment of the utility rate base will be reviewed by the Board to ensure that there is compliance with the Board's guidelines with regard to the definition of distribution activities. If incorporation is not completed at the time of filing, a proforma projection should be prepared. In either case, the utility must present the rate base both before and after separation. The amounts removed from the integrated rate base, actual or notional, should be based on net book value.

3.3.8 In order for the Board to determine the adjustment required to reflect a market return on rate base, the Board requires information on the return achieved. The Board has determined that it would be appropriate to use year end 1999 data for determining the initial rate base.

3.3.9 In comparing the after-tax market return in establishing the initial rates with the achieved 1999 return, the Board's implicit assumption is that the integrated utility earned the same rate of return on all its business activities. The Board recognizes that there may have been differences in the contribution of different activities to the overall return but, in light of the complexities and substantial effort and time required to address such matters, the Board has determined that this assumption is reasonable in order for the distribution systems to be able to have initial rates in place before market opening.

3.3.10 The Board is cognizant of the fact that in the absence of shareholders, and through the previous regulator's cap on working capital levels, many of the municipally-owned electricity distribution utilities have historically earned below market-based returns. Upon corporatization, with the municipalities as their shareholders, the distribution utilities may wish to propose rates to target returns up to the allowable MBRR. Under this scenario, the Board is concerned with the resulting rate impacts in the establishment of the initial rates.

3.3.11 Throughout this proceeding the Board has heard from intervenors that ratemaking should as much as possible be a local decision. The Board agrees. The decision to implement full MBRR for all components of the rate base is a decision that falls upon the management, directors and the shareholders of the local utility, and the Board will require the utility to inform and explain the rate changes to their customers as well as the reasons thereof.

3.3.12 Based on the report of the distribution rates task force, implementation of a market-based return and taxes may result in an average increase on revenue required for distribution and cost of power of 6.1 percent. The revenue requirement for some utilities would be lower than that under the existing rates. For the majority of utilities the revenue requirement would be higher. In order to mitigate rate impact in the implementation of the initial rates, the draft Rate Handbook proposes that a deferral mechanism be put in place. Subject to the Board's findings later in this chapter that the initial rates will not incorporate any transition costs, the Board accepts the deferral mechanism proposal in the draft Rate Handbook.

3.3.13 Given the flexibility afforded to the utilities through the deferral mechanism, the Board will expect the utilities to take advantage of that flexibility and to propose initial rates that will not result in undue rate impacts. In its review of rate proposals and under its authority to fix rates, the Board will either seek revised proposals or fix the rates itself should it be found that rate impacts have not been adequately addressed.

Treatment of Contributed Capital

3.3.14 The draft Rate Handbook stipulates that:

> *Contributed capital collected under Ontario Hydro's regulatory regime and currently included in rate base will remain in rate base. The distributors will continue to earn a return on the contributed capital portion of the existing rate base until these assets are fully depreciated. However, the rate of return that will be applied to this component of the*

rate base will be the 1994-1999 average equity rate of return for the utility, subject to a zero per cent floor and a 9.75% maximum.

Going forward, under the Board's regulation, contributed capital collected by the electric distributors will not be included in rate base. As a result, the distributors will not be earning a return on the contributed capital collected in the future, nor will they be allowed to charge the associated depreciation expense to operating expense.

3.3.15 Board staff proposed this approach in the belief that it gives consideration to the regulatory framework that the distributors were subject to prior to the Board's assumption of this regulatory oversight role. As well, Board staff believed this approach leaves both the distributor and its customers no worse off than they were under the previous regulatory regime.

3.3.16 Prior to 1994, under the regulatory oversight of Ontario Hydro, municipal electric utilities were not allowed to include contributed capital (otherwise known as contributions in aid of construction) collected from developers and other new customers in the utility rate base. The asset base for revenue requirement purposes was the net book value of fixed assets minus the unamortized balance of the contributed capital associated with those fixed assets. In addition, contributed capital was accounted for as a deferred credit that was amortized and credited to operations, in effect offsetting the depreciation charge to operations associated with assets financed through contributed capital.

3.3.17 Ontario Hydro reviewed its policy in 1993 and concluded that exclusion of assets financed through contributed capital from rate base and depreciation expense from operating costs had the potential to cause distortions in the application of rate of return on rate base regulation. The stated rationale was that utilities with a high proportion of contributed capital would be unable to generate sufficient funds from operations for normal reinvestment requirements in the utility, and the uniform application of Ontario Hydro's regulatory guidelines among utilities was in jeopardy of being inconsistently applied.

3.3.18 Accordingly, commencing in 1994, Ontario Hydro's accounting policy on contributed capital was changed. Contributed capital was included in rate base thereby earning a return, and the associated depreciation expense was included in the utility annual revenue requirement.

Positions of the Parties

3.3.19 The parties to the proceeding were generally divided on the treatment of historic contributed capital, and differing positions were offered on the allowable rate of return on contributed capital.

3.3.20 A large group of intervenors (Mississauga et al, Upper Canada, Nepean, The Coalition, ECMI, PSEG, GEC) argued that historic contributed capital should attract a full market-based rate of return. The group generally held that no valid argument could be made to treat one form of capital in a different way from another since, in one way or another, all of the utility's assets were financed by the ratepayer. The group also held that Board staff's proposal was essentially tantamount to writing down the value of the utility's assets. Nepean contended that, since its average historical return in the 1994-1997 period was negative, the proposal essentially removes contributed capital from rate base in its case. The consultant for Mississauga et al, Frontier Economics, submitted that the cost of capital services used in distribution services is based on a measure of the market cost of capital for the regulated entity and that no other measure will produce economically efficient prices. Mississauga et al interpreted the Government's 1997 White Paper, Direction for Change, and the Act, as giving the right to municipalities, as owners, to structure the new utility corporations however they see fit. This right includes the ability to value, for all business purposes, the assets being transferred into the new corporation. Mississauga et al also expressed concern that the proposed treatment of contributed capital will have a serious impact on debt repayment through the loss of transfer tax and payments-in-lieu of taxes revenues.

3.3.21 Energy Probe submitted that contributed capital should be treated no differently than the rest of rate base, and that a common recovery policy be applied to both forms of capital. However, Energy Probe did not believe that a market-based rate of return should apply to any investments made by municipal electric utilities ("MEUs") when they were operated as "co-ops". Therefore, in its view, historic contributed capital and all other capital should not attract a market-based rate of return.

3.3.22 FOCA and VECC submitted that historic contributed capital should be removed from rate base. VECC stated that Board staff's proposed treatment of historic contributed capital is inconsistent with the Board staff proposal to exclude future contributed capital from rate base and with standard regulatory practice. VECC noted that the standard practice in other Canadian jurisdictions is to treat contributed capital as a source of funds that does not attract a return and that the Board itself uses this approach in the regulation of the Ontario natural gas distribution utilities. Both VECC and FOCA argued that, in the case of contributed capital, MEUs have not invested anything themselves and have not assumed the risk of an accumulating debt obligation. If customer contributed capital is included in the rate base, customers would essentially be paying twice for the assets being used to serve them; once through the contributed capital they have provided and again through the distribution charges they pay. VECC and FOCA argued that all customer contributed capital should be excluded from the rate base.

3.3.23 CAC and Chatham-Kent Hydro accepted Board staff's proposed treatment of historic contributed capital. Chatham-Kent Hydro qualified its support for the use of the1994-1999 average equity rate of return with the proviso that the rate of return be on an after tax basis. Dr. Bauer, on behalf of CAC, qualified his support stating that the proposal is a sensible compromise that avoids regulatory recontracting. However, he argued that, from an economic efficiency view, contributed capital should be removed from rate base as the use of contributed capital diminishes the need for the utility to raise debt or equity capital. He noted that, while the capital contributions are used to augment the capital basis of the utility, there is no need to compensate investors for their time-preference or risk. Dr. Bauer also expressed the view, as did certain other parties, that inclusion of contributed capital in rate base would lead to double-payments. However, he stated that accepting a specific notion of fairness, namely not to change past arrangements, the Board staff proposal is acceptable.

3.3.24 CAC took issue with the legal argument put forth by Mississauga et al. CAC argued that nowhere in the legislation or the White Paper are absolute rights or sole discretion conveyed to municipalities or MEUs. CAC argued that section 128(2) of the Act means the powers of the Board prevail over any by-law passed by a municipality. CAC submitted that the Board has the jurisdiction to value contributed capital as part of the process of establishing a mechanism for the determination of just and reasonable rates, and that the Board should do so in the exercise of that jurisdiction. PWU submitted that, for the purpose of ratemaking, the Board's statutory authority is broad and unfettered, and not bound by any valuation of assets made by any municipality in a transfer by-law.

Board Findings

3.3.25 The Board notes that no parties questioned the Board staff proposal that future capital contributed on or after January 1, 2000 not be included in rate base. The Board confirms this approach and this will ensure similar treatment between gas and electricity distribution utilities in the future.

3.3.26 In evaluating the alternative treatments of historic contributed capital there are two questions that need to be addressed by the Board. The first is whether or not historic contributed capital should be included in rate base; the second, if included, what rate of return should apply.

3.3.27 The Board has been persuaded by the arguments that historic contributed capital for electricity distribution utilities is a unique case. The Government indicated in its White Paper that MEUs will be put on a commercial footing consistent with other commercial businesses operating in Ontario. The Government also indicated that, in reviewing local distribution tariffs, the Board would be expected to make an appropriate allowance for a normal rate of return. In establishing the new utilities, the assets of the local municipal utility have been or will be transferred to the municipality as the shareholder. From a regulatory point of view, the new shareholder of these assets will have the rights and responsibilities accorded to them under the applicable legislation. This includes a fair rate of return on the total capital employed.

3.3.28 The Board also notes that there are economic and fairness arguments in favour of not distinguishing the two sources of capital. Differentiating a source of capital for the purpose of pricing such capital at different rates would lead to both inequities among utilities and would result in inappropriate market pricing signals for the services provided by the distribution companies. On the first point in particular, the Board is aware of the wide differences among utilities with regard to the relative portion of historical contributed capital to the total capital employed by the utility. As some parties noted, all of the capital has been contributed by the ratepayers whether by means of contributed capital or through rates. To introduce a policy that would allow a return to the utilities that had funded their capital through rates rather than contributed capital, but to deny this opportunity to those utilities who had for the most part used development charges/contributed capital would, in the Board's view, put the utilities on an unequal commercial footing in this regard.

3.3.29 Given the above, the Board concludes that historic contributed capital should be included in rate base and that the same rate of return should apply to all capital, exclusive of future contributed capital, employed by the distribution utility.

Transition Costs

3.3.30 The draft Rate Handbook indicates that the initial rates may, subject to certain criteria such as causality, materiality, management's inability to control and prudence, include costs associated with the transition to the new market structure. The Handbook further states that all such costs must be specifically identified and justified.

Positions of the Parties

3.3.31 Parties' arguments generally addressed transition costs together with their argument regarding Z factors as presented in the draft Rate Handbook. Some parties expressed concern about the reasonableness of including transition costs in rates. Parties also suggested that transition costs claimed for inclusion be audited and benchmarked.

Board Findings

3.3.32 The Board concludes that transitional costs should be classified into two categories. The first category is costs related to corporate reorganization and to the transfer by-law whereby the municipal corporation acquires the assets of the municipal electric utility. The second is costs related to the business re-engineering of the incorporated distribution company to conform to the new business orientation and requirements of a "wires only" company.

3.3.33 With respect to the costs of corporate reorganization, the Board notes that, under the Act, the municipalities are the shareholder of the distribution utilities. Along with the benefits of such ownership, there are also responsibilities. These responsibilities include bearing the cost of corporatization and corporate reorganization. In dealing with such issues in the regulation of the gas utilities, the Board has generally found such costs to be the responsibility of the shareholder. The Board therefore finds that this category of costs should be to the account of the shareholder.

3.3.34 With respect to the business re-engineering costs, the Board concludes that these costs will likely be incurred over a period of time that will likely extend beyond the date of the initial rates being in place. Therefore, the Board finds that these costs should be deferred and dealt with as part of the Z factor mechanism included in the price cap formula. The Board accepts the proposal in the draft Rate Handbook that such costs will have to be specifically identified, justified and meet the four criteria tests mentioned above. Further, the Board will not require that specific applications be made for establishing deferral accounts in respect of these costs; this Decision should be viewed as the only regulatory instrument required to establish such accounts.

3.3.35 On the basis of the above discussion and findings, the Board will not permit incorporation of any transition costs for purposes of establishing initial rates.

4. ANNUAL RATE ADJUSTMENTS

4.1.1 The draft Rate Handbook proposes a price cap mechanism to adjust the distribution rates for the second and third years of the first generation PBR term. The formula for the price cap adjustment includes an input price index ("IPI"), a productivity factor ("PF"), and an adjustment factor ("Z factor") to reflect extraordinary items. The Board deals with these matters in this chapter.

4.2 INPUT PRICE INDEX

4.2.1 The draft Rate Handbook states that:

> *The purpose of the input price index adjustment is to allow each utility the discretion to pass through changes in the prices of the inputs it purchases - at a rate determined by the* <u>*typical*</u> *distributor's experience with input prices during the previous year. A distributor whose own input prices rose less than the input prices of the typical distributor would increase its earnings if it chose to adjust its own price cap by the full amount...This input price index is specific to the electric distributors in Ontario. The index comprehensively measures changes in the prices of inputs employed by the distributors including capital, labour and materials.*

Positions of the Parties

4.2.2 Certain parties (Upper Canada, OHSC, Chatham-Kent Hydro) argued that an existing index, such as the Consumer Price Index ("CPI"), be used rather than the proposed IPI. These parties were concerned about the lack of transparency and untried nature of the IPI. Chatham-Kent Hydro was concerned about relying upon a newly created factor that is not commercially tracked or forecasted, when other indexes such as CPI and Gross Domestic Product Price Index ("GDPPI") are commonly available. Additional concerns were expressed about the ability of the Board to deliver an IPI calculation to all utilities by February 15 based on a filing deadline of February 1. OHSC was concerned about the variability of IPI and questioned the ability of the capital portion of the index to measure the actual costs that utilities face. Upper Canada had similar concerns and their consultant pointed out that CPI is used in other jurisdictions' PBR plans, is simple, and yields real price declines to distribution consumers.

4.2.3 Mississauga et al consultant, Frontier Economics, submitted that the choice of an inflation index is essentially irrelevant. Frontier Economics acknowledges that there may be certain advantages to using an input price index if the productivity measure is particularly volatile. In general, however, Frontier Economics held that the choice of an index is a trivial issue in incentive regulation but that such choice would impact the setting of the productivity factor.

4.2.4 Dr. Bauer, on behalf of CAC, held that, in calculating input price inflation from industry data, the proposed input price inflation measure violates the salient principle of incentive regulation that the plan parameters be derived from data external to the regulated utility. He noted that this is somewhat mitigated by the fact that there are a large number of utilities and no individual utility is able to influence the overall index unduly. Nonetheless, he felt that there may be an incentive for utilities to exaggerate cost data but allowed that this risk can be reduced by strict auditing requirements.

4.2.5 Energy Probe supported the use of the proposed input price index rather than CPI.

Board Findings

4.2.6 The Board has been presented with two alternatives regarding the price index adjustment. The first is the proposal made by Board staff in section 4.2 of the draft Rate Handbook. Board staff have outlined an input price index specific to Ontario electric distribution utilities that measures changes in the prices of inputs employed by the distributors, including capital, labour and materials. The alternative proposal was to use an economy-wide index such as CPI.

4.2.7 The Board notes the reasoning behind the Board staff proposal. The proposed index compares the prices of the factor inputs (capital, labour, materials) in any given year with a base year in order to determine an industry specific input price index that is reflective of the input costs of Ontario electricity distribution utilities. One major shortcoming of the CPI, highlighted by Board Staff, is that it does not measure changes in the price of capital, which is crucial in determining the appropriate change in input prices for capital intensive operations such as electricity distribution utilities. CPI is also influenced by factors such as changes in consumption taxes and food prices, which have no effect on the input prices faced by electricity distribution utilities.

4.2.8 The Board notes the parties' perception that the capital price portion of the index fluctuates unduly and may not measure the actual costs electricity distribution utilities face. The Board recognizes that Board staff proposed a user-cost of capital approach to determining the price of capital. In this approach, the cost of using a unit of capital is the opportunity cost of the capital including depreciation. The opportunity cost is represented by the interest forgone by having resources committed in the form of the asset. Board staff have used the 10 year Canada Long Bond Rate as the interest rate, a widely accepted method in setting a risk-free rate of return. The Board accepts this as an appropriate approach. The main purpose in moving towards PBR is to give the distribution firms the same price and cost signals as faced by unregulated companies. In addition, the industry IPI serves as a benchmark that the utilities can aim to outperform, through superior procurement and capital financing strategies.

4.2.9 In accepting the IPI approach, the Board has considered criticisms that utilities are constrained by the existing cost and term of their debt obligations, that is, the embedded cost of debt. Competitive companies have the opportunity to access capital markets when it is in their interest to do so. The Board accepts that PBR is intended to provide incentive for this behaviour. Even though the price cap adjustment to the rates will not apply until 2001, it is expected that, in the meantime, utilities will be making their capital financing decisions mindful of the application of the IPI to their operations and rates.

4.2.10 The Board also considered the criticism by some intervenors that the IPI could be influenced by the collusive activities of some distributors. In light of the fact that there are over 250 utilities in the province, the Board does not consider this a valid criticism. In addition, the Board notes that much of the data used to calculate the IPI is obtained from sources external to the utility. The Rate Handbook will include the sources of data used to derive the IPI. Going forward, the calculation of the IPI will be made from data available from external sources and from the filings by the utilities. This should address the parties' concerns regarding transparency.

4.2.11 However, the Board shares the concerns expressed by some parties regarding the ability of the industry to cope with the volatility of the IPI from year to year. In the Board's view, such volatility will be better managed as the industry gains experience with PBR. The Board recognizes that utilities may require a transition period before implementation of the IPI. The Board notes that the source of the volatility comes mainly from the capital cost component. In order to mitigate potential volatility in the IPI in the first generation PBR, the Board finds that the changes to the cost of capital component of the IPI will be limited to one half of the observed change. The Board recognizes that this is an arbitrary number but is of the view that it will directionally address concerns regarding year to year volatility.

4.3 THE PRODUCTIVITY FACTOR AND SHARING

4.3.1 The draft Rate Handbook states that:

> *The purpose of the productivity factor is to account for the downward influence on the price of a utility's product from gains in efficiency broadly considered...TFP* [total factor productivity] *has been used extensively in the application of PBR in many regulated industries, including electric. The task forces and Board staff reviewed many of these applications and the underlying approaches...the plan allows utilities to select the particular productivity factor from a set of six that it believes best reflects the combination of circumstances, opportunities, risks and rewards facing the utility.*

4.3.2 The draft Rate Handbook sets out the following menu of options for the relationship between productivity factor and rate of return on common equity ceiling.

Selection	Productivity Factor (percent change per year)	ROE Ceiling (Percent)
A	1.25	10
B	1.50	11
C	1.75	12
D	2.00	13
E	2.25	14
F	2.50	15

4.3.3 The figures shown as the ROE Ceiling are subject to change from year to year to reflect annual adjustments to the Board-approved market rate of return on common equity. Returns achieved up to those levels are to the account of the shareholder. Returns achieved above those levels would be returned to customers.

4.3.4 Research over the 1988 to 1997 time period as documented in the draft Rate Handbook found that the average annual change in TFP across Ontario distributors, based on a sample of 48 distributors, was approximately one percent. The PF value of 1.25 was set as the default value including a "stretch factor" of 25 basis points.

Positions of the Parties

4.3.5 Discussion by the parties fell into three general categories: the default PF value, the relationship between PF and ROE, and the concept of earnings-sharing.

4.3.6 A number of parties (OHSC, Upper Canada, The Coalition, Enbridge Consumers, MEA, Toronto Hydro) felt that the default PF value was too high. Some pointed out that the ten-year historic average annual TFP is only 0.86 per cent. In addition, it was argued that there may be a correlation between growth in output and growth in TFP that may bias the TFP in favour of high growth MEUs, so that low growth MEUs are disadvantaged. There was also concern expressed that distributors who have recently increased efficiency would be disadvantaged relative to those who had not.

4.3.7 Some parties (Mississauga et al, OHSC, Upper Canada) were concerned about the methodology chosen and the inability to check the data used by Board staff and its consultants in reaching their conclusions. In addition, Mississauga et al submitted that the foundation of the default value of 1.25 percent is subjective and its impact is unknown, and suggested a default PF in the area of 0.5 percent. Certain parties (Enbridge Consumers, The Coalition, Upper Canada) argued that only about one-third of a utility's total costs are controllable. Enbridge Consumers suggested a PF in the order of 0.3 percent, which would require an Operating and Maintenance Expense annual productivity gain of approximately 0.7 to 1.2 percent.

4.3.8 Dr. Bauer, on behalf of CAC, submitted that it cannot be concluded without further evidence that higher past productivity gains cannot be continued in the future. Noting the ten-year annual average TFP of 0.86 percent and the achievement of approximately two percent in the last five years, he contended that the chosen range of PF values reflects the lower boundary of reasonable values, suggesting that an upward shift by several tenths of a percentage point would be justified. In his view, to compensate for the past monopoly behaviour of the industry, it would be appropriate to include a stretch factor in the area of 0.5 to 1.0 percent. Energy Probe suggested that the sample collected by Board staff underestimates the potential for productivity improvement.

4.3.9 Some parties cautioned against a “one size fits all” approach. Specifically, Toronto Hydro suggested that a utility size-specific menu be available.

4.3.10 Certain parties believed that there is no economic basis for the PF-ROE ceiling schedule, and that there is no analytical basis for the proposed linear relationship between the PF and ROE ceiling. Mr. Todd, on behalf of VECC, posited that the PF-ROE menu does not provide an adequate incentive for a distribution utility to select a productivity target that realistically reflects its achievable productivity gain. He suggested that the proposed menu would encourage a utility to choose the lowest PF. He further suggested that an earnings-sharing mechanism can overcome this shortcoming. Some parties submitted that the proposed menu is too complex. Enbridge Consumers suggested the replacement of the proposal with a single PF and an earnings-sharing mechanism. Several parties (Toronto Hydro, OHSC, MEA) suggested that the ROE ceiling be averaged over the PBR term rather than calculated annually.

4.3.11 Several suggestions were made with regard to possible earnings-sharing mechanisms, including a sharing over any menu adopted by the Board or sharing over the ROE ceiling with or without a deadband. A sharing split of 50/50 was presented as a possible option. Some parties proposed that any sharing mechanism should be symmetrical, others suggested that the differential sharing levels be dependent on the level of ROE and productivity factor chosen.

Board Findings

4.3.12 In assessing the issues raised, the Board's conclusions have been influenced by the scope and objectives of a first term PBR. In this regard, the Board favours a model or methodologies that are easily understood and implementable, while at the same time providing incentives to the utilities to make productivity improvements.

4.3.13 The Board acknowledges the concerns expressed by parties regarding the unnecessary complexity encompassed in the proposed menu. The Board also notes the comments by some parties that the default productivity level would be the preferred choice of most utilities therefore placing into question the effectiveness of the proposed menu. The Board has assessed this concern against the arguments by some parties that a "one size fits all" approach should not be adopted by the Board. On balance, the Board concludes that the proposed menu approach should for first generation PBR be replaced by a single productivity factor for all utilities, combined with an earnings-sharing mechanism as proposed by some parties.

4.3.14 The Board therefore must first find the appropriate level of the productivity factor. The Board notes the information provided by some distributors that doubling the assumed productivity factor would result in a rate of return on common equity adjustment of approximately 40 basis points. Clearly, while the choice of the appropriate level of a productivity factor is important, its precise level is not of critical importance to the financial integrity of the utility. In the transition period for the electricity distribution utilities, there will likely be more critical considerations that may affect their profitability.

4.3.15 Having rejected the proposed menu in which the 1.25 productivity factor was the minimum of all options, the Board is concerned that in the absence of a menu, which incorporated higher levels, the 1.25 level no longer represents a reasonable base level to apply to all utilities. The Board notes that the default value is comprised of an average of 0.86 percent rounded by Board staff to a one percent productivity level achieved over a ten-year period plus a stretch factor of 25 basis points. The Board accepts 25 basis points as a reasonable stretch factor for purposes of first generation PBR. However, in the Board's view, the base productivity factor ought to be adjusted upward. In assessing a reasonable level for that base, the Board notes that, on the basis of the information provided in the proceeding, the achieved annual average productivity growth for the sample of 48 electric utilities was 0.86 percent for the most recent ten-year period and 2.05 percent for the most recent five-year period. The Board notes the arguments by certain parties that the most recent five-year period ought not to influence the Board's deliberations on the grounds that this period was not representative. Nevertheless the Board considers that some recognition must be given to the results achieved in the most recent five-year period. The Board has therefore adjusted the base productivity factor by giving a weight of two-thirds to the ten-year average result and one-third to the five-year average result. The Board therefore finds 1.5 percent as the appropriate productivity factor, inclusive of a stretch factor of 0.25 percent.

4.3.16 The Board has also considered the numerous presentations made in support of a sharing mechanism for earnings beyond the ROE ceiling. Elsewhere in this Decision the Board has dealt with the adjustment necessary to determine the initial ROE for the establishment of initial rates. The ROE representing the market-based rate of return for the second and third years of the PBR term will be determined in accordance with the Board's guidelines for determining the rate of return on common equity. To ensure that no excessive leveraging occurs, the Board expects that the actual proportion of the common equity component will not be materially lower from that deemed by the Board. The equity risk premium shall first be determined as discussed in Chapter 3 of this Decision.

4.3.17 The Board is of the view that the shareholder should retain a portion of the excess earnings over the ROE ceiling for the first PBR term. In considering all the alternatives proposed by the parties, and in light of the Board's findings with respect to the proposed menu, the Board finds that the excess earnings (after tax) resulting from any difference between the achieved and the Board-specified rate of return on common equity will be shared equally between the shareholder and customers.

4.3.18 The Board is of the view that the 50/50 sharing will provide sufficient incentive to encourage utilities to pursue productivity improvements above that included in the productivity factor. This sharing mechanism is set for first generation PBR and the issue of earning-sharing and productivity factor(s) will be subject to review for second generation.

4.3.19 As to the method for returning any excess earnings to the ratepayers, the Board accepts the provisions stipulated in the Supplement to the draft Rate Handbook dated August 12, 1999. These provisions allow for the excess earnings to be used as an offset to other charges, such as Z factors and deferral account balances, and if there are any remaining over-earnings these should be returned to ratepayers as a one-time rebate.

4.4 THE Z FACTOR

4.4.1 The draft Rate Handbook stipulates that:

> *A Z factor has been incorporated into the PBR rate mechanism to address extraordinary events and transition costs. In order for costs to be included in the Z factor, the costs must satisfy four tests:*
>
> C *Causation ....*
> C *Materiality...*
> C *Inability of Management to Control...*
> C *Prudence...*
>
> *The Board reserves the right to review the amounts claimed under the Z factor or transition cost treatment at any time during the term of the PBR plan.*

Positions of the Parties

4.4.2 Parties' arguments generally addressed transition costs together with their argument regarding Z factors. The Board has dealt with the issue of transition costs earlier in Chapter 3 of this Decision. The Board has attempted to summarize in this section its understanding of the parties' positions on Z factors.

4.4.3 VECC suggested that Z factor costs be benchmarked on a dollar per customer basis to avoid excessive costs and to streamline the process for determining prudence. It also suggested that the review process include public review. VECC and CAC suggested that any tax or accounting changes or changes of a legislative or judicial nature that affected the entire economy should not be eligible as a Z factor. VECC further suggested that if a distribution utility incurs costs in the anticipation of future benefits as a result of judicial or legislative actions, such costs should not be eligible as Z factors. CAC also proposed that Z factors be more narrowly defined and proposed amounts be audited. Energy Probe was generally opposed to all Z factors.

4.4.4 There was a suggestion by some parties that Demand Side Management ("DSM") could be incorporated into a price cap by means of a Z factor.

Board Findings

4.4.5 In Chapter 3 of this Decision, the Board categorized the transition costs into those related to corporate reorganization and to the municipal transfer by-law and those related to the business re-engineering of the incorporated distribution utility. The Board found only the latter to be eligible for inclusion in rates through the Z factor mechanism.

4.4.6 With respect to the suggestion of benchmarking Z factor costs on a dollar per customer basis, while this suggestion may have merit in the future, based on the information provided in this proceeding the Board has not been persuaded that this approach is workable or appropriate at this time. In the absence of better information the Board is concerned that adoption of such a suggestion would unduly disadvantage small utilities.

4.4.7 With respect to the suggestion that more precise definitions be provided of what would constitute Z factors, the Board questions the plausibility of the suggestion. The very nature of a Z factor is that it must be extraordinary, unpredictable and unmanageable. Further, the Board is concerned that it does not create the opportunity for utilities to game the system by diverting costs that should be part of the normal operations of the company into a Z factor treatment. The Board is of the view that a more suitable approach is to consider extraordinary event and transition costs on a case-by-case basis as proposed in the draft Rate Handbook.

4.4.8 The Board has not been persuaded that a separate and distinct process is required to address matters pertaining to the accounting, audit, or disposition of Z factor accounts (deferral accounts). Z factor applications will form part of the overall application and review of each distribution utility's rate adjustment. The Board of course has the authority to audit the accounts and accounting practices of the utilities at any time.

4.4.9 As for the suggestion that expenditures related to DSM activities be considered a Z factor, in light of the Board's findings in Chapter 6 on matters dealing with DSM generally, the Board has determined that it is premature to make a specific finding at this time.

4.5 INTER-CLASS RATE FLEXIBILITY

4.5.1 The draft Rate Handbook proposes that:

> *...a utility could structure a price cap mechanism separately for baskets of residential, general service and large use customers subject to the following constraints:*
>
> > *The results of the three price cap adjustments to the baskets do not produce an overall cap which exceeds the ceiling imposed on the utility's average price.*
> >
> > *None of the caps on individual baskets falls outside of a 5% flexibility adjustment zone.*

4.5.2 Board staff noted in their opening statement at the technical conference that the flexibility was intended to allow distribution utilities to adjust rates towards their own cost allocation circumstances over the term of the first generation PBR plan and to deal with threats of bypass by large customers.

4.5.3 Some parties expressed concern that the rate flexibility could be used for inappropriate inter-class subsidization, shifting revenue responsibility to captive customers, such as the residential class, from users that may have competitive options.

Board Findings

4.5.4 The Board notes that, during the proceeding, there was some confusion on how Board staff's pricing flexibility proposal was interpreted. To the extent that the five percent flexibility adjustment was intended to apply to the absolute price level, the Board finds merit in parties' arguments that there is a possibility of undue subsidy among customer classes. To the extent that the five percent flexibility adjustment was intended to apply only to the price cap adjustment, not the price itself, the Board questions the value of the scope of the flexibility. Further, it is not clear to the Board as to how average prices would be determined at any point in time. For all of the above reasons, and consistent with the Board's general approach not to unduly complicate the introduction of PBR, the Board does not adopt the pricing flexibility and baskets provision [section 4.5.1] in the draft Rate Handbook.

4.5.5 The Board however accepts that a utility may wish to confirm the reasonableness of class rates relative to cost causality. In proposing realignment of rates to better align rates with costs, the Board expects the utility to file an appropriate cost allocation study.

5. SERVICE QUALITY

5.1.1 The draft Rate Handbook proposes that all distribution utilities measure six customer service indicators and three service reliability indicators for first generation PBR. A minimum level of service performance is proposed for each of the customer service indicators. For the distribution utilities that have at least three years data on a service reliability index, the distribution utility is expected to, at minimum, remain within the range of its historic performance. The draft Rate Handbook proposes that six of the nine indicators be reported to the Board, while the remaining three service quality measures need not be reported, but should be used by distribution utilities as standards for minimum guidelines in adopting management policy.

5.1.2 The following table outlines the service quality and reliability indicators proposed in the draft Rate Handbook:

Customer Service	Service Quality
Indicators Requiring Reporting: Connection of New Services Underground Cable Locates Appointments Indicators not Requiring Reporting: Telephone Accessibility Written Response to Inquiries Emergency Response	Indicators Requiring Reporting: System Average Interruption Index (SAIDI) System Average Interruption Frequency Index (SAIFI) Customer Average Interruption Duration Index (CAIDI)

5.1.3 The draft Rate Handbook also proposes that distribution utilities report performance results annually to the Board. Utilities would also be required to file remedial action reports in cases of substandard performance. The proposal anticipates that economic consequences for service degradations may be in place for second generation PBR.

Positions of the Parties

5.1.4 Some parties noted that service quality was historically dealt with locally (by the municipal government or Commission) and suggested that centralized service quality regulation is unnecessary. Other parties commented that service quality might be reduced as firms seek to reduce costs in pursuit of efficiency gains, and therefore regulation of service quality is appropriate. Section 1(3) of the Act was highlighted. This section states that one objective to guide the Board in carrying out its responsibilities is that it must act to protect the interests of consumers with respect to prices and the reliability and quality of electricity service.

5.1.5 Many parties commented that the proposals lacked detail and sought clarification to the definitions of indicators and standards. Others suggested that the indicators should measure only incidents that are directly controllable by the distribution utility and exclude failures in generation or transmission and *force majeure* incidents. CAC and Sault Ste. Marie Hydro submitted that the proposal for remedial action plans lacked specificity.

5.1.6 Some parties suggested that the proposed service quality indicators were inappropriate. For example, Upper Canada commented that indicators such as cable locates form an insignificant part of the distribution utility's operations. Others commented that while the indicators were appropriate, they were inadequate for allowing the Board to monitor the service performance of distribution utilities. Enbridge Consumers suggested that the number of service quality indicators was burdensome and should be reduced.

5.1.7 VECC and PWU suggested that data on momentary outages, in the form of an indicator called Momentary Average Interruption Frequency Index ("MAIFI"), be collected and reported.

5.1.8 FOCA and PWU suggested that aspects of public and employee health and safety should be reported as indications of performance while others held that employee safety was a responsibility of the organization and does not need to be reported.

5.1.9 GEC, Pollution Probe, and FOCA advocated that environmental performance be included in service quality monitoring. FOCA suggested that PCB handling could be one such environmental indicator.

5.1.10 Several parties (VECC, PWU, CAC) expressed concern about the effectiveness of service quality standards in the absence of economic penalties for non-compliance. PWU also suggested that financial penalties be imposed for non-compliance with data collection and reporting.

5.1.11 VECC suggested that earnings in excess of the market-based rate of return be tied to quality standards, similar to schemes in British Columbia and Quebec. However, they acknowledged that data may be a problem in the short term.

5.1.12 CAC and PWU suggested that all indicators should be reported and subject to some form of audit or review.

5.1.13 VECC and CAC suggested that performance results reported by the distribution utilities to the Board be made publicly available. It was also suggested that public reporting could motivate improvement of service quality.

5.1.14 Some parties commented that the introduction of systems to measure and report on service quality is a cost and burden on utilities not already doing so. It was also suggested that costs related to the introduction of service quality measurement systems should be allowable transition costs.

Board Findings

5.1.15 One of the objectives of the Act is protection of the consumers' interests with respect to prices, quality and reliability of electricity service. Any reduction in the quality and/or reliability of a service represents a reduction in the value of that service. Therefore, as part of its function in regard to approving or fixing just and reasonable rates, the Board has a responsibility to oversee that service quality is preserved and improved.

5.1.16 The Board recognizes that electricity industry restructuring introduces many unknown factors that could impact on performance levels and customer expectations. Further, there is a lack of consistent information on historical performance. Therefore, the Board is of the view that, for first generation PBR, a cautious approach to introducing service quality performance indicators and standards is warranted. The proposed approach in first generation PBR appropriately focuses on data collection, reporting, and monitoring of service quality and reliability performance by all distribution utilities.

5.1.17 The Board notes that the Board staff proposals for service quality indicators and standards were developed through the task force process which benefitted from input from the industry and other stakeholders and from a survey conducted by the task force itself. Although the task force found inconsistency in the measurement of service quality performance in the industry, nevertheless its surveys indicated that the proposed service quality and reliability measures are applicable to utilities of varying sizes and with varying operational characteristics (size, density, urban/rural, etc.).

5.1.18 The Board finds that the service quality indicators proposed in the draft Rate Handbook are appropriate for indications on the service performance of the distribution utilities over the course of first generation PBR.

5.1.19 The Board notes parties' comments seeking clarification of the definitions. To the extent that this is possible and practical, the Board will do so in the Rate Handbook.

5.1.20 The Board notes that, generally, parties representing electricity distribution utilities indicated that the proposed minimum standards are appropriate and achievable.[10] As a result, the Board favours the minimum standards proposed in the draft Rate Handbook for first generation PBR. The Board notes that these standards represent the minimum acceptable performance; a utility should continue to establish its operating performance at any level better than the minimum standard, taking into consideration the needs and expectations of its customers and of cost implications.

5.1.21 The Board considers that service interruptions as experienced by customers, regardless of cause, should be reported to the Board. The Board notes that the cause of service interruption is to be documented as well. In any instances of service interruptions, the Board will take into account exogenous factors that impact on the reported performance.

5.1.22 In contrast to the proposal in the draft Rate Handbook, the Board is of the view that all of the nine proposed indicators should be reported. The Board and the industry require the information that the reporting process will provide, in order to assess the adequacy of service delivered to customers, and in order to determine needed adjustments in second generation PBR. Accordingly, electricity distribution utilities are expected to measure and report to the Board their performance with respect to these indicators, in accordance with filing requirements described in the draft Rate Handbook.

10 Board staff, under questioning during the Technical Conference, corrected the proposed standard for Connection of New Services (< 750 Volts) from 100% to 90%.

5.1.23 The Board sees merit in the suggestion that a measure of system reliability for shorter duration or momentary outages (MAIFI) be monitored and reported. However, the Board was not provided with sufficient information on the current use of MAIFI within the Ontario distribution electricity industry. The Board expects that this measure will be further investigated and considered in the review for second generation PBR.

5.1.24 With respect to suggestions that the list of reported indicators should be augmented to include measures of employee and public health, safety, and of environmental performance, the Board notes that utilities are accountable to other government institutions with respect to their performance in these areas. The Board has not been persuaded to add these measures.

5.1.25 The Board agrees with suggestions that service quality performance results of the distribution utilities should be reported to inform customers and the general public. The specifics regarding dissemination of such information will be addressed in due course.

5.1.26 The draft Rate Handbook proposes that service quality results be reported annually; there is no commentary about the periodicity of the results to be recorded (annual, quarterly, or monthly). Furthermore, there was no discussion by parties with respect to this issue. The Board has some concern that an annual average result may not provide it with adequate information on service degradation. Annual results can conceal seasonal variations in performance. Also, reporting only on an annual basis could result in a significant lag in identification of a service issue. The Board therefore will require utilities to record service performance on a monthly basis and for the first year to report the results to the Board at the time of the utilities' filings for year two of the PBR plan. The Board will review these results to determine whether more frequent reporting will be required. Further information is required to establish the appropriate criteria for determining that degradation has occurred; for example, degradation could be deemed to have occurred if the utility failed to meet the minimum prescribed standard for a certain number of months in a year. Such information should be available at the time of the filing for the second year of the PBR plan.

5.1.27 The Board has also considered the suggestions by parties that the PBR plan include remedial action and financial consequences in the case of service quality degradation. In the Board's view an appropriate assessment of these matters cannot be made until the Board and the industry have gained experience with the application of the PBR plan for the first year and appropriate service quality performance data becomes available.

DEMAND SIDE MANAGEMENT

6.

6.1.1 The draft Rate Handbook made no reference to Demand Side Management (DSM). In their opening remarks at the technical conference, Board staff stated as follows:

> *The current electric industry is in a state of flux. Many of the distribution utilities have stated the intent to enter the competitive energy retailing business. Such mixtures of competitive retailing businesses, even when separated through an affiliate code and subsidized DSM services delivered through a monopoly distribution business, raise substantial issues over potentially unfair advantage, illegal tying arrangements, discriminatory access to monopoly services and fairness in retailing.*
>
> *These issues of monopoly provided DSM programs for the benefit of unregulated entities have arisen in other jurisdictions, notably Norway and New Zealand.*
>
> *Further, the issue of the role of the distribution sector, particularly when many of the players are of such small scale in delivery of DSM services, has not been examined by the Board. For these reasons, the issue of DSM is considered to be beyond the scope of the first generation PBR process.*

Positions of the Parties

6.1.2 Pollution Probe and GEC reminded the Board that one of its responsibilities under the Act is "To facilitate energy efficiency and the use of cleaner, more environmentally benign energy sources in a manner consistent with the policies of the Government of Ontario." They argued that inclusion of DSM in the Rate Handbook, on either a mandatory or voluntary basis, would be consistent with the objectives of the Act. They pointed out that Board staff's proposals for a price cap mechanism act against DSM and that price caps are more adverse to DSM than are some other forms of PBR, such as revenue caps. Pollution Probe and GEC suggested that the same regulatory mechanisms that currently apply to the natural gas utilities should also apply to the electrical distribution utilities. At a minimum it was suggested that such approaches be voluntary, but that the Board should encourage utilities to undertake DSM programs. In addition, Pollution Probe and GEC submitted that DSM should be further considered for second generation PBR. In this regard, they suggested that a stakeholder forum or some other regulatory process be established to consider energy efficiency initiatives as part of second generation PBR.

6.1.3 FOCA suggested that utilities be required to report to the Board on DSM programs that they are currently engaged in. At a minimum, the Board should make a statement on the acceptability of distribution utilities initiating or continuing with DSM programs. Upper Canada suggested that the utilities that have already implemented DSM programs should be given the benefit of carrying on with such programs through the transition period.

6.1.4 Other parties acknowledged that the current restructuring of the industry creates confusion of the appropriate role of the distribution utilities with regard to DSM.

Board Findings

6.1.5 The Board acknowledges that facilitation of energy efficiency is one of the objectives of the Act and the Board acknowledges the importance of DSM in achieving such objective. However, there are a number of other objectives stated in the same Act. The Board's role is to find an acceptable balance among those objectives, especially when there is an appearance of competing ends. The Board notes Board staff's statement that the role of the electricity distribution industry with regard to DSM has not been examined as yet. Further, the Board notes that Board staff are currently in the process of consulting toward the development of guidelines with regard to section 71 of the Act. This section addresses the business activities in which electricity distribution utilities may engage.

6.1.6 Furthermore, substantive issues may arise from the monopoly "wires only" entity's involvement with DSM programs, and its relationship to the unregulated electricity sector's business. Also, the question of how DSM will be delivered in the restructured electricity industry requires better understanding.

6.1.7 In light of the above, it is the Board's view that a better understanding of all the issues surrounding DSM is needed before DSM principles, programs and mechanisms can be incorporated into a PBR regime for the electricity distribution industry.

6.1.8 The Board notes that parties indicated that some distribution utilities currently have active DSM programs. The Board encourages those distribution utilities to continue to offer these programs until such time as the guidelines regarding the appropriate business activities of the utilities and the role of DSM are established.

6.1.9 Further, the Board finds that, subject to the business activities guidelines and role of DSM issues discussed above, distribution utilities that wish to introduce DSM programs for first generation PBR can do so as long as the costs of these programs fit within the price caps.

6.1.10 The Board expects Board staff to include the appropriate considerations of DSM as part of the review for second generation PBR. The Board will include this conclusion in the Rate Handbook.

7. COMPLETION OF THE PROCEEDING AND COSTS

Implementation

7.1.1 Chapter 7 of the draft Rate Handbook deals with the sequence of events leading to the rate approval process, the process for annual rate adjustments for years two and three of the PBR plan, and for the development of a second generation PBR plan.

7.1.2 The draft Rate Handbook stipulated October 1, 2000 as the target date for the new unbundled rates to coincide with the date for market opening. The period from January 1, 2000 to October 1, 2000 would be utilized to complete the filing and approval process for the new rates. The draft Rate Handbook used May 1, 2000 as the final date for filing evidence for utilities with more than 30,000 customers, and August 1, 2000 for utilities with less than 30,000 customers.

7.1.3 This Decision does not alter the requirement for unbundled rates to be in place no later than market opening, currently anticipated to be in November 2000. Although the Rate Handbook is not yet available, with the issuance of this Decision utilities will be able to commence their preparation for filing their evidence with the Board. The Rate Handbook will be available as soon as practical. In the meantime, Board staff will continue to develop the unbundling and rate design model and will make the model available as soon as it has been adequately tested.

Costs

7.1.4 During the proceeding various parties requested an award of costs. The Board has received some cost statements from certain parties. At least one party suggested that no costs should be awarded for this proceeding. The Board would be assisted by submissions from parties regarding the awarding of costs in this proceeding. Submissions may address whether costs should be awarded in this proceeding and, if so, to whom they should be awarded and from whom they should be recovered. Parties are requested to file any submissions in this regard no later than February 15, 2000. Parties claiming costs should also file cost statements by this date.

DATED at Toronto January 18, 2000.

George Dominy
Vice Chair and Presiding Member

Paul Vlahos
Member

Sally Zerker
Member

CHAPTER 6
RATE ADJUSTMENT - CALCULATIONS

6.1 INTRODUCTION

This chapter deals with calculation methodology and implementation issues associated with the annual rate adjustment mechanism underlying the price cap plan. After a brief overview of how the price cap formula works, the derivation of an utility's IPI and its components is described, thereby providing the utility with sufficient information should it wish to calculate its own utility-specific IPI. In addition, an example of the application of Z factors to transition and extraordinary costs is presented. The calculations and data used in this chapter are examples only, and should not be construed as reflecting actual values of any individual utility's IPI or cost structure, or the actual industry IPI for 2001 and 2002.

6.2 PRICE CAP ADJUSTMENT MECHANISM

The formula for the price cap adjustment mechanism, as outlined in formula [5-1] is:

$$\%\Delta P^t_j = \%\Delta IPI^t_{LDC} - \%\Delta PF + \%\Delta Z^t_j \qquad [6\text{-}1]$$

where:

$\%\Delta P^t_j$ = the percentage change in the *j*th's utility's price ceiling in year t;

$\%\Delta IPI^t_{LDC}$ = the percentage change in Ontario utilities' input prices from year *t-1* to year *t*;

$\%\Delta PF$ = the productivity factor or index expressed as a constant percent change each year. For 2002 and 2003 this has been set at 1.50 by the Board; and

$\%\Delta Z^t_j$ = the extraordinary event adjustment factor expressed as a percent change from prices in year *t-1* to prices in year t for the *j*th utility.

For utility j, this means that their distribution prices in each service class will be capped to the percentage change in industry IPI (%ΔIPI^{t}_{LDC}) minus the required annual 1.50 per cent productivity offset (%ΔPF) plus any Z factor adjustments for transition or extraordinary event costs, expressed as an annual percentage change in rates. This price cap adjustment formula will apply as of March 1, 2002, for the 2002 rate adjustment, and March 1, 2003, for the 2003 rate adjustment. It is up to the discretion of the utility as to whether any or all of a price increase related to the PBR adjustment is implemented. However, if a price decrease is called for, the utility must implement the full price decrease.

For example, suppose utility j had the following rate schedule in place for May 1, 2001:

<u>Residential class distribution rates:</u>

Monthly service charge = $10.00; Distribution kWh charge = .62¢/kWh

General service class distribution rates, demand metered:

Monthly service charge = $55.00, demand (kW) charge = $1.34/kW

On or before February 15, 2002, the Board will publish the industry IPI which will reflect the *typical* utility's experience with input prices during the year 2001. As an example, suppose the following industry IPI numbers were published based on information available for the years 2001 and 2002:

Table 6-1

Sample Industry IPI[1]		
Date	IPI (IPI_{LDC})	Per Cent Change (%ΔIPI_{LDC})
March 1, 2001	102.4	2.4%
March 1, 2002	104.1	1.7%

Also, suppose that utility j has demonstrated that it has valid extraordinary event costs which warrant a rate increase of 0.3 per cent for all rate classes.

[1] Note: This is a sample for illustrative purposes only and does not represent the actual IPI that will be used.

According to the formula for the price cap adjustment mechanism, the allowable annual change in utility j's rates on or after March 1, 2002, would be calculated as follows:

% Change in Price = 1.7% - 1.50% + 0.3% = 0.5% [6-2]

Therefore, utility j can increase its prices by up to 0.5 per cent as of March 1, 2002. The new rate schedule may look as follows:

<u>Residential class distribution rates:</u>

Monthly service charge = $10.05; Distribution kWh charge = .6231¢/kWh

General service class distribution rates, demand metered:

Monthly service charge = $55.275, demand (kW) charge = $1.3467/kW

This is a simple illustration of the PBR rate adjustment mechanism. As a result of phase-in of market returns, additional adjustments to rates in 2002 and 2003 will also occur. In addition, upon market opening, the government will be introducing PILs which will also affect rates. Further information regarding rate adjustment as a result of PILs will become available when a date for market opening is announced.

6.2.1 The IPI

6.2.1.1 General Formula for IPI

The basis for the IPI calculation is a price index which compares the prices of the factors of production (inputs that the utilities consume in order to produce their output) in any given year to a base year. The IPI is based on a three factor model; the factors of production are capital, labour, and materials. In general, the IPI formula for any given utility *j* in time period *t*, can be expressed as:

$$IPI_t = \frac{\sum_{i=1}^{n} P_{it} e_i}{\sum_{i=1}^{n} P_{i0} e_i} \cdot 100 \qquad [6\text{-}3]$$

Where P_{it} represents the price of the three factor inputs: $P_{1t} = P_{Kt}$, the price of capital services in time t; $P_{2t} = P_{Lt}$, the price of labour in time t; and $P_{3t} = P_{Mt}$, the price of materials in time t. The base period prices are represented by P_{i0} and are 1999 prices. 1999 will be the first year for which all utilities complete a PBR data filing as well as the base period for initial rates. The term e_i represents the cost shares of the three factors: e_K is the cost share of capital, e_L is the cost share of labour, e_M is the cost share of materials. For any utility that wishes to calculate its specific cost shares, it should be noted that capitalized labour is not included in the labour cost share to avoid double counting. In analysis conducted by Board staff and its consultants on 1988-1997 data, it was found that, for the typical utility, capital accounts for about 51 per cent of costs, labour accounts for about 34 per cent of costs, and materials accounts for about 15 per cent of costs[2].

If an individual utility desires to calculate its own utility-specific IPI, the above general formula for the IPI (formula [6-3]) can be broken down to the constituent components, which are the three factors of production - capital, labour, and materials:

$$IPI_t = \frac{\sum_{i=1}^{n} P_{it}e_i}{\sum_{i=1}^{n} P_{i0}e_i} \cdot 100 = \left\{ \frac{P_{Kt} \cdot e_K + P_{Lt} \cdot e_L + P_{Mt} \cdot e_M}{P_{K0} \cdot e_K + P_{L0} \cdot e_L + P_{M0} \cdot e_M} \right\} \cdot 100 \qquad [6\text{-}4]$$

Calculation of the constituent price indexes (the price of capital services, labour, and materials) is dealt with below.

The industry IPI used for the price cap is determined by the *typical* utility's experience with input prices during the previous year. Thus, if an individual utility's own input prices rose less than the input prices of the typical utility, that utility would increase its earnings if it chose to adjust its own price cap by the full amount allowed by the Board. On the other hand, a utility whose own input prices rose more than those of the typical utility would experience a reduction in earnings due to the allowed adjustment.

[2] In calculating these shares, the Board has adopted a fixed-weight approach. The weights utilized are 1993 weights. See Board Staff report, "Productivity and Price Performance for Electric Distributors in Ontario," OEB, July 16, 1999 for details.

6.2.1.2 Price of Capital Services

The capital portion of the IPI is calculated based on a user-cost of capital approach. Generally, it is conceptually easier to assign a price to goods, such as materials or labour which are consumed in the period they are purchased, than capital, which has a long life and is "*consumed*" over a long period of time. Essentially, the cost of capital is determined by looking at the change in the cost of acquiring capital assets (i.e., acquisition cost) as well as the opportunity cost of making the capital investment. In simple terms, the opportunity cost is the return that an investor has forgone in order to make the capital investment. In addition, the rate of depreciation of the capital stock is also a cost of using capital. For utility "j" in the example below, we assume a depreciation rate of 5.39 per cent.

The cost of using capital is defined as the opportunity cost plus depreciation times the acquisition price. For purposes of calculating the IPI, the opportunity cost of capital has been defined as the 10 year Canada Long Bond yield (r_t), as reported by the Bank of Canada[3]. The acquisition price is represented by the Price Index for Electric Utility Distribution Systems Construction as reported by Statistics Canada[4] ("*CAP"*). The depreciation rate (d) is calculated from utility specific data on level of capital stock and capital stock retirement.

Therefore, capital service price index for any given utility j in time t is given by:

$$PK_t = (r_t + d) \cdot CAP_t \qquad [6\text{-}5]$$

The index is an annual number with a base year of 1999. In order to calculate the index, the monthly series on long bond yields reported by the Bank of Canada (B 14071) needs to be annualized by taking a simple average of the monthly values. The price index for electric utility distribution systems construction is an annual index reported by Statistics Canada. The following table provides an example of how the price of capital services component of the IPI for utility "j" is calculated:

[3] Statistics Canada CANSIM databank number B 14071.

[4] Statistics Canada CANSIM databank number P219188.

Table 6-2

Sample calculation of capital price index for utility "j"						
Year	10yr bond yield	Depreciation	CAP	P_K	P_K (1999=1.0)	% chg
1999	5.5%	5.39%	123.0	0.133947	1	2.0%
2000	5.9%	5.39%	124.6	0.140673	1.05	5.0%
2001	6.15%	5.39%	125.0	0.14425	1.077	2.6%

However, for the purposes of calculating the IPI for the first generation PBR, the Board has limited the change in the capital portion of the IPI to one half of the observed change. Therefore, the above index needs to be modified before the IPI is calculated. Starting in the base year of 1999, the capital price index (P_K) is restricted to one half of the observed change, as noted in Table 6-2. Table 6-3 illustrates the modified index:

Table 6-3

Modified sample capital price index for utility "j"		
Year	PK (1999=1.0)	% chg
1999	1	
2000	1.025	2.5%
2001	1.038	1.3%

6.2.1.3 Price of Labour

The price of labour for any given utility *j* in time *t* (PL_t) is represented by the utility's line crew wage rate. These data are compiled by the Municipal Electric Association (MEA). The position taken is that the year-to-year change in the line crew wage rate is a good proxy for the year-to-year change in labour costs in general, as the line crew wage rate moves, either formally or informally, with wage changes of other utility employees. For consistency, this index should be revalued to 1999=1.0, by dividing the entire series by the 1999 index value.

6.2.1.4 Price of Materials

The price of materials (PM_t) is represented by the Industrial Producer Price Index (IPPI)[5] published by Statistics Canada. This monthly series is converted to an annual series by averaging the 12 monthly observations. As above, this index should be revalued to 1999=1.0 by dividing the entire series by the 1999 index value.

6.2.1.5 Calculation of Utility's IPI

The IPI is calculated from the above components according to formula [6-4]. The only remaining information needed is the cost shares of each factor. For illustrative purposes, assume that utility j has the cost structure of a ″typical″ utility:

Capital (e_K): 0.51 or 51%

Labour (e_L): 0.34 or 34%

Materials (e_M): 0.15 or 15%

The following table illustrates utility "j's" IPI calculation using the capital price index from Table 6-3 above and assumed values for materials and labour:

Table 6-4

Sample Calculation of IPI								
Year	P_K	e_K	P_L	e_L	P_M	e_M	IPI	% chg
1999	1	0.51	1	0.34	1	0.15	100.0	
2000	1.025	0.51	1.025	0.34	1.019	0.15	102.4	2.4%
2001	1.038	0.51	1.05	0.34	1.029	0.15	104.1	1.7%

[5] All finished goods industrial product price index, CANSIM databank number P1295.

6.2.2 The Z Factor

The Z factor in the PBR formula is a mechanism whereby approved costs associated with extraordinary events (which may, subject to Board review, include transition costs) can be incorporated into rates. To apply the Z factor mechanism, the incremental revenue associated with extraordinary event cost must be converted into a percentage change to rates. If a particular extraordinary cost is identified to be assigned (to a greater or lesser degree) to a specific rate class, the utility must provide the Board with sufficient justification before rate class specific Z factors are applied.

It is important that two properties of the Z factor be noted. First, the Z factor is a transitory adjustment to rates, not a permanent adjustment. The Z factor is in place only for the period of time necessary to recover the costs for which it was invoked. Once the costs have been recovered, rates revert to what they would have been had no Z factor been applied. On-going costs will be examined and considered at the time of rebasing.

The Z factor is intended to recover only the costs that have been approved by the Board. If, as a result of fluctuation in total revenue, a utility recovers an amount greater (or less) than the cost approved for recovery, a balance in the appropriate deferral account must occur. Therefore, the utility must track the revenue it is receiving as a result of implementing the Z factor mechanism.

Order Instituting Rulemaking to Review the Time Schedules for the Rate Case Plan and Fuel Offset Proceedings.; In the Matter of the Application of SOUTHERN CALIFORNIA GAS COMPANY to Adopt Performance Based Regulation ("PBR") for Base Rates to be Effective January 1, 1997

Decision No. 97-07-054, No. R.87-11-012 (Filed November 13, 1987), Application No. 95-06-002 (Filed June 1, 1995)

California Public Utilities Commission

1997 Cal. PUC LEXIS 751; 179 P.U.R.4th 237

July 16, 1997; As Corrected August 26, 1997; As Corrected September 30, 1997

CORE TERMS: customer, productivity, rate base, ratepayer, throughput, indexing, recommend, noncore, shareholder, reduction, plant, formula, margin, benchmark, annual, ratemaking, inflation, recommendation, estimate, sharing, satisfaction, forecast, funding, methodology, effective, stretch, savings, adjust, rate of return, reward

(See Appendix C for appearances.)

PANEL: [*1] P. Gregory Conlon, President, Jessie J. Knight, Jr., Henry M. Duque, Josiah L. Neeper, Richard A. Bilas, Commissioners

OPINION: OPINION

I. Summary of Decision

In this decision we consider a proposal by Southern California Gas Company (SoCal or applicant) for adoption of performance-based ratemaking (PBR) for the portion of SoCal's rates that recovers the costs of providing gas utility service that the Commission has reviewed in the past through the General Rate Case (GRC) process. n1

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n1 SoCal uses the term "regulation" rather than "ratemaking" to characterize its proposal, but the rubric refers to a method for adjusting rates annually without prior Commission approval of the adjustment. The Commission has used the term "performance-based ratemaking" in similar proceedings previously, and does so here for the sake of consistency.

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Our decision today adopts a PBR system for SoCal which differs in several respects from the proposal advanced by SoCal. Most significantly, we adopt a system[*2] which requires SoCal to share with ratepayers the savings produced by the indexing method. We also adopt an indexing method, adjustments and exclusions, provisions to insure that high standards of service quality and safety are maintained, and a base margin to which the indexing will be applied.

Our decision is effective immediately. The rates based upon our adopted base margin revisions shall become effective August 1, 1997. The PBR mechanism shall become effective January 1, 1998, unless SoCal elects to operate under the mechanism effective as of January 1, 1997.

II. Background of Application

A. Description of Applicant

SoCal is an investor-owned utility subject to the jurisdiction of this Commission. It is engaged in the transmission, storage, and distribution of natural gas. SoCal is the principal subsidiary of Pacific Enterprises.

B. Procedural History

SoCal filed its application on June 1, 1995. Filing of the formal application was preceded by a series of workshops held by SoCal in December 1994 and January 1995, in which SoCal met with interested parties to present the contemplated proposal. SoCal's application includes some changes from its original proposed [*3]concept, which were made after the workshops. n2

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n2 Conceptually, the most significant of these was a change from the Consumer Price Index (CPI) to an industry-specific index in the indexing formula.

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Before filing the application SoCal also requested a suspension of the requirement to file a test year (TY) 1997 GRC. SoCal's last GRC had been for TY 1994, and its TY 1997 GRC was due to be filed under the Commission's rate case plan. The reason given by SoCal for its request was that it was actively pursuing a PBR system to become effective February 1, 1997, eliminating the requirement for a TY 1997 GRC. In Decision (D.) 95-04-072 in Rulemaking (R.)

87-11-012, the Commission granted the suspension, subject to conditions designed to protect ratepayers from the risks created by that suspension. The order also directed the Commission's staff to conduct an audit, as required at least every three years under Public Utilities (PU) Code 314.5, in connection with the PBR proceeding. The Commission later extended the order, suspending[*4] the requirement to file a TY 1998 GRC because the PBR application was being processed in a timely manner.

The assigned administrative law judge (ALJ) held preheating conferences (PHCs) on September 25, 1995, and January 29, 1996. In response to a joint motion filed January 4, 1996 to request a specified procedural schedule, the ALJ ruled that SoCal must serve its recorded data for 1995 on February 14, 1996, and make a supplemental showing with respect to 1996 estimated expenses on June 6, 1996. This is the showing used by the parties, by agreement, to develop the base margin figures and other features of the PBR program considered here.

On October 14, 1996, Pacific Enterprises and Enova Corporation, the parent company of San Diego Gas & Electric Company (SDG&E), announced that they proposed to merge, and filed an application for approval by the Commission (Application (A.) 96-10-038). The Southern California Utility Power Pool and the Imperial Irrigation District (SCUPP/IID) and Southern California Edison Company (SCE) moved to suspend the procedural schedule in this proceeding in contemplation of these merger plans, but the ALJ denied that request by ruling dated October 23, 1996. [*5] The assigned commissioner denied reconsideration of that request on November 14, 1996.

The formal evidentiary hearing commenced December 2, 1996, and concluded December 19, 1996. Two rounds of briefs were filed, and the proceeding was submitted on February 14, 1997.

C. Proposed Decision

The Proposed Decision of ALJ Ryerson (PD) was filed on April 21, 1997, pursuant to <=1> @ 311(d) of the Public Utilities (PU) Code and Rule 77.1 of the Commission's Rules of Practice and Procedure (Rules). n3

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n3 The PD was issued before the expiration of the 90-day statutory time limit following submission at the request of the applicant and the Commission, in order to facilitate coordination with A.96-10-038.

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D. Comments on Proposed Decision

Comments on the PD were filed by SoCal, ORA, SCE, SDG&E, SCUPP/IID, CEC, Enron, and Insulation Contractors Association. The Commission also received a letter from TURN indicating that it would not file comments, but would reserve the option to file replies to the comments of other parties. [*6]

SoCal's comments are critical of several aspects of the PD's treatment of both policy issues (i.e., the PBR mechanism) and the base margin. Specifically, SoCal criticizes the TURN/DGS formula adopted by the decision as being company-specific in nature, contrary to our policy of using external industry yardsticks; the stretch factor as being too rigorous in light of SoCal's recent history of productivity gains; the absence of pricing flexibility; the adoption of revenue indexing rather than rate indexing; and the absence of "tools" (particularly pricing flexibility) to enable it to attain greater productivity through sales. On the base margin side, SoCal criticizes the resolution of a number of individual items on the grounds of legal or factual error.

ORA generally supports the PD as a whole, but in its comments offers a series of recommendations which would make the decision clearer and conceptually tighter, consistent with the adopted resolution of major issues. ORA also suggests corrections to a number of figures based on inadvertent factual errors.

SCE also generally supports the PD, but suggests certain clarifications and corrections.

SDG&E's comments are critical of the adopted[*7] indexing methodology and the PD's description of other PBR decisions, and of two of the items in the base margin section, the treatment of the Torrance and Mountain View facilities and the removal of Line 6900 from rate base.

SCUPP/IID reiterates concerns expressed by other parties about an ambiguity in the effective date of the decision, and about the discussion of exclusion of costs for Lines 6900 and 6902 from rate base.

CEC's brief comments are generally supportive of the PD, but suggests two changes: that energy efficiency funds be transferred to the Energy Efficiency Board, and that $ 5 million of SoCal's energy efficiency budget be allocated for market transformation efforts.

Enron and the Insulation Contractors Association filed comments that are directed specifically at the issue of unregulated new products and services, but are fully supportive of the PD. Certain of the other comments contain discussions of the new products and services issue.

Reply comments were filed by SoCal, ORA, SCE, DGS, NRDC, TURN, Enron, and the Plumbing-Heating-Cooling Contractors.

Revisions to the PD made in response to the comments and replies are reflected in this final decision. Additional revisions[*8] were made to correct or clarify the text. All areas changed are indicated on the margin.

E. Description of SoCal's Proposal

The application proposes a new method for revising SoCal's rates annually by applying an index, based upon a measure of recorded input price inflation less a productivity factor, to its rates. The productivity factor would be fixed at this time, and would not be revised during the minimum five-year term that the new ratemaking system is proposed to be in effect, but adjustments to certain aspects of the rates would be made by annual rate revision filed by SoCal. In this section we describe the specific features of the PBR methodology SoCal has proposed. n4

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n4 The details of SoCal's proposal are contained in prepared testimony and exhibits that were initially filed as part of the application. A number of modifications were made since the initial proposal, and the details of the current proposal, along with the supporting testimony, are contained in SoCal's direct testimony (Exh. 1-Exh. 33) and the jointly sponsored testimony (Exh. 200-Exh. 210) received at the evidentiary hearing.

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[*9]

1. Rate Indexing

SoCal proposes to index core and noncore base rates and certain miscellaneous charges, as opposed to indexing total authorized margin or authorized margin per customer, i.e., revenue requirement. This means that rates would be indexed directly to inflation less the pre-set productivity factor. SoCal claims that its proposal for rate indexing "fixes the throughput forecast used to set rates over the PBR period and puts utility shareholders at risk/reward for any differences between forecast and actual throughput and customer count." (SoCal Opening Brief, p. 44.) SoCal asserts that its ratepayers will benefit, because the level of rates, in real terms, is guaranteed to decline over the period that this mechanism is in effect, by reason of enforced productivity gains over the period. SoCal supports this contention with a ten-year backcast analysis demonstrating that PBR would have resulted in rates 13% lower than under traditional "cost-plus" ratemaking.

a) Core Demand Forecast

The methodology chosen by SoCal is rate indexing, which depends upon fixing a specific throughput forecast for calculating the rate level at the outset. For core rates SoCal proposes[*10] that we adopt its recorded 1996 customer count and core throughput, normalized to average temperature conditions, in establishing the starting point for indexing. Also, because the current core rates are based upon throughput which uses a "normal" temperature measure that is set too low in relation to updated temperature averages, SoCal proposes to change this measure in establishing this starting point.

Under current ratemaking, a balancing account called the Core Fixed Cost Account (CFCA) operates to insure that SoCal over time will recover in rates exactly the amount of Commission-authorized margin, regardless of the actual level of customer demand (i.e., core throughput). However, if throughput is foreordained as part of the base margin, this balancing account cannot function. Core demand (throughput) will in fact vary because of variations in average temperatures from year to year, but rates cannot be adjusted because the throughput figure is set beforehand. As part of its proposal, SoCal therefore would eliminate the CFCA and substitute two other devices, the Weather Normalization Mechanism (WNM) and the Energy Efficiency Adjustment Factor (EEAF), to adjust rates in its place. [*11]

The WNM would adjust core rates to reflect differences in throughput due to differences between recorded and normal temperature conditions. The WNM would be used to adjust the bill of each customer at the time the bill is issued for variations from normal temperature conditions in the period for which the bill is rendered. n5 SoCal contends that this is appropriate because temperature conditions are wholly beyond the control of its management, and temperature variations could create large variations in core revenues relative to its authorized return on equity.

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n5 The WNM would apply only to core customers, and would exclude core gas engine and air-conditioning customers, because their load is basically not sensitive to heating requirements.

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The EEAF would adjust rates for the effect on revenues from core throughput lost each year due to gas conservation and energy efficiency measures actually implemented by SoCal's customers. Under SoCal's proposal, the first 0.3% of rate impact would not be adjusted for, on the presumption[*12] that the PBR index already reflects that impact. SoCal also proposes to cap the amount of EEAF adjustment at 1.0% annually. SoCal argues that implementing the EEAF as part of its proposal would be justified, because it eliminates SoCal's incentive to discourage conservation, as the PBR mechanism rewards the utility for selling more gas. SoCal also argues that the EEAF would eliminate the reduction in its earnings that would be caused by government-mandated or subsidized conservation measures.

b) Noncore Demand Forecast and Rates

The methodology proposed for fixing noncore rates for PBR indexing is entirely different, principally because of the effect of an agreement, the Global Settlement, that has been adopted by the Commission. The Global Settlement provides that, from August 1, 1994 through July 31, 1999, SoCal will calculate noncore rates based upon 1991 actual throughput. SoCal therefore proposes to use two sets of noncore rates for PBR indexing. The first is based upon 1996 adjusted base margin and allocation, but uses 1991 throughput. The second is based upon 1996 base margin and 1996 throughput, calculated in the same manner as the first set, but not effective until[*13] August 1, 1999. In its proposal, SoCal refers to these as "shadow rates." Both sets of rates rely, however, upon the use of a fixed throughput figure for establishing the base rate for PBR indexing.

2. Index to be Applied

a) Inflation Measure

The inflation measure proposed by SoCal is a weighted average of recorded indices of prices for labor operating and maintenance (O&M) costs, nonlabor O&M costs, and capital-related costs. n6 In the price index, the measure for labor O&M is the index of average hourly earnings of workers in gas production and distribution as reported by the U.S. Bureau of Labor Statistics. The measure for nonlabor O&M is the Data Resources, Inc. (DRI)/McGraw Hill nonlabor O&M index for gas utilities. The inflation measure for capital-related costs is based upon the DRI/McGraw Hill indices for capital service prices and for the price of gas distribution capital goods. These measures would be weighted according to the average of expenditures in each category by SoCal for the past five years. Although a forecast of inflation would be used, the forecast would be trued up to recorded inflation at the next annual PBR rate adjustment. Rates for a year would[*14] be set using the latest available forecast for the price index elements for that forthcoming year, and the following year's rate filing would include an adjustment to true up any difference the forecast and actual price index.

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n6 SoCal refers to this measure as the gas utility input price index, or GUPI.

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b) Productivity Factor

SoCal proposes to employ a constant productivity factor of 1.0% per year as the second element of the PBR adjustment mechanism. SoCal's selection of this figure is based upon two components: historical gas distribution average productivity of 0.5%, plus a factor of 0.5% as an incentive to improve productivity over past performance. n7 SoCal asserts that this 1% total productivity factor, which would be applied for the entire period that PBR rates are in effect, affords an adequate incentive for the company to strive for greater efficiency.

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n7 SoCal refers to this element of the productivity factor as a "stretch factor" or "consumer dividend."

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[*15]

In support of the component percentages, SoCal offers a study of 49 gas utilities nationwide as evidence that the 0.5% productivity increase is close to the national average. n8 The additional 0.5% "stretch factor" is essentially based upon the company's judgment of productivity gains that can reasonably be anticipated. SoCal asserts that this figure is consistent with Commission precedent and policy, and argues that a higher percentage would be unreasonable or unattainable in light of the cost forecasts and cost relationships upon which higher factors proposed by other parties rely.

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n8 This was a multifactor productivity study of the gas local distribution service delivery industry conducted by Christensen Associates, which found the historic range to be 0.4% to 0.5%. (Exh. 5.)

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c) Starting Rate Level

SoCal proposes that its level of base rates for 1997 would be determined by applying the PBR index to a starting level of rates and to the existing level of miscellaneous charges. n9 Establishment of the starting[*16] level is based upon a "test year" showing and analysis resembling that for a GRC. The basis selected for analysis is SoCal's calendar year 1996 internal operating budget. The approach to setting base margin in 1997 under PBR is to take the figure representing the reasonable level of expense and rate base for SoCal in 1996, and to adjust that revenue requirement for one year with the PBR index adopted by the Commission in this proceeding. This will produce rates to be in effect when a PBR decision goes into effect in 1997.

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n9 The "base rate" is the part of rates reflecting gas margin, and excluding gas costs, pipeline demand charges, and other specifically identified items; it is only the base rate that is guaranteed to be reduced under PBR. Final rates measured in constant dollars will decline unless increases in gas costs and excluded items more than offset the reduction in the indexed portion of the rate. (Exh. 1, p. 13.)

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d) Exclusions

Certain costs would not be recovered through the portion of rates that [*17] would be subject to the PBR index. These would remain subject to recovery through other existing ratemaking mechanisms. In general, the principle behind these exclusions from PBR is that the costs are already subject to incentive-type mechanisms, that they are beyond SoCal's control, or that the level of expenditure is specifically authorized by this Commission or by the Federal Energy Regulatory Commission (FERC) in separate proceedings. The specific costs proposed to be excluded are discussed later in this decision.

e) "Z" Factor Adjustments

A "Z" factor, as recognized by this Commission, is an exogenous and unforeseen event largely beyond the utility's control that has a material impact upon the utility's costs. Examples of Z factors include accounting rule changes adopted by governing boards and agencies, state and federal tax law changes, and new government mandates.

SoCal proposes that its rates be adjusted, either upward or downward, by the amount of change in its costs exceeding a one-time $ 5 million "deductible" amount per qualifying Z factor. The amount of change in SoCal's costs subject to Z factor treatment would be reduced by the amount by which SoCal would already [*18]be compensated by the inflation factor in the PBR index formula. SoCal also proposes a specific procedure for handling each Z factor event.

f) Adjustments for Gain or Loss on Sale

SoCal proposes an adjustment in rates in addition to the PBR index if the company sells at a gain or loss land that was acquired and held in rate base before the implementation of PBR. SoCal proposes to credit its customers with one-half of the gain, but SoCal could request, on a case-by-case-basis, that the Commission authorize a smaller sharing of gain from the sale and replacement of a particular parcel of land, when the benefit from the sale and replacement to SoCal is less than the 50% of gain that it would otherwise have to refund in rates. Sales of all or a portion of a distribution system qualifying for allocation to shareholders under the holding of Decision (D.) 89-07-016 (City of Redding II), <=2> 32 CPUC2d 233 (1989), would not produce any reduction in rates under PBR. There would be no adjustment in rates for purchase or sale of land acquired after implementation of PBR.

g) Cost of Capital

SoCal does not propose to make any changes in PBR indexed rates in response to changes in costs[*19] of capital, except in the event that the 12-month trailing average yield on long-term Treasury Bonds increases or decreases radically, i.e, more than 250 basis points from the DRI average rate for the calendar year 1997 forecast, as adopted in SoCal's 1997 cost of capital proceeding. n10 During at least the minimum five-year term of PBR, SoCal proposes not to file annual cost of capital applications, and rates would not be adjusted for changes in the cost of debt, preferred or common equity capital, or changes in capital structure, unless variation exceeded the 250 basis point "trigger."

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n10 See D.96-11-060.

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In the event that the trigger is exceeded by an increase in interest rates, SoCal proposes to have the option to file a cost of capital application; in the event of a 250 basis point decrease, SoCal would be required to file a cost of capital application. In either event the Commission would determine whether any change in rates was appropriate in light of all factors affecting the cost of capital. Any rate change, [*20] whether an increase or decrease, would be prospective only from the effective date of a Commission decision.

h) Effective Date and Term of PBR Rates

SoCal initially proposed that its PBR mechanism would become effective on January 1, 1997, and would continue for a minimum term of five years, through year-end 2001. However, the time required to process the application has not permitted implementation of a PBR by the original target date, necessitating an adjustment of the proposed implementation schedule. Under the revised schedule SoCal continues to propose a five-year minimum term for PBR, and thus the original dates for all events would be extended to dates corresponding to the additional time involved in concluding the proceeding. Assuming the Commission issues a decision placing PBR rates in effect on July 1, 1997, the minimum term of the PBR would expire on June 30, 2002.

SoCal proposes that no change be made in PBR indexing during the five-year minimum term of the proposed mechanism, except to the extent such express features as Z factor adjustments and cost of capital revisions require. SoCal therefore asks that we forgo provision for any formal midterm review process, [*21]continuous "forum" proceeding, or "off-ramp" that would permit or require suspension of the PBR during the initial five-year term.

SoCal proposes that the PBR continue automatically beyond the minimum period, unless changed at the behest of a party or the Commission. At any time after June 30, 2000, any party, or the Commission on its own motion, could institute a proceeding to change or replace the PBR mechanism effective on or after the expiration date.

i) Maintenance of Service Quality

In order to insure that SoCal's focus on increased productivity through cost reductions does not have a deleterious effect upon the quality of service, SoCal proposes a mechanism to ensure the maintenance of service quality during the period when the PBR rates are in effect. Originally, SoCal proposed a service quality guarantee for core customers based upon random customer telephone survey responses to questions concerning customer satisfaction with SoCal's call center response time; call center employee performance; field service employee response time; and field service employee performance. SoCal proposed the adoption of a benchmark for its performance, namely, the average recorded level[*22] of customer satisfaction for July 1993 through June 1996 in random surveys on these four service dimensions. A "deadband" below this benchmark would allow for some sampling error, but below the deadband the company would be required to reduce rates in increments of $ 1 million per year up to a maximum of $ 4 million per year for failure to meet the criterion. No incentive was proposed for exceeding the benchmark for customer satisfaction. SoCal proposed to retain its existing Service Interruption Credit (SIC) mechanism for service to noncore customers, but did not propose any other service guarantees for noncore customers in recognition that competition provides an incentive for SoCal to assure adequate, efficient, just, and reasonable service to noncore customer.

Subsequent negotiations among the parties produced a proposal for a somewhat different customer satisfaction measure. The concept of this proposal is essentially the same as that of the one it replaces in the original application.

j) Employee Safety

Originally, SoCal did not propose any specific safety performance measures for public, customer, or employee safety, on the assumption that existing federal and state[*23] safety laws and regulations mandate standards with which SoCal must comply. However, SoCal, TURN, and ORA have agreed to propose an annual employee safety standard which would be used to adjust rates if SoCal's performance fell below or above the standard by a material margin.

The proposed standard is 9.3 incidents per 200,000 hours worked, with a deadband of 1.0 incidents in each direction, measured annually from the Occupational Safety and Health Administration (OSHA) Recordable Injury and Illness Rate. Should the annual rate exceed 10.3 incidents, customers would receive a rate reduction through the annual rate adjustment filing process. Conversely, SoCal would receive a reward through the annual rate adjustment filing process if its performance were better than an annual rate of 8.3 incidents. The customer rate adjustment would be based upon $ 20,000 for each 0.1 point above or below the deadband.

k) New Products and Services

In its application SoCal seeks authorization to offer on a competitive and unregulated basis products and services that it has not previously offered. SoCal also seeks the authorization to provide support to its non-regulated affiliates in connection[*24] with their offering of new products and services. SoCal states that these new products and services would be provided entirely at shareholder risk, and would not be funded by the rates charged for utility services.

l) Rate Design Changes

SoCal proposes to include several changes in rate design in its program for PBR. These include changes in residential rate design, and a proposal for flexibility to negotiate rate discount agreements and offer optional rate schedules for certain core customers.

Currently, the company's monthly residential customer charge, which went into effect in 1996, is $ 5.00. Effective with PBR implementation, SoCal proposes to charge single-family and master meter residential customers a monthly customer charge of $ 7.11, and multifamily customers $ 5.47 per month. By January 1, 2001, SoCal proposes to charge a single-family and master meter residential customers a monthly customer charge of $ 13.57 and multifamily customers $ 10.35 per month (stated in 1996 dollars). Customer charges upon PBR implementation, and on each January 1 thereafter through 2001, would be increased by 1/5 of the difference between the 1996 customer charge of $ 5 and the aforementioned[*25] 2001 charges. n11 Corresponding reductions would be made in residential volumetric rates.

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n11 SoCal recommends that these customer charge rate level adjustments be made on January 1 of each year in order to coincide with the other annual rate changes under the PBR index formula.

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Upon implementation of PBR, SoCal also proposes to reduce the differential between residential volumetric Tier I and Tier II rates from the current 35% to 10%, and to maintain this relationship at least through the end of the minimum PBR period. SoCal claims that these proposed residential design changes are necessary to bring rates more into line with costs, as fixed residential customer-related costs are currently understated, and that the increased customer charges and decreased volumetric rates will reflect the true long-run marginal cost of gas service. n12

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n12 SoCal proposes certain other changes in rate design in addition to these basic changes. SoCal proposes to update the submetering credit for master meter customers, and to index that credit; to reduce baseline allowances in climate zone 1 from the current 50 therms to 46 therms in winter and from the current 15 therms to 14 therms in summer, with similar reductions in climate zones 2 and 3; and to modify non-residential core rate design.

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[*26]

SoCal proposes to be granted authority to negotiate rate discount agreements with individual core customers, and to offer core rate schedules that customers meeting the applicability requirements would have the option to select. The proposed discounting flexibility would apply only to the "base rate" element of core bundled rates. Under SoCal's proposal, negotiated agreements of less than five years' duration would not require Commission approval prior to becoming effective.

Optional core rate schedules would become effective upon filing with the Commission without the requirement of prior Commission approval, and could be withdrawn by SoCal upon 30 days' notice to the Commission, unless otherwise specified by the terms of the schedule. SoCal's authorized rates would be the default rates for qualified customers who do not want to avail themselves of the optional schedules.

m) Storage Costs

SoCal proposes to apply the PBR rate index to the base rate elements that recover the cost of storage which is currently bundled in core and noncore rates. This request was not in the original application, but was later included in its request in response to a proposal by ORA to eliminate[*27] the Noncore Storage Balancing Account (NSBA) and put SoCal wholly at risk for market demand for the costs allocated to unbundled noncore storage service when the PBR rates become effective. SoCal asserts that its request is consistent with the overall concept that PBR substitutes for a general rate case, in which the revenue requirement for bundled storage costs would otherwise have been adopted by the Commission. SoCal states that because it is proposing to be at risk for throughput under PBR, it would also be at risk for the recovery of the portion of storage costs that is bundled in transmission rates.

n) Monitoring and Evaluation

SoCal states that it recognizes the need for the Commission to monitor the functioning of the PBR mechanism and to be prepared to evaluate the program at the conclusion of the minimum term. Nevertheless, SoCal urges the elimination of a significant number of existing reporting and recordkeeping requirements, and advocates the avoidance of new reporting requirements insofar as possible, in the interest of simplifying and streamlining regulation.

o) Base Margin

SoCal initially proposed a starting base margin which represented a $ 61.2 million[*28] reduction as compared to its 1995 authorized level. Following several revisions in response to discussions with ORA, SoCal's final position is a $ 110 million reduction in margin compared to the 1995 authorized level. SoCal and ORA have agreed upon a variety of base margin items, and the individual items are described, along with our resolution, in the discussion below.

III. Discussion

A. Introduction: Performance-based Ratemaking

In general, performance-based ratemaking refers to any of a variety of ratemaking mechanisms designed to improve utility performance and also return financial benefits to the utility's ratepayers. Its purpose is to break the direct link between costs and rates by inserting "an independent and explicit incentive [for the utility] to increase efficiency through lowering costs," so that ratepayers will not have to bear the risk of inefficient utility operation. (D.96-09-092, mimeo., p. 14, September 20, 1996.) The mechanism itself is intended to emulate an unregulated market.

The basic PBR concept involves two basic steps:

"First, the PBR regulator sets an initial price based on the utility's observed and projected costs. Next, the regulator[*29] provides the utility with incentives to reduce these costs and pass some of the resulting savings onto the consumer. To assure that the utility does not achieve costs savings simply by cutting safety, reliability or quality, the PBR system must also include a quality-control mechanism." Navarro, "The Simple Analytics of Performance-based Ratemaking: A Guide for the PBR Regulator" (Yale Journal on Regulation 13:1 (Winter 1996), p. 107.)

The hallmarks of the PBR system under the previous practice of this Commission are an incentive device to encourage cost reduction and revenue enhancement, and a device to ensure sharing of the savings produced thereby with customers.

We first replaced traditional rate case regulation with PBR in D.89-10-031, which placed the two major California local exchange telecommunications companies under an incentive form of regulation. The mechanism we adopted is often called "CPI-X" regulation. As we explained in our most recent PBR decision, D.96-09-092, which adopted PBR regulation for SCE:

"This form of PBR regulation adopts starting rates based on an analysis of utility costs with these rates then updated in each subsequent year by a rule which[*30] includes expected changes in input prices, CPI, and productivity, X. . . . We refer to this price less productivity adjustment, or CPI-X, as the update rule.

"To make this update of utility rates independent of the utility's costs, the price and productivity values should come from national or industry measures and not from the utility itself. The independence of the update rule from the utility's own costs allows PBR regulation to resemble the unregulated market where the firm faces market prices which develop independently of its own cost and productivity. In contrast, traditional regulation often updates rates through a review of the utility's own costs and productivity. The form of this PBR update rule of "price less productivity" or CPI-X arises from the unregulated market where, independent of demand response, a firm's output price will change to reflect changes in its input prices less its change in productivity, where productivity is simply the change in the firm's outputs less its change in inputs, both value weighted.

"Finding a measure for the price term in the update rule requires a choice between a general price index such as the well-known CPI or an industry specific [*31] index. The former choice involves less controversy but uses a general approximation to industry specific prices, and this approximation can work reasonably well during periods of generally low inflation. While the latter choice clearly tracks industry costs more closely, it does engender more controversy because often it requires construction of a new industry specific price index to track industry price changes closely. Complexity readily arises in the construction of price indices; for example, an accurate current price index for labor requires a weighted average wage for...many different classifications of workers from clerks to system engineers.

"The productivity measure should come from a forecast of industry-specific productivity. However, such studies are not common and most published econometric studies not only assume efficient operation but also use historical data. In D.89-10-031, we relied on a study of AT&T's historical productivity and expert judgment in setting the productivity value for the local exchange utilities. Realizing that technological change in telecommunications offered the opportunity for substantial productivity and wanting to encourage increased efficiency[*32] in utility operations, we added a "stretch" factor to set the productivity value or X.

"We note that improved efficiency can arise from three sources: adopting more efficient technology in meeting current demand, realizing economies of scale when expanding the operation, or reducing existing inefficiencies in the current operation. ... Particularly in the distribution business, the first source of productivity may contribute only selectively toward greater efficiency and lower rates. The incentives of this PBR should discover the opportunities to increase the efficiency of the current operation and thereby lower rates.

"In D.89-10-031, we also adopted a net revenue sharing rule which allows the utility to keep some of the increased net revenue which occurs if the utility can reduce its costs. Adoption of this rule should increase the utility's incentive to reduce costs. Allowing the utility to retain some of the net revenue from cost reduction efforts also resembles the competitive market where a firm can increase its profits by lowering its costs. Combined with the use of independent prices, the use of a net revenue sharing rule emulates the outcome of a competitive market.
[*33]
"Thus, we see PBR as emulating the competitive process to encourage utility management to make decisions which resemble an efficient or competitive outcome. An efficient utility will control rates which benefits ratepayers. However, we want to ensure fairness to ratepayers, employees, and shareholders in the PBR process. This requires balancing potentially conflicting interests. The utility can increase short run profits through reducing variable costs, but without revenue sharing such cost reductions will not lower rates. Moreover, such reductions not only can affect staff immediately but the service quality impact may only appear much later." (D.96-09-092, mimeo., pp. 14-16.)

We have already expressed our preference for replacing traditional cost-of-service regulation with performance-based regulation in those areas of the electric services industry which exhibit natural monopoly attributes. See Order Instituting Rulemaking and Order Instituting Investigation in R.94-04-031 and I.94-04-032 ("Blue Book"). Our policy favoring that deployment of PBR reflects our successful experience with it in the field of telecommunications. Certainly, we are favorably disposed to using PBR[*34] wherever it would further our regulatory goals and policies.

At the commencement of I.94-04-003, the SCE proceeding, supra, we stated our goals for undertaking the development of PBR. These included:

. Improving the efficiency and performance of the utility;

. Improving incentives and removing disincentives for utility cost reductions;

. Simplifying and streamlining the regulatory process;

. Moving rates for all customer classes, in real dollars, steadily down the national average for investor-owned utilities;

. Maintaining a reasonable opportunity for the utility to earn a fair rate of return; and

. Maintaining and improving quality of service.

We still regard these as our general goals in evaluating any PBR proposal, and as the policy yardstick for measuring SoCal's proposal in the present instance.

We have embraced PBR in concept with the clear recognition of our "fundamental and enduring duty to protect California's consumers of [energy]," a duty which we have pledged not to change during the transition to a streamlined and more efficient regulatory approach. (Blue Book, p. 34.) This means that, despite our preference for PBR, we will not approve any PBR [*35] proposal just because it encourages efficiency on the part of the utility. The other part of the equation, protection of ratepayer interests, must also be satisfied.

B. The SoCal PBR Proposal Must be Modified to be Acceptable, but Much of SoCal's PBR Proposal is Consistent with our Stated Goals for PBRs

We have examined SoCal's proposal on the threshold question of whether elements of the proposed mechanism conflict with existing Commission decisions and orders, or with the policies we have articulated above. Consistent with the parties testimony, we conclude that in several respects it does. We must therefore modify SoCal's PBR to conform to these overriding principles.

1. The SoCal PBR Proposal Violates the Terms of the Global Settlement

Both the Commission's Office of Ratepayer Advocates (ORA) and The Utility Reform Network (TURN) criticize SoCal's proposal as being inconsistent with the Global Settlement. That agreement was adopted in final form by the Commission in D.94-07-064, <=3> 55 CPUC2d 452 (1994), and governs a number of aspects of ratemaking for SoCal's gas utility operations for the period from August 1, 1994, through July 31, 1999, when it expires.

TURN asserts[*36] that there are five inconsistencies between SoCal's PBR proposal and the Global Settlement which preclude adoption of SoCal's proposal in its present form. First, TURN states that SoCal's proposal to base rates upon 1996 adjusted throughput violates a provision of the Global Settlement that requires rates instead to be based upon 1991 throughput. Second, TURN argues that SoCal's proposal to extend the cost allocations adopted by the Global Settlement beyond the term of that agreement would violate a provision requiring cost allocations to be determined in the 1998 Biennial Cost Allocation Proceeding (BCAP). Third, TURN alleges that the proposal to use one definition of a "normal" temperature year for setting rates, and another for allocating costs between classes, to the detriment of the core class, also violates the Global Settlement. Fourth, TURN claims that SoCal's proposal to index rates, thus doing away with the authorized revenue requirement allocated by the Global Settlement, violates the settlement. Fifth, TURN argues that the proposal to eliminate the CFCA violates the Global Settlement, because the continued operation of that account was a basic assumption underpinning the[*37] settlement. We conclude that SoCal's PBR proposal conflicts with the Global Settlement at least in some of these respects, and that the proposal will have to be modified to avoid these conflicts.

Section II, paragraph 1, of the Global Settlement states:

"SoCal shall calculate rates based on 1991 actual throughput, with [specified adjustments] for the five-year period commencing upon the date that this [settlement] becomes effective." <=4> (55 CPUC2d 458.)

Notwithstanding this language, SoCal proposes to use 1996 customer count and core throughput, normalized for average temperature conditions, to set throughput because it would be "fair and reasonable" to do so. This would vary the express language of the Global Settlement. Moreover, it would not be consistent with the table of specified average year volumes and customer counts for basing cost allocation and calculating rates during the period covered by the Global Settlement. See Global Settlement Implementation Appendix, Section C.1, paragraph 2 <=5> (55 CPUC2d at 469).

As justification for this variance, SoCal argues that its proposal would also eliminate the CFCA, and that use of the Global Settlement throughputs would impose[*38] upon it a $ 39 million annual revenue penalty because of the resultant undercollection. We do not find SoCal's position to be persuasive. The Commission has a strong policy favoring settlements as a means of resolving issues in its proceedings, and we will not undermine that policy by changing the terms of a settlement after it becomes a Commission order.

In addition to expressly providing that cost allocation and rates during the five-year term of the Global Settlement would utilize specific throughput volumes based upon adjusted 1991 data, the Global Settlement also reflects the parties' intent that the cost allocation be terminated by the 1998 BCAP. Under the PBR, by contrast, the cost allocation would continue for the entire PBR period, some two and one half years beyond the term of the Global Settlement. The significance, as explained by TURN witness Florio, is that SoCal's approach would harm core customers because of the underlying temperature assumption used to develop the throughput for the purposes of calculating core rates. The company now uses 1506 annual heating degree days (HDDs) to define an average temperature year under the Global Settlement. SoCal's suggested reduction[*39] would reduce the average year forecast of throughput by 5%. The lower measure of HDDs suggested by SoCal for use in designing core rates would deny ratepayers

the benefit of the lower throughput forecast for purposes of cost allocation.
n13

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n13 SoCal is now willing to accept the figure of 1330 HDDs in place of the 1316 HDDs it originally proposed, but the result is essentially the same.

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The Global Settlement contemplates that there will be a specific allocation of costs to customer classes during its five-year term. Section II, paragraph 3, sets up a memorandum account to track the variance between costs allocated to noncore and wholesale markets and SoCal's actual noncore and wholesale revenues. By contrast, the PBR would not have explicit costs allocated to noncore and wholesale markets, or an annual cost used to develop the effective rates for noncore transportation service. As explained by witness Florio, the Global Settlement,

"plainly contemplated that there would be an authorized revenue requirement that [*40] was allocated between the core and noncore markets during the entire term of the settlement. The fact that SoCal would now like to shift to a program of rate indexing cannot overcome the deal that the company made." (Ex. 55, p. 20, l. 11-16.)

Consequently, we cannot accept this feature of the PBR proposal.

TURN argues that the Global Settlement mechanism implies that revenue variations are to be passed onto core ratepayers through the CFCA, and that elimination of the CFCA would therefore violate the intent of the Global Settlement. We agree. The Global Settlement would be unworkable without the CFCA, and SoCal's proposal would therefore violate the terms of that agreement.

2. The Absence of a Sharing Mechanism is Inconsistent with Commission Policy

In most respects, SoCal's proposal fits our model of PBR. However, the proposal omits any mechanism for sharing the savings between shareholders and ratepayers. Instead, SoCal argues that the productivity factor (or "X" factor) utilized in adjusting rates annually, and particularly the "stretch" component incorporated into that productivity factor, should be considered an "upfront" device that will adequately compensate for lack[*41] of an after-the-fact mechanism to allocate savings, because it creates a downward pressure on costs and, therefore, rates. We disagree.

In previous PBR proceedings we have rejected substitution of a productivity factor for a sharing mechanism for SDG&E and for SCE. There are several reasons for this. First, <=6> PU Code @ 728 imposes upon us a duty to insure that utility rates are maintained at a level that is just and reasonable. This can only be assured if the overall level of profits is effectively controlled by placing a practical limit on how far the utility is willing to go to earn a share of the marginal profit. The consequence is that profits, and therefore rates, are maintained at reasonable levels.

A sharing mechanism is the ultimate "safety net" for ratepayers, as it corrects for the possible adoption of a productivity factor that turns out to be overly conservative, understating the productivity increases which the utility is actually able to achieve. With a sharing mechanism, if the utility attains productivity increases that exceed the adopted productivity factor, the resultant profits must be shared with the ratepayers rather than going solely to the utility. SoCal argues[*42] that this would "dilute" its incentives to achieve greater productivity goals, but we see no reason why we should fix a productivity index based upon imperfect forecasting techniques, and permit it to remain undisturbed for a five-year period, based upon speculation that this mechanism will adequately benefit the ratepayers. If the utility is actually able to reap benefits above the level reflected by the adopted productivity factor, it would not be "just and reasonable" to require ratepayers to be satisfied with only the share of savings based upon attaining the productivity estimate made at the outset of the program.

SoCal admits that the reduction in its rate base alone will result in an increase in its rate of return of 87 basis points. This is simply a consequence of depreciation of its rate base rather than cost-cutting. A sharing mechanism would insure that the ratepayers will receive their fair share of the rewards of improved productivity, however those rewards are achieved. Because a PBR with a sharing mechanism simultaneously allows higher profits than at present, and lower rates due to increased productivity, a sharing mechanism creates the potential for a "win-win" situation. [*43]

3. The SoCal PBR Must be Modified Because it Does not Simplify Regulation

Certain features of SoCal's PBR proposal would also be contrary to the Commission's goal of simplifying regulation under performance-based ratemaking. Rather than eliminating balancing accounts and reducing the degree of Commission oversight, SoCal's proposal introduces altogether new concepts, the WNM and the EEAF, to reduce its level of risk. Monitoring the operation of these new devices will add to, rather than lessen, the Commission's regulatory tasks, representing a movement away from the Commission's goal of lessening the regulatory burden that is ultimately borne by ratepayers.

4. Certain Features of the Proposal are not Related to Performance-based Ratemaking, and Should not be Adopted by the Commission as an Aspect of SoCal's PBR Proposal

SoCal's proposal includes some features that are extraneous to a scheme which encourages efficiency on the part of the utility through a system of incentives. Instead, these additional features appear to have been included by SoCal as a "wish list" of items which, if authorized, would enhance the potential profitability of SoCal without rewarding ratepayers[*44] in kind. Specific examples include the proposals for major changes in residential rate design, and gain on sale exceptions, which appear to be designed only to enhance SoCal's profitability without any relation to ratepayers' interests. Residential rate design issues were addressed by the decision in SoCal's BCAP, adopted on April 23, 1997.

We are also mindful that we should not make any major changes in general industry policy in a proceeding which involves a single utility, such as this one. Questions of new products and services and gain on sale are broad ones which potentially apply to an entire class of utilities, and any major changes should be adopted in a generic proceeding to insure that they will apply evenhandedly to all utilities in the class. We must therefore refrain from addressing such proposals in this proceeding.

5. Conclusion: The SoCal PBR Methodology must be Modified for Adoption by the Commission

In recognition of these conceptual problems, we cannot adopt the PBR proposal advanced by SoCal. Doing so would contradict important Commission policies and orders, and would represent an abdication of our responsibility to ratepayers. Although we favor performance-based[*45] ratemaking as a tool for regulating utilities in the current regulatory environment, we must in some respects replace SoCal's proposal with a program which more accurately advances our regulatory goals.

C. The Commission's Adopted PBR

In this section we enumerate the essential features of our adopted PBR for SoCal. This PBR will become effective immediately. Insofar as possible it retains the elements of the SoCal proposal, but it includes changes that bring it into conformance with other decisions, goals, and policies of the Commission.

The features we adopt are: (1) the productivity index (inflation less productivity); (2) the quantity indexed; (3) exclusions and adjustments; (4) offramps and termination provisions; (5) service quality, customer satisfaction, and safety incentives; and (6) monitoring and evaluation provisions. We also establish the amount of the base margin for indexing.

1. Indexing Method

As earlier explained, we must first select the overall index (price index minus "X") to be applied to the indexed quantity in order to obtain the subsequent years' base rates.

a) Inflation Measure

SoCal is proposing an inflation measure (the GUPI) based upon[*46] a weighted average of the recorded indices of labor O&M, nonlabor O&M, and capital-related costs. In the GUPI, the measure for labor O&M is the index of average hourly earnings of workers in gas production and distribution as reported by the U.S. Bureau of Labor Statistics. The measure for nonlabor O&M is the DRI/McGraw Hill nonlabor O&M index for gas utilities. The inflation measure for capital-related costs would be based on the DRI/McGraw Hill indices for capital service prices and for the price of gas distribution capital goods. These measures would be weighted according to the average of expenditures in each category for the past five years.

SoCal proposes that rates for a year would be set using the latest available forecasts for the GUPI elements for that forthcoming year at the time that SoCal makes its annual PBR rate formula rate filing, but that the next year's rate filing would include an adjustment to "true up" any difference between the forecast and actual GUPI.

SoCal originally proposed to use a weighting of input price inflation based on SoCal's own historical ratio of labor expense, nonlabor expense and capital inputs to total costs. ORA proposed using a weighting[*47] that was the average of gas operations for SoCal, Pacific Gas and Electric Company (PG&E), and SDG&E. The rationale for ORA's recommendation was that it would make it easier for the Commission to administer PBRs for the three major gas utilities it regulates. In any event, a broader-based price index is consistent with the Commission's disinclination to use company-specific indexes. n14 SoCal has accepted ORA's alternative.

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n14 SCUPP/IID propose a weighting based on five to ten western U.S. gas utilities. This proposal is vague and undefined; the exact companies are not identified and there is no basis for comparing it to other parties' positions. It would not simplify the Commission's administration of PBR, and we will not adopt it.

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We adopt the approach to price indexing proposed by ORA.

b) Productivity Factor

As explained earlier, the productivity or "X" factor consists of two parts. The first component is a historic measure of industry productivity. The second component represents an additional productivity[*48] target, or aspiration measure, which is based upon potential incremental productivity improvement that the utility can expect to achieve over and above the historical average. SoCal refers to this as the "stretch" factor, or "consumer dividend," because it creates downward pressure on costs and, by extension, on rates.

(1) Industry Productivity Measure

SoCal proposes using a historical industry productivity measure of 0.5%. This figure was developed from the Christensen Associates study, and elicited little criticism from the parties. We adopt the 0.5% historical industry productivity figure.

(2) "Stretch" Factor

The second component, the "stretch" factor, is more problematic. SoCal proposes that this component also be fixed at 0.5%, and claims that this is a liberal figure in relation to the productivity gains it expects to be able to achieve beyond the historical average.

ORA advocates a 1% stretch factor, double that proposed by SoCal. This would produce a total productivity factor of 1.5%. TURN/Department of General Services (DGS) supports ORA's estimate as reasonable in the long run, but believes that the pendency of the Enova-Pacific Enterprises merger will cause an [*49] increase in productivity. This is based upon the experience of witness Marcus, who testified that during the period of the SCE-SDG&E merger proposal, (1) staff, members sought jobs outside the company because of organizational uncertainty and were not all replaced because of the possibility of postmerger job consolidations, and (2) capital spending was curtailed. Thus, TURN/DGS recommends adoption of a 1.5% stretch factor while the merger application is pending.

Although the subject of merger savings is not a part of our consideration here, we believe that the pendency of the merger proceeding distinguishes this period of time from that which was examined in developing SoCal's productivity and stretch factors. Given the nature of management's motivation, it is indeed likely that capital spending will be curtailed and expenses otherwise forgone before the merger is consummated or disapproved. We therefore believe that the stretch factor proposed by SoCal is likely to be conservative.

SoCal's objection to the adoption of a stretch factor greater than 0.5% is based primarily on the number of multiples of historical productivity that each figure represents. Thus, SoCal states that ORA's[*50] suggestion of a 1.5% total productivity factor would be three times the historical average, and TURN/DGS's 2.5% figure would be five times the historical average. SoCal argues that this would not be reasonable.

We find that ORA's suggestion comes as close to the mark as any, particularly in view of the likelihood that disproportionately large productivity gains may be on the near-term horizon. It is appropriate to "set the bar high" in the expectation that SoCal will, indeed, stretch to maximize productivity. Were we to set too low a goal, SoCal's benefit could come at the expense of the ratepayers, even allowing for a sharing mechanism. There would be no advantage to adopting such a PBR over traditional ratemaking methodology. Nevertheless, we recognize that productivity improvements are not likely to occur all at once. Both cost reductions and revenue enhancements may take several years to come to fruition. We recognized this in D.9-09-092 in SCE's PBR when we adopted an "X" factor, including a stretch factor, which ramped up from 1.2% to 1.6% over the life of the PBR. We believe it is appropriate to take a similar approach here.

We will adopt a stretch factor that increases incrementally[*51] over the initial five-year PBR timetable resulting in an X factor of 1.1% in Year 1, 1.2% in Year 2, 1.3% in Year 3, 1.4% in Year 4, and 1.5% in Year 5.

c) Quantity Indexed

SoCal proposes to index rates directly, rather than indexing total authorized margin or authorized margin per customer, for several reasons. First, SoCal contends that this mechanism will put it at risk for the level of customer demand (throughput), and that this is the direction in which the Commission wants to move; SoCal points to the Commission's recent adoption of rate indexing for SCE to support this contention. SoCal also argues that this mechanism will best prepare it for the transition to a competitive marketplace, and will change its corporate culture. SoCal claims that rate indexing will allow the elimination of a major balancing account, the CFCA, and thus simplify regulation. Finally, SoCal argues that this approach is consistent with the direction the Commission has already taken by putting SoCal at risk for a specific throughput for most noncore customers under the Global Settlement.

We do not find SoCal's arguments persuasive in relation to its unique circumstances. First, the probability[*52] of risk to the shareholders is far lower than SoCal suggests, because realistic throughput forecasts indicate a growing core market. n15 In addition, SoCal's president, Mr. Mitchell, acknowledged on cross-examination that the company continues to seek new throughput opportunities, such as business ventures in Mexico. Under traditional regulation, a portion of the cost of these ventures would be allocated to the resultant new loads, reducing rates for existing customers. This would not be true under PBR. In light of these realities, we prefer not to give SoCal carte blanche to increase its throughput and apply what will almost surely be a positive index each year (reflecting inflation in excess of productivity) to actual throughput.

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n15 See, for example, Exh. 62A, Attachment 7, p. 25: SoCal projects systemwide sales growth of 3.4% between the years 1996 and 2000, principally in the high-margin residential sector.

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Preservation of the CFCA, at least through the period covered by the Global Settlement, is central to[*53] this indexing method. The Global Settlement establishes throughput based on the 1991 level. SoCal has agreed to this through the term of the agreement. Although the Global Settlement does not specifically refer to the CFCA, as SoCal says, once throughput is fixed in this fashion, the CFCA handles overcollection or undercollection from sales variations. Retention of CFCA is therefore implicit in the Global Settlement, as the mechanism will not work properly without it.

As we have already explained, retention of the CFCA in connection with throughput variations requires the use of revenue indexing. This is required by the Global Settlement. Other provisions of the Global Settlement also require the existence of a revenue requirement. These include "a memorandum account to track the variance between the costs allocated to the noncore and wholesale markets and [SoCal's] actual noncore and wholesale mechanisms," which is calculated using "a debit entry equal to one twelfth (1/12) of the authorized annual cost used to develop the effective rates for noncore transportation service including EOR [Enhanced Oil Recovery]." (TURN/DGS Opening Brief, p. 9, quoting Global Settlement, Section II, [*54] para. 3 and Implementation Appendix, p. 21.) These features preclude rate indexing, and must be retained until expiration of that agreement.

Another circumstance unique to SoCal compels us to adopt indexing of the revenue requirement, rather than rates. Specifically, the proposed Enova-Pacific

Enterprises merger will create a need to track savings, which cannot be accomplished with rate indexing. Although the merger application is not directly relevant to the SoCal PBR proposal, we take notice that if we approve the merger, we will have to determine the amount of merger savings in that proceeding. Those savings are expressed in the same terms as the total revenue requirement. Indexing the total revenue requirement will enable that sum to be deducted from the pre-merger totals. On the other hand, if rates are indexed where throughput forecasts are no longer calculated, then savings cannot be passed back to customers. This means that if we were to adopt rate indexing now, we would have to revisit the subject in the merger proceeding and translate the PBR results in order to insure consistency after the merger takes place, if it is approved.

Finally, we conclude that revenue rather than[*55] rates must be indexed because SoCal's rate base is declining at the time the PBR is to go into effect. SoCal's proposal to index rates, which would fix SoCal's rate base at the 1996 level and index it for at least five years thereafter, fails to recognize this fact. Rate indexing would benefit SoCal's shareholder because its capital spending is declining. This is an important fact, as SoCal's earnings will consequently increase by 87 basis points more than its currently authorized rate of return as the sole result of depreciation. n16

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n16 SCUPP/IID considers this fact sufficient to justify retention of traditional ratemaking for SoCal rather than moving to a PBR system at this time. That course would be contrary to our policy of favoring PBR, and we believe it is too extreme. Alternatively, SCUPP/IID proposes a methodology which would separately index the O&M portion and the capital portion of the base margin rate. This would correct for the declining rate base, but would provide an incentive for SoCal's management to substitute capital for O&M expenses wherever possible, thus perpetuating one of the disadvantages of traditional ratemaking.

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The operation of depreciation is best understood in relation to the level of a utility's capital expenditures. If a utility's plant additions increase more than its plant is depreciated, rate base and associated taxes will grow. On the other hand, if the utility's plant additions are lower than its depreciation expense, the level of depreciated plant, and hence rate base, will decline. SoCal's additional capital expenditures are less than depreciation, thus significantly reducing rate base as well as the amount of return and of associated taxes. This is because SoCal is experiencing low customer growth (Exh. 52, pp. 4-5). The low customer growth rate is reducing investment requirements to a level lower than its depreciation expense, and its rate base is declining.

As explained by SCUPP/IID witness Yap, SoCal's 1995-1999 Financial Plan sets out the Company's projection of the decline in its average rate base. The table and chart on page 8-5 of the Financial Plan shows a decline beginning in 1995, acknowledging the trend: "Depreciation exceeds capital expenditures in traditional markets beginning in 1995." See Exh. 52, p. 5 (SCUPP/IID - Yap). This projection is consistent with SoCal's[*57] 1995 10-K report to the Securities Exchange Commission (SEC), which reflects a 3.4% decrease in rate base for 1995. The 10-K report projects 1996 capital expenditures of $ 224 million, while SoCal's Summary of Earnings Table for 1996 filed in this proceeding projects $ 255 million in depreciation (Exh. 24, Table 12-A). When compared to the $ 231 million capital expenditure level and $ 237 million depreciation level that accompanied the 3.4% reported decline in rate base during 1995, it is clear that the decline in rate base is accelerating. (Exh. 52, p. 5 (SCUPP/IID - Yap.))

Under traditional ratemaking, declining rate base tends to reduce rates. Declining rate base results in lower depreciation expense, return, and associated taxes, which are reflected in lower rates. But if rate base is "frozen" and rates are indexed, they will rise despite the fact that rate base is declining.

d) Adopted Indexing Formula

For the reasons we have described, it is necessary to index SoCal's revenues, rather than rates. SoCal's rate indexing proposal, however, is easily adapted into an equivalent revenue-indexing mechanism. SoCal's rate indexing proposal is

PBR rates (year 2) = PBR rates [*58] (year 1) x (1 + inflation - productivity)

This is a standard price cap formula, in its basic form identical to the ones we have adopted for Pacific Bell and GTEC, and for Southern California Edison. n17 Recognizing that by definition SoCal's revenues are the product of rates and the quantity of gas sold or transported (throughput), this formula can be translated into an equivalent revenue setting mechanism:

PBR revenue requirement (year 2) = PBR revenue requirement (year 1) x (1 + inflation - productivity + growth in throughput)

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n17 Typically such formulas include as well a term for so-called "Z factors." The Z-factor term is ignored in the above discussion just to keep things simple.

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Since throughput by definition is average throughput per customer times the number of customers, the last term--growth in throughput--can be decomposed further into the sum of customer growth and growth in throughput per customer. Making this substitution in the revenue indexing formula results in SoCal's proposal [*59] for rates translated into its equivalent for indexing revenues:

PBR rev. req. (year 2) = PBR rev. req. (year 1) x [1 + inflation - productivity + customer growth + growth in throughput per customer]

Finally, this formula can be converted into its equivalent for revenue requirement per customer n18 by deleting the customer growth term on the right hand side:

PBR rev. req. per customer (year 2) = PBR rev. req. per customer (year 1) x [1+inflation - productivity + growth in throughput per customer]

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n18 Actual customers are used to calculate customer growth and convert revenue per customer into total revenues.

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Like SoCal, ORA proposes to index rates using the same, standard inflation minus productivity format. Its proposal, translated into the equivalent revenue per customer indexing formula, therefore looks exactly the same as SoCal's depicted above. The only difference--as described earlier--is that ORA proposes a 1.5 percent productivity factor, while SoCal's is 1.0 percent.

Unlike SoCal[*60] and ORA, TURN/DGS proposes to index revenues directly. Like the two other parties' proposals, its indexing mechanism is driven by inflation, productivity and customer growth. However, because the proposal is not based on indexing rates, it does not reward the utility with additional revenues from increasing throughput per customer. Additionally, it includes a minus 1.41% constant term in the formula n19 that is missing from the other two. Perhaps most importantly, it does not give the same weight to the common factors it shares with the SoCal and ORA proposals--inflation, productivity and customer growth. TURN/DGS's indexing mechanism assigns less weight to inflation and the productivity offset, and more weight to customer growth, in determining the utility's revenue requirement. TURN/DGS's revenue indexing proposal for revenue per customer is: n20

PBR rev. req. per cust. (year 2) = PBR rev. req. per cust. (year 1) x [1 + 0.610 x inflation - 0.610 x productivity + 0.605 x cust. growth - 1.41%]

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n19 This number, because it is negative, could be interpreted as an additional productivity offset.[*61]

n20 TURN/DGS provide formulas both for indexing total revenues and revenues

per customer. The differences in the parameters, however, are insignificant. TURN/DGS argues that a long-run PBR indexing mechanism should index revenues per customer. See Exh. 63, p. 20 (TURN/DGS - Marcus).

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Although the TURN/DGS formula relies upon essentially the same set of factors as SoCal's and ORA's the difference in results is not insignificant. With the throughput per customer term dropped in the SoCal and ORA proposals for directness of comparison, the results for a 1.0 percent customer growth rate and inflation of 3 percent are: n21

SoCal
PBR Rev. Req. per cust. (year 2) = (1 + .03 - .01) x PBR Rev. Req. per cust. (year 1)

= 102% of PBR year 1 Rev. Req. per customer

ORA
PBR Rev. Req. per cust. (year 2) = (1 + .03 - .015) x PBR Rev. Req. per cust. (year 1)

= 101.5% of PBR year 1 Rev. Req. per customer

TURN/DGS
PBR Rev. Req. per cust. (year 2)

= [1 + 0.610 x (.03 - .015) + 0.605 x .01 - .0141] x PBR Rev. Req. per cust. (year1)

= 100.11% of[*62] PBR year1 Rev. Req. per customer

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n21 The omission of the average throughput per customer factor is not trivial. SoCal Gas' forecast of throughput growth is 2 percent per year; for customers, 1 percent growth. The implied growth in throughput per customer therefore is 1 percent. When this effect is included in the SoCal and ORA proposals, the respective escalation factors become 103% and 102.5%.

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A PBR mechanism provides an incentive to utilities to cut costs by disconnecting their rates from their actual costs. Traditional ratemaking sets rates and revenues on the basis of utilities' actual costs. The poor cost-cutting incentives provided by such ratemaking are too well known to repeat here. A PBR mechanism, on the other hand, sets a limit for revenues or rates--independent of the utilities subsequent actual cost performance--based on the general factors that drive costs: inflation, customer and output growth, with an offset for productivity gains.

This does not mean, however, that we cannot ignore special[*63] circumstances that may affect a specific utility's costs. We agree with TURN/DGS that an indexing method should be chosen which, among other things, would leave ratepayers at least as well off under PBR as they would have been under traditional ratemaking. Without some assurance to that effect, there is no real "consumer dividend" for ratepayers from adopting PBR.

In this context, SoCal (and ORA's) approach fails to take into account its specific circumstances, and therefore omits an important consideration that needs to be taken into account in setting its indexing formula. As noted in the previous section, SoCal's projected plant expenditures are less than projected depreciation, thus significantly reducing future rate base and the associated amount of return and taxes. The. low customer growth rate SoCal is experiencing is reducing investment requirements to a level lower than its depreciation expense, and its rate base is declining.

Two utilities could face the same inflation and have the same level of productivity (X), but could have very different trajectories in revenue requirements if one was growing more rapidly and had an increasing rate base and the other was growing more[*64] slowly and faced declining rate base. A simple inflation minus X indexing formula--for revenue per customer--would give the same revenue increase to both utilities, possibly yielding a windfall for one and a loss for the other.

Thus, if one is constructing a single "X" factor, it may not be sufficient to construct that factor from a historical factor productivity study plus a stretch, as SoCal and ORA have proposed. Neither SCE nor SDG&E claimed that they would face rate base declines, as SoCal forecasts that it will. TURN/DGS's methodology attempts to take into account SoCal's current investment plans over the next five years. However, while we agree with the basic logic of the TURN/DGS approach, we are unwilling to go so far as to adopt its proposed formula. The formula relies on a complex regression analysis, underlying which is a set of assumptions and variables. One important assumption is that the projected rate base decline will occur as SoCal has projected in its 1996-2000 financial plan. SoCal's future investment plans may well vary due to a variety of factors, including the rate of customer growth and the incentives afforded by this PBR decision. The TURN/DGS approach assumes[*65] that SoCal's management will have no control over the extent of future capital investments. While we agree that the general trend is likely to be as presented in the 1996-2000 financial plan, we cannot rely on the exact numbers in that plan as the mathematical basis for the indexing formula.

As noted earlier, the indexing formula is intended to give utility management the incentive to improve productivity through reasonable management of costs and practices that are within its control. Thus, the productivity factor takes into account expected gains on an industry-wide level, and adds a stretch factor to provide a "consumer dividend" and account for the fact that implementation of the PBR necessarily will require increased productivity if the utility is to receive a fair benefit from the new system. We also adjust the base margin to ensure that the utility is starting from a reasonable starting point, just as we would under traditional ratemaking. TURN/DGS makes the case that the same concept should be applied to rate base. If rate base is falling due to factors extrinsic to the PBR, returns will increase unless an adjustment is made, and vice versa. While this issue was not introduced[*66] in other PBR cases, it is a legitimate consideration.

We would prefer to adopt a method to take rate base changes into account outside of the indexing formula. A methodology such as a direct revenue offset or adjustment of the benchmark rate of return could accomplish this. However, no party has proposed such a method, and we must rely upon the indexing methodology, in which rate base factors are effectively translated into productivity. SoCal estimates in its comments on the Proposed Decision (p. 4) that the impact of the TURN/DGS formula may result in an effective productivity factor as high as 2.9 percent, which is 1.4 percent above the 1.5 percent final stretch "X" factor. This suggests that it may be possible to translate directly the TURN/DGS formula into a straight productivity figure and thus roughly reconcile the TURN/DGS concept with the indexing methodologies adopted in other PBRs.

Since some of the capital spending decisions in the future are presumed to be under SoCal management's control, we find it reasonable to adopt a lower effective X factor than the 2.9 percent imputed from the TURN/DGS methodology. Accordingly, we will adopt a 1.0 percentage point increase to the[*67] ramped stretch productivity factor. Our final adopted productivity "X" factor will be 2.1 percent in year 1; 2.2 percent in year 2; 2.3 percent in year 3; 2.4 percent in year 4; and 2.5 percent in year 5.

The PBR indexing formula therefore that we adopt is:

PBR rev. req. per customer (year 2) = PBR rev. req. per customer (year 1) x [1+inflation - X],

with our adopted "X" factors described in the previous paragraph.

2. Sharing Mechanism

SoCal proposes that there be no adjustment in rates during the minimum five-year PBR period to share with ratepayers any difference between its recorded rate of return and a benchmark rate of return. We reject this aspect of SoCal's proposal, and require a sharing mechanism as part of the PBR for SoCal.

ORA, SCUPP/IID, SCE, and TURN/DGS advocate the inclusion of a sharing mechanism as an integral feature of SoCal's PBR, and two specific proposals have been advanced for our consideration. ORA's proposal would allow SoCal to retain all profits up to the level of 75 basis points above authorized rate of return (ROR), and 50% of any profits earned above that benchmark level. ORA states that earnings at the 75 basis point benchmark[*68] level will enable SoCal to keep $ 37.5 million of its revenues as a reward for its efforts, and above this level SoCal would net additional rewards, albeit at a proportionately lower rate. By contrast, TURN/DGS urges us to adopt a mechanism which shares cost savings with ratepayers on a progressive basis. This approach affords better insurance for ratepayers in the event that the productivity factor turns out to be unrealistically low, and profits therefore to be excessive.

TURN/DGS recommends as our basic model the PBR we adopted for SCE in D.96-09-092. That mechanism shares both profits and losses within "bands" above and below the benchmark return on equity (ROE). Under this approach, shareholders receive all of the gains and losses up to 50 basis points above and below the benchmark rate of return, which we termed the inner band. Our intent in so doing was to assign shareholders the responsibility for the gains and losses associated with routine operation. (Id., mimeo., p. 42.) Beyond the inner band, from 50 to 300 basis points, the shareholder share of gains rises continuously from 25 through 100%, while the ratepayer share correspondingly declines from 75 to 0%. This we defined[*69] as the middle band. The shareholders receive all gains 300 basis points above the benchmark and remain responsible for all losses more than 300 basis points below the benchmark.

TURN/DGS proposes one alteration to this mechanism. In recognition of the fact that SoCal will not be exposed to revenue fluctuations due to short-run temperature based sales fluctuations if we retain the CFCA, TURN/DGS recommends that the level of the inner band should be reduced to no more than 25 basis points, or be eliminated altogether. We agree. The allowance of the inner band for SCE was partially to account for weather-based sales fluctuations that were beyond the discretion of utility management. For SoCal we will retain the CFCA as part of the PBR and limit the inner band to 25 basis points to account for minor fluctuations in operations. Thus shareholders will receive 100% up to the level of 25 basis points above the benchmark ROR, and an increasing percentage in steps from 25 up to 300 basis points, above which level they will receive 100%. We refer to a mechanism of this type, where the utility share of net revenue increases as its earned return becomes greater than the benchmark return (and the[*70] ratepayer share correspondingly decreases), as progressive sharing.

Between 25 basis points above the benchmark ROR and 300 basis points above the benchmark, we will adopt 8 bands. The more bands that exist, the greater the potential to move into a new band and for shareholders to collect an increasing marginal share of the higher profits. The first band will be from 25 to 50 basis points above the benchmark. In this band, shareholders will receive 25% of the marginal revenues in the band and ratepayers 75%. Each successive band will see an increase of 10% in the incremental share allocated to shareholders and a decrease of 10% in the ratepayers share. The sixth band will fall between 150 and 200 basis points above the benchmark, with shareholders receiving 75% and ratepayers 25%. The seventh band will be between 200 and 250 basis points above the benchmark, and shareholders will receive 85% and ratepayers 15%. The eighth band will be between 250 and 300 basis points above the benchmark; shareholders will receive 95% and ratepayers 5%.

Under this system, shareholders may gain up to 68% of the increment up to 300 basis points above the benchmark. However, as shareholders may keep [*71] all of the increment above 300 basis points above the benchmark (subject to the offramp discussed below), it is possible for shareholders to gain significantly more than 68% of the increment. For example, if returns are 400 basis points above the benchmark, shareholders would retain 76% of the increment. This system gives an excellent and increasing incentive to shareholders, and is fair to ratepayers who receive both the "consumer dividend" in the productivity formula and a larger share of early (and presumably easier) productivity gains.

We do not perceive a need to impose any sharing below the ROR benchmark, except for the offramp provisions discussed below. Even under traditional cost-of-service ratemaking, we have never guaranteed the utility its authorized ROR. Our PBR mechanism is designed to allow SoCal to "stretch" for higher levels of revenue, and to keep a progressively greater amount of what it is able to earn. By setting the proper ROR benchmark, we will calibrate the mechanism so that it rewards improvements which exceed that baseline, and accomplishes the efficiency gains that we intend for the benefit of the ratepayers by providing for progressive sharing above [*72] the benchmark. We will set the ROR benchmark at the current ROR.

Shareholders	Ratepayers		Basis Points
100	0	* 2 years	300
95	5		250
85	15		200
75	25		150
65	35		125
55	45		100
45	55		75
35	65		50
25	75		25
100	0		
Benchmark Rate of Return			
100	0	* 2 years	-175

Sharing Mechanism

We have focused on the question of how cost changes are dealt with in a rate PBR versus revenue PBR. Our decision to adopt a revenue PBR has much to do with our view of the appropriate treatment of cost reductions. We now turn to the treatment of revenue increases (also called revenue enhancements) in this PBR. SoCal may be able to increase net revenues in several ways. As discussed elsewhere in this order, SoCal may be able to expand current service offerings unrelated to the provision of natural gas (such as meter repair), or offer new products or services. SoCal may increase revenues through pricing flexibility approved in this order. SoCal may also experience customer growth or increases in usage per customer.

With the exception of throughput increases, SoCal can benefit from each of the methods of revenue enhancement discussed above. Revenue[*73] enhancement increases productivity, and improved productivity is one of the primary goals of performance-based regulation. We believe the adoption of this PBR will encourage SoCal to seek out both cost reductions and revenue increases. If revenue increases occur, they will be factored along with associated costs into the total rate of return calculation that is a part of the revenue PBR. If any revenue increases push SoCal into the sharing range, or further into the sharing range (as discussed below), both SoCal shareholders and ratepayers will benefit from the productivity increases.

3. Exclusions

SoCal proposes that several cost categories handled by existing regulatory mechanisms be excluded from the PBR. These would be preserved, and would maintain their separate existence for adjudication by the Commission. The proposed exclusions are as follows:

. Catastrophic Event Memorandum Account (CEMA). The Commission authorized all utilities to establish this account under Resolution no. E-3238 (July 24, 1991) as a reaction to the 1989 Loma Prieta earthquake to record the costs of restoring utility service to customers; repairing, replacing, or restoring damaged utility[*74] facilities; and complying with government agency orders resulting from declared disasters. It was designed to expedite and facilitate prompt response by utilities in restoring services disrupted by declared disasters. SoCal proposed to exclude CEMA from PBR so that it will fulfill its intended purpose. ORA initially recommended that CEMA expenses be reviewed using Z-factor criteria to determine potential recovery (Exh. 107, p. 63), but subsequently stipulated that CEMA be treated as an exclusion.

. Hazardous Substance Cost Recovery Account (HSCRA). This mechanism is a long-term performance-based cost recovery mechanism for hazardous substance and insurance litigation costs related to hazardous substance sites identified by the utility for cost recovery from third parties, insurance carriers and ratepayers.

. Low Emission Vehicle (LEV) Program. In D.93-07-054, 50CPUC2d 452, the Commission ordered that all funding for utility LEV programs was to be established separate from the normal general rate case proceedings, and required all energy utilities to file separate applications for funding of six-year LEV programs under specified guidelines established in that decision. [*75] SoCal complied with that requirement. In D.95-11-035, -- CPUC2d -- (1995), the Commission allowed continued ratepayer funding of LEV fleet expenses subject to a one-way balancing account, and specified the treatment of the costs of customer-site stations. SoCal proposes that capital-related costs for utility LEV and customer-site stations remain in the PBR Base Margin showing, and that all expenses covered under the one-way balancing account be excluded from PBR and continue as a separate regulatory funding mechanism.

. Regulatory Transition Costs. SoCal proposes that all regulatory transition costs whose regulatory treatment is in the process of being determined at the federal and local levels to be excluded from the PBR to be separately resolved by the Commission. These matters are not subject to reasonable estimation, and SoCal describes them as both significant and potentially volatile. Transition costs identified by SoCal consist of Take-or-Pay (TOP) costs, Minimum Purchase Obligation (MPO) Transition costs, PITCO/POPCO n22 Transition costs, and the Interstate Transition Cost Surcharges (ITCS).

. Wheeler Ridge Interconnection Costs and Revenues. D.95-04-078, [*76] CPUC2d (1995), in SoCal's 1994 BCAP, sets forth the adopted incremental ratemaking treatment for the Wheeler Ridge facilities. SoCal states that implementation requires that Wheeler Ridge interconnection costs and revenues be excluded from PBR.

. Mandated Social Programs. SoCal proposes that mandated social programs such as California Alternate Rates for Energy (CARE) and the low-income Direct Assistance Program (DAP) should be excluded from PBR because they are created by legislative or administrative mandate, and are not within SoCal's control.

. Gas Costs and Pipeline Demand Charge. Gas costs and pipeline demand charges for core sales customers are forecasted and recovered through rates adopted in BCAPs. SoCal proposes to exclude these charges from PBR to maintain the existing BCAP cost recovery system.

. Costs Imposed by the Commission. SoCal proposes that certain costs imposed by the Commission, such as intervenor compensation fees and costs related to Commission staff -supervised management of financial costs should be excluded from PBR because they are subject to separate cost recovery treatment.

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n22 These acronyms, respectively, refer to Pacific Interstate Transmission Company and Pacific Offshore Pipeline Company, both of which are SoCal affiliates.

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[*77]

There is no longer any serious dispute concerning exclusion of these items. All of them appear to be appropriate for exclusion from the PBR mechanism, because they are beyond the control of SoCal's management, or are subject to recovery through other existing ratemaking mechanisms. We will approve these proposed exclusions.

4. "Z" Factors

We agree with SoCal that events which qualify as Z factors should be handled outside of the PBR mechanism. We also agree that the adopted procedure must insure that there is no double-counting of Z factor events in the inflation index. We will adopt the following procedure proposed by SoCal to handle Z factors under PBR.

When a potential Z factor event occurs, SoCal will promptly advise the Commission of its occurrence and establish a memorandum account for the event. The notification of the event will provide all relevant information about the event, such as a description, the amount involved, and the timing, and will advise of the establishment of the memorandum account. This notification will be followed by a supplement to the annual rate adjustment procedure for Commission review.

For each event, SoCal's shareholders will absorb the first[*78] $ 5 million per event of otherwise compensable Z factor adjustments. This will be accomplished through the operation of a "deductible." The deductible is cumulative for each Z factor event from year to year, and is exhausted when the cumulative Z factor costs exceed the deductible amount. The deductible is separately applicable to each Z factor event.

To implement the adjustment, we adopt SoCal's proposal for use of a formula based on the level of integration with the GUPI to avoid double-counting the Z factor event in the inflation index. This formula is based upon the extent to which the Z factor impact is captured in the GUPI, and excludes that amount. SoCal will have the burden of proof in a Z factor proceeding to demonstrate both the total cost of the Z factor event, and the percentage of such cost estimated to be captured within the GUPI.

ORA initially recommended that CEMA become a Z factor. However, ORA and SoCal have agreed to recommend that CEMA be treated a an exclusion rather than a Z factor. As part of the agreement SoCal will maintain commercial insurance for earthquake and other disaster coverage unless major adverse changes to premium levels occur in the future. We[*79] will adopt the agreement between ORA and SoCal.

5. Core Pricing Flexibility

SoCal has proposed that it be given the flexibility to offer optional tariffed rates and to negotiate discounted rates with core customers. Any discounts would be applied to the base rate portion of the default PBR rate (i.e., gas costs would not be discounted). With its proposed elimination of the CFCA, SoCal's shareholders would be at risk for any discounts provided to customers. SoCal proposes that optional tariffs and discounted rates be priced no lower than short-run marginal cost and go into effect on the date of filing.

ORA supports SoCal's request to be able to offer discounted rates provided that shareholders bear 100% of the risk associated with revenue shortfalls and that the price floor for contracts is long-run marginal cost. ORA also supports the concept of optional tariffs for the core but opposes authorizing them at this time, because SoCal has provided insufficient information. Therefore, ORA recommends that SoCal either submit an application that would allow for consideration of specific optional tariffs, as occurred for SCE, or to approve optional tariffs on a case by case basis.

Allowing[*80] for negotiated rates and optional tariffs will provide SoCal with opportunities to increase utilization of its system, which benefits ratepayers. Under our adopted sharing mechanism, incremental revenues translate into benefits for both ratepayers and shareholders, providing SoCal with the incentive to more efficiently operate the system. Therefore, allowing SoCal to enter into negotiated contracts and offer optional tariffs is consistent with our PBR goals.

We would prefer to authorize optional tariff offerings with more details than SoCal has provided in its application. However, because shareholders will be entirely at risk for the revenue shortfalls, we will allow SoCal to negotiate discounts and offer optional tariffs, provided that the price floor is above class average long-run marginal cost (LRMC) and allow the tariffs to be effective upon 20 days after filing unless protested on the basis that the price floor is below class average LRMC. n23 If protested, the optional tariff filing will proceed through the normal advice letter process. The optional tariffs must be available to all similarly situated customers that meet the eligibility criteria. If SoCal wishes to offer rates[*81] that are customer specific or targeted at some subset of a class and therefore below the class average LRMC, then additional information must be submitted, consistent with information required for long-term contracts under the Expedited Application Docket (EAD), and the contract or tariffs will be subject to Commission approval through the EAD process. Contracts with terms of five years or longer must be approved by the Commission. Consistent with allowing SoCal to offer core customers discounts, we will also allow SoCal to offer firm noncore customers negotiated discounts of less than five years' duration. Negotiated contracts must be filed with the Commission, but the confidentiality provisions in place for noncore contracts will also apply for core contracts.

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n23 Nothing in this decision is intended to prevent parties from protesting such filings on any other basis, as well.

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Electric utilities who retain the Electric Revenue Adjustment Mechanism (ERAM) and offer discounted rates for which shareholders are at risk[*82] must currently include an adjustment to ERAM to ensure that ratepayers are not at risk for any revenue shortfall associated with discounted rates. Because we have retained the CFCA, we direct SoCal to develop an adjustment mechanism to the CFCA to ensure that ratepayers are isolated from any risk of revenue shortfall associated with discounted core rates or optional tariff offerings.

6. Implementation Date

The rates based upon our adopted base margin shall become effective August 1, 1997. We recognize that changing objectives as a result of implementing PBR mid-year may create implementation problems and therefore the PBR mechanism shall become effective as of January 1, 1998, unless SoCal elects to operate under the mechanism effective as of January 1, 1997.

7. "Offramp" Provisions

SoCal proposes that the Commission not terminate or modify the PBR mechanism before its minimum term, even if SoCal's recorded rate of return falls below or rises above any particular level during that period, and proposes to take full risk for the level of its earnings under PBR for at least the proposed minimum duration of the PBR mechanism. For the protection of both SoCal and its ratepayers, [*83] we conclude that this should not be the case.

a) Cost of Capital Trigger

Although SoCal proposes not to make any changes in PBR indexed rates for changes in cost of capital, it proposes an exception in the event that the 12-month trailing average yield on long-term Treasury Bond increases or decreases more than 250 basis points from the forecast average rate for calendar year 1997, as adopted in D.96-11-060 in SoCal's 1997 cost of capital application. Thus, SoCal acknowledges the need for an escape valve, or offramp of sorts, in the event of a dramatic change in the cost of capital.

Under the proposed mechanism, SoCal would have the option to file a cost of capital application in the event that the 250 basis point "trigger" were exceeded. In the event of a 250 basis point decrease, SoCal would be required to file a cost of capital application. In either event, the Commission would determine whether any change in rates was appropriate in light of all factors affecting the cost of capital. Any rate change, whether an increase or decrease, would be prospective from the effective date of a Commission decision.

ORA generally supports the trigger mechanism concept, but proposes a[*84] somewhat different approach to cost of capital. The principal differences between SoCal's proposal and ORA's proposal are that: (1) ORA's mechanism would not be triggered unless actual interest rates changed by more than 150 basis points and the then-current DRI forecast was for interest rates to continue to be at least 150 basis points different from the benchmark interest rate under PBR; and (2) if ORA's threshold were triggered, there would be an automatic adjustment of rates according to a pre-established formula. SCUPP/IID also supports the basic concept of using a triggering mechanism with a single-index PBR, and prefers ORA's proposal over SoCal's.

We prefer ORA's approach over that proposed by SoCal for two reasons. First, that approach is more sensitive to a realistic level of interest-rate savings. Secondly, it is a system which will not involve as great a level of regulatory burden on the Commission, because a cost of capital application would not have to be filed when the trigger level was reached.

We adopt for SoCal the ORA triggering mechanism for changes in cost of capital during the PBR period, coupled with the "MICAM" mechanism for rate adjustment that we recently[*85] adopted for SDG&E in D.96-06-055.

b) Rate of Return Offramp

SoCal opposes any offramp which would have the effect of allowing or requiring suspension or modification of the PBR mechanism before the expiration of the five-year minimum term in the event that SoCal earns a specified amount more or less than the benchmark rate of return. SoCal argues that this would result in dilution of the penalties for poor performance and rewards for superior performance, and tend to defeat or impair the incentive provided by the mechanism for the utility to operate efficiently.

As part of its proposal for a sharing mechanism, ORA advocates an offramp mechanism to protect both ratepayers and SoCal from significant deviations from anticipated earnings under this new and untested PBR system. For upside deviation, ORA proposes an offramp trigger set at 300 basis points above authorized earnings for two consecutive years. For downside deviation, ORA proposes an offramp at 175 basis points below authorized earnings for two consecutive years. This proposal conforms well to the sharing mechanism we adopt and is very similar to the approach we have taken with SDG&E. We also prefer an offramp "trigger" [*86] device to the adoption of an interim PBR with a shorter duration, which is the approach espoused by TURN.

We will adopt ORA's rate of return offramp proposal. The PBR mechanism will be subject to a motion for voluntary suspension if SoCal reports two consecutive years of net operating income that is at least 175 basis points below its authorized rate of return. Either SoCal or ORA may file this motion seeking suspension of the PBR mechanism. If the motion is granted, suspension of the PBR would be required. If SoCal reports return of 300 or more basis points above its authorized rate of return for two consecutive years, the PBR mechanism will automatically be suspended, and we will conduct a formal regulatory review to determine what, if any, changes in the ratemaking mechanism are required.

c) Mid-course Review

Although SoCal opposes any regulatory change to the PBR system prior to expiration of the 5-year minimum term (except for the cost of capital trigger), the experimental nature of the PBR and SoCal's own unique circumstances compel us to conclude that there is a need for reexamination of the program before five years elapse.

First, according to the Global Settlement, [*87] the expiration of that agreement on July 31, 1999, will alter SoCal's ratemaking environment and require the institution of a BCAP. As SoCal's witness Van Lierop acknowledges,

"The Global Settlement requires that [SoCal] file a BCAP application in October of 1998 with rates to become effective on August 1, 1999. The key purpose of this BCAP filing is to terminate the provision in the Global Settlement that rates and cost allocation be based on 1991 throughput. . . . [SoCal] proposes that "shadow rates" - adopted in this proceeding -go into effect as actual base rates on August 1, 1999, which will terminate the 1991 throughput provision with respect to base rates. The 1998 BCAP filing is still required to replace 1991 throughput, with a forecasted throughput level for the purpose of determining exclusions surcharges. [SoCal] proposes that the 1998 BCAP be used to adopt surcharges and cost-of-gas rates for the remainder of the PBR period, i.e., from August 1, 1999 to December 31, 2001." (Exh. 11, pp. 69-70.)

This in itself establishes the need for a mid-course proceeding, currently anticipated to be in the form of the 1998 BCAP, to revisit certain of the issues in this PBR. [*88]

Notwithstanding explicit language to the contrary in the Global Settlement, SoCal's PBR proposal is premised upon retaining the inter-class cost allocation based on 1991 throughput for the entire PBR period, which extends well beyond the August 1, 1999, expiration of the Global Settlement. TURN's witness Florio testified that this would be particularly harmful to core customers, because the effect of the SoCal proposal would be to reduce the average year forecast of throughput by 5%, while at the same time denying core ratepayers the benefit of the lower throughput forecast for purposes of cost allocation. (Ex. 55, pp. 16-17.) Consistency must be assured through the 1998 BCAP or its equivalent.

TURN asserts that there is another reason why cost allocation issues must be resolved in the 1998 BCAP. In the current (1996) BCAP, ORA, and TURN have proposed certain refinements to the Commission's LRMC methodology which SoCal claims to exceed permissible cost allocation changes as defined by Section C.5 of the Global Settlement's Implementation Appendix. In the current BCAP we may conclude that these changes must await the expiration of the Global Settlement. However, SoCal's PBR proposal[*89] would preclude the allocation of base margin among customer classes from consideration in the 1998 BCAP, because the rates set in this proceeding (as indexed) will remain in force beyond the Global Settlement's expiration. Consequently, ORA and TURN would be foreclosed from proposing adjustments to the LRMC methodology well beyond the expiration of the Global Settlement unless there is a mid-course review.

The merger application of Enova Corporation and Pacific Enterprises, which is currently pending before us, also portends significant changes in SoCal's ratemaking environment. Approval of the merger application could result, for example, in alteration of the base margin, particularly if there are significant productivity gains due to what SoCal has characterized as "synergies" such as the consolidation of administrative and general office functions of the merged parent companies. Although we have declined to examine the financial implications of the pending merger application in this proceeding, we cannot turn a blind eye to the probability that the merger may have considerable impact on SoCal, requiring some adjustment of the PBR.

We have also identified a number of features of[*90] SoCal's PBR proposal which are simply not appropriate for inclusion. Among these features are changes in residential rate design, additional pricing flexibility, and gain on sale. To the extent that these items were not addressed in SoCal's current BCAP, they should be addressed in the next BCAP (or its successor proceeding).

Finally, SoCal, ORA, and TURN have agreed to recommend that a mid-course review be undertaken to examine the status of customer service quality indicators, including the penetration of the CARE program. The 1998 BCAP (or its successor) could be utilized as a vehicle for conducting this review.

In recognition of these circumstances, we conclude that there is a need for a mid-course evaluation of SoCal's PBR, and that SoCal's 1998 BCAP (or its successor) should serve as the forum for that effort. In that proceeding, we will address the issues of SoCal's throughput forecast, cost allocation, rate design, and other matters which may come to light from the interim results of

SoCal's PBR experience.

d) Termination

Under SoCal's proposal, the PBR would remain in effect at least five years from its inception. Based upon this minimum term, SoCal proposes that [*91] any party, or the Commission on its own motion, could institute a proceeding to change or replace the PBR mechanism upon its expiration. ORA and SCUPP/IID object to the automatic continuation of SoCal's PBR. ORA proposes that the PBR be formally evaluated near the conclusion of the five-year PBR term to provide the Commission with a complete evaluation of the PBR mechanism.

ORA proposes that SoCal be required to notify the Commission and all parties of record of its intention to file either a general rate case application or a PBR application 24 months prior to the end of the PBR cycle. If SoCal indicates that it plans to file a general rate case application rather than a PBR application, ORA will submit its master data request to SoCal within one month after SoCal notifies the Commission. Thereafter, the procedural schedule would follow the rate case plan in accordance with R.87-11-012. Alternatively, ORA proposes that if SoCal notifies the Commission that it desires to continue with a PBR program, SoCal should be required to file a PBR application no less than 18 months prior to the end of the PBR cycle. In its filing, SoCal should provide both an evaluation of its existing PBR program[*92] and a recommendation as to what modifications should be made to the PBR mechanism for the future.

ORA witness Bower specifies the issues that, at a minimum, should be addressed in its filing requesting continuation of PBR. These are:

. Was SoCal successful in meeting or beating the adopted benchmarks?

. What happened to system average rates over the period of the PBR? How did this compare to the average national rate and to the overall rate of inflation?

. If SoCal was successful, how were the reductions accomplished? What types of expenses were reduced? Were there any side effects of the expense reduction?

. What was the operating environment of SoCal over the PBR period? Were there developments that either made it easier or more difficult to achieve the established goals? If so, what were those developments?

. Did the Commission and SoCal work together effectively in the process of monitoring and evaluating the PBR? If not, what parts of the monitoring and evaluation process did not work?

. Did the Commission and SoCal work together effectively in the event of any interim modifications to the PBR? If not, how could this process have been improved?

. Did the PBR demonstrate[*93] a more or less efficient method of regulation than the conventional general rate case method? What specific features of the PBR were either better or worse?

. Were the specific performance indicators in this PBR adequate. to measure the effectiveness of the PBR? If not, how should the performance indicators be modified?

. Was SoCal successful in maintaining a stable credit rating over the term of the PBR? What other financial measures should be examined? What was SoCal's annual ROE and ROR performance over the PBR, and how did that compare to the company's authorized numbers? How did this performance compare to SoCal's historical record for periods prior to the PBR?

. What other consequences of the PBR were identified, if any? What was the impact of those consequences on the PBR? What was the impact of those consequences on SoCal, its ratepayers, the environment, and others? Were the consequences positive or negative?

. Considering the results of the PBR, what should be the next steps? Should the PBR be continued? If so, what "start up" conditions should prevail? Should those alternatives include a return to the general rate case or attrition process?
(Exh. 107, pp. 16-18 [*94] - 16-19.)

ORA's proposal is well considered. Although we have no disinclination to continue SoCal's PBR beyond the five-year minimum, there is a need to insure that the system does not continue indefinitely without being subjected to one scrutiny, and to insure that it is meeting its intended goals and furthering our regulatory policy. The procedure for continuing the PBR outlined by ORA is far less onerous than the requirements for filing a GRC, and is appropriate for evaluation of a program that has been in force for five years, as contrasted with the three-year life of a GRC.

We will adopt ORA's proposal.

8. Service Quality, Customer Satisfaction, and Safety Incentives

By its nature, customer satisfaction is difficult to measure and to quantify. SoCal's original proposal to measure ongoing customer satisfaction by using an index figure generated considerable controversy, resulting in a great deal of discussion among the parties during the course of the hearing. The outcome of these negotiations was a joint position on behalf of SoCal, ORA, and TURN, which is set forth in Exh. 210. That exhibit provides a comprehensive joint recommendation for measures to ensure that customer[*95] satisfaction, service quality, and employee safety performance will be maintained in SoCal's PBR environment.

The four primary features of this comprehensive plan are:

. Individual targets would be established for each of the four key service attributes, with each service attribute carrying a potential rate reduction should the performance level for that attribute fall below its prescribed target and deadband. These four key service attributes are:

(1) Customer satisfaction with the telephone customer service representative (CSR);

(2) Customer satisfaction with the scheduling of an appointment for a field service call;

(3) Satisfaction with the field Appliance Service Representative (ASR); and

(4) Percentage of on-time arrival for the service call;

. An additional call center "prescriptive" performance standard would require 80% of all telephone calls to be answered within 60 seconds for regular calls, and 90% of all leak and emergency telephone calls to be answered within 20 seconds. SoCal would be subject to rate reduction for failure to meet these targets.

. In addition to rate incentives, SoCal would assume responsibility to provide reports to the Commission, [*96] on a quarterly basis, containing monthly data on several service quality indicators, as follows: level of telephone busy signals, percentage of estimated meter readings, leak response time, percentage of missed appointments, and percentage of customer problems resolved on the first service call.

. The Commission will undertake a mid-course review of the status of the customer service quality indicators.

The program specifies penalties for failure to attain goals below a deadband. Aggregate penalties of more than $ 4 million will trigger an investigation by the Commission.

SCE objects that the service program does not provide for rewards for attaining levels above the goals. This overlooks the purpose of our quality control efforts, which is to ensure that standards of service are upheld at least at current levels despite the adoption of PBR, and particularly that cost cutting will not result in the degradation of service and safety. We are concerned that if we provide rewards for the attainment of higher levels, we will encourage efforts to overdeliver service, thereby increasing the cost to provide service. The cost of the rewards would be passed along to customers through [*97] higher rates. This would be contrary to our purpose in adopting PBR. We have already described the terms to which SoCal, ORA, and TURN have agreed relative to attainment of the employee safety standard. As contrasted with the customer satisfaction provisions, this part of the agreement provides for both rewards and penalties.

The program agreed to by SoCal, ORA, and TURN is a rational and systematic approach to insuring the maintenance of service quality, customer satisfaction, and safety. We adopt that program as part of our order. n24 We also adopt the parties' recommendation to conduct a midterm review of the operation of these features. As stated above, we have selected the 1998 BCAP (or its successor) as the vehicle for conducting this review.

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n24 The portion of Exh. 210 which sets forth that program is included in our Order as Appendix A.

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9. Additional Customer Service Issues

SoCal states that there are two additional unresolved issues which pertain to the customer satisfaction measure. First, in the event [*98] that SoCal is authorized to implement a late payment charge with respect to its core customers, TURN proposes additional service quality measures, with potential monetary penalties, pertaining to the mailing of customer bills and the posting of customer payments. Second, SCUPP/IID seeks to increase the amount of the SIC, which SoCal offered to its noncore customers as part of the Capacity Brokering Settlement in 1991. SoCal opposes both of these measures.

SoCal's proposal to impose a late payment charge on overdue balances for both core and noncore customers bears no immediate relationship to its proposal to move to a PBR system of ratemaking. Accordingly, TURN's responsive proposal to impose standards on the date of bill mailing and payment posting, and penalties in the event that those standards are not met, is equally immaterial for this PBR. There is no logical nexus between the economic incentives under PBR, or the related provisions to insure service quality, and this controversy over administrative processing of bills. We therefore decline the request for additional service incentives relating to billing and payment, and defer the matter of instituting a late payment charge [*99] to a more appropriate Commission proceeding.

SCUPP/IID's request for an increase in the SIC is apparently intended to protect noncore customers from service interruptions caused by deferral of maintenance, replacements, and expansion of facilities. The SIC was originally negotiated as part of the 1991 Capacity Brokering Settlement, which was approved by the Commission in D.91-11-025, <=7> 41 CPUC2d 668 (1991). Specific provisions which apply to SoCal in that settlement allow SoCal to offer a performance guarantee in its tariffs by providing the customer with a credit equal to $ 2.50/dth of gas for curtailment episodes, with a maximum credit of $ 5 million in any calendar year. SCUPP/IID proposes that we make this penalty mandatory, adopt a higher $ 10 million initial penalty, and increase the penalty ceiling every time the maximum penalty is triggered.

We perceive no reason to adopt this measure as part of the quality assurance measures for SoCal's PBR. SoCal states that there have been no curtailments of intrastate transmission service since the SIC was implemented, and SCUPP/IID has not demonstrated any change in circumstances which would justify an increase in SoCal's penalty exposure. [*100] Moreover, for noncore business, SoCal faces significant competitive threats in the form of interstate pipeline bypass, alternate fuel consumption, and cheap imported electricity. Thus market forces, rather than penalties, will provide the impetus for service quality assurance for noncore customers.

10. Monitoring and Evaluation

Because PBR is intended as a means to reduce the need for periodic reexamination of a utility's financial results through the GRC process, its success depends upon an effective program of monitoring and evaluation. In order to discharge our responsibility, we must be in a position to understand and evaluate the performance of SoCal's PBR during interim periods between formal proceedings.

SoCal proposes to file a detailed annual advice letter to implement the annual PBR rate adjustment and report on the customer service performance measures, including any rate adjustment associated with customer service measures. This annual advice letter would be comprehensive in that it would include all elements of the PBR indexing and adjustment mechanisms, i.e., inflation, productivity, Z factors, and customer service refunds, if any. SoCal proposes to file this annual[*101] advice letter on October 1 to allow sufficient time for review and approval so that the rates can become effective

January 1, and to furnish supporting documentation and workpapers to the appropriate staff divisions on October 1.

Apart from this advice letter filing, SoCal's proposal for monitoring and evaluation consists principally of recommendations for the discontinuation of many current reporting requirements in the interest of streamlining the regulatory process. SoCal proposes to eliminate or modify approximately ten reports. (See Exh. 107, Table 16-1.) Four of these reports are required by Commission General Orders and apply to all energy utilities.

ORA in its comments states that a procedural mechanism is needed so that SoCal can report its earnings annually. ORA does not object to the annual October 1 filing proposed by SoCal, but proposes that an additional annual filing be made to review the performance of the PBR during the previous calendar year. ORA notes that both telephone and energy utilities which currently operate under adopted PBR mechanisms are required to make annual filings to report on the performance of the PBR during the previous year. Telephone utilities[*102] are required to file sharable earnings advice letters evaluating the prior year's operating results no later than April 1 of each year. (D.89-10-031, Ordering Paragraph 16.) SDG&E must file a draft of its performance report by April 15, and a final version of the report by May 15. (D.94-08-023, p. 80.) SDG&E's filing includes a review not only of any sharable earnings, but also reviews the reliability, safety, customer satisfaction, and price performance components of the SDG&E PBR. SCE is required to file an annual performance report similar to the SDG&E report by March 31 of each year. (Advice Letter 1191-E, as adopted by Resolution E-3478.) ORA also requests an extended time period for the review of the performance report to allow parties more time than the usual amount for advice letter protests. ORA suggests the following schedule:

April 1 - SoCal provides a draft sharable earnings advice letter to appropriate Commission staff, which includes workpapers detailing operating results for SoCal's base rates.

July 1 - Commission staff can submit a report on its audit or analysis of SoCal's draft sharable earnings results.

July 10 - SoCal files its final performance advice [*103] letter, with supporting workpapers.

July 31 - Protests in accordance with General Order 96-A can be filed.

ORA, SCUPP/IID, and SCE object to the modification or elimination of existing reporting requirements. As ORA witness Bower states:

"If the Commission is to successfully implement a monitoring and evaluation plan, it must continue to receive these reports. These reports will be essential tools in evaluating SoCal's performance under the PBR mechanism. The Commission will have the opportunity to evaluate the usefulness of these reports in a PBR environment and determine whether the reports should be modified, eliminated, or expanded. Some reports may prove to be essential while others may prove to be unnecessary. DRA [now ORA] recommends that SoCal continue to provide nine of the ten reports it proposes to eliminate." (Exh. 107, pp. 10-11.)

We acknowledge that reduction of regulatory paperwork in the interest of improving efficiency is certainly a worthy goal. It is not, however, an integral part of PBR. We would like to reduce the volume of reports for all utilities, not just SoCal. Particularly for those which are required by a Commission general order, a generic proceeding[*104] would be required in order to change the requirement. We cannot discriminate in favor of SoCal by eliminating reporting requirements in this proceeding merely because it would reduce SoCal's regulatory burden. The proposal to do so bears no direct relationship to the institution of a PBR system.

We will adopt SoCal's proposal for an annual PBR advice letter filing but deny its request to modify or eliminate any current reporting requirement in the interest of maintaining our ability to monitor and evaluate SoCal's performance under PBR for the present. n25 The existing reporting requirements, plus SoCal's annual PBR advice letter filing, will enable the Commission to monitor and evaluate SoCal's PBR program, and should remain in place until changed through mid-course review or other proceeding, as appropriate. We will also require an annual PBR performance report similar in scope to the SDG&E annual performance report, and will adopt ORA's suggested schedule for review of the filing. The filing should not only review the PBR performance including a report of any sharable earnings, but should also report on the service quality, customer satisfaction, and safety incentives which we [*105] have adopted. Finally, any party who wishes to receive a copy of the draft filing to be made on April 1 should make such a request to SoCal, and such requests should be honored by the Company.

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n25 Other requirements, such as that which obligates SoCal to obtain our express permission before closing any branch offices, are also unaffected by this decision. (See D.92-08-038, <=8> 15 CPUC2d 301 (1992).)

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D. New Products and Services

As we summarized earlier in this decision, SoCal seeks the ability to offer new products and services, either itself or through an affiliate, without prior Commission approval. It also asks us to agree that the Commission not regulate the prices, terms, and conditions for new products and services; that the profits or losses from new products and services flow entirely to shareholders; and that existing products and services that are offered on an unbundled basis in the future be treated in the same manner as new utility-related products and services. SoCal's proposal is opposed by ORA, [*106] SCE, TURN, and others, on a number of grounds.

On December 9, 1996, Enron Capital and Trade Resources, New Energy Ventures, Inc., the School Project for Utility Rate Reduction, and the Regional Energy Management Coalition, TURN, UCAN, and XENERGY, Inc. (collectively, Petitioners) filed a petition which, for procedural reasons, was accepted as a motion in the electric restructuring docket. In their motion, the Petitioners requested the Commission to issue an order instituting a rulemaking to establish standards of conduct governing relationships between natural gas local distribution companies (like SoCal) and electric utilities and their affiliated, unregulated marketing entities. The Petitioners also requested that the utilities be required to have their nonregulated activities conducted by their affiliate companies, rather than the utility itself, subject to the affiliate standards. The Petitioners stated that the utility providing services within a monopoly structure should be required to limit its actions to those services, so that equal treatment among competitors can be ensured. It was pointed out in response to the motion that the Petitioners' motion was opposed to the proposal[*107] offered here by SoCal. In the rulemaking drafted for the Commission's consideration, staff recommended that this aspect of SoCal's proposal be consolidated with the rulemaking to assure that SoCal and its affiliates would not be placed at an unfair advantage vis a vis the other California energy utilities and their affiliates.

In the rulemaking and investigation docket (OIR) opened April 9, 1997, in response to the motion, we provided instead "...that our decision in the PBR docket on flexibility in introducing new products and services may be interim." (R.97-04-011, I.97-04-012.) We also stated that "entry by the energy utilities and their affiliates into the unregulated market for energy products and services should be on an equal footing with respect to regulatory posture." (Id.)

Although the OIR explicitly preserved the opportunity in this proceeding to adopt an interim order with respect to SoCal's proposal for flexibility in introducing new products and services, we decline to do so at this time. Now that we have carefully reviewed SoCal's proposal and the opposing pleadings, we believe it would be premature, at best, to allow SoCal to offer new products and services in [*108] competitive markets on an unregulated basis while requiring

SoCal's competitors, the remaining energy utilities, to participate in the rulemaking and investigation before allowing them to offer the same services into the same markets on an unregulated, untariffed basis.

SoCal may choose to make the same proposal, or to modify it, in our affiliates rulemaking and investigation. A number of questions arise from this proposal that may need further consideration.

First, SoCal has not clearly specified the types of products or services which it seeks authority to offer on an unregulated basis. During the course of this proceeding, SCE and Enron each raised legitimate concerns about the types of services that SoCal would seek to offer on an unregulated basis, particularly concerning the unbundling of traditional services. In response, SoCal states that with respect to the service unbundling of concern to Enron and SCE, SoCal "expects" to file separate regulatory and ratemaking applications. This pledge leads to two further questions: (1) If SoCal will not be offering on an unregulated basis the services and products which are of concern to SCE and Enron, what products and services will it[*109] seek to offer? and (2) Is SoCal's "expectation" that it will seek further authority before unbundling any traditional services, a binding pledge not to do so, pending further regulatory approval?

Second, SoCal has not offered explicit criteria to define the relevant markets into which SoCal seeks entry on an unregulated basis. What criteria and process should the Commission utilize in determining the relevant market, the degree of competition or the extent of SoCal's market power? For example, SoCal has asked that it be able to unbundle existing elective after meter services (such as pilot lighting or appliance inspection) and offer these services on an unregulated basis "where there is no market power." (Exh. 144, p. 2.) However, SoCal has not explained how to determine, or who will determine, that SoCal has no market power with respect to a particular product or service.

One particular aspect of SoCal's proposal which is of concern to us is SoCal's assertion that it is considering offering new products and services in "either competitive markets which already exist...or are ripe for competition." (Exh. 7, p. 27.) As SCE observes, "Plainly, the fact that SoCalGas believes a market[*110] is 'ripe for competition' is a far cry from finding that a market is, in fact competitive...Under this proposal SoCalGas could conceivably unbundle a regulated monopoly bundled service into several unregulated monopoly unbundled services and then charge monopoly prices for them." (Exh. 50, pp. 17-18.) This issue needs further review.

We also note SoCal's argument that the Commission should presume that if SoCal does not currently offer a service, it cannot have market power with respect to it, and it is therefore a competitive service. By the very nature of

SoCal's monopoly position in the energy and energy services market, its access to comprehensive customer records, its access to an established billing system, and its "name brand" recognition, it may be that SoCal enjoys significant market power with respect to any new product or service in the energy field.

Third, SoCal has not proposed what regulatory tools would be used to prevent cross-subsidization between the services SoCal would continue to provide on a monopoly basis and those it would provide as competitive services. In its rebuttal testimony to ORA, SoCal argues that the opportunity for a utility to cross-subsidize the[*111] launch of competitive services would be virtually eliminated. (Exh. 119, p. 11.) SoCal's argument seems to rest on the premise that because its PBR proposal contains no sharing mechanism, all profits would accrue to shareholders, and management is consequently free to distribute all revenues which it derives from the monopoly enterprise in any manner it sees fit. Elsewhere in this decision we expressly require SoCal's PBR to contain a sharing mechanism. But even if the absence of a sharing mechanism, cross-subsidization cannot be permitted.

SoCal may renew its request along with its competing utilities, properly defined and detailed, in the newly instituted OIR. The level of detail which we would expect of a proposal to offer new products and services is equivalent to that which we set forth when we adopted the three categories of services for telecommunication products and accompanying accounting safeguards. (See D.89-10-031.)

While we are deferring consideration of SoCal's proposal regarding new products and services, we are not changing anything in this decision with regard to SoCal's ability to provide services currently offered or to apply to offer new products or services. SoCal[*112] currently offers certain services beyond the provision of natural gas. For example, SoCal currently provides meter repair services for SDG&E at its shop. This service, and others like it, may continue (subject to our jurisdiction). SoCal may also use the appropriate application or advice letter process to seek our approval to offer new products or services. We will consider any such filing in the normal course of review, and we will coordinate any such decision with our conduct of the proceeding on affiliate transactions, R.97-04-011 and I.97-04-012.

If SoCal expands its current service offerings and/or gains approval for new products or services, SoCal may be able to increase net revenues. We see this as a type of productivity improvement that would be consistent with the goals of PBR. Under the PBR we adopt in this order, returns above the target arising from either cost decreases or revenue increases will be shared between ratepayers and shareholders.

E. Base Margin

1. Introduction

SoCal now proposes that the base rates for 1997 be developed by applying the PBR index to a starting level of rates based upon SoCal's 1996 operating budget. After SoCal filed its supplemental[*113] showing in May 1996, its proposed base margin was $ 1,451,981,000, which represented a $ 61.2 million reduction in gas margin as compared to the 1995 authorized level. ORA's Base Margin Report (Exh. 106), with errata filed December 2, 1996, proposed a starting margin of $ 1,235,376,000. ORA's proposal excluded Demand-Side Management (DSM), Research, Demonstration & Development (RD&D), and Direct Assistance Program (DAP) expense
from base margin, but even allowing for this, the gap between ORA's and SoCal's position was $ 170 million as the proceeding entered the evidentiary hearing stage.

As the hearing neared its conclusion, several of the parties filed joint testimony which recommended the resolution of eight base margin and two policy issues (Exhs. 200-210). This reduced the difference between ORA's and SoCal's position to $ 71.7 million. We must now consider the recommended resolution of these issues and resolve those issues as to which there is still no agreement.

As is our practice with general rate case orders, we address these items on an exception basis. We do not address accounts or funding requests which were not at some point excepted to, or those which do not require [*114] our attention in order to ensure that they comply with the law or Commission policy. In such instances we implicitly find the utility's proposal to be reasonable.

2. Nonlabor Escalation Rate

In developing their estimates of reasonable base rates for the various cost categories, parties used a base year and escalated or deflated it to correspond to the test year, depending on the base year applied. ORA proposes a nonlabor escalation rate of 2.23% for such purposes. SoCal proposed a rate of 3.72% but did not oppose ORA's recommended rate. SoCal recommends, however, that the Commission use the same value to deflate 1996 dollars as it uses to inflate 1995 dollars in order to make consistent the showings of ORA and SoCal. We adopt ORA's proposed inflation rate as reasonable as well as ORA's recommendation to use the 1995 numbers in the record.

3. Customer Accounts (Accounts 901, 902, 903, 904, Sub-Account 184.103)

For customer accounts generally, ORA, TURN, and SoCal ultimately agreed to a level of expenses for customer accounts. They jointly recommend a level of $ 111.77 million for accounts 901, 902, and 903 and sub-account 184.103. They also recommend a reduction of $ 0.3 million[*115] for account 904 to recognize a reduction in industrial uncollectibles. The parties' joint recommendation recognizes $ 7 million in estimated benefits derived from SoCal's implementation of its Customer Information System (CIS). It also provides that costs for the administration of the CARE program would be appropriate until and unless a party other than SoCal administers the program. We adopt these recommendations.

4. Late Payment Charges

SoCal proposes a late payment charge to be assessed on customers who do not pay their bills on time. The parties recommend different approaches with regard to the implementation of a late payment charge and the appropriate late payment charge rate. As we have already stated, however, the institution of a late payment charge bears no direct relationship to the PBR proposal, and therefore should not be a part of this proceeding. We decline to adopt that part of SoCal's proposal here.

5. Gas Storage, Transmission, and Distribution Expenses

SoCal, TURN, and ORA agreed to total expenses of $ 20.37 million for gas storage and $ 25.017 million for gas transmission. SoCal observes that the amounts are in 1995 dollars and must be adjusted to account[*116] for inflation. We adopt the stipulated amounts and adjust them consistent with SoCal's recommendation.

SoCal and ORA do not dispute the estimated expenses for gas distribution. ORA's estimate is somewhat lower than SoCal's as a result of its estimated escalation factor, which SoCal does not dispute, and which we have adopted. We therefore adopt gas distribution expenses of approximately $ 176 million, which is a reduction in these accounts of about $ 35.3 million from levels recorded for 1994.

6. Marketing Expenses

ORA, TURN, and SoCal resolved any differences that initially existed for expenses associated with DSM, other marketing expenses not related to demand side management ("non-DSM marketing"), and the DAP, which is designed to provide conservation measures to low-income customers. The parties recommend DSM costs of about $ 27 million be included in a one-way balancing account rather than as part of base rates. TURN and DGS support this proposal.

The stipulation between ORA and SoCal also recommends that other marketing costs be reduced from the existing level of $ 29.14 million to $ 24.136 million and that capital costs for the Energy Resource Center would remain in base[*117] rates. Consistent with the parties' recommendations, we adopt total base rate marketing expenses of $ 24.136 million.

Funding and administration for DAP was not fully resolved in the stipulation. SoCal proposes a reduction in direct assistance funding from $ 18 million to $ 12 million. SoCal observes that the program is not cost-effective and that it is having difficulty finding new DAP customers because of program saturation.

Natural Resources Reference Council (NRDC) proposes retaining the $ 18 million funding level, arguing that the cost-effectiveness of the program has always been marginal and that SoCal has not justified changing funding on this basis. NRDC also observes that only 33% of income eligible households have received DAP help, contrary to SoCal's view that the market has been saturated.

We adopt SoCal's reduced funding levels in recognition that fewer customers are available to take advantage of the program as a result of the program's success. We also grant SoCal's request for increased program flexibility which would permit it to put the weatherization component of the program out to bid, among other things. We do not adopt any flexibility which would change SoCal's [*118]discretion to use the funds for other programs.

7. Administrative and General Accounts

a) Consultant Fees (Account 920)

Account 920 includes funds for outside consultants. ORA recommends disallowing $ 94,000 for a consultant hired for this proceeding because the consultant's work appears speculative after the test year. SoCal replies that it requires the funding for monitoring and evaluation of its PBR mechanism. We reject SoCal's argument, which appears to presume regulatory activity will increase as a result of PBR regulation. We adopt ORA's adjustment to this account.

b) Executive Compensation (Account 920 and 921)

TURN recommends adjusting labor costs by $ 0.606 million to reflect what it believes to be excessive compensation to executives. TURN observes that ORA's compensation study finds executive compensation to be almost 13% above market even though ORA does not recommend any reduction in SoCal's labor cost request. TURN's adjustment would amount to about 0.19% of SoCal's total request for employee compensation.

SoCal argues that its executive compensation rates are comparable to those offered to individuals working in markets from which SoCal recruits. [*119] It does not, however, present any evidence to support its argument. We therefore adopt TURN's adjustment to executive compensation.

c) Outside Expenses

(1) Stock Options Expenses (Account 923)

SoCal offers high level employees stock options as part of their compensation plans. ORA recommends that the Commission disallow expenses associated with stock options for executives, which ORA believes raises SoCal's long-term incentive levels to 21% above market levels. ORA observes that SCE's and PG&E's stock options programs are funded entirely by shareholders, and that the incentives are rewards for financial accomplishments which do not benefit ratepayers.

SoCal responds that ORA has improperly isolated a single element of SoCal's total compensation package. SoCal observes that ORA does not dispute that total compensation at SoCal is not above market levels. Isolating stock options expenses would therefore reduce the package of total compensation further.

We concur with SoCal that as long as its total compensation levels are appropriate we will not dictate how SoCal distributes compensation among various types of employment benefits.

(2) Lobbying Expenses

Following some[*120] initial disagreement regarding appropriate lobbying expenses, SoCal and ORA resolved their differences, proposing to reduce SoCal's request by $ 0.4 million. We adopt their agreement.

(3) Affiliate Transactions

SoCal pays its parent company for some services pursuant to direct billings which reflect specific services. ORA recommends a disallowance of $ 1.924 million of such affiliate costs sought by SoCal following an audit of related expenses. ORA proposes the disallowance on the basis that SoCal had failed to provide any meaningful documentation of $ 4.02 million worth of services provided to it by its parent, Pacific Enterprises. It is especially concerned with the lack of documentation for $ 3.32 million of law department charges.

SoCal replies that ORA and its auditors are not the "arbiters of how much documentation is 'enough.'" It argues that the law department of Pacific Enterprises could be expected to spend most of its resources on SoCal's needs because SoCal is the largest of the Pacific Enterprise companies. Finally, the SoCal level of funding for legal expenses is an estimate of 1996 expenses, not an accounting of actual expenses for 1995.

SoCal has the burden to [*121] demonstrate the reasonableness of its requests. In this instance, SoCal failed to provide sufficient documentation to support its request. However, SoCal submitted some documentation, which is adequate and to justify some payment by ratepayers for the services of SoCal's parent company. We therefore adopt ORA's recommendation of disallowing approximately 50% of SoCal's request, and allowing the rest.

(4) Multifactor Allocation Formula (Account 920)

SoCal pays its parent company for some services on the basis of indirect allocations to SoCal in cases where direct billings for specific services are not practical. ORA opposes elements of the formula SoCal uses to allocate such costs. Specifically, ORA would weigh operating expenses and payroll more heavily than assets. Applying ORA's methodology to the relevant costs, ORA recommends a disallowance of $ 2.939 million less than SoCal requests.

ORA believes SoCal's allocation to new lines of business - less than two tenths of a percent - is unrealistic. It would increase the amount to 20%.

SoCal responds with various arguments, among which are that its formula is used by other utilities and other jurisdictions, and that its other[*122] business units are designed to assist in new product development for sister units and are not independent of SoCal. SoCal also argues that its affiliates are considerably smaller than SoCal in terms of employees and assets.

The record suggests that the purpose of SoCal's affiliates is to promote new product development which is not related directly to utility expenses that would be recoverable here. If that were not the case, there would be scant reason to create such entities, considering the potential inefficiencies of having utility operations in two separate units. We are not concerned with how other jurisdictions view SoCal's allocation methods so much as we are inclined to consider the method on its merits. We find that ORA's method is superior to the one proposed by SoCal, and we adopt that method.

(5) Law Department Rent (Account 923)

SoCal receives its legal services from its parent company, Pacific Enterprises, which bills SoCal for related costs. ORA recommends an adjustment of $ 889,669 to reflect billings by Pacific Enterprises for rental of property to house the Legal Department. The billings are in excess of the actual costs of the Gas Company Tower lease. SoCal[*123] responds that the adjustment would be unfair because the rate is nearly identical to that paid at the Gas Company Tower. SoCal believes ORA should not be able to penalize the company for a lease cost that was reasonable at the time SoCal entered into it, even if prevailing market rates are considerably lower.

We have made adjustments to the Gas Company Tower lease to reflect unused space, and by implication the effects of the Law Department's remaining at another location. ORA has not demonstrated that the Law Department's lease is unreasonable. We therefore adopt SoCal's request for the costs of the Law Department's lease.

d) Insurance Expenses (Account 924)

ORA believes corporate reorganization will cause eight facilities no longer to be useful. Elimination of these facilities and the costs to insure them, according to ORA, will offset increases in insuring remaining facilities. ORA recommends a $ 16,000 reduction over SoCal's estimate.

SoCal responds that it is not anticipating a reduction in these costs in the near future. Although they might decrease at some point as a result of corporate restructuring, SoCal argues that it has not asked for recovery of cost increases [*124] which might occur at some unspecified point and should therefore not be required to forgo uncertain decreases.

We reject ORA's adjustment in this account on the basis that ORA has not demonstrated that SoCal will stop using the facilities in question during the test year.

e) Injuries and Damages (Account 925)

Account 925 includes funds for compensating employees for injuries and damages sustained at the workplace. ORA recommends a $ 1.9 million reduction in SoCal's estimate for Account 925 to recognize employee reductions and associated reduced costs for this account. SoCal argues ORA inappropriately reached its estimate by applying year end accruals of employee settlements in lawsuits rather than looking to actual cash payments to estimate these revenues.

Consistent with existing policy, we adopt SoCal's recommended level of funding in this account using actual cash payments as the basis for estimating net costs.

f) Franchise Fees (Account 927)

ORA and SoCal resolved most issues concerning franchise fees, arguing that this proceeding should not be a forum for changing the franchise fee methodology, and that estimates adopted in this proceeding would include $ 23.31 [*125] million in revenues from miscellaneous services. SoCal and ORA did not agree on the appropriate rate for franchise fees. We adopt SoCal's number, because ORA's is based on an assumption that the methodology would be changed.

ORA stipulated to retain the methodology in deriving a level of revenues; we therefore apply SoCal's rate for consistency.

g) Regulatory Commission Expenses (Account 928)

Account 928 includes funds for the costs of participating in regulatory commission activities. ORA recommends about $ 26,000 less in this account than SoCal. ORA uses the 1994 level and adds inflation for 1996. SoCal adds certain expenses and 1995 inflation to the 1994 level.

We adopt ORA's adjustment to recognize the likelihood that regulatory Commission expenses should not be increasing in the foreseeable future.

h) Rents (Account 931)

(1) Gas Company Tower

ORA recommends a disallowance of $ 5.384 million to reflect unused space at the Gas Company Tower, SoCal's corporate headquarters. ORA's recommended disallowance is based on ORA's assertion that 131,063 square feet of the site's 550,000 square feet is vacant.

ORA's recommendation is based on the analysis of its auditor, [*126] Overland. In its audit, Overland found that about 25% of the rentable space at Gas Company Tower was vacant, assuming that 375 employees would be moved to the Gas Company Tower. Based on SoCal's records, Overland concludes that SoCal has conducted "continuing review" of excess real estate rather than dispose of it or use it for company operations. ORA rejects company promises to move more employees to the Gas Company Tower, because such promises have not been fulfilled in the past. Specifically, ORA refers to SoCal's stated intent to move its Law Department to the Gas Company Tower during SoCal's last general rate case, which the Commission relied upon in granting associated funds for the Gas Company Tower.

SoCal responds that it has developed plan to occupy 97% of the Gas Company Tower in 1997. It presents a timeline which it developed shortly prior to hearing in this proceeding. Its witness asserts that at the time of the hearing the Gas Company Tower was 89% occupied. SoCal argues that it would not make sense for it to have sublet the unused space at the Gas Company Tower in the depressed Los Angeles rental market. SoCal states it attempted to sublease Gas Company Tower space but, [*127] at a market rental value of $ 13 to $ 15 a square foot, the revenue would have barely covered SoCal's building operations costs.

SoCal claims that the fact that the Law Department did not relocate to Gas

Company Tower is irrelevant. SoCal states that the relocation was deferred because of the need to house displaced employees at the Gas Company Tower, and because of the "extraordinary" cost of relocating the Law Department library.

ORA responds that the Commission should give no weight to the move plan, because the moves have been previously found to be uneconomic or are for personnel from CIS who are to be terminated. ORA argues that SoCal's analysis of future use of the Gas Company Tower assumes the company requires 120 workstations for equipment that is appropriately located on employee desks and 273 spaces for contractors, though only 140 contractors were expected to work for the company after December 1996. ORA also observes that Overland's report is generous because it does not account for 153 employees who have left the company since the audit was completed.

SoCal leased the space under a 20-year contract beginning in 1991. We originally reviewed the costs of the Gas Company[*128] Tower lease in D.92-11-017. In that order, we disallowed a portion of the excess space at Gas Company Tower on the basis that SoCal had not demonstrated the reasonableness of the costs. Subsequently, we reinstated much of the disallowance in D.93-12-043.

We begin by rejecting SoCal's argument that ORA is improperly relitigating this matter. As SoCal itself observes, D.93-12-043 permitted a reconsideration of the findings of that order with a showing of changed circumstances. ORA is seeking to demonstrate changed circumstances which would justify additional disallowances.

Indeed, circumstances have changed since 1994. Occupancy in the Gas Company Tower, assuming SoCal's analysis is correct, was 85% in 1995 and less than 80% in 1996. SoCal's assertion that the Gas Company Tower was 89% occupied at the time of hearing was refuted by ORA's auditors after a physical inspection of the building in November 1996. SoCal has not argued with Overland's findings of that physical inspection. Additionally, SoCal has presented no evidence to demonstrate that market prices would not permit it to recover operational costs.

SoCal has presented nothing but a promise that the occupancy rate at Gas Company[*129] Tower will increase to 97% in 1997. We have relied on promises with regard to Gas Company Tower occupancy in the past. The result is that ratepayers have paid at least $ 4 million annually in 1995 and 1996 for space at Gas Company Tower which is vacant and therefore not "used and useful."

SoCal must assume some portion of the risk for the long term lease it signed for its corporate headquarters, just as all businesses must assume such risks. Rather than make the best use of the Gas Company Tower under changing circumstances, SoCal appears to have deferred company consolidation and rejected opportunities to mitigate its losses by subletting portions of the Gas Company

Tower.

ORA and its auditors have presented a reasonable analysis of the Gas Company Tower occupancy which, as SoCal observes, gives "partial credit" for the utility's plan to occupy the Gas Company Tower. We therefore adopt ORA's position to disallow recovery for 131,063 square feet of vacant space at Gas Company Tower at a cost of $ 41.08 per square foot, for a total disallowance of $ 5.384 million.

(2) Other Lease Savings

ORA proposes to exclude $ 1.02 million in costs related to leases for six facilities. ORA states[*130] SoCal will not be using these facilities beginning in 1997. SoCal replies that ORA has improperly violated test year ratemaking policy by applying 1997 savings to 1996 costs.

We concur with SoCal's position. The test year is 1996. We therefore will not adjust rates for 1997 cost savings.

(3) Other Net Savings

ORA recommends adjusting base rates by $ 0.74 million to account for ongoing savings associated with SoCal's restructuring efforts. SoCal replies that the amounts, which were referenced in an internal memo, are mainly for the six facilities which it will no longer use beginning in 1997.

Consistent with our determination above for the six facilities, we decline to make this ORA adjustment.

i) Maintenance of General Plant (Account 935)

SoCal seeks $ 6.723 million for plant maintenance in Account 935, the same amount it recorded in 1995. ORA recommends a reduction for Account 935 that is $ 1.296 million less than SoCal's request. ORA's adjustments result from its removal of nonrecurring costs. ORA argues that the Commission's policy does not permit such costs in rates. SoCal responds that it has already removed the nonrecurring costs to which ORA objects, that is, the[*131] costs associated with real estate moves. We are persuaded that SoCal has removed nonrecurring costs from its estimate of expenses, and we therefore reject ORA's adjustment.

j) Employee Pension and Benefits (Account 926)

ORA originally proposed disallowances in pension and benefits funding of $ 44.39 million for certain costs related to pension and pension benefits, certain medical benefits and miscellaneous benefits. SoCal and ORA settled their disagreements in these areas. As a result, the total amounts for these expenses would be reduced from SoCal's original estimate of $ 110.267 million to $ 82.124 million. The parties also agree that if the pension trust contributions must exceed $ 12 million annually, SoCal may enter the additional funding requirement to a memorandum account and obtain recovery of the amounts in its subsequent PBR filing. We adopt the provisions of SoCal and ORA's agreement in this account.

k) PBOPs Overcollections During 1992-1995 (Account 926)

Account 926 includes funds for post-retirement benefits other than pensions (PBOPs). D.93-12-043 required SoCal to return to ratepayers PBOPs revenues collected in excess of amounts required for the account. [*132] ORA recommends a refund of $ 3.5 million to recognize this requirement. SoCal opposes the adjustment on the basis that ORA in its view has improperly adopted an account-specific method for calculating the amounts. The approach results in the use of a 21% escalation factor, rather than an 11% escalation factor which is a composite rate.

ORA's method appears consistent with the one we adopted in D.93-12-043, and its results are consistent with those presented by SoCal's actuary. It is appropriate to calculate the overcollection using account-specific information because the Commission ordered an account-specific refund. We adopt ORA's adjustment. ORA states in its comments that the decision should specify a mechanism for accomplishing the refund associated with PBOPs. ORA suggests crediting the CFCA and NSBA. We require SoCal to adjust the appropriate entries to the CFCA and NSBA.

l) Capitalization of Administrative and General Expenses

ORA recommends removing $ 7.245 million from Account 922 for costs which it believes should have been capitalized rather than expensed. ORA's auditors believe SoCal's proposal to capitalize only 2.5% is contrary to industry norms which are to[*133] capitalize more than 8% of administrative and general expenses. ORA proposes that expensing such a large portion of overheads creates intertemporal inequities between today's ratepayers and tomorrow's. SoCal responds that the Commission has historically expensed most utility overhead costs on the basis that future ratepayers should not be saddled with past costs.

We decline ORA's proposal to modify our ratemaking practice in this area at this time. We adopt SoCal's proposal to expense administrative and general costs rather than include them in rate base.

8. Clearing Accounts

a) Call Center Communication Expenses (Sub-Account 184.003)

The Call Center handles incoming calls from customers needing assistance. ORA recommends a reduction of $ 1.8 million for call center expenses on the basis that the average call length is four minutes rather than eight minutes, as SoCal estimates. ORA, TURN, and SoCal subsequently reached an agreement to reduce the funding level for call center expense from $ 4.06 million to $ 3.46 million. We adopt the stipulated figure.

b) Communications (Account 184.7)

ORA recommends a reduction of $ 124,000 for nonrecurring costs associated with[*134] past improvements to SoCal's microwave network. Removing this cost from communications expenses, ORA stipulated to an increase for this account of 23%. This is a substantial increase and provides a cushion for future unanticipated expenses. We adopt the ORA adjustment.

c) Calculation Errors

ORA identified several calculation errors in Account 163.0 and Account 184.3 amounting to $ 15,000. SoCal does not dispute ORA's associated adjustments. We will therefore adopt them.

9. Rate Base

a) Beginning Plant

Beginning plant refers to plant which is to be included in rate base at the start of the test year. Disputed amount are usually related to plant for which construction was completed prior to the beginning of the test period. SoCal seeks $ 5.574 billion in rate based plant. ORA recommends $ 5.528 billion, a difference of about $ 46 million. SCUPP/IID and California Manufacturer's Association/California Industrial Group (CMA/CIG) generally concur with ORA's recommendations in this area. The difference between ORA's and SoCal's estimates is attributable to the parties' respective recommendations regarding allocation of costs of new gas lines, office space and noncore[*135] customer information systems, addressed below.

(1) Lines 6902, 325, and 6900

In recent years, SoCal has constructed or upgraded certain gas lines. Based on its independent audit, ORA recommends that $ 29.028 million be excluded from rate base for new construction associated with Lines 6902, 325, and 6900. ORA argues these projects were built to serve incremental noncore load. ORA observes that the Global Settlement permitted SoCal to retain the profits from noncore load and to assume the risk for fluctuations in throughput. ORA believes that consistency and fairness demand that SoCal assume the costs and risks associated with new plant which will serve noncore load. ORA does not recommend that the plant be excluded from rate base permanently, but only as long as the ratemaking treatment in the Global Settlement is in effect.

ORA states that SoCal planning documents refer to Line 325 as necessary to serve a new hydrogen plant which is a noncore customer and recommends that 50% of the costs of the plant be included in rate base to reflect the benefits of the upgrade to core customers. ORA contends that Line 6900 should not be included in rate base in this case in any event because[*136] it was not scheduled for completion until after the test period in late 1996.

SoCal responds that the Global Settlement specified only that noncore load building (or marketing), but not capital costs, were to be assumed by SoCal. It points out that Line 6900 is part of an integrated network designed to serve growth in the core market. It also argues that ORA's audit overlooks the benefits of Line 6902, which was designed to serve core and noncore growth in the Imperial Valley. With regard to Line 325, SoCal observes that the area in which the line was constructed had been previously subject to problems because of low pressure, and the new line eliminated these problems.

D.94-04-088 states simply and clearly that all capital costs and expenses related to increasing noncore load, and therefore earnings under the settlement, must be accounted for below the line. Construction of gas lines to serve noncore load permits SoCal to recover additional noncore revenues. Therefore, associated construction costs should not be included in rate base.

SoCal has not convinced us that Lines 6900, 6902, and 325 were constructed to serve core needs. In each instance, the line appears to have been constructed [*137]for the primary purpose of serving the needs of noncore customers, and any benefits they may provide to the core are incidental. ORA has reflected those benefits in its recommended disallowances. In any event, SoCal may not include Line 6900 in 1995 rate base, because the project was not scheduled for completion until 1996. We therefore adopt ORA's recommendation to exclude costs for construction of Lines 6900, 6902, and 325 from rate base. We make associated adjustments in the Construction Work in Progress account for Line 6900.

(2) GasSelect Restructure Project

ORA recommends excluding from rate base $ 2.8 million spent on upgrades to SoCal's GasSelect Project. The project is an electronic bulletin board and information system designed to help customers with competitive services make decisions regarding their gas purchase and transportation options. SoCal responds that the GasSelect upgrade will benefit all customers and that it is not, as ORA seems to assume, a noncore load-building project.

SoCal's description of the GasSelect upgrades clarifies that the project is designed to permit "customers to nominate transportation and storage...view daily balance statements...and create[*138] customized reports to meet their business requirements." Core customers do not use or require such services or information. The project is therefore designed to serve noncore customers. D.93-12-043 disallowed associated project expenses on the bases that the GasSelect program offers "services that are available or potentially available from competitors...customers who receive these services should therefore pay for them so that SoCal does not have a competitive advantage." SoCal has not distinguished the GasSelect upgrades from the GasSelect project funding which we declined to include in rate base. Consistent with our previous order, we exclude these costs from rate base.

(3) Gas Energy Management Systems (GEMS)

The GEMS project provides automated meter reading and related facilities to noncore customers. ORA proposes excluding $ 2.7 million from rate base for costs associated with the GEMS project on the basis that competitive services to noncore customers should not be included in rate base. SoCal opposes the adjustment to rate base on the basis that the GEMS project improves day-to-day operations which benefit core customers.

The GEMS project is designed to serve noncore customers[*139] who have competitive options. To the extent improved monitoring and metering may benefit core customers, it appears that the activity would not be required but for the activities of noncore customers. SoCal has not demonstrated that core customers benefit from the facilities, except to the extent noncore customer activity might otherwise impose planning problems. In SoCal's last GRC order we rejected SoCal's request to include these costs in rate base and thereby impose them on core customers. The Global Settlement provided that facilities which may improve service to noncore customers or increase throughput are the responsibility of SoCal, not its general body of ratepayers. We adopt ORA's recommended adjustment to rate base.

(4) Torrance and Mountain View Headquarters

ORA recommends that the costs of the Torrance and Mountain View Headquarters facilities, about $ 23.4 million, be removed from rate base. ORA argues that the facilities are to be sold or leased and are therefore not used and useful. ORA would defer the issue of gain on sale until and unless the property is sold.

SoCal replies that ratepayers are not entitled to the gross cost savings associated with the retirements, [*140] but only the net savings. Otherwise, SoCal would not be able to recover prudent costs associated with the restructuring of its operations. SoCal also states Commission policy is to adjust rate base for gains and losses only after they are accrued.

During the test period, SoCal had not sold the Torrance and Mountain View Headquarters. Therefore, consistent with our policy to include those investments made at the time of review in rate base, we will not adjust rate base to reflect a future sale.

(5) Pacer Project

ORA has recommended an increase of $ 2.762 million for capitalization of the Pacer project based on the Overland audit. SoCal is asking for an increase of $ 3.708 million. The difference between ORA and SoCal's amounts is in the inclusion of 1995 costs.

ORA's request takes into account the implementation schedule of the project, thus allowing 100% of 1994 and 50% of 1995 costs. SoCal indicates that errors were made regarding certain 1994 and 1995 costs for the Pacer project, which were against SoCal's capitalization policy. SoCal notes that certain costs should have been capitalized rather than expensed. Accordingly, SoCal requests 100% of 1994 and 100% instead of 50% of[*141] 1995 amounts.

We agree with ORA's position regarding the project implementation schedule and ORA's treatment of certain costs after the project was placed in operation. We therefore allow 100% of 1994 and 50% of 1995 amounts.

(6) Overhead Capitalization

ORA recommends an increase of $ 8.9 million to rate base, based upon the Overland audit. SoCal has indicated that it acquiesces in ORA's position and the recommended adjustment for distribution of clearing accounts costs between capital and expense. Although SoCal concurs with Overland's recommendation, it believes its existing procedures are adequate and reasonable.

We do not find ORA's recommendation of capitalization of the overhead costs appropriate. Moreover, we do not find SoCal's concurrence with ORA persuasive for adopting this recommendation. We therefore reject ORA's and SoCal's recommendation regarding this issue.

b) Ventura/Ojai Project

In 1993, SoCal customer appliances were damaged by nitrous oxides in gas received from certain of SoCal's producers. SoCal sued the producers, and the suit settled in 1996. ORA proposes to offset rate base and depreciation with the settlement proceeds of $ 3 million, on the basis[*142] that they were effectively contributions in aid of construction. ORA also recommends that the associated legal expenses of $ 0.8 million be disallowed on the basis that they are nonrecurring costs. ORA argues that SoCal has been compensated for related costs, because its rate of return has exceeded authorized amounts during the period in question.

SoCal responds that the costs associated with the project were never in rates, and any proceeds associated with it should accordingly accrue to shareholders.

ORA's ratemaking theory is contrary to our usual policy. If SoCal has assumed the risk of the project, it is entitled to associated gains. The fact that SoCal's previous rate of return exceeded our expectations is not germane to our disposition of cost recovery going forward. We decline to adopt ORA's proposed rate base adjustment. We will, however, reduce SoCal's legal expenses by $ 0.8 million for the sake of consistency. Since SoCal's revenues are below the line, its rates should not be increased to permit it to recover associated expenses.

c) CIS Costs

ORA recommends three adjustments to CIS costs, all of which would reduce recovery of expenses and increase capital funding. [*143] SoCal concedes ORA's recommendation to increase rate base to reflect $ 719,000 in "conversion" costs associated with computer software. SoCal opposes ORA's recommendation to capitalize $ 1.45 million in computer training and hardware maintenance costs. We adopt ORA's proposal for these costs.

Except for these disputed items, ORA and SoCal reached agreement on the appropriate level of rate base for CIS of $ 62.385 million, with a twenty-year depreciable life. SCUPP/IID oppose the inclusion of 100% of CIS costs in rates since only 40% of CIS investment is included in the 1996 rate base. SCUPP/IID observe that the inclusion of all costs in 1996 rates under these circumstances is contrary to Commission policy.

We adopt SCUPP/IID's proposal to include only 40% of CIS costs in rate base for the test period, consistent with our policy to include only those investments which have been made at the time of review. If we were to find otherwise, we would have to reconsider our decision in other parts of this order which apply this policy in SoCal's favor.

d) Working Cash

Working cash is funding for the cost of money required for day-to-day operations, upon which the utility earns a rate[*144] of return. SoCal seeks $ 35.996 million in working cash. ORA recommends a reduction in revenue requirement for working cash of $ 33.021 million. Their specific disagreements are discussed below.

(1) Deferred Credits

Like many businesses, SoCal sets aside funds in anticipation of litigation and regulatory losses. SoCal has set aside $ 58 million for this purpose. ORA would exclude this sum from working cash, and thereby reduce rate base by the corresponding amount, because SoCal has not demonstrated that the amount is not cost-free capital.

SoCal refused to provide information to ORA and its auditors about the source or purpose of the funds on the basis that the information is privileged. SoCal also argues that the amounts are not relevant to this proceeding because they are not requested as part of base rates. ORA responds that the company's access to the capital affects the working cash calculation.

SoCal has provided evidence which adequately refutes ORA's claim that its reserves are cost-free. Therefore, we do not adopt ORA's adjustment to the working cash reserve.

(2) Vacation Accrual

Like employees of other companies, SoCal's employees accrue vacation time rather than[*145] using it as they receive it. ORA recommends reducing working cash by $ 18 million to reflect vacation accrual on the company's books. ORA states the vacation accrual represents cost-free capital. SoCal responds that it has not been reimbursed in rates for vacation accruals and that therefore the amounts are consequently not cost-free.

SoCal receives in rates all of the costs of doing business, including the costs of offering vacation time to its employees. To the extent that employees accrue vacation time rather than use it as it becomes available, SoCal has access to cost-free capital. This finding is consistent with our treatment of the same issue for PG&E. We adopt ORA's recommended adjustment for this item.

(3) Workers' Compensation Accrual

SoCal accrues workers' compensation funds which it pays out as needed for workers' compensation claims. ORA recommends an adjustment to working cash of $ 21 million to reflect workers' compensation accruals. It does so for the same reasons it adjusted working cash for vacation accruals. SoCal responds by stating that workers' compensation is not cost-free capital, and the amounts have not been funded by ratepayers. ORA observes that SoCal[*146] has in fact requested over $ 1 million in this proceeding for workers' compensation accruals.

For the same reasons we adopted ORA's adjustments for vacation accruals, we adopt ORA's adjustments for workers' compensation accruals.

(4) Customer Advances for Construction

ORA proposes disallowing $ 11.6 million from working cash for unbilled customer advances. SoCal makes these advances to developers who are constructing new projects requiring gas service. ORA makes its recommendation on the basis that SoCal has in recent years delayed its presentation of bills for customer advances for construction. ORA states the average time for such billings is required to be no later than six months, but that SoCal's average billing period is now twenty months. The average collection time period is 33 months. These delays represent mismanagement which increase working cash requirements, according to ORA. DGS and TURN concur with ORA's proposal.

SoCal replies that the $ 11.6 million does not represent cost-free capital and must therefore be included in working cash. SoCal states the delays in billing and collections are in many cases outside of its control.

The periods between project completion[*147] and SoCal's billings and final collection of amounts owed are excessive. SoCal's ratepayers should not be required to subsidize either the mismanagement of SoCal's billing and collection system or the delays in remitting of amounts owed by developers. In this proceeding, SoCal urges the Commission to adopt a late payment charge for its gas customers. A similar charge for late paying developers would reduce SoCal's liability for these payments and promote timely payment. The encouragement of such efficiency is at the heart of our PBR philosophy, and consistency compels us to adopt ORA's recommended adjustment to working cash.

ORA recommends an additional $ 0.899 million reduction associated with customer advances for construction. SoCal does not oppose the adjustment. We will adopt ORA's recommendation.

(5) Customer Deposits

Some of SoCal's customers provide security deposits to SoCal as a condition of service. TURN and DGS recommend using customer deposits to reduce working cash. They observe that SoCal has $ 29 million in such funds as of the end of 1995, which constitute a permanent source of capital. SoCal pays the commercial paper rate on these funds, about 800 basis points[*148] below its authorized rate of return. The difference accrues to SoCal.

SoCal responds that the matter has already been litigated in cost of capital proceedings and in Commission workshops. It proposes that the Commission reject the proposal on this basis.

DGS and TURN have presented a strong argument that we should consider customer deposits as part of working cash. However, because is issue has been previously deferred by the Commission to a workshop, we will not consider the matter on the merits here. A staff workshop on these issues was held in May 1996 and a workshop report is pending. We will not prejudge the outcome of the workshop by ordering an adjustment to working cash at this time. We make this determination subject to refund; if the Commission ultimately finds that customer deposits should be considered part of working cash, we will order DGS and TURN's adjustment for the PBR period.

(6) Materials and Supplies

ORA proposes a reduction of materials and supplies costs in rate base of $ 202,000, reducing SoCal's request to $ 14.303 million. SoCal does not oppose this adjustment. We adopt ORA's recommendation.

e) 1996 Plant Additions and Retirements

SoCal and ORA's[*149] estimates of 1996 net plant additions differ by $ 94.1 million. ORA utilized separate five-year trend analysis of gross plant additions and retirements to develop its net plant additions estimate for 1996. SoCal's methodology averaged 3 years of net plant additions after retirements had been removed from rate base. We find ORA's methodology of incorporating the most recent recorded data in its estimating methodology appropriate. Therefore, we will adopt ORA's estimate for 1996 net plant additions.

10. Depreciation Expenses

Depreciation expenses are calculated according to amounts permitted in rate base and are designed to permit the utility to recover its capital investments over the period during which associated facilities are used and useful. SoCal seeks $ 254.79 million in annual depreciation expense. ORA estimates depreciation expense to be $ 17.097 million lower than SoCal, mostly on the basis of recommendations regarding plant which should appropriately be included in rate base, that we have addressed previously.

a) Plant Balances for 1995 Plant

ORA proposes to reduce 1995 plant balances amount by $ 1.755 million assuming that the system average depreciation rate[*150] equals 4.4%. SoCal estimates the average depreciation rate to be 4.41%. The difference between the SoCal and ORA results from disparities regarding items which should be appropriately included in rate base. We addressed these items in portions of this order addressing rate base and the depreciation expense should be modified to correspond to the rate base adjustments.

b) Estimated 1996 Net Plant Additions

SoCal and ORA's estimates of depreciation for 1996 net plant additions differ by $ 7.433 million. The controversy occurs mainly because of a difference of approach in how to apply the weighting factor used to calculate depreciation expense on plant additions. SoCal recommends a 100% weighting factor; ORA recommends a 40.29% weighting factor. ORA states that SoCal's use of 100% ignores the fact that 1996 plant additions are unlikely to reflect actual plant additions in the subsequent five years because it is not a weighted average plant additions occurring each year. More importantly, ORA claims that SoCal's method fails to recognize the fact that future year net plant additions will only have a weighted affect on that particular year's depreciation expense. Thus, additions[*151] made in 1997 will only have a partial year effect on depreciation expense for that year. SoCal's method assumes that all plant additions will occur on January 1 of each year.

SoCal responds that the timing of the adjustments in this PBR dictates a 100% weighting factor. Because the base rate adjustments will be made mid-year, a lower weighting factor will not recognize all of the depreciation expense. SoCal appears to propose that the net plant additions for every subsequent year be treated as if they occurred on the first day of each year, thereby giving the company credit for a full year's expense when in fact plant additions are made throughout the year. ORA's methodology might fail to reflect a small portion of the 1996 plant additions. ORA appears to have adjusted for that effect by recognizing that SoCal's plant additions may be higher in 1996 than they are likely to be in subsequent years. SoCal has not provided any reasonable alternative to ORA's proposal. We therefore adopt ORA's proposal, which is consistent with our usual practice for estimating net plant and fairly reflects anticipated practice.

c) CIS

SoCal observes that ORA failed to adjust depreciation in recognition[*152] of ORA's and SoCal's agreement to capitalize certain training costs. We adjust depreciation by $ 36,000 accordingly. SoCal and ORA agree that the rest of the annual depreciation expense associated with CIS is $ 3.119 million. We adjust this amount consistent with our earlier finding that 40% of CIS investment costs should be included in rate base, rather than the full amount to which SoCal and ORA have stipulated.

d) Torrance and Mountain View Facilities

ORA observes that if the Commission adopts ORA's proposal to retire the Torrance and Mountain View facilities, it should also adjust depreciation expenses by $ 0.46 million. SoCal argues that the amount must remain in rates until the facilities are sold.

We have not adopted ORA's recommendations regarding retirement of these facilities, so we will not adjust the associated depreciation accounts.

e) Capitalized Overheads

ORA's estimate for capitalized overheads is $ 66,000 lower than SoCal's due to its use of a 4.4% depreciation expense rate, compared to SoCal's rate of 4.41%. We adjust this item to make it consistent with the expense rate which derives from allowable plant balances for 1995.

f) Depreciation Reserve [*153] Account

ORA proposed a negative $ 50.939 million figure for the depreciation reserve account, equal to retirements less net salvage. SoCal opposes ORA's reductions to this account, which derive mainly from differences in 1995 plant balances discussed elsewhere. We incorporate the findings on these issues in setting the appropriate level for the reserve account.

11. Taxes

SoCal and ORA reached agreement regarding the appropriate tax rates. We adopt their recommendation to apply a California Corporate Franchise Tax rate of 8.84%.

SoCal and ORA do not agree to the estimate for ad valorem taxes associated with construction. ORA recommends reducing the SoCal request for tax expenses by $ 1.2 million and including the associated amounts in rate base. SoCal replies that the Commission has traditionally allowed utilities to recover ad valorem taxes as expenses rather than rate base.

We are not convinced that capitalizing ad valorem taxes offers any advantage to ratepayers or shareholders. We reject ORA's proposal to capitalize ad valorem taxes.

12. Research, Development and Demonstration (RD&D)

SoCal and ORA reached agreement with regard to RD&D funds. They recommend base margin[*154] funding of $ 7.8 million which would not be subject to prevailing Commission policy prohibiting SoCal from shifting RD&D funds between programs. They also propose $ 0.5 million for "public goods" RD&D which would be subject to "one-way" balancing account treatment. Royalties attributable to RD&D projects underway or completed prior to the implementation of PBR would accrue 100% to ratepayers. Royalties from subsequent work would be shared equally between ratepayers and shareholders.

NRDC opposes the proposal to eliminate the one-way balancing account for RD&D, believing that shareholders will retain part of the RD&D funding to accomplish short-term profit objectives at the expense of long-term benefits.

We adopt the recommendations of SoCal and ORA for RD&D programs and funding, with the exception that we will retain the one-way balancing account as NRDC proposes. SoCal did not make a compelling case that it would actually spend the RD&D funds on RD&D efforts.

Findings of Fact

1. On June 1, 1995, SoCal filed an application requesting adoption of PBR for the portion of its rates that recovers the costs of providing gas utility service that the Commission normally reviews through[*155] the GRC process.

2. SoCal filed its recorded data for 1995 results of operations on February 14, 1996, and a supplemental showing with respect to 1996 estimated results on June 6, 1996. The parties agreed that this would be used to develop the base margin in this proceeding.

3. On October 14, 1996, Pacific Enterprises, the parent of SoCal, and Enova Corporation, the parent of SDG&E, announced their intention to merge, and filed an application for authority to do so with the Commission (A.96-10-038).

4. SoCal's proposal for PBR is based upon a system of indexing its base rates annually, using an index of recorded input price inflation less than a productivity factor. The inflation factor would be trued up annually, but the productivity factor would remain constant throughout the minimum period that PBR remains in effect.

5. SoCal proposes a minimum period of five years for its PBR to be in effect.

6. SoCal's indexing proposal would put its shareholders, rather than its ratepayers, at risk or reward for any differences between forecast and actual throughput and customer count.

7. For its inflation measure, SoCal proposes a weighted average of recorded indices of prices for labor O&M[*156] costs, nonlabor O&M costs, and capital-related costs. SoCal refers to this as the gas utility input price

index, or GUPI.

8. For its productivity factor, SoCal proposes to employ a constant factor of 1.0%, based upon a historical gas distribution productivity component of 0.5%, and a "stretch factor" or "consumer dividend" of 0.5%.

9. Under SoCal's proposal, only the base rate would be adjusted under PBR. The base rate is the part of rates reflecting gas margin, and excluding gas costs, pipeline demand charges, and other specifically identified items.

10. Under SoCal's proposal 1997 rates would be set by applying one year's PBR index to the reasonable level of expense and rate base for 1996.

11. Under SoCal's proposal, costs which are already subject to incentive-type mechanisms, are beyond SoCal's control, or are specifically authorized at a given level under separate governmental proceedings would be excluded from PBR indexes.

12. Under SoCal's proposal the cost of exogenous and unforeseen events largely beyond SoCal's control that have a material impact upon its costs (Z factors) would be subject to a special process of adjustment that would tend to exclude them from rates.

13. [*157] SoCal proposes an adjustment in rates in addition to the PBR index for land sold at a gain or loss.

14. Under SoCal's proposal the benchmark for cost of capital would be the DRI average rate for the calendar year 1997 forecast, as adopted in SoCal's 1997 cost of capital proceeding. No changes would be made in PBR indexed rates in response to changes in cost of capital, unless the 12-month trailing average yield on long-term Treasury Bonds increases or decreases more than 150 basis points from this benchmark during the minimum PBR term.

15. SoCal, ORA, and TURN have proposed a recommended plan to ensure the maintenance of standards of service quality, customer satisfaction and safety during the PBR period.

16. As part of its proposal, SoCal seeks authorization to offer on a competitive and unregulated basis products and services that it has not previously offered, and to provide support to its unregulated affiliates in connection with their offering of new products and services. SoCal proposes that these new products and services be provided entirely at the risk of shareholders, and not be funded by the rates charged for utility services.

17. As part of its proposal, SoCal proposes[*158] several changes in its rate

design, including residential rate design changes, rate flexibility, and optional rate schedules for core customers.

18. The Commission's policy favors PBR for the utilities we regulate, wherever it would further our regulatory goals and policies.

19. The features of SoCal's proposed PBR that would base rates on 1996 adjusted throughput, extend cost allocations beyond July 30, 1999, alter the definition of a "normal" temperature year, and eliminate the CFCA would violate the terms of the Global Settlement.

20. The Commission has a strong policy favoring settlements as a means of resolving issue in its proceedings, and will generally not change the terms of a settlement after it becomes a Commission order.

21. Certain features of SoCal's proposal are unrelated to the PBR system of incentives.

22. The pendency of the merger of Pacific Enterprises and Enova Corporation increases the likelihood that capital spending will be curtailed and expenses otherwise forgone before the merger is consummated or disapproved.

23. It is probable that SoCal will experience systemwide sales growth in the next five years.

24. Consideration of the pending Enova-Pacific Enterprises[*159] merger requires us to be able to track savings. Savings with respect to SoCal cannot be tracked if rates, rather than the revenue requirement, are indexed.

25. SoCal's rate base has been declining since 1995 as the result of depreciation.

26. SoCal's proposed indexing mechanism fails to recognize its unique circumstances, particularly its declining ratebase and the likelihood of increased throughput.

27. SoCal's proposed PBR does not include a mechanism for sharing net savings with ratepayers.

28. In R.97-04-011/I.97-04-012, the Commission preserved the opportunity to adopt an interim order with respect to SoCal's proposal for flexibility in introducing new products and services.

29. It would be unfair to allow one energy utility to operate on an unregulated and competitive basis while requiring the remaining energy utilities

to participate in R.97-04-011 and I.97-0-012 before allowing them to offer the same services into the same market on a detariffed, competitive basis.

30. If the Commission considers SoCal's requests with respect to the introduction of new products and services, there are a number of questions that would need to be answered for the Commission to fulfill its regulatory[*160] responsibilities under the proposal and to ratepayers generally.

31. SoCal and ORA reached agreement on several disputed issues during the course of the hearing. At the time of submittal, ORA and SoCal had disagreement over approximately $ 71.7 million in costs.

32. SoCal proposes that the same rate be used to escalate and deflate the estimates presented in this proceeding to make them comparable.

33. ORA, TURN and SoCal agreed to a level of expenses for customer accounts of $ 111.77 million. They also agreed that costs for administration of the CARE program should be included in SoCal's rates until and unless another party is responsible for the administration of the program.

34. SoCal's proposed late payment charge is not necessary for the establishment of base margin.

35. SoCal, TURN, and ORA agreed to total expenses of $ 20.37 million for gas storage and $ 25.017 million for gas transmission.

36. SoCal's request for gas distribution costs is somewhat lower than ORA's due to a difference in their respective escalation rates.

37. ORA, TURN, DGS, and SoCal agree to funding for DSM in the amount of $ 27 million, to be included in a one-way balancing account.

38. ORA, TURN, and SoCal[*161] agree to fund non-DSM marketing at a level of $ 24.136 million.

39. SoCal proposes a level of $ 12 million for funding direct assistance programs. NRDC proposes retaining the existing funding level of $ 18 million. SoCal's requested funding level recognizes that the direct assistance program market is becoming saturated.

40. SoCal did not demonstrate that its PBR will increase regulatory activity.

41. SoCal did not demonstrate with evidence that its executive compensation rates are comparable to those offered to individuals working in markets from which SoCal recruits.

42. SoCal's total compensation levels are reasonably close to market levels.

43. SoCal did not present adequate documentation to support the reasonableness of billings from Pacific Enterprises for the work of 50 attorneys.

44. SoCal's affiliates promote new lines of business that are not directly related to utility activities or that are not activities for which SoCal may seek funding from ratepayers.

45. SoCal and ORA reached agreement on issues regarding franchise fees with the exception of the appropriate rate.

46. SoCal did not occupy or lease to others 15% of the Gas Company Tower in 1995. It did not occupy or [*162] lease to others 20% of the Gas Company Tower in 1996. SoCal did not demonstrate that the Gas Company Tower will be 97% occupied in 1997.

47. ORA proposes a disallowance of Gas Company Tower lease costs which recognizes, in part, SoCal's plan to increase occupancy.

48. The Commission's policy in general rate cases is to base revenue requirement changes on a test year forecast.

49. SoCal appears to have removed non-recurring costs in its forecast of general plant maintenance costs.

50. ORA and SoCal agreed to an expense level of $ 82.124 million for various pension and benefits costs. The parties also agreed that, if annual pension trust contributions must exceed $ 12 million annually, SoCal may enter the additional funding requirement into a memorandum account and seek recovery of amounts in a subsequent PBR filing.

51. ORA's estimate of PBOP overcollections during 1992 through 1995 appears consistent with the one the Commission adopted in D.93-12-043 and the method's results are consistent with those presented by SoCal's actuary.

52. SoCal shall adjust the CFCA and NSBA with appropriate entries to reflect the $ 3.5 million refund for PBOP for 1992-1995.

53. SoCal's request for funding[*163] of non-recurring costs associated with its microwave network is excessive. Removing $ 0.124 million from the account results in an increase of 21% to Account 184.7.

54. ORA made several adjustments in Account 163.0 and Account 184.7 to reflect calculation errors, which SoCal does not dispute.

55. The Global Settlement states that all capital costs and expenses related to increasing noncore load and related earnings are the responsibility of SoCal.

56. SoCal did not demonstrate that Line 6900, Line 6902 or Line 325 construction would serve core needs except incidentally.

57. D.93-23-043 determined that the GasSelect project served noncore customers and should therefore not be included in rate base. SoCal has not distinguished the GasSelect upgrade in ways which would change this determination.

58. SoCal has not demonstrated that the GEMS project will benefit core customers except incidentally.

59. SoCal has not used half of the space available at the Torrance and Mountain View Headquarters and intends to sell or lease the facilities in the near future.

60. SoCal appears to have assumed the risk associated with litigation arising from nitrous oxides in gas received from certain of its[*164] producers. SoCal would include the costs of litigation in rates but not the settlement proceeds.

61. Only 40% of the CIS investment is included in 1996 rate base. For rate base calculations, Commission policy provides that rates include only those investments that are included in rate base during the review period.

62. SoCal provided adequate evidence to refute ORA's claims that SoCal's deferred credits for regulatory and litigation losses are cost-free for purposes of calculating working cash requirements.

63. Vacation accruals represent cost-free capital for purposes of calculating working cash requirements.

64. Workers' compensation accruals represent cost-free capital for purposes of calculating working cash requirements.

65. The average time SoCal takes for billing and collecting customer advances for construction is 33 months, an amount that is attributable either to mismanagement or tolerance of subsidies to developers who are late in remitting payments.

66. SoCal does not oppose ORA's proposed reduction of $ 0.899 million in

estimates of customer advances for construction.

67. SoCal has access to about $ 29 million in capital attributable to customer deposits.

68. SoCal does[*165] not oppose ORA's proposed reduction of materials and supplies costs in rate base in the amount of $ 0.202 million.

69. SoCal and ORA's estimates of some depreciation expenses and plant balances for 1995 differ as a result of their differing estimates of rate base.

70. SoCal's methodology for calculating 1996 plant additions assumes that all plant additions occur on the first day of the year, giving the company credit for rate base investments that are not made until subsequent periods.

71. ORA's method for estimating 1996 plant additions is consistent with the Commission's usual practice and fairly reflects anticipated investments.

72. The Commission has traditionally allowed utilities to recover ad valorem taxes as expenses rather than as capital costs.

73. SoCal and ORA agreed to RD&D expense levels of $ 7.8 million. They also agree that 100% of royalties attributable to projects underway or completed prior to the implementation of PBR would accrue to ratepayers and that royalties from subsequent projects would be shared equally between ratepayers and shareholders.

74. SoCal did not demonstrate that it intended to spend all funds allocated to RD&D on RD&D projects.

Conclusions [*166] of Law

1. SoCal's proposed PBR conflicts with existing Commission decisions and orders, or with policies we have articulated previously. In order to ensure that SoCal's PBR conforms to these principles, we must modify the PBR program before we can adopt it.

2. SoCal's proposal would conflict in certain respects with the terms of the Global Settlement.

3. The absence of a sharing mechanism in SoCal's PBR proposal is contrary to Commission policy, and the adopted PBR program should therefore include a sharing mechanism.

4. The Weather Normalization Mechanism and the Energy Efficiency Adjustment

Factor proposed by SoCal would increase, rather than simplify, regulation.

5. Features of SoCal's proposal which are unrelated to the PBR system of incentives should not be adopted as part of our order in this proceeding.

6. We should adopt ORA's proposal for price indexing, consisting of a weighting of labor expense, nonlabor expense, and capital inputs to total costs, that is the average of gas operations for SoCal, PG&E, and SDG&E.

7. We should adopt a Year 5 total productivity factor of 1.5%, consisting of 0.5% historical productivity and a 1.0% "stretch" factor (or "consumer dividend") [*167] for factors within the control of utility management. The productivity factor should be "ramped" up in each of the five years of the PBR, so that year 1 will be 1.1%, Year 2 will be 1.2%, year 3 will be 1.3%, year 4 will be 1.4%, and year 5 will be 1.5%. Recorded data should be used to determine the 1996 customer count.

8. The CFCA should be retained, at least until the expiration of the Global Settlement, in the PBR program we adopt.

9. The PBR program we adopt for SoCal should index the revenue requirement per customer rather than rates.

10. Establishment of the base margin for SoCal's PBR program should not place SoCal shareholders at risk/reward for variations in throughput at least until the expiration of the Global Settlement.

11. We should not adopt SoCal's proposed indexing mechanism.

12. The adopted indexing mechanism should recognize the special circumstances of SoCal's declining rate base. In order to conform the proposal to other adopted PBRs, while at the same time accounting for uncertainty in estimating the impact of this special circumstance, we should add 1.0 percent each year to the adopted productivity factor. The adopted "X" factor therefore should be 2.1 percent[*168] in year 1; 2.2 percent in year 2; 2.3 percent in year 3; 2.4 percent in year 4; and 2.5 percent in year 5.

13. SoCal's PBR program should include a mechanism for sharing net savings with ratepayers.

14. We should adopt a sharing mechanism as part of SoCal's PBR that will increase in eight steps SoCal's share of net revenue from 25% to 100% from 25 basis points above the benchmark rate of return up to 300 basis points above that benchmark, and should not share the deficit below that benchmark. The benchmark rate of return should be the current adopted rate of return.

15. We should adopt the cost categories suggested by SoCal for exclusion from PBR.

16. Z factors should be handled outside of the PBR mechanism and separately adjusted in the manner proposed by SoCal.

17. PBR rates under the adopted program should be implemented at the beginning of the next calendar year but could, at SoCal's discretion, be implemented as of the beginning of the current calendar year if this program is adopted before the end of the calendar year.

18. We should adopt ORA's proposal for a cost of capital triggering mechanism during the PBR period, coupled with the "MICAM" mechanism for rate adjustment that[*169] we recently adopted in D.96-06-055.

19. We should adopt ORA's proposal for a rate of return "offramp," which would suspend SoCal's PBR program before the five-year minimum term if rate of return deviates by 300 basis points above authorized earnings, or 175 basis points below authorized earnings, for two consecutive years.

20. We should conduct a midcourse review of SoCal's PBR program before the end of the five-year minimum term. SoCal's 1998 BCAP (or its successor proceeding) should serve as the forum for that review.

21. SoCal's PBR should remain in effect for a minimum five-year term, and should be terminable in the manner proposed by ORA.

22. We should adopt the program for ensuring maintenance of service quality, customer satisfaction, and safety that is proposed by SoCal, ORA, and TURN, and set forth in Exhibit 210.

23. We should adopt SoCal's proposal to implement the annual PBR rate adjustment and report on all aspects of the PBR program through the filing of a detailed annual advice letter and supporting workpapers on October 1.

24. We should deny SoCal's request to eliminate or modify existing reports required by the Commission at this time and require SoCal to file an [*170] annual PBR performance report, similar to that which is now filed by SDG&E.

25. SoCal should be allowed to offer negotiated rates and optional tariffs provided that the price floor is above class average long-run marginal cost and shareholders are entirely at risk for revenue shortfalls.

26. SoCal's request for flexibility in introducing new products and services

should be considered in the affiliates rulemaking and investigation (R.97-04-011, I.97-04-012).

27. The Commission should calculate non-labor cost forecasts by deflating the 1996 dollars using a factor of 3.72%, and inflating them by using a factor of 2.23%.

28. The Commission should adopt all matters resolved by way of stipulation between SoCal and ORA except as provided herein.

29. The Commission should adopt ORA's adjustment to account 920 regarding consultant fees.

30. The Commission should adopt TURN's proposal to reduce Accounts 921 and 920 to reflect excessive executive compensation.

31. The Commission should disallow $ 1.924 million associated with affiliated transactions.

32. The Commission should disallow $ 2.939 million for costs estimated using SoCal's multi-factor allocation formula for calculating the cost of[*171] service provided to SoCal by its affiliates.

33. The Commission should reduce Account 928 by $ 0.026 million to reflect the lower costs of regulatory activity.

34. The Commission should disallow $ 5.384 million attributable to Gas Company Tower costs to recognize that substantial portions of the property is not used and useful.

35. The Commission should calculate the PBOPs overcollection for the period between 1992 and 1995 using a 21% escalation factor, consistent with D.93-12-043. SoCal should adjust the CFCA and NSBA with appropriate entries to reflect the $ 3.5 million refund for PBOPs for 1992-1995.

36. The Commission should reduce funding for Account 184.7 by $ 0.124 million to reflect SoCal's inclusion of nonrecurring costs for maintaining its microwave network.

37. The Commission should remove from rate base $ 29.028 million associated with construction on Lines 6900, 6902, and 325, and all costs associated with the GEMS upgrade and the GasSelect project, consistent with Commission determinations that the costs of serving noncore customers in competitive markets should not be allocated to the general body of ratepayers. In addition, the Commission should remove $ 6.18 million[*172] associated with Pacer and

overheads capitalization.

38. The Commission should not remove $ 23.4 million from rate base related to the Torrance and Mountain View Headquarters.

39. The Commission should reduce Account 920 by $ 0.8 million to recognize the cost of litigating the Ventura/Ojai Project but permit SoCal to retain the proceeds of the settlement reached from associated lawsuits.

40. The Commission should recognize in rate base 40% of CIS costs, rather than 100% as ORA and SoCal propose.

41. The Commission should not adjust SoCal's estimate of working cash to reflect $ 58 million in deferred credits, and $ 29 million in customer deposits.

42. The Commission should adjust SoCal's estimate of working cash to reflect $ 18 million in vacation accruals, $ 21 million in workers compensation accruals, and $ 11.6 million in customer advances for construction.

43. The Commission should adopt depreciation expenses consistent with its findings regarding appropriate levels of rate base.

44. The Commission should adjust SoCal's estimate of 1996 plant additions by $ 7.433 million to reflect a 40.29% weighting factor rather than SoCal's 100% weighting factor, which assumes all plant additions[*173] are made on the first day of the year.

45. The Commission should retain a one-way balancing account for RD&D.

ORDER

IT IS ORDERED that:

1. The application of Southern California Gas Company (SoCal) for adoption of a system for performance-based ratemaking (PBR), for the portion of SoCal's rates that recovers the costs of providing gas utility service which are normally reviewed through the general rate case (GRC) process, is granted with the modifications set forth in the foregoing opinion, and in the findings of fact, conclusions of law, and appendices to the Order.

2. Not later than July 23, 1997, SoCal shall file a detailed advice letter which shall include:

a. A revised set of proposed tariffs, constructed in accordance with paragraph 1 of this Order for the portion of SoCal's rates that recovers the cost of providing gas utility service; and

b. An election of the effective date of the PBR mechanism adopted pursuant to this Order.

3. Within 30 days after the effective date of this order, SoCal shall file an advice letter to implement this PBR. This advice letter will be subject to approval by the Commission by means of a resolution.

4. The Commission staff shall monitor[*174] and evaluate the operation of the adopted PBR program throughout the period it remains in effect.

5. Midcourse review of all aspects of SoCal's PBR shall be conducted as part of SoCal's 1998 Biennial Cost Allocation Proceeding (BCAP), or the successor proceeding if the Commission no longer conducts the proceeding as a BCAP.

6. SoCal shall file an annual PBR performance report as set forth in the opinion, for processing on the following schedule:

a. April 1 - SoCal shall furnish a draft sharable earnings letter to the Commission's staff, including workpapers showing detailed operating results for its base rates.

b. July 1 - Commission staff shall submit its report on its audit analysis of SoCal's sharable earnings results.

c. July 10 - SoCal shall file its final performance advice letter, with supporting workpapers.

d. July 31 - Protests may be filed in accordance with General Order 96-A.

7. On October 1 of each year, SoCal shall file an advice letter which will implement the annual PBR rate adjustment for the following year.

8. During the period that SoCal's PBR program remains in effect, the requirement for SoCal to file a GRC is suspended, except as specifically provided under the[*175] terms of the adopted PBR program.

9. SoCal's request for flexibility in introducing new products and services, as described in Exhibit 7, section E, is denied.

10. Application 95-06-002 is closed.

This order is effective today.

Dated July 16, 1997, at San Francisco, California.

We will file a joint dissent in part.

/s/ HENRY M. DUQUE

Commissioner

/s/ JOSIAH L. NEEPER

Commissioner

APPENDIX A

CUSTOMER SATISFACTION, EMPLOYEE SAFETY, AND SERVICE QUALITY

Measuring Customer Satisfaction

Annual targets will be established for four service attributes: (1) customer satisfaction with the telephone Customer Service Representative (CSR), (2) customer satisfaction with the scheduling of the appointment for a field service call, (3) satisfaction with the field Appliance Service Representative (ASR), and (4) the percentage of on-time arrival for the service call. Customer satisfaction with these four service attributes is currently measured by way of question numbers 9, combined 19 and 28, 23, and 29, respectively, in the SoCalGas' customer satisfaction telephone survey.

The annual targets will be based upon the average performance for 1994 through 1996 for each of the four service attributes, [*176] measured as the percentage of customers "satisfied" with the service provided (i.e., responding with an 8, 9, or 10 on a 10 point scale) on the first three attributes, and the percentage of "yes" responses on the on-time arrival attribute.

Each service attribute carries a potential monetary penalty. For purposes of determining whether a performance penalty will be imposed upon SoCalGas, the target for each service attribute will have a one point deadband below the target.

As long as each performance level remains at or above the one point deadband, SoCalGas will not be penalized. Should performance decline below the deadband, SoCalGas will be penalized $ 10,000 per 0.1 point decline for the first point below the deadband. For any further performance decline, SoCalGas will be penalized $ 20,000 per 0.1 point decline.

Based upon the average customer satisfaction telephone survey results for

1994, 1995, and through November 1996, the current targets would be as follows:

	Target	Deadband
CSR Performance (Q9)	90.7	89.7
Appointment Scheduling (Q19 & 28)	79.1	78.1
ASR Performance (Q23)	94.3	93.3
On Time Arrival (Q29)	95.2	94.2

The ultimate target amounts will be based[*177] on averages including the entire year's results for 1996. Table 1 attached hereto contains the data that forms the basis for the target and deadband calculations.

Telephone Response Time

In addition to the foregoing customer satisfaction targets, an annual call center performance standard will require 80% of all telephone calls to be answered within 60 seconds for regular calls, and will require 90% of all leak and emergency telephone calls to be answered within 20 seconds. SoCalGas will be penalized $ 20,000 per 0.1 point decline below each standard (i.e., 80% and 90%), with no deadband.

Employee Safety Standard

Also, an annual employee safety standard will be established at 9.3 incidents per 200,000 hours worked, with a deadband of 1.0 point in each direction. The annual measure for this standard will be the OSHA Recordable Injury and Illness Rate (Rate). Penalties would be paid by SoCalGas if the annual Rate exceeds 10.3. Rewards would be paid to SoCalGas if the Rate falls below 8.3. Penalties and rewards will be assessed at $ 20,000 per 0.1 point outside the deadband.

Quarterly Reports

In addition to the foregoing incentive mechanisms, SoCalGas will provide reports[*178] to the Commission, on a quarterly basis, containing monthly data on the following customer service quality indicators:

. Level of busy signals in the call center (number of customers receiving a busy signal per each 100 calls)

. Estimated meter reads (percentage of total reads that were estimated)

. Leak response time (percentage of leak calls responded to within 30 minutes Monday through Saturday between 7:00 a.m. and 5:00 p.m., and within 45 minutes during other times)

. Missed appointments (percentage of appointments missed due to utility error)

. Customer problems resolved on the first service call (percentage of survey respondents indicating their problems were resolved on the first service call)

At this time, no penalties will be assessed with respect to these performance indicators.

The busy signals and leak response time report data would be available to the public. At the time of the initial filing of other reports, SoCalGas may elect to use Commission procedures to seek confidential treatment of the remaining report data, or part thereof. Any party may challenge SoCalGas' designation of materials as confidential.

Review of Customer Service Quality

These[*179] parties recommend that a review be undertaken to examine the status of customer service quality indicators, including the penetration of the CARE program. This review would be done either in a mid-course review proceeding or forum OII if the Commission adopts such proceedings, or alternatively, in another appropriate Commission proceeding.

Penalty/Reward Treatment

Penalties and/or rewards will be assessed as a part of the Annual Rate Adjustment Filing. The initial measurement period will begin on July 1, 1997, or the implementation date of PBR if it is later. It will end on June 30, 1998. Any rewards and/or penalties will be reflected as an increase or decrease in rates on January 1, 1999.

Table 2, attached hereto, illustrates the penalty amounts associated with various levels of performance on the four customer service attributes and the two telephone response time indicators. Table 3 illustrates the reward and penalty amounts associated with various levels of performance on the employee safety standard.

Should the aggregate total of penalties assessed pursuant to the forgoing mechanism in any one year reach or exceed $ 4 million, SoCalGas will refund $ 4 million to ratepayers[*180] and an investigation by the CPUC would be triggered to consider whether the penalty mechanism is working properly, and/or whether appropriate remedies are in place to address service deterioration. SoCalGas could argue that penalties beyond $ 4 million should not be assessed, and other parties could oppose that request. SoCalGas would be subject to whatever additional penalties the Commission determined to be appropriate at the conclusion of its investigation.

With the exception of the performance indicators recommended by TURN that relate to the late payment charge (i.e., mailing bills and posting payments), the recommendations made herein would be implemented in lieu of various satisfaction, service, and safety measures proposed in the prepared testimonies described above. The performance indicators that relate to the late payment charge are not a part of this joint settlement proposal, and will remain subject to a litigated outcome. Accordingly, the joint recommendation does not include an aggregate customer satisfaction index; mandatory customer monetary credits for missed appointments, delayed leak responses, disconnects by reason of utility error, or winter outages greater than[*181] 24 hours; a mandatory customer satisfaction mail survey requirement; or, quarterly reports upon any service quality indicators other than those identified herein.

Table 1

Customer Service Attributes

1991-1996

YEAR	# of Customers Answering Question	Satisfaction CSR Q9 %8-10	Satisfaction Apt Arrangement Q19/Q28 %8-10
1991	11887	88.6%	
1992	24145	89.2%t	93Q2
1993	25707	90.8%	81.7%
1994	26859	89.9%	78.3%
1995	29218	90.5%	79.1%
1996 YTD November	24913	91.6%	79.9%
94-96 average		90.7%	79.1%
Deadbands		89.7%	78.1%

YEAR	Satisfaction ASR Q23 %8-10	On Time Appointment Q29 %YES
1991	93.2%	
1992	94.5%	93Q2
1993	94.3%	95.7%
1994	94.0%	94.7%
1995	94.3%	95.4%
1996 YTD November	94.6%	95.7%
94-96 average	94.3%	95.2%
Deadbands	93.3%	94.2%

Table 3

Example of Reward/Penalty Structure

Employee Safety Standard

Reward *	OSHA Recordable Rate	Penalty *
	:	:
	10.8	$ 100,000
	10.7	$ 80,000
	10.6	$ 60,000
	10.5	$ 40,000
	10.4	$ 20,000
Deadband	10.3	$ 0
Target $ 0	9.3	$ 0
Deadband $ 0	8.3	
$ 20,000	8.2	
$ 40,000	8.1	
$ 60,000	8.0	
$ 80,000	7.9	
$ 100,000	7.8	
:	:	

* $ 20,000 penalty/reward per tenth of point decline in performance

[*182]

APPENDIX B

TABLES ESTABLISHING BASE MARGIN

Table 1
SOUTHERN CALIFORNIA GAS COMPANY
SUMMARY OF EARNINGS
AT PRESENT AND ADOPTED RATES
Test Year 1996
(Thousands of Dollars)

Line No.	Description	PRESENT (A)	ADOPTED (B)	ADOPTED Exceeds Present Amount (C=B-A)	ADOPTED Exceeds Present Percent (D=C/A)
	Operating Revenues				
1	Gas Base Margin	1,544,704	1,315,341	(229,363)	-14.8%
2	Other Revenues	53,387	53,387	0	0.0%
3	Total	1,598,091	1,368,728	(229,363)	-14.4%
4	Less: Cost of Gas	0	0	0	# N/A
5	Net Operating Revenues	1,598,091	1,368,728	(229,363)	-14.4%
6	Operating Expenses				
7	Reassignments	(39,429)	(39,429)	0	0.0%
8	Clearing Accounts	53,079	53,079	0	0.0%

9	Underground Storage	20,373	20,373	0	0.0%
10	Transmission	25,016	25,016	0	0.0%
11	Distribution	170,599	170,599	0	0.0%
12	Customer Accounts	105,367	105,367	0	0.0%
13	Uncollectibles	7,332	6,347	(985)	-13.4%
14	Marketing	23,408	23,408	0	0.0%
15	Administrative & General	277,468	277,468	0	0.0%
16	Franchise Requirements	23,142	19,755	(3,387)	-14.6%
17	Exec Comp Adjustment	(606)	(606)	0	0.0%
18	P & B Adjustment	0	0	0	# N/A
19	Subtotal (1995 Dollars)	665,749	661,377	($ 4,372)	-0.7%
20	Labor Escalation Amount	10,115	10,115	0	0.0%
21	Non-Labor Escalation Amount	7,116	7,116	0	0.0%
22	Subtotal (1996 Dollars)	682,980	678,608	($ 4,372)	-0.6%
23	Productivity Adjustment	0	0	0	# N/A
24	Depreciation	241,147	241,147	0	0.0%
25	Taxes Other Than On Income	61,011	61,011	0	0.0%
26	CA Corporation Franchise Tax	48,572	28,683	(19,889)	-40.9%
27	Federal Income Tax	187,384	103,637	(78,747)	-42.0%
28	Total Operating Expenses	1,221,095	1,118,087	($ 103,008)	-8.4%
29	Net Operating Revenues	$ 376,996	$ 250,641	($ 126,355)	-33.5%
30	Rate Base	2,660,734	2,660,734	0	0.0%
31	Rate of Return	14.17%	9.42%	-4.75%	-33.5%

[*183]

Table 1-A
SOUTHERN CALIFORNIA GAS COMPANY
Comparison of
SUMMARY OF EARNINGS AT ADOPTED RATES
Test Year 1996
(Thousands of Dollars)

Line No.	Description (A)	ADOPTED (B)	SoCalGas
	Operating Revenues		
1	Gas Base Margin	1,315,341	1,366,275
2	Other Revenues	53,387	53,387
3	Total	$ 1,368,728	$ 1,419,662
4	Less: Cost of Gas	0	0
5	Net Operating Revenues	$ 1,368,728	$ 1,419,662
6	Operating Expenses		
7	Reassignments	(39,429)	(39,984)
8	Clearing Accounts	53,079	53,291
9	Storage	20,373	20,373
10	Transmission	25,016	25,017
11	Distribution	170,599	170,599

12	Customer Accounts	105,367	105,760
13	Uncollectibles	6,347	6,566
14	Marketing	23,408	23,815
15	Administrative & General	277,468	290,384
16	Franchise Requirements	19,755	20,507
17	Exec Comp Adjustment	(606)	0
18	P & B Adjustment	0	0
19	Subtotal (1995 Dollars)	$ 661,377	$ 676,328
20	Labor Escalation Amount	10,115	10,216
21	Non-Labor Escalation Amount	7,116	7,300
22	Subtotal (1996 Dollars)	$ 678,608	$ 693,844
23	Productivity Adjustment	0	0
24	Depreciation	241,147	252,504
25	Taxes Other Than On Income	61,011	61,383
26	CCFT	28,683	31,312
27	Federal Income Tax	108,637	119,191
28	Total Operating Expenses	$ 1,118,087	$ 1,158,234
29	Net Operating Revenues	$ 250,641	$ 261,428
30	Rate Base	2,660,734	2,775,698
31	Rate of Return	9.42%	9.42%

[*184]

Table 2
SOUTHERN CALIFORNIA GAS COMPANY
CLEARING ACCOUNTS SUMMARY
(Thousands Of 1995 Dollars Unless Otherwise Indicated)
Test Year 1996

Line No.	Account No.	Description	ADOPTED (A)
		General Services	
1	163.0	Stores Expense	4,450
2	184.1	Shop Expense	8
3	184.2	Tool Expense	5,474
4	184.3	Auto & Const. Equipment	27,678
5	184.4	Miscellaneous Pipeline Material	626
6	184.5	Print Shop	4
7		Total General Services	$ 38,240
		Communications	
8	184.7	Communications Expense	14,836
9		Total Communications	$ 14,836
		Operations Support	
10	184.1	Other Shop Expense-Bldg Opn's	3
11	184.6	HQ Bldg Expense	0
12		Total Operations Support	$ 3
13		TOTAL CLEARING ACCOUNT (1995$)	$ 53,079

	Escalation Amounts, 1995 to 1996	
14	Labor	495
15	Non-Labor	826
16	Other	0
17	Total	$ 1,321
18	TOTAL CLEARING ACCOUNT (1996$)	$ 54,400
19	LABOR ADJUSTMENT (1996$)	$ 0

Table 3

SOUTHERN CALIFORNIA GAS COMPANY
UNDERGROUND GAS STORAGE EXPENSE
SUMMARY
(Thousands of 1995 Dollars Unless Otherwise Indicated)
Test Year 1996

Line No.	Account No.	Description	ADOPTED (A)
		Operation	
1	814.0	Supervision and Engineering	2,639
2	815.0	Maps and Records	0
3	816.0	Wells expenses	1,753
4	817.0	Lines expenses	852
5	818.0	Compressor Station expenses	3,090
6	819.0	Compressor Sta. Fuel and Power	0
7	820.0	Measuring & Regulating Station Exp	150
8	821.0	Purification Expense	1,477
9	823.0	Gas Losses	0
10	824.0	Other Expenses	1,767
11	825.0	Storage Well Royalties	354
12	826.0	Rents	212
13		Total Operation expenses	$ 12,294
		Maintenance	
14	831.0	Structures and Improvements	76
15	832.0	Wells	2,660
16	833.0	Lines	649
17	834.0	Compressor Station Equipment	3,268
18	835.0	Measuring & Reg Station Equip.	173
19	836.0	Purification Equipment	1,032
20	837.0	Other Equipment	220
21		Total Maintenance expenses	$ 8,078
22		TOTAL UNDERGR. STORAGE (1995$)	$ 20,373
		Escalation Amounts, 1995 to 1996	
23		Labor	328
24		Non-Labor	218
25		Other	0

26		Total	$ 546
27		TOTAL UNDERGR. STORAGE (1996$)	$ 20,919
28		LABOR ADJUSTMENT (1996$)	$ 0

[*185]

Table 4

SOUTHERN CALIFORNIA GAS COMPANY

GAS TRANSMISSION EXPENSE

SUMMARY

(Thousands Of 1995 Dollars Unless Otherwise Indicated)

Test Year 1996

Line No.	Account No.	Description	ADOPTED (A)
		Operation	
1	850.0	Supervision and Engineering	7,571
2	851.0	System Con. & Load Dispatching	1,663
3	853.0	Compressor Station	1,638
4	854.0	Gas For Compressor Station Fuel	0
5	856.0	Mains Expenses	1,692
6	856.0	Removal of Condensate	0
7	857.0	Measuring & Reg. Station Exp.	1,327
8	858.0	Trans & Comp. of Gas by Others	0
9	859.0	Transmission Maps and Records	0
10	859.0	Other Expenses	2,713
11	859.0	Joint Expenses	0
12	860.0	Rents	3,208
13		Total Operation	$ 19,812
		Maintenance	
14	861.00	Supervision and Engineering	0
15	862.00	Structures and Improvements	108
16	863.00	Mains	2,205
17	864.00	Compressor Station Equipment	2,345
18	865.00	Measuring & Reg Station Equip.	417
19	867.00	Other Equipment	129
20		Total Maintenance	$ 5,204
21		TOTAL TRANSMISSION (1995$)	$ 25,016
		Escalation Amounts, 1995 to 1996	
22		Labor	467
23		Non-Labor	221
24		Other	0
25		Total	$ 688
26		TOTAL TRANSMISSION (1996$)	$ 25,704
27		LABOR ADJUSTMENT (1996$)	$ 0

[*186]

Table 5

SOUTHERN CALIFORNIA GAS COMPANY
GAS DISTRIBUTION, MEASUREMENT, ENGINEERING &
ENVIRONMENTAL EXPENSES SUMMARY
(Thousands Of 1995 Dollars Unless Otherwise Indicated)
Test Year 1996

Line No.	Account No.	Description	ADOPTED (A)
		Operation	
1	870.0	Supervision and Engineering	31,163
2	874.0	Mains and Services Expenses	0
3	875.0	Meas & Reg Station Exp	361
4	878.0	Meter & house regulator expense	539
5	879.0	Customer Install. Exp.	68,383
6	880.0	Other expenses	34,371
7	881.0	Rents	11
8		Total Operation	$ 134,828
		Maintenance	
9	885.00	Supervision and Engineering	0
10	887.00	Mains	13,867
11	889.00	Meas & Reg Station Equip	713
12	892.00	Services	15,456
13	893.00	Meters & House Regulators	5,735
14	894.00	Other Equipment	0
15		Total Maintenance	$ 35,771
16		TOTAL EXPENSES (1995$)	$ 170,599
		Escalation Amounts, 1995 to 1996	
17		Labor	4,562
18		Non-Labor	513
19		Other	0
20		Total	$ 5,075
21		TOTAL EXPENSES (1996$)	$ 175,674

Table 6
SOUTHERN CALIFORNIA GAS COMPANY
CUSTOMER ACCOUNTS EXPENSE
SUMMARY
(Thousands of 1995 Dollars Unless Otherwise Indicated)
Test Year 1996

Line No.	Account No.	Description	ADOPTED (A)
1	901.0	Supervision	7,151
2	902.0	Meter Reading Expenses	17,770
3	903.0	Cust.Rec.& Collec.Exp.(Co.7-B)	80,446
4	904.0	Uncollectible Accts (Pres.Rates)	7,332

5	905.0	Misc. Customer Accounts Exp.	0
6		TOTAL CUSTOMER ACCTS. (1995$)	$ 112,699
7		Total (Less Uncollectibles)	$ 105,367
		Escalation Amounts, 1995 to 1996	
8		Labor	2,544
9		Non-Labor	393
10		Other	0
11		Total	$ 2,937
12		TOTAL CUSTOMER ACCTS. (1996$)	$ 115,636
13		Total (Less Uncollectibles)	$ 108,304
14		LABOR ADJUSTMENT (1996$)	$ 0

[*187]

Table 7

SOUTHERN CALIFORNIA GAS COMPANY
MARKETING EXPENSES
SUMMARY
(Thousands Of 1995 Dollars Unless Otherwise Indicated)
Test Year 1996

Line No.	Account No.	Description	ADOPTED
			(A)
		DIRECT EXPENSES	
		OPERATION	
1	907.0	Supervision	902
2	908.0	Customer Assistance Expenses	2,603
3	909.0	Informational Instrctl. Ads	3,733
4	910.0	Misc. Customer Svc & Info Expenses	16,169
5	911.0	Supervision	0
6	916.0	Misc. Sales Expenses	0
5		TOTAL MARKETING EXPENSES(1995$)	$ 23,408
		Escalation Amounts, 1995 to 1996	
6		Labor	341
7		Non-Labor	387
8		Other	0
9		Total	$ 728
10		TOTAL MARKETING EXPENSES (1996$)	$ 24,136
11		LABOR ADJUSTMENT (1996$)	$ 0

Tables 8

SOUTHERN CALIFORNIA GAS COMPANY
ADMINISTRATIVE AND GENERAL EXPENSE
SUMMARY
(Thousands Of 1995 Dollars Unless Otherwise Indicated)
Test Year 1996

Line No.	Account No.	Description	ADOPTED

			(A)
		Operation	
1	920.0	Administrative & Gen. Salaries	42,278
2	921.0	Office Supplies and Expenses	32,576
3	922.0	Admin. & Gen. Transfer Credit	0
4	923.0	Outside Services Employed	58,565
5	924.0	Property Insurance	2,796
6	925.0	Injuries and Damages	20,042
7	926.0	Employee Pensions and Benefits	80,332
8	927.0	Franchise Reqmnts (@Pres.Rates)	23,142
9	928.0	Regulatory Commission Expenses	269
10	930.2	Misc.General Expenses	12,661
11	931.0	Rents	21,440
12		Total Operation	$ 294,101
		Maintenance	
13	935.0	Maintenance of General Plant	6,509
14		Total Maintenance	6,509
15		TOTAL ADMIN. & GEN. (1995$)	$ 300,610
16		Total (Less Franchise Req.)	$ 277,468
		Escalation Amounts, 1995 to 1996	
17		Labor	1,398
18		Non-Labor	4,558
19		Other	0
20		Total	$ 5,956
21		TOTAL ADMIN. & GEN. (1996$)	$ 306,566
22		Total (Less Franchise Req.)	$ 283,424
23		LABOR ADJUSTMENT (1996$)	$ 0

[*188]

Table 9

SOUTHERN CALIFORNIA GAS COMPANY

REASSIGNMENTS

(Thousands Of 1995 Dollars Unless Otherwise Indicated)

Test Year 1996

ADOPTED

Line No.	TABLE No.	Description	ADOPTED (A)
1	4	Clearing Accounts	14,216
2	5	Underground Gas Storage	135
3	6	Gas Transmission	1,016
4		SUBTOTAL	$ 15,367
5	7-A	Gas Distribution-Operations Expenses	7,302
6	7-B	Gas Distribution-Measurement Expenses	0
7	7-C	Gas Distribution-Engineering Expenses	28
8	7-D	Environmental & Safety Expenses	0

9	8	Customer Accounts	0	
10	9	Marketing Expenses	0	
11	10	Administration & General	15,756	
12		SUBTOTAL	$ 23,087	
13		TOTAL REASSIGNMENTS (1995$)		$ 38,454
		Escalation Amounts, 1995 to 1996		
14		Labor	423	
15		Non-Labor	552	
16		Other	0	
17		Total	$ 975	
18		REASSIGNMENTS (1996$)		$ 39,429
19		ADJUSTMENT (1996$)		$ 0
20		TOTAL REASSIGNMENTS (1996$)		$ 39,429

Table 10
SOUTHERN CALIFORNIA GAS COMPANY
DEPRECIATION EXPENSE
Test Year 1996
(Thousands of 1996 Dollars)

Line No.	Description	ADOPTED (A)
1	Underground Storage	18,907
2	Transmission Plant	20,934
3	Distribution Plant	164,617
4	General Plant	32,801
5	Subtotal	$ 237,259
6	Net Additions	2,211
7	Adjustment for Plant Issues	394
8	Adjustment for CIS dep'n accrual	1,284
9	Total Depreciation Expense	$ 241,147
10	1996 Depreciation Expense Estimate	$ 241,147

[*189]

Table 11
SOUTHERN CALIFORNIA GAS COMPANY
DEPRECIATION RESERVE
Test Year 1996
(Thousands of 1996 Dollars)

Line No.	Description	ADOPTED (A)
1	Reserve Balance @ 12/31/95	$ 2,586,090
2	Depreciation Accrual	241,147
3	Retirements & Net Salvage	(50,939)
4	Clearing Account	0
5	Reserve Balance @ 12/31/96	$ 2,776,298

6	Average Depreciation Accrual	120,574
7	Average Retirements & Net Salvage	(25,470)
8	Average Clearing Account	0
9	1996 Total Weighted Avg. Reserve (Line 1 + 6 + 7 + 8)	$ 2,681,194

Table 12
SOUTHERN CALIFORNIA GAS COMPANY
TAXES OTHER THAN ON INCOME
Test Year 1996
(Thousands of Dollars)

Line No.	Description	ADOPTED (A)
	Ad Valorem Taxes	
1	California	35,519
2	Total Ad Valorem Taxes	35,519
	Payroll Taxes	
3	Federal Insurance Contrib. Act	24,344
4	Federal Unemployment Insurance	398
5	State Unemployment Insurance	750
6	Exhibit 57 Payroll Tax Changes	0
7	Total Payroll Taxes	25,492
	Other Taxes	
8	Sales Tax Increase	0
9	Hazardous Substance Tax	0
10	Total Other Taxes	0
11	Total Taxes OTOI	$ 61,011

Table 13
SOUTHERN CALIFORNIA GAS COMPANY
INCOME TAX ADJUSTMENT
Test Year 1996
(Thousands of 1996 Dollars)

Line No.	Description	ADOPTED (A)
	California Income Tax Adjustments	
1	Tax Depreciation	204,431
2		0
3		0
4		0
5	Fixed Charges-Operating	91,536
6	Removal Costs	6,871
7	Repair Allowance	4,000
8		0
9		0
10	Miscellaneous-Net	(2,198)

11		0
12	Total CCFT Adjustments	$ 304,640
	Federal Income Tax Adjustments	
13	Tax Depreciation	182,573
14		0
15		0
16		0
17		0
18		0
19		0
20		0
21	Fixed Charges-Operating	91,536
22	Removal Costs	5,222
23		0
24		0
25	Miscellaneous-Net	17
26		0
27	Total FIT Adjustments	$ 279,348

[*190]

Table 14
SOUTHERN CALIFORNIA GAS COMPANY
TAXES ON INCOME - PRESENT RATES
Test Year 1996
(Thousands of 1996 Dollars)

Line No.	Description	ADOPTED (A)
	California Corporation Franchise Tax	
1	Operating Revenues	$ 1,598,091
2	Operating Exp (incl prod adjust)	682,980
3	Taxes Other Than On Income	61,011
4	Income Tax Adjustments	304,640
5	California Taxable Income	$ 549,459
6	CCFT Tax Rate	0.0884
7	CCFT	$ 48,572
8	State Tax Adjustment	0
9	Subtotal	$ 48,572
10	Defense Facilities Credit	0
11	Deferred Taxes	0
12	Total CCFT	$ 48,572
	Federal Income Tax	
13	Operating Revenues	$ 1,598,091
14	Operating Exp (incl prod adjust)	682,980
15	Taxes Other Than On Income	61,011
16	CCFT(Prior Year)	30,364

17	Income Tax Adjustments	279,348
18	Federal Taxable Income	$ 544,388
19	FIT Tax Rate	0.35
20	Federal Income Tax	$ 190,536
21	Investment Tax Credit	(2,867)
22		0
23		0
24		0
25	Average Rate Assumption	(285)
25	Total Federal Income Tax	$ 187,384

Table 15
SOUTHERN CALIFORNIA GAS COMPANY
TAXES ON INCOME - ADOPTED RATES
Test Year 1996
(Thousands of 1996 Dollars)

Line No.	Description	ADOPTED (A)
	California Corporation Franchise Tax	
1	Operating Revenues	$ 1,368,728
2	Operating Exp (incl prod adjust)	678,608
3	Taxes Other Than On Income	61,011
4	Income Tax Adjustments	304,640
5	California Taxable Income	$ 324,468
6	CCFT Tax Rate	0.0884
7	Total CCFT	$ 28,683
8	State Tax Adjustment	0
9	Subtotal	$ 28,683
10	Defense Facilities Credit	0
11	Deferred Taxes	0
12	Total CCFT	$ 28,683
	Federal Income Tax	
13	Operating Revenues	$ 1,368,728
14	Operating Exp (incl prod adjust)	678,608
15	Taxes Other Than On Income	61,011
16	CCFT	30,364
17	Income Tax Adjustments	279,348
18	Federal Taxable Income	$ 319,397
19	FIT Tax Rate	0.35
20	Federal Income Tax	$ 111,789
21	Investment Tax Credit	(2,867)
22	Capitalized Int & Prop Txs	0
23	Superfund Tax (Line 18*0.0012)	0
24	Capitalized Employee Benefits	0
24	Average Rate Assumption	(285)

25	Total Federal Income Tax	$ 108,637

[*191]

Table 16
SOUTHERN CALIFORNIA GAS COMPANY
GAS PLANT IN SERVICE
Test Year 1996
(Thousands of 1996 Dollars)

Line No.	Description	ADOPTED (A)
1	1996 BOY GAS PLANT	$ 5,555,550
	1996 NET ADDITIONS:	
2	Gross Additions	163,196
3	Less Retirements	(38,454)
4	Net Additions	124,742
	1996 WEIGHTED AVG. ADDITIONS:	
5	Weighting Percentage	40.29%
6	Weighted Avg Net Additions	50,259
	1996 CUSTOMER INFO SYSTEM:	
7	Net Addition	24,954
8	Wtd. Avg. Addition	24,954
	SPECIAL RETIREMENTS:	
9	Plant No Longer Used & Useful	0
10	1996 EOY PLANT (1+4+7-9)	5,705,246
11	1996 WTD. AVG. PLANT (1+6+8-9)	5,630,762

Table 17
SOUTHERN CALIFORNIA GAS COMPANY
WEIGHTED AVERAGE DEPRECIATED RATE BASE
AT ADOPTED RATES
Test Year 1996
(Thousands of 1996 Dollars)

Line No.	Description	ADOPTED (A)
	Weighted Average Gas Plant:	
1	Gas Plant	5,630,762
2	Total Weighted Average Plant	5,630,762
	Working Capital:	
3	Materials and Supplies	14,303
4	Accum. Def. IT/Contrib.&Adv.	22,249
5	Work in Progress	12,388
6	Working Cash	26,485
7	Total Working Capital	$ 75,425
8	Total (Line 2+7)	5,706,187
	Less Adjustments:	

9	Customer Advances	53,299
10	Deferred Rev. Net Of FIT	9,624
11	Acc. Deferred FIT-Depreciation	293,237
12	Acc. Deferred Taxes	0
13	Acc. Deferred ITC	1,344
14	Aliso Gas Rights	210
15	Gain On Sales	6,545
16	Total Deductions	$ 364,259
17	Depreciation Reserve	2,681,194
18	Total Adjustments (Line 16+17)	3,045,453
19	Total Rate Base (Line 8-18)	$ 2,660,734

[*192]

Table 18
SOUTHERN CALIFORNIA GAS COMPANY
DETERMINATION OF AVERAGE AMOUNTS OF WORKING
CASH CAPITAL SUPPLIED BY INVESTORS
Test Year 1996
(Thousands of Dollars)

Line No.	Description	ADOPTED (A)
	Operational Cash Requirements	
1	Required Bank Balances/Cash	0
2	Special Deposits & Working Funds	160
3	Other Receivables	11,140
4	Other Prepayments	2,750
5	Deferred Debits	3,520
6	Total Operat'l Cash Requirement	$ 17,570
	Plus: Working Cash Rqmnt from lag in	
7	Collection of Revenues	68,122
	Less: Amounts Not Supplied By Investors	
8	Collection of state regulatory fees	370
9	Collection of utility users tax	690
10	Collection of transport tax before payment	(30)
11	Collect'n of municipal surchrg before paymnt	2,820
12	Employees withholding	1,280
13	Purchase of capitalized items	4,620
14	Purchase of materials and supplies	210
15	Current and accrued liabilities	28,234
16	Available Cash Balance Adjustment	0
17	Deferred Credit Adjustments-Overland	21,013
18	Total deductions	$ 59,207
19	Working Cash Capital (Line 6+7)	$ 85,692
	Plus: Average Required	
20	Lead Lag @ ADOPTED Rates (Line 7)	68,122

	Working Cash Capital Supplied by Investors	
21	Calculated @ ADOPTED rate (Line 6 + 20 -1	26,485
22	Use @ ADOPTED rate	$ 26,485

[*193]

Table 19
SOUTHERN CALIFORNIA GAS COMPANY
DEVELOPMENT OF AVERAGE LAG IN PAYMENT OF EXPENSES
Test Year 1996
(Thousands of Dollars)

Line No.	Description	Expense (A)
1	Federal Income Tax	108,637
2	FIT: SIT Ded. Timing Adj. # 1	0
3	FIT: SIT Ded. Timing Adj. # 2	0
4	State Income Tax	28,683
5	Deferred Income Taxes	0
6	Franchise Requirements	37,963
7	Natural Gas Purchased	1,209,335
8	Company Labor	337,474
9	Pension Expense	0
10	Disability Plan	4,412
11	Retirement Saving Plan	6,829
12	Life Insurance	1,392
13	Medical & Dental	22,811
14	Health Maint. Organizations	4,246
15	Goods and Services	22,068
16	Materials From Storeroom	1,058
17	Depreciation	241,147
18	Ad Valorem Tax - CA	35,519
19	FICA Tax	24,344
20	Unemployment Tax - Federal	398
21	Unemployment Tax - California	750
22	Real Estate Rental Payments	24,239
23	Equipment Lease Payments	16,185
24	Amort. Of Insurance Premiums	6,887
25	Workers Comp.	12,986
26	Benefits Fees & Services	3,542
27	TOTAL	2,150,904
28	Expense Lag Days = (C)/(A) =	35.79
29	Revenue Lag Days	47.35
30	Working Cash From Lead Lag	68,122
31	Rate Base At ADOPTED Rates	2,660,734
32	Rate of Return	9.42%

[*194]

Table 20
SOUTHERN CALIFORNIA GAS COMPANY
Development of the Net To Gross Multiplier
Test Year 1996

Line No.	Description	(A)	(B)	(C=AxB)
1	Gross Operating Revenues			1.000000
2	Less: Uncollectibles	0.004776	1.000000	0.004776
3			0.995224	
4	Less: Franchise Requirements	0.014828	0.995224	0.014757
5			0.980467	
6	Less: Superfund Tax	0.000000	0.980467	0.000000
7			0.980467	
8	Less: State Income Tax	0.088400	0.980467	0.086673
9			0.893794	
10	Less: Federal Income Tax	0.350000	0.980467	0.343163
11	Net Operating Revenues			0.550630
12	Net To Gross Multiplier (A/B)	1.000000	0.550630	1.816100

APPENDIX C

LIST OF APPEARANCES

MASTER LIST R87-11-012/A95-06-002
CRTD :11/26/96 lil
Udated: 4/17/97 ioa
Added : 4/17/97 ioa
DOC.ID: R15815

DISSENTBY: Duque

COMMISSIONER HENRY M. DUQUE, DISSENTING IN PART:

Throughout my deliberations on the proposed decision and the alternate pages, I have been supportive of simplifying the indexing formula. However, in examining ways to simplify the indexing formula, most proposed approaches focused on increasing the productivity factor to achieve a similar revenue requirement result as the TURN/DGS formula. This is the approach that President Conlon's alternate took and is the approach adopted in this decision. I reviewed President Conlon's alternate pages with great interest, given my preference for a simple formula. However, I ultimately concluded that if we believe that the results of the TURN/DGS methodology are sound, and by adjusting the productivity factor we were simply trying to emulate those results using a different formula, that we should adopt the TURN/DGS methodology. The complexity in the formula is in its development, not in its implementation, as it relies on the same inputs as the more simple formula. [*203] I believe that the proposed decision prepared by the ALJ accurately reflected productivity in the productivity factor, and accurately reflected the declining rate base in the indexing formula. In my opinion, the alternate approach adopted in this decision masks the declining rate base issue in the productivity factor and this is why the adopted productivity factor in the proposed decision was so different from that in the alternate pages.

For these reasons, I file this partial dissent regarding the indexing formula.

/s/ HENRY M. DUQUE

Henry M. Duque

Commissioner

I concur with Commissioner Duque's partial dissent.

/s/ JOSIAH L. NEEPER
Josiah L. Neeper
Commissioner

San Francisco, California
July 16, 1997

COM/RB1/rmn

Mailed 5/18/99

Decision 99-05-030 May 13, 1999

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (SDG&E) for Authority to Implement a Distribution Performance-Based Ratemaking Mechanism (U 902-M).	Application 98-01-014 (Filed January 16, 1998)

(See Appendix A for list of appearances.)

OPINION REGARDING SAN DIEGO GAS & ELECTRIC COMPANY'S DISTRIBUTION PERFORMANCE-BASED RATEMAKING MECHANISM

Summary

In this decision, we consider the performance indicators and the design of the San Diego Gas & Electric Company (SDG&E) distribution performance-based ratemaking (PBR) mechanism. We adopt the settlement agreement regarding the performance indicators proposed by SDG&E, the Office of Ratepayer Advocates (ORA), the Utility Consumers' Action Network (UCAN), the Federal Executive Agencies (FEA), the Coalition of California Utility Employees (CCUE), the City of San Diego, the California Farm Bureau Federation (Farm Bureau), and the Natural Resources Defense Council (NRDC). This agreement is an all-party settlement and resolves all issues raised in connection with the requested performance indicators.

We adopt a distribution PBR mechanism modeled after those adopted for Southern California Gas Company (SoCalGas) in Decision (D.) 97-07-054 and Southern California Edison (Edison) in D.96-09-092. We adopt a rate indexing mechanism, a progressive sharing mechanism, and a productivity factor that includes a stretch factor. The revenue requirement used as the starting point for this distribution PBR mechanism is $563.4 million for electric distribution and $201.5 million for gas base rate revenues, as approved in D.98-12-038.[1]

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[1] Including expected Demand-side Management (DSM) shareholder incentives and compared to revenues at present rates, D.98-12-038 adopts a decrease of $14.2 million in the electric department (2.46% decrease as a system average rate change) and an increase of $3.9 million for the gas department (1.97% increase on a system average

Footnote continued on next page

Procedural History

In D.97-04-067, we ordered SDG&E to file an application requesting approval of a distribution PBR mechanism. On January 6, 1998, SDG&E filed Application (A.) 98-01-014 to request authority to establish such a mechanism. ORA and UCAN filed timely protests, to which SDG&E filed a reply. SDG&E, ORA, and UCAN (jointly for UCAN, NRDC, Enron, FEA, and City of San Diego) filed prehearing conference statements.

On January 1, 1998, Senate Bill 960 became effective, which established various procedures for our proceedings. These rules are delineated in Public Utilities (PU) Code §§ 1701 et seq. and Article 2.5 of our Rules of Practice and Procedure. In accordance with the SB 960 rules, this proceeding has been categorized as ratesetting (ALJ 176-2986, as noticed in the Daily Calendar of February 6, 1998).

On March 17, 1998, Assigned Commissioner Neeper and Assigned Administrative Law Judge (ALJ) Minkin presided at a prehearing conference. Commissioner Neeper then issued a scoping memo which designated ALJ Minkin as the principal hearing officer for this proceeding. The scoping memo set forth the issues to be included in this proceeding and established a procedural schedule under which the Commission would issue a final decision in this proceeding by March 1999, or in no event no later than 18 months from the date of filing of the application, pursuant to SB 960, Section 13. Commissioner

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basis). The effect for combined departments is a $10.3 million decrease, (1.33% decrease on a system average basis).

Neeper also encouraged parties to meet and confer on an informal basis to attempt to resolve issues.

At the request of parties, the scoping memo was amended to revise the procedural schedule to delay hearings and set a second prehearing conference on August 10, 1998. ORA,UCAN, FEA, CCUE, and NRDC submitted testimony on SDG&E's proposal on July 3, 1998. SDG&E and CCUE submitted rebuttal testimony on July 31. Informal discussions among the parties led to two technical workshops held in San Francisco on August 20 and 27. A formal settlement conference was noticed on September 2, in conformance with Rule 51, and held on September 14. The settling parties filed and served the Joint Motion for Adoption of Settlement Agreement on PBR Performance Indicators on September 15, 1998. No party filed comments.[2] No evidentiary hearings were held on the issues addressed in the proposed settlement agreement.

PBR design issues were addressed in four days of evidentiary hearings held on September 2, 3, 4, and 14. Commissioner Neeper was in attendance for closing arguments on September 16. Public participation hearings were held in San Diego and Escondido on September 23 and September 24, respectively, at which Commissioner Neeper and ALJ Minkin presided. This proceeding was

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[2] The settling parties also requested that the Commission shorten the time for opening comments and reply comments on the proposed settlement agreement. There was no reason to shorten time, but given the all-party nature of the settlement, no comments were filed. Thus, this request is moot.

submitted upon opening and reply briefs, filed on October 9 and October 23, respectively.[3]

Framework for Incentive-Based Ratemaking

We have long considered incentive-based ratemaking superior to command-and-control regulation. PBR mechanisms send the important message that minimizing costs without sacrificing service quality and reliability can result in greater rewards with "less" regulation than traditional cost-of-service regulation. In order to provide these incentives, we must necessarily break the link between rates and costs. Cost-of-service regulation uses the utility's own costs in setting rates and often results in inefficiency, because utilities are rewarded by increased rates for increased costs.

We have established several goals to be addressed by incentive regulation for energy utilities. In our comprehensive rulemaking (R.94-04-031) and investigation (I.94-04-032) addressing proposed policies on electric restructuring and reforming regulation, we stated our intention to replace cost-of-service regulation with performance-based regulation. It is worth reviewing the goals stated in that document:

> "First, prices for electric services in California are simply too high. The shift to performance-based regulation can provide considerably stronger incentives for efficient utility operations and investment, lower rates, and result in more reasonable, competitive prices for California's consumers. Performance-based regulation also

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[3] By separate motions filed on October 26, UCAN requests leave to file a corrected opening brief and to file its reply brief late. Good cause being shown, these motions are granted.

promises to simplify regulation and reduce administrative burdens in the long term. Second, since the utilities' performance-based proposals currently before us leave both industry structure and the utility franchise fundamentally intact, consumers can expect service, safety and reliability to remain at their historically high levels. Third, the utilities' reform proposals are likely to provide an opportunity to earn that is at a minimum comparable to opportunities present in cost-of-service regulation. Finally, performance-based regulation can assist the utilities in developing the tools necessary to make the successful transition from an operating environment directed by government and focussed on regulatory proceedings, to one in which consumer, the rules of competition, and market forces dictate." [all footnotes omitted.] (R.94-04-031/I.94-04-032, mimeo. at pp. 35-36.)

In D.94-08-023, we adopted an experimental base rate PBR mechanism for SDG&E and stated our goals and objectives for improving regulation:

"1. To provide greater incentive than exists under current regulation for the utility to reduce rates.

"2. To provide a more rational system of incentives for management to take reasonable risks and control costs in both the long and short run. This includes extending the relatively short-term planning horizon associated with the three-year GRC cycle and reducing the company's incentive to add to rate base to increase earnings.

"3. To prepare the company to operate effectively in the increasingly competitive energy utility industry. This entails providing greater flexibility for management to take risks combined with a greater assignment of the consequences of those risks to the company.

"4. To reduce the administrative cost of regulation.

"Again, it is not sufficient to define these objectives for a regulatory reform experiment. We must also ensure that the achievement of regulatory reform does not come at the expense of the primary purpose or other relevant objectives of regulation. We reiterate the standards for review … which the parties generally purport to embrace. The experiment must have a reasonable potential for improving on existing regulation without jeopardizing regulatory goals, and therefore, (1) respond to the goal of safe, reliable, environmentally sensitive service at reasonable rates; (2) be designed to enable the Commisison to judge the success of the experiment when it is over; and (3) not in itself create unreasonable risks. … we accept and adopt the following additional criteria:

"1. To the extent that an individual program component or the proposal as a whole imposes greater risks on ratepayers, it should also remove, reduce, provide compensation for, or transfer those risks to the utility. This does not necessarily mean …that we need to require rate reductions in return for ratepayer assumption of risk, notwithstanding our objective of rate reduction. It does mean that the program, taken as a whole, should provide a reasonable balancing of the attendant risks and rewards. There should be an equitable sharing of the benefits that reform is intended to achieve.

"2. The adopted regulatory program should maintain system quality, reliability, safety, and customer satisfaction even as expected cost reductions occur. Thus, it should … prevent or discourage long-run disinvestment in the system that could otherwise result in unintended system degradation.

"3. The program should avoid or minimize unintended consequences in interplay among various regulatory programs, including DSM incentive, low income rate assistance programs, etc.

"4. The experimental program should be flexible enough to allow needed changes during its term, yet sufficiently fixed in form and content to provide a predictable framework for management planning and to allow evaluation.

> "5. There should be explicit provisions for a program of monitoring and evaluation which will enable us to become aware of problems requiring solution during the term of the experiment and which will provide information needed to decide on the program of regulation which will be implemented at the conclusion of the experiment." (55 CPUC 2d 592, 615-616.)

Our Preferred Policy Decision (D.95-12-063, as modified by D.96-01-009) in the electric restructuring rulemaking and investigation reiterated these goals and directed California's three major investor-owned utilities, including SDG&E, to file applications to establish separate generation and distribution PBRs:

> "Our goal is to have an improved regulatory process that offers flexibility and encourages utilities to focus on their performance, reduce operation cost, increase service quality, and improve productivity. At the same time, we must ensure that safety, quality of service, and reliability are not compromised. There is broad but not universal consensus that Performance Based Ratemaking (PBR) can accomplish these objectives by providing clear signals to utility managers with respect to their business decisions and helping them make the transition from a tightly regulated structure to one that is more competitive. Under PBR, utility performance is measured against established benchmarks. Superior performance, above the benchmark, would receive financial rewards, and poor performance would result in financial penalties to the shareholders. By providing financial incentives to utilities, we will encourage them to operate more efficiently to maximize their profits." (Preferred Policy Decision, mimeo. at p. 82.)

In both D.96-09-092 (adopting a PBR mechanism Edison) and D.97-07-054 (adopting a PBR mechanism for SoCalGas), we confirmed our goals for developing PBR mechanisms:

* Improving the efficiency and performance of the utility;

* Improving incentives and removing disincentives for utility cost reductions;
* Simplifying and streamlining the regulatory process;
* Moving rates for all customer classes, in real dollars, steadily down the national average for investor-owned utilities;
* Maintaining a reasonable opportunity for the utility to earn a fair rate of return; and
* Maintaining and improving quality of service.

Taken together, these established goals help us to develop the framework for considering SDG&E's distribution PBR proposal.

Background

SDG&E has been operating under a base rate PBR mechanism since 1994. Edison operates under a distribution PBR mechanism, as described in D.96-09-092, D.98-07-077, and D.98-08-015. SoCalGas also operates under a PBR mechanism, as described in D.97-07-054. As approved in D.98-03-073, SoCalGas and SDG&E are now operating entities within the holding company of Sempra Energy, Inc., as a result of the merger of Enova Corporation and Pacific Enterprises, the parent companies of SDG&E and SoCalGas, respectively. We will briefly review the design of each of these mechanisms.

The process of developing an effective PBR mechanism begins with selecting an appropriate starting point for revenue requirements. In this proceeding, we have approved a settlement for this amount, as discussed in D.98-12-038. Revenue requirements or rates are then adjusted annually to account for inflation and productivity, using indexing methods. Taken together, inflation with the productivity offset is commonly described as "Consumer Price

Index (CPI) minus X" or the "update rule." Incentives are then developed to ensure that utility decision-makers are motivated to achieve cost savings.

Earnings sharing mechanisms track actual earnings and share with ratepayers any earnings or losses that fall above or below a certain threshold. Generally, earnings sharing mechanisms have *deadbands* in which there is no sharing; i.e., ranges in which only shareholders are at risk for the earnings variations. A live band is the range of an applicable PBR performance indicator against which the compared utility performance may result in varying rewards or penalties. Adopting an effective PBR mechanism requires a balance between providing appropriate incentives to utilities with adhering to our stated goals of providing an equitable sharing of the benefits. In addition, our objective of encouraging the utilities to operate more effectively in a competitive marketplace suggest that these benefits must be shared with ratepayers.

Earnings sharing mechanisms may be either progressive or regressive. A *regressive* mechanism is one in which the utility's share decreases as cost savings increase. In contrast, a *progressive* mechanism is one in which the utility's share increases as cost savings increase. Finally, *"Z" factors* apply to exogenous or unforeseen events that are beyond the utility's control and that have a material impact on the utility's costs. In D.94-06-011, we adopted nine criteria for determining whether the cost impact from these unexpected events should be included in the utility's revenue requirements. In sum, the formula describing PBR regulation is as follows:

$R_n = (r *(esc\ -X)) + Z$

where:

R = rates or revenue requirements in years following initial period

n = year for which rates or revenue requirements are determined

r = starting point rates or revenue requirements

esc = escalation or inflation measure

X = productivity measure

Z = any one-time unforeseen costs that must be accounted for

In addition, each PBR mechanism has various performance indicators. These performance indicators are designed to ensure that the utility's service quality, customer service, reliability, and safety do not deteriorate under PBR regulation. The utility's performance is reviewed according to certain criteria and either earns a reward or suffers a penalty. These rewards and penalties are in addition to any earnings or losses achieved under the earnings sharing component of the mechanism.

SDG&E's Base Rate PBR Mechanism

SDG&E's initial PBR mechanism was adopted on September 1, 1994 and applied to the period 1994 through 1998. This base rate PBR mechanism required a sales forecast and the 1993 GRC revenue requirements were adopted as the starting point for this mechanism, as escalated to 1994 using specific PBR formulas for operation and maintenance (O&M) costs and net plant additions. Different inflation components were applied to labor O&M costs (the SDG&E labor escalation factor), non-labor O&M costs (the DRI national inflation index), and plant additions (the Handy Whitman inflation index). The productivity component was fixed at 1.5% and was applied only in O&M formulas. A customer growth factor was incorporated in both O&M inflation factors and the plant additions inflation factor.

There is no earnings sharing up to 100 basis points[4] above the authorized rate of return. The 100 basis points consist of a deadband. From 100 to 150 basis points above the authorized rate of return, a regressive sharing mechanism was adopted in which 75% accrues to shareholders and 25% accrues to ratepayers. From 150 basis points above authorized rate of return, sharing is 50/50. There is no downside risk to ratepayers. No specific Z-factor treatment was adopted, but parties had the ability to file petitions for modification. No specific exclusions were accounted for, but SDG&E could apply to request exclusion of certain material external events above $500,000. A midterm review was required, with reports on annual performance and annual escalation updates. Offramps to the PBR mechanism were built in at 150 basis points below the authorized rate of return and 300 basis points above and below the authorized rate of return.

During the period 1994 through 1997, SDG&E has earned approximately $136 million in after-tax dollars from its earnings sharing mechanism. In 1994, SDG&E earned 94 basis points above its authorized rate of return, which is within the deadband. In 1995, SDG&E earned 130 basis points above the authorized rate of return, which is 30 basis points above the deadband area. In 1996, SDG&E earned 152 basis points above its authorized rate of return, or 52 basis points above the deadband. In 1997, SDG&E earned 153 basis points

[4] A basis point is 1/100th of 1%; i.e., 100 basis points equals 1%.

above its authorized rate of return, or 53 basis points above the deadband.[5] SDG&E also accrued net performance rewards of approximately $18.7 million through 1997. As adjusted by Resolution E-3512, ratepayers' share of earnings above authorized rate of return equaled $6.8 million through 1996. Ratepayers' share in 1997 is expected to equal approximately $4.4 million for a total of $11.2 million over the four-year period.

Edison's Distribution PBR Mechanism

Edison's initial PBR mechanism was adopted in D.96-09-092, to be effective for the period 1997 through 2001. This electric distribution base rate PBR mechanism does not require a sales forecast and the 1996 GRC revenue requirements, as separated transmission and distribution components, were adopted as the starting point for this mechanism, as escalated to 1997 using the "CPI - X" formula applied to rates. The inflation component consists of the Consumer Price Index. The productivity component ramps up from 1.2% in 1997 to 1.4% in 1998 and 1.6% in 1999, 2000, and 2001. No customer growth factor is incorporated.

There is no earnings sharing up to 50 basis points (.5%) above the authorized return on equity. The 50 basis points equal the deadband. This is a progressive sharing mechanism, with ratepayers earning a range of 75% to 0 as

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[5] Final 1997 earnings above authorized rate of return and corresponding shares have not yet been authorized by the Commission. In Resolution E-3562, dated December 17, 1998, the Commission ordered SDG&E to recalculate its revenue sharing amounts for 1994 to 1997, excluding the expenses for various employee and senior management incentive rewards.

the return on equity increases from 50 basis points to 300 basis points above the authorized return on equity. Similarly, shareholders earn a range of 25% to 100% over the same range. Ratepayers share in the downside risk in the same percentage. The Commission adopted specific Z-factor criteria for Edison, as previously approved for telephone utilities, with a $10 million deductible. Generation, special one-time amortization accounts, hazardous waste, research, design and development, demand-side management, and low-emission vehicle expenditures were all excluded from this PBR mechanism. A midterm review is required in 1999, with reports on annual performance and annual escalation updates. The PBR mechanism will trigger an offramp at 600 basis points above or below the benchmark return on equity.

In 1997, Edison's actual return on equity was 13.62%, 202 basis points above the authorized return on equity. Ratepayers earned approximately $42.6 million from this sharing mechanism, with shareholders earning about $36.3 million.[6] Edison also accrued a $5 million reward for its health and safety performance indicators.

SoCalGas' PBR Mechanism

SoCalGas' PBR mechanism was adopted in D.97-07-054, to be effective for the period 1998 through 2002. This base rate revenue requirement PBR mechanism requires a sales forecast and the 1997 revenue requirements were adopted as the starting point for this mechanism, as escalated to 1998 using the "CPI - X" formula applied to revenue requirement per customer. The

[6] These results have not yet been approved by the Commission.

inflation component consists of a weighting of the DRI inflation factors for labor O&M, non-labor O&M, and capital additions. This weighting is based on the three California gas utilities. Then overall productivity component ramps up from 2.1% in 1998 to 2.5% in 2002. The productivity factor includes a stretch factor and takes into account declining rate base. The SoCalGas PBR incorporates customer growth in a revenue requirement per customer adjustment.

There is no earnings sharing up to 25 basis points (.25%) above the authorized rate of return. The 25 basis points equals the deadband. The SoCalGas PBR includes a progressive sharing mechanism, with ratepayers earning a range of 75% to 0 as the rate of return increases from 25 basis points to 300 basis points above the authorized return. Similarly, shareholders earn a range of 25% to 100% over the same range. There is no downside risk for ratepayers. The Commission adopted the same specific Z-factor criteria for SoCalGas as was previously approved for Edison, with a $5 million deductible. Several programs are excluded from the PBR mechanism. A midterm review is required in the next Biennial Cost Allocation Proceeding (BCAP), with reports on annual performance and annual escalation updates. If earnings are either 300 basis points above the authorized rate of return or 175 basis points below the authorized rate of return for two years in a row, this will trigger an offramp review of the PBR mechanism. No results have been reported yet for SoCalGas' PBR mechanism.

The Proposed Settlement on Performance Indicators

The proposed settlement on performance indicators addresses safety, reliability, customer satisfaction, and call center responsiveness, as well as certain customer service guarantees. Performance indicators offer rewards and penalties for specific actions, as described above. Other than service guarantees, each of the performance indicators described below has a symmetrical reward and penalty. (See Appendix B for a comparison of each party's position and the settlement position.)

The proposed settlement agreement identifies certain performance indicators which SDG&E has agreed to withdraw. SDG&E agrees to provide to the Commission and to the settling parties an annual report which provides quarterly data for various items related to customer service, emergencies, and call center responsiveness. Because tracking systems for several of these measures are not yet in place, SDG&E proposes to begin tracking this data two months after issuance of this decision. The first report will be submitted in early 2000, addressing data through December 31, 1999. SDG&E agrees to withdraw its proposed competition enhancement and environmental citizenship performance indicators. Finally, no party opposes SDG&E's proposal to gather data for the purposes of developing an electric system maintenance performance indicator.

We describe below each of the performance indicators proposed in the settlement agreement.

Safety Performance Indicator

The employee safety performance indicator is based on an Occupational Safety and Health Administration (OSHA) frequency standard. This standard compares SDG&E's regulated OSHA-reportable lost time and non-lost time injuries and illnesses to SDG&E employee working hours, as adjusted for personnel changes due to the approved merger between Enova and Pacific Enterprises. The settlement agreement recommends the following parameters:

Benchmark: OSHA-reportable rate of 8.80

Deadband: +/- 0.20

Liveband: +/- 1.20

Unit of change: 0.01

Incentive per unit: $25,000

Maximum incentive: +/- $3 million

Reliability Performance Indicators

Reliability is measured by various benchmarks which apply to SDG&E's facilities and exclude planned outages and major events (as defined in D.96-09-045).[7] These benchmarks include the System Average Interruption Duration Index (SAIDI), the System Average Interruption Frequency Index (SAIFI), and the Momentary Average Interruption Frequency Index (MAIFI).

The following measures are recommended for the SAIDI:

Benchmark: 52 minutes (excluding underground cable failures) for each year 1999, 2000, 2001. 73 minutes (including underground cable failures) for 2002.

Deadband: 0

Liveband: +/- 15

Unit of change: 1

Incentive per unit: $250,000

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[7] Any events that are the direct result of failures in the Independent System Operator (ISO) controlled bulk power market or non-SDG&E owned transmission facilities are excluded from these reliability benchmarks. In addition, D.96-09-045 defines excludable major events as events caused by earthquake, fire, or storms of sufficient intensity to give rise to a state of emergency being declared by the government or any other disaster that affects more than 15% of the system facilities or 10% of the utility's customers, whichever is less for each event. (D.96-09-045, mimeo. at Appendix A, p. 2.)

Maximum incentive: +/- $3.75 million

The following measures are recommended for the SAIFI:

Benchmark: 0.90 outages per year

Deadband: 0

Liveband: +/- 0.15

Unit of change: 0.01

Incentive per unit: $250,000

Maximum incentive: +/- $3.75 million

The following measures are recommended for the MAIFI:

Benchmark: 1.28 outages per year

Deadband: 0

Liveband: +/- 0.30

Unit of change: 0.015

Incentive per unit: $50,000

Maximum incentive: +/- $1million

Customer Satisfaction Performance Indicator

SDG&E's Customer Service Monitoring System (CSMS) indicator measures overall customer satisfaction with recent service transactions. The proposed CSMS measure is recommended with the following parameters:

Benchmark: 92.5% very satisfied

Deadband: +/- 0.5%

Liveband: +/- 2.0%

Unit of change: 0.1%

Incentive per unit: $75,000

Maximum incentive: +/- $1.5 million

Call Center Responsiveness Performance Indicator

This performance indicator measures SDG&E's responsiveness to customer telephone inquiries. The settlement agreement recommends the following parameters:

Benchmark: 80% of calls answered in 60 seconds, as measured on an annual basis

Deadband: 0

Liveband: +/- 15%

Unit of change: 0.1%

Incentive per unit: $10,000

Maximum incentive: +/- $1.5 million

No standard is recommended for emergency calls at this time.

Service Guarantees

The settling parties recommend that certain service guarantees be implemented but agree that in order to provide adequate time for implementation, SDG&E will begin these guarantees approximately two months after the issuance of this decision, but no sooner than April 1, 1999.

SDG&E makes appointments for services when access is required to the customer's premises and the customer requests to be present. These appointments may be set for a four-hour window when requested by customers or they may be set for a particular day. If SDG&E is not able to meet the appointment commitment, the customer's account will be credited with $50. However, if the customer is notified at least four hours before the end of the appointment period, SDG&E is excused from applying the credit. For establishment of service (turn-on orders), the customer will be credited with the applicable service establishment charge ($15 or $30) rather than $50. This guarantee does not apply to gas pilot light appointments, or if SDG&E documents that the service person missed the appointment due to natural disaster, labor strike or was called to work on an Emergency Order, including fire or explosion, broken or blowing gas line, high pressure gas, emergency carbon monoxide, and hazardous leaks. Emergency Orders are excluded from this guarantee, due to SDG&E's public safety obligations.

When a customer requests a date for a permanent new service establishment, SDG&E will turn on the new service on the day promised (prior to midnight) or credit the customer's account with the service establishment charge ($15 for electric service; $30 for both gas and electric service). The credit will not apply if at least 24 hours' notice of a date change is provided to the customer. Notice provided by message left on an answering machine or voice mail is sufficient. For the guarantee to be valid, there must be open access to the facility and the meter panel or gas service; all required inspections must be completed and approved; there must be no threats of harm to employees; and credits will be paid only when the customer is currently without service. SDG&E agrees to develop a centralized complaint tracking system and will provide annual reports to the Commission and to settling parties on results achieved.

Discussion of Settlement on Performance Indicators

This is an "uncontested settlement" as defined in Rule 51(f), i.e., a settlement that "…is not contested by any party to the proceeding within the comment period after service of the stipulation or settlement on all parties to the proceeding." Rule 51.1(e) requires that settlement agreements must be reasonable in light of the whole record, consistent with the law, and in the public interest.

D.92-12-019 considered a settlement of the SDG&E 1993 General Rate Case. In that decision, the Commission outlined four criteria that must be satisfied in order for the Commission to approve an all-party settlement. The proposed settlement must specify:

> "a. that it commands the unanimous sponsorship of all active parties to the instant proceeding;
>
> "b. that the sponsoring parties are fairly reflective of the affected interests;
>
> "c. that no term of the settlement contravenes statutory provisions or prior commission decisions; …and
>
> "d. that the settlement conveys to the commission sufficient information to discharge our future regulatory obligations with respect to the parties and their interests." (D.92-12-019, 46 CPUC2d 538, 500-551 (1992).)

We are satisfied that the proposed settlement commands the sponsorship of all active parties sponsoring testimony on performance indicators. The sponsoring parties reflect a broad spectrum of affected interests. ORA represents ratepayers in general, while UCAN represents residential and small commercial ratepayers in particular. Large customers, governmental interests, and agricultural customers are represented by FEA, City of San Diego, and Farm Bureau. CCUE represents the interests of utility employees in reliability and safety issues. NRDC considers the effects of such determinations upon the environment and SDG&E obviously considers the impact of the settlement on its shareholders. Considering the thorough review of SDG&E's proposals and the broad spectrum of interests supporting the proposed settlement, we are satisfied that sponsoring parties fairly reflect the affected interests.

The settlement is reasonable in light of the whole record and does not contravene any statute or prior Commission decision. SDG&E submitted extensive testimony and workpapers supporting its recommended revenue requirement increases. Similarly, ORA and UCAN conducted thorough investigations and analysis of SDG&E's request and developed their own recommendations. FEA, CCUE, and NRDC also submitted testimony addressing performance indicators.

Thus, the extensive testimony served by the settling parties provides sufficient information to the Commission to properly judge the reasonableness of the settlement and to discharge its future regulatory responsibilities. Parties have included a comparison exhibit, pursuant to Rule 51.1(c), which allows us to compare original positions to the proposed settlement amounts. The settlement is the result of the parties compromising and reaching agreement on their widely divergent positions, resulting in agreement on performance indicators related to safety, reliability, customer satisfaction, call center responsiveness, and service guarantees related to missed appointments and new installations.

SDG&E can earn or lose a maximum of $14.5 million from the rewards and penalties associated with performance indicators. We are satisfied that this settlement is in the public interest and avoids costly litigation on these issues. We will make specific findings related to the proposed reporting requirements, which we discuss in the section addressing timing of reports, term of the PBR mechanism, and comprehensive reviews.

SDG&E's Proposal

SDG&E proposes to establish a completely new PBR mechanism for the period 1999-2002, but with the preference that this PBR mechanism would be perpetual. SDG&E proposes a rate index PBR, i.e., rates would be directly adjusted each year for escalation and a productivity offset. Rather than the usual sharing mechanism in which amounts to be shared are flowed back to ratepayers as a one-time adjustment, SDG&E proposes to use the sharing mechanism to adjust the starting point from which future rates are calculated. SDG&E characterizes this mechanism as a self-calibrating rate mechanism, in which information on the results of one year's performance is used to adjust the starting point for setting rates in future years. SDG&E argues that its proposed PBR mechanism should be evaluated in light of balancing all components of the mechanism. Although its parent company recently merged with Pacific Enterprises (the parent of SoCalGas), SDG&E states that SoCalGas' PBR design components are not applicable.

Rate Indexing

The rate indexing mechanism is captured in the following formula:

$Rate_{(n)} = (Rate_{(n-1)} * (1+ Esc - X)) + \text{or} - Z$

where Rate = electric distribution rate component or gas base rate component;

n = year for which rates are being determined

Esc = escalation or inflation factor

X = productivity factor; and

Z = exogenous factors to be either added or subtracted

SDG&E argues that a rate indexing mechanism is simpler and more direct than either a revenue requirement indexing mechanism or a revenue-per-customer indexing mechanism. Each rate component is adjusted annually according to the above formula. A revenue requirement indexing formula applies an index to a total revenue requirement. The resulting revenue requirement is then used to establish rates through use of a forecast of kilowatt hours or therms delivered. Balancing accounts are used to true-up the revenue amount when subsequent actual volumes do not match. These mechanisms often include a component to account for customer growth. A rate mechanism usually does not include such a component and applies an indexing formula directly to rates.

SDG&E argues that a rate indexing mechanism is appropriate because the Commission has eliminated the Electric Revenue Adjustment Mechanism (ERAM), which was the balancing account used to true-up the revenue requirements for recorded sales versus forecast sales on the electric side. SDG&E also proposes to eliminate the Gas Fixed Costs Account (GFCA) as of the beginning of 1999. If both of these accounts are eliminated and a rate indexing mechanism is used, SDG&E asserts that it is now subject to the risk of variations in delivery quantities. If actual delivered throughput (whether kilowatts or therms) differs from the throughput used to determine the initial starting rate, SDG&E will either gain revenue through greater sales or lose revenue if sales are less than forecast. Because there is no adjustment for customer growth, SDG&E is at risk to recover the costs of new customers out of the revenue stemming from the increases in volumes delivered.

Escalation

As described in Exhibit 74, SDG&E's proposed escalation measure is based on historical and forecasted industry-specific data, published quarterly. Separate escalation factors are used for electric and gas. Each proposed index is designed to measure changes in price levels of labor, nonlabor and capital inputs purchased by utilities. SDG&E asserts that this methodology is superior to using a national aggregate price index, such as the CPI, because these CPI-type indices are not designed to provide a framework for analyzing changes in the price level of inputs purchased by utilities, but measure economy-wide changes in the price level of goods and services.

The base rate cost indices proposed by SDG&E are composed of national-level utility-specific cost indices obtained from the Standard & Poor's DRI/McGraw-Hill Economic and Utility Cost Forecasting Services (DRI). The component national level utility cost indices are combined into base rate cost indices using expenditure weights developed from historical expenditures by electric and gas utilities located in California. SDG&E explains that the base rate cost indices are designed to measure changes in the price level of inputs that California electric distribution and gas utilities purchase to operate and maintain public utility assets.

This cost escalation proposal is generally based on the methodology adopted for SoCalGas in D.97-07-054. SDG&E proposes to use average hourly earnings for electric, gas, and sanitary services as the basis for its labor cost index for both electric distribution and gas. Historical data is reported by the United States Bureau of Labor Statistics (BLS) and this data forms the basis of the DRI labor cost index referred to as AHE49NS. Forecasts of this index are readily available from DRI. The proposed labor cost index differs slightly from that adopted for SoCalGas, which is based on two indices.

The proposed index for electric distribution nonlabor O&M expenses utilizes five DRI cost indices: total distribution plant O&M cost index (JEDOMMS), customer accounts operation cost index (JECAOMS), customer service and information operation cost index (JECSIIOMS), sales operation cost index (JESALOMS), and total administrative and general O&M cost index (JEADGOMMS). SDG&E proposes to use the DRI total gas utility nonlabor O&M cost index (JGTOTALMS), the same index adopted for SoCalGas.

The proposed cost index for capital-related electric distribution costs is based on an estimate of the rental price of electric distribution utility structures, which is estimated from three data series obtained from DRI: rental price of capital - nonresidential structures-public utilities (ICNRCOSTPU); chain type price index - investment in nonresidential structures - public utilities (PCWICNRPU), and the Handy-Whitman electric utility construction cost index - total distribution plant, Pacific Region (JUEPD@PCF). All of these indices are obtained from DRI. The proposed cost index for capital related gas costs is based on an estimate of the rental price of gas utility structures, which is estimated from three data series obtained from DRI: rental price of capital - nonresidential structures-public utilities (ICNRCOSTPU); chain type price index - investment in nonresidential structures - public utilities (PCWICNRPU), and the Handy-Whitman gas utility construction cost index-total plant, Pacific Region (JUG@PCF).

While the fundamental basis of the capital-related cost indices is the same as that adopted for SoCalGas, SDG&E proposes to use a three-year moving average of the rental price of utility structures to calculate the capital-related cost indices. SDG&E believes this approach reduces the volatility related to rental prices of public utility structures which means that annual changes in the base rates escalated with these indices are less variable.

The cost indices for electric distribution and gas base rates are each a weighted average of the component cost indices for labor, nonlabor, and capital-related expenses, as described above. The weights used to construct the weighted average are based on average state-level electric distribution expenditures or gas utility expenditures expressed in real 1996 dollars for the period 1992-1996. The annual adjustments for electric distribution base rates average 1.9% per year from 1993 through 1996 compared to average projected adjustments of 1.2% per year from 1997 through 1999. The annual adjustments for gas base rates average 2.5% per year from 1996 through 1996 compared to an average projected adjustment of 1.9% per year from 1997 through 1999.

SDG&E's escalation proposal has not been challenged. Starting in the year 2000, SDG&E proposes to use the percentage changes in the base rate cost indices in the rate indexing formulae to adjust the electric distribution and gas base rates for changes in the cost of inputs purchased by the utility. Exhibit 28 demonstrates that electric escalation is forecasted to average 1.2%, which is 120 basis points below the CPI, which ORA forecasted to average 2.4% over the 1997-2002 time period.

SDG&E will continue to rely on the Market Indexed Capital Adjustment Mechanism (MICAM) to true-up the cost of capital in base rates for significant changes in nominal interest rates. SDG&E explains that the capital-related cost indices provide a basis for partial annual adjustments to base rates for changes in the cost of capital. These partial adjustments would only affect base rates in years when MICAM is not triggered. MICAM adjustments are only made after interest rates change by 100 basis points or more from the previous benchmark.[8] In years when a MICAM adjustment is triggered, the annual cost of capital adjustments embedded in the PBR cost escalation proposal would be trued up to the MICAM adjustment cost of capital.

Productivity Factors

SDG&E proposes to apply a 0.92 productivity factor for electric distribution and a 0.68 productivity factor for gas. These factors were developed from a national utility industry study conducted by Christensen Associates, which developed Total Factor Productivity (TFP) indices. A TFP index measures the ratio of its output quantity index to its input quantity index. It compares the growth trend in the unit cost of the industry to the trend in prices of labor, capital services, and other production inputs.

SDG&E argues that an industry-wide study is appropriate to develop productivity factors because this approach is comparable to the operation of competitive markets. SDG&E states that this study was undertaken in response to the Commission's direction in D.96-09-092, the Edison PBR decision:

> "The price and productivity values should come from national or industry measures and not from the utility itself. … The productivity measure should come from a forecast of industry-specific productivity." (D.96-09-092, mimeo. at p. 15.)

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[8] Interest rates are measured by averaging the yield on a single-A utility bonds over a six-month period from April to September.

Despite the fact that its proposed productivity factors are less than those adopted for any other energy utility, SDG&E asserts that no stretch factor is necessary. A stretch factor is an addition to the productivity factor to ensure that the utility to which it is applied is indeed "stretching" to achieve efficiency gains. SDG&E argues that the use of a stretch factor is only appropriate when there is a change from traditional ratemaking to PBR, when there is the presumption that significant efficiency gains may be realized, or when there is uncertainty about the level of an appropriate productivity factor. In SDG&E's view, none of these circumstances apply. SDG&E also argues that because the earnings sharing calibration guarantees any gains will benefit customers in future years, the calibration approach is essentially a stretch factor. Finally, SDG&E urges us to consider its proposed productivity factors in conjunction with the proposed escalation methodology. SDG&E contends that using a utility-specific inflation index makes achieving productivity gains more difficult because the update rule will result in a lower figure than if a different measure of inflation were used.

Earnings Sharing

SDG&E's proposed symmetrical earnings sharing mechanism is designed to incorporate a self-calibrating feature to the rate setting formula. Rather than providing customers with a one-time adjustment based on the outcome of the sharing mechanism, SDG&E proposes to adjust the next year's indexing of rates. The actual net operating income is compared to that of the authorized rate of return. The difference is then subject to earnings sharing. The proposed mechanism contains a symmetrical 100-basis-point deadband, i.e., shareholders are responsible for the first 100 basis points (1%) over or under the authorized rate of return. Outside the deadband, in the liveband, 20% of any gains or losses is flowed through to the customer through an adjustment to the next year's rates.

The deadband is designed to account for gains and losses associated with routine operation of the company. SDG&E acknowledges that its proposed deadband is larger than that adopted for either Edison (50 basis points around Edison's authorized return on equity) or SoCalGas (25 basis points above SoCalGas' authorized rate of return). SDG&E argues that its deadband should be wider than Edison's because 1) short-run temperature-based sales fluctuations are more volatile for gas customers than electric customers, 2) the deadband should account for changes in throughput resulting from electric industry restructuring, and 3) removing generation and transmission from the PBR means that the earnings sharing component operates on lower overall net operating income. Because SoCalGas did not eliminate the Core Fixed Cost Account, SDG&E contends that the Commission explicitly adjusted SoCalGas' deadband downward to account for the reduced risk of routine operations. SoCalGas' deadband is also adjusted to account for a declining rate base.

SDG&E explains that the self-calibrating nature of its proposed sharing mechanism justifies the low 20% it proposes to "share" with customers. According to SDG&E, the 20% adjustment in rates would be carried forward indefinitely and would compound through the term of the PBR mechanism. The savings compound over time, because the prospective adjustments to rates are permanent. SDG&E maintains that such adjustments ensure that shareholders and ratepayers won't have to pay taxes on the difference between what would have been collected under more traditional earnings sharing mechanisms and the proposed mechanism. SDG&E admits that the power of the earnings sharing mechanism is inextricably tied to the term of the mechanism. The proposed sharing rate of 20% of actual returns above deadband is associated with the proposed five-year initial term for the mechanism. Due to the compounding effect, if a longer term were adopted, SDG&E states that a lower sharing percentage would achieve the same effect. If a shorter term were adopted, a higher sharing percentage would be required to achieve the same impact. SDG&E recommends that the sharing mechanism be symmetrical, i.e., any losses outside of the deadband would be reflected in permanent increases in rates using the same self-calibrating approach.

SDG&E believes that a "utility's best incentive to pursue productivity-enhancing investments would be to allow the utility to retain 100% of the benefit of those investments." (Exhibit 8, p. PBR5-5.) While acknowledging that this approach is unlikely to be implemented, SDG&E recommends that a symmetrical sharing mechanism with a reasonably large deadband makes sense according to economic theory and in terms of equity because the deadband is sized to the amount of risk absorbed by the utility and still allows customers to share in the efficiency gains. Thus, the proposed earnings sharing mechanism is neither progressive nor regressive. While recognizing that the bulk of the benefits accrue to the utility, SDG&E believes this is counteracted by compounding the customers' share of the gains in future years.

Z factor and Exclusions

SDG&E recommends that the nine criteria adopted for Z-factor treatment in Edison's and SoCalGas' PBR be applied to its proposed mechanism.

Pursuant to the cost of service settlement adopted in D.98-12-038, certain costs will not be included in the PBR mechanism, but are subject to other forms of ratemaking. Tree-trimming expenses are not included in the PBR sharing mechanism, but are subject to a one-way balancing account. For the duration of the PBR period, revenues and incurred expenses for tree trimming will be excluded from the indexing mechanism and from recorded base rate revenue expenses before SDG&E calculates its actual earned rate of return for revenue sharing purposes.[9] In addition, costs attributable to senior executive retirement plans or executive bonuses are also excluded from the indexing mechanism and from earnings sharing during the PBR period. The costs for the Natural Gas Vehicle (NGV) program will be excluded for the year 2000 update rule because they are recovered under the NGV balancing account, which is expected to be eliminated at the end of 2000. Future costs related to the Catastrophic Event Memorandum Account (CEMA) and the Gas Hazardous Substance Cost Recovery Account will be recovered through those respective balancing accounts, not through the PBR.

Offramps

SDG&E proposes to retain the offramps existing in its base rate PBR mechanism. There is a voluntary offramp at 150 basis points below the authorized rate of return and a mandatory review of the mechanism if SDG&E's actual rate of return varies by 300 basis points from the authorized rate of return.

SDG&E does not propose a new mechanism to update for changes in the cost of capital. SDG&E's current cost of capital mechanism, the MICAM, is

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[9] If SDG&E achieves and documents a 50% reduction in tree-trimming expenses from its 1999 budget, SDG&E may request termination of balancing account treatment.

proposed to continue unless changed by the cost of capital proceeding which is to be filed in May 1998.[10] The results of that proceeding will be incorporated into the 1999 starting point rates. Changes resulting from the MICAM or any subsequent mechanism will be incorporated in future annual indexing changes.

Elimination of the Gas Fixed Cost Account (GFCA)

SDG&E proposes to eliminate the GFCA as it applies to SDG&E's gas base costs as of the beginning of 1999. SDG&E maintains this approach is consistent with Commission policy and with its proposed establishment for rate indexing. On the electric side, ERAM was eliminated in D.97-10-057. SDG&E explains that there is no reason to track differences between forecasted and actual sales with a rate index PBR mechanism.

ORA's Proposal

ORA agrees that a rate indexing mechanism should be adopted, but otherwise prefers a PBR mechanism modeled after SoCalGas' PBR. ORA proposes that a stretch factor be added to SDG&E's proposed productivity factors, that a 25-basis-point deadband be adopted, and that a progressive sharing mechanism similar to SoCalGas' be adopted. ORA contends that there is little evidence to support the workings of SDG&E's proposed self-calibration mechanism, which has not been adopted by any other public utilities commission in the United States.

[10] SDG&E's cost of capital application was filed in May 1998. A decision in that proceeding is expected in the Spring of 1999.

ORA recommends that a stretch factor of 100 basis points be applied to the productivity factors proposed by SDG&E. ORA points out that all other energy utilities operating under a PBR mechanism have stretch factors incorporated within their productivity factors. ORA dismisses SDG&E's use of the results of the Christensen Associates' study of the productivity of a national sample of utilities, which recommends a .92% productivity factor for electric and .68% for gas operations. ORA reminds us that the component utilities in this study consisted largely of utilities subject to traditional cost of service regulation. ORA contends that basing an average productivity factor on utilities under such traditional regulation results in only an average productivity factor, which is not appropriate to be applied to SDG&E. ORA recommends that we consider a paper prepared by the National Economic Research Associates (NERA) (Reference Item G). This study found that the average total factor productivity of electric utilities increased by 2.08% per year over the period 1984-1994, which is even greater than the 1.94% ORA proposes for electric operations.

While ORA admits that the mechanics of SDG&E's proposed escalation methodology may result in more challenging productivity improvements, ORA submits that this effect is irrelevant. ORA recommends that use of a utility-specific inflation index is appropriate because it reflects the actual inflationary pressures experienced by the distribution utility, rather than a more broadly based measure that reflects the performance of all sectors of the economy.

ORA asserts that SDG&E's proposed mechanism is inequitable and continues the results of the base rate PBR. In ORA's view, the fact that SDG&E was able to earn approximately $130 million above its authorized rate of return over the past four years, with ratepayers receiving approximately $11 million, is evidence that the previous PBR mechanism was overly generous to shareholders. ORA believes that a more equitable mechanism would have shared the $130 million equally between shareholders and ratepayers. ORA explains that the majority of the $130 million accruing to shareholders came from earnings within SDG&E's deadband. ORA fears that the wide deadband proposed by SDG&E in this proceeding could lead to similar results. Thus, ORA recommends that a 25-basis-point deadband be adopted for SDG&E, identical to that adopted for SoCalGas.

While ORA supports a rate indexing mechanism because this approach sends the proper signals to utility management to control costs of operation, ORA also recommends that any excess earnings above the authorized rate of return be used to accelerate the recovery of transition costs. Under ORA's proposal, these excess earnings would be credited to the Transition Cost Balancing Account (TCBA). "ORA does not believe that increasing electric sales should lead to higher profits for SDG&E absent some improved corporate performance that accompanies those increased sales." (ORA opening brief, at p. 14.)

ORA recommends the same progressive sharing approach adopted for SoCalGas. ORA maintains that this approach correctly aligns shareholder and ratepayer interests by awarding an increasingly higher proportion of earnings above the authorized rate of return to shareholders when SDG&E achieves more difficult efficiencies and cost savings.

ORA supports SDG&E's proposed Z-factor treatment, but also urges us to apply Z-factor treatment to Postretirement Benefits Other than Pensions (PBOPs). According to ORA, several decisions state that PBOP costs shall be recovered through a Z-factor adjustment in annual filings. If this approach is not adopted, ORA is concerned that unreasonable windfall profits will accrue to utility shareholders. ORA contends that the Z-factor ratemaking approach for PBOPs applies to energy utilities as well as telecommunication utilities.

ORA supports SDG&E's proposal to eliminate the GFCA, but recommends that it be terminated as of April 30, 1999, which is the date that coincides with the ending month of the account's annual cycle. The GFCA records the difference between authorized base revenue requirement and recovery of base revenues plus other charges related to the transportation and delivery of gas. The Commission authorizes the base revenue requirement and a recovery rate based on predicted volumes or gas sales as part of SDG&E's Biennial Cost Allocation Proceedings (BCAP). The purpose of the GFCA is to track expenses and revenues over an annual cycle and the account's over- or undercollection at the end of the cycle depends on how closely actual sales match forecasted sales.

ORA is concerned that SDG&E's proposal to terminate the account as of January 1, 1999 would result in considering only a partial yearly cycle for this last year, which would result in SDG&E accruing an undercollection of as much as $8 million, which would then have to be collected from ratepayers. This effect occurs because residential heating loads cause monthly revenues to accrue to the GFCA in a consistent annual pattern. Revenues collected December through March exceed recorded expenses, while revenues collected April through November are not equal to expenses. Therefore, the account's balance is generally closer to zero at the end of the winter heating season, and ORA recommends that this account be terminated at that time.

UCAN's Proposal

UCAN believes that a PBR mechanism must demonstrably benefit customers and should be designed to put downward pressure on rates. UCAN argues that the PBR mechanism should model competition where it does not exist and that the interests of the ratepayers are a critical consideration in approving a PBR proposal.

UCAN recommends that a revenue-per-customer index method be adopted for a PBR mechanism to last five years, expiring at the time when the merger savings mechanism expires. UCAN asserts that the revenue-per-customer methodology counters SDG&E's incentive to increase sales, is consistent with Christensen Associates' study of productivity estimates, avoids the problem of windfalls accruing to SDG&E, and sends proper signals regarding costs, i.e., to reduce utility energy service costs per customer. UCAN explains that the revenue-per-customer approach can be implemented using recorded data, although it agrees that a demand forecast is necessary for purposes of retaining the GFCA.

UCAN asserts that a PBR mechanism must distinguish between monopoly and competitive services and therefore recommends that three separate PBR mechanisms be adopted. UCAN asserts that under a single PBR mechanism, SDG&E could cross-subsidize efficiency losses in one area with gains in another and recommends that the PBR mechanisms should be separately unbundled into electric wires, electric metering and billing, gas pipes, and gas metering and billing.

UCAN believes that SDG&E's proposed productivity factors are too low. UCAN states that SDG&E's current productivity level is 1.5% and should not be decreased to .92% on the electric side. UCAN explains that an X factor or an indexing method should be selected so that ratepayers are at least as well off under PBR regulation as they would have been under traditional ratemaking. Because SDG&E's electric revenues will increase more rapidly than the increase in the number of customers as throughput per customer grows, UCAN asserts that SDG&E's revenues are weighted towards throughput. Therefore, Christensen Associates' model which is based largely on number of customers served is inappropriate.

UCAN agrees that a "base" productivity factor of 0.92% for electricity and 0.68% for gas, assuming revenue per customer, is appropriate. UCAN also recommends that a stretch factor be applied to these base figures and argues that stretch factors are appropriately applied to industries facing competitive pressure. UCAN recommends a stretch factor of 0.75% for electric and gas distribution and 1.00% for metering and billing, because communications technologies and impacts of competition are improving productivity more rapidly. As adjusted for issues addressed by the cost of service settlement and to remove one-time costs, as demonstrated in Exhibit 32, updated by Exhibit 33, UCAN proposes a productivity factor of 1.9% for the PBR applying to electric wires (electric distribution), 2.0% for the PBR applying to electric and gas metering and billing, and 2.2% for the PBR applying to gas pipes (gas transmission and distribution).

UCAN believes that it is critical to adopt a similar sharing mechanism as is established for SoCalGas. UCAN asserts that SDG&E and SoCalGas share gas service persons, customer service functions and allocate common administrative and general (A&G) costs. Therefore, UCAN agrees with ORA that a progressive earnings sharing mechanism similar to SoCalGas' should be adopted, with a 25-basis-point deadband for electric and gas distribution and no sharing of losses, but recommends that the GFCA be retained.

UCAN recommends a different deadband for electric and gas metering and billing functions. UCAN proposes that a deadband of after-tax profits above the benchmark rate of return equal to 1% of total metering and billing revenues be used for earnings sharing in the proposed metering and billing PBR. UCAN explains that this figure is approximately equal to the combined electric and gas distribution deadbands as a percentage of revenue and reflects the GFCA.

UCAN recommends that ratepayers receive 70% of incremental sharing immediately above the deadband, which would decline linearly to a 10% ratepayer share at 300 basis points above the benchmark, or 10% of revenue for metering and billing. This approach would encourage savings by SDG&E while ensuring that ratepayers obtain significant sharing over a wide range of outcomes.

UCAN recommends that the GFCA be retained because gas sales fluctuations are largely weather driven. More importantly, UCAN believes that eliminating the GFCA creates perverse incentives under any PBR mechanism, but particularly under SDG&E's calibrated sharing mechanism. According to UCAN, very cold weather could increase sales and result in a large cash surplus accruing to SDG&E, which must then be spent or returned to customers. UCAN maintains that this perverse incentive prompts SDG&E's proposal to implement a wide deadband, but argues that retaining the GFCA eliminates risk and has the advantage of narrowing the deadband required by SDG&E.

UCAN agrees that Z factors should be limited to those costs successfully meeting the nine criteria adopted for Edison and SoCalGas. UCAN proposes limited Z factors and offramps and maintains that public purpose programs should be excluded from PBR treatment, as well as direct access costs, pensions, premium payments made by affiliates for labor transfers and intellectual property, generation-related franchise fees, and nonrecurring costs. UCAN asserts that we should also consider reopening the PBR structure in the event that significant changes are made to the responsibility of the utility for providing services or equipment. UCAN argues that the 150-basis-point voluntary offramp should be removed, but that the 300-basis-point offramp be expanded to 400 basis points.

FEA's Proposal

FEA recommends a rate index similar to that in place for Edison. FEA believes that a rate index is logical and straightforward and opposes a revenue-per-customer approach. FEA contends that the proposed productivity factor for electric operations is too low and recommends a Multi-Factor Productivity (MFP) analysis yielding a productivity factor of 1.17%.

FEA prefers Edison's progressive sharing mechanism based on return on equity, but does not oppose the use of SoCalGas' progressive sharing based on a benchmark rate of return. FEA asserts that SDG&E's proposed deadband is too wide and would allow SDG&E to reap substantial benefits. FEA explains that this proposed deadband is equivalent to $24 million in revenues and $14.5 million in operating income, assuming a tax rate of 40%. While acknowledging that the deadband encompasses both gains and losses, FEA is concerned that the first $14.5 million of benefits (or losses) would go to shareholders before customers see any benefits. FEA assumes that since the PBR is designed to encourage improvements in productivity, SDG&E would tend to seek out efficiencies and earn in excess of its benchmark rate of return, all things being equal.

FEA points out that the deadbands for other mechanisms are significantly more narrow than 100 basis points. Edison has a PBR with an earnings sharing deadband of 50 basis points above or below authorized return on equity. Since equity comprises approximately 50% of SDG&E's capital structure, a 50-basis-point deadband on return on equity translates to a 25-basis-point deadband on authorized rate of return. The SoCalGas earnings sharing deadband is 25 basis points above the benchmark rate of return, but has no similar deadband for losses.

FEA believes SDG&E's proposed 20% calibration mechanism is inequitable to customers. FEA recommends a progressive sharing mechanism, as is currently in place for both Edison and SoCalGas. FEA asserts that this progressive structure is more reasonable because it provides customers with the benefit of most of the initial savings gains, which are those most easily accomplished. As more difficult efficiency gains are achieved, shareholders appropriately retain more earnings.

FEA believes that the self-calibrating mechanism benefits customers only in circumstances where there is a large one-time savings which is not repeated in subsequent years. As Exhibit 6 demonstrates, FEA expects that productivity benefits would compound over time. FEA doubts the tax savings benefit of the self-calibration mechanism alleged by SDG&E. FEA maintains that for tax purposes, it is immaterial whether the utility makes a one-time refund to ratepayers or reduces rates by the same amount.

FEA states that Exhibits 100 and 101 demonstrate that the Edison and SoCalGas PBR mechanisms are more favorable to customers than the SDG&E proposed approach. SDG&E's mechanism benefits consumers where earnings are below the authorized rate of return, which is contrary to PBR expectations.

NRDC's Proposal

NRDC recommends that a revenue-per-customer indexing mechanism be adopted, rather than a rate indexing approach. NRDC contends that SDG&E's proposed approach creates perverse incentives, because it would reward SDG&E for load building and sales increases. As demonstrated in Exhibit 24, a 2% sales increase results in an $11.8 million increase in revenues, which approximates a 5% increase in profits. NRDC maintains that because a rate indexing mechanism creates penalties (in terms of reduced profits) for reduced sales, this approach would create a disincentive for SDG&E to pursue energy efficiency and other demand-side management (DSM) measures. NRDC explains that the utilities will have a continued role in administering DSM programs until the end of 1999 and may continue to act as contract administrators after that time. NRDC asserts that such disincentives could lead to discouraging affiliates from investing in energy efficiency or promoting energy consuming appliances, as has occurred for other utility distribution companies. For these reasons, NRDC predicts that a rate indexing mechanism will have adverse environmental impacts.

NRDC therefore supports UCAN's proposal for a revenue-per-customer indexing methodology. For electricity, the rates in the current period would be adjusted for three factors in order to determine rates for the next period. First, current period rates would be multiplied by the update rule (i.e., 1+ escalation - X). Second, this result would be multiplied by customer growth (1 + customer growth). Third, this result is divided by (1 + growth in weather adjusted sales per customer). The revenue-per-customer methodology requires deriving two calculations: customer growth and weather-adjusted sales per customer, which can be obtained from recorded data. NRDC notes that this approach is similar to that adopted for SoCalGas.

NRDC observes that certain concerns were expressed in Edison's PBR proceeding regarding the revenue requirement indexing approach, which included the need for controversial sales forecasts or balancing accounts, the need for customer forecasts, incremental cost forecasts, and growth allowances, which are all eliminated in the revenue-per-customer mechanism. While acknowledging ORA's support for the rate indexing approach, NRDC explains that ORA criticizes the "windfall profits" SDG&E stands to benefit from under this approach and ORA proposes that earnings above the authorized rate of return be applied to the TCBA to pay off transition costs as quickly as possible. (Exhibit 24, p. 1-8.)

NRDC also recommends that a distributed resources performance indicator be adopted. Distributed resources are also known as distributed generation. On December 17, 1998, we instituted Rulemaking (R.) 98-12-015, in which we defined distributed generation as follows:

> "Also referred to as 'distributed energy resources' (DER) or 'distributed resources' (DR). [Distributed generation] generally refers to generation, storage, or demand-side management (DSM) devices, measures, and/or technologies that are connected to or injected into the distribution level of the transmission and

> distribution (T&D) grid (i.e., "below" the bulk power transmission system). Micro-turbines, fuel cells, photovoltaics, wind turbines, and flywheels are some examples of [distributed generation] technologies. Because these devices are more modular and flexible than a large central power station, they can be located at the customer's premises on either the system side or the customer side of the meter, or at other points in the distribution system such as a UDC substation. [Distributed generation] covers a wide range of technologies and is not exclusively limited to cogeneration." (R.98-12-015, mimeo. at p. 2.)

Because distributed generation has the potential to offer significant environmental and economic benefits and because the UDCs may have an important role to play in facilitating the use of these resources, NRDC advocates implementing a performance indicator rewarding SDG&E for such facilitation. NRDC maintains that SDG&E has no incentive to facilitate the use of distributed generation under current regulation and would have a disincentive to encourage distributed generation under a rate index. Even under a revenue-per-customer approach, NRDC believes that SDG&E would be neutral in encouraging use of distributed generation technologies. Therefore, NRDC recommends implementing a performance indicator which applies a reward or penalty of $3 million to provide the necessary incentive. NRDC proposes that this performance indicator be adopted in the PBR proceeding, but that details of the performance indicator be developed in the rulemaking. NRDC recognizes that it is somewhat unusual to propose such a placeholder, but asserts that it is important to do so now rather than wait until the term of this PBR has expired to develop such an incentive mechanism.

City of San Diego's Proposal

In its opening brief, City of San Diego supports a rate indexing mechanism, but recommends that a stretch factor be incorporated into SDG&E's proposed productivity factors. City of San Diego points out that a margin should be included in the productivity factors to protect consumers from inexact forecasts of future productivity trends and recommends that SDG&E be encouraged to stretch beyond the amount of historical productivity in the utility industry, which is one of the main purposes of PBR regulation. City of San Diego recommends comparable productivity factors to those adopted to Edison and SoCalGas: 1.2%, 1.4%, and 1.6% on the electric side and 1.2%, 1.3%, and 1.4% on the gas side. These values represent a midway position between the high and low proposals in this proceeding. Because SDG&E competes within the same industry within Southern California, City of San Diego believes productivity improvements should be roughly similar.

City of San Diego essentially supports ORA's proposal and recommends that a progressive earnings sharing mechanism similar to SoCalGas' be adopted. City of San Diego asserts that the merged utilities should share the same type of PBR mechanism and thinks consumers in San Diego should benefit from the same type of mechanism enjoyed by consumers in SoCalGas' service territory. City of San Diego prefers SoCalGas' approach over Edison's because ratepayers are insulated from downside risk, i.e., they do not share in losses below the authorized rate of return. However, City of San Diego recommends a 50-basis-point deadband rather than a 25-basis-point deadband because if the GFCA is eliminated, SDG&E is at greater risk from sales fluctuations in gas throughput than is SoCalGas. City of San Diego also believes that SDG&E

should be rewarded for proposing an electric escalation factor based on utility industry inputs which is less advantageous to shareholders.

Monitoring and Evaluation Stipulation

SDG&E and UCAN each submitted recommendations concerning measurement and evaluation of the proposed distribution PBR mechanism. Because the cost of service settlement adopted in D.98-12-038 includes a cost of service review in 2002, these parties were able to reach stipulation on measurement and evaluation issues.

The stipulation proposes that by February 15 of each year, SDG&E will file an annual electric distribution report that addresses the performance indicators and earnings sharing results for the previous calendar year. This report will be filed by advice letter with the Commission's Energy Division. Within 45 days after the end of each calendar quarter, SDG&E will submit quarterly reports to the Energy Division and interested parties that address the 12 months-to-date sharing and year-to-date performance indicator results. SDG&E and UCAN believe that a cost of service review in 2002 precludes the necessity for a comprehensive review. Future evaluative reports will be determined in those cost of service proceedings.

SDG&E and UCAN recommend that performance over the 1999-2001 time frame be reviewed in a timely fashion so that this analysis can be incorporated into the 2002 cost of service proceeding. These parties suggest that the evaluation process begin early in 2001 with a workshop facilitated by the Energy Division. The goals of this workshop would be to develop appropriate evaluative criteria for the review, establish whether an independent review is necessary, and, if so, how it should be conducted.

SDG&E and UCAN suggest that an independent evaluation may be necessary if the Energy Division and ORA indicate that they cannot conduct a timely and comprehensive evaluation of the PBR mechanism. According to the stipulation, the parties would select the independent consultant using a Request for Proposal (RFP) process not to exceed $400,000. SDG&E and UCAN suggest that the cost of this consultant be shared equally between the ratepayers and shareholders. If parties can't agree on a consultant, the Energy Division would select the consultant based on nominations from the parties. The consultant would enter into a contract with SDG&E, approved by the Energy Division. SDG&E would be able to submit its own evaluative report at the same time other parties or the independent consultant submit their reports.

SDG&E and UCAN suggest that the goals of this PBR mechanism should be articulated in this decision and evaluation of the mechanism should be based on these goals.

Discussion

SDG&E recommends a "new and innovative approach" to PBR and incentive regulation. While several PBR mechanisms are in place, we have not developed consistent and rigorous evaluative criteria. Thus, we do not yet have measurable results delineating how incentive ratemaking motivates utility management. We are always open to consideration of a "new and innovative approach" to PBR ratemaking that will serve the public interest and achieve our broadly stated goals related to PBR regulation. However, we are not convinced that the SDG&E proposal is the best approach to meeting our goals.

Rather, we are persuaded that the most reasonable and prudent approach is to model SDG&E's distribution PBR mechanism after that adopted for

SoCalGas where applicable, and for Edison where applicable. ORA, UCAN, and NRDC support the SoCalGas approach as a matter of general principle, as does the City of San Diego. SDG&E's approach is different from both the SoCalGas or Edison approaches, but has elements of both. While we have often stated that "one size does not fit all" in terms of applying PBR mechanisms to California's utilities, the record demonstrates that adopting a mechanism incorporating elements of both PBRs (although not as proposed by SDG&E) allows both the shareholders and the customers to benefit.

The term of the adopted PBR is 1999 through 2002. D.98-12-038 adopted a cost of service settlement, in which parties have agreed that SDG&E must file a 2003 cost of service study no later than December 21, 2001. We affirm that recommendation here. We also make provisions for a comprehensive review, as discussed below. There is no dispute regarding the escalation methodology proposed by SDG&E; therefore, we adopt this methodology. (See Attachment 1.)

While we agree with UCAN that a PBR mechanism must distinguish between monopoly and competitive services, we will not adopt the proposal to establish separate PBR mechanisms for electric wires, electric metering and billing, gas pipes, and gas metering and billing. Although we are exploring the competitive nature of metering and billing services, UCAN's proposal is premature. In addition, this approach would add needless complexity to the PBR mechanism.

However, we recognize it is possible that SDG&E could subsidize efficiency losses in competitive services with gains in monopoly services. Therefore, we will consider this issue during the comprehensive review and will require parties to develop monitoring and evaluative criteria to track such possibilities, as discussed below. Similarly, we are not convinced that a performance indicator for distributed generation should be established at this time. NRDC's proposal is premature. Such performance indicators should be established if we develop a particular approach for distributed generation, as determined in R.98-12-015.

The PBR Indexing Formula

We must choose between two proposals for the indexing formula: a rate indexing formula or a revenue-per-customer formula. We adopt the rate indexing approach. A primary purpose of PBR regulation is to provide the proper incentives to SDG&E management. We assume that SDG&E management will then act on those incentives. The rate indexing approach provides an incentive to increase sales. The revenue-per-customer approach attempts to mute this incentive by eliminating the opportunity to profit from sales increases which do not result from management actions.

However, we prefer a Rate Indexing mechanism for several reasons. First it is a simpler mechanism, requiring fewer calculations and adjustments. Second, it is closer to the Edison mechanism which is more comparable in this instance to the SDG&E situation; the SoCalGas revenue/customer index was substantially dictated by the Global Settlement. Third, the NRDC environmental concerns are being addressed through other policies. SDG&E is required by AB 1890 to spend $32 million/year on demand-side management and energy efficiency programs. SDG&E has been operating under a rate indexing method throughout its PBR experiment; no party represents that SDG&E has failed to put forth appropriate efforts to achieve energy efficiency. There are other related policies implemented for similar environmental purposes; for example, the California Energy

Commission has allocated many millions for renewables credits and other related programs designed to mitigate plant emissions. The rate indexing method also comports with our goal of using PBR mechanisms to assist the utilities in making the transition from a tightly regulated structure to one that is more competitive. We will adopt the rate indexing mechanism and address any potential windfall by an adjustment to the mechanism. While recommending a rate index, ORA also recommends that all excess revenues be used to offset transition costs. ORA proposes this approach because of the concern that SDG&E could earn windfall profits due to a sales increase, but admits that we have rejected this approach in D.97-10-057. ORA also advocates eliminating the GFCA, but proposes delaying its elimination due to concern over another potential windfall because of timing. ORA thus strongly caution us against a potential sales windfall. As discussed below, we will adopt a modification to the sharing mechanism to mitigate against this windfall.

We eliminated the ERAM and Energy Cost Adjustment Clause (ECAC) balancing accounts because of changes in the regulatory environment. Under our adopted PBR, it is also appropriate to eliminate the GFCA, to eliminate balancing account treatment for sales volatility. While SDG&E now argues that a wide deadband is required to absorb the risk of sales volatility, it would be inappropriate to now allow SDG&E a large deadband to essentially absorb the "risk" of sales volatility, when it can generally be expected from historical trends that sales will increase, and under a rate index SDG&E will have an incentive to increase sales when advantageous to shareholders. We will adopt ORA's proposal to terminate the GFCA, however, we must determine the most appropriate date on which to do so.

SDG&E proposed ending the gas margin component of the GFCA on January 1, 1999, and establishing another account for the remaining portions of the GFCA. ORA agreed that the GFCA should be eliminated, but proposed ending the GFCA on April 30, 1999. ORA's position is that the GFCA should be terminated as of whatever month the GFCA began operation to more accurately account for seasonal adjustments. It was later determined during hearings that the GFCA was initially established in May 1988, but that it may have been implemented to close out several other accounts, and there may have been a change in the way the account was calculated in August 1991.

SDG&E opposed during hearings an April 30th termination date simply to avoid "customer confusion" about an additional rate change. SDG&E stated that "… if you look at the way balancing accounts are set up, it doesn't really matter when you terminate the balancing account." (Trans. pg. 247.) However, in its Reply Brief, SDG&E stated that an April 30th termination date would "…harm SDG&E because a revenue shortfall would occur during the first quarter of 1999." (SDG&E Reply Brief, pg. 16.) Later, in its Comments on the Alternate Proposed Decision of Commissioner Bilas, dated March 11, 1999, SDG&E stated that it would not be able to collect its authorized gas revenue requirement in 1999 if the GFCA was eliminated on April 30, 1999. SDG&E stated that it would under-recover its 1999 gas authorized margin by $30 million. SDG&E's forecast of its under-recovery, and its concerns regarding the 1999 calendar year shortfall were not made on the record as written or oral testimony.

The main purpose of the GFCA is to allow SDG&E to recover its authorized gas margin while balancing out the effect of actual gas sales compared to forecasted sales. The account itself balances primarily gas margin with actual revenues. As shown by Exhibit 16, the account is generally undercollected from the spring through late fall, and then overcollected in the winter through early spring. Not considering the other components of the GFCA, if the account balance is near zero, then SDG&E will have recovered its authorized gas margin through that point in time. The amortization of the GFCA balance also impacts the amount of the balance at any point in time.

It is difficult to determine from the record evidence of this case the exact starting date for the GFCA since the GFCA was not an entirely new account when it was established in May 1988. Our D.87-12-039 ordered that the GFCA be established, partly in accordance with a settlement filed in I.86-06-005. The GFCA balance was a consolidation of previously existing accounts, the Consolidated Adjustment Mechanism (CAM) and the Supply Adjustment Mechanism (SAM). SDG&E has stated in its Reply Brief and in its Comments on the Alternate Decision that the SAM was established in August 1978. In addition, it appears that the types of costs which have been included in the GFCA, and the manner in which the balance has been calculated, has changed over the years.

We generally agree with ORA that it is appropriate for SDG&E to go through a full "cycle", but we are not able to determine from the record exactly what that cycle should be. SDG&E voiced its concerns about a forecasted under-recovery of its authorized revenue requirements not in testimony subject to rebuttal, but after hearings were concluded. Its testimony was that it really does not matter when the account is terminated, that the GFCA may have been a consolidation of other accounts, and that changes to the method of calculation were made in August 1991. Based on the record in this proceeding, we find that the most appropriate resolution of this matter is to simply end the GFCA as the balance next approaches zero. This would allow SDG&E to fully recover its authorized gas margin under the GFCA, while allowing for the impact of actual gas sales compared to forecasted sales. SDG&E should file an advice letter the month before it forecasts the balance will next approach zero, but no later than November 1, 1999. The advice letter should include the termination of the GFCA and an amortization methodology for any remaining balance.

SDG&E explained in its testimony (Exhibit 14, p. 14-5) that the GFCA reflects the recovery of the base cost revenue amounts and other charges related to the transportation and delivery of gas. These "other" charges represent the carrying cost of storage inventory, the recorded transportation charges billed to SDG&E by SoCalGas, and amounts collected for the recovery of franchise fees and uncollectibles. SDG&E proposed that the only GFCA component which should be discontinued is the base cost balancing component, while the "other" costs and revenues should continue to be recorded in a new account. This proposal was unopposed, and we will adopt it.

Using the rate indexing methodology, rates will be determined as follows. The "starting point" for electric distribution and gas rates will be the 1999 authorized rates as determined in the Cost of Service portion of this proceeding in D.98-12-038. In subsequent years, through 2002, electric distribution and gas rates will be determined by multiplying the "update rule" formula, i.e. 1 + inflation - productivity, by the previous year's rates. This formula will be applied to each electric distribution and gas transportation rate and rate component, as described in Exhibit 82, pg. PBR13A-2. Consistent with our policy to use the most recent sales forecast, SDG&E shall file an advice letter after the new sales forecast is adopted in A.98-01-031, SDG&E's Biennial Cost Allocation Proceeding (BCAP) to update the gas sales forecast in the PBR.

We are not adopting SDG&E's proposal for a "permanent" rate adjustment if a revenue sharing adjustment is needed. If a revenue sharing adjustment results from SDG&E's previous year's performance under the PBR, this will be made as a "one-time" adjustment to the rates calculated using the update rule. SDG&E shall file an advice letter by October 1 of each year to implement the rate adjustment.

Productivity

SDG&E proposes productivity factors of 0.92% for electric and 0.68% for gas. SDG&E's proposed productivity factors are based on a study by Christensen Associates. The Christensen study is largely based on companies under traditional regulation. However, one of the chief objectives of PBR regulation is to simulate competition. The premise of incentive regulation is that competitive companies are more efficient and productive.

SDG&E does not propose a stretch factor, asserting that this is no longer appropriate for its proposal. SDG&E appears to implicitly assume that as long as SDG&E performs mildly better than the historical average productivity, 100% of the gain should accrue to shareholders, with no benefit to ratepayers. In the SoCalGas PBR, an additional stretch factor was adopted due to SoCalGas' declining rate base. SDG&E recommends that no productivity adder is necessary to account for declining rate base. We agree that while total rate base is declining due to decreases in generation rate base, SDG&E's rate base in electric distribution and gas department rate base is not declining, and is actually increasing.

Both ORA and UCAN agree to the base historical productivity figures, but propose that stretch factors also be applied.. (See, e.g., Exhibit 24, p. 2-1.) ORA is the only other party that presented testimony specifically on the Christensen study. While ORA recognizes that SDG&E's approach of basing the X factor on industry-wide estimates of TFP growth is consistent with past Commission decisions, ORA also found merit in the NERA study. For the purpose of establishing an appropriate productivity benchmark, we agree with ORA that it is reasonable to consider the Christensen results as the lower bound in the range of productivity, which supports the addition of a productivity stretch factor (Exhibit 24, p. 2-15).

UCAN also argues that SDG&E's proposal for a rate indexing mechanism is inconsistent with the Christensen study's productivity estimates. UCAN notes that the output measures in the study are heavily weighted to the number of customers served. We are not convinced by UCAN's arguments. The productivity estimates are independent of what type of PBR is authorized. The SDG&E productivity estimates are reasonable on their merits.

FEA recommends a total productivity factor similar to that adopted for Edison. This productivity factor was based on Edison's historical productivity factors of 0.9% for nongeneration plus a small stretch factor. In D.96-09-092, we adopted a total productivity factor of 1.2% for 1997, which then increased to 1.4% in 1998, and 1.6% thereafter. The stretch factor averages about 0.5%. We stated a precise forecast of productivity was unnecessary, because the progressive revenue sharing would allow ratepayers to keep more of the achievable productivity gain. We note that the Edison historical factor is quite close to the 0.92% productivity factor which Christensen Associates calculated for SDG&E's

electric department. While SDG&E emphasizes that the Edison productivity factor was adopted because of the absence of an "industry-wide" study, this was only one of several considerations we made in determining the appropriate productivity factor for Edison.

SDG&E asserts that the consumer price index (CPI) adopted for Edison is likely higher than the inflation factor proposed here, so one should not strictly make a direct comparison to Edison's productivity factor. But as the City of San Diego reminds us, the inflation factor will be reviewed again for Edison in its midterm review. Further, we assume that the inflation factor presented by SDG&E, which was unopposed, is reasonably accurate. Therefore, its relation to the Edison inflation factor should not be a consideration in determining the productivity factor.

SDG&E's O&M productivity growth rate under its current PBR was a modified 1.5% and SDG&E easily exceeded its authorized rate of return. Based on evidence from recent years, we do not expect SDG&E's productivity to decrease significantly. We agree with ORA that it is not reasonable to adopt an average productivity target, which would allow SDG&E to rest on its laurels in terms of achieving productivity gains. (ORA reply brief, p. 12.)

SDG&E argues that if consistency with SoCalGas is desired, the implied stretch factor should be no more than 0.7%. SDG&E refers to ORA's testimony in A.97-12-020, Pacific Gas and Electric's (PG&E) general rate case (GRC) proceeding, in which ORA characterizes SDG&E as being at the "efficiency frontier." When taken in context, however, this is a technical term used by the

ORA consultant on productivity benchmarking in the PG&E GRC for efficient utilities.[11] SDG&E also argues that the results of the PBR experiment, which showed returns well into the sharing range, have been taken into account in the cost of service agreement. Further, SDG&E argues that since it has been operating under a PBR for several years, the incentives of a continuing PBR do not present the same opportunity for stretch productivity as there would be when first embarking upon a PBR (as compared to cost of service regulation). On the other hand, we believe that a PBR system provides utilities with continuing incentives to find more and better productivity opportunities.

On the whole, a productivity factor that includes a stretch factor of 0.4% to 0.7% (for an average of 0.55%) is appropriate, reasonably consistent with the productivity factors adopted for SoCalGas, and fair in view of all the evidence. As we stated in D.97-05-054:

> "It is appropriate to 'set the bar high' in the expectation that SoCal will, indeed, stretch to maximize productivity. Were we to set too low a goal, SoCal's benefit could come at the expense of the ratepayers, even allowing for a sharing mechanism. There would be no advantage to adopting such a PBR over traditional ratemaking methodology. Nevertheless, we recognize that productivity improvements are not likely to occur all at once." (D.97-07-054, mimeo. at p. 29.)

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[11] In A.97-12-020, ORA's consultant indicates that transmission and distribution (T&D) utilities are more efficient than a general vertically integrated utility in their T&D operations. As a utility sheds its generation function, and concentrates on its T&D function, it can be expected that the utility would become more efficient in its T&D operations. (ETI testimony by R. Silkman at pp. 32-33.)

It is reasonable to ramp up the stretch factor incrementally over the term of the PBR, which recognizes both that productivity improvement will not occur all at once and that SDG&E's escalation factor is lower than the CPI. We will adopt a stretch factor that increases over the term of the PBR mechanism, resulting in an X factor on the electric side of 1.32% in 2000, 1.47% in 2001, and 1.62% in 2002. On the gas side, we adopt an X factor of 1.08% in 2000, 1.23% in 2001, and 1.38% in 2002.

Earnings Sharing Mechanism

We reject SDG&E's proposed earnings sharing approach. The calibration method could lead to potentially unintended consequences. We reject SDG&E's proposal for several reasons. SDG&E's proposed revenue sharing (or earnings sharing) deadband (100 basis points above and below the authorized ROR) is too wide and the percentage of revenue sharing by ratepayers (a fixed 20% outside the deadband) is too low. There are certain perverse incentives inherent in SDG&E's proposal. SDG&E may have a disincentive beyond a certain point to continue lowering costs if it knows that rates will go down on a permanent basis, since rate reductions will make it more difficult to achieve favorable rates of returns. Even SDG&E concedes that this problem exists and recommends that the Commission allow a lower ratepayer share to avoid this disincentive. (SDG&E's brief, pp. 5-6.)

SDG&E's proposed revenue sharing (or earnings sharing) deadband (100 basis points above and below the authorized ROR) is too wide and the percentage of revenue sharing by ratepayers (a fixed 20% outside the deadband) is too low. The deadband is approximately four times that adopted for Edison (Exhibit 17, p. 8.) or SoCalGas. Gains or losses would have to be relatively large before being shared with customers. (Exhibit 17, p. 9.) As UCAN points out, very little sharing of revenues above the benchmark has occurred under SDG&E's current PBR, due to the 100 basis point deadband and the low percentage of sharing with ratepayers in the first tier. We have made the same finding in Resolution E-3562, issued on December 17, 1998.

The 20% sharing calibration method does not comport with our regulatory goals, because there is not an equitable sharing of benefits. As FEA points out, under the calibration method, decreases in rates one year would have a negative impact on net operating income the following year. This effect could lead to a lowered incentive to continue to reduce costs, which is contrary to a primary goal of PBR regulation.

The 100 basis point deadband is intended to account for the gains and losses associated with routine operations, including sales and throughput fluctuations. (Exhibit 19.) We prefer to implement a narrow deadband and to eliminate the GFCA as discussed above. We adopt a progressive sharing mechanism, similar to the progressive sharing mechanism that is established for SoCalGas. PU Code § 728 imposes a duty upon us to ensure that utility rates are maintained at a level that is just and reasonable. Under incentive regulation, profits and thus rates, must be maintained at reasonable levels. In D.97-07-054 we explained:

> "A sharing mechanism is the ultimate 'safety net' for ratepayers, as it corrects for the possible adoption of a productivity factor that turns out to be overly conservative, understating the productivity increases which the utility is actually able to achieve. With a sharing mechanism, if the utility attains productivity increases that exceed the adopted productivity factors the resultant profits must be shared with the ratepayers rather than going solely to the utility. … If the

> utility is actually able to reap benefits above the level reflected by the adopted productivity factor, it would not be 'just and reasonable' to require ratepayers to be satisfied with only the share of savings based upon attaining the productivity estimate made at the outset of the program." (D.97-07-054, mimeo. at p. 24.)

The progressive sharing mechanism protects ratepayers in the event that the adopted productivity factors are low, provides a mechanism to encourage SDG&E to stretch for higher levels of cost savings and revenues, and provides the proper incentives by allowing shareholders to retain progressively greater amounts of its earnings. The easy cost savings provide relatively small shareholder benefit, and the progressive tiers would provide a strong incentive for the utility to strive for more difficult savings. (Exhibit 32, pp. 37-38.)

Exhibits 100 and 101 compared the revenue sharing proposals under several scenarios, using the parameters established by the SDG&E proposed mechanism, the SoCalGas mechanism, and the Edison mechanism. While complex, these comparisons demonstrate that a mechanism modeled after the PBR mechanism adopted for SoCalGas is superior to both the Edison mechanism and the SDG&E proposal. Ratepayers receive much smaller shares and are exposed to downside risk under the SDG&E proposal, compared to the SoCalGas mechanism, while shareholders stand to gain huge benefits under the SDG&E proposal.

ORA suggests that SDG&E's sharable earnings go to reducing transition costs in order to allow ratepayers to share in the "windfall" associated with certain sales increases. However, the Commission rejected this idea previously. Further, SDG&E expects transition costs to end this year (and ORA's method would adjust for more than just sales windfall). We prefer instead to adjust the sharing mechanism to allow ratepayers to capture more of the earnings that would likely come from exogenous sales increases. We will widen the first sharing band from 25 basis points to 50 basis points, where ratepayers receive a higher percentage of sharing. The resulting sharing mechanism would be as follows:

0 - 25 bp -- deadband: 100% shareholders
25-75 bp – 75% ratepayers/25% shareholders
75-100 bp – 65% ratepayers, 35% shareholders
100-125 bp – 55% ratepayers, 45% shareholders
125-150 bp – 45% ratepayers, 35% shareholders
150-175 bp – 35% ratepayers, 65% shareholders
175-200 bp – 25% ratepayers, 75% shareholders
200-250 bp – 15% ratepayers, 85% shareholders
250-300 bp -- 5% ratepayers, 95% shareholders

Therefore, we adopt a progressive sharing mechanism with a deadband of 25 basis points above the benchmark rate of return. Shareholders shall receive 100% of earnings up to the level of 25 basis points above the benchmark rate of return and an increasing percentage in steps from 25 up to 300 basis points, above which level shareholders will also receive 100% of the earnings. Similar to our approach in SDG&E's prior base rate PBR mechanism, and as acknowledged by parties in the performance indicator settlement, the calculation of rewards and penalties and the earnings sharing mechanism will be based on a full year for 1999.

Like the mechanism adopted for SoCalGas, we will adopt eight bands between 25 basis points above the benchmark rate of return and 300 basis points above the benchmark rate of return. The first band shall be from 25 to 75 basis points above the benchmark. Shareholders shall receive 25% of the marginal revenues in this band and ratepayers shall receive 75% of the marginal revenues. Each of the next five successive bands shall be 25 basis points wide and increase the incremental share allocated to shareholders by 10% and decrease the incremental share allocated to ratepayers by 10%. The sixth band shall fall between 175 and 200 basis points above the benchmark, with shareholders receiving 75% and ratepayers 25%. The seventh band shall be between 200 and 250 basis points above the benchmark, with shareholders receiving 85% and ratepayers 15%. The eighth band shall be between 250 and 300 basis points above the benchmark, with shareholders receiving 95% and ratepayers 5%. These bands result in sharing amounts that change in step functions, rather than in a linear fashion, as was adopted for Edison.

This progressive sharing mechanism creates a "win-win" for both shareholders and ratepayers. For earnings above 300 basis points above the benchmark, there is unlimited upside potential for SDG&E. As we determined in D.97-07-054:

> "Under this system, shareholders may gain up to 68% of the increment up to 300 basis points above the benchmark. However, as shareholder may keep <u>all</u> of the increment above 300 basis points above the benchmark…, it is possible for shareholders to gain significantly more than 68% of the increment. For example, if returns are 400 basis points above the benchmark, shareholders would retain 76% of the increment. This system given an excellent and increasing incentive to shareholders, and is fair to ratepayers who receive both the 'consumer dividend' in the productivity formula and a larger share of early (and presumably easier) productivity gains." (D.97-07-054, mimeo. at p. 40.)

Z-Factor Treatment

We will adopt Z-factor treatment only for those costs successfully meeting the nine criteria previously adopted for Edison and SoCalGas. In D.96-09-092, we determined that unexpected events which meet the following criteria would be recoverable as an adjustment to the annual update rule:

1. The event causing the cost must be exogenous to the utility.
2. The event must occur after implementation of the PBR.
3. The utility cannot control the cost.
4. The costs are not a normal cost of doing business.
5. The event affects the utility disproportionately.
6. The PBR update rule must not implicitly include the cost.
7. The cost must have a major impact on the utility.
8. The cost impact must be measurable.
9. The utility must incur the cost reasonably.

We need not consider reopening the PBR structure in the event that significant changes are made to the responsibility of the utility for providing services or equipment at this time, as UCAN suggests, but we can certainly consider such impacts at the comprehensive review, as discussed below.

When a potential Z-factor event occurs, SDG&E must promptly advise us of its occurrence by advice letter and establish a memorandum account for the event. The notification shall provide all relevant information, including a description, amount involved, timing, and how the event conforms to the nine adopted criteria. We will review all such events in the comprehensive review.

For each event, SDG&E's shareholders will absorb the first $5 million per event of otherwise compensable Z-factor adjustments. This deductible is separately applied to each Z-factor event. The $5 million deductible should be a one-time deductible per Z-factor event, even if the costs associated with the event are incurred in more than one year.

We will adopt both the 150-basis point voluntary offramp and the 300-basis-point mandatory offramp for earnings below the authorized rate of return. This approach will ensure that there is a mechanism to protect both ratepayers and shareholders from significant deviations in anticipated earnings. In addition, this approach provides increasing incentives to SDG&E because it retains 100% of earnings for increments above 300 basis points above the benchmark. Therefore, SDG&E or ORA may file a motion for voluntary suspension if SDG&E reports net operating income that is at least 150 basis points below its authorized rate of return. If SDG&E reports net operating income indicating a return of 300 or more basis points below its authorized rate of return, the PBR mechanism will be automatically suspended, and we will require SDG&E to file an application which will lead to a formal review of the mechanism.

We adopt the exclusions recommended by the cost of service settlement. Pursuant to D.98-12-038, certain costs will not be included in the PBR mechanism, but are subject to other forms of ratemaking. Tree-trimming expenses are not included in the PBR sharing mechanism, but are subject to a one-way balancing account. As described in D.98-12-038, if SDG&E achieves and documents a 50% reduction in tree-trimming expenses from its 1999 budget, SDG&E may request termination of this balancing account treatment. For the duration of the PBR period, revenues and incurred expenses for tree trimming will be excluded from the indexing mechanism and from recorded base rate revenue expenses before SDG&E calculates its actual earned rate of return for revenue sharing purposes.

Costs attributable to senior executive retirement plans or executive bonuses are also excluded from the indexing mechanism and from earnings sharing during the PBR period. The costs for the NGV program will be excluded from the year 2000 update rule because they are recovered under the NGV balancing account, which is expected to be eliminated at the end of 2000. Future costs related to the CEMA and the Gas Hazardous Substance Cost Recovery Account will be recovered through those respective balancing accounts, not through the PBR. The cost of service settlement also provides that there is not ratepayer contribution to pension expenses.

We agree with SDG&E that exclusions should be kept to a minimum. UCAN recommends that the DSM and research, development and demonstration (RD&D) one-way balancing accounts should be excluded from the PBR. SDG&E states that such one-way balancing accounts are subject to a separate ratemaking treatment and therefore should not be included in the PBR calculation. In effect, these accounts are excluded from the PBR. UCAN also argues that payments made if utility employees are transferred to affiliates should be excluded from the PBR. This appears to be settled in the cost of service settlement, which provides that affiliate payments for such purposes are refunded to ratepayers through the PBR as an offset to any reward SDG&E earns or as an adder to any penalty SDG&E pays. The cost of service settlement also provides that SDG&E may recover $10.2 million for generation-related franchise fees. If a different recovery mechanism for such fees is authorized in the future, the amount included in electric generation will be adjusted accordingly.

Direct access implementation costs are being addressed in A.98-05-006. The cost of service settlement provides that if SDG&E is not allowed to recover such costs as § 376 costs, SDG&E will record these costs in a new memorandum account and seek recovery through a separate application. UCAN also argues that known and measurable nonrecurring expenses, such as hazardous waste expenses and Year 2000 computer expenses should be excluded from the PBR. The cost of service settlement addresses both issues. Hazardous waste expenses are referred to the Hazardous Waste collaborative. Year 2000 computer expenses are settled at $1.2 million and are not escalated.

In D.92-12-015, we ordered annual adjustments to Z-factor recovery for PBOP costs for telephone utilities under the New Regulatory Framework (NRF). The cost of service settlement identified $1.43 million in PBOP overcollections to be refunded for the years 1993-1997. ORA recommends that SDG&E submit annual requests for PBOP recovery under the Z factor, rather than including PBOP costs within the PBR mechanism itself. SDG&E contends that PBOP costs, just like any other one-time, discrete event, must adhere to the Z-factor criteria. SDG&E asserts that the cost of service settlement resolves the PBOP overcollection issue. Even if it were still an issue, this overcollection would not qualify because it does not meet the $5 million Z-factor deductible.

No Z-factor treatment was adopted for PBOPs in SoCalGas' PBR mechanism. It appears that Z-factor treatment applies to the change due to accounting differences, which was a transition from cash-basis to accrual accounting, as confirmed in D.97-04-043, mimeo. at p. 23. We will not adopt Z-factor treatment for PBOP recovery.

Monitoring and Evaluation and Comprehensive Review

While SDG&E believes that its current PBR mechanism was effective, ORA, UCAN and other parties strongly disagree with this conclusion. We wish to establish clear objectives related to monitoring and evaluation, building on SDG&E's and UCAN's stipulation. We adopt the reporting requirements proposed by SDG&E and UCAN. By February 15 of each year, SDG&E will file an annual electric distribution report that addresses the performance indicators and earnings sharing results for the previous calendar year. This report will be filed by advice letter with the Commission's Energy Division. Within 45 days after the end of each calendar quarter, SDG&E will submit quarterly reports to the Energy Division and interested parties that address the 12-months-to-date sharing and year-to-date performance indicator results

D.98-12-038 adopted a settlement agreement regarding cost of service issues that included an agreement that the agreed-upon levels of revenues, sales, expenses, and rate base would be in effect for the years 1999 through 2002, subject to any adjustments made by the Commission. We adopt this same time period for the PBR mechanism. We note that SoCalGas' PBR also expires at the end of 2002. SDG&E is required to file a cost of service study for the year 2003 no later than December 21, 2001, which will trigger a cost of service review in 2002.

SDG&E and UCAN believe that a cost of service review in 2002 precludes the necessity for a mid-term review. We agree. However, we wish to proceed with developing thoughtful monitoring and evaluation criteria. D.97-07-054 called for a comprehensive evaluation of SoCalGas' PBR mechanism because of the merger application, among other factors. The merger of Enova Corporation and Pacific Enterprises is complete, but we have not yet fully explored the ramifications of combining these two utilities. In addition, the rate freeze for electric service should be nearing an end by the end of 2001 and competition in generation may become more prevalent. We will assess these issues in the comprehensive review of SDG&E's PBR mechanism so that we might better understand the effect of incentives in the changing regulatory environment. In addition, D.96-11-021 requires that the utilities develop performance indicators related to maintenance, repair, and replacement of major electric distribution facilities. In the Performance Indicator Settlement agreement, parties have agreed that SDG&E will gather data for the purposes of developing an electric system maintenance performance indicator. The comprehensive review provides an appropriate forum for SDG&E to present the data collected and to begin the process of discussing appropriate performance indicators related to maintenance, repair, and replacement.

SDG&E and UCAN agree that the PBR mechanism performance over the 1999-2001 time frame should be timely reviewed so that this analysis can be factored into the 2002 cost of service proceeding. We will adopt this recommendation, but will accelerate the process. In order to adhere to the requirements imposed on the Commission by Senate Bill 960, SDG&E shall file an application to develop evaluation criteria for the formal comprehensive review by June 30,2000. The evaluation process shall begin in mid-2000 with workshops facilitated by the Energy Division. The goals of this workshop are to develop appropriate evaluative criteria that can be expressed in measurable terms for the comprehensive review. This workshop should result in a workshop report to be filed with the Commission by year-end 2000. This approach will allow the Commission time to assess and adopt the recommended criteria for evaluating SDG&E's PBR mechanism.

We prefer that the Energy Division conduct the comprehensive review of the PBR mechanism. If a consultant is hired to conduct an independent evaluation, the Energy Division must be in charge of the RFP and the selection process, and it must administer the contract. We often order the utilities to pay for such reviews (see, e.g., D.96-09-032) with these costs later recovered from ratepayers. It is reasonable that the cost of an independent consultant be capped at $400,000 and shared equally between the ratepayers and shareholders, as SDG&E and UCAN suggest. SDG&E will be able to submit its own evaluative report at the same time other parties or the independent consultant submit their reports.

We agree with the goals and objectives articulated by SDG&E and UCAN, and will look to the workshops to further define these goals. Monitoring and evaluative criteria must be developed so that each goal and objective can be measured. Only then will we have a true picture of the effectiveness of incentive regulation. Therefore, evaluation of the distribution PBR mechanism should be based on considering whether the adopted mechanism achieves the following goals:

* Improve SDG&E's efficiency and performance;
* Provide adequate incentives and remove disincentives to reduce costs and operate efficiently;
* Demonstrate simplified and streamlined regulatory oversight for the Commission and SDG&E;
* Provide a stable and predictable regulatory environment;
* Provide a reasonable opportunity for the utility to earn a fair rate of return;
* Allow management to focus primarily on costs and markets rather than on regulatory proceedings;

* Align interests of shareholders and customers;
* Maintain and improve quality of service; and
* Achieve other regulatory goals.

In order to evaluate whether these goals have been achieved, these parties recommend that the following questions be asked and examined. We ask the Energy Division to explore these questions in workshops and to work with parties to develop measurable forms to answer these questions:

Is SDG&E reducing costs and operating efficiently?

Are risks and rewards fairly balanced for SDG&E?

Are the interests of shareholders and customers aligned?

Is quality of service and employee safety maintained or improved by specific performance indicators?

Are competitive services included in the PBR? What are the links between cost-of-service, competitive services, and monopoly services?

Is the PBR effective given the rate freeze and its later termination?

How should we evaluate the structure of the PBR mechanism and its applicability as the market structure changes?

Does the PBR mechanism remain appropriate for the monopoly utility given that competitive markets exist to provide the same services that are targeted?

Does the PBR mechanism result in utility actions that are inconsistent with the PBR goals? How can such unintended consequences be addressed?

What reporting requirements would improve future evaluation efforts?

Are there other goals that should be considered in assessing PBR performance?

No later than December 21, 2001, SDG&E shall file an application with its cost of service study for 2003. This application will trigger the formal comprehensive review of the distribution PBR mechanism. SDG&E should consider the goals and evaluative criteria established at Energy Division workshops in filing this application, as well as the criteria delineated in D.97-07-054. In this way we can ensure that SDG&E's distribution PBR mechanism is meeting our intended goals and furthering our regulatory policy.

Comments on Alternate Decision

Comments on the Alternate Decision were filed by SDG&E, UCAN, NRDC, and ORA. Based on SDG&E's comments, we have adjusted the ramp up of the stretch factor to apply over three years instead of four because the update rule only applies in years 2000, 2001, and 2002. We have also revised the termination date of the GFCA and incorporated other minor clarifications and corrections throughout the order.

Findings of Fact

1. We have long considered incentive-based ratemaking superior to command-and-control regulation and have established several goals to be addressed by incentive regulation for energy utilities.

2. Performance-based regulation can provide stronger incentives for efficient utility operations and investment, lower rates, and result in more reasonable, competitive prices for California's consumers.

3. Performance-based regulation can simplify regulation and reduce administrative burdens in the long term, without sacrificing service, safety, and reliability.

4. Incentive regulation can prepare utilities to operate effectively in the increasingly competitive energy utility industry.

5. Incentive regulation should provide a reasonable balancing of risks and rewards, with an equitable sharing of the benefits that reform is intended to achieve.

6. The adopted regulatory program should maintain or improve quality of service, reliability, safety, and customer satisfaction despite expected cost reductions, and should avoid or minimize unintended consequences in interplay among various regulatory programs.

7. SDG&E has been operating under a base rate PBR mechanism since 1994.

8. As approved in D.98-03-073, SoCalGas and SDG&E are now operating entities within the holding company of Sempra Energy, Inc.

9. Once a starting point is selected, PBR mechanisms adjust revenue requirements or rates annually to account for inflation and productivity.

10. Adopting an effective PBR mechanism requires a balance between providing appropriate incentives to utilities with adhering to our stated goals of providing an equitable sharing of the benefits.

11. Performance indicators are designed to ensure that the utility's service quality, customer service, reliability, and safety do not deteriorate under PBR regulation.

12. Under its base rate PBR mechanism, SDG&E earned approximately $136 million in after-tax dollars from its earnings sharing mechanism during the period 1994 through 1997.

13. Ratepayers' share of earnings is expected to total approximately $11.2 million during the period 1994 through 1997.

14. SDG&E, ORA, UCAN, FEA, CCUE, the City of San Diego, Farm Bureau, and NRDC filed a joint motion seeking Commission approval of a settlement resolving performance indicators addressing safety, reliability, customer satisfaction, and call center responsiveness, as well as certain customer service guarantees cost of service issues in this proceeding.

15. There is no known opposition to approving the settlement, and no need to hold a hearing on these issues.

16. The settlement satisfies the Commission criteria for an all-party settlement, as set forth in our Rules of Practice and Procedure and D.92-12-019.

17. No party disputes SDG&E's proposed escalation measure, which is based on historical and forecasted industry-specific data, published quarterly. Separate escalation factors are used for electric and gas. Each index is designed to measure changes in price levels of labor, nonlabor and capital inputs purchased by California utilities.

18. Cost of capital will continue to be addressed in cost of capital proceedings and through the MICAM mechanism.

19. Adopting a PBR mechanism modeled after that adopted for SoCalGas in D.97-07-054 and Edison in D.96-09-092 allows both the shareholders and the customers to benefit.

20. The revenue requirement used as the starting point for SDG&E's PBR mechanism is $563.4 million for electric distribution and $201.5 million for gas base rate revenues, as approved in D.98-12-038.

21. The term of the adopted PBR should be 1999 through 2002, with provisions for a comprehensive review.

22. SDG&E must file a 2003 cost of service study no later than December 21, 2001.

23. UCAN's proposal to implement separate PBR mechanisms for electric wires, electric metering and billing, gas pipes, and gas metering and billing is premature.

24. NRDC's proposal to establish a performance indicator for distributed generation is premature.

25. Under a rate indexing approach, SDG&E would have a direct interest in increasing electricity usage and gas throughput since its base rate revenues would increase with increases in usage.

26. The revenue-per-customer approach would increase revenue requirements as the number of customers increases but does not allow additional revenue recovery due to sales increases.

27. Adopting the rate indexing formula is simpler, more relevant to SDG&E's circumstances, and more compatible with an emerging competitive market.

28. It is reasonable to eliminate the GFCA with a rate indexing methodology. GFCA components other than base cost balancing component should continue to be recorded in a new account.

29. It is reasonable to terminate the GFCA when balance next approaches zero.

30. An adjustment to the sharing mechanism can counteract the potential windfall effect of sales increases which are likely to occur without effort on SDG&E's part. Environmental concerns arising from an incentive to increase sales are mitigated by other state policies, including targeted energy efficiency and renewable energy programs.

31. A Total Factor Productivity (TFP) index measures the ratio of its output quantity index to its input quantity index and compares the growth trend in the unit cost of the industry to the trend in prices of labor, capital services, and other production inputs.

32. SDG&E asserts that no stretch factor is necessary, despite the fact that its proposed productivity factors are less than those adopted for other energy utilities.

33. The premise of incentive regulation is that competitive companies are more efficient and productive.

34. It is important to apply a stretch factor to the productivity factor to ensure that the utility to which it is applied is "stretching" to achieve efficiency gains.

35. Edison's historical productivity factor of 0.9% is close to the productivity factor of 0.92% calculated by Christensen Associates for SDG&E.

36. SDG&E's O&M productivity growth under its current PBR mechanism was a modified 1.5% and SDG&E easily exceeded its authorized rate of return.

37. It is reasonable to ramp up the stretch factor incrementally over the term of the PBR, which recognizes both that productivity improvements will not occur all at once and that SDG&E's escalation factor is lower than the CPI.

38. Certain perverse incentives are inherent in SDG&E's rate calibration proposal, because SDG&E may have a disincentive to continue lower costs,

knowing that rates will decrease on a permanent basis, since rate reductions will make it more difficult to achieve a favorable rate of return.

39. SDG&E's proposed deadband is approximately four times that adopted for Edison or SoCalGas; therefore, gains or losses would have to be relatively large before being shared with customers.

40. Relatively few of SDG&E's earnings have been shared with ratepayers under SDG&E's current PBR mechanism, due to the 100 basis point deadband and the low 25% sharing with ratepayers in the first tier.

41. Under the calibration method, decreases in rates one year would have a negative impact on net operating income the following year, which could lead to a lowered incentive to continue to reduce costs, contrary to a primary goal of PBR regulation.

42. The 20% sharing calibration method and 100 basis point deadband does not comport with our regulatory goals, because there is not an equitable sharing of benefits.

43. SDG&E's proposed 100 basis point deadband is intended to account for gains and losses associated with routine operations, including sales and throughput fluctuations.

44. SDG&E acknowledges that its proposed deadband is wider than than adopted for either Edison or SoCalGas.

45. The progressive sharing mechanism creates a "win-win" for both shareholders and ratepayers, because SDG&E has unlimited upside potential to retain earnings above 300 basis points above the benchmark.

46. A progressive sharing mechanism protects ratepayers because it corrects for the potential of adopting a productivity factor that turns out to be too low and allows equitable sharing of benefits of SDG&E's cost reduction efforts.

47. A progressive sharing mechanism provides the proper incentives by allowing shareholders to retain progressively greater amounts of its earnings as higher rates of return are achieved.

48. The cost of service settlement identified $1.43 million in PBOP overcollections to be refunded for the years 1993-1997.

49. The GFCA should be eliminated to eliminate balancing account treatment for sales volatility.

50. Adopting a 150-basis point voluntary offramp and a 300-basis point mandatory offramp for earnings below the authorized rate of return ensures that there is a mechanism to protect ratepayers and shareholders from significant deviations in earnings.

51. The adopted PBR mechanism provides increasing incentives to SDG&E, because SDG&E retains 100% of earnings for increments above 300 basis points above the benchmark.

52. Monitoring and evaluation are particularly important in determining whether a PBR mechanism is effective, i.e., is providing the desired incentives and results.

53. Monitoring and evaluative criteria must be developed so that each goal and objective can be measured.

54. The comprehensive review provides an appropriate forum for SDG&E to present the data collected regarding maintenance, repair, and replacement of major electric distribution facilities.

55. The Energy Division should conduct the comprehensive review of the PBR mechanism.

Conclusions of Law

1. In R.94-04-031 and I.94-04-032, we stated our intention to replace cost-of-service regulation with performance-based regulation and directed the utilities to file applications requesting distribution PBR mechanisms.

2. The performance indicator settlement is an "uncontested settlement" as defined in Rule 51(f).

3. The performance indicator settlement is reasonable in light of the whole record, consistent with law, and in the public interest, and should be approved.

4. Adopting SDG&E's proposed distribution PBR mechanism will not serve the public interest nor achieve our broadly stated goals related to PBR regulation.

5. It is reasonable and prudent to base SDG&E's distribution PBR mechanism on the PBR adopted for SoCalGas in D.97-07-054 and the PBR adopted for Edison in D.96-09-092.

6. It is reasonable to adopt SDG&E's proposed escalation methodology, which no party disputed.

7. It is reasonable to review the issue of distinguishing between monopoly and competitive services, and possible cross-subsidies, during the comprehensive review and to develop monitoring and evaluation criteria to track such possibilities.

8. Performance indicators related to distributed generation should be established after we develop a particular approach for distributed generation in R.98-12-013.

9. Adopting a rate index approach may lead to a windfall for SDG&E due to projected sales increase unrelated to management efforts, and there should be an adjustment to the sharing mechanism to account for this.

10. It is reasonable to adopt the base historical productivity figures proposed by SDG&E as a starting point in determining productivity factors.

11. Adopting a productivity factor that includes a stretch factor of 0.4% ramping up to 0.7% is appropriate, reasonably consistent with the productivity factors adopted for SoCalGas and Edison, and provides incentive to SDG&E to stretch beyond average productivity gains.

12. It is reasonable to eliminate the base cost balancing component of the GFCA when the balance next approaches zero. The SDG&E proposal for a new account to record costs and revenues associated with the carrying costs of storage inventory, the recorded transportation charges billed to SDG&E by SoCalGas, and amounts collected for the recovery of franchise fees and uncollectibles was unopposed, is reasonable, and should be adopted.

13. SDG&E should file an advice letter the month before it forecasts the GFCA balance will next approach zero, but no later than November 1, 1999.

14. PU Code § 728 imposes a duty upon us to ensure that utility rates are maintained at a level that is just and reasonable; therefore, under incentive regulation, profits and thus rates must be maintained at reasonable levels.

15. Consistent with our regulatory goals, adopting an aggressive productivity factor and a progressive sharing mechanism ensures that ratepayers will be at least as well off under the PBR as under traditional ratemaking.

16. Z-factor treatment should be applied only to those costs successfully meeting the nine criteria previously adopted in D.96-09-092 and D.97-07-054:

a) The event causing the cost must be exogenous to the utility.

b) The event must occur after implementation of the PBR.

c) The utility cannot control the cost.

d) The costs are not a normal cost of doing business.

e) The event affects the utility disproportionately.

f) The PBR update rule must not implicitly include the cost.

g) The cost must have a major impact on the utility.

h) The cost impact must be measurable.

i) The utility must incur the cost reasonably.

17. It is reasonable to adopt the exclusions recommended by the cost of service settlement approved in D.98-12-038.

18. No Z-factor treatment was adopted for PBOPs in SoCalGas' PBR mechanism and PBOP recovery does not conform to the Z-factor criteria adopted in this decision.

19. It is reasonable to adopt the reporting requirements proposed by SDG&E and UCAN.

20. The term of the PBR mechanism should be 1999 through 2002, consistent with the cost of service settlement adopted in D.98-12-038.

21. Because of the changing regulatory environment, it is reasonable to develop rigorous evaluative criteria, so that we will better understand the effect of incentives.

22. Should Energy Division determine that it is necessary to hire an independent consultant, it is reasonable that the cost be capped at $400,000 and that ratepayers and shareholder share the cost equally.

23. This order should be effective today, so that SDG&E's distribution PBR mechanism can be implemented on a timely basis.

24. This proceeding should be closed.

O R D E R

IT IS ORDERED that:

1. The Joint Motion for Adoption of Settlement Agreement on PBR Performance Indicators in the San Diego Gas & Electric Company (SDG&E) Application (A.) 98-01-014 is granted.

2. The Settlement Agreement is attached to this decision as Appendix B and is adopted as reasonable in light of the whole record, consistent with the law, and in the public interest.

3. SDG&E shall use a rate indexing methodology for its PBR. The "starting point" for electric distribution and gas rates will be the 1999 authorized rates as determined in the Cost of Service portion of this proceeding in D.98-12-038. In subsequent years, through 2002, electric distribution and gas rates will be determined by multiplying the "update rule" formula, i.e. 1 + inflation - productivity, by the previous year's rates. This formula will be applied to each electric distribution and gas transportation rate and rate component, as described in Exhibit 82, pg. PBR13A-2. Adjustments, due to such factors as revenue sharing, or PBR performance rewards or penalties, will be made as one-time adjustments. SDG&E shall file an advice letter by October 1 of each year to implement the rate adjustment. SDG&E shall file an advice letter to terminate the GFCA when the balance next approaches zero. The advice letter should be filed

the month before SDG&E forecasts a zero balance, but no later than November 1, 1999.

4. SDG&E shall implement a distribution performance-based ratemaking (PBR) mechanism using the revenue requirements adopted in Decision (D.) 98-12-038 as a starting point. The PBR shall use a rate indexing approach, the adopted escalation methodology (Attachment 1), and a progressive earnings sharing mechanism as described in this decision. SDG&E shall apply a stretch factor that increases over the term of the PBR mechanism, resulting in an X factor on the electric side of 1.32% in 2000, 1.47% in 2001, and 1.62% in 2002. On the gas side, SDG&E shall apply an X factor of 1.08% in 2000, 1.23% in 2001, and 1.38% in 2002.

5. SDG&E shall construct the progressive sharing mechanism with a deadband of 25 basis points above the benchmark rate of return. Shareholders shall receive 100% of earnings up to the level of 25 basis points above the benchmark rate of return and an increasing percentage in steps from 25 to 300 basis points, above which level shareholders will also receive 100% of the earnings.

6. SDG&E shall construct the progressive sharing mechanism with eight bands between 25 basis points above the benchmark rate of return and 300 basis points above the benchmark rate of return. The first band shall be from 25 to 75 basis points above the benchmark. Shareholders shall receive 25% of the marginal revenues in this band and ratepayers shall receive 75% of the marginal revenues. Each of the next five successive band shall increase the incremental share allocated to shareholders by 10% and decrease the incremental share allocated to ratepayers by 10%. The sixth band shall fall between 175 and 200

basis points above the benchmark, with shareholders receiving 75% and ratepayers 25%. The seventh band shall be between 200 and 250 basis points above the benchmark, with shareholders receiving 85% and ratepayers 15%. The eighth band shall be between 250 and 300 basis points above the benchmark, with shareholders receiving 95% and ratepayers 5%.

7. When a potential Z-factor event occurs, SDG&E shall promptly advise us of its occurrence by advice letter and shall establish a memorandum account for the event. The notification shall provide all relevant information, including a description, amount involved, timing, and how the event conforms to the nine adopted criteria. All such events shall be reviewed in the comprehensive review. For each event, SDG&E's shareholders shall absorb the first $5 million per event of otherwise compensable Z-factor adjustments. This deductible shall be separately applied to each Z-factor event. The deductible shall be a one-time deductible per Z-factor event, even if the costs associated with the event are incurred in more than one year.

8. SDG&E or ORA may file a motion for voluntary suspension if SDG&E reports net operating income that is at least 150 basis points below its authorized rate of return. If SDG&E reports net operating income indicating a return of 300 or more basis points below its authorized rate of return, the PBR mechanism shall be automatically suspended and SDG&E shall file an application which will lead to a formal review of the mechanism.

9. For the duration of the PBR period, the following items, which are included in 1999 authorized revenues, shall be excluded from the indexing mechanism before SDG&E calculates its annual escalation of revenue requirements:

a. Tree-trimming authorized revenues, as described in the settlement adopted in D.98-12-038.

b. Costs associated with the Natural Gas Vehicle (NGV) program, which shall be excluded for the year 2000 update rule only. Beginning in 2001, NGV costs shall be included in the PBR indexing mechanism.

c. Costs associated with gas research, development and demonstration (RD&D), as these are subject to a one-way balancing accounts.

d. Fixed A&G Costs that SDG&E may be able to recover through contracts under which it will provide O&M services to its divested fossil fuel plants, as adopted in D.98-12-038. If SDG&E is able to recover any of these costs through a maintenance contract, it will make a corresponding downward adjustment to the authorized revenue requirement.

e. Year 2000 computer expenses at $1.2 million per year.

f. Rewards for Demand Side Management (DSM) programs.

10. For the duration of the PBR period, the following items shall be excluded from recorded PBR base rate revenues and/or expenses before SDG&E calculates its actual earned rate of return for <u>revenue sharing purposes</u>:

a. Tree-trimming revenues and incurred expenses, as described in the settlement adopted in D.98-12-038.

b. Costs attributable to senior executive retirement plans and executive bonuses.

c. Costs associated with the NGV program for 1999 and 2000. Beginning in 2001, these costs should be included as PBR expense for revenue sharing purposes.

d. Costs associated with gas RD&D, as this is subject to a one-way balancing account.

e. Any under run of the fixed A&G costs associated with the maintenance contract for divested power plants pursuant to the adopted settlement in D.98-12-038.

f. Hazardous waste costs, which are recovered through the Hazardous Waste Collaborative.

g. Future costs related to the Catastrophic Event Memorandum Account and the Gas Hazardous Substance Cost Recovery Account, which are recovered through those respective balancing accounts.

h. DSM and PBR rewards.

11. By February 15 of each year, SDG&E shall file an annual electric distribution report that addresses the performance indicators and earnings sharing results for the previous calendar year. This report shall be filed by advice letter with the Energy Division. Within 45 days after the end of each calendar quarter, SDG&E shall submit quarterly reports to the Energy Division and interested parties that address the 12-month-to-date sharing and year-to-date performance indicator results.

12. SDG&E shall file an application to develop evaluation criteria for the comprehensive review by June 30, 2000. The evaluation process shall begin in mid-1999 with workshops facilitated by the Energy Division. The Energy Division shall file and serve a workshop report by year-end 2000.

13. If a consultant is hired to conduct an independent evaluation, the Energy Division shall develop and issue the Request for Proposal (RFP), administer the selection process, and administer the contract. The cost of an independent consultant shall be shared equally between the ratepayers and shareholders.

SDG&E and interested parties may submit evaluative reports at the same time other parties or the independent consultant submit their reports.

14. The Energy Division shall work with other parties to develop measurable evaluation criteria based on the following goals outlined in this decision:

* Improve SDG&E's efficiency and performance;
* Provide adequate incentives and remove disincentives to reduce costs and operate efficiently;
* Demonstrate simplified and streamlined regulatory oversight for the Commission and SDG&E;
* Provide a stable and predictable regulatory environment;
* Provide a reasonable opportunity for the utility to earn a fair rate of return;
* Allow management to focus primarily on costs and markets rather than on regulatory proceedings;
* Align interests of shareholders and customers;
* Maintain and improve quality of service; and
* Achieve other regulatory goals.

15. SDG&E is authorized to implement the distribution performance-based ratemaking mechanism described in this decision. SDG&E shall file a compliance advice letter implementing all required tariff changes necessitated by this decision within 10 days of the effective date of this decision. SDG&E shall include in its advice letter which implements this decision the establishment of a new account to record costs and revenues for the carrying cost of storage inventory, the recorded transportation charges billed to SDG&E by SoCalGas, and amounts collected for the recovery of franchise fees and uncollectibles.

16. SDG&E shall file an advice letter after the new sales forecast is adopted in A.98-01-031 to update the gas sales forecast in the PBR.

17. SDG&E shall file an application with a comprehensive cost of service study for the year 2003 no later than December 21, 2001, which will trigger a cost of service review in 2002.

18. Application 98-01-014 is closed.

This order is effective today.

Dated May 13, 1999, at San Francisco, California.

RICHARD A. BILAS
President
JOSIAH L. NEEPER
Commissioner

I will file a dissent.

/s/ HENRY M. DUQUE
Commissioner

TABLE OF CONTENTS

(See Formal Files for Appendices A and B.)

ATTACHMENT 1
Page 1

ESCALATION

SDG&E's escalation measure is based on historical and forecasted industry-specific data. Separate escalation factors are used for electric and gas. These escalation factors are designed to measure changes in price levels of labor, non-labor and capital inputs purchased by California utilities.

The escalation factors are developed using national-level utility-specific cost indices obtained from the Standard & Poor's DRI/McGraw-Hill Economic and Utility Cost Forecasting Services (DRI). The component national level utility cost indices are combined into electric distribution and gas escalation factors using expenditure weights developed from historical expenditures by electric and gas utilities located in California. The electric utilities are SDG&E, Southern California Edison, and Pacific Gas and Electric Company (PG&E). The gas utilities are SDG&E, Southern California Gas Company, and PG&E.

Labor O&M Cost Index

Average hourly earnings for electric, gas, and sanitary services are used as the basis for the labor cost index for both electric distribution and gas. Referred to as AHE49NS by DRI, historical data for this data series is reported by the United States Bureau of Labor Statistics (BLS). This data is used as the basis for the DRI labor cost index, and forecasts of AHE49NS are available from DRI.

ATTACHMENT 1
Page 2

Non-Labor O&M Cost Indices

Separate non-labor cost indices are developed for electric distribution and gas. The index for electric distribution non-labor O&M expenses utilizes five DRI cost indices: total distribution plant O&M cost index (JEDOMMS), customer accounts operation cost index (JECAOMS), customer service and information operation cost index (JECSIIOMS), sales operation cost index (JESALOMS), and total administrative and general O&M cost index (JEADGOMMS).

The index for gas non-labor O&M expenses is the DRI total gas utility non labor O&M cost index (JGTOTALMS).

Capital-Related Cost Indices

The cost index for capital related electric distribution costs is based on an estimate of the rental price of electric distribution utility structures, which is estimated from three data series obtained from DRI: rental price of capital - nonresidential structures-public utilities (ICNRCOSTPU); chain type price index - investment in nonresidential structures - public utilities (PCWICNRPU), and the Handy-Whitman electric utility construction cost index -total distribution plant, Pacific Region (JUEPD@PCF). All of these indices are obtained from DRI. The rental price of capital for electric distribution utility structures (ICNRCOSTPUED) is calculated as follows:

ICNRCOSTPUED = ICNRCOSTPU*(JUEPD@PCF/PCWICNRPU)

The cost index for capital related gas costs is based on an estimate of the rental price of gas utility structures, which is estimated from three data series obtained from DRI: rental price of capital - nonresidential structures-public utilities (ICNRCOSTPU); chain type price index - investment in nonresidential structures - public utilities (PCWICNRPU), and the Handy-

ATTACHMENT 1
Page 3

Whitman gas utility construction cost index -total plant, Pacific Region (JUG@PCF). The rental price of gas utility structures (ICNRCOSTPUG) is calculated as follows:

ICNRCOSTPUG = ICNRCOSTPU*(JUG@PCF/PCWICNRPU)

A three-year moving average of the rental price of utility structures is used to calculate the capital -related cost indices.

Weighting Factors

The escalation factors for electric distribution and gas are each a weighted average of the component cost indices for labor, non-labor, and capital-related expenses. The weights used to construct the weighted average are based on average state-level electric distribution expenditures or gas utility expenditures expressed in real 1996 dollars for the period 1992 - 1996. These weights are shown below:

California State-Level Weights

	Electric	Gas
Labor	0.179216	0.234234
Non-Labor		0.312008
Distribution	0.062799	
Customer Accounts	0.028032	
Customer Service	0.043102	
Sales	0.001225	
Admin. & General	0.109725	
Capital	0.575900	0.453757
Total	1.000000	1.000000

ATTACHMENT 1
Page 4

Annual Escalation Calculation

Starting in the year 2000, the percentage changes in the weighted cost indices will be used in the PBR indexing formulae to adjust the electric distribution and gas base rates for changes in the cost of inputs purchased by the utility. In mid-August 1999, one-year ahead projections of the cost indexes and the percentage changes in these indexes will be estimated. These estimates will be based on the most recent historical and forecast data available from Standard and Poor's DRI/McGraw-Hill Economic and Utility Cost Information Services. In mid-August of every year starting in the year 2000, historical and forecast cost indexes and percentage changes in these indexes will be estimated from the most recent historical and forecast data available from DRI. The historical and forecast percentage changes will be used in the rates indexing formulae to obtain rates for the next year. Both forecast and historical percent changes back to 1999 are required to true-up rates to the most recent and accurate cost escalation estimates available after 1999. The updated historical and forecast percentage changes should capture all revisions in the DRI data used to compute the cost indexes.

(END OF ATTACHMENT 1)

ATTACHMENT 2

EARNINGS SHARING MECHANISM

The earnings sharing mechanism we adopt in this decision is illustrated below:

Shareholder and Ratepayer Percentage Share of Revenues Associated with Rate of Return (ROR) Above Authorized

Shareholders %	Ratepayers %	Basis Points Above Authorized ROR
100	0	Above 300
95	5	250 to 300
85	15	200 to 250
75	25	175 to 200
65	35	150 to 175
55	45	125 to 150
45	55	100 to 125
35	65	75 to 100
25	75	25 to 75
100	0	0 to 25
100	0	ROR below authorized*

*If SDG&E reports an ROR which is 150 basis points or greater below the authorized ROR, SDG&E or ORA may file for voluntary suspension of the PBR mechanism. If SDG&E reports an ROR which is 300 basis points or more below its authorized ROR, the PBR mechanism will be automatically suspended, and SDG&E will be required to file an application which will lead to a formal review of the mechanism.

(END OF ATTACHMENT 2)